them. A French military officer noted in 1750 that Indians living near Fort Duquesne (now the site of Pittsburgh) set fire to an oil-slicked creek as part of a religious ceremony. As settlement by Europeans proceeded, oil was discovered in many places in northwestern Pennsylvania and western New York—to the frequent dismay of the well-owners, who were drilling for salt brine.

In the mid-1800s expanding uses for oil extracted from coal and shale began to hint at the value of rock oil and encouraged the search for readily accessible supplies. This impetus launched the modern petroleum age, which began on a Sunday afternoon in August 1859 at Oil Creek, near Titusville in northwestern Pennsylvania. The credit has traditionally gone to "Colonel" Edwin L. Drake, a railroad conductor on sick leave employed by the Pennsylvania Rock Oil Company. After months of effort and many setbacks, Drake's homemade drilling rig drove down to 70 feet, and the bit came up coated with oil. Ironically, Drake wasn't there that day to witness the historic event. And except for the slow and uncertain mails of the time, which delayed a letter from his financial backers ordering him to cease operations, it might not have happened in Oil Creek at all.

"Great excitement ensued" following Drake's discovery, according to the account in the 1883 edition of *Mineral Resources of the United States*. The succeeding oil boom was driven by strong demand for lighting fuel and lubricants. Over the next four decades the boom spread to Texas and California in the United States and to Romania, Baku (in Azerbaijan), Sumatra, Mexico, Trinidad, Iran, and Venezuela. Overproduction temporarily drove prices down, but the rapid adoption and spread of internal combustion engines in the late 19th century helped create vast new markets. With only temporary interruptions, world petroleum consumption has expanded ever since.

Until the 1950s the United States produced nearly all the petroleum it needed. But by the end of the decade the gap between production and consumption began to widen and imported petroleum became a major component of the U.S. petroleum supply (Figure 11). After 1992, imports exceeded production.

Production of petroleum (crude oil and natural gas plant liquids) in the U.S. lower 48 States reached its highest level in 1970 at 9.4 million barrels per day (Figure 12). A surge in Alaskan oil output at Prudhoe Bay beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska's production peaked in 1988 at 2.0 million barrels per day and fell to 1.0 million barrels per day in 1999. By then U.S. total output had dropped to 7.8 million barrels per day, 31 percent below its peak.

Figure 11. Petroleum Production and Consumption

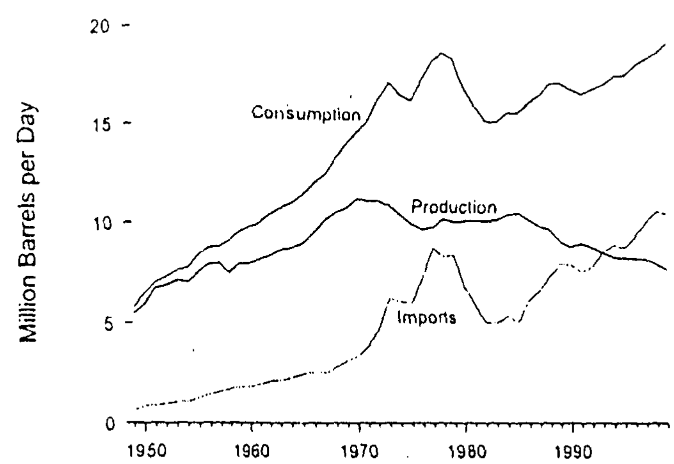
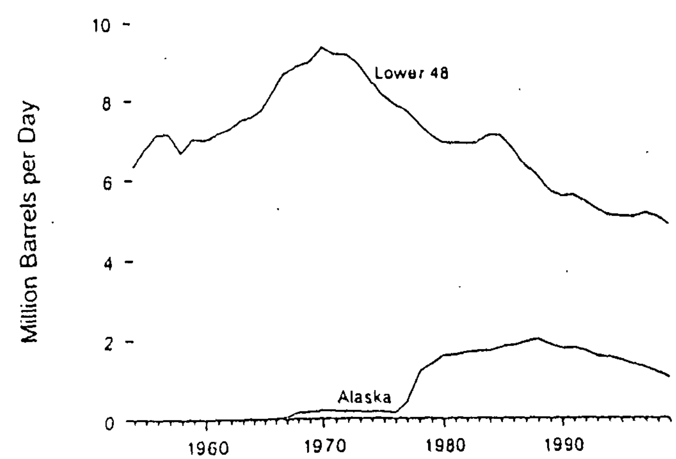


Figure 12. Lower 48 and Alaskan Crude Oil Production



8975

8976

Another index of the Nation's petroleum output is oil well productivity, which fell from a high of 18.4 barrels per day per well in 1972 to 10.7 barrels per day per well in 1999 (Figure 13).

U.S. petroleum consumption rose annually until 1973, when the Arab OPEC embargo stalled the annual increases for two years. The increases then resumed, raising consumption to 18.8 million barrels per day in 1978, before rising prices drove it down to a post-embargo low of 15.2 million barrels per day in 1983. Consumption began to rebound the following year and was boosted by plummeting crude oil prices in 1986. By 1999 it had reached 19.4 million barrels per day, an all-time high.

Of every 10 barrels of petroleum consumed in the United States in 1999, more than 4 barrels were consumed in the form of motor gasoline. The transportation sector alone accounted for two-thirds of all petroleum used in the United States in 1999 (Figure 14).

To meet demand, crude oil and petroleum products were imported at the rate of 10.5 million barrels per day in 1999, while exports measured 0.9 million barrels per day. Between 1985 (when net imports fell to a post-embargo low) and 1999, net imports of crude oil and petroleum products more than doubled from 4.3 million barrels per day to 9.6 million barrels per day. The share of U.S. net imports that came from OPEC nations reached 72 percent in 1977, subsided to 42 percent in 1985, and climbed back to 50 percent in 1999. Total net imports as a share of petroleum consumption reached a record high of 52 percent in

Figure 13. Oil Well Productivity

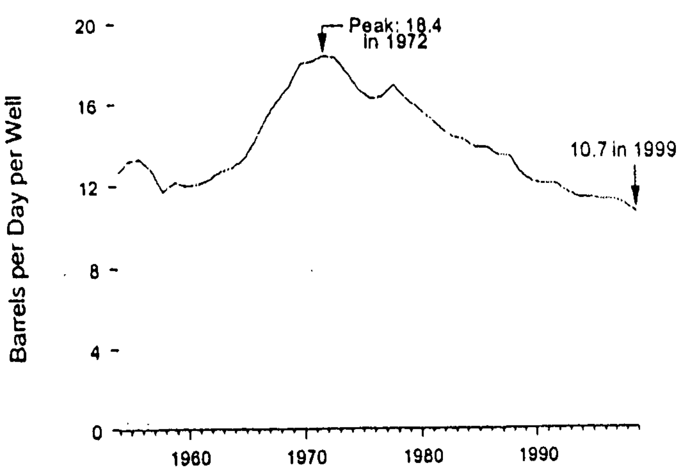


Figure 14. Petroleum Consumption by Sector

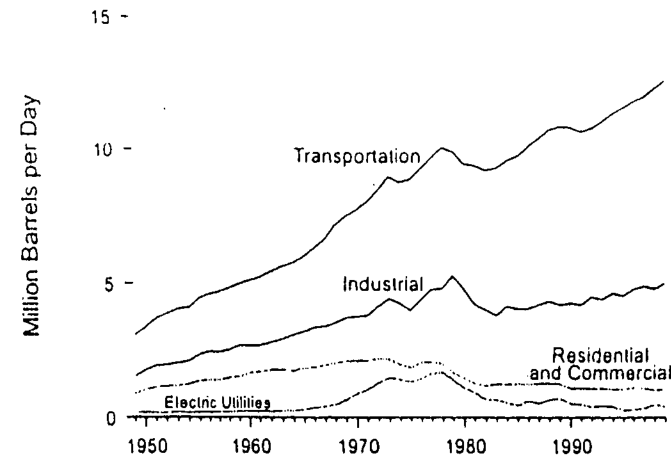
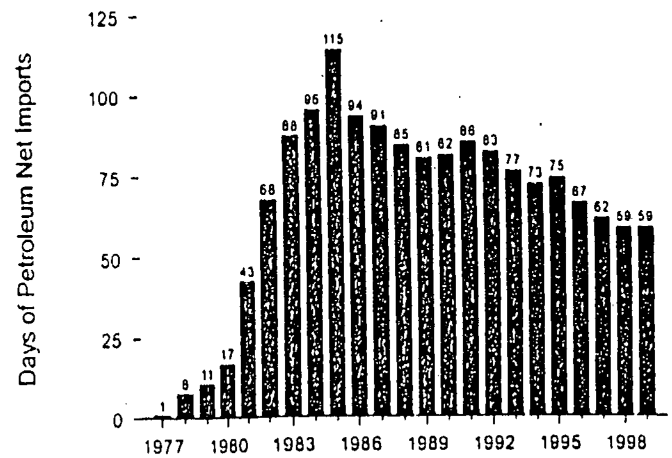
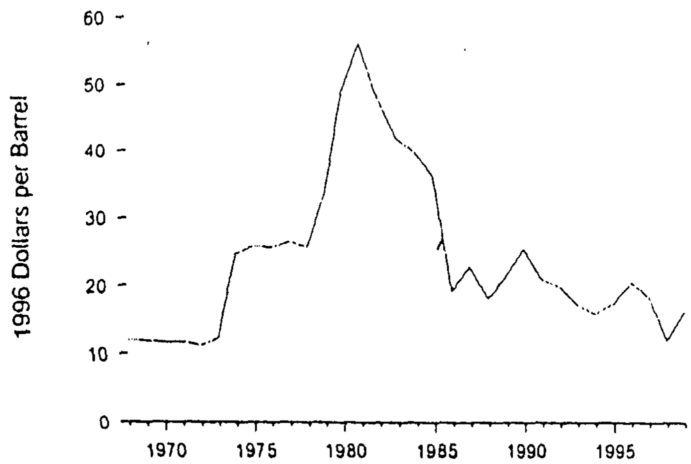


Figure 15. Strategic Petroleum Reserve Stocks



8977

Figure 16. Inflation-Adjusted Cost of Crude Oil



1998 before declining to 50 percent the following year. The five leading suppliers of petroleum to the United States in 1999 were Saudi Arabia, Venezuela, Canada, Mexico, and Nigeria.

To protect against supply disruptions, the United States began to build a Strategic Petroleum Reserve in the late 1970s. By 1985 the reserve's holdings reached 493 million barrels, which would have provided enough crude oil to replace about 115 days' worth of net petroleum imports that year (Figure 15). In 1999, the reserve held 567 million barrels of crude oil. Due to the increased rate of imports, however, that amount would replace only 59 days' worth of net imported petroleum.

Despite recent price increases, petroleum remains relatively cheap in the United States. Refiners' acquisition costs for crude oil in 1999 averaged $17.46 per barrel. When adjusted for inflation, the cost was $16.69 (chained 1996 dollars), 37 percent above the previous year's cost but 70 percent below 1981's record inflation-adjusted cost of $56.50 per barrel (Figure 16).

Natural Gas

Natural gas is mostly a mixture of methane, ethane, and propane, with methane making up 73 to 95 percent of the total. Often encountered when drilling for oil, natural gas was once considered mainly a nuisance. When either uses or—more likely today—accessible markets were lacking, it was simply flared (burned off) at the wellhead. Major flaring sites were sometimes the brightest areas visible in nighttime satellite images. Today, however, the gas is mostly reinjected for later use and to encourage greater oil production.

The first practical use of natural gas dates to 200 B.C. and is attributed, like so many technical developments, to the Chinese. They used it to make salt from brine in gas-fired evaporators, boring shallow wells with crude percussion rigs and conveying the gas to the evaporators via bamboo pipes. Natural gas was used extensively in Europe and North America in the 19th century as a lighting fuel, until the rapid development of electricity beginning in the 1890s ended that era. The development of steel pipelines and related equipment, which allowed large volumes of gas to be easily and safely transported over many miles, launched the modern natural gas industry. The first all-welded pipeline over 200 miles in length was built in 1925, from Louisiana to Texas. U.S. demand for natural gas grew rapidly thereafter, especially following World War II. Residential demand grew fifty-fold between 1906 and 1970.

Figure 17. Natural Gas Overview

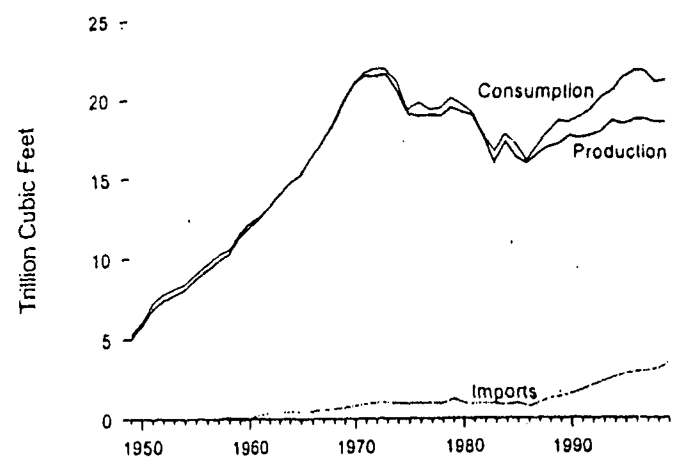


Figure 18. Natural Gas Net Imports as Share of Consumption

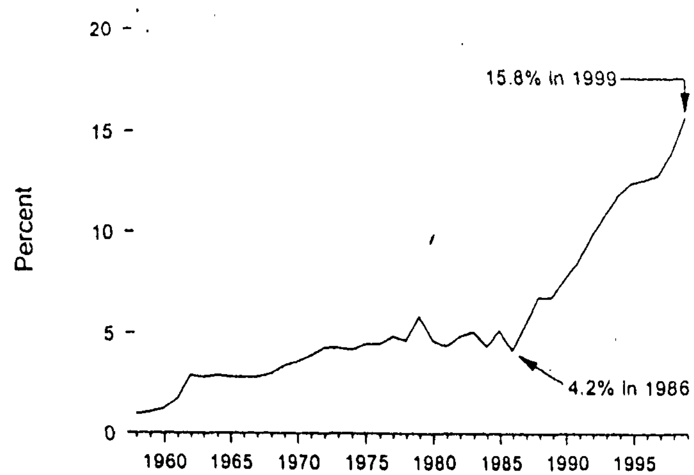
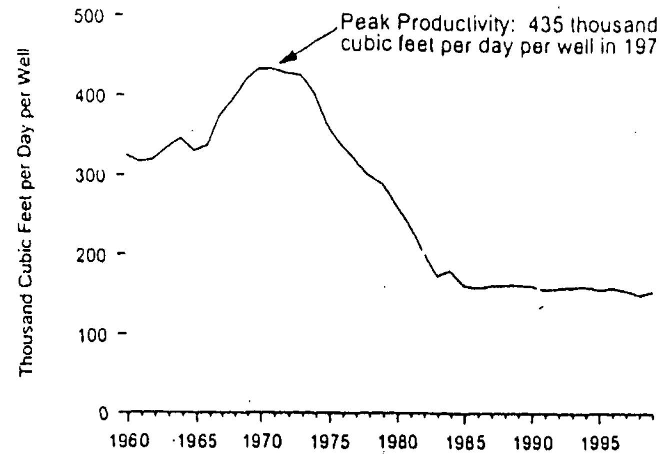


Figure 19. Natural Gas Well Productivity



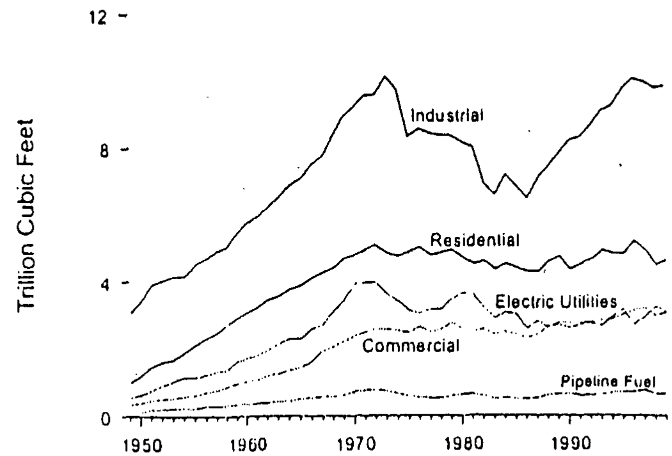
The United States had large natural-gas reserves and was essentially ~~self-sufficient in natural gas until the late 1980s, when consumption~~ began to significantly outpace production (Figure 17). Imports rose to make up the difference, nearly all coming by pipeline from Canada, although small volumes were brought by tanker in liquefied form from Algeria and, in recent years, from a few other countries as well. Net imports ~~as a~~ share of consumption more than tripled from 1986 to 1999 ~~(Figure~~ 18).

U.S. natural gas production in 1999 was 18.7 trillion cubic feet, well below the record-high 21.7 trillion cubic feet produced in 1973. Gas well productivity peaked at 435 thousand cubic feet per well per day in 1971, then fell steeply through the mid-1980s before stabilizing. Productivity in 1999 was 157 thousand cubic feet per well per day (Figure 19).

Three States (Texas, Louisiana, and Oklahoma) account for ~~over~~ half of all natural gas produced in the United States. Texas alone produced 6.9 trillion cubic feet in 1999. Advancing drilling technology has made offshore sites more important, and over the last two decades about one-fifth of all U.S. production has come from offshore sites.

~~For decades, the industrial~~ sector of the economy has been the heaviest user of natural gas (Figure 20). In 1999 industrial entities (including most electric power producers other than utilities) accounted for nearly half of all natural gas consumption, followed by the residential sector, which used another fifth of the total. In recent years, very small amounts of natural gas (about 5 billion cubic feet in 1998) have been reported for use in vehicles.

Figure 20. Natural Gas Consumption by Sector



The price of natural gas at the wellhead (i.e., where the gas is produced) was $1.98 per thousand cubic feet in 1999, in real terms (chained 1996 dollars), well below the historical high of $3.76 per thousand cubic feet in 1983. In nominal dollars, the 1999 wellhead price was $2.07 per thousand cubic feet.

Coal

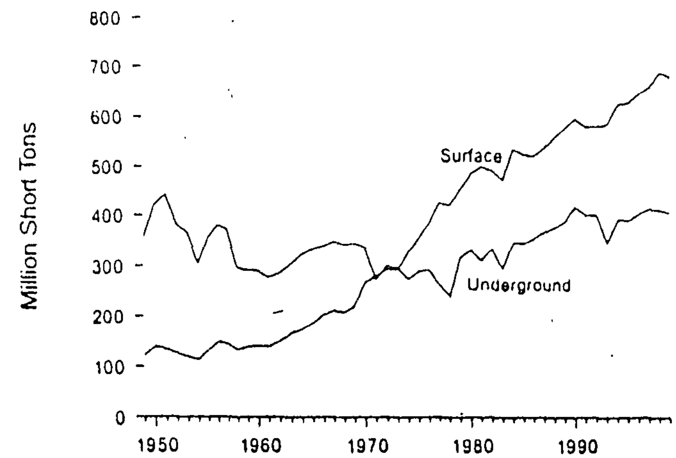
Scattered records of the use of coal as a fuel date from at least 1100 B.C. However, coal was not used extensively until the Middle Ages, when small mining operations in Europe began to supply it for forges, smithies, lime-burners, and breweries. The invention of firebricks in the late 1400s, which made chimneys cheap to build, helped create a home heating market for coal. Despite its drawbacks (smoke and fumes), coal was firmly established as a domestic fuel by the 1570s. By that time, production in England was high enough that exports were thriving. Eventually, some of that coal went to the American colonies.

The total amount of coal consumed in the United States in all the years before 1800 was an estimated 108,000 tons, much of it imported. The U.S. market for coal expanded slowly and it was not until 1885 that the young and heavily forested nation burned more coal than wood. However, the arrival of the industrial revolution and the development of the railroads in the mid-nineteenth century inaugurated a period of generally growing production and consumption of coal that continues to the present time. Today, the United States extracts coal in enormous quantities. In 1998 U.S. production of coal reached a record 1.12 billion short tons and was second worldwide after China. U.S. 1999 production was 1.10 billion short tons.

From 1885 through 1951, coal was the leading source of energy produced in the United States. Crude oil and natural gas then vied for that role until 1982. Coal regained the position of the top resource that year and again in 1984, and has retained it since. At 23 quadrillion Btu in 1999, coal accounted for a third of all energy produced in the country.

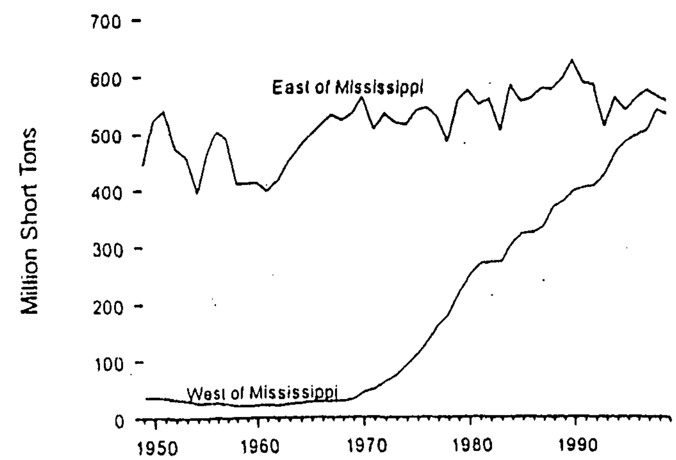
Over the past several decades, coal production shifted from primarily underground mines to surface mines (Figure 21). In addition, the coal resources of Wyoming and other areas west of the Mississippi River underwent tremendous development (Figure 22).

Figure 21. Coal Production by Mining Method



Technological improvements in mining and the shift toward more surface-mined coal, especially west of the Mississippi, have led to great improvements in coal mining productivity. In 1949 U.S. miners produced 0.7 short tons of coal per miner hour; by 1998 that rate had increased to 6.2 short tons per miner hour.

Figure 22. Coal Production by Location



Since 1950, the United States has produced more coal than it has consumed. The excess production allowed the United States to become a significant exporter of coal to other nations. In 1999 U.S. coal exports totaled 58 million short tons, which, measured in Btu, accounted for 40 percent of all U.S. energy exports. About 38 percent of the year's coal exports went to Europe, while the individual nations buying the most American coal were Canada, Japan, Brazil, Italy, and the Netherlands. While the quantities of coal leaving the country are huge, in 1999 they represented only 7 percent of the Btu content of the petroleum coming *into* the United States.

The uses of coal in the United States have changed dramatically over the years. In the 1950s, most coal was consumed in the industrial sector, but many homes were still heated by coal and the transportation sector still consumed significant amounts in steam-driven trains and ships (Figure 23). In 1999 the industrial sector used less than half as much coal as in 1949. Today only 9 percent of all coal consumed in the United States goes to the industrial sector. Ninety percent is used in the electric power sector; coal-fired units accounted for 51 percent of U.S. electricity generation in 1999 (Figure 24).

Coal-fired electric generating units emit gases that are of environmental concern. In 1998 U.S. carbon dioxide emissions from the combustion of coal for electric utility generation were nearly half a billion metric tons of carbon, 32 percent of total carbon dioxide emitted from all U.S. fuel sources.

Figure 23. Coal Consumption by Sector

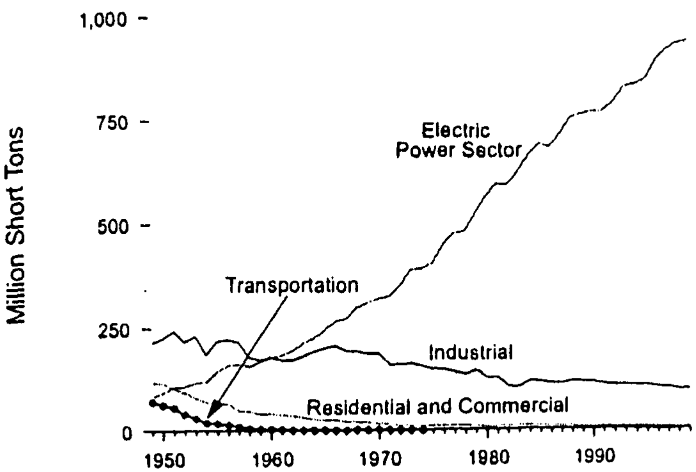
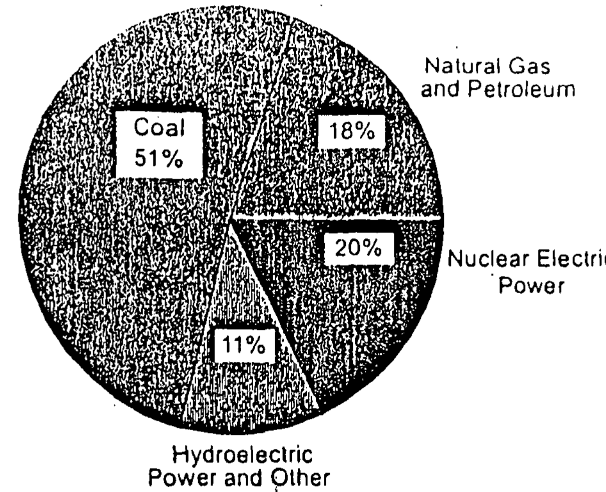


Figure 24. Electricity Net Generation by Source, 1999



Except for a post-oil-embargo price spike that peaked in 1975, real (inflation adjusted) coal prices have generally fallen over the last half-century. The average price in 1999 was 44 percent lower than it was in 1949. Coal is the least expensive of the major fossil fuels in this country: in nominal dollars, 1999 production prices for coal were 84 cents per million Btu compared with $1.86 per million Btu for natural gas and $2.68 per million Btu for crude oil.

Electricity

Electric power arrived barely a hundred years ago, but it has radically transformed and expanded our energy use. To a large extent, electricity defines modern technological civilization.

The reasons may not be easy to appreciate for those who have never known the filth, toil, danger, scarcity and/or inconvenience historically associated with obtaining and deploying such fuels as wood, coal, and whale oil. By contrast, at the point of use electricity is clean, flexible, controllable, safe, effortless, and instantly available. In homes, it runs everything from toothbrushes and televisions to heating and cooling systems. Outdoors, electricity guides traffic, aircraft, and ships, and lights up the night. In business and industry, electricity enables virtually instantaneous global communication and powers everything from trains, auto plant assembly lines, and

8980

restaurant refrigerators to the computers that run the New York Stock Exchange and the automatic pin-setting machines at the local bowling alley.

Electric power developed slowly, however. Humphrey Davy built a battery-powered arc lamp in 1808 and Michael Faraday an induction dynamo in 1831, but it was another half-century before Thomas Edison's primitive cotton-thread filament burned long enough to prove that a workable electric light could be made. Once past that hurdle, progress accelerated. Edison opened the first electricity generating plant (in London) less than 3 years later, in January 1882, and followed with the first American plant (in New York) in September. Within a month, electric current from New York's Pearl Street station was feeding 1,300 lightbulbs, and within a year, 11,000—each a hundred times brighter than a candle. Edison's reported goal was to "make electric light so cheap that only the rich will be able to burn candles."

Though he fathered the electric utility industry, Edison failed in his attempts to dominate its business and technical sides. Other companies surpassed his efforts to build central power stations, and Edison's dogged faith in direct current (DC) betrayed him. DC could only be transmitted 2 miles, while a rival alternating-current (AC) system developed by George Westinghouse and Nikola Tesla (whom Edison had fired) enabled long-distance transmission of high-voltage current and stepdowns to lower voltages at the point of use—essentially the system in place today. Edison even subsidized construction of an AC-powered electric chair to convince the public that AC was dangerous, but to no avail.

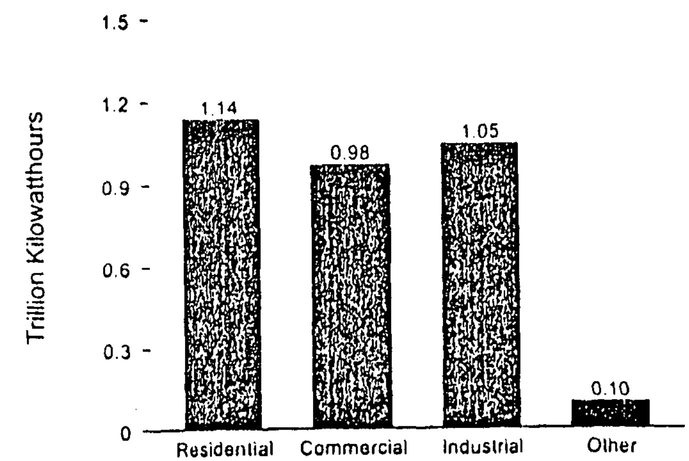
The process of electrification proceeded in fits and starts. Industries like mining, textiles, steel, and printing electrified rapidly during the years between 1890 and 1910. Electricity's penetration of the residential sector was slowed by competition from gas companies, which had a large stake in the lighting market. Nevertheless, by 1900 there were 25 million electric incandescent lamps in use and homeowners had been introduced to electric stoves, sewing machines, curling irons, and vacuum cleaners. In parallel, generating equipment and distribution systems developed to meet the demand. By 1903 utility executive Samuel Insull had commissioned a 5 megawatt steam-driven turbine generator—the first of its type and the largest of any generator then built—and launched a revolution in generating hardware.

The cities received electric service first, because it has always been cheaper, easier, and more profitable to supply large numbers of customers when they are close together. High costs and the Great Depression, which dried up most investment capital, delayed electric service to rural Americans until President Franklin Roosevelt signed into law the Rural Electrification Administration (REA) in 1935. The REA loaned money at low interest and helped to set up electricity cooperatives. Though interrupted by World War II, rural electrification proceeded rapidly thereafter. By 1967 more than 98 percent of American farms were using electricity from central station power plants.

The depth of electricity's penetration into our economy and way of life is reflected in the fact that, over the last half century, annual increases in total electricity sales by electric utilities faltered only twice, in 1974 and 1982; in every other year, sales grew. From 1949 to 1999, while the population of the United States expanded 83 percent, the amount of electricity sold by utilities grew 1,180 percent. Per-capita average consumption of electricity in 1999 was seven times as high as in 1949. Electricity's broad usage in the economy can be seen in the sector totals, which were led in 1999 by the residential sector, followed closely by the industrial sector, and then the commercial sector (Figure 25).

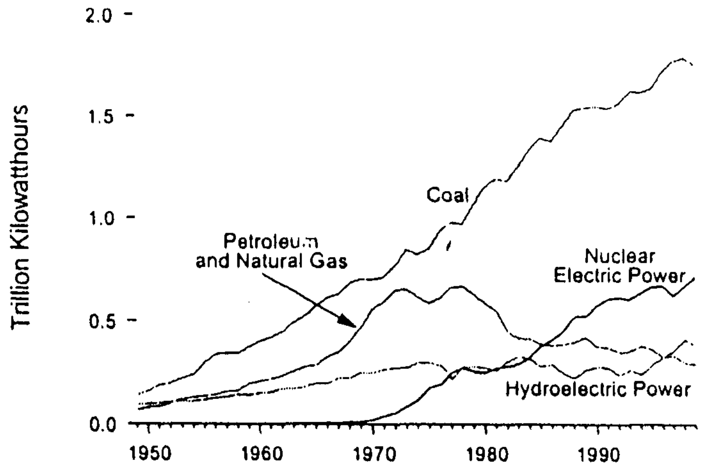
Where does all this electricity come from? In the United States, coal has been and continues to be the source of most electricity, accounting for over half of all electricity generated by utilities in 1999 (Figure 26).

Figure 25. Electric Utility Retail Sales of Electricity, 1999



898

Figure 26. Electricity Net Generation at Utilities

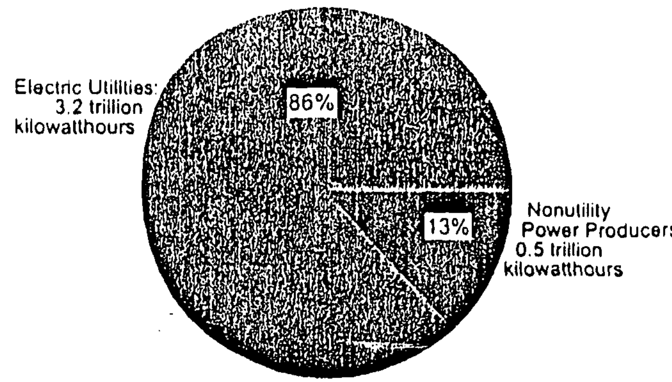


Hydroelectric power was an early source of U.S. electricity—accounting for almost a third of all utility generation in 1949—and remains a dependable contributor (over 9 percent of the total in 1999). Natural gas and petroleum grew steadily as sources of electricity in the late 1960s. Their combined usage peaked at 37 percent of the total in 1972 and stood at 18 percent in 1999. Meanwhile, a new source entered the picture: nuclear electric power. A trickle of nuclear electricity began flowing in 1957, and the stream widened steadily except for downturns in 1979 and 1980, following the accident at Three Mile Island, and again in 1993. Nuclear generation declined 7 percent in 1997 but rebounded 16 percent between 1997 and 1999.

Just as electricity's applications and sources change over time, so is the structure of the electric power sector itself evolving. The sector is now moving away from the traditional, highly regulated organizations known for many decades as electric utilities and toward an environment marked by lighter regulation and greater competition from and among nonutility power producers. In 1999, 13 percent of the total net generation of electricity came from nonutility power producers, such as independent power producers and nonutility cogenerators (Figure 27).

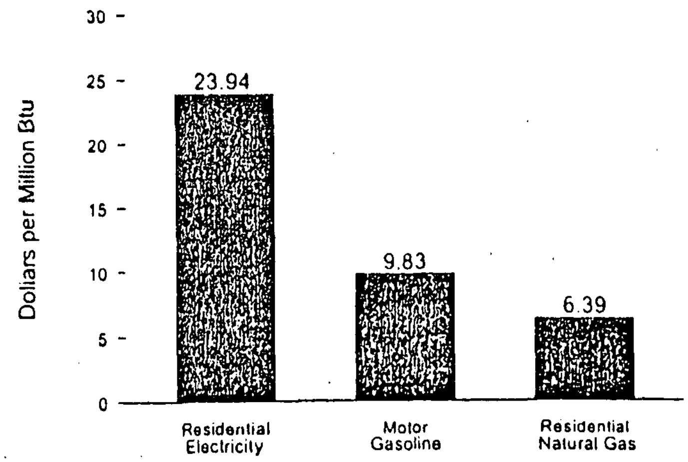
Electricity's great assets as a form of energy are reflected in its cost to the end user. The price paid by the consumer includes the cost of converting the energy from its original form, such as coal, into electricity and the cost of delivering it. In 1999 consumers paid an average of $23.94 per million Btu for the electricity delivered to their residences (Figure 28). In contrast, consumers paid an average of only $6.39 per million Btu for the natural gas

Figure 27. Electricity Net Generation, 1999



Total: 3.7 trillion kilowatthours

Figure 28. Consumer Prices, 1999



purchased for their homes and an average of $9.83 per million Btu for the motor gasoline to fuel their vehicles.

The unit cost of electricity is high because most of the energy that must be purchased to generate it does not actually reach the end user but is expended in creating the electricity and moving it to the point of use. In 1999, for example, approximately 35 quadrillion Btu of energy were consumed to generate electricity at utilities in the United States, but only 11 quadrillion Btu worth of electricity were actually used directly by consumers. Where did the other 24 quadrillion Btu go? Energy is never destroyed but it does change form. The chemical energy contained in fossil fuels, for example, is converted at the generator to the desired electrical energy. Because of theoretical and practical limits on the efficiency of conversion equipment, much of the energy in the fossil fuels is "lost," mostly as waste heat. The overall energy efficiency of a system can be increased through the tandem production of electricity and some form of useful thermal energy. This process, known as cogeneration, reduces waste energy by utilizing otherwise unwanted heat in the form of steam, hot water, or hot air for other purposes, such as operating pumps or for space heating or cooling.

In addition to the conversion losses, line losses occur during the transmission and distribution of electricity as it is transferred via connecting wires from the generating plant to substations (transmission), where its voltage is lowered, and from the substations to end users (distribution), such as homes, hospitals, stores, schools, and businesses. The generating plant itself uses some of the electricity. In the end, for every three units of energy that are converted to create electricity, only about one unit actually reaches the end user.

Nuclear Energy

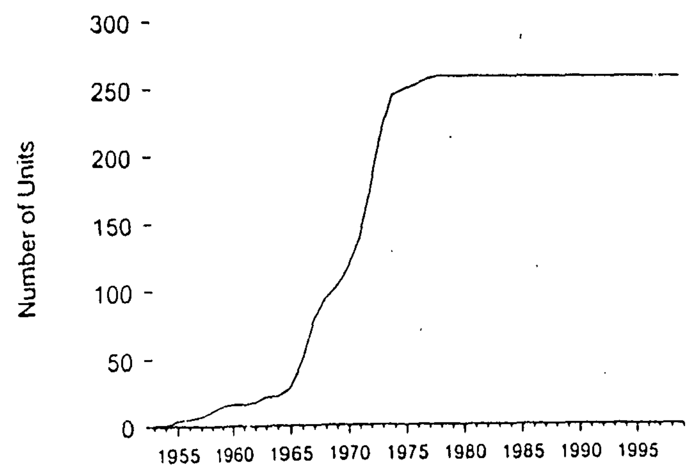
Among all the major forms of energy now in use, only nuclear power is native to the 20th century. The central insight—that the controlled fission of heavy elements could release enormous energies—came to British physicist Ernest Rutherford in 1904, and research during the 1930s convinced scientists that a controlled chain reaction was possible. Enrico Fermi's group achieved such a reaction for the first time in December 1942 at the University of Chicago in a primitive graphite-moderated reactor built on a vacant squash court.

World War II postponed further progress toward commercial nuclear electric power, but the theoretical foundation had been established and several factors encouraged nuclear power's development when peace returned. It was believed that fuel costs would be negligible and therefore that nuclear power would be relatively inexpensive. In addition, both the United States and Western Europe became net importers of crude oil in the early 1950s and nuclear power was seen as critical to avoiding energy dependence. Geopolitics appear to have played a role as well; President Dwight Eisenhower's Atoms for Peace program was intended in part to divert fissionable materials from bombs to peaceful uses such as civilian nuclear power.

In 1951 an experimental reactor sponsored by the U.S. Atomic Energy Commission generated the first electricity from nuclear power. The British completed the first operable commercial reactor, at Calder Hall, in 1956. The U.S. Shippingport unit, a design based on power plants used in nuclear submarines, followed a year later. In cooperation with the U.S. electric utility industry, reactor manufacturers then built several demonstration plants and made commitments to build additional plants at fixed prices. This commitment helped launch commercial nuclear power in the United States.

The success of the demonstration plants and the growing awareness of U.S. dependency on imported crude oil led to a wave of enthusiasm for

Figure 29. Cumulative Orders for Nuclear Generating Units



nuclear electric power that sent orders for reactor units soaring between 1966 and 1974 (Figure 29). The number of operable units increased in turn, as ordered units were constructed, tested, licensed for full power operation, and connected to the electricity grid (Figure 30). However, the curve of operable units lagged behind the curve of ordered units somewhat because of the long construction times required for the large, complex plants. The total number of U.S. operable reactor units peaked in 1990 at 112.

Orders for new units fell off sharply after 1974. Of the total of 259 units ordered to date, none was ordered after 1978. Although safety concerns, especially after the accident at Three Mile Island in 1979, reinforced a growing wariness of nuclear power, the chief reason for its declining momentum in the United States was economic. The promise of nuclear electric power had been that it would, in the now-famous phrase, make energy "too cheap to meter." In reality, nuclear power plants have always been costly to build and, for several reasons, became radically more costly between the mid-1960s and the mid-1970s. Utilities began building large plants before much experience had been gained with small ones. Expected economies of scale did not materialize. Many units were forced to undertake costly design changes and equipment retrofits, partially as a result of the Three Mile Island accident. Meanwhile, nuclear power plants have also had to compete with conventional coal- or natural gas-fired plants with declining operating costs.

Figure 30. Operable Nuclear Generating Units

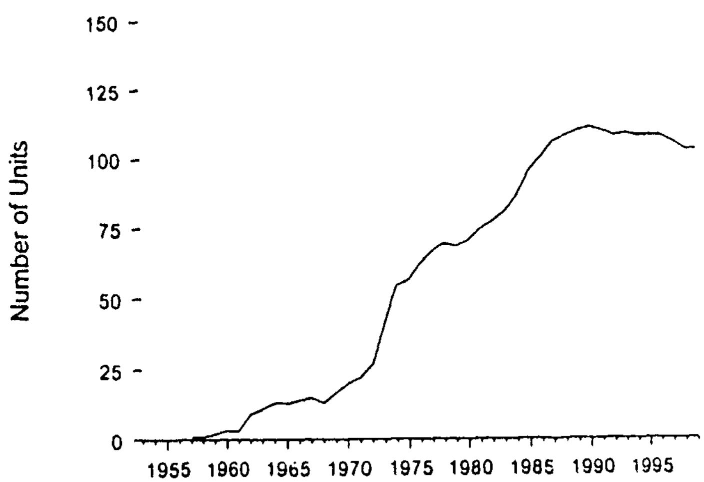
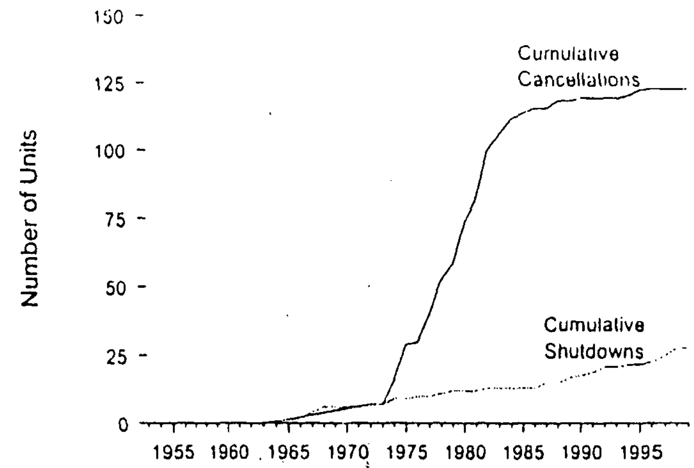


Figure 31. Nuclear Generating Units Cancelled or Shut Down



These trends disillusioned many utilities and investors. Interest in further orders subsided and many ordered units were cancelled before they were built. By the end of 1999, 124 units had been cancelled, 48 percent of all ordered units (Figure 31).

The average capacity factor of U.S. nuclear units—the ratio of the electricity they actually produced in a given year to the electricity they could have produced if run at continuous full power—has improved steadily over the years, and reached 86 percent in 1999. However, as operable nuclear power plants have aged, some have become uneconomic to operate or have otherwise reached the end of their useful lives. By the end of 1999, 28 once-operable units had been shut down permanently. The joint effect of shutdowns and lack of new units coming on line is that the number of U.S. operable units has fallen off since 1990 to 104. In its *Annual Energy Outlook 2000*, EIA projects that 41 percent of the nuclear generating capacity that existed at the end of 1998 will be retired by 2020. No new plants are expected to be built during the period.

Renewable Energy

For all but the most recent fraction of humanity's time on Earth, virtually all energy was renewable energy. Prior to the widespread use of fossil fuels and nuclear power, which arrived only an eyeblink ago in relative terms, there was essentially nothing else. Our ancestors warmed themselves directly in the sun, burned brush and fuelwood fashioned by photosynthesis from sunlight and nutrients, harnessed the power of wind and water created mainly by sun-driven atmospheric and hydrologic cycles, and of course used their own musclepower and that of animals.

We still depend heavily on renewable energy in these primeval forms. But various cultures have also found more inventive means of harnessing renewable resources, from mounting sails on wheelbarrows, as did ancient Chinese laborers, to gathering and burning buffalo dung, as did American settlers making their way west. The story of renewable energy is one of the invention and refinement of technologies for extracting both more energy and more useful forms of it from a wider variety of renewable sources. Many energy experts believe that the age of fossil fuels is only an interlude between pre- and post-industrial eras dominated by the use of renewable energy.

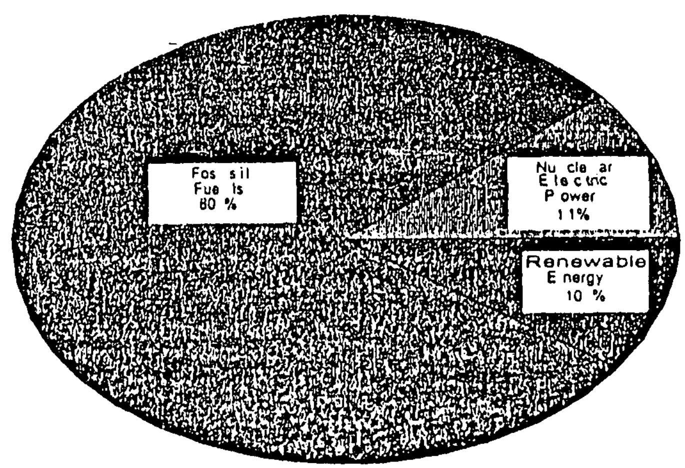
Some renewable energy technologies, such as water- and wind-driven mills, have been in use for centuries. Grain mills powered by waterwheels have existed since at least the first century B.C. and became commonplace long ago. In England, for example, the Domesday Book survey of 1086 counted 5,624 mills in the south and east alone. They were to be found throughout Europe and elsewhere and were used for a wide variety of mechanical tasks in addition to milling, from pressing oil to making wire. Some installations were surprisingly large. The Romans built a mill with 16 wheels and an output of over 40 horsepower near Arles in France. A giant 72-foot waterwheel with an output of 572 horsepower, dubbed Lady Isabella, was erected at a mine site on the Isle of Man in 1854. Further development of waterwheels ended with the invention of water turbines. Both types of machines were supplanted by large steam engines, which could be sited nearly anywhere. Turbines, however, found an important niche with the development of hydroelectric power.

Windmills are a younger but still ancient technology, dating at least to the 10th century in the Middle East, a bit later in Europe. In one form or another, windmills have remained in use ever since, for milling grain, pumping water, working metal, sawing, and crushing chalk or sugar cane. As mentioned in the introduction, American farms of the 19th century erected millions of small windmills to pump water for livestock or household use. In the modern era, technologically advanced windmills have been developed for generating electricity.

Modern renewable sources in the United States contribute about as much (roughly one-tenth) to total energy production as does nuclear power (Figure 32). Just as water power was relatively more important than wind energy in pre-industrial times, renewable energy today is dominated by hydroelectric power. About 45 percent of the U.S. renewable total in 1999 came from hydroelectric power generation, which uses dam-impounded water to drive turbine generators that make electricity. The American hydropower infrastructure is extensive and includes the great dams of the intermountain West, the Columbia basin, and the Tennessee River valley, as well as hundreds of other smaller installations nationwide.

Most of the rest of the U.S. renewable energy total came from wood and waste, a diverse category that includes not only the obvious candidates (such as wood, methanol, and ethanol) but also peat, wood liquors, wood sludge, railroad ties, pitch, municipal solid waste, agricultural waste, straw, tires, landfill gas, fish oil, and other things. Wood and wood byproducts are the most heavily used form of biomass and figure prominently in the energy consumption of such industries as paper manufacturing and lumber, which have ready access to them. Geothermal was third in 1999, accounting for about 5 percent of U.S. renewable energy production. 1 2

Figure 32. Renewable Energy in Total Energy Production, 1999



Despite their cachet, solar energy (photovoltaic and thermal) and wind energy contribute relatively little to the renewable total (about 1 percent and one-half percent respectively). The peak year for U.S. manufacturers' shipments of solar thermal collectors was 1981, when 21 million square feet were shipped. From 1991 through 1998, an average of 7.4 million square feet were shipped each year. Over 90 percent of the solar thermal collectors went to the residential sector in 1998. Ninety-three percent of the newly shipped collectors were used to heat swimming pools, while 6 percent were used for water heating and less than 1 percent for space heating. Prices for photovoltaic cells have fluctuated in recent years, while the volume of shipments in 1998 was nearly nine times the 1985 volume. U.S. wind energy production rose 58 percent between 1989 and 1999 but remains a very small factor in renewable energy here.

Environmental Indicators

The use of energy brings undisputed benefits, but it also incurs costs. Some of these costs show up on consumers' utility bills. The charges levied on consumers by an energy producer (an electric utility with a coal-fired generating plant, for instance) are designed to cover the producer's costs of building the power plant, extracting coal from the ground, transporting it to the power plant, crushing it to the proper size for combustion, maintaining the generating turbines, paying workers and managers, and so on.

One important category of costs that often is not reflected in consumers' bills is energy-related environmental effects. These unwanted effects can be thought of as the tail end of the energy cycle, which begins with extraction and processing of fuels (or gathering of wind or solar energy), proceeds with conversion to useful forms by means of petroleum refining, electricity generation, and other processes, and then moves on to distribution to, and consumption by, end-users. Once the energy has rendered the services for which it is consumed, all that is left are the byproducts of energy use, i.e., waste heat, mine tailings, sulfur dioxide and carbon dioxide gases, spent nuclear fuel, and many others.

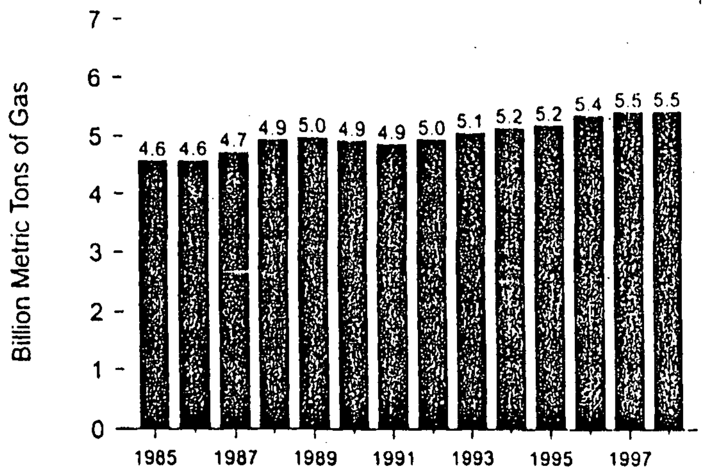
All energy use has unwanted effects of one kind or another; even a simple campfire produces eye-stinging smoke as well as warmth. The effects can be local or widespread, and neither type is only a concern of modern times. King Edward I of England, for instance, so objected to the noxious smoke and fumes from London's many coal-burning fires that in 1306 he tried (unsuccessfully) to ban its use by anyone except blacksmiths. But the enormous scale of modern energy use has sharply increased concerns about unwanted environmental effects. No form of energy production is entirely free of them, including renewable energy. Damming rivers and streams for hydropower facilities radically alters natural stream flows in ways that can threaten or endanger aquatic species. Wind-turbine generators can make noise and kill birds. Biomass generating plants that rely on plantation forestry for fuel can displace natural forest habitat and reduce biological diversity.

Among the most significant environmental effects of energy production and consumption is the emission of greenhouse gases. Such gases—carbon dioxide, methane, nitrous oxide, and others—block infrared radiation from the Earth to space and retain the captured heat in the atmosphere. This greenhouse effect keeps the Earth's climate hospitable to life. But the possibility of carbon-dioxide-forced warming of the climate has been postulated since 1861, and in recent years many scientists have come to believe that anthropogenic (human-caused) additions to greenhouse gases are raising global average temperatures and may produce harmful changes in the global climate. Energy-related greenhouse gas emissions make up a significant fraction of all such emissions, and the United States, as one of the world's largest producers and consumers of fossil fuels, is responsible for a major portion of global energy-related emissions.

Carbon dioxide (CO_2) accounts for the largest share of combined anthropogenic greenhouse gas emissions. In 1998 U.S. anthropogenic CO_2 emissions totaled about 5.5 billion metric tons (of gas; 1 ton of carbon equals 3.667 tons of carbon dioxide gas), 0.2 percent higher than the year before and 20 percent higher than in 1985 (Figure 33). Nearly 99 percent of this total was energy-related emissions, especially from petroleum consumed by the transportation sector, coal burned by electric utilities, and natural gas used by industry, homes, and businesses.

Energy-related emissions of methane, another important greenhouse gas, remained at 10 million metric tons in 1998. While about 35 percent of U.S. methane emissions stemmed from energy use, most came from landfills and such agricultural sources as ruminant animals (cattle and sheep) and their wastes. Emissions of a third potent greenhouse gas, nitrous oxide, remained about the same in 1998, at 1.2 million metric tons.

Figure 33. Carbon Dioxide Emissions



All sectors of the U.S. economy contribute to energy-related greenhouse gas emissions, especially CO_2. Of 1998 energy-related CO_2 emissions of 1.5 billion metric tons of carbon (5.4 billion tons of gas), the industrial and transportation sectors each accounted for about one-third, the residential sector for about one-fifth, and the commercial sector for the remainder. Industry's emissions derive from a broad mix of fossil-origin energy, including electricity, petroleum, natural gas, and coal. Not surprisingly, the transportation sector emits carbon dioxide mostly via the consumption of petroleum (especially motor gasoline, distillate fuels such as diesel, and jet fuel). Residential- and commercial-sector emissions are owed mostly to the use of electricity and natural gas.

The U.S. Energy Outlook

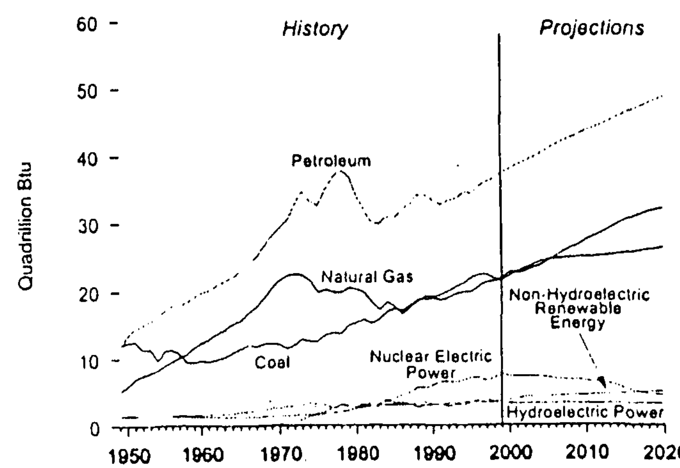
Future patterns of energy production, use, and consequences in the United States are, of course, purely speculative. But educated guesses can be made by means of sophisticated computer models, such as the Energy Information Administration's National Energy Modeling System (NEMS). EIA's current projections are published in its *Annual Energy Outlook 2000* (*AEO 2000*) and extend through 2020. Although emphatically not to be taken as predictions—no existing or imaginable model pretends to be able to foresee critical but unexpected events, such as the 1973 oil embargo—the projections can sketch a plausible general picture of future developments given known trends in technology and demographics and current laws and regulations.

The projections in *AEO 2000* suggest our near-term energy future will be one of more: consumption, production, imports, and emissions. Real energy prices are expected either to increase slowly (petroleum and natural gas) or to decline (coal and electricity). These circumstances will encourage greater consumption (Figure 34), and *AEO 2000* projects U.S. total consumption to reach 121 quadrillion Btu in 2020, 27 percent higher than in 1998. Consumption rises in all sectors, but growth is especially strong in transportation because of more travel and greater freight requirements.

Despite the general increase in energy consumption, efficiency gains and rising population keep per-capita use of energy roughly stable through 2020, according to the projections. Energy intensity, expressed as energy use per dollar of gross domestic product, has declined since 1970 and is expected to continue falling.

More energy consumption, of course, means more energy production—somewhere. Because the output of aging U.S. oil fields will continue to drop, rising demand for petroleum will have to be met by imports. The share of U.S. petroleum consumption met by net imports is projected to

Figure 34. Energy Consumption by Fuel, 1949-2020



rise from 52 percent in 1998 to 64 percent in 2020. Domestic natural gas production, on the other hand, increases 1.5 percent per year on average, an increase sufficient to meet most of the higher demand. Output from the Nation's vast coalfields likewise increases to meet rising domestic demand. Growth in production of energy from renewable sources is less than 1 percent per year, while output from nuclear power facilities declines significantly.

Unless policies to reduce emissions of carbon dioxide (such as those proposed under the 1997 Kyoto Protocol) are adopted, greater use of fossil fuels, slow market penetration by renewable energy sources, and less use of nuclear power will inevitably lead to higher emissions. *AEO 2000* projects U.S. energy-related carbon dioxide emissions to reach nearly 2 billion metric tons of carbon (7.3 billion tons of gas) in 2020, 33 percent more than in 1998.

What of our long-term energy future? That is even more speculative. Many would argue that the world is destined to move beyond fossil fuels eventually; if the threat of global climate change does not compel it, then exhausted supplies and rising prices may. The far future seems likely to belong to renewable sources of energy. Although the form they take may be radically different than in the past—solar hydrogen and advanced photovoltaics, perhaps, rather than fuelwood and dung—humankind's sources of energy thus will have come full circle.

Figure Source Notes

1. *Annual Energy Review 1999*, Appendix F, Tables F1a and F1b.
2. Ibid., Table 1.2.
3. Ibid., Tables 1.2 and 1.3.
4. Ibid., Table 1.1.
5. Ibid., Table 5.1.
6. Ibid., Table 2.1.
7. Ibid.
8. Ibid.
9. Ibid., Table 1.15.
10. Ibid., Table 2.9.
11. Ibid., Table 5.1.
12. Ibid., Table 5.2.
13. Ibid.
14. Ibid., Tables 5.12a and 5.12b.
15. Ibid., Table 5.15.
16. Ibid., Table 5.19.
17. Ibid., Table 6.1.
18. Ibid., Table 6.3.
19. Ibid., Table 6.4.
20. Ibid., Table 6.5.
21. Ibid., Table 7.2.
22. Ibid.
23. Ibid., Table 7.3.
24. Ibid., Table 8.2.
25. Ibid., Table 8.9.
26. Ibid., Table 8.3.
27. Ibid., Table 8.1.
28. Calculated from data in *Annual Energy Review 1999*, Tables 8.13 (residential electricity) and A6, 5.22 (all types of motor gasoline) and A3, and 6.9 (residential natural gas) and A4.
29. *Annual Energy Review 1999*, Table 9.1.
30. Ibid.
31. Ibid.
32. Ibid., Table 1.2.
33. Ibid., Table 12.1.
34. **History:** Energy Information Administration, *Annual Energy Review 1999*, Table 1.3. **Projections:** Energy Information Administration, *Annual Energy Outlook 2000*, Tables A1 and A18.

Bibliography

Banks, F. *The Political Economy of Natural Gas*. London: Croom Helm, 1987.

Dukert, J. *A Short Energy History of the United States*. Washington, DC: Edison Electric Institute, 1980.

Energy Information Administration. *Annual Energy Outlook 2000: With Projections to 2020.* DOE/EIA-0383 (2000). Washington, DC: December 1999.

Gielecki, M. and Hewlett, J. "Commercial Nuclear Electric Power in the United States: Problems and Prospects." Energy Information Administration, *Monthly Energy Review*, August 1994, DOE/EIA-0035(94/08) (Washington, DC, August 1994).

Glasstone, S. *Energy Deskbook*. Washington, DC: U.S. Department of Energy, Technical Information Center, 1982.

Herbert, J. *Clean Cheap Heat: The Development of Residential Markets for Natural Gas in the United States.* New York: Praeger, 1992.

Hyman, L. *America's Electric Utilities: Past, Present, and Future.* Arlington, VA: Public Utilities Reports, 1983.

Lindbergh, K. and Provorse, B. *Coal: A Contemporary Energy Story.* Seattle: Scribe Publishing Corporation, 1977.

McCaig, R. *Electric Power in America.* New York: Putnam, 1970.

Schurr, S. and Netschert, B. *Energy in the American Economy, 1850–1975: An Economic Study of Its History and Prospects.* Baltimore: The Johns Hopkins Press, 1960.

Smil, V. *Energy in World History.* Boulder: Westview Press, 1994.

———. *General Energetics: Energy in the Biosphere and Civilization.* New York: John Wiley & Sons, 1991.

Tenner, E. *Why Things Bite Back: Technology and the Revenge of Unintended Consequences.* New York: Knopf, 1996.

Tussing, A. and Tippee, B. *The Natural Gas Industry: Evolution, Structure, and Economics.* Tulsa: PennWell Books, 1995.

United States Geological Survey, *Mineral Resources of the United States.* Washington, DC, 1883.

Walton, R. *The Power of Oil.* New York: Seabury Press, 1977.

Kelliher, Joseph

From: Vernet, Jean
Sent: Saturday, June 09, 2001 11:47 AM
To: Otis, Lee; Kelliher, Joseph
Cc: Anderson, Margot; Conti, John; Carter, Douglas; Breed, William; McNutt, Barry
Subject: Update: NEP NSR Review

Sensitivity: Confidential

From the road, Bill Harnett answered my 6/8 inquiry on status in a voice mail:

8990

DOE015-2333

Kelliher, Joseph

From: Vernet, Jean
Sent: Thursday, June 07, 2001 7:27 AM
To: Otis, Lee
Cc: Kelliher, Joseph; Anderson, Margot; Conti, John
Subject:

Sensitivity: Confidential

Ms. Otis,

Per Joe's request.

Jean

Jean E. Vernet
Office of Policy, PO-21
U.S. Department of Energy
202.586.4755
fax 202.586.5391

-----Original Message-----
From: Kelliher, Joseph
Sent: Wednesday, June 06, 2001 6:02 PM
To: Vernet, Jean
Subject: RE: Update on NEP NSR review
Sensitivity: Confidential

Jean, please provide this information to Lee Otis, the new General Counsel. She is our lead on NSR.

-----Original Message-----
From: Vernet, Jean
Sent: Tuesday, June 05, 2001 10:13 AM
To: Anderson, Margot; Conti, John; Kelliher, Joseph
Cc: Carter, Douglas; McNutt, Barry; Breed, William; Moses, David
Subject: Update on NEP NSR review
Sensitivity: Confidential

To all,

Please do not forward this message.

Work with EIA.

Kelliher, Joseph

From: Vernet, Jean
Sent: Tuesday, June 05, 2001 10:13 AM
To: Anderson, Margot; Conti, John; Kelliher, Joseph
Cc: Carter, Douglas; McNutt, Barry; Breed, William; Moses, David
Subject: Update on NEP NSR review

Sensitivity: Confidential

To all,

Please do not forward this message.

Work with EIA.

8993

DOE015-2336

Kelliher, Joseph

From: Vernet, Jean
Sent: Tuesday, May 29, 2001 7:47 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Breed, William; Conti, John
Subject:

Margot, Joe,

Bill Harnett called this am to update me on progress.

Jean

-----Original Message-----
From: Vernet, Jean
Sent: Wednesday, May 23, 2001 7:30 AM
To: Anderson, Margot; Conti, John
Cc: Kelliher, Joseph; Breed, William
Subject: EPA Process for NSR Review under the NEP

Message from Bill Harnett, EPA OAQPS, indicating that

8997

DOE015-2340

Kelliher, Joseph

From: Vernet, Jean
Sent: Wednesday, May 23, 2001 7:30 AM
To: Anderson, Margot; Conti, John
Cc: Kelliher, Joseph; Breed, William
Subject:

Message from Bill Harnett, EPA OAQPS, indicating that

8998

Kelliher, Joseph

From: Vernet, Jean
Sent: Friday, May 18, 2001 3:10 PM
To: Kelliher, Joseph
Cc: Anderson, Margot; Conti, John
Subject: RE: new source review/national coal council report

Importance: High

Joe,

If there is anymore to add after Council staff return my call, I'll ship it off quickly.

Jean

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, May 18, 2001 1:40 PM
To: Anderson, Margot; Conti, John; Vernet, Jean
Subject: new source review/national coal council report
Importance: High

Kelliher, Joseph

From: Koch, Matthew
Sent: Tuesday, June 05, 2001 5:34 PM
To: Kelliher, Joseph
Cc: Tripodi, Cathy
Subject: Policy Talking Points

Joe,

As per our conversation, I have highlighted specific programs and proposals from the National Energy Policy that would be of interest to State and Local governments.

I would appreciate your taking a moment to review the attached material and provide me with your thoughts or comments.

I may play with the format a bit - but expect to leave the contant alone except for your input or recommendations.

Thank you in advance for your help,

Matt Koch

Policy statepoints.doc

Kelliher, Joseph

From: Kolevar, Kevin
Sent: Tuesday, June 05, 2001 1:22 PM
To: Hutto, Chase; Faulkner, Doug; Kelliher, Joseph; Reed, Craig
Cc: McSlarrow, Kyle
Subject: First draft of Chapter by Chapter

About 56 pages long

NEP chapter by chapter.dc:

9005

DOE015-2348

b - 6

Kelliher, Joseph

From: Kolevar, Kevin
Sent: Monday, June 04, 2001 7:19 PM
To: Hutto, Chase; Kelliher, Joseph
Subject: NEP Action Plan

This is the version for Chase's input.

* Kyle's email address is

Kelliher, Joseph

From: Kolevar, Kevin
Sent: Monday, June 04, 2001 10:04 AM
To: Hutto, Chase; Kelliher, Joseph
Subject: draft of new NEP action plan

NEP Action Plan 11.doc

9075

DOE015-2418

Kelliher, Joseph

From: Kolevar, Kevin
Sent: Thursday, May 31, 2001 10:40 AM
To: Kelliher, Joseph; Hutto, Chase
Subject: NEP action plan

NEP Action Plan.doc

Kelliher, Joseph

From: Koch, Matthew
Sent: Wednesday, May 23, 2001 4:20 PM
To: Kelliher, Joseph
Cc: Tripodi, Cathy
Subject: Transfer of funds into LIHEAP

Joe,

Thank you in advance for your assistance.

Matt Koch
Office of Congressional and Intergovernmental

9089

DOE015-2432

Kelliher, Joseph

From: JWeisgal, :internet [(b)(6)
Sent: Wednesday, May 23, 2001 11:21 AM
To: Kelliher, Joseph
Cc: tdbonner@midamerican.com%internet
Subject: Geothermal recommendations

DA011420027.doc

See attached. Please feel free to call with any questions or comment

CONCEPTS FOR AN EXECUTIVE ORDER

FOR GEOTHERMAL DEVELOPMENT ON FEDERAL PUBLIC LANDS

POLICY – Consistent with the National Energy Policy relating to all energy sources, and specifically to renewable sources, all federal agencies, under the lead of the Departments of Energy and Interior are directed, consistent with applicable law, to undertake appropriate actions to expedite the development and production of geothermal resources from federal lands and to facilitate the sale of electricity from geothermal sources into the energy market.

SPECIFIC DIRECTIVES

- It is a national priority, consistent with other laws, to develop and expand the use of geothermal energy resources on federal lands. Federal agencies including, but not limited to the Bureau of Land Management (BLM) and the U.S. Forest Service (USFS), involved in geothermal leasing, permitting or other reviews are directed to give geothermal energy projects expeditious and priority consideration and minimize impediments and unnecessary requirements upon geothermal operations;

- The Department of the Interior (DOI) is directed to review its regulations and existing legal authority to enhance BLM's authority under the Geothermal Steam Act to ensure timely decisions or actions involving geothermal leases and subsequent permitting or review, including actions taken by other agencies, and to establish specific goals and timeframes for completion of leasing, permitting and other actions;

- The DOI is directed to expeditiously review all moratoria and withdrawals of land preventing exploration and development in Known Geothermal Resource Areas, and where considerations of additional energy supply outweigh the original purposes of the moratoria or withdrawal, to modify any such order to permit consideration of development under applicable law;

- The DOI is directed that all active pending administrative appeals concerning geothermal energy development should be expedited, including the consideration of assumption of jurisdiction of such appeals by the Secretary in order to reach final decisions on such appeals;

- The BLM is directed to decide whether or not to issue leases or hold a competitive lease sale within 90 days for all pending lease applications;

- DOI is directed to examine whether a portion of the federal share from geothermal royalties should be set aside for Native American Tribes that demonstrate historical ties to the land or operate as local units of government and to take appropriate regulatory action or propose legislative amendments as it determines necessary;

- BLM is directed to work with the U.S. Geological Survey, DOE, and USFS to fund geophysical studies, including the drilling of temperature gradient core holes.

to help characterize new potential geothermal resources in order to define high potential areas that can be offered for competitive bidding;

- BLM is directed to review its geothermal lease management rule, guidelines and practices to ensure that they promote and facilitate development;
- Federal agencies, especially the power marketing administrations, are directed to consider purchasing geothermal energy as part of their "green" power promotion efforts, and DOD is directed to consider long-term geothermal contracts in order to promote new development; and
- DOI is directed to review geothermal leasing and regulations by other agencies (including DOD) and to report on actions that could be taken to promote geothermal development and ensure uniform lease terms, administration and royalty policies;
- The Department of Energy is directed to establish a National Geothermal Coordinating Committee (as recommended by the February 28, 2001 NREL Report) to facilitate agency actions supporting and expediting the expanded production or energy from geothermal resources; and
- The Department of the Treasury is directed, in cooperation with the Department of Energy, to consider expanding the production tax credit to geothermal energy as part of its deliberations implementing the tax recommendations of the NEPDG.

9093

b-5

Kelliher, Joseph

From: Magwood, William
Sent: Tuesday, May 22, 2001 5:55 PM
To: Kelliher, Joseph; Cook, Trevor
Subject: RE: reprocessing paper

Joe,

Let me know if you need further information.

WDM

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 22, 2001 1:50 PM
To: Cook, Trevor
Cc: Magwood, William
Subject: RE: reprocessing paper
Importance: High

-----Original Message-----
From: Cook, Trevor
Sent: Tuesday, May 22, 2001 9:21 AM
To: Kelliher, Joseph
Cc: Magwood, William
Subject: reprocessing paper
Importance: High

Joe,

Here is the paper, its just over a page.

Trevor.

<< File: ONE PAGER ON REPROCESSING.doc >>

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, May 21, 2001 3:15 PM
To: Magwood, William; Cook, Trevor
Subject: hearing prep: reprocessing

9094

DOE015-2437

Kelliher, Joseph

From: Cook, Trevor
Sent: Tuesday, May 22, 2001 3:04 PM
To: Kelliher, Joseph
Subject: RE: reprocessing paper

Importance: High

3-7046

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 22, 2001 1:50 PM
To: Cook, Trevor
Cc: Magwood, William
Subject: RE: reprocessing paper
Importance: High

-----Original Message-----
From: Cook, Trevor
Sent: Tuesday, May 22, 2001 9:21 AM
To: Kelliher, Joseph
Cc: Magwood, William
Subject: reprocessing paper
Importance: High

Joe.

Here is the paper, its just over a page.

Trevor.

<< File: ONE PAGER ON REPROCESSING.doc >>

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, May 21, 2001 3:15 PM
To: Magwood, William; Cook, Trevor
Subject: hearing prep: reprocessing

Kelliher, Joseph

From: Kripowicz, Robert
Sent: Tuesday, May 22, 2001 1:53 PM
To: Kelliher, Joseph
Subject: RE: CCT successes

Importance: High

Sec-Clean Coal.wpd

Attached is what I just sent to Chase and Kevin.

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 22, 2001 1:48 PM
To: Kripowicz, Robert
Subject: CCT successes
Importance: High

Kelliher, Joseph

From: Kripowicz, Robert
Sent: Tuesday, May 22, 2001 1:18 PM
To: Kelliher, Joseph
Subject: FW: Kelliher request: NCC report

Importance: High

-----Original Message-----
From: Carter, Douglas
Sent: Tuesday, May 22, 2001 1:10 PM
To: Kripowicz, Robert
Cc: Rudins, George
Subject: Kelliher request: NCC report

Doug Carter (FE-26)

9099

DOE015-2442

Kelliher, Joseph

From: Anderson, Margot
Sent: Tuesday, May 22, 2001 11:11 AM
To: Kolevar, Kevin; Kelliher, Joseph
Subject: NEP Implementation

Kevin and Joe,

R&D Reviews.

Margot

National Academy of Sciences R...

R&D Council Overview.doc

9106

DOE015-2449

Kelliher, Joseph

From: McMonigle, Joe
Sent: Friday, May 18, 2001 8:30 PM
To: Kelliher, Joseph
Subject: chapter 7 summary and recommendations

Importance: High

NEP.Chapter7.JOE.doc

Kelliher, Joseph

From: Kolevar, Kevin
Sent: Friday, May 18, 2001 5:56 PM
To: Kelliher, Joseph
Subject: Chapter 4 synopsis and recommendations

Chapter Four-Using Energy Wise...

Martin, Adrienne

From: KYDES, ANDY
Sent: Friday, May 04, 2001 3:03 PM
To: Anderson, Margot
Subject: RE: need information

You are always welcome.

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Friday, May 04, 2001 11:46 AM
To: Kydes, Andy
Subject: RE: need information

Thank you Professor Kydes!

-----Original Message-----
From: KYDES, ANDY
Sent: Friday, May 04, 2001 1:[illegible]7 PM
To: Anderson, Margot
Cc: HUTZLER, MARY
Subject: RE: need information

9119

I hope this helps.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Thursday, May 03, 2001 5:59 PM
To: Kydes, Andy
Subject: need infor

Andy,

Muchas

Margot

Martin, Adrienne B(5)

From: Tom Kimbis
Sent: Friday, May 04, 2001 12:04 PM
To: Anderson, Margot
Subject: RE: Revisions to Renewables Chapter

bpwd96v

I'm temporarily at 586-9264 (squatting in a window office while people get shuffled).

My usual number (where my voicemail is) is 586-7055.

Tom

Margo Anderson@HQMAIL on 05/04/2001 11:57:51 AM

: Tom Kimbis/EE/DOE@DOE@HQMAIL

: RE: Revisions to Renewables Chapter

what's your phone number?

-----Original Message-----
From: Tom Kimbis
Sent: Friday, May 04, 2001 9:50 AM
To: Anderson, Margot
Subject: RE: Revisions to Renewables Chapter

Anderson@HQMAIL on 05/03/2001 04:59:45 PM

Tom Kimbis/EE/DOE@DOE@HQMAIL

: RE: Revisions to Renewables Chapter

-----Original Message-----
From: Tom Kimbis
Sent: Thursday, May 03, 2001 2:11 PM

To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip
Subject: RE: Revisions to Renewables Chapter

No problem. This was a team effort by everyone cc:d on the email...

Margot Anderson@HQMAIL on 05/03/2001 01:53:18 PM

To: Tom Kimbis/EE/DOE@DOE@HQMAIL
cc: Lawrence Mansueti/EE/DOE@DOE@HQMAIL, Michael York/EE/DOE@DOE@HQMAIL, MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL, Phillip Tseng/EE/DOE@DOE@HQMAIL

Subject: RE: Revisions to Renewables Chapter

Thanks, Tom. Much appreciate your hard work.

-----Original Message-----
From: Tom Kimbis
Sent: Thursday, May 03, 2001 1:50 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeti; Tseng, Phillip
Subject: Revisions to Renewables Chapter
Importance: High

Margot:

Let me know if you have any further questions.

Tom

586-9264
586-7055 - vm

<< File: CHP schematic.ppt >>

<< File: bpxvd66o >>

b5

Martin, Adrienne

From: KYDES, ANDY
Sent: Friday, May 04, 2001 1:17 PM
To: Anderson, Margot
Cc: HUTZLER, MARY
Subject: RE: need information

b

I hope this helps.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Thursday, May 03, 2001 5:59 PM
To: Kydes, Andy
Subject: need infor

Andy,

Muchas

Margot

9125

DOE015-2468

Martin, Adrienne

From: Tom Kimbis
Sent: Friday, May 04, 2001 9:50 AM
To: Anderson, Margot
Subject: RE: Revisions to Renewables Chapter

bpsvd66o

Margo. Anderson@HQMAIL on 05/03/2001 04:59:45 PM

To: Tom Kimbis/EE/DOE@DOE@HQMAIL
cc:

Subject: RE: Revisions to Renewables Chapter

-----Original Message-----
From: Tom Kimbis
Sent: Thursday, May 03, 2001 2:11 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip
Subject: RE: Revisions to Renewables Chapter

No problem. This was a team effort by everyone cc:d on the email...

Margo. Anderson@HQMAIL on 05/03/2001 01:53:18 PM

To: Tom Kimbis/EE/DOE@DOE@HQMAIL
cc: Lawrence Mansueti/EE/DOE@DOE@HQMAIL, Michael York/EE/DOE@DOE@HQMAIL, MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL, Phillip Tseng/EE/DOE@DOE@HQMAIL

Subject: RE: Revisions to Renewables Chapter

Thanks, Tom. Much appreciate your hard work.

-----Original Message-----
From: Tom Kimbis
Sent: Thursday, May 03, 2001 1:50 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip

Subject: Revisions to Renewables Chapter
Importance: High

Margot:

Let me know if you have any further questions.

Tom

586-9264
586-7055 - vm

<< File: CHP schematic.ppt >>

9127

DOE015-2470

Martin, Adrienne

From: Tom Kimbis
Sent: Thursday, May 03, 2001 2:11 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip
Subject: RE: Revisions to Renewables Chapter

No problem. This was a team effort by everyone cc:d on the email...

Margo Anderson@HQMAIL on 05/03/2001 01:53:18 PM

To: Tom Kimbis/EE/DOE@DOE@HQMAIL
cc: Lawrence Mansueti/EE/DOE@DOE@HQMAIL, Michael York/EE/DOE@DOE@HQMAIL, MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL, Phillip Tseng/EE/DOE@DOE@HQMAIL

Subject: RE: Revisions to Renewables Chapter

Thanks, Tom. Much appreciate your hard work.

-----Original Message-----
From: Tom Kimbis
Sent: Thursday, May 03, 2001 1:50 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip
Subject: Revisions to Renewables Chapter
Importance: High

Margot:

Let me know if you have any further questions.

Tom

586-9264
586-7055 - vm

<< File: CHP schematic.ppt >>

b(5)

Martin, Adrienne

From: Tom Kimbis
Sent: Thursday, May 03, 2001 1:50 PM
To: Anderson, Margot
Cc: Mansueti, Lawrence; York, Michael; Zimmerman, MaryBeth; Tseng, Phillip
Subject: Revisions to Renewables Chapter

Importance: High

CHP schematic.ppt

Margot:

Let me know if you have any further questions.

Tom

586 9264
586 7055 vm

b(5)

Martin, Adrienne

From: Carter, Douglas
Sent: Wednesday, May 02, 2001 9:54 AM
To: Anderson, Margot
Subject: FW: high cost of oil production

Margot -

Doug

-----Original Message-----
From: Allison, Edith
Sent: Tuesday, May 01, 2001 11:41 AM
To: Anderson, Margot
Cc: Carter, Douglas; Braitsch, Jay; DeHoratiis, Guido
Subject: high cost of oil production

Edith Allison
Exploration Program Manager
Department of Energy
Office of Natural Gas and Petroleum Technology
Telephone: 202-586-1023
Fax: 202-586-6221
email edith.allison@hq.doe.gov

Martin, Adrienne

From: KYDES, ANDY
Sent: Tuesday, May 01, 2001 8:26 PM
To: Anderson, Margot
Subject: Final suggestions/checks on Infrastructure Chapter

CH1-EIA.DOC

These are the final comments we have on the Infrastructure Chapter

They are on pages 8-10 on the attached and are highlighted in yellow.

Andy

Andy S. Kydes, EI-80
U.S. DOE/EIA
1000 Independence Ave. SW
Washington, D.C. 20585
email: akydes@eia.doe.gov
Tel: (202) 586-2222
fax: (202) 586-3045

Please see our website http://www.eia.doe.gov for access to EIA's energy information and publications. Please call NEIC at (202) 586-8800 or email them
at infoctr@eia.doe.gov if you have general questions regarding such information
or how to locate it.

Martin, Adrienne

From: KYDES, ANDY
Sent: Tuesday, May 01, 2001 7:05 PM
To: Anderson, Margot
Subject: FW: <NULL>

It appears that our particular problems with the international write-up is
fine
to go forward with. See the note below.

Andy

-----Original Message-----
From: Cato, Derriel
Sent: Tuesday, May 01, 2001 2:31 PM
To: Kydes, Andy; Butler, George; Holte, Susan; Sitzer, Scott; McArdle,
Paul; Earley, Ronald
Cc: Kilgore, Cal; Hutzler, Mary; Pettis, Larry
Subject: RE: <NULL>

Andy

Derriel

-----Original Message-----
From: Kydes, Andy
Sent: Tuesday, May 01, 2001 9:22 AM
To: Cato, Derriel; Butler, George; Holte, Susan; Sitzer, Scott; McArdle,
Paul; Earley, Ronald
Cc: Kilgore, Cal; Hutzler, Mary; Pettis, Larry
Subject: FW: <NULL>

Thanks for your help.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Tuesday, May 01, 2001 9:03 AM
To: Kydes, Andy; MaryBeth Zimmerman_at_HQ-NOTES at X400PO
Cc: Darrell Beschen_at_HQ-NOTES at X400PO; Michael York_at_HQ-NOTES at X400PO
Subject: <NULL>

Martin, Adrienne

From: Vernet, Jean
Sent: Tuesday, May 01, 2001 3:12 PM
To: Kelliher, Joseph; Anderson, Margot
Cc: Conti, John; Carter, Douglas
Subject: RE: NSR

Importance: High

Joe,

Just got to look at this. I was out of the office yesterday and this morning at a conference. Please let me know your reaction, and where this stands.

Jean

-----Original Message-----
From: Kelliher, Joseph
Sent: Sunday, April 29, 2001 5:05 PM
To: Vernet, Jean; Anderson, Margot
Subject: NSR

9154

DOE015-2497

-----Original Message-----
From: Schmidt.Lorie@epamail.epa.gov%internet
[mailto:Schmidt.Lorie@epamail.epa.gov]
Sent: Tuesday, April 24, 2001 12:08 PM
To: Kelliher, Joseph
Cc: Stevenson, Beverley
Subject: NEPD Recommendations

Joe

I believe that Tom and Rob will want to talk to you about this again -- I think we are trying to set up something for Wednesday or Thursday.

I didn't catch Jean's last name, so could you please forward this to her?

Thanks,

Lorie Schmidt
564-1681

(See attached file: nsr rec 4-24.wpd)

(5)

Martin, Adrienne

From: Freitas, Christopher
Sent: Tuesday, May 01, 2001 2:16 PM
To: Anderson, Margot
Subject: RE: infrastructure

Margot, Thanks for all your support on this.

Sincerely,

Christopher J. Freitas
Program Manager, Natural Gas Infrastructure
(202) 586-1657

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 1:25 PM
To: Kelliher, Joseph
Cc: Freitas, Christopher; Kripowicz, Robert
Subject: FW: infrastructure

Joe.

Margot

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 9:55 AM
To: Charles Smith (E-mail)
Cc: Freitas, Christopher
Subject: infrastructure

Charlie.

Margot

<< File: chapter 9 DOE comments april 23.DOC >>

9156

DOE015-2499

Martin, Adrienne

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 1:27 PM
To: Anderson, Margot
Subject: RE: infrastructure

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 1:25 PM
To: Kelliher, Joseph
Cc: Freitas, Christopher; Kripowicz, Robert
Subject: FW: infrastructure

Joe,

Margot

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 9:55 AM
To: Charles Smith (E-mail)
Cc: Freitas, Christopher
Subject: infrastructure

Charlie,

Margot

<< File: chapter 9 DOE comments april 23.DOC >>

9157

DOE015-2500

Martin, Adrienne

From: KYDES, ANDY
Sent: Tuesday, May 01, 2001 3:17 PM
To: Anderson, Margot
Cc: BEAMON, JOSEPH; HUTZLER, MARY; PETTIS, LARRY
Subject: RE: Going to Press: Clean up of Chapter 1

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Tuesday, May 01, 2001 8:40 AM
To: Kydes, Andy; Douglas Carter_at_HQ-EXCH at X400PO; Joseph Kelliher_at_HQ-EXCH at X400PO
Subject: Going to Press: Clean up of Chapter 1

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 4:42 PM
To: Kelliher, Joseph; Anderson, Margot; Robert_C._McNally@oa.eop.gov%internet
Cc: Andrew_D._Lundquist@ovp.eop.gov%internet; Karen_Y._Knutson@ovp.eop.gov%internet; Kjersten_S._Drager@ovp.eop.gov%internet
Subject: Clean up of Chapter 1

Please get us responses to the open items by noon, Tuesday, May 1, 2001.

b(5)

Martin, Adrienne

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 11:50 AM
To: Anderson, Margot
Cc: Kripowicz, Robert; Rudins, George; Braitsch, Jay
Subject: Chap 3 - Coal gasification intro

Margot -

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:49 AM
To: Cook, Trevor; Carter, Douglas
Cc: Magwood, William
Subject: Going to Press: chapter 3

Doug and Trevor,

By 10:00 if possible. Thanks.

Margot

-----Original Message-----
From. Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent. Monday, April 30, 2001 10:25 PM
To: Kelliher, Joseph; Anderson, Margot;
Moss.Jacob@epamail.epa.gov%internet;
William_bettenberg@ios.doi.gov%internet; Tom_fulton@ios.doi.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: chapter 3

9160

DOE015-2503

I need this literally first thing in the am. Chapter 3 is to be laid out starting about noon.

Charlie

b(5)

Martin, Adrienne

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 11:23 AM
To: Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert; Anderson, Margot; Braitsch, Jay
Subject: RE: clean coal

Joe -

Doug

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 10:37 AM
To: Carter, Douglas; Anderson, Margot
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

-----Original Message-----
From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug,

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM

9162

DOE015-2505

To: Anderson, Margot
Subject: RE: clean coal

Yes, in addition. They want something like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

Is this beyond what we already sent them (from FE) a few hours ago? If so, we should ask Doug Carter and/or Guido DeHoratiis to answer (I note that Bob K. is out today). By when?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

Martin, Adrienne

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 10:37 AM
To: Carter, Douglas; Anderson, Margot
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

-----Original Message-----
From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug.

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM
To: Anderson, Margot
Subject: RE: clean coal

Yes. in addition. They want something like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe.

9164

DOE015-2507

Is this beyond what we already sent them (from FE) a few hours ago? If so, we should ask Doug Carter and/or Guido DeHoratiis to answer (I note that Bob K. is out today). By when?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

Martin, Adrienne

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug.

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM
To: Anderson, Margot
Subject: RE: clean coal

Yes, in addition. They want something like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe.

Is this beyond what we already sent them (from FE) a few hours ago? If so, we should ask Doug Carter and/or Guido DeHoratiis to answer (I note that Bob K. is out today). By when?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot

Subject: clean coal

Martin, Adrienne

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:26 AM
To: Anderson, Margot; Kelliher, Joseph; Kripowicz, Robert
Cc: Rudins, George
Subject: RE: clean coal

Attached is descriptive info on the CCTP.

Doug

Clean Coal Technology Program....

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

Is this beyond what we already sent them (from FE) a few hours ago? If so, we should ask Doug Carter and/or Guido DeHoratiis to answer (I note that Bob K. is out today). By when?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Knpowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

Martin, Adrienne

From: Cook, Trevor
Sent: Tuesday, May 01, 2001 10:04 AM
To: Kelliher, Joseph; Anderson, Margot
Cc: Magwood, William
Subject: nuclear safety words

attached is a MS word file with the requested text.

nuclear safety.doc

9170

Martin, Adrienne

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 9:10 AM
To: Anderson, Margot
Subject: RE: chapter 5 fact check

Sure, we've been waiting for something to do.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 5:54 PM
To: Carter, Douglas; DeHoratis, Guido
Subject: chapter 5 fact check

All,

Margot

9172

DOE015-2515

(b)(5)

Martin, Adrienne

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 8:52 AM
To: Anderson, Margot
Subject: RE: nuclear safety

Yes

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:51 AM
To: Kelliher, Joseph
Subject: RE: nuclear safety

Joe,

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 8:10 AM
To: Magwood, William; Cook, Trevor
Cc: Anderson, Margot
Subject: nuclear safety

9173

DOE015-2516

b(5)

Martin, Adrienne

From:	Kelliher, Joseph
Sent:	Tuesday, May 01, 2001 8:10 AM
To:	Magwood, William; Cook, Trevor
Cc:	Anderson, Margot
Subject:	nuclear safety

Martin, Adrienne

From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM
To: Anderson, Margot
Subject: RE: clean coal

Yes, in addition. They want somethirg like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe.

Is this beyond what we already sent them (from FE) a few hours ago? If so, we should ask Doug Carter and/or Guido DeHoratiis to answer (I note that Bob K. is out today). By when?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

9175

DOE015-2518

Martin, Adrienne

From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

9176

DOE015-2519

Martin, Adrienne

From: KYDES, ANDY
Sent: Monday, April 30, 2001 8:32 PM
To: Anderson, Margot
Cc: HUTZLER, MARY
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

More data checking on 5.

Andy

-----Original Message-----
From: Benneche, Joseph
Sent: Monday, April 30, 2001 5:31 PM
To: Kydes, Andy
Subject: RE: Info. Needed for Chapter 5 by 3:00 TODAY...

-----Original Message-----
From: Kydes, Andy
Sent: Monday, April 30, 2001 1:59 PM
To: Schnapp, Robert; Benneche, Joseph
Cc: Pettis, Larry; Hutzler, Mary
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Bob:

Thanks for your help.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Monday, April 30, 2001 11:15 AM
To: Kydes, Andy; Douglas Carter_at_HQ-EXCH at X400PO; William Breed_at_HQ-EXCH at X400PO
Cc: Joseph Kelliher_at_HQ-EXCH at X400PO
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Doug and Andy,

Andy What's reasonable goal for fact checking this chapter?

Bill, PO should be on call to help if asked.

Margot

-----Original Message-----
From: Kjersten_S._Drager@ovp.eop.gov%internet

[mailto:Kjersten_S._Drager@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:56 AM
To: McSlarrow, Kyle; Anderson, Margot; Kelliher, Joseph
Cc: Karen_Y._Knutson@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Charles_M._Smith@ovp.eop.gov%internet
Subject: Info. Needed for Chapter 5 by 3:00 TODAY...

(See attached file: Chapter Five Assignments.doc)

(See attached file: CHAPTER 5 - original.doc)

Also attached is a copy of the Chapter Five draft that we've been working from so you can refer to that it if you don't already have a copy.

Margot - we still need EIA to fact check Chapters 3, 5, 6, 7 and 8.

Thanks so much! -Kjersten << File: CHAPTERF.DOC >> << File: CHAPTER5.DOC >>

Kelliher, Joseph

From: Kelliher, Joseph
Sent: Monday, June 25, 2001 6:29 PM
To: Anderson, Margot
Subject: NEP meetings

Thanks.

Kelliher, Joseph

From: Anderson, Margot
Sent: Tuesday, June 26, 2001 8:01 AM
To: Kelliher, Joseph
Subject: more meetings

Joe,

2/26 - White House NEP meeting at 3:30 (can't tell from my calendar topic or who attended)

3/23 - NEP meeting at Jackson Place. Topic not clear. I did attend a meeting (with you and Kevin) at Jackson Place that discussed options (the meeting where work groups were set up). Can't tell if this is that meeting but it might well be.

Margot

Kelliher, Joseph

From: Kelliher, Joseph
Sent: Tuesday, June 26, 2001 9:27 AM
To: Anderson, Margot
Subject: RE: more meetings

Actually, the 2/26 meeting was cancelled at the last minute and rescheduled for 2/28 at 4. I came across an email from Charlie from 10:41 am on 2/26 to that effect.

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, June 26, 2001 8:01 AM
To: Kelliher, Joseph
Subject: more meetings

Joe,

2/26 - White House NEP meeting at 3:30 (can't tell from my calendar topic or who attended)

3/23 - NEP meeting at Jackson Place. Topic not clear. I did attend a meeting (with you and Kevin) at Jackson Place that discussed options (the meeting where work groups were set up). Can't tell if this is that meeting but it might well be.

Margot

9182

DOE015-2525

Kelliher, Joseph

From: Anderson, Margot
Sent: Tuesday, June 26, 2001 10:23 AM
To: Kelliher, Joseph
Subject: RE: meetings

I have on my calendar on 3/6 NEP meeting at WH. That's it. Nothing from Fenzel on the 3/6 meeting (he tended to weigh in on only on principals' meetings). This was probably a staff meeting.

Did you see Energy Daily today? Looks like WH is not willingly wanting to engage on the GAO request.

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, June 26, 2001 9:52 AM
To: Anderson, Margot
Subject: meetings

Hopefully, my last question. Was there a working group meeting on 3/6? I have a email from John Fenzel to that effect, but nothing on my calender.

9183

DOE015-2526

Williams, Ronald L

From: Poche, Michelle [Michelle.Poche@ost.dot.gov]
Sent: Monday, March 26, 2001 7:18 AM
To: Anderson, Margot
Subject: RE: DOT Comments

Have asked staff to provide source(s).
Thanks!
--MP

-----Original Message-----
From: Anderson, Margot [mailto:Margot.Anderson@hq.doe.gov]
Sent: Sunday, March 25, 2001 1:29 PM
To: 'Poche, Michelle'; Kelliher, Joseph
Cc: 'Symons.Jeremy(a)EPA.gov'
Subject: RE: DOT Comments

Michelle,

Margot

-----Original Message-----
From: Poche, Michelle [mailto:Michelle.Poche@ost.dot.gov]
Sent: Saturday, March 24, 2001 4:18 PM
To: Kelliher, Joseph
Cc: Anderson, Margot; 'Symons.Jeremy(a)EPA.gov'
Subject: DOT Comments

Joe and Margot,
Here are some comments from DOT policy staff on your chapters. Since our systems don't always talk to each other, I'll paste them below into this email as well as attaching a document. Please let me know if you have questions, and I'll run them down with the folks who have offered these suggestions.

Jeremy, Joe and Margot,

B-5

Thanks,
Michelle

9205

DOE015-2548

<< File: DOT comments.doc >>

Williams, Ronald L

From: Poche, Michelle [Michelle.Poche@ost.dot.gov]
Sent: Monday, March 26, 2001 7:57 AM
To: Anderson, Margot; Kelliher, Joseph
Subject: FW: New Chapter 9 from DOT

Margot/Joe,
Here's the new draft of Chapter 9. Wanted to get it to you ahead of the rest of the crew, since I'm requesting energy info from DOE.
Look for brackets to identify places where I've identified needs for info.
Thanks a million.
--Michelle

-----Original Message-----
From: Poche, Michelle
Sent: Monday, March 26, 2001 7:55 AM
To: 'Karen_Y._Knutson@ovp.eop.gov'; 'Charles_M._Smith@ovp.eop.gov'; John_Fenzel@ovp.eop.gov
Subject: New Chapter 9 from DOT

Charlie, since I didn't have a second peer review meeting, would it be possible to distribute this to the full group as soon as possible to solicit edits/comments?
Thanks very much.
--Michelle

Ch9.03.26.doc

9209

DOE015-2552

Williams, Ronald L

From:	Kelliher, Joseph
Sent:	Monday, March 26, 2001 9:05 AM
To:	Garrish, Ted; Kolevar, Kevin; Anderson, Margot
Subject:	national energy policy options
Importance:	High

Here is the list where it now stands. I want to finalize a list that we could give to the Secretary this afternoon. Please identify the proposals that raise serious problems so we can discuss, and also indicate if there are glaring omissions from the list. Thanks.

fedactlst3.doc

Kelllher, Joseph

From: Dave Nevius [Dave.Nevius@nerc.net]
Sent: Tuesday, July 17, 2001 10:18 AM
To: Glotfelty, Jimmy
Cc: Kelliher, Joseph; Linda Stuntz (E-mail); DNC (E-mail)
Subject: RE: Reliability Legislation and National Grid Study

Reliability legislation and FE... IndustrySRRO.pdf

Jimmy

I suspect we'll talk more about this in the days and weeks ahead, especially as the Administration prepares to release its proposed legislation.
dave

-----Original Message-----
From: Glotfelty, Jimmy [mailto:Jimmy.Glotfelty@hq.doe.gov]
Sent: Tuesday, July 17, 2001 9:02 AM
To: Dave Nevius
Cc: Kelliher, Joseph; 'Linda Stuntz (E-mail)'; 'DNC (E-mail)'
Subject: RE: Reliability Legislation and National Grid Study

!

Jimmy Glotfelty
Senior Policy Advisor
Office of the Secretary of Energy
1000 Independence Avenue, SW
Washington, DC 20585
202-586-5478
jimmy.glotfelty@hq.doe.gov

-----Original Message-----
From: Dave Nevius [mailto:Dave.Nevius@nerc.net]
Sent: Tuesday, July 17, 2001 7:47 AM
To: Glotfelty, Jimmy
Cc: Kelliher, Joseph; Linda Stuntz (E-mail); DNC (E-mail)
Subject: RE: Reliability Legislation and National Grid Study

Jimmy

Sorry you asked?

dave

-----Original Message-----
From: Glotfelty, Jimmy [mailto:Jimmy.Glotfelty@hq.doe.gov]
Sent: Monday, July 16, 2001 5:52 PM
To: Dave Nevius
Subject: FW: Reliability Legislation and National Grid Study

Dave: Joe forwarded me your email - since I am in charge of the Grid Study.

Thanks for your comments on outside experts to run the grid study.

Jimmy Glotfelty
Senior Policy Advisor
Office of the Secretary of Energy
1000 Independence Avenue, SW
Washington, DC 20585
202-586-[illegible]
jimmy.glotfelty@hq.doe.gov

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, July 13, 2001 5:20 PM
To: Glotfelty, Jimmy
Subject: Reliability Legislation and National Grid Study

FYI

-----Original Message-----
From: Dave Nevius [mailto:Dave.Nevius@nerc.net]
Sent: Friday, July 13, 2001 11:47 AM
To: Kelliher, Joseph
Subject: Legislation and National Grid Study

Joe
Two separate things:

Thanks.

dave

Release

SR/OIAF/2001-01

The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply

May 2001

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

9246

Contacts

This report was prepared by the Office of Integrated Analysis and Forecasting, Energy Information Administration. General questions concerning the report may be directed to Mary J. Hutzler (202/586-2222, mary.hutzler @eia.doe.gov), Director of the Office of Integrated Analysis and Forecasting, and James M. Kendell (202/586-9646, james.kendell@eia.doe.gov), Director of the Oil and Gas Division. Specific questions about the report may be directed to the following analysts:

Background
Stacy MacIntyre .... 202/586-9795 stacy.macintyre@eia.doe.gov

Vehicle Technologies
John Maples .... 202/586-1757 john.maples@eia.doe.gov

Refinery Technologies
Han-Lin Lee .... 202/586-4247 han-lin.lee@eia.doe.gov

Oil Pipelines
James Kendell .... 202/586-9646 james.kendell@eia.doe.gov

Individual Refinery Analysis
Bruce Bawks .... 202/586-6579 bruce.bawks@eia.doe.gov

Equilibrium Analysis
Stacy MacIntyre .... 202/586-9795 stacy.macintyre@eia.doe.gov

Comparisons
Stacy MacIntyre .... 202/586-9795 stacy.macintyre@eia.doe.gov

Significant contributions were also made to Chapter 2 by Mark Friedman; to Chapter 3 by Stacy MacIntyre, John Hackworth, and James Kendell; to Chapter 4 by Cheryl Trench, C.R. Wilson, and Albert Walgreen; to Chapter 5 by John Hackworth, John Marano, Jared Ciferno, and Howard McIlvried; to Chapter 6 by Han-Lin Lee, Bruce Bawks, Elizabeth May, and Andy Kydes; and to Chapter 7 by Albert Walgreen.

9246A

Preface

In December 2000 the U.S. Environmental Protection Agency (EPA) issued a final rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. The purpose of the rulemaking is to reduce emissions of nitrogen oxides and particulate matter from heavy-duty highway engines and vehicles that use diesel fuel. The rulemaking requires new emissions standards for heavy-duty highway vehicles that will take effect in model year 2007. "The pollution emitted by diesel engines contributes greatly to our nation's continuing air quality problems," the EPA noted in its regulatory announcement. "Even with more stringent heavy-duty highway engine standards set to take effect in 2004, these engines will continue to emit large amounts of oxides of nitrogen (NO_x) and particulate matter (PM), both of which contribute to serious public health problems in the United States."

While the review of this rule was underway, the Committee on Science of the U.S. House of Representatives asked the Energy Information Administration (EIA) to provide an analysis of the proposal (Appendix A). The Committee noted that the proposed rule would reduce the level of sulfur in highway diesel by 97 percent. "These deep sulfur reductions will require significant investment s that not all refiners may choose to make. As a result, diesel fuel supplies could be affected," the Committee's letter stated.

In response to the Committee's request, EIA undertook an analysis incorporating two different analytical approaches. Mid-term issues and trends are addressed through scenario analysis using EIA's National Energy Modeling System. In addition, refinery cost analysis addresses the uncertainty of supply in the short term. Discussion of the key issues and uncertainties related to the distribution of ultra-low-sulfur diesel is based on interviews with a number of pipeline carriers. As suggested by the Committee, most of the major assumptions in this report are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule.

Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review earlier versions of this analysis and provide comment. The reviewers provided comments on two draft versions of the report and discussed their comments in a joint meeting. All comments from the reviewers either have been incorporated or were thoroughly considered for incorporation. As is always the case when peer reviews are undertaken, not all the reviewers may be in agreement with all the methodology, inputs, and conclusions of the final report. The contents of the report are solely the responsibility of EIA. The assistance of the following reviewers in preparing the report is gratefully acknowledged:

Raymond E. Ory
Baker and O'Brien, Inc.

Norman Duncan
Energy Institute, University of Houston

Kevin Waguespack
PricewaterhouseCoopers

The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the U.S. Department of Energy or any other organization.

Contents

Page

Executive Summary . . . ix

1. Background and Methodology . . . 1
Introduction . . . 1
Summary of the Final ULSD Rule . . . 1
Summary of the Request for Analysis . . . 2
Background . . . 3
Methodology . . . 4
Assessment of Short-Term Effects of the Rule . . . 4
Assessment of Mid-Term Effects of the Rule . . . 5
Assessment of Distribution and Marketing Effects of the Rule . . . 6

2. Efficiency and Cost Impacts of Emission Control Technologies . . . 9
Background . . . 9
Emission Control Technologies . . . 9
Technology Costs . . . 11
Efficiency Losses . . . 11

3. Desulfurization Technology . . . 13
Introduction . . . 13
ULSD Production Technologies . . . 13
Hydrotreating . . . 14
NEMS Approach to Diesel Desulfurization Technology . . . 17
Individual Refinery Analysis Approach to Diesel Desulfurization Technology . . . 18
Expected Developments and Cost Improvements . . . 19
Deployment of Desulfurization Technologies . . . 19
Conclusion . . . 22

4. Impact of the ULSD Rule on Oil Pipelines . . . 23
Introduction . . . 23
The Role of Refined Petroleum Product Pipelines . . . 23
Overview of Key Pipeline Operations . . . 24
Challenges of the ULSD Rule . . . 25
Estimation of Interface Generation . . . 26
Strategies for Buffering ULSD in a Pipeline . . . 27
The 20-Percent Downgrade Rule . . . 28
Residual Sulfur in a Pipeline . . . 29
Product Testing . . . 29
Special Issues Related to the Phase-In . . . 32
Overview of Tariff Rate Issues . . . 33
Distribution Costs in the EIA Model . . . 34
Summary . . . 34

Contents (Continued)

5. **Short-Term Impacts on ULSD Supply** . . . 37
Background . . . 37
Cost Analysis . . . 38
Analysis of ULSD Production Decisions . . . 40
Economic Considerations . . . 40
Supply Scenarios . . . 41
Imports . . . 41
Demand Issues . . . 42
Cost Curves and Demand Estimates for 2006 . . . 44
Balancing Demand and Supply in 2006 . . . 48
Summary . . . 50

6. **Mid-Term Analysis of ULSD Regulations** . . . 51
Assumptions . . . 51
Results . . . 54
Regulation Case . . . 55
Higher Capital Cost Case . . . 55
2/3 Revamp Case . . . 55
10% Downgrade Case . . . 56
4% Efficiency Loss Case . . . 57
1.8% Energy Loss Case . . . 57
Severe Case . . . 57
No Imports Case . . . 58
10% Return On Investment Case . . . 58
Regional Variations in Refining Costs . . . 58
Conclusion . . . 58

7. **Comparison of Studies on ULSD Production and Distribution** . . . 61
Analyses of Refining Costs . . . 61
EPA Analysis . . . 63
Mathpro Analysis . . . 64
NPC Analysis . . . 65
CRA/BOB Analysis . . . 65
EnSys Analysis . . . 66
ANL Analysis . . . 66
Summary of Investment Estimates . . . 67
Distribution Cost Analyses . . . 70
Downgrade Analysis . . . 72

Bibliography . . . 73

Appendixes

A. Letters from the Committee on Science, U.S. House of Representatives . . . 79
B. Differences From the *AEO2001* Reference Case . . . 85
C. Pipeline Regions and Operations . . . 89
D. Short-Term Analysis of Refinery Costs and Supply . . . 97
E. Model Results . . . 107

9248A

Tables

ES1. Short-Term Scenarios . . . x
ES2. Short-Term Demand Estimates, 2006 . . . xi
ES3. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015 . . . xiv
1. Projected Fuel Expenditures for Heavy-Duty Diesel Vehicles, 2006-2020 . . . 12
2. Desulfurization Units Represented in the NEMS Petroleum Market Module . . . 18
3. Range of Hydrotreater Units Represented in the Individual Refinery Analysis . . . 18
4. Estimated Peak Engineering and Construction Labor Requirements for Gasoline and Diesel Desulfurization Projects . . . 21
5. EPA Estimates of Desulfurization Unit Startups, 2001-2010 . . . 21
6. Sample Results from the ULSD Cost Model . . . 38
7. Estimate of Revamps and New Hydrotreaters for ULSD Production . . . 41
8. Supply and Demand Estimates in the Reference Case, 2006 . . . 46
9. Supply and Demand Estimates in the High Economic Growth Case, 2006 . . . 47
10. Supply and Demand Estimates in the Low Economic Growth Case, 2006 . . . 47
11. Supply and Demand Estimates in the Higher Capital Cost Sensitivity Case, 2006 . . . 50
12. Supply and Demand Estimates in the 10% Return on Investment Sensitivity Case, 2006 . . . 50
13. Comparison of EIA and EPA Assumptions . . . 52
14. Variation from Reference Case Projections of Cumulative Capital Expenditures for Hydrogen and Distillate Hydrotreating Units in EIA Sensitivity Cases, 2007, 2010, and 2015 . . . 55
15. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015 . . . 56
16. Variations from Reference Case Projections of Fuel Distribution Costs in the Regulation and 10% Downgrade Cases . . . 57
17. Variations from Alternative Reference Case Projections in the 10% Return on Investment Case, 2007-2015 . . . 58
18. Variations from Reference Case Projections of ULSD Marginal Refinery Gate Prices by Region in the Regulation and Sensitivity Analysis Cases, 2007-2015 . . . 59
19. Methodologies Used To Estimate ULSD Refining Costs . . . 62
20. Characteristics of ULSD Cost Studies . . . 62
21. EPA Estimates of Increased Costs To Meet the 15 ppm Highway Diesel Standard . . . 63
22. Mathpro Estimates of the Costs of Producing 15 ppm Highway Diesel, with Non-Road Diesel at 3,500 ppm Sulfur . . . 64
23. Comparison of ULSD Production Cost Estimates: Individual Refinery Representation . . . 67
24. Comparison of ULSD Production Cost Estimates: LP Model or Based on LP Results . . . 68
25. Comparison of Key Hydrotreator Investment Assumptions for Various Refinery Models . . . 69
26. Comparison of ULSD Distribution Cost Estimates and Assumptions . . . 70
27. Projected Relative Price Decrease by PADD and Percentage of Diverted Diesel . . . 72
D1. API/NPRA Survey of Distillate Product Compositions, 1996 . . . 98
D2. Cetane Number of Light Cycle Oil From Some World Crude Oils . . . 99
E1. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 5-Percent Return on Investment . . . 108
E2. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 10-Percent Return on Investment . . . 109

Figures

ES1. ULSD Cost Curve Scenarios with 2006 Demand Estimates . . . xi
ES2. Difference Between End-Use Prices of ULSD and 500 ppm Diesel in the Reference Case, 2007-2015 . . . xiv
1. Pipeline Shipments of Distillate Fuels Between PADDs, 1999 . . . 25
2. Monitoring Pipeline Product for Contamination . . . 30
3. Monitoring Pipeline Batch Change . . . 31
4. Imports of Low-Sulfur Diesel Fuel into PADD I, 1993-2000 . . . 42
5. Low-Sulfur Diesel Consumption and Product Supplied, 1993-1999 . . . 43
6. ULSD Cost Curve Scenarios with 2006 Demand Estimates . . . 44
7. ULSD Higher Capital Cost Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates . . . 48
8. ULSD 10% Return on Investment Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates . . . 49
C1. Typical Product Sequence and Interfaces in a Refined Products Pipeline . . . 93
D1 Cost Curve for Ultra-Low-Sulfur Diesel ($1,200 Baseline ISBL Costs) . . . 102
D2. Cost Curve for Ultra-Low-Sulfur Diesel ($1,200 and $1,600 Baseline ISBL Costs) . . . 102

Executive Summary

This study was undertaken at the request of the Committee on Science, U.S. House of Representatives. The Committee asked the Energy Information Administration (EIA) to provide an analysis of the Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, which was signed by President Clinton in December 2000.[1]

The purpose of the rulemaking is to reduce emissions of nitrogen oxides (NO_x) and particulate matter (PM) from heavy-duty highway engines and vehicles that use diesel fuel. The new rule requires refiners and importers to produce highway diesel meeting a 15 parts per million (ppm) maximum requirement, starting June 1, 2006; however, pipelines are expected to require refiners to provide diesel fuel with an even lower sulfur content, somewhat below 10 ppm, in order to compensate for contamination from higher sulfur products in the system, and to provide a tolerance for testing. Diesel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010; the remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

The purpose of this study is to assess the possible impact of the new sulfur requirement on the diesel fuel market. The study discusses the implications of the new regulations for vehicle fuel efficiency and examines the technology, production, distribution, and cost implications of supplying diesel fuel to meet the new standards. In order to address both the short-term and mid-term supply issues identified by the Committee on Science, this analysis incorporates two different analytical approaches. Refinery cost analysis addresses the uncertainty of supply in the short term, during the transition to ultra-low-sulfur diesel fuel (ULSD) in 2006. Mid-term issues and trends (2007 through 2015) are addressed through scenario analysis using EIA's National Energy Modeling System (NEMS). The Committee on Science requested that these analyses use assumptions consistent with the Regulatory Impact Analysis published by the U.S. Environmental Protection Agency (EPA). Discussion of the key issues and uncertainties related to the distribution of ULSD is based on interviews with a number of pipeline carriers.

Although highway-grade diesel is the second most consumed petroleum product, gasoline is the most important product by far. In 1999 highway diesel accounted for 12 percent of total petroleum consumption and gasoline 43 percent.[2] Consumption of highway-grade diesel (500 ppm) accounted for 68 percent of the distillate fuel market in 1999, although 9 percent went to non-road (rail, farming, industry) and home heating uses.[3] Higher sulfur distillate (more than 500 ppm sulfur), used exclusively for non-road and home heating needs, accounted for the other 2 percent of the distillate market.

Assessment of Short-Term Effects of the Rule

Whether there will be adequate supply of diesel fuel as the new standard becomes effective in June 2006 is one of the key questions raised by the House Committee on Science in the request for analysis. To assess this possibility, cost increases for individual refineries to produce ULSD were estimated, the cost increases were arrayed from smallest to largest, and the resulting cost curves were matched against projected demand and imports. The cost curves reflect investment requirements and operating costs for refineries in Petroleum Administration for Defense Districts (PADDs) I through IV.[4] ULSD production costs were estimated for different groups of refineries based on size, sulfur content of feeds, fraction of cracked stocks in the feed,[5] boiling range of the feed, and fraction of highway diesel produced. Unlike ULSD analyses conducted by the EPA and others, the cost curves relied on proprietary stream data collected by

[1] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[2] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3.

[3] Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0525(99) (Washington, DC, September 2000), Tables 19-23.

[4] PADD V was not included in this analysis, because supply concerns are less of an issue in the transition period, and the requirement for California Air Resources Board diesel makes the PADD V market different from those in PADDs I-IV.

[5] Cracked stocks are previously processed streams that are more difficult to treat.

EIA.[6] The capital and operating costs for the different groups were developed for EIA by the staff of the National Energy Technology Laboratory (NETL), consistent with the EPA analysis. Return on investment was assumed to be 5.2 percent after taxes, consistent with the EPA's assumption of a 7-percent before-tax return on investment. Costs were not adjusted to take sulfur credit trading into account, because of the uncertainty about whether trading would occur and the value of the credits. If credit trading occurred, costs could be reduced.

Cost representations of desulfurization units were used to develop four sets of cost curves, based on four different investment rationales (Table ES1). Within a given supply curve, the relative costs of different groups of refineries provide an indicator of possible supply shortfalls at the beginning of the ULSD requirement in the summer of 2006. Some refiners may be able to produce ULSD at a cost of about 2.5 cents per gallon; however, at the volumes needed to meet demand, costs are estimated at 5.4 to 6.8 cents per gallon,[7] and they could be higher if supply falls short of demand and consumers bid up the price. The behavior of refiners will be influenced by their expectation of what others will do and is therefore subject to considerable uncertainty.

The four refinery investment scenarios have progressively more volume and are defined as follows:

- The **Competitive Investment** scenario includes only those refiners that are very likely to prepare to produce ULSD in 2006. They currently hold market share and are estimated to be able to produce ULSD at a competitive cost. Refiners with highway diesel as a relatively low fraction of their distillate production are assumed to abandon the market unless their cost per unit of production is competitive at current highway diesel production levels.
- In the **Cautious Expansion** scenario, current producers with competitive cost structures for ULSD production and high fractions of highway diesel production (greater than 70 percent) are assumed to maintain current production levels and, possibly, to push production of ULSD toward 100 percent of their distillate production if only minor increases in per-unit production costs occur for the increased volume.
- The **Moderate New Market Entry** scenario assumes that a selective number of refineries currently producing little or no highway diesel will enter the ULSD market. The underlying premise is that a limited number of companies would think that they would be able to gain market share without depressing margins to the extent of undercutting profits.
- The **Assertive Investment** scenario assumes that a larger number of refiners would make the requisite investments to either maintain or gain share in the highway diesel market. In this scenario, refiners would believe that most of their competitors were overly cautious, and that they could succeed by taking a contrary strategy (which in reality would be adopted by far more refiners than anticipated).

As a result of distribution limitations and non-road uses, the amount of ULSD actually needed to balance demand in 2006 is highly uncertain. Accordingly, a range of demand estimates was developed to account for some of the uncertainty (Table ES2 and Figure ES1). The Small Refiner and Temporary Compliance Options demand estimate was calculated as 80 percent of the estimated demand for transportation distillate for both highway and non-road uses in PADDs I-IV in 2006 (excluding production by small refineries, which are allowed to request waivers to delay production until 2010), representing the EPA's requirement to produce 80 percent ULSD after the regulation takes effect. The Small Refiner and Temporary Compliance Options with Imports

Table ES1. Short-Term Scenarios

Scenario	Number of Refineries Producing ULSD	Characteristics
(1) Competitive Investment	66	Current low-sulfur diesel producers maintain market share. Low-fraction producers drop out.
(2) Cautious Expansion	66	Some low-sulfur diesel producers in Scenario 1 expand production.
(3) Moderate New Market Entry	67	One refinery not currently producing low-sulfur diesel enters the ULSD market. Nine other producers in Scenario 2 expand production.
(4) Assertive Investment	74	A larger number of refineries not currently producing low-sulfur diesel enter the ULSD market. Some others expand production.

Notes: Current low-sulfur diesel contains 500 ppm sulfur. ULSD contains 7 ppm sulfur to compensate for contamination and to provide a tolerance for testing.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[6]The EPA used EIA data on refinery capacity and diesel production in its refinery-by-refiney analysis.
[7]These are marginal costs on the industry supply curve, based on average refinery costs for producing ULSD. These cost estimates do not include additional costs for distribution, estimated at 1.1 cents per gallon in the mid-term analysis.

9250A

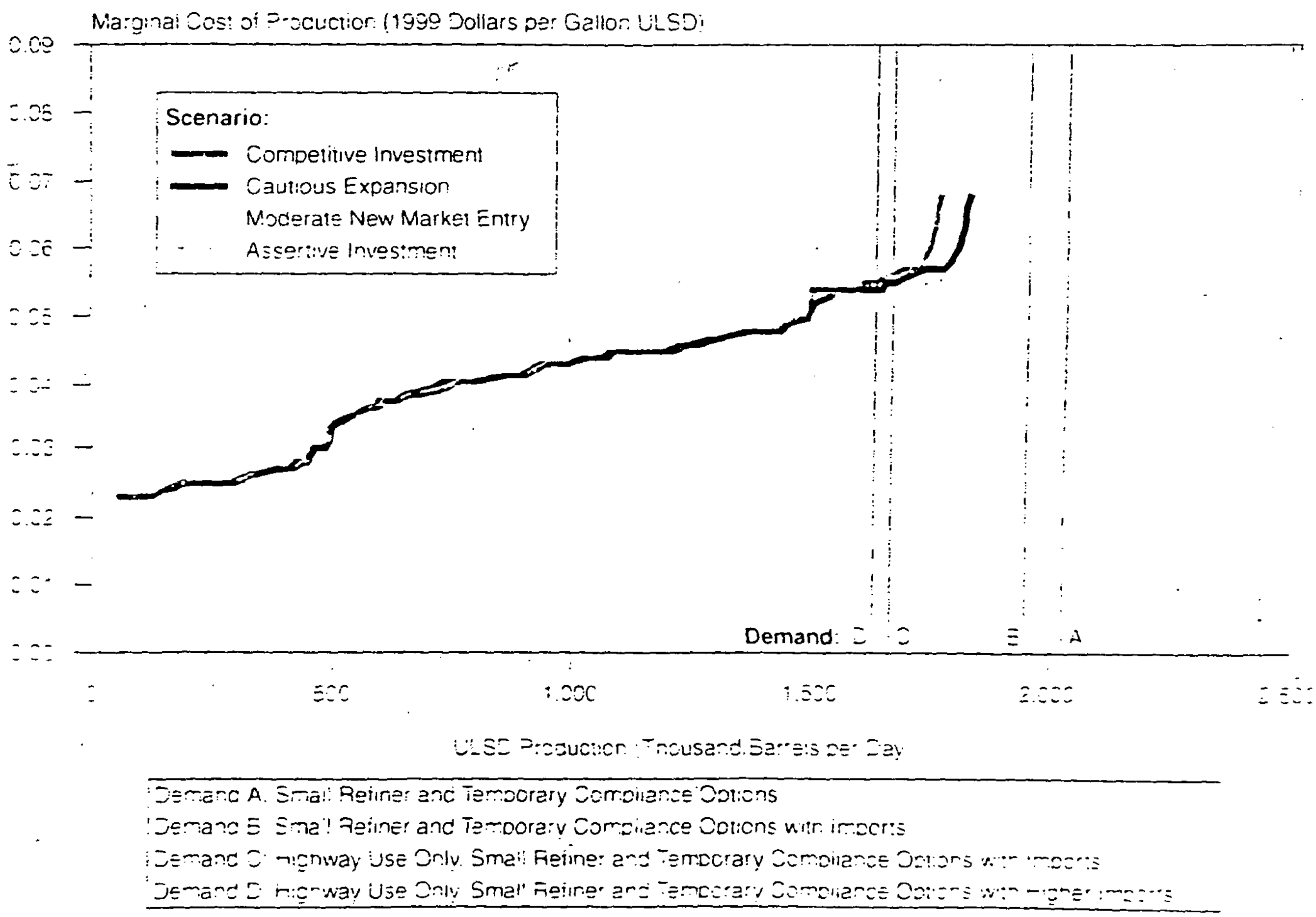
estimate assumes that imports from Canada and the Virgin Islands will continue at historical levels (Demand B, which matches the demand projection in the mid-term analysis described in Chapter 6). The Highway Use Only, Small Refiner and Temporary Compliance Options with Imports estimate (Demand C) assumes that ULSD will be used only to meet highway transportation demand, that the temporary compliance option will further reduce this demand by 20 percent, and that imports will remain at historical levels. Finally, the Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports estimate (Demand D) assumes a higher level of ULSD imports.[8]

Table ES2. Short-Term Demand Estimates, 2006

Estimate	Demand Level (Thousand Barrels per Day)	Characteristics
Demand A: Small Refiner and Temporary Compliance Options	2,026	76 percent of transportation demand.
Demand B: Small Refiner and Temporary Compliance Options with Imports	1,946	Demand estimate A, less projected imports from Canada and the U.S. Virgin Islands.
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	65 percent of transportation demand, less projected imports from Canada and the U.S. Virgin Islands.
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,626	Demand estimate C, less higher projected imports

Source: National Energy Modeling System, run DSU7INV.D043001A.

Figure ES1. ULSD Cost Curve Scenarios with 2006 Demand Estimates



Sources: Cost curve scenarios, Appendix D. Demand estimates, National Energy Modeling System, run DSU7INV.D043001A.

[8] Additional demand estimates are analyzed in Chapter 5.

9251

The combined cost curves for PADDs I-IV show that the total volume of ULSD production on the cost curves for the Competitive Investment and Cautious Expansion scenarios, production reaches the two lowest demand estimates, although at different costs (Figure ES1). In the Moderate New Market Entry scenario, production just reaches the Small Refiner and Temporary Compliance Options with Imports estimate. In the Assertive Investment scenario, production just reaches the Small Refiner and Temporary Compliance Options estimate.

The largest shortfall—estimated at 264,000 barrels per day relative to the Small Refiner and Temporary Compliance Options demand estimate (Demand A, the highest demand estimate in Table ES2)—occurs in the Competitive Investment scenario (which assumes the most cautious investment strategy and has the lowest production estimate). The largest surplus—517,000 barrels per day relative to the Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports estimate (the lowest demand estimate)—occurs in the Assertive Investment scenario (which assumes the most aggressive investment strategy and has the highest production estimate).

With the Highway Use Only, Small Refiner and Temporary Compliance Options with Imports demand estimate (Demand C), all the production scenarios project sufficient supply (at least in the aggregate). For the Small Refiner and Temporary Compliance Options with Imports demand estimate (Demand B), the Moderate New Market Entry and Assertive Investment production scenarios provide supplies that are higher than demand by 197,000 barrels per day and 6,000 barrels per day, respectively. Supplies in the Competitive Investment and Cautious Expansion scenarios fall short of Demand B by 184,000 and 123,000 barrels per day, respectively. For the Small Refiner and Temporary Compliance Options demand estimate (Demand A), only the Assertive Investment production scenario provides sufficient supply.

Two sensitivity cases were used to examine the effects of assumptions about hydrotreater capital costs and about return on investment. The capital costs assumed in the initial set of four scenarios are similar to those used in the EPA analysis. When the capital costs for hydrotreater units are assumed to be about 40 percent higher than assumed in the initial set of scenarios, production of ULSD is projected to be 25,000 to 55,000 barrels per day lower, and the production costs are projected to be from 0.5 to 1.1 cents per gallon higher. When a 10-percent return on investment is assumed, as compared with 5.2 percent assumed in the initial set of scenarios, production is projected to be 40,000 to 66,000 barrels per day lower and costs 0.8 to 1.2 cents per gallon higher. Because of the reduced volumes, estimated production levels in the Moderate New Market Entry Scenario fall short of the demand level projected in the Small Refiner and Temporary Compliance Options with Imports estimate in both the higher capital cost and higher required return on investment sensitivity cases.

The scenarios indicate the possibility of a tight diesel market when the ULSD Rule is implemented. Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand scenarios show adequate supply to meet estimated demand. Furthermore, this analysis compares supply and demand at a very aggregate level. Maintaining a balance of supply and demand across regions and throughout the distribution system could be even more difficult.

If supplies fell short of demand, sharp price increases would likely occur to balance supply and demand. Sharply higher prices would curtail demand for diesel fuel. Truckers would reduce consumption to the extent possible and try to pass higher fuel costs on to customers, who would then look for alternative means to transport goods. In this situation refiners would attempt to maximize ULSD production. Some additional production may be possible by, for example, shifting some non-road distillate or jet fuel streams into ULSD. Additional imports of ULSD or jet fuel could be forthcoming if there were large price differentials between markets.

In 2006, little ULSD will actually be needed, because few new vehicles requiring ULSD will be on the road by then. If it becomes apparent that there will be inadequate supply, or if distillate markets are tight, the EPA could temporarily reduce the required proportion of ULSD production, which could make additional diesel supplies available. However, a temporary reduction would reduce the availability of ULSD supplies for new vehicles. In its final rulemaking the EPA required refiners and importers to submit a variety of reports to ensure a smooth transition, and the agency plans to establish an advisory panel to look at issues of diesel supply and monitor the progress of related technologies.

Assessment of Mid-Term Effects of the Rule

The mid-term analysis for this study was performed using the NEMS Petroleum Market Module (PMM) to assess the impact of new requirements for ULSD in the years 2007 through 2015. The PMM represents domestic refinery operations and the marketing of petroleum products to consumption regions. Refining operations are represented by a three-region linear programming formulation of the five PADDs. PADDs I (East Coast) and V (West Coast) are treated as single regions, and

9251A

PADDs II (Midwest), III (Gulf Coast), and IV (Rocky Mountains) are aggregated into one region. Each region is considered as a single firm, for which more than 80 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region.

Unlike previous ULSD analyses, the PMM provides multi-year scenarios. These scenarios reflect market prices rather than average costs and implicitly include investment and import decisions. In contrast to the cost curves used in the short-term analysis, the NEMS projections reflect equilibrium market prices. That is, the results of the PMM scenarios assume that, in the long run, refiners will increase supply to meet demand. As a result, the NEMS analysis reflects more aggressive investment behavior than that portrayed for individual refiners in the short-term analysis.

The PMM was used to develop a ULSD Regulation case based on the provisions of the EPA's final ULSD Rule. A Severe case was developed to combine five sensitivity cases associated with greater uncertainty in industry operations and costs.[9] Finally, a No Imports case and a 10% Return on Investment case were developed.

In the **Regulation case**, highway diesel at the refinery gate is assumed to contain a maximum of 7 ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process. Revamping existing units to produce ULSD is assumed to be undertaken by 80 percent of refineries, while 20 percent build new units. The amount of ULSD that is to be downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to total 4.4 percent. The energy content of the ULSD is assumed to decline by 0.5 percent, because undercutting and severe desulfurization will result in a lighter stream composition than 500 ppm diesel. The Rule is assumed to result in no loss in vehicle fuel efficiency. The actual after-tax return on investment is assumed to be 5.2 percent, which is equivalent to a 7-percent before-tax return on investment. As suggested by the Committee, the major assumptions in this case are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule.[10]

The **Severe case** combines five sensitivities at variance with the above assumptions. In the "2/3 Revamp" sensitivity case, two-thirds of upgrades at refineries are assumed to be accomplished by retrofitting existing equipment and one-third by construction of all new units, consistent with the results of the individual refinery analysis. In the "10% Downgrade" case, 10 percent of the 15 ppm diesel produced is assumed to be downgraded to a lower value product because of contamination with higher sulfur products in the distribution system. In the "4% Efficiency Loss" case it is assumed that manufacturers will meet the emissions requirements of the ULSD Rule by installing after-treatment technology on new vehicles beginning in 2010, which would result in a 4-percent loss of fuel efficiency that is phased out as new technology emerges. In the "1.8% Energy Loss" case, a greater loss of energy content is assumed than in the Regulation case. In the "Higher Capital Cost" case, the capital costs of the hydrotreaters are 24 percent higher and 33 percent higher than in the Regulation case, based on a review of the most recent industry cost data.

The **No Imports case** assumes that foreign imports of ULSD will not be available. This assumption was not included in the Severe case because it was deemed to be less likely. Foreign supplies should be available from Canadian refiners, who likely will move to the U.S. standard at the same time as the United States, and from a large refinery in the U.S. Virgin Islands that is jointly owned by Armada Hess and Venezuela's national oil company, PdVSA. Both owners of the Virgin Islands plant see the United States as a strategic market. The greatest uncertainty for import availability is likely to occur in the early years of the program, because foreign refiners may delay investment until the market outlook for ULSD is more certain.

The **10% Return on Investment** case uses the after-tax rate of return assumed in most other studies, which is higher than the 5.2-percent after-tax rate used in the Regulation case and in the other sensitivity cases in this study, consistent with the EPA's assumption. At a rate of return less than 10 percent, investors may hesitate to put money into the refinery industry, especially for equipment designed for a new product.

In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011 (Table ES3 and Figure ES2).[11] The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD. In absolute terms, real marginal prices range from $1.29 to $1.35 per gallon in the Regulation and Severe cases from 2007 to 2011.[12] Refiners are projected to invest $6.3 to $9.3 billion to meet full compliance with the ULSD Rule through 2011.

[9] Results for the five sensitivity cases are provided in Chapter 6 and Appendix E.

[10] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*, EPA420-R-00-026 (Washington, DC, December 2000).

[11] Analysis of 2006 is discussed above. As a partial year, 2006 is not included in the equilibrium analysis.

[12] These cases are based on variations from a reference case similar to that in EIA's *Annual Energy Outlook 2001*.

After 2011, the first full year of 100 percent ULSD, the projected differential of marginal prices is generally expected to decline, because of lower distribution and capital investment costs. About 0.7 cents of the projected decline results from using the EPA's assumption that the additional capital investments for distribution and storage of a second highway diesel fuel will be fully amortized during the transition period. The remainder of the drop in the post-2011 differential occurs because refineries are assumed to have completed the upgrades necessary for full compliance, to be making additional investment only to meet incremental demand, to be replacing and upgrading existing equipment, and to be making incremental operating improvements that make ULSD production less challenging. A similar decline in the price differential also occurs in all the sensitivity cases.

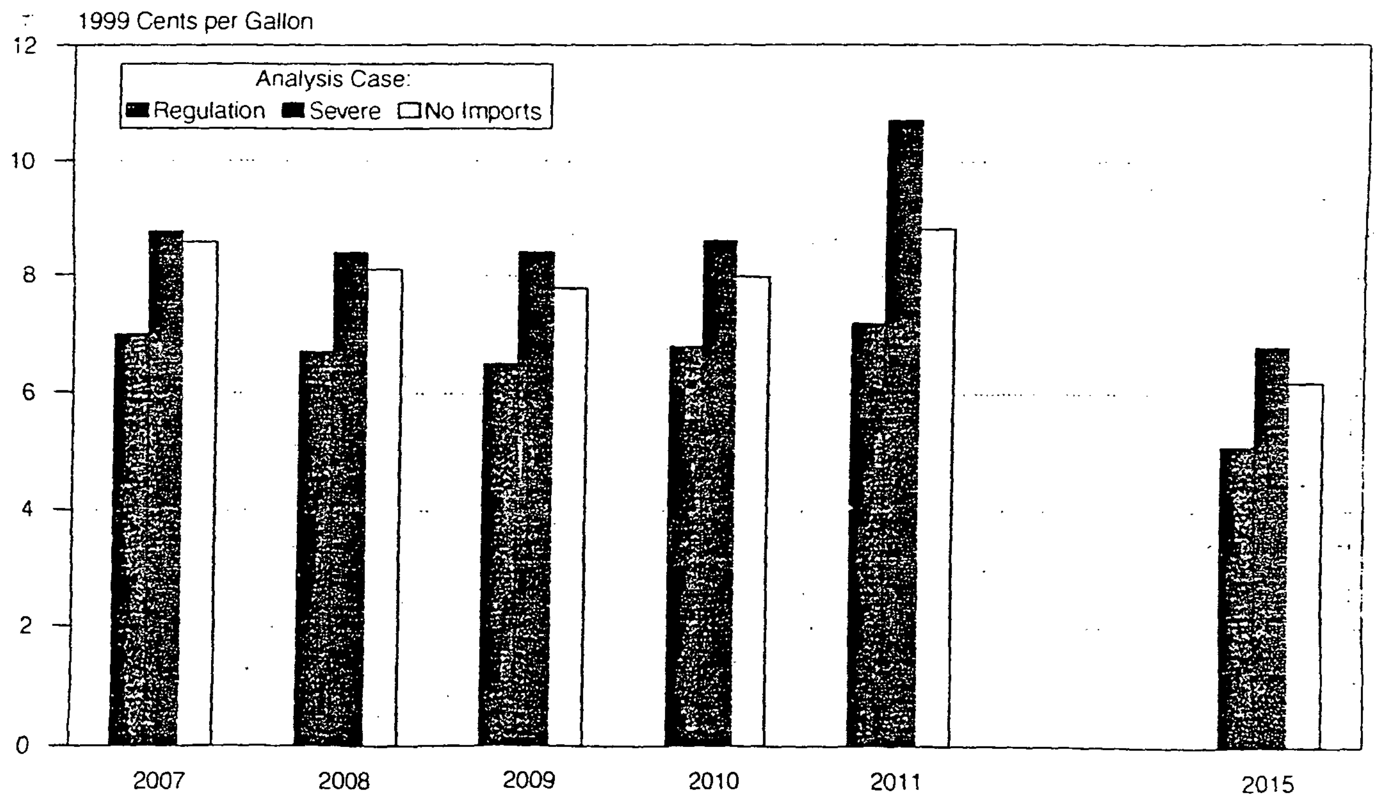
Through 2010, the Regulation case projections for highway diesel consumption exceed the reference case levels

Table ES3. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015

Analysis Case	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)								
Regulation	7.0	6.7	6.5	6.8	7.2	5.1	6.8	5.4
Severe	8.8	8.4	8.4	8.6	10.7	6.8	8.6	7.4
No Imports	8.6	8.1	7.8	8.0	8.8	6.2	8.1	6.8
Total Highway Diesel Fuel Consumption (Thousand Barrels per Day)								
Regulation	10	10	8	8	83	85	9	83
Severe	41	40	39	57	355	374	44	366
No Imports	10	9	7	7	81	83	8	81
Total Imports of Highway Diesel Fuel (Thousand Barrels per Day)								
Regulation	-36	-1	-1	0	0	0	-10	0
Severe	-36	-1	-1	0	0	0	-10	0
No Imports	-120	-125	-125	-125	-125	-125	-124	-125

Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7ALL.D050101A, and DSUIMP0.D043001A.

Figure ES2. Difference Between End-Use Prices of ULSD and 500 ppm Diesel in the Reference Case, 2007-2015



Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7ALL.D050101A, and DSUIMP0.D043001A.

9252A

by up to 10,000 barrels per day, which can be attributed to the assumption of 0.5-percent loss in energy content. In 2011 the differential in consumption increases to 83,000 barrels per day, because ULSD contaminated in the distribution system can no longer be downgraded to 500 ppm highway diesel, and refiners must therefore make more ULSD.

In the Severe case, up to 57,000 barrels per day of additional highway diesel is projected to be consumed between 2007 and 2010, and an average of 366,000 barrels per day of additional consumption is projected between 2011 and 2015. The ULSD Rule by itself accounts for an average of 9,000 barrels per day of the additional consumption through 2010 and an average of 83,000 barrels per day after 2010. The combined effects of the 2/3 Revamp, 10% Downgrade, 4% Efficiency Loss, 1.8% Energy Loss, and Higher Capital Cost cases raise consumption beyond that in the Regulation case by at least 30,000 barrels per day through 2010, primarily because of energy losses and higher capital cost, and by an average of 283,000 barrels per day after 2010 because of energy losses, downgrading, and efficiency losses. The higher downgrade assumption accounts for about 210,000 barrels of the additional demand after 2010. ULSD-related investments in the Severe case are projected to total $9.3 billion through 2011, $3 billion more than in the Regulation case. Higher demand in the Severe case generally results in marginal prices 1.7 to 1.9 cents per gallon above those in the Regulation case, although costs range up to 3.5 cents per gallon higher in 2011.

The No Imports case explores the impact of the ULSD Rule by assuming that foreign imports will not be available to meet the new sulfur standard. In the Regulation case, projected imports of highway diesel are lower than in the reference case in the first few years, because foreign refiners are expected to be more hesitant to invest to meet a U.S. regulation. The No Imports case assumes that no imports of ULSD are available, and that imports of highway diesel are reduced by 120,000 to 125,000 barrels per day between 2007 and 2015, relative to the reference case. The lack of imports means that domestic refineries must produce more ULSD. The requirement for more production results in marginal prices 1.1 to 1.6 cents per gallon higher than in the Regulation case. The higher prices in the No Imports case result in a slight dampening of demand compared with the Regulation case.

Because the Regulation case assumes a 5.2-percent after-tax return on investment, the 10% Return on Investment case must be compared with an alternative base case that assumes the same return on investment. The resulting price differentials range from 7.5 to 8.0 cents per gallon between 2007 and 2011 and are 0.9 cents per gallon higher on average than when the 5.2-percent after-tax rate is assumed.

Differences between regional end-use prices in the analysis cases relative to those in the reference case reflect variations in the marginal costs of producing ULSD between regions. The cost curve analysis described in Chapter 5 indicates that PADD IV, which is made up of relatively small refineries, can be expected to be the highest cost region. The relatively high cost in PADD IV is obscured in the mid-term analysis (Chapter 6), because PADD IV is aggregated with both PADD II and the largest and lowest cost refining region, PADD III. In the transition years of the Regulation case, regional refining costs range from an average of 4.8 to 5.3 cents per gallon. PADD I is the highest cost region, PADD V is the lowest cost region, and PADDs II-IV (and average U.S.) costs fall in between. Average marginal refining costs generally narrow by about 0.5 cents per gallon in the post-2010 period, as refineries make incremental improvements that allow them to produce ULSD more efficiently.

Additional Uncertainties

Uncertainties about the pace of engine, refinery, and pipeline testing technology development; the availability of personnel, thick-walled reactors, and reciprocating compressors; the behavior of ULSD in the oil pipeline system; and cost recovery by oil pipelines further cloud the outlook for the transition to very low levels of sulfur in diesel fuel. The new ULSD Rule requires not only that the sulfur content of transportation diesel fuel oil produced by domestic refineries be drastically reduced by 2007, but also that emission controls on heavy-duty diesel engines be imposed to reduce emissions of NO_x, PM, and hydrocarbons (HC).

Historically, engine manufactures have met new emissions standards through modifications to engine design. To meet the 2007 standard, manufacturers will have to rely heavily on component and system development by emission control equipment manufacturers. In particular, engine manufacturers must implement an exhaust after-treatment catalyst technology to control NO_x emissions. Currently, the EPA expects NO_x adsorbers to be the most likely emission control technology applied by the industry. Using current catalyst technology, the fuel-rich cycle could reduce fuel efficiency by 4 percent. To date, no NO_x adsorber system has proven feasible. Although NO_x adsorbers have demonstrated compliance using ULSD (7 ppm), the systems show losses in conversion efficiency after 2,000 miles of operation. In order to meet the 2007 emission standards for heavy-duty diesel engines, conversion efficiencies must be improved, and exhaust gas recirculation equipment must be optimized. The considerable time available for research and development, however, may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies.

Beyond traditional hydrotreating to remove sulfur from diesel streams, new technologies are under development that could reduce the cost of desulfurization. They include sulfur adsorption, biodesulfurization, sulfur oxidation, gas-to-liquids, and biodiesel. Each of these technologies is in the first stages of commercialization. Although they are being spurred by the EPA Rule, it is uncertain whether any of the new technologies will make a significant contribution to meeting the requirements of the ULSD Rule in 2006, although they may have some impact later in the decade.

Before the ULSD Rule takes effect in 2006, sulfur testing methods must also be improved. The designated method, ASTM 6428-99, was developed for testing sulfur in aromatics and has not yet been adapted or evaluated by industry as a test for sulfur in diesel fuel. Because the diesel methodology has not yet been developed for the designated method, it has not yet been tested by multiple laboratories. There is also no readily available and appropriate test for sulfur that will permit the precise cuts between batches that will be required in handling ULSD. Most oil pipeline operators will probably want or need to perform in-line monitoring of sulfur content, because degradation of ULSD will easily and, possibly, frequently occur in as little as a minute's time. However, current instruments for testing sulfur do not have adequate sensitivity, accuracy, or speed for the job. Current machines require 5 to 10 minutes to complete one analysis of a passing product stream—far too long to permit a pipeline operator to make a correctional response if off-specification material is detected in a batch of ULSD.

The deployment of diesel desulfurization technologies will hinge not only on the ability and willingness of refiners to invest and the timing of investment and permitting but also on the ability of manufacturers to provide units for all U.S. refineries at once, and the availability of engineering and construction resources. In addition to providing diesel hydrotreaters, the same contractors will be designing and building gasoline desulfurization units for the Tier 2 gasoline sulfur reduction requirements that will be phased in between 2004 and 2007. The EPA's breakout of the expected startup of gasoline and diesel desulfurization units reflects an overlap of 26 gasoline units and 63 diesel units in 2006, more than any other year except 2004. The EPA estimates that 30 percent more workers will be required for the gasoline and diesel programs together than for the gasoline program alone. If thick-walled reactors are required for deep hydrotreating, delivery lead times will be longer, because only one or two U.S. companies produce thick-walled reactors. Another type of critical equipment is reciprocating compressors. Two reciprocating compressors will be required for each diesel desulfurization project. Reciprocating compressors will also be required for gasoline desulfurization projects. Excluding the former Soviet Union, there are only five manufacturers of reciprocating compressors in the world.

The exact sulfur level at which refineries will be required to produce ULSD is not certain, because there is no experience with distributing ULSD in a non-dedicated or common transportation system. Residual sulfur from high-sulfur material could contaminate subsequent pipeline material beyond the interface between the two products. Recently, Buckeye Pipe Line conducted a test of possible sulfur contamination from one product batch to another. Buckeye carefully measured the sulfur content in batches of highway diesel fuel following a batch of high-sulfur diesel fuel and found that the sulfur content of the second batch of highway diesel fuel increased. Exact sulfur levels have implications for the amount of material downgraded during pipeline and terminal operations.

If no other application or action were taken by an oil pipeline company, the existing tariff rates covering diesel fuel would apply to ULSD when that material is distributed to markets; however, oil pipelines will incur large incremental capital and operating costs in distributing the new diesel fuel. If an oil pipeline carrier is operating under the Federal Energy Regulatory Commission's commonly approved index method and applies its existing tariff rate to ULSD, there will be no basis for the carrier to recover its incremental costs in the approved rate. A carrier might file a new tariff rate expressly covering ULSD.

Comparison with Other Studies

Earlier studies related to ULSD supply and costs included analyses by the U.S. Environmental Protection Agency (EPA), Mathpro, the National Petroleum Council (NPC), Charles River and Associates with Baker and O'Brien, EnSys Energy & Systems, Inc., and Argonne National Laboratory (ANL). The studies were based on two general types of methodologies: a linear programming (LP) approach used by Mathpro, NPC, EnSys, ANL, and EIA; and a refinery-by-refinery approach used by Charles River, EPA, and EIA.

Cost estimates from the different studies are not easy to compare, because differences in estimation methodologies make them conceptually different. Both average and marginal costs can be based on LP models that operate as a single firm, or estimated from analysis of individual refineries. In general, marginal cost estimates that represent the cost of the last barrel of required supply can be seen as estimates of market prices. Average cost estimates usually reflect refinery investment, but they are not good estimates of market prices. Much of the variation in investment and cost estimates reflects

9253A

different assumptions about the cost of technologies; unit size; contingency factors; the extent to which refiners will modify existing equipment or build entirely new hydrotreaters; the cost and quantity of additional hydrogen required; the extent to which some refineries may reduce highway diesel production; and the amount of highway diesel downgraded due to fuel contamination during distribution. Nevertheless, the studies using LP models reported cost increases ranging from 4.0 to 10.7 cents per gallon, excluding distribution costs and taxes. The marginal refinery gate prices reported in this study for the post-2006 period, which exclude distribution costs and taxes, range from 4.7 to 9.2 cents per gallon.

Likewise, the costs derived from refinery-by-refinery analysis included average costs for the industry and average costs for the marginal firm, different estimates of the penetration of ULSD, different consumption estimates, different assumptions about the cost of technologies, different assumptions about the extent to which refiners will modify existing equipment or build entirely new hydrotreaters, different assumptions about the cost and quantity of additional hydrogen required, and different regions. The range of estimated cost increases reported in the studies using refinery-by-refinery analysis was 4.1 to 6.8 cents per gallon. This study's range for the 2006 analysis is at the higher end, because it leaves out the lower cost PADD V, is based on marginal industry costs rather than average refinery costs, and has 63 percent of refineries revamping their hydrotreaters, as compared with 80 percent in the studies with lower cost estimates.

1. Background and Methodology

Introduction

This study was undertaken at the request of the Committee on Science, U.S. House of Representatives. The Committee asked the Energy Information Administration (EIA) to provide an analysis of the Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, which was signed by President Clinton in December 2000.[1] Along with all other regulations finalized at the end of the Clinton Administration, the Rule underwent a 60-day review by the Bush Administration. On February 28, 2001, the Administrator of the U.S. Environmental Protection Agency (EPA), Christine Todd Whitman, gave her approval to move forward with the new rule, citing the great benefits to public health and the environment.[2]

The purpose of the rulemaking is to reduce emissions of nitrogen oxides (NO_x) and particulate matter (PM) from heavy-duty highway engines and vehicles that use diesel fuel. The rulemaking requires new emissions standards for heavy-duty highway vehicles that will take effect in model year 2007. Because the advanced emission control devices that will be required to meet the 2007 emissions standards are damaged by sulfur, and because the 2007 model year begins September 1, 2006, the rulemaking also requires the sulfur content of highway diesel to be substantially reduced by mid-2006.

The purpose of this study is to assess the possible impact of the new sulfur requirement on the diesel fuel market. The study does not address the impact of the rulemaking on vehicle emissions or public health.[3] This study discusses the implications of the new regulations for vehicle fuel efficiency and examines the technology, production, distribution, and cost implications of supplying diesel fuel to meet the new standards.

A summary of the new sulfur requirement, the analysis issues identified by the Committee on Science, and the methodology of the report are provided in the remainder of this chapter. Chapter 2 describes emission control technologies for heavy-duty diesel engines, their effects on fuel efficiency, and expected costs. Chapter 3 discusses technologies for producing ultra-low-sulfur diesel fuel (ULSD) and the analysis approaches used in this study to assess their future costs. Chapter 4 discusses the impact of the ULSD Rule on oil pipeline operations. Chapter 5 addresses the issue of future supply of ULSD, particularly during the transition period in 2006, and the potential responses of refinery operators. Chapter 6 summarizes mid-term projections (2007 through 2015) for diesel fuel prices, based on a range of assumptions in cases analyzed using EIA's National Energy Modeling System (NEMS). A comparison of the assumptions and estimates from this study with those from other analyses is provided in Chapter 7.

Summary of the Final ULSD Rule

The new ULSD Rule requires refiners and importers to produce highway diesel meeting a 15 parts per million (ppm) maximum requirement starting June 1, 2006.[4] Pipeline operators are expected to require refiners to provide diesel fuel with even lower sulfur content (somewhat below 10 ppm) in order to compensate for possible contamination from higher sulfur products in the system and to provide a tolerance for testing. Diesel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. This time schedule is driven by the need to provide fuel for the 2007 model year diesel vehicles that will become available in September 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010. The remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

The ULSD Rule provides for an averaging, banking, and trading (ABT) program. Refineries that produce more than 80 percent of their highway diesel to meet the 15 ppm limit can receive credits, which may be traded with other refineries within the same Petroleum Administration Defense District (PADD) that do not meet the 80-percent production requirement. Starting June 1, 2005, refineries can accrue credits for producing any

[1] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[2] U.S. Environmental Protection Agency, "EPA Gives the Green Light on Diesel-Sulfur Rule," Press Release (February 28, 2001).

[3] Sources addressing the impact of the ULSD Rule on vehicle emissions and public health are included in the bibliography.

[4] The State of Alaska and the U.S. Territories have been exempted from the program.

volume of highway diesel that meets the 15 ppm limit.[5] The trading program will end on May 31, 2010, after which time all refineries must produce 100 percent of their highway diesel at a low enough sulfur level to ensure 15 ppm at retail. The ABT program will not include refineries in States that have State-approved diesel fuel programs, such as California, Hawaii, and Alaska.

The Rule includes provisions for refiners in a Geographical Phase-In Area (GPA) that includes Colorado, Idaho, Montana, New Mexico, North Dakota, Utah, Wyoming, and parts of Alaska. The highway diesel provisions in the GPA are linked to the Tier 2 gasoline program. While the rest of the country is required to average 30 ppm gasoline sulfur requirements by January 2006, refineries in the GPA are granted an additional year to meet this requirement. Under the highway diesel provisions, refineries in the GPA that meet the ULSD standard by June 1, 2006, for all their highway diesel may receive a 2-year extension on gasoline compliance to December 31, 2008. To receive the extension, the refinery must maintain production of 15 ppm highway diesel fuel that is at least 85 percent of its average 1998 and 1999 highway diesel production.

Hardship provisions are allowed for small refiners with up to 1,500 employees corporate-wide and that had a corporate crude oil capacity of 155,000 barrels or less per calendar day in 1999. The small refiner provisions include: (1) production of 500 ppm diesel fuel until May 31, 2010; (2) the ability to acquire credits for producing 15 ppm highway diesel prior to June 1, 2010; and (3) a 2-year extension of the refiner's applicable interim gasoline standards if all its highway diesel fuel is 15 ppm sulfur beginning June 1, 2006.

Summary of the Request for Analysis

In its July 2000 letter (see Appendix A), the Committee on Science requested that EIA undertake a study addressing the possible supply and cost implications of the diesel fuel regulations. The Committee specifically asked EIA to address the following production and supply issues related to the ULSD Rule:

- The potential impacts of the Rule on highway diesel fuel supply and on costs to end users of diesel fuel[6]
- The potential impacts of the diesel fuel regulation on other middle distillate products such as home heating oil, non-road diesel, and jet fuel
- The cost and availability of ULSD imports
- The impact of the Rule on refinery operations
- The impact of the Rule on fuel efficiency (related to engine after-treatment devices) and on diesel fuel demand
- The cost of current and future technologies that are expected to allow refineries to meet the new sulfur standard, and their costs
- The likelihood that the necessary technologies will be adequately deployed to meet the new standards.

The memorandum also identified a number of issues related to the distribution of ULSD that are addressed in the study, including:

- The effects of the ULSD Rule on the U.S. oil distribution system both during and after the phase-in period
- How the distribution system would handle the second highway diesel product during the phase-in period, the infrastructure and investments required, and how the investments might be recouped
- The extent to which fuel contamination might occur when ULSD is shipped in common pipelines with other, higher sulfur products
- The capability of current testing methods to measure sulfur at the 15 ppm level
- The operational changes required in the distribution system, and how they will affect consumer costs.

In a followup letter dated January 24, 2001, the Committee on Science modified its initial request to reflect provisions included in the EPA's final rule. The Committee directed EIA to reflect the assumptions used by the EPA, to the extent possible. Where EPA's assumptions diverge meaningfully from industry expectations, EIA was asked to provide a sensitivity analysis. The Committee noted several issues that might require sensitivity analysis, including:

- The difference in production of 7 ppm versus 10 ppm diesel fuel
- The energy content of ULSD
- Fuel efficiency losses associated with engine after-treatment devices
- Additional distribution costs.

[5]Credits for 15 ppm diesel fuel can be accrued before this date if the refiner can certify that the fuel is to be used in vehicles certified to meet the 2007 model year heavy-duty engine standards.

[6]The Committee also asked about several issues relevant to the proposed rule but not to the Final Rule: how potential supply might change if the effective date of the diesel regulation were later and did not overlap those for gasoline sulfur requirements, and how potential supply would change if the ULSD requirement were phased in.

9255A

Background

The ULSD Rule represents a unique financial and logistical challenge to refiners and distributors, because it places an unprecedented low sulfur limit on a secondary product. Although highway-grade diesel, which is currently limited to 500 ppm sulfur, is the second most consumed petroleum product, gasoline is the most important product by far. In 1999, 500 ppm diesel accounted for 12 percent of total petroleum consumption while gasoline accounted for 43 percent.[7] The ULSD Rule comes less than a year after a new nationwide sulfur standard for gasoline was finalized by the EPA at an average 30 ppm.[8] Some concerns have been raised that resources may be both financially and physically challenged to meet both the gasoline and diesel sulfur standards.[9]

In February 2000, the EPA finalized a rule on Tier 2 vehicle emissions and gasoline sulfur standards. The sulfur content of gasoline across the country is to be phased down to 30 ppm on average between 2004 and 2007. Like the diesel sulfur standard, reduced sulfur gasoline is required in order to accommodate new emissions control technologies required for meeting tighter vehicle emissions standards. Gasoline produced by most refiners will be required to meet a corporate average sulfur content of 120 ppm in 2004 and 90 ppm in 2005, compared with a national average of around 340 ppm in 1998.[10] By 2006, most refiners must meet a refinery level annual average of 30 ppm with a maximum of 80 ppm in any gallon.

Refiners producing most of their gasoline for the Geographical Phase-In Area (GPA), generally encompassing the Rocky Mountain region, will also be allowed a more gradual phase-in because of less severe ozone pollution in the area. These refiners will be required to meet a refinery average of 150 ppm in 2006 and must meet the 30 ppm requirement in 2007. Small refiners will not be required to meet the 30 ppm standard until 2007. The date for GPA and small refiner gasoline sulfur compliance has been extended an additional 2 years for those refineries that produce 15 ppm diesel at 85 percent of baseline highway diesel production levels.[11]

Consumption of highway-grade diesel (500 ppm sulfur) accounted for 68 percent of the distillate fuel market in 1999,[12] although 9 percent of that fuel went to non-road (rail, farming, and industry) and home heating uses.[13] Higher sulfur distillate (more than 500 ppm) used exclusively for non-road and home heating needs accounted for the other 32 percent of the distillate market. These other distillate markets will also be affected by the new highway diesel standard and may play a role in how some refineries respond to the rule. For instance, instead of investing in ULSD production, some refineries may opt to switch production to non-road or heating markets.

The EPA is in the process of promulgating "Tier 3" non-road engine emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.[14] The level of sulfur reduction required for Tier 3 vehicles is highly uncertain because of the diversity of the non-road market. Diesel engines used for farming, construction, rail, and other industrial markets have different performance requirements that need to be reconciled.[15] Both the American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA) have expressed concerns about complying with potential non-road standards before full implementation of the 15 ppm highway diesel standards.[16]

In addition to refinery issues, there are concerns about the ability of the distribution system to handle the requirements of the ULSD Rule. Between June 2006 and June 2010, the 80/20 rule will allow up to 20 percent of highway diesel production to continue at the current 500

[7] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3

[8] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Control Requirements," *Federal Register*, 40 CFR Parts 80, 85, and 86 (February 10, 2000).

[9] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3, U.S.A.

[10] U.S. Environmental Protection Agency, *EPA Staff Paper on Gasoline Sulfur Issues*, EPA420-R-98-005 (Washington, DC, May 1998). The average sulfur content has declined since the sulfur content of reformulated gasoline was reduced substantially to meet Phase 2 reformulated gasoline emissions requirements, which became effective in 2000.

[11] The EPA announced on May 4, 2001, that National Cooperative Refining Association and Wyoming Refining would be given additional time to meet the sulfur standard for gasoline. Both refiners are planning to comply with the 2006 highway diesel requirements on time.

[12] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3

[13] Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0525(99) (Washington, DC, September 2000), Tables 19-23

[14] U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3.

[15] Nonroad Workgroup, Minutes of the Workgroup's Meeting (Alexandria, VA, January 16, 2000)

[16] *Diesel Fuel News*, Vol. 5, No. 3 (February 5, 2001)

ppm limit. That fuel must be segregated in the distribution system from the remaining 80 percent of highway diesel meeting the 15 ppm limit. As a result, some pipelines, terminals, and retail outlets may temporarily need to carry an extra diesel product, requiring capital investment for the additional infrastructure requirements and additional operating costs for distributing the extra product. Both pipeline operators and fuel marketers are concerned that contamination from higher sulfur petroleum products might require some ULSD to be downgraded to a higher sulfur product that would have a lower market value. Moreover, a second new distillate product may be required if Tier 3 requirements also become effective before 2010.

A number of groups representing refiners and retailers are taking legal action against the ULSD Rule, including the National Petrochemical and Refiners Association (NPRA), the American Petroleum Institute (API), the Society of Independent Gasoline Marketers of America (SIGMA), and the National Association of Convenience Stores (NACS). The four groups have cited concerns about the possibility of inadequate ULSD supply under the Rule. The retailer groups also oppose the phase-in provision of the ULSD Rule ("the 80/20 rule"), because it will temporarily require costly storage of an additional product. SIGMA's lawsuit also questions the feasibility of the 15 ppm sulfur limit on ULSD.[17] On the other hand, the Rule has been strongly supported by a diverse coalition of environmental, manufacturing, regulatory, and trucking groups.[18] State and local regulators are supportive of the ULSD Rule because it is an integral part of their State Implementation Plans for meeting air quality standards.

Some State and local areas have begun to set their own requirements for ULSD. Texas and Southern California have already finalized ULSD regulations, and the State of California is in the process of doing so.[19] During the Bush Administration's review of the Federal ULSD rule, a group of State and local air pollution regulators warned that more States would follow suit with their own regulations if the ULSD rule were delayed or changed in any way.[20]

Methodology

In order to address both the short-term and mid-term supply issues identified by the Committee on Science, this analysis incorporates two different analytical approaches.

Refinery cost analysis addresses the uncertainty of supply in the short term. In addition, mid-term issues and trends are addressed through NEMS scenario analysis.[21] Discussion of the key issues and uncertainties related to the distribution of ULSD is based on interviews with a number of pipeline carriers.

As suggested by the Committee, most of the major assumptions in this report are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule. Before conducting this study, EIA consulted with representatives from diesel engine and emissions control manufacturers, the refining industry, and Government[22] to discuss the methodology and assumptions. EIA also received input through EIA's Independent Expert Review program.[23] On the basis of the information received and a review of other analyses, EIA identified the analysis assumptions that contained the most significant uncertainties. Where possible, sensitivity analyses were developed to provide a measure of uncertainty in the projections.

Assessment of Short-Term Effects of the Rule

For the purpose of assessing the short-term supply situation as the new standard becomes effective in June 2006 (see Chapter 5), industry-level cost curves were

[17] *Diesel Fuel News* (March 19, 2001).

[18] The coalition includes the Alliance of Automobile Manufacturers, the American Lung Association, the Association of International Automobile Manufacturers, the Association of Local Air Pollution Control Officials, the California Trucking Association, the Clean Air Network, the International, Truck and Engine Corporation, Manufacturers of Emission Control Association, the Natural Resources Defense Council, Northeast States for Coordinated Air Use Management, the Sierra Club, the State and Territorial Air Pollution Program Administrators, U.S. Public Interest Research Group, and the Union of Concerned Scientists.

[19] Discussions with Mr. Bill Jordan, Texas Natural Resource Conservation Commission, and Mr. Tim Dunn, California Air Resources Board.

[20] *Diesel Fuel News*, Vol. 5, No. 4 (February 19, 2001).

[21] Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), www.eia.doe.gov/oiaf/aeo/overview/index.html.

[22] Contact with diesel engine manufacturers included Cummins, Inc., Mack Truck, Inc., and Caterpillar, Inc. Contact with emission control manufacturers included Johnson Matthey and Engelhard Corporation. Refining industry contacts included the American Petroleum Institute (API), the Cenex Harvest States Cooperatives, UniPure Corporation, Equilon Enterprises, LLC, Lyondell Citgo Refining Company, Ltd., ExxonMobil Refining and Supply Company, Marathon Ashland Petroleum, LLC, and the National Petrochemical and Refining Association (NPRA). Government contacts included the U.S. Department of Energy's Office of Policy and Office of Transportation Technologies and the U.S. Environmental Protection Agency.

[23] Independent expert reviewers were Mr. Raymond E. Ory, Vice President, Baker and O'Brien, Inc.; Mr. Norman Duncan, Energy Institute, University of Houston; and Mr. Kevin Waguespack, PricewaterhouseCoopers.

constructed, based on refinery-specific analysis of investment requirements and operating costs.[24] Unlike the NEMS projections discussed below, the cost curves do not reflect an equilibrium market price.

The cost curves developed for this study are the result of a refinery-by-refinery analysis. Because of the proprietary nature of the data, this analysis does not disclose information about individual refineries. The ULSD production costs were estimated for different groups of refineries based on their size, the sulfur content of the feeds, the fraction of cracked stocks in the feed, the boiling range of the feed, and the fraction of highway diesel produced. The capital and operating costs for the different groups were developed for EIA by the staff of the National Energy Technology Laboratory (NETL).[25]

The technology cost representations were used to develop four sets of cost curves based on four different investment rationales. Within a given supply curve, the relative costs of different groups of refineries provide an indicator of possible supply problems. A large range of compliance costs in which investment costs are much higher for some refiners than for others may be an indication that some refiners may forgo investment. The behavior of refiners will be influenced by their expectation of what others will do and is therefore subject to great uncertainty. In order to explore the uncertainty of refinery behavior and the possible implications for supply, cost curves were developed based on the four different scenarios of investment behavior discussed below:

- **Competitive Investment Scenario.** This scenario assumes that some refineries will produce ULSD in 2006, while others may find it more economical to abandon the market. Refiners that have competitive costs of production are assumed to maintain market shares similar to current highway diesel market shares. Refineries currently producing a relatively low fraction of diesel fuel may abandon the market unless their cost per unit is competitive at current highway diesel production levels.
- **Cautious Expansion Scenario.** Current producers with competitive cost structures for ULSD production and a high yield of diesel production (greater than 70 percent of middle distillates) are assumed to increase production if the unit cost of the increased production is not substantial. Other refineries may also increase their fraction of highway production if economical and if the non-road market will allow. For instance, the Northeast has a strong heating oil market, potentially limiting a shift toward highway diesel production.
- **Moderate New Market Entry Scenario.** This cost curve assumes that a selective number of refineries that are currently producing little or no highway diesel will enter the ULSD market. The underlying premise is that there would be a limited number of companies that think they will be able to gain market share without depressing margins to the extent of undercutting profits. Only a few will make this move, while the rest wait for a clear indication of ULSD margins.
- **Assertive Investment Scenario.** Refineries were assumed to make the requisite investments to either maintain or gain highway diesel market share.

The scenarios discussed above are based on capital cost and return on investment assumptions that are consistent with EPA's analysis. Due to the uncertainty of these assumptions, two sets of sensitivity analysis are also provided. To address the uncertainty associated with the cost of installing or modifying distillate hydrotreaters for producing ULSD, a set of scenarios was developed assuming capital costs for hydrotreater units that are about 40 percent higher than the initial set. An additional set of scenarios explores the impact of assuming a 10-percent after-tax rate of return on investment, used in most of the studies compared in Chapter 7, instead of the 5.2-percent after-tax rate (equivalent to 7 percent before tax) assumed in the initial set.

Assessment of Mid-Term Effects of the Rule

The mid-term analysis for this study was performed using the NEMS Petroleum Market Module (PMM). The PMM represents domestic refinery operations and the marketing of petroleum products to consumption regions. PMM solves for petroleum product prices, crude oil and product import activity (in conjunction with the NEMS International Energy Module and Industrial Demand Module), and domestic refinery capacity expansion and fuel consumption. PMM is a regional, linear programming representation of the U.S. petroleum market. Refining operations are represented by a three-region linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs). PADDs I (East Coast) and V (West Coast) are treated as single regions, and PADDs II (Midwest), III (Gulf Coast), and IV (Rocky Mountains) are aggregated into one region. Each region is considered as a single firm where more than 80 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region over each 3-year period. As a result, cumulative

[24] The EPA and Baker and O'Brien also developed refinery-specific cost analyses, but their estimates did not reflect data related to the quality of crude oil inputs and the quality of diesel fuel components input to downstream units, collected by EIA.

[25] The technology costs were developed in consultation with Mr. John Hackworth and were reviewed by Mr. Ray Ory, one of EIA's independent expert reviewers, and by members of API.

investment for any given year may include investment to meet future product expectations.

Unlike previous ULSD analysis sponsored by the EPA or industry groups, the PMM provides multi-year scenarios. These scenarios reflect market prices rather than average costs and implicitly include investment and import decisions. Because each model region operates as a single firm, the impact of the ABT refinery credit program is also implicitly represented. The PMM cannot differentiate between the costs of different types of refineries, but the impact of the temporary compliance option for small refiners is partially accounted for in this analysis by reducing the refinery production of ULSD by 4 percent prior to 2010.

The PMM was used to develop a ULSD Regulation case based on the provisions of the EPA's final ULSD Rule. Five sensitivity cases were developed for assumptions associated with greater uncertainty, as well as a Severe case, which combines the five sensitivity case assumptions in a single scenario, a No Imports case, and a 10% Return on Investment case. The eight alternative cases explore the impacts of the following assumptions:

- The capital costs associated with distillate hydrotreaters (the Higher Capital Cost case).
- The reliance of refineries on revamped equipment versus new equipment (the 2/3 Revamp case)
- The percentage of ULSD that is downgraded to a lower value product because of contamination from higher sulfur products in the distribution system (the 10% Downgrade case)
- The fuel efficiency loss associated with meeting new diesel emissions standards (the 4% Efficiency Loss case)
- The loss in ULSD energy content resulting from more severe desulfurization processes (the 1.8% Energy Loss case)
- The combined effects of the alternative assumptions in the previous five sensitivity cases (the Severe case)
- The impact of the ULSD Rule assuming that foreign imports meeting the new sulfur standards will not be available (the No Imports case).
- The rate of return on investment (the 10% Return on Investment case).

The PMM provides average annual marginal prices. Because of its aggregate regional and annual nature, the PMM cannot be used to address short-term supply issues. The results of the PMM scenarios assume that, in the long run, refiners will increase supply to meet demand.

Assessment of Distribution and Marketing Effects of the Rule

The temporary compliance and small refinery provisions were incorporated into the Final Rule as a "safety valve" to minimize potential supply problems by allowing up to 20 percent of a refinery's highway diesel fuel production to remain at the current 500 ppm sulfur standard between June 1, 2006, and May 31, 2010, and by allowing small refineries (representing about 5 percent of total diesel fuel production) to delay compliance with the new standard until June 1, 2010. These provisions provide flexibility to refiners during the transition period but will effectively require the distribution system to temporarily handle an additional product. Aside from carrying an additional product, the distribution system will face new challenges related to transporting a very-low-sulfur fuel in the same system with other, high-sulfur products. The discussion of the implications of the ULSD Rule for the pipeline distribution system (Chapter 4) is based on interviews with a number of pipeline companies representing a cross-section of size, capacity, location, markets, corporate structures, and operating modes.[26]

The mid-term scenarios generated by the PMM include additional distribution costs associated with getting the ULSD to market during the transition period and after 2010. The incremental distribution costs reflect both the cost of capital for pipelines, terminals, and retail outlets and the costs associated with downgrading highway diesel that is contaminated during distribution. The capital component of the distribution costs used in this analysis is the same as that used in the EPA's Regulatory Impact Analysis (RIA) and is similar to those estimated by two other studies (Chapter 7). The cost of downgraded product is estimated by EIA using EPA's total

[26]The companies that participated in the interviews included Buckeye Pipe Line Company, Colonial Pipeline, Conoco Pipe Line Company, Kaneb Pipeline Partners, L.P., Kinder Morgan Energy Partners L.P., Marathon Ashland Petroleum, LLC, TE Products Pipeline Company, L.P., and Williams Energy Services.

9257A

downgrade assumption of 4.4 percent and the price differential between ULSD and other diesel.[27] Estimates for the percent of downgraded product range between EPA's 4.4 percent estimate to 17.5 percent by Turner Mason and Associates.[28] Due to the uncertainty about the extent of downgrade that will occur in the pipeline system, EIA has also projected the costs associated with larger downgrade assumptions (see Chapter 6).

[27] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf

[28] Turner, Mason & Company, *Revised Supplement to Report: Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, August 8, 2000)

2. Efficiency and Cost Impacts of Emission Control Technologies

Background

The new ultra-low-sulfur diesel (ULSD) Rule issued by the U.S. Environmental Protection Agency (EPA) requires not only that the sulfur content of transportation diesel fuel oil produced by domestic refineries be drastically reduced by 2007, but also that emission controls on heavy-duty diesel engines be imposed to dramatically reduce emissions of nitrogen oxides (NO_x), particulate matter (PM), and hydrocarbons (HC). This chapter summarizes the new heavy-duty engine emission standards, discusses the feasibility of meeting the standards based on a review of the EPA-identified emission control technology options that might be available, and assesses cost implications of the technology options.

The new ULSD standards finalized by the EPA are crucial to the successful development of emission control equipment for heavy-duty diesel engines. The catalysts to be used in meeting the emission standards can be severely damaged by sulfur contamination. For example, catalyst-based particulate filters for diesel engines have shown significant losses of conversion efficiency with fuel containing 30 ppm sulfur, particularly in colder climates. With respect to NO_x adsorbers, researchers have found that at fuel sulfur levels above 10 ppm, the heavy truck emission standard may not be attainable.

The EPA's final emission standards will affect new heavy-duty vehicles in model years 2004, 2007, and 2010. Although this study focuses on the impact of the 2007 standard, discussion of the 2004 standards and the associated impacts on technology, cost, and efficiency are relevant to the analysis. In 1997, the EPA proposed new emission standards for 2004 and later model year heavy-duty diesel engines that required a combined standard for NO_x and HC of 2.4 grams per brake horsepower-hour (g/bhp-hr).[29] The current standard for NO_x is 4 g/bhp-hr, and the standard for HC is 1.3 g/bhp-hr. The proposed standard was reviewed by industry, and in 1998 the EPA signed consent decrees with several heavy-duty engine manufacturers, stating that the 2004 emission standards would be met by October 2002.[30] The standards for new heavy-duty highway vehicles in model years 2004 and later were finalized July 2000.

In December 2000, EPA published additional standards for on-road heavy-duty diesel engines that would take effect beginning in 2007. These standards will require stricter control of PM (0.01 g/bhp-hr), NO_x (0.20 g/bhp-hr), and HC (0.14 g/bhp-hr) emissions. The new standards apply to diesel-powered vehicles with gross vehicle weight (GVW) of 14,000 pounds or more. The PM standard applies to all on-road heavy- and medium-duty diesel engines. The NO_x and HC standards are to be phased in at 50 percent of new vehicle sales in model years 2007 through 2009. In 2010, all new on-road vehicles will be required to meet the NO_x and HC standards.

For years 2007 through 2009, the EPA allows diesel engine manufacturers flexibility in meeting the NO_x and HC standards.[31] Engine manufacturers are provided the option of producing all diesel engines to meet an average of 2004 and 2007 NO_x and HC emission standards (1.1 g/bhp-hr). Engine manufacturers and EPA have confirmed that the industry intends to design and produce engines that meet the average NO_x/HC emission standard, providing engine manufacturers the ability to comply with the standards by using less stringent emission control systems.[32] If manufacturers produce low-emission engines in 2006, the number produced can be deducted from 2007 production requirements.

Emission Control Technologies

Historically, engine manufactures have met new emissions standards through modifications to engine design. The continuation of this trend is seen in the projection of technologies used to meet the EPA's 2004 emission standards for heavy-duty diesel engines. An EPA-commissioned technology study that addressed

[29] The brake horsepower of an engine is the effective power output, sometimes measured as the resistance the engine provides to a brake attached to the output shaft. A bhp-hr is that unit of work or energy equal to the work done at the rate of 1 horsepower for 1 hour

[30] U.S. Environmental Protection Agency, *Final Emission Standards for 2004 and Later Model Year Highway Heavy-Duty Vehicles and Engines*, EPA420-F-00-026 (Washington, DC, July 2000), p. 4.

[31] U.S. Environmental Protection Agency, *Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*, EPA420-F-00-057 (Washington, DC, December 2000), p. 2.

[32] Based on telephone interviews with engine manufacturers and the U.S. Environmental Protection Agency.

technology, availability, cost, and efficiency concerns concluded that engine manufacturers could meet the 2004 emission standards with engine control strategies—primarily, exhaust gas recirculation (EGR) and high-pressure fuel injection systems with retarded fuel injection strategies.[33] The EPA also stated that other advanced diesel engine technologies—such as waste-gated turbochargers, air-to-air after-coolers, advanced combustion chamber design, and electronic controls—could be used to help meet the 2004 emission standards.

Although the EPA states that implementation of cooled EGR will achieve most of the necessary emission reductions and that increases in fuel consumption are expected due to pumping losses, they believe that advanced turbochargers, advanced combustion chamber design, and electronic controls will also be used to overcome losses in efficiency. The EPA also mentions various catalyst technologies that might be used to meet the NO_x and PM standards but concedes that engine manufacturers will opt for engine control strategies to meet the NO_x standard, due to both economic and technological concerns regarding the catalyst technologies for NO_x reduction. The EPA concludes that particulate traps or oxidation catalysts will be used to control PM.[34] The assumptions reflected in the EPA study were recently confirmed when several engine manufacturers reported that they would implement the above-mentioned engine technologies to meet the 2004 standards.[35,36,37]

Whereas engine manufacturers have been able in the past to meet new emission standards by using advanced engine controls and technologies, they will have to rely heavily on component and system development by emission control equipment manufacturers to meet the 2007 standard. In particular, engine manufacturers must implement an exhaust after-treatment catalyst technology to control NO_x emissions.

Several NO_x control after-treatment devices are currently being investigated, including lean-NO_x catalysts, NO_x adsorber catalysts, and urea-based selective catalytic reduction (SCR) devices. Lean-NO_x catalysts have not seen significant improvement in NO_x reduction efficiency during the past 3 years and are not considered a viable option, but NO_x adsorber and SCR systems have shown potential for significant reduction of NO_x emissions.[38] The NO_x absorber catalyst works by temporarily storing NO_x during normai engine operation on the adsorbent. When the adsorbent becomes saturated, engine operating conditions and fuel delivery rates are adjusted to produce a fuel-rich exhaust, which is used to release the NO_x as N_2. The SCR process involves injecting a liquid urea solution into the exhaust stream before it reaches a catalyst. The urea then breaks down and reacts with NO_x to produce nitrogen and water. Using the SCR system, it might be possible to meet the NO_x emission standard without ultra-low-sulfur diesel fuel.

Industry experts have indicated that the SCR system shows more promise than the NO_x adsorber system for reduction of NO_x emissions in truck applications.[39] There is currently no infrastructure in place for the distribution of urea, however, and other issues remain to be addressed, including freezing of the urea solution in extreme weather conditions as well as operator compliance. Several engine manufacturers are working on infrastructure development plans for liquid urea. Although the EPA agrees that the technology is promising, it has serious concerns about compliance issues, because truck drivers may forgo refilling the urea tanks in an effort to save on operating costs. Engine manufacturers are working with the EPA to develop engine control systems to address this and other engineering issues. The SCR technology will not be viable until infrastructure plans are established and engine manufacturers can demonstrate to the EPA that compliance can be assured through reasonable engine control strategies.

Currently, the EPA expects NO_x adsorbers to be the most likely emission control technology applied by the industry.[40] Using current catalyst technology, the fuel-rich cycle reduces fuel efficiency by 4 percent.[41] The majority of the reduction in fuel efficiency comes from

[33]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 21.

[34]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 46.

[35]DieselNet, "Caterpillar Announces New Emission Technology," web site www.dieselnet.com/news/0103cat.html (March 2001).

[36]Newport's Truckinginfo.com, "Mack To Use EGR To Meet '02 Emissions Standards," web site http://www.trcukinginfo.com/news/news_print.asp?news_id=42839 (March 20, 2001).

[37]DieselNet, "Cummins in Support of Cooled EGR Technology," web site www.dieselnet.com/news/0103cummins.html (March 2001).

[38]U.S. Department of Energy, Office of Transportation Technologies, "Impact of Diesel Fuel Sulfur on CIDI Emission Control Technology" (August 21, 2000), p. 2.

[39]Based on telephone interviews with manufacturers of heavy-duty diesel engines.

[40]U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-3.

[41]U.S. Department of Energy, Office of Transportation Technologies, "Diesel Emission Control: Sulfur Effects (DECSE) Program Phase II Summary Report: NO_x Adsorber Catalysts" (October 2000), p. 21.

9259A

the reduction of sulfur in the exhaust stream. The sulfur accumulates on the NO_x adsorber catalyst, and eventually adsorber storage capability is completely lost. Even at ultra-low-sulfur levels, further desulfurization must occur to ensure that the NO_x adsorber is not "poisoned."

To date, no NO_x adsorber system has proven feasible. Although NO_x adsorbers have demonstrated compliance using ULSD (7 ppm), the systems show losses in conversion efficiency after 2,000 miles of operation.[42] Concerns have also been raised about the ability of the technology to perform over a range of operating temperatures and loads. Industry and government research efforts are seeking ways to overcome the obstacles facing the NO_x adsorber technology.

In order to meet the 2007 emission standards for heavy-duty diesel engines, the EPA makes the following assumptions regarding the performance of NO_x adsorber emission control technology:

- Conversion efficiencies will improve so that the overall loss of fuel economy will be only 2 percent: 1 percent for the fuel-rich cycle and 1 percent for pumping losses.
- EGR equipment will be optimized as a result of the improved efficiency of NO_x adsorber emission control equipment. The optimized EGR air-to-fuel mixture will provide a 1-percent increase in fuel efficiency, which will offset the 1-percent loss in efficiency from the fuel-rich exhaust cycle.
- The application of the new emission control technology will provide a 3-percent or greater increase in efficiency by offsetting the fuel efficiency reductions that were incurred to meet the 2004 standard when diesel engine manufacturers manipulated fuel injection timing to optimize for low NO_x emissions.

Based on these assumptions, EPA predicts that there will be no loss in fuel efficiency associated with the NO_x adsorber catalyst designed to meet the 2007 emission standard.[43] Although experts agree that this is possible, it has yet to be proven.[44] Current field tests reveal a 4- to 5-percent fuel efficiency loss with current state-of-the-art technology, which still requires EGR and timing control. Experts agree, however, that NO_x adsorber catalysts are expected to improve and that the associated optimization of EGR and timing control will eventually be achieved.

Technology Costs

The EPA's cost analysis of the technologies required to meet the 2004 standard assumed that fuel injection and turbocharger improvements would occur without the new emission standards. Therefore, when estimating increases in engine costs, the EPA excluded 50 percent of the technology costs in the total cost estimation. The incremental costs for medium-duty engines were estimated to be $657 in 2004, decreasing to $275 in 2009. Heavy-duty engine costs were estimated at $803 in 2004, decreasing to $368 in 2009.[45]

The EPA also estimated increases in annual operating costs of $49 for medium-duty engines and $104 for heavy-duty engines for the maintenance of the EGR system. The cost of the NO_x adsorber emission control system for medium-duty engines was estimated at $2,564 in 2007, decreasing to $1,412 in 2012. For heavy-duty trucks, the cost of control technology was estimated at $3,227 in 2007, decreasing to $1,866 in 2012.[46] Although engine manufacturers state that these costs are optimistic, no studies have been completed to dispute the EPA estimates.

Efficiency Losses

EPA assumptions for the impacts of the ULSD Rule on diesel engine fuel efficiency are used for the Regulation case in this analysis. Because the emission control technology development needed to meet the 2007 standards remains to be developed, however, a sensitivity case was analyzed to evaluate the possible impacts of fuel efficiency reductions.[47] In the 4% Efficiency Loss case for this study, it is assumed that meeting the emission standards in 2010 will reduce the average fuel efficiency of highway heavy-duty diesel engines by 4 percent, improving to no efficiency loss in 2015. It is assumed in this scenario that engine manufacturers will not be able to overcome fuel efficiency losses in order to meet the standards in 2010, but with continued improvements in NO_x adsorber efficiency and desulfurization catalysts, they will be overcome by 2015.

[42] Manufacturers of Emission Controls Association, *Catalyst-Based Diesel Particulate Filters and NO Adsorbers: A Summary of the Technologies and the Effects of Fuel Sulfur* (August 14, 2000), p. 19.

[43] U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-34.

[44] Based on phone interviews with emission control equipment manufacturers.

[45] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From: Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 88.

[46] U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-38.

[47] Although this case reflects a scenario in which losses in efficiency from emission contol are not overcome by new technology, the considerable time available for research and development may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies.

The reference case for this analysis includes assumptions for the market penetration of advanced engine and vehicle technologies and resulting improvements in fuel efficiency. Included in the slate of technologies are low rolling resistance tires, improved aerodynamics, lightweight materials, advanced electronic engine controls, advanced turbochargers, and advanced fuel injection systems. Market penetration is estimated using a payback function in which the incremental capital cost for each technology is compared to a stream of fuel savings over a specified technology payback period (1 to 4 years), discounted at 10 percent. In the reference case it is projected that average new truck fuel efficiency will increase from 6.4 miles per gallon in 2000 to 7.4 miles per gallon in 2020.

New vehicle fuel efficiency is reduced slightly in the 4% Efficiency Loss case, but the impact on stock efficiency is marginal because the number of new vehicles expected to enter the market is small relative to the total numbe of vehicles on the road. Fuel expenditures for heavy trucks are projected to be $1.9 billion higher in 2007 in the 4% Efficiency Loss case than in the reference case, and the difference grows to $2.9 billion in 2011 (Table 1), an increase of $410 in average fuel expenditures per truck. Cumulative fuel expenditures from 2007 to 2015 are projected to be $17.6 billion higher in the Regulation case than in the reference case and an additional $3.0 billion higher in the 4% Efficiency Loss case. The projected cumulative increase in energy use in the 4% Efficiency Loss case is approximately 80 trillion British thermal units (Btu). Energy consumption projections are discussed in Chapter 6.

Table 1. Projected Fuel Expenditures for Heavy-Duty Diesel Vehicles, 2006-2020
(Billion 1999 Dollars)

Analysis Case	2007	2008	2009	2010	2011	2015	Total, 2007-2015
			Total Fuel Expenditures				
Reference	39.45	40.46	41.46	42.19	42.98	45.96	385.63
Regulation	41.37	42.31	43.09	44.40	45.55	47.95	403.24
4% Efficiency Loss	41.37	42.31	43.09	44.58	45.92	48.44	406.21
			Incremental Fuel Expenditures				
Regulation	1.92	1.85	1.63	2.21	2.57	1.99	17.62
4% Efficiency Loss	1.92	1.85	1.63	2.38	2.94	2.49	20.58

Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, and DSU7TRN.D043001A.

9260A

3. Desulfurization Technology

Introduction

The availability of technologies for producing ultra-low-sulfur diesel fuel (ULSD) was one of the issues raised by the House Committee on Science. First, do adequate and cost-effective technologies exist to meet the ULSD standard? Second, are technologies being developed that could reduce the costs in the future? Last, is it likely that the needed technologies can be deployed into the market in time to meet the ULSD requirements of the rule?

A review of the technologies reveals that current technologies can be modified to produce diesel with less than 10 parts per million (ppm) sulfur. A small number of refineries currently produce diesel with sulfur in the 10 ppm range on a limited basis. The existence of the requisite technology does not ensure, however, that all refineries will have that technology in place in time to meet the new ULSD standards. Widespread production of ULSD will require many refineries to invest in major revamps or construction of new units. In addition to the status of desulfurization technologies, this chapter discusses possible impediments to their deployment.

Refineries in the United States are characterized by a wide range of size, complexity, and quality of crude oil inputs. Upgrades at a given refinery depend on individual circumstances, including the refinery's existing configuration, its inputs, its access to capital, and its perception of the market. The sulfur in petroleum products comes from the crude oil processed by the refinery. Refiners can reduce the sulfur content of their diesel fuel to a limited extent by switching to crude oil containing less sulfur; however, sulfur reduction from a switch in crude oil would fall well short of the new ULSD standard. Refineries will require substantial equipment upgrades to produce diesel with such limited sulfur.

In order to allow for some margin of error and product contamination in the distribution system, refineries will be required to produce highway diesel with sulfur somewhat below 15 ppm. Due to limited experience with such low-sulfur products, the exact sulfur level that will be required by refineries is not certain. In the Regulatory Impact Analysis for the ULSD Rule, the EPA assumed highway diesel production with an average of 7 ppm. Whether production is at 10 ppm or 7 ppm, the same technology would be used. In general, a relatively lower sulfur content would be achieved with more severe operating conditions at a higher cost.

Considerable development in reactor design and catalyst improvement has already been made to achieve ULSD levels near or below 10 ppm. In some cases low sulfur levels are the consequence of refiners' efforts to meet other specifications, such as low aromatic levels required in Sweden and California. In other cases refiners have decided to produce a "premium" low-sulfur diesel product, as in the United Kingdom, Germany, and California. These experiences, though limited, provide evidence for both the feasibility of and potential difficulties in producing ULSD on a widespread basis.

Refineries currently producing ULSD in limited quantities rely on enhanced hydrotreating technology. Technology vendors expect that this will also be the case for widespread production of ULSD. The following section focuses on hydrotreating as the primary means to achieve ULSD levels. A few emerging and unconventional desulfurization technologies are also discussed, which if proven cost-effective eventually may expand refiners' options for producing ULSD.

ULSD Production Technologies

Very-low-sulfur diesel products have been available commercially in some European countries and in California on a limited basis. Sweden was the first to impose very strict quality specifications for diesel fuel, requiring a minimum 50 cetane, a maximum of 10 ppm on sulfur content, and a maximum 5 percent on aromatics content. To meet these specifications the refinery at Scanraff, Sweden, installed a hydrotreating facility based on SynTechnology.[48] The Scanraff hydrotreating unit consists of an integrated two-stage reactor system with an interstage high-pressure gas stripper. The unit processes a light gas oil (LGO) to produce a diesel product with less than 1 ppm sulfur and 2.4 percent aromatics by volume. It is important to note that the Scanraff plant is highly selective of its feedstock to achieve the ultra-low sulfur content which may not be generalized to most U.S. refineries.

[48] B. van der Linde (Shell), R. Menon (ABB Lummus), D. Dave & S. Gustas (Criterion), "SynTechnology: An Attractive Solution for Meeting Future Diesel Specifications," presentation to the 1999 Asian Refining Technology Conference, ARTC-99.

In addition to Sweden, other European countries are encouraging the early introduction of very-low-sulfur diesel fuel ahead of the shift to a European requirement for 50 ppm diesel in 2005. The United Kingdom and Germany have structured tax incentives for the early introduction of 50 ppm diesel fuel and have discussed incentives for introduction of a 10 ppm diesel fuel. An example of a European refinery capable of producing diesel fuel for these markets, is BP's refinery at Grangemouth, United Kingdom, which has a 35,000-barrel-per-stream-day unit originally designed for 500 ppm sulfur in 1995.[49] The hydrotreater at Grangemouth has a two-bed reactor, no quench, and operates at about 950 pounds per square inch gauge (psig). Operating at a space velocity of 1.5 and using a new higher activity AK30 Nobel catalyst (KF757), the unit is producing 10 to 20 ppm sulfur diesel product. The feed is primary LGO with a sulfur content of about 1,800 ppm, derived from a low-sulfur crude. BP reported that on several occasions the feed had included a small fraction of cycle oil, which resulted in a noticeable increase in catalyst deactivation rate.

In 1999 Arco announced that it would produce a premium diesel fuel— which Arco termed "EC Diesel"—at its Carson, California, refinery.[50] EC Diesel is a "super clean" diesel designed to meet the needs of fleets and buses in urban areas. The reported quality attributes include less than 10 ppm sulfur, less than 10 percent aromatics, and 60 cetane, among others.[51] Arco indicated that the crude slates of the Carson refinery would remain unchanged, with only the operating conditions modified. The refinery had to selectively take out a sulfurous, aromatic cycle oil feed stream to the diesel unit and repeat this every few days for batches. If continuous production were required, a major capital investment would have to be made. In April 2000, Equilon also announced that its Martinez refinery in Northern California could provide ULSD for fleet use in that region of the State.[52]

The challenge of producing ULSD from feedstocks that are difficult to desulfurize is well represented by the experience of Lyondell-Citgo Refining (LCR) at its refinery in Houston, Texas. In 1997 the refinery moved to a diet of 100 percent Venezuelan crude.[53] The gravity of the crude oil was less than 20 °API, and it was highly aromatic. To produce suitable quality low-sulfur diesel product the refinery had revamped a hydrotreater to SynSat operation in 1996 and then converted to SynShift in 1998. The revamped hydrotreater has a capacity o 50,000 barrels per day and consists of a first-stage reactoı operating at 675 psig pressure, a high-pressure stripper, and a second-stage reactor that uses a noble metal catalyst. The feed to the unit is a blend of light cycle oil (LCO), coker distillate, and straight-run distillate (approximately equal volumes) with 1.4 percent sulfur by weight, 70 percent aromatics, and a cetane number of 30. The product has about 40 percent aromatics, a cetane number of 38.5, and sulfur content less than 140 ppm.

Citgo reported that the LCR hydrotreating unit was the largest reactor of its type when installed in 1996 and that the volume of catalyst in the unit, which had been 40,000 pounds in the old unit, had increased to 1.7 million pounds in the revamped unit. The diesel sulfur level produced in the unit reportedly met the 15 ppm sulfur cap at initial conditions at start of run, but as the desulfurization catalyst aged, the reactor temperature had to be revised to achieve target sulfur levels. If the revamped unit had to consistently meet a 15 ppm diesel sulfur limit, the cycle life could be greatly reduced from current operation, causing frequent catalyst replacement and more frequent shutdowns. Under the current mode of operation, the frequency of catalyst changeout is managed by reducing the cracked stocks in the feed to the unit. More frequent catalyst changeouts to meet a 15 ppm sulfur cap reportedly could raise the cost of diesel production.[54]

Hydrotreating

Conventional hydrotreating is a commercially proven refining process that passes a mixture of heated feedstock and hydrogen through a catalyst-laden reactor to remove sulfur and other undesirable impurities. Hydrotreating separates sulfur from hydrocarbon molecules; some developing technologies remove the molecules that contain sulfur (see box on page 16). Refineries can desulfurize distillate streams at many places in a refinery by hydrotreating "straight-run" streams directly following crude distillation, hydrotreating streams coming out of the fluid catalytic cracking (FCC) unit, and/or hydrotreating the heavier streams that go through a hydrocracker. Over half of the streams currently going into highway-grade diesel (500 ppm) are made up from straight-run distillate streams, which are the easiest and least expensive to treat.

[49] L.A. Gerritson, F. Stoop (Akzo Nobel Catalyst), P. Low, J. Townsend, D. Waterfield, and K. Holdes (BP Amoco), "Production of Green Diesel in the BP Amoco Refineries," presented at the WEFA Conference (Berlin, Germany, June 2000).

[50] Now part of BP Amoco.

[51] "Arco's EC Diesel Dominates CARB Advisory Discussion," *Diesel Fuel News* (April 26, 1999), p. 5.

[52] "Equilon Offers 15 PPM Sulfur Diesel for N. California," *Diesel Fuel News* (April 10, 2000), p. 10.

[53] L. Allen (Criterion Catalyst Co.), "Economic Environmental Fuels with SynTechnologies," presented at the World Fuels Meeting, EAA-World Fuels-98 (Washington, DC, Fall 1998).

[54] *Diesel Fuel News* (April 11, 2000), p. 17.

9261A

Refineries with hydrotreaters are likely to achieve production of ULSD on straight runs by modifying catalysts and operating conditions. Desulfurizing the remainder of the distillate streams is expected to pose the greatest challenge, requiring either substantial revamps to equipment or construction of new units. In some refineries the heavier and less valuable streams, such as LCOs, are run through a hydrocracker. The distillates from the cracked stocks contain a larger concentration of compounds with aromatic rings, making sulfur removal more difficult. The need for some refineries to desulfurize the cracked stocks in addition to the straight-run streams may play a key role in the choice of technology.

When the 15 ppm ULSD specification takes effect in June 2006, refiners will have to desulfurize essentially all diesel blending components, especially cracked stocks, to provide for highway uses. It is generally believed that a two-stage deep desulfurization process will be required by most, if not all refiners, to achieve a diesel product with less than 10 ppm sulfur. The following discussion reviews a composite of the technological approaches of UOP, Criterion Catalyst, Haldor Topsoe, and MAKFining (a consortium effort of Mobil, Akzo Nobel, Kellogg Brown & Root, and TotalFinaElf Research).

A design consistent with recent technology papers would include a first stage that reduces the sulfur content to around 250 ppm or lower and a second stage that completes the reduction to less than 10 ppm. In some cases the first stage could be a conventional hydrotreating unit with moderate adjustments to the operation parameters. Recent advances in higher activity catalysts also help in achieving a higher sulfur removal rate.[55] The second stage would require substantial modification of the desulfurization process, primarily through using higher pressure, increasing hydrogen rate and purity, reducing space velocity, and choice of catalyst. To deep desulfurize cracked stocks, a higher reactor pressure is necessary. Pressure requirements would depend on the quality of the crude oil and the setup of the individual refinery.

The level of pressure required for deep desulfurization is a key uncertainty in assessing the cost and availability of the technology. In its 2000 study, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels*, the National Petroleum Council (NPC) suggested that in order to produce diesel at less than 30 ppm sulfur, new high-pressure hydrotreaters would be required, operating at pressures between 1,100 and 1,200 psig.[56] Pressures over 1,000 psig are expected to require thick-walled reactors, which are produced by only a few suppliers (see discussion later in this chapter) and take longer to produce than reactors with thinner walls. In contrast to NPC's expectations, EPA's cost analysis reflected vendor information for revamps of 650 psig and 900 psig units that would not require thick-walled reactors. The vendors indicated that an existing hydrotreating unit could be retrofitted with a number of different vessels, including: a reactor, a hydrogen compressor, a recycle scrubber, an interstage stripper, and other associated process hardware.[57]

The amount of hydrogen required for desulfurization is also uncertain, because the industry has no experience with widespread desulfurization at ultra-low levels. One of the primary determinants of cost is hydrogen consumption and the related investment in hydrogen-producing equipment. Hydrogen consumption is the largest operating cost in hydrotreating diesel, and minimizing hydrogen use is a key objective in hydrotreating for sulfur removal. In general, 10 ppm sulfur diesel would require 25 to 45 percent more hydrogen consumption than would 500 ppm diesel, in addition to improved catalysts.[58] Hydrogen requirements at lower sulfur levels rise in a nonlinear fashion.

In addition to improvements in design and catalysts, other modifications to refinery operations can contribute to the production of ULSD. For example, high-sulfur compounds in both straight runs and cracked stocks lie predominantly in the higher boiling range of the materials. Thus, reducing the final boiling point for the streams and cutting off the heaviest boiling segment can reduce the difficulty of the desulfurization task. If a refiner has hydrocracking capability, the hydrocracker would be an ideal disposition for these streams. Some refiners making both high- and low-sulfur distillate products may be able to allocate the more difficult distillate blend streams to the high-sulfur product; however, the EPA is in the process of promulgating "Tier 3" non-road engine

[55]The type of improvement in catalyst activity is illustrated by Akzo Nobel new KF757 cobalt-molybdenum (CoMo) catalyst. Comparing KF 757 with its predecessor catalyst Akzo states, "A diesel unit designed to achieve 500 wppm product sulfur with KF 752 can easily achieve less than 250 ppm product sulfur with KF 757 while maintaining the same operating cycle." Source: C.P. Smit, "MAKFining Premium Distillates Technology: The Future of Distillate Upgrading," presentation to Petrobras (Rio de Janeiro, Brazil, August 24, 2000), p. 4.

[56]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 7, pp. 132-133.

[57]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-69.

[58]Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000), p. 26.

Developing Technologies and Ultra-Low-Sulfur Alternatives

Sulfur Adsorption

One new technology on the horizon is the "S Zorb" processing under development by Phillips Petroleum. S Zorb has been promoted for gasoline desulfurization to meet EPA's Tier 2 requirements. The major distinction of this process from conventional hydrotreating is that the sulfur in the sulfur-containing compounds adsorbs to the catalyst after the feedstock-hydrogen mixture interacts with the catalyst. Thus the catalyst needs to be regenerated constantly. Phillips is promoting the S Zorb process for highway diesel as potentially having lower capital cost than conventional hydrotreating options and reportedly is on the fast track to demonstrate the process in a pilot plant in 2001.[a] Phillips estimates on-site capital costs at $1,000 to $1,400 per barrel per day.

Biodesulfurization

Biodesulfurization is another innovative technology, which uses bacteria as the catalyst to remove sulfur from the feedstock. In the biodesulfurization process, organosulfur compounds, such as dibenzothiophene and its alkylated homologs, are oxidized with genetically engineered microbes, and sulfur is removed as a water-soluble sulfate salt. Several factors may limit the application of this technology, however. Many ancillary processes novel to petroleum refining would be needed, including a biocatalyst fermentor to regenerate the bacteria. The process is also sensitive to environmental conditions such as sterilization, temperature, and residence time of the biocatalyst. Finally, the process requires the existing hydrotreater to continue in operation to provide a lower sulfur feedstock to the unit and is more costly than conventional hydrotreating.[b] Biodesulfurization has been tested in the laboratory, but detailed engineering designs and cost estimates have not been developed.

Sulfur Oxidation

The latest entry in unconventional desulfurization involves sulfur oxidization. This process creates a petroleum and water emulsion in which hydrogen peroxide or another oxidizer is used to convert the sulfur in sulfur-containing compounds to sulfone.[c] The oxidized sulfone is then separated from the hydrocarbons for post-processing. Most of the peroxide can be recovered and recycled. The major advantages of this new technology include low cost, lower reactor temperatures and pressures, short residence time, no emissions, and no hydrogen requirement.

Advocates for the sulfur oxidation technology estimate capital costs at $1,000 per barrel of daily installed capacity—less than half the cost of a new high-pressure hydrotreater.[d] The technology preferentially treats dibenzothiophenes, one of streams that is most difficult to desulfurize, but it does not work as well on straight-run distillate. Because the process removes molecules containing sulfur, some volume losses also occur. One company working on the technology has proposed installation of 1,000 to 5,000 barrel per day units at distribution terminals to "polish" material that might otherwise be downgraded. Construction of a pilot plant is planned, but to date there has been no real-world demonstration of the process.

Fischer-Tropsch Diesel and Biodiesel

One way to add to ULSD supply without desulfurization is to rely on a non-oil-based diesel. The Fischer-Tropsch process, for example, can be used to convert natural gas to a synthetic, sulfur-free diesel fuel. Two gas-to-liquids (GTL) facilities have operated commercially: the Mossgas plant in South Africa with output capacity of 23,000 barrels per day and the Shell Bintulu plant in Malaysia at 12,500 barrels per day. Other plants are in the planning stages.

Commercial viability of GTL projects depends on capital costs, the market for petroleum products and possible price premiums for GTL fuels, the value of byproducts such as heat and water, the cost of feedstock gas, the availability of infrastructure, the quality of the local workforce, and potential government subsidies. Capital costs for GTL projects are currently less than $25,000 per daily barrel of capacity. An EIA analysis of a hypothetical GTL project estimated the cost of GTL fuel at almost $25 per barrel in 1999 dollars. Thus, a GTL project with present technology could be cost-competitive only if investors were confident that crude oil prices would stay in the range of $25 to $30 per barrel and natural gas feedstock prices would remain at 50 cents per thousand cubic feet.[e]

(Continued on page 17)

[a]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-31–IV-32.

[b]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 75.

[c]Sulfone is any of various sulfur-containing organic compounds having a bivalent radical SO_2 attached to two carbon atoms.

[d]R.E. Levy et al., "UniPure's ASR-2 Diesel Desulfurization Process: A Novel, Cost-effective Process for Ultra-Low Sulfur Diesel," presented at the National Petrochemical and Refining Association 2001 Annual Meeting (New Orleans, LA, March 18-20, 2001).

[e]"Gas-to-Liquids Technology: The Current Picture," *International Energy Outlook 2000*, DOE/EIA-0494(2000) (Washington, DC, March 2000), pp. 59-60; and S. Weeden, "Financial Commitments Brighten 2001 GTL Prospects," *Oil & Gas Journal* (March 12, 2001).

9262A

Developing Technologies and Ultra-Low-Sulfur Alternatives (Continued)

A second way to avoid desulfurization is with biodiesel made from vegetable oil or animal fats. Although other processes are available, most biodiesel is made with a base-catalyzed reaction. A fat or oil is reacted with an alcohol, such as methanol, in the presence of a catalyst to produce glycerine and methyl esters or biodiesel. The methanol is charged in excess to assist in quick conversion and recovered for reuse. The catalyst, usually sodium or potassium hydroxide, is mixed with the methanol. Increased production of biodiesel could create more surfactants than the market would be able to absorb. Biodiesel is a strong solvent and can dissolve paint as well as deposits left in fuel lines by petroleum-based diesel, sometimes leading to engine problems. Biodiesel also freezes at a higher temperature than petroleum-based diesel. Biodiesel advocates claim that a 1-percent blend of biodiesel can improve lubricity by as much as 65 percent. At least eight companies are marketing biodiesel in all parts of the United States, according to the National Biodiesel Board.[f]

[f]Web site www.biodiesel.org/marketers.htm.

emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.[59]

A processing scheme that has been promoted primarily in Asia and Europe employs a combination of partial hydrocracking and FCC to produce very-low-sulfur fuels. In this scheme a partial conversion hydrocracking unit is placed in front of the FCC unit to convert the vacuum gas oil to light products (distillate, kerosene, naphtha, and lighter) and FCC feed. The distillate product is low in sulfur (less than 200 ppm) and has a cetane number of about 50. The cracked stocks produced in the FCC unit are also lower in sulfur and higher in cetane. The relatively greater demand for distillate relative to gasoline demand in Europe and Asia and the higher diesel cetane requirement are more in keeping with the strengths of this process option than is the case for most U.S. refineries.

A few new technologies that may reduce the cost of diesel desulfurization—sulfur adsorption, biodesulfurization, and sulfur oxidation—are in the experimental stages of development (see box above). Although they are being spurred by the EPA rule, they are unlikely to have significant effects on ULSD production in 2006; however, they may affect the market by 2010. In addition, methods have been developed to produce diesel fuel from natural gas and organic fats, but they still are costly.

NEMS Approach to Diesel Desulfurization Technology

The Petroleum Market Module (PMM) in the National Energy Modeling System (NEMS)[60] projects petroleum product prices, refining activities, and movements of petroleum into the United States and among domestic regions. In addition, the PMM estimates capacity expansion and fuel consumption in the refining industry. The PMM is also revised on a regular basis to incorporate current regulations that may affect the domestic petroleum market.

The PMM optimizes the operation of petroleum refineries in the United States, including the supply and transportation of crude oil to refineries, the regional processing of these raw materials into petroleum products, and the distribution of petroleum products to meet regional demands. The production of natural gas liquids from gas processing plants is also represented. The essential outputs of the model are product prices, a petroleum supply/demand balance, demands for refinery fuel use, and capacity expansion.

The PMM employs a modified two-stage distillate deep desulfurization process based on proven technologies.[61] The first stage consists of a choice of two distinct units, which accept feedstocks of various sulfur contents and desulfurize to a range of 20 to 30 ppm (Table 2). The

[59]U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3

[60]NEMS was developed by EIA for mid-term forecasts of U.S. energy markets (currently through 2020). NEMS documentation can be found at web site www.eia.doe.gov/bookshelf/docs.html. PMM documentation can be found at web site www.eia.doe.gov/pub/pdf/model.docs/m059(2001).pdf.

[61]The PMM incorporates the technology database from EnSys Energy & Systems, Inc., a consultant to EIA, for refinery processing modeling.

second stage also includes a choice of two processing units, which further deep desulfurize the first-stage streams to a level below 10 ppm. The purpose of reducing the sulfur level to 20 to 30 ppm in the first stage, rather than the common goal of 250 ppm or less, is to enable a more accurate representation of costs for processing streams.

The PMM retains the option of conventional distillate desulfurization when 500 ppm sulfur diesel can still be produced (before June 2010). Because the PMM models an aggregation of refinery capacities in each of the refinery regions,[62] the above representation of multiple processing options is possible, although in reality individual refineries may choose one process over the other on the basis of strategic and economic evaluations.

Individual Refinery Analysis Approach to Diesel Desulfurization Technology

To assess the supply situation during the transition to ULSD in 2006, industry-level cost curves were constructed for this study and matched against assumed demand and imports. The cost curves are the result of a refinery-by-refinery analysis of investment requirements and operating costs for refineries in Petroleum Administration for Defense Districts (PADDs) I through IV. The ULSD production costs were estimated for different groups of refineries based on their size, the sulfur content of the feeds, the fraction of cracked stocks in the feed, the boiling range of the feed, and the fraction of highway diesel produced. The capital and operating costs for the different groups were developed for EIA by the staff of the National Energy Technology Laboratory (NETL).

For the study, a semi-empirical model was developed to size and cost new and retrofitted distillate hydrotreating plants for production of ULSD. Sulfur removal was predicted using a kinetic model tuned to match the limited literature data available on deep distillate desulfurization. Correlations were used in the model to relate hydrogen consumption, utility usage, etc., to the three major constituents of the distillate pool: straight-run distillate, cat-cracker light cycle oil, and coker gas oil. (See Appendix D for a discussion of the assumptions used to construct the model.)

Capital costs ranged from $592 to $1,807 per barrel per day, depending on the size of the unit, whether it was new or retrofitted, and the percentage of straight run feedstock (Table 3). A large hydrotreater using only straight-run distillate derived from high-sulfur crude had the least cost for both new and retrofitted units. The most expensive units were small hydrotreaters running 32 percent cracked stocked, about the average proportion of cracked feedstocks in PADD II.

Table 2. Desulfurization Units Represented in the NEMS Petroleum Market Module

Unit	Capacity (Barrels per Day)	Feedstock	Capital Cost[a] (1999 Dollars per Barrel per Day)	Total Capital Cost per Unit[a] (Million 1999 Dollars)
HL1/HS2. . . .	25,000	All except coker gas oil and high-sulfur light cycle oil	1,331	33.3
HD1/HD2 . . .	10,000	All	1,849	18.5

[a]Only on-site costs for hydrotreaters are included in this table. See NEMS documentation for hydrogen and sulfur plant costs. Revamped unit costs are estimated to be 50 percent of new unit costs.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 3. Range of Hydrotreater Units Represented in the Individual Refinery Analysis

Type	Throughput (Barrels per Day)	Straight-Run Feedstock (Percentage)	Capital Cost[a] (1999 Dollars per Daily Barrel)	Total Capital Cost per Unit[a] (Million 1999 Dollars)
New	50,000	100	995	49.8
New	10,000	68	1,807	18.1
Revamp	50,000	100	592	29.6
Revamp	10,000	68	1,210	12.1

[a]Includes only on-site costs.
Source: National Energy Technology Laboratory.

[62]Within the PMM, the refinery sector is modeled by a linear programming representation for three refining regions. The first region consists of Petroleum Administration for Defense District (PADD) I; the second of PADD's II, III, and IV; and the third of PADD V. Each model region represents an *aggregation* of the individual refineries in the region, rather than a notional refinery.

9263A

Expected Developments and Cost Improvements

Recent experience indicates that consistent, high-volume production of ULSD is a technologically feasible goal, although many refineries could face major retrofits or new unit construction. The variation in feedstock concerning both sulfur content and the amount of cracked stock may be influential in the choice of process option and the cost of desulfurization, which may also entail a different allocation of streams to products. Although unconventional desulfurization technologies have been promoted recently by various vendors, none has made sufficient progress toward the commercial stage to warrant consideration by most refiners who must start producing ULSD by June 2006.[63]

The two-stage desulfurization process can be accomplished through revamping existing units, building new units, or a combination of both. Several aspects of unit design are important. Properly designed distribution trays can greatly improve desulfurization efficiency, in that catalyst bypassing can make it virtually impossible to produce ULSD. Because hydrogen sulfide (H_2S) inhibits hydrodesulfurization reactions, scrubbing of recycle gas to remove H_2S will improve desulfurization. New design or revamps will also include gas quench to help control temperature through the reactor. In the design of a two-stage system, there will be a hot stripper between the two reactors where ammonia and H_2S are stripped from the first-stage product.

As more commercial evidence and cost information become available for diesel desulfurization in the next few years, it will be possible to better assess the technology choices—including equipment requirements, operating conditions, and production logistics—that most refiners will have to make in order to meet the new ULSD standards. However, the EPA's tight compliance timetable for producing ULSD might short-circuit the learning process for refiners to acquire necessary experience to make cost-effective decisions.[64] The many caveats within current vendors' statements must be carefully scrutinized, to avoid overestimating the capability or underestimating the costs for new or revamped distillate hydrotreating facilities. Most vendors state that their goal is to use or revamp a client refiner's current process units whenever possible. In trying to reach a 10 ppm or lower sulfur target, however, many units may be unsuitable or require major capital outlays. Uncertainty about the level of revamp is a major source of uncertainty in estimating the cost of the ULSD Rule.

Further consolidation of the refinery industry may achieve better economies of scale, although some industry analysts have expressed concern that a shortage of diesel supply could materialize in the short term if some economically challenged refineries exit the diesel market. Catalyst improvements are expected to be one of the main factors in reducing operating costs, both in terms of recycle rate and efficient use of hydrogen. Other factors, such as the dependence of the refinery on distillates, access to lower-sulfur crude, level of competition, and ability to upgrade infrastructure, must also be taken into account. The European experience could also provide valuable insights for U.S. refineries.

Deployment of Desulfurization Technologies

The deployment of diesel desulfurization technologies will hinge on several factors, such as the ability and willingness of refiners to invest, the timing of investment and permitting, the ability of manufacturers to provide units for all U.S. refineries at once, and the availability of engineering and construction resources.

One impediment to acquiring desulfurization upgrades may be the willingness and ability of individual refiners to obtain capital. The EPA estimates that average investment for diesel desulfurization will cost $50 million per refinery, slightly more than the estimated $44 million per refinery required to meet the Tier 2 gasoline sulfur requirement. Most refiners will invest in the gasoline sulfur upgrade because gasoline is their major product. Because U.S. refineries typically produce three to four times as much gasoline as highway diesel fuel, the per gallon investment cost of ULSD will be three to four times as high.[65]

In its Regulatory Impact Analysis, the EPA provided an analysis of capital requirements indicating that the combined annual capital investment for gasoline and diesel desulfurization would be $2.15 billion in 2004 and $2.49 billion in 2005.[66] The EPA analysis spread the diesel investments over a 2-year period (to reflect "a somewhat more sophisticated schedule for the expenditure of capital throughout a project") and assumed that the gasoline

[63] It is believed that, to comply with the new ULSD cap of 15 ppm, a refiner would require about 4 years lead time to secure a permit and to design, build, and optimize a new desulfurization process before commercial production is ready.

[64] Small refiners, which may delay ULSD production under special provisions of the Rule, could adopt emerging technologies later in the decade when any of those technologies becomes cost-competitive.

[65] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV.

[66] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-63- IV-64.

investments would be incurred in the year before a unit came on line. The EPA concluded that this level of investment should be sustainable by the industry because it is roughly two-thirds of the estimated environmental investments incurred during 1992-1994, when the industry was responding to the 500 ppm highway diesel and oxygenated and reformulated gasoline requirements. Other estimates of ULSD investment costs range from $3 billion to $13 billion (see Chapter 7).

Although not discussed in the EPA's investment analysis, the 1990s was a period of rationalization for the refining industry, marked by refinery sales, mergers, and closures. Between January 1990 and January 1999, 50 of 205 refineries were closed (4 of which were merged wth adjacent refineries).[67] The NPC attributes the refinery closures to heightened competitiveness. Although the environmental requirements of the 1990s cannot be pointed to as the cause of the closures, they contributed to the inability of some refineries to compete economically. Refiners who chose not to invest in the 500 ppm sulfur limit (required for highway diesel since 1993) found it more economical to shift their existing high-sulfur diesel production to non-road markets.

Some refiners will be more able than others to obtain capital for Tier 2 gasoline and ULSD projects. Assuming that capital is accessible, a refiner's willingness to invest in ULSD projects will depend on its assessment of the economics of the market. For instance, a refiner would be less likely to invest if it believed it could not compete favorably with others because the investments would result in a higher cost per gallon. History may lead some refiners to be cautious about investment. In the 1990s refinery upgrades for meeting reformulated gasoline requirements resulted in excess gasoline production capacity. As a result, gasoline margins were depressed, making it difficult for refiners to recoup investments.

Profit margins for ULSD could be depressed if refiners build too much capacity, and the fear of overinvestment could lead some refiners to delay investment until more highway diesel production is required. On the other hand, refiners anticipating inadequate supply of ULSD may choose to invest as early as possible to benefit temporarily from higher margins and sell credits to those that do not invest early. The EPA believes that any lack of investment will be compensated for by the temporary compliance options and credit trading provisions of the ULSD Rule.

Another possible hurdle to the timely adoption of desulfurization technologies is the ability of the engineering and construction industries to design and build diesel hydrotreaters in a timely manner. In addition to providing diesel hydrotreaters, the same contractors will be providing gasoline desulfurization units for the Tier 2 gasoline sulfur reduction requirements that will be phased in between 2004 and 2007. Moreover, engineering and construction requirements will also be expanding outside the United States. The Canadian government has committed to harmonizing gasoline and diesel requirements with the United States. In Europe, refiners will be making upgrades to meet tighter gasoline and diesel requirements in 2005 and have may incentives to produce even cleaner fuels for markets in Germany and the United Kingdom (see discussion in Chapter 6).

In its 2000 study, the NPC provided an analysis of the number of construction projects required for U.S. refiners to provide both gasoline and diesel fuel meeting a 30 ppm sulfur cap. The analysis concluded that "if a diesel sulfur reduction is required for 2006, implementation would overlap significantly with the Tier 2 Rule gasoline sulfur reduction, and engineering and construction resources will likely be inadequate, resulting in higher costs, implementation delays, and failure to meet the regulatory timelines." The study also concluded that if a 15 ppm diesel standard is required, further investments in new units will be required and there will be a significant risk of inadequate diesel supplies.

The NPC estimated that 89 refineries will require gasoline hydrodesulfurization units by 2004 and that 89 refineries (presumably the same ones) would make upgrades for new highway diesel standards and concluded that if the diesel standard were required within 12 months of completion of Tier 2 gasoline projects, construction labor shortages could occur. The analysis provided peak monthly engineering and construction personnel requirements for five scenarios with different assumptions about the timing and overlap of Tier 2 gasoline and ULSD requirements (Table 4). The scenarios ranged from a "balanced implementation" case, in which one-fourth of the required projects would begin in each quarter of the first year (Scenario A), to highly front-end loaded cases (Scenarios D and E), in which three-fourths of the projects would begin in the first quarter of the first year. Scenarios B and C assumed that refiners would start projects as late as possible.

In the Regulatory Impact Analysis for the ULSD Rule, the EPA conducted its own analysis of the personnel requirements for design and construction services related to the overlapping requirements of the Tier 2 gasoline and ULSD requirements. The analysis provided monthly estimates for each personnel category, assuming that in a given year 25 percent of the projects would be completed per quarter. The monthly estimates were used to develop estimates of the maximum number of personnel required in any given month for the

[67] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 23.

9264A

Tier 2 gasoline program alone and for the gasoline and ULSD programs together, both with and without a temporary compliance option. The estimates of the two programs taken together without the temporary compliance option were about double the employment estimates for the Tier 2 gasoline program only, in all three job categories. When the temporary compliance option is taken into account, personnel requirements for the two programs are only about 30 percent higher than for the Tier 2 gasoline program alone.

Because the largest impact is expected to occur in front-end design, where 30 percent of available U.S. personnel are required, the EPA believes that the engineering and construction workforce can provide the equipment necessary for compliance. It appears that the EPA's criterion for the adequacy of engineering and construction personnel lies somewhere between 30 percent and 50 percent over the personnel requirements of the Tier 2 requirements alone.

The EPA's estimates without a temporary compliance option are most consistent with the timing assumptions of NPC's Scenario A. EPA's analysis indicates that engineering and construction requirements will be lower given the temporary compliance option of the ULSD Rule; however, NPC Scenarios D and E demonstrate that different assumptions about project timing lead to very different estimates for personnel. The range of personnel estimates shown in Table 4 highlights the uncertainty of the estimates.

The EPA's analysis assumed that a total of 97 units would be added to make Tier 2 gasoline and that 121 diesel desulfurization units would be added for ULSD (Table 5). The expected startup dates for the gasoline and diesel desulfurization units indicate an overlap of 26 gasoline units and 63 diesel units in 2006. The 2006 overlap in gasoline and diesel startups is noteworthy because it is significantly greater than it would have been with ULSD implementation in any other year except 2004.

Another possible hurdle to implementing technology for the ULSD Rule raised by the NPC is the ability of manufacturers to provide critical equipment. As mentioned earlier, the NPC analysis assumed that a sulfur requirement below 30 ppm would require new deep hydrotreaters with reactor pressures in the range of 1,100 to 1,200 psig, requiring thick-walled reactors. As compared with other reactors, the delivery time for thick-walled reactors is longer and the number of suppliers is more limited. Only one or two U.S. companies produce thick-walled reactors, whereas four to six can supply reactors with more typical wall widths. Outside the United States, 10 to 12 companies are able to supply

Table 4. Estimated Peak Engineering and Construction Labor Requirements for Gasoline and Diesel Desulfurization Projects
(Percent of Current Workforce)

Analysis Case	Front-End Design Workforce	Detailed Engineering Workforce	Construction Workforce
NPC Scenario A	42	32	—
NPC Scenario B	59	45	—
NPC Scenario C	62	56	—
NPC Scenario D	82	[illegible]	—
NPC Scenario E	82	49	—
EPA Without Temporary Compliance Option	46	27	[illegible]
EPA With Temporary Compliance Option	30	17	[illegible]

Sources: NPC: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Table 7-6. EPA: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, Table IV.B-5.

Table 5. EPA Estimates of Desulfurization Unit Startups, 2001-2010

Unit Type	2001-2003	2004	2005	2006	2007	2008	2009	2010
Gasoline Units								
After Promulgation of the Tier 2 Gasoline Sulfur Program	10	37	6	26	[illegible]	[illegible]	—	—
After Promulgation of the ULSD Program	10	37	6	[illegible]	[illegible]	3	[illegible]	[illegible]
Diesel Units	—	—	—	63	—	—	—	[illegible]

Source: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, Table IV.B-3.

reactors regardless of wall width. This view is at odds with the EPA analysis, which was based on vendor estimates, with reactor pressures in the range of 650 to 900 psig.

Another type of critical equipment identified by the NPC is reciprocating compressors. The NPC indicated that two reciprocating compressors will be required for each diesel desulfurization project. Reciprocating compressors will also be required for gasoline desulfurization projects, and the NPC listed them as the principal constraining factor for the gasoline projects. Excluding the former Soviet Union, there are only five manufacturers of reciprocating compressors in the world. Two are in Europe and were assumed to be occupied with orders for European gasoline sulfur reduction projects through 2003. The NPC analysis did not account for additional orders from Canadian desulfurization projects.

Conclusion

Technology for reduction of sulfur in diesel fuel to 15 ppm is currently available and new technologies are under development that could reduce the cost of desulfurization. Variations in feedstock sulfur content and the amount of cracked stock may be very influential in the choice of process option and cost of desulfurization. Estimates of investment costs related to ULSD production range from $3 billion to $13 billion. The ability and willingness of refiners to invest depends on an assessment of market economics. Experience with upgrades to meet reformulated gasoline requirements in the early 1990s may lead some refiners to be cautious. The availability of personnel, thick-walled reactors, and reciprocating compressors may delay some construction.

9265A

4. Impact of the ULSD Rule on Oil Pipelines

Introduction

The petroleum products pipeline distribution system is the primary means of transporting diesel fuel and other liquid petroleum products within the United States. The Nation's refined petroleum products pipeline system is not monolithic. Pipelines are distinguished by the region they serve, the type of service they offer, their mode of operation, their size, the size of the interfaces between batches, and how they dispose of them. In preparing this report, several pipeline companies were contacted.[68] These companies represent a cross-section of size, capacity, location, markets, corporate structures, and operating modes. The assessment of the impact of the ultra-low-sulfur diesel (ULSD) Rule is complex, both because the pipeline system is complex and because there are uncertainties that cannot be resolved without operating experience with ULSD.

The first question appears to be: "Can the Nation's oil pipeline system successfully distribute ULSD without degrading its sulfur concentration?" While the answer seems to be yes, lingering uncertainties that come with the unique specifications of this new and untested product prevent a clear assertion. Among the uncertainties are the following:

- Protecting the product integrity of 15 parts per million (ppm) product will be more difficult than protecting the product integrity of the current 500 ppm highway diesel. Not only is the sulfur specification lower, with less room for error, but also the relative "potency" of the sulfur in products further upstream is higher.
- The behavior of sulfur molecules in ULSD has not been field-tested to allow conclusions about whether pipeline wall contamination is a real problem or simply a fear, and whether the migration of sulfur will require a significant increase in the volume downgraded at the interface.
- There are few pieces of the approved test equipment now in use, but its reliability and accuracy are unproven.

Although the overall costs of the program may be lower if the rule is phased in, the incremental costs associated with temporarily transporting ULSD, in addition to low-sulfur diesel and heating oil fall on pipelines and other players in downstream distribution. During the transition phase, some 20 percent of the highway diesel volume will be 500 ppm. The increased cost of tankage for handling this small volume of 500 ppm material is borne solely by the affected regions. On a cost-per-gallon basis for the small volume in the limited region, the increased cost more than doubles the current pipeline tariff for the largest carriers. Whether such an increase can be passed through in tariff rates is a matter of significant concern for pipeline operators.

Finally, there is a concern that further limitations on distribution flexibility will contribute to price spikes or spot outages. The distribution of ULSD will reduce the system's flexibility by imposing testing requirements that will increase transit times by increasing the product lost to downgrade and by "freezing" storage capacity in the event of product contamination. These adverse impacts inject new supply risks into the system, making an already burdened oil distribution system more vulnerable to product supply imbalances in local and regional markets. Supply imbalances, if they occur, could cause increased product price volatility, price spikes, and product outages. This concern is not just theoretical. During 2000, logistics problems contributed to large and sudden price spikes in the Midwest gasoline market.[69] To the extent that the system is overburdened, stresses and unforeseen circumstances will cause imbalances more often, and with greater impact.

The Role of Refined Petroleum Product Pipelines

Oil pipelines transport more crude oil and refined petroleum products in the United States than any other means of transportation.[70] Typically, as common carriers (which transport for any shipper on a nondiscriminatory basis), oil pipelines are subject to State authority if

[68] Buckeye Pipe Line Company, Colonial Pipeline, Conoco Pipe Line Company, Kaneb Pipeline Partners, L.P., Kinder Morgan Energy Partners L.P., Marathon Ashland Petroleum LLC, TE Products Pipeline Company, L.P., and Williams Energy Services.

[69] Joanne Shore, Energy Information Administration, "Supply of Chicago/Milwaukee Gasoline Spring 2000," web site www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/supply_of_chicago_milwaukee_gasoline_spring_2000/cmsupply2000.htm (August 9, 2000).

[70] According to the Association of Oil Pipe Lines, *Shifts in Petroleum Transportation 1999* (2001), pipelines account for 75 percent of the ton-miles of oil transported in the United States. (One ton of oil transported one mile equals one ton-mile.)

they are in intrastate service, or to the U.S. Department of Transportation for operations and safety and to the Federal Energy Regulatory Commission for tariff rates, if they provide interstate service. Interstate pipeline carriers transport the higher volume, by far. Accordingly, the Federal Government is the major regulator of oil pipelines. Some pipelines are private, serving private (proprietary) transportation needs. These private oil pipelines are not regulated with respect to tariff rates or other economic issues. Today, transportation of refined petroleum products by pipeline is essential to move more than 19 million barrels per day of refined petroleum products to markets throughout the Nation.

The United States is divided into five Petroleum Administration for Defense Districts (PADDs), each with distinct population levels, indigenous oil production, refinery and pipeline systems, and crude oil and refined product flows. Imbalances that result from these different characteristics are brought into equilibrium by trade and hence transportation. The trade can consist of imports from abroad and shipments from other regions. Shipments from the Gulf Coast (PADD III) dominate (Figure 1), first to the East Coast (PADD I) and second to the Midwest (PADD II). Shipments from the East Coast to the Midwest are third. Thus, shipments between PADDs east of the Rockies account for almost all the interregional trade. Intraregional movements are also a core element in the market logistics, but few data are available on these movements. (See Appendix C for a more detailed discussion of the U.S. regions and their key pipelines.)

Overview of Key Pipeline Operations

Refined petroleum product pipelines in the United States fall into two service categories. Trunk lines serve high-volume, long-haul transportation requirements; delivering pipelines transport smaller volumes over shorter distances to final market areas. As the system reaches its furthest capillaries, the inflexibilities imposed by the smaller scale become more apparent. A "lockout" can occur when a terminal does not have room to accept a scheduled shipment and there are no other terminals at hand to accept the product. The pipeline is thus stalled until the product can be delivered.

Petroleum product pipelines also differ by whether they operate on a batch or fungible basis. In batch operations, a specific volume of refined petroleum products is accepted for shipment. The identity of the material shipped is maintained throughout the transportation process, and the same material that was accepted for shipment at the origin is delivered at the destination. In fungible operations, the carrier does not deliver the same batch of material that is presented at the origin location for shipment. Rather, the pipeline carrier delivers material that has the same product specifications but is not the original material.

In general, fungible product operation is more efficient; however, customer requirements for segregation limit fungible operation, and batch service is often the only feasible choice. Like the difference between trunk and delivering carriers, the difference between fungible and batch service is one of scale for many operating parameters. An oil pipeline in batch service has considerably less flexibility to offset operating "hiccups" (such as product contamination at a shipper's terminal tank) than does an oil pipeline operating in fungible service.

Product pipelines routinely transport various grades of motor gasoline, diesel fuel, and aircraft turbine fuel in the same physical pipeline. (For the most part, oil pipelines do not transport both crude oil and refined petroleum products in the same pipeline.) To carry multiple products or grades in the same pipeline, different petroleum products or grades are held in separate storage facilities at the origin of a pipeline and are delivered into separate storage facilities at the destination. The different types or grades of petroleum product are transported sequentially through the pipeline. While traversing the pipeline, a given refined product occupies the pipeline as a single batch of material. At the end of a given batch, another batch of material, a different petroleum product, follows. A 25,000-barrel batch of produc occupies nearly 50 miles of a 10-inch diameter pipeline.

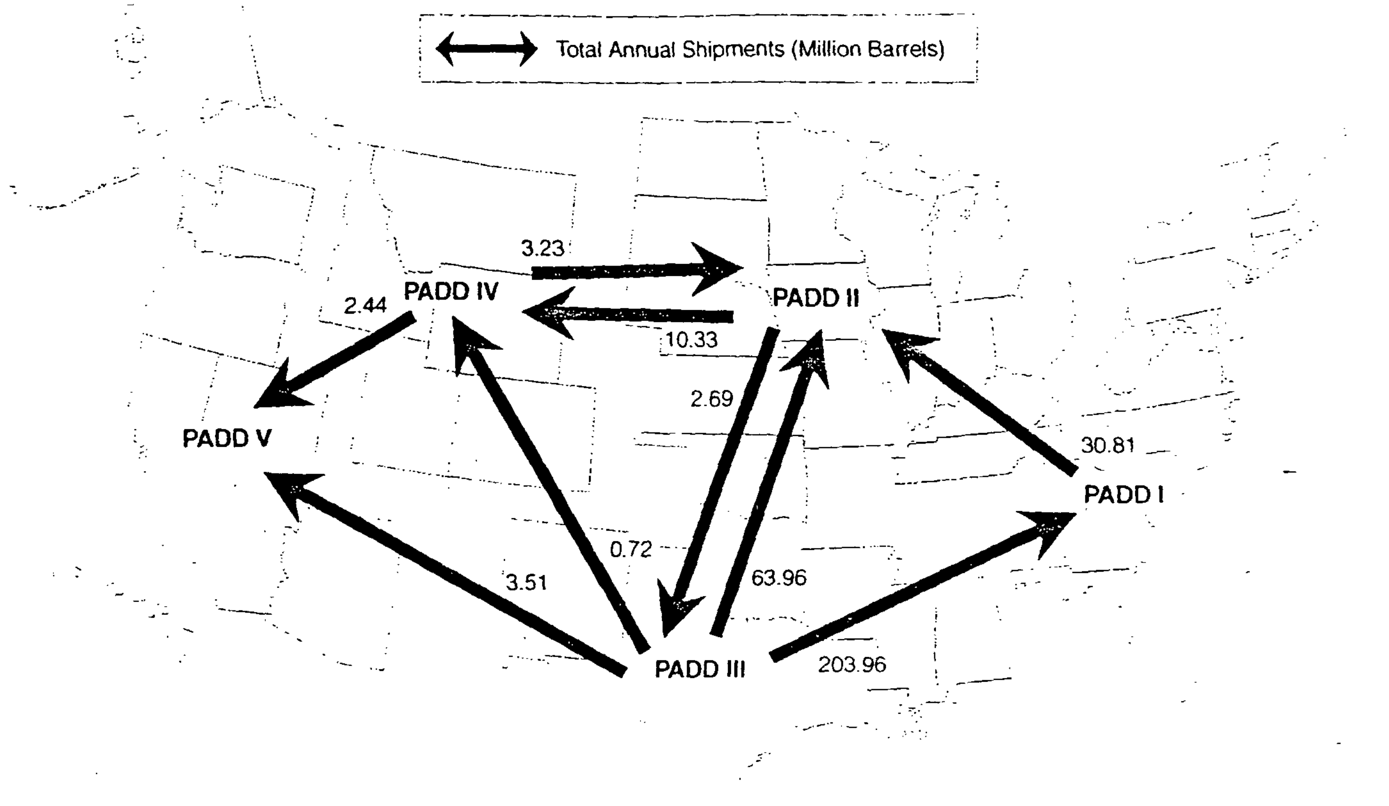
Generally, such batches are butted directly against each other, without any means or devices to separate them. At the interface of two batches in a pipeline, some (but relatively little) mixing occurs. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material ("transmix") to be generated in a 10-inch pipeline over a shipment distance of 100 miles. The hydraulic flow in a pipeline is also a crucial determinant of the amount of mixing that occurs. "Turbulent flow," as occurs in most pipelines, minimizes the generation of interface. Operations that require the flow to stop and start generate the most interface material.

The composition of the mixed (or interface) material reflects the two materials from which it is derived. While it does not conform to any standard petroleum product specification or composition, it is not lost or wasted. For interface material resulting from adjacent batches of different grades of the same product, such as mid-grade and regular gasoline, the mixture typically is blended into the lower grade. This "downgrading" reduces the volume of the higher quality product and increases the volume of the lower quality product.

Typically, refined oil products are transported from a source location, such as a refinery or bulk terminal, to a distribution terminal near a market area. Large

9266A

Figure 1. Pipeline Shipments of Distillate Fuels Between PADDs, 1999



Note: Includes low-sulfur (highway) diesel fuel and high-sulfur distillate fuel oil (non-road diesel fuel and heating oil).
Source: Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0304(99)/1 (Washington, DC, June 2000), Table 33.

aboveground storage tanks at an origin location accumulate and hold a given petroleum product pending its entry into the pipeline for transport. Petroleum products are also stored temporarily in aboveground storage tanks at destination terminals. Such tanks usually are dedicated to holding a single petroleum product or grade. Most storage tanks used in pipeline operation are filled and drained up to four or more times per month.

In addition to the minor creation of interface material that occurs in pipeline transit, creation of interface material also occurs in the local piping facilities (station piping) that direct petroleum products from and to respective origin and destination storage tanks and in the tanks themselves. Essentially, station piping represents the connection between a main pipeline segment and its requisite operating tanks. The concept is simple in theory, but in practice the configuration of station piping is not. Station piping layouts become more complex as the tanks at a pipeline terminal facility become more numerous.

The interface generation in station piping and breakout tanks may be even more important than during pipeline ансit. The volume of interface material thus generated ꞇ due to the physical attributes of the system. It has fewer variables but approaches a fixed value on a barrel-per-batch, not a percentage, basis. For instance, one pipeline operator creates 25,000 barrels of high-sulfur/ low-sulfur distillate interface per batch whether the batch is 250,000 barrels or 1,000,000 barrels. In addition, a given batch of product might be transported in multiple pipelines between its origin and its final destination and even within the same system might require a stop in breakout tanks, as noted above. Each segment of the journey generates additional interface.

Challenges of the ULSD Rule

Because pipeline operators do not have experience with 15 ppm product, there are significant uncertainties related to its transport. This section discusses some of the issues:

- The volume of downgraded product likely to be produced from deep pipeline cuts necessary to preserve the integrity of ULSD
- Likely strategies for protecting the product integrity of 15 ppm diesel and their impact on the generation of interfaces and transmix
- Limitations on downgrading from 15 ppm to 500 ppm product within the diesel pool

- The sulfur content of products reprocessed from transmix
- The possibility that residual sulfur adhering to mainline pipeline walls may contaminate ULSD as it transits the pipeline
- Product testing
- The challenges and costs of the phase-in period.

Estimation of Interface Generation

The U.S. Environmental Protection Agency (EPA) estimates that the interface that will be generated under the ULSD rule will be 4.4 percent of the highway diesel fuel volume transported by pipeline. EPA arrived at this 4.4 percent figure by estimating the current level of interface as a percentage of highway diesel fuel volume and doubling the current level.[71] There are significant uncertainties in the EPA's calculation.

At the EPA's request, the Association of Oil Pipelines (AOPL) and the American Petroleum Institute's pipeline Committee surveyed their members on the impact of the ULSD rule. The survey and its cover letter are comments to the EPA's Notice of Proposed Rulemaking.[72] AOPL points out that pipeline companies do not now separately account for interface volumes and indicated that the estimates of downgraded interface from the survey should not be used for economic analysis.[73]

Six respondents provided numerical estimates of the current diesel fuel downgrade. These estimates ranged from 0.2 percent to 10.2 percent of diesel shipped by the pipeline on an annual basis. In making its calculation of the total current downgrade of highway diesel, the EPA used the range of downgrade percentages from the AOPL survey and information from a database on the pipeline distribution system published by PennWell.

The EPA assigned each pipeline diameter in the PennWell database a value between 0.2 percent and 10.2 percent (the range of response in the AOPL survey), with the smallest diameter at the low end and the largest at the high end. EPA then multiplied the assigned values by the miles of a given diameter of pipe and divided the result by the total number of pipeline miles in the database to arrive at an average downgrade of 2.5 percent.

Pipeline diameter is only one of the factors in determining the amount of interface material. The velocity of the flow and the topography of the land are also important factors. A pipeline that can run in a turbulent flow will have a lower volume of interface for a given diameter than one in which the flow slackens for any number of operating reasons. Interface generation is also affected by batch size. Moreover, station piping and breakout tanks are additional and large generators of downgrade volume. (The EPA accounted for the role of station piping and breakout tanks by assigning higher percentages to the larger diameter pipe, as a proxy for the greater complexity of the large systems.) In addition, the higher product flow in the larger lines is not taken into account. If a system like the Colonial Pipeline has a downgrade rate of 10 percent, it would result in a much higher number of downgraded barrels than an 8-inch-diameter line. In the AOPL's submission, the operator with the 10-percent downgrade accounted for 90 percent of all downgrade.

EPA then adjusted its initial estimate of downgrade volumes downward by 15 percent. EPA made this adjustment based on the following assumption:

> *Data from the Energy Information Administration (EIA) indicates that 85 percent of all highway diesel fuel supplied in the United States is sold for resale. Therefore, we believe it is reasonable to assume that only this 85 percent is shipped by pipeline, with the remaining 15 percent being sold directly from the refiner rack or through other means that does not necessitate the use of the common fuel distribution system. By multiplying 2.5 percent by 0.85 we arrived at an estimate of the current amount of highway diesel fuel that is downgraded today to a lower value product of 2.2 percent of the total volume of highway diesel fuel supplied.*[74]

This downward adjustment of downgrade volumes has some limitations. EIA's Form 782A collects data from refiners. There is no way to determine whether the volumes sold to end users transit a pipeline or not. They may have, if they were sold in a refiner's integrated system. Form EIA-782A excludes sales to other refiners, and some of the excluded volumes may also have been transported in a pipeline. Finally, the volume throughput in a pipeline system is not necessarily equal to consumption, because some volumes may travel in more than one pipeline before reaching the consumer. Thus, "sales for resale" as a share of total refiner sales is not an ideal proxy for the share of highway diesel transported by pipeline.

[71] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-93.

[72] Cited in the EPA's documents as "Comments of Association of Oil Pipelines (AOPL) on the NPRM, Docket Item IV-D325." Cited here "AOPL Comments."

[73] AOPL Comments, p. 2.

[74] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-93.

The EPA assumed the level ULSD downgrade volumes at 4.4 percent of ULSD supplied, double their current estimate of 2.2 percent of highway diesel supplied. The EPA based this assumption in part on comments made by respondents to the AOPL survey. In its Regulatory Impact Analysis, the EPA stated a desire to ". . . yield a conservatively high estimate of our program's impact . . ." and noted ". . . an appropriate level of confidence that we are not underestimating the impact of our sulfur program . . . will help account for various unknowns that may cause downgrade volumes to increase."[75]

Pipeline operators have several concerns about the downgrade volume of ULSD. One concern is that the simple use of specific gravity—the current method—may not be a sufficiently sensitive indicator to make the interface cut. One of the AOPL/API survey respondents noted, for instance: "Our initial studies of trailback from [heating oil] to [low-sulfur diesel] indicates that trailback in interfaces to ULSD diesel may be as much as 4 times that of the gravity change between products."[76] However, the EPA viewed increased trailback from heating oil to ULSD as less of a concern.[77]

The EPA assumed that pipeline operators would not have to substantially change their current methods to detect the interface between ULSD and adjacent products in the pipeline. In the EPA's view it was highly unlikely that there would be any difference in the physical properties of ULSD versus the current 500 ppm highway diesel that would cause a substantial change in the trailback of sulfur from preceding batches into batches of ULSD.[78]

Another concern is that a protective cut, when it can be calibrated using real-world experience, may require a large volume downgrade. The conventional approach is to buffer distillate products against other distillate products to facilitate blending, as noted in the previous discussion. A batch of 500 ppm diesel might be wrapped between a batch of 2,000 ppm jet fuel and a batch of dye non-road distillate fuel oil (heating oil) at 3,000 to 5,000 ppm. Thus, the product with the sulfur restriction (500 ppm diesel) is wrapped by a product with four times the sulfur (2,000 ppm jet fuel), and by a product with six to eight times the sulfur (3,000 to 5,000 ppm heating oil). In practice, the current highway diesel is usually considerably less than the 500 ppm limitation (300 ppm would not be uncommon). Under these circumstances, it is relatively unlikely that chance contamination could move the diesel from 300 ppm to nonconforming status at more than 500 ppm.

The current situation, however, contrasts significantly to the ULSD situation. ULSD (15 ppm) may be adjacent to jet fuel at 2,000 ppm, 133 times the ULSD sulfur concentration, or to heating oil at 3,000 to 5,000 ppm, 200 to 300 times the ULSD concentration. In this case, a tiny contamination will move the ULSD batch to nonconforming status. According to one of the AOPL/API respondents, ". . . a 0.15 percent contamination (15 bbls in 10,000 bbls) of [heating oil] in ULSD will raise the sulfur level by 3 ppm . . . ." According to another, ". . . the [heating oil] at 2000 ppm can contaminate the ULSD at levels as low as 0.22 percent."[79] In combination with the concerns raised about the sulfur trailback, the issue of the volume necessary for the protective cut is another significant uncertainty in the handling of ULSD.

The assumption made about the size of the increase in interface generated after a switch from the current standard for highway diesel (500 ppm) to ULSD becomes important when calculating the cost of the regulation. EPA's estimate of additional costs of the ULSD rule that can be attributed to increased product downgrades was 0.3 cents per gallon of ULSD supplied once the ULSD rule was fully implemented and all highway diesel must meet the 15 ppm standard. This 0.3 cents per gallon cost was with the 4.4 percent downgrade assumption.[80] Turner Mason and Company conducted a study of distribution costs for the API and came up with a cost increase of 0.9 cents per gallon for product downgrade. Turner Mason assumed that 17.5 percent of ULSD shipped would be downgraded.

Strategies for Buffering ULSD in a Pipeline

Because there is no experience with distributing ULSD in a non-dedicated or common transportation system, pipeline operators are unsure how they will sequence the new product in the pipeline. Those that now ship highway diesel adjacent to jet fuel are unlikely to be able to continue the practice unless the sulfur content of the jet fuel is also lowered. At the current jet fuel sulfur content, ULSD cannot tolerate the contamination from the protective cut necessary to protect the other properties

[75] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-93–IV-94.

[76] AOPL Comments, Attachment, p. 2.

[77] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-96.

[78] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-94.

[79] AOPL Comments, Attachment, p. 2 and p. 5.

[80] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-124.

of the jet fuel. According to the EPA, pipelines might have to treat a mixture of jet fuel and 15 ppm diesel as transmix in separate tanks, because it will not be acceptable either as jet fuel or as 15 ppm diesel. The need for new tanks to handle this new hybrid, however, would be difficult to accommodate. In addition, it is not clear how the hybrid would be reprocessed for reentry into the petroleum products distribution system.

There is currently no regulatory requirement that the sulfur content of jet fuel be lowered to 15 ppm. Even kerosene/jet fuel used for blending into 15 ppm diesel is controlled by the specification of the finished product, not the blending component. As a practical matter, however, any kerosene/jet fuel destined for blending must have ultra-low sulfur content. Whether an ultra-low-sulfur jet fuel will present additional lubricity problems for jet engines is another unknown.

While there is a 500 ppm product in use, operators might be able to buffer 15 ppm ULSD with the 500 ppm product. Such buffering is limited by the volumes that can be downgraded within the diesel pool, however, as discussed below.

Gasoline, at an average of 30 ppm and a maximum of 80 ppm, will represent the next lower sulfur content in the overall product transportation slate. Some operators have speculated that if the trailback is significant, gasoline buffers might be the best alternative. There are considerable problems, however, with the increased generation of transmix. The availability of reprocessing facilities is the first. In addition, some transmix is now reprocessed in purpose-built facilities—a simple distillation column—on station property. Such a simple facility, or even a more complex purpose-built facility, has never needed to accommodate desulfurization. Thus, the reprocessing of transmix will be routinely more difficult under the ULSD program, and it is unclear that the facilities will exist to reprocess increased volumes of transmix.

Pipeline operators will establish interface minimization strategies on a case-by-case basis. Trunk line operators will seek to ship ULSD in as large a batch as possible. Delivery pipeline operators will do the same, but with more difficulty, because delivery pipelines ship smaller volumes and face more operating permutations related to time and location requirements. Operators of fungible pipeline systems will have an advantage in protecting the integrity of ULSD in transit and minimizing the expense of downgrading. It is worthwhile to note that the use of large batches requires more careful inventory management on the part of pipelines and shippers, to assure that requisite tanks have room for the incoming product. Given the inventory environment in oil markets, any new rigidity imposed by the logistics system can reverberate through market prices.

The result of deeper cuts will be significantly more product downgrading. The practical effect of creating a greater volume of high-sulfur distillate is difficult to estimate. Depending on market circumstances at various locations, it will range from none to significant. The worst case will be found where the creation of high-sulfur distillate affects terminals that do not have capacity to accept and store the material or in markets that do not have enough demand to absorb it.

The 20-Percent Downgrade Rule

The ULSD Rule prohibits any party downstream of the refiner or importer from downgrading more than 20 percent of its annual volume of 15 ppm highway diesel to 500 ppm highway diesel.[81] (There is no limitation on downgrading from 15 ppm diesel to the non-road pool.) This provision is designed to discourage downgrading within the diesel pool during the phase-in period.[82] The pipeline industry, however, is likely to be handling significantly increased volumes of downgraded material and to have substantial incentive to minimize the downgrade, because of the economic penalty involved. Furthermore, the downgrade limitation applies to normal interfaces.

As noted previously, the generation of some interface is irreducible, fixed by the physical attributes of the system. An operator with a high-interface system may have little room against the 20- percent limitation when all the other increases in ULSD interface are factored in. The 20-percent limitation also applies to the accidental contamination of a batch. If a batch were accidentally contaminated on a high-interface system, the operator might be required to deny that product to the diesel pool, even though it met all the specifications for 500 ppm material. Chances of localized diesel fuel supply imbalances are increased, and with them, the possibility that a system could get "frozen" by nonconforming product.

Given the uncertainties surrounding the transport of ULSD, the 20-percent downgrade rule will be particularly difficult when the first batches of ULSD are transported. There may be multiple contaminated batches before operating norms are established and equipment is calibrated.

[81] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Stanrds and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Part 80.527 (January 18, 2001).

[82] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR, Preamble (January 18, 2001), p. 281.

9268A

Residual Sulfur in a Pipeline

In comments on the proposed ULSD Rule, pipeline operators raised a concern over whether residual sulfur from high-sulfur material could contaminate subsequent pipeline material beyond the interface. The concern was based on limited experience. Recently, in light of the prospect of transporting ULSD, Buckeye Pipe Line conducted a test of possible sulfur contamination from one product batch to another. In the test on one segment of its pipeline system, Buckeye made a careful measurement of sulfur content in batches of highway diesel fuel following a batch of high-sulfur diesel fuel. Buckeye found that the sulfur content of the second batch of highway diesel fuel increased.[83] However, the EPA stated: "We believe there is no reason to surmise that contamination from surface accumulation will represent a significant concern under our sulfur program."[84] This issue cannot be resolved without further testing. Until it is, it will remain an uncertainty about the impact of the ULSD Rule.

Product Testing

Product testing is another area of considerable concern for those involved in the transport of highway diesel fuel, for two reasons: (1) The designated test method was developed for testing sulfur in aromatics and has not yet been adapted or evaluated by industry as a test for sulfur in diesel fuel. (2) There is no readily available and appropriate test for sulfur that will permit the precise interface cuts between batches that will be required in handling ULSD. The first of these issues is important for all players in ULSD markets, and the second is specific to the oil pipelines that will transport ULSD.

Currently, oil pipeline operators test the petroleum products they transport in a variety of ways, for a variety of parameters. Each product has its own relevant test parameters, and grades of a particular product are tested to confirm their defining characteristics within a product group. In many pipelines, product batches are tested four times at various stages of their entry to or transit through the pipeline:

- Rigorous testing is performed *before products enter* a pipeline to assure that relevant specifications are within the normal range.
- Many pipelines monitor materials *at strategic pipeline locations en route* for contamination.
- *At or near a product's delivery point*, pipelines perform oversight testing covering a limited number of key product parameters (but not sulfur content).
- Most pipelines test *random pipeline batches* using a full battery of tests.

All tests except in-line testing, the second testing regime outlined above, are performed on a batch basis. All but the fourth testing regime outlined above are performed on each batch of products. Pipeline operators are equipped at their own pumping and delivery stations to perform oversight testing on an expedient, on-site basis. Other batch testing is typically performed at an off-site laboratory. Some operators use test laboratories owned and operated internally and some use third-party laboratories. The large laboratories, whether operated by a pipeline operator or by a third party, will be able to meet any testing requirements. However, the designated test method presents uncertainties even to the most sophisticated laboratories, as discussed more fully below. ULSD regulations on testing apply directly only to refiners and importers, leaving additional leeway for parties downstream to choose a test method. Thus, the concerns with respect to test method apply even more strongly to refiners and importers than to pipelines and other downstream parties.

The designated testing method will be ASTM 6428-99,[85] not the widely-used ASTM 5453-99, which has been approved by the State of California and has been demonstrated to be reliable in testing very low sulfur content. The designated method, ASTM 6428-99, was developed for testing sulfur in aromatics. There is no currently available test methodology to apply the test to sulfur in diesel fuel. Because the diesel methodology has not yet been developed for the designated method, it has not yet been tested by multiple laboratories. By industry convention, new test methods are subjected to "round robin" testing under the oversight of the American Society of Testing and Materials (ASTM), in which multiple laboratories apply the test method to multiple batches to develop an objective evaluation of the method's reliability and accuracy. The correlation of the round robin's results becomes the industry standard and is used to calibrate other test methods against the designated method. The correlation is critical to the choice of test method and equipment for downstream players.

While ASTM 5453-99 has been designated as an alternative test method, its results must be correlated with the

[83]Operators at Explorer Pipeline, which formerly carried crude oil and refined products as batches in the same pipeline, also observed that refined products following high sulfur crude oil in the pipeline experienced a material increase in sulfur content. (The physical characteristics of crude oil are distinct from refined products, and its sulfur content can be considerably higher than the sulfur content of refined petroleum products shipped in a pipeline.)

[84]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-99.

[85]U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; Final Rule," *Federal Register*, 40 CFR Part 80.580(a)(2) (January 18, 2001).

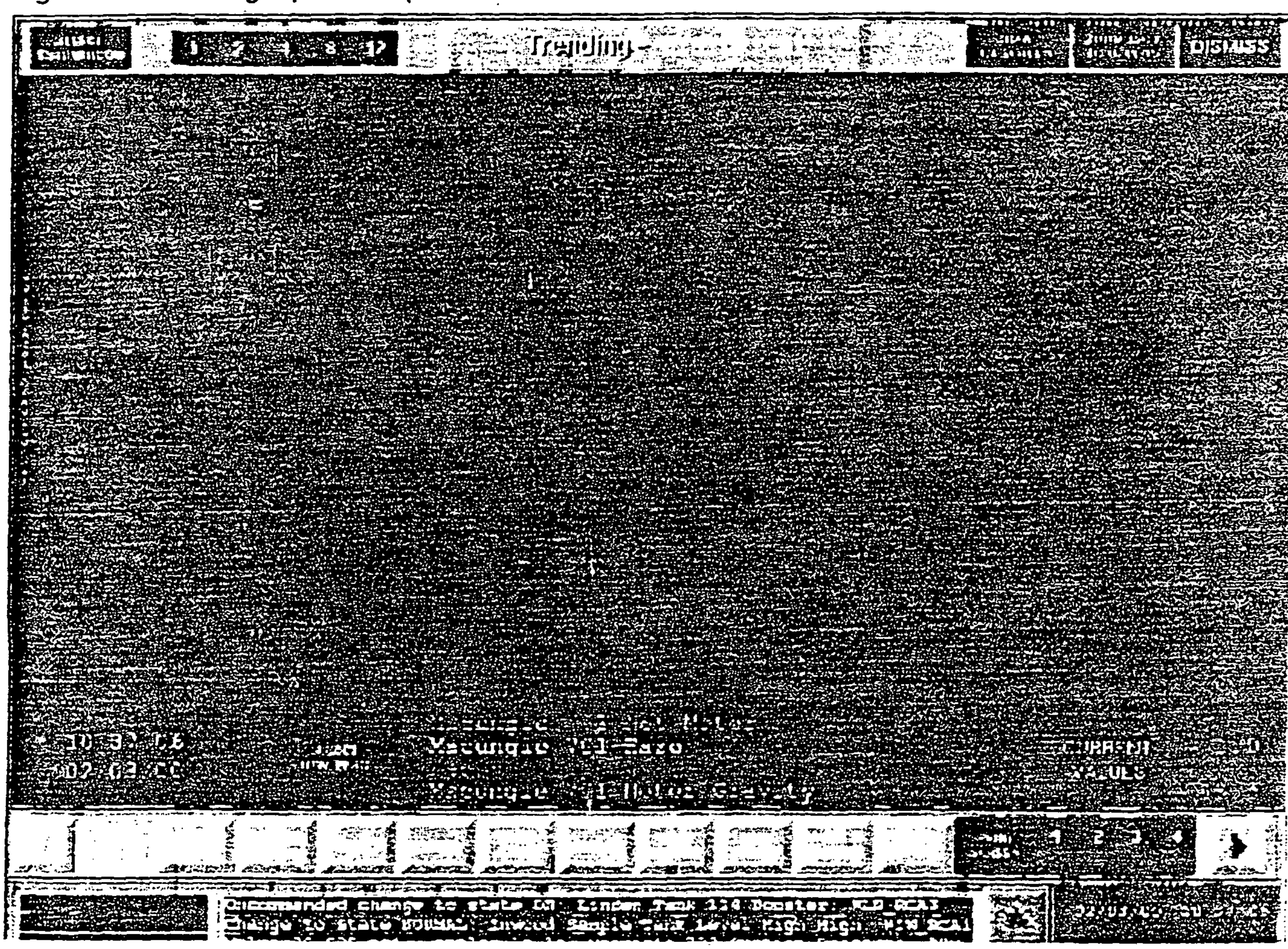
designated method. Hence, even those with experience using ASTM 5453-99 cannot be confident of the impact of the designated method on their testing practices. A downstream testing tolerance of 2 ppm will be allowed,[86] but whether this is the appropriate level, given the designated method's performance, also cannot be determined until the method is adapted for use with diesel fuel and correlated in the round robin.

Upon their entry to a pipeline, distillate fuels are given a full battery of tests, typically examining approximately 18 separate parameters. In an oversight test for distillate fuels, products are tested for flash point, specific gravity, and appearance. With respect to highway diesel fuel, sulfur content is also analyzed. Other tests relevant to distillate fuels, such as cetane, cloud point, freeze point, or corrosiveness, are performed at an off-site laboratory. The same rigorous level of testing is performed that is randomly applied to other products on a sampling basis

The sulfur content of existing highway diesel fuel is often well under the 500 ppm specification. It is not uncommon for highway diesel to contain only 200 ppm sulfur. Thus, the statistical reproducibility of sulfur testing can comfortably be more than 20 to 50 ppm, and is Operators anticipate that sulfur testing of ULSD will have to work within a 3 to 5 ppm reproducibility error.

With a 3 to 5 ppm reproducibility in the test, a product could be tested at 10 ppm as it enters the system and at 15 ppm as it exits. Generally, pipeline operators do not have a consensus on the sulfur content they will require as the product enters the pipeline system. Some have mentioned levels as low as 7 to 8 ppm in order to

Figure 2. Monitoring Pipeline Product for Contamination



Note: Taken from an oil pipeline control center's SCADA (Supervisory Control and Data Acquisition) system, this screen illustrates gasoline contamination (indicated by the drop in flashpoint) during a change from one kerosene batch to a second kerosene batch. The Net Meter stops climbing and shows where the pipeline was shut down to investigate the source of the problem (likely a late cut leaving gasoline/kerosene mix in the tank line that became evident when the pipeline began to draw product from the tank). The time scale across the screen is in hours. There is no similar monitoring available for ULSD.

[86]U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Part 80.580(a)(4) (January 18, 2001).

9269A

leave room for test reproducibility and unavoidable contamination.

Currently, most oil pipeline operators use X-ray fluorescent sulfur analyzers such as those manufactured by Oxford Instruments, Asoma Instruments, or Horiba, Ltd., for oversight sulfur content testing of highway diesel fuel. These analyzers, however, will be unable to monitor ULSD. Some oil pipelines use Antek Instruments, administering ASTM 5453-99 in a laboratory to monitor sulfur content on a batch basis. However, this equipment and test will help with the interface cut only in some situations, because its application for in-line testing presents a number of challenges (see below).

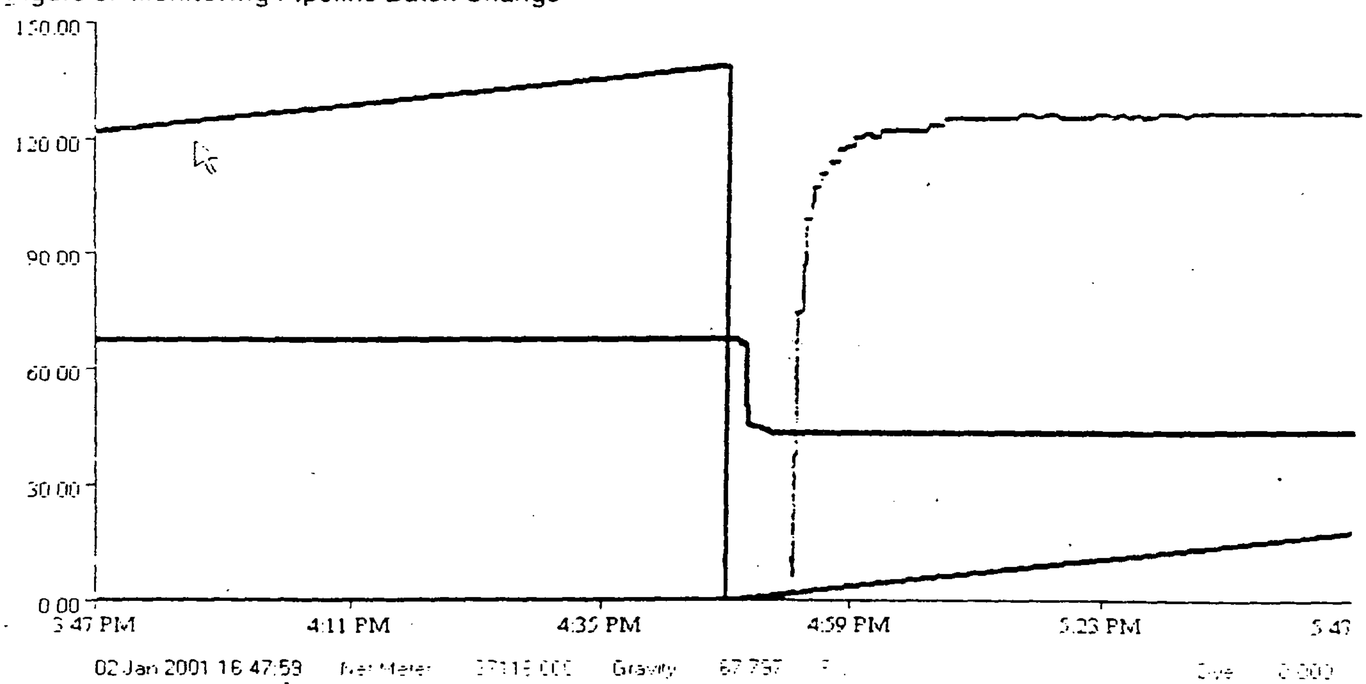
Some oil pipelines use in-line testing equipment to detect contamination close to and downstream from potential source locations where foreign or off-specification material might be inadvertently introduced into pure material (Figure 2). Early detection of contamination gives operators flexibility in correcting problems before they become intractable. However, there is no in-line test for sulfur content.

Product testing is different from instrumented detection of specific gravity, which is used to identify and track product batches in a pipeline system. Batch tracking and identification are accomplished by in-line monitoring of the pipeline stream's specific gravity at strategic pipeline locations. Such locations are typically station entry points or other locations where batches need to be "cut" and separately directed to subsequent pipeline segments in a system or to storage tanks for segregation (Figure 3). The cut, as noted previously, does not depend on sulfur content.

Most oil pipeline operators will probably want or need to perform in-line monitoring of sulfur content, because degradation of ULSD will easily and, possibly, frequently occur. The entry, for example, of only 35 barrels of heating oil (3,000 ppm) into a 10,000-barrel batch of ULSD will contaminate the batch.[87] A 10-inch diameter pipeline flowing at 4 miles per hour (a representative rate for a delivering carrier) is flowing at some 34 barrels per minute. Other carriers may be flowing faster, and on larger diameter pipelines, are moving more product. Hence, flow rates can exceed 300 barrels per minute. The 35-barrel contamination, then, is quick to occur. A normal cut, illustrated above, might take some minutes.

In-line testing for sulfur will represent a difficult challenge for the oil pipeline industry and for test instrument manufacturers. Current in-line instruments such as flash point or dye/haze analyzers cost $40,000 each to acquire, but there is no similar instrument available to meet ULSD test requirements. Current instruments for testing sulfur do not have adequate sensitivity, accuracy, or speed.

Figure 3. Monitoring Pipeline Batch Change



Note: This screen capture, originating from the pipeline's SCADA system, illustrates a normal batch change from gasoline ([illegible] API gravity) to kerosene (47 API gravity and 123 minimum flashpoint).

[87] [(9,965 x 7) + 935 x (35 x 3,000)] / 10,000 = 17.5 ppm.

With respect to speed of analysis alone there is a significant performance deficiency with current in-line analysis techniques. Current machines require 5 to 10 minutes to complete one analysis of a passing product stream. Five minutes is far too long to permit a pipeline operator to make a correctional response if off-specification material is detected in a batch of ULSD. One suggested solution would move the testing equipment to an upstream (earlier) location. The pipeline could construct a test loop, fed by samples from the main line. Samples regularly extracted from the product stream could flow through the loop to the test equipment housed in a shed, and readouts of the results could be returned to controllers to identify the interface as the product approaches.

Operators point to a number of difficulties with such an upstream testing mechanism. According to industry experts, many refiners test the sulfur content of outgoing product using ASTM 5453-99 with such a test loop, and at least one major pipeline system uses ASTM 5453-99 with an upstream test loop, so it is clearly an effective alternative for some applications. Refineries may have more success using the ASTM 5453-99 with a test loop, because product flow is slower in refinery piping than in oil pipelines, and the speed of the product flow dictates the placement of the test loop. For example, such a loop would have to be positioned far enough upstream to allow the sample flow to reach the test equipment, perform the test, and return the readout in time to make the batch cut. If the loop transit and testing took 5 minutes, for instance, and the product flowed through the pipeline at 8 miles per hour, the equipment would have to be positioned about two-thirds of a mile upstream of the valve. This distance would commonly be outside of a station property, on the right-of-way.

Although positioning certain equipment upstream is a relatively common pipeline practice, restrictions on the use of or availability of space on the right-of-way would be among the factors that could be obstacles to positioning anything as substantial as a free-standing shed on the pipeline right-of-way. Power and communications availability on the right-of-way could also be impediments. The expense of the equipment is an additional deterrent to placing equipment in an unstaffed remote location. Finally, an oil pipeline with many delivery points—a delivering carrier might have 100, for example—would find it prohibitively expensive to install such equipment at each delivery location.

Special Issues Related to the Phase-In

The temporary compliance option as well as the provisions related to small refiners provide flexibility for refiners and importers to phase in ULSD, at the expense of pipelines and other downstream distributors. The phase-in provision assumes that some operators carry an additional grade of diesel/distillate fuel oil during the transition years, providing concomitant facilities for segregating the product. As noted earlier, the East Coast is the only region where operators consistently carry both diesel, at 500 ppm, and heating oil, at 3,000 to 5,000 ppm. Many pipelines carry only 500 ppm product, serving both highway and non-road needs with the same fungible grade (dye is added at the destination terminal). Most also carry jet fuel. The ULSD phase-in will push them to carry an additional grade of distillate fuel oil—diesel at 15 ppm—in addition to diesel at 500 ppm and, for some, heating oil at 3,000 to 5,000 ppm plus jet fuel.

Tank size and utilization have been optimized at most terminals to carry the existing product slate. Pipeline executives are universal and adamant in their opinion that sufficient storage tanks and other pipeline assets are not available in most pipeline systems to segregate a third grade of distillate. Many small terminals are unable to add tanks because of space and permitting concerns, and even at larger terminals such constraints may be a factor. Permits can take years to obtain. For terminals that are able add tanks, new tanks cost $1 million or more each, an expenditure that is necessary only to carry a discrete product for a limited period of time. In addition, because of the limited volumes involved, the tanks may be used inefficiently during the ULSD transition period.

The EPA estimated that there are 853 terminals, excluding tanks at refineries, that carry highway diesel. The EPA assumed that, of these 853 terminals, 40 percent would build a new tank to distribute both 15 ppm and 500 ppm diesel fuel during the transition period. At a cost of $1 million per new tank, the additional cost of new terminal tankage was estimated to be approximately $340 million.[88]

Beyond the terminal level, the EPA estimated there are 9,200 "bulk plants" that carry highway diesel fuel, excluding tanks at refineries. Again, the EPA assumed that 40 percent of these bulk plants would build a new tank to accommodate both 500 ppm and 15 ppm diesel fuel. The EPA assumed a cost of $125,000 for each of these smaller tanks, giving a total cost of new tankage at the bulk plant level of $460 million.[89]

Finally, at the truck stop level, the EPA assumed there are 4,800 truck stops operating in the United States, of which 50 percent would sell both 500 ppm and 15 ppm

[88] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

[89] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

9270A

diesel fuel. The EPA cited a survey on the expected cost of handling a second grade of diesel fuel by the National Association of Truck Stop Operators of its members. Based on this survey, the EPA estimated an average cost of $100,000 per truck stop to handle the two diesel grades, giving a total of $240 million. A Petroleum Marketers Association of America estimate gave costs of $50,000 per truck stop.[90] The total costs of new tanks and equipment to handle both 500 ppm and 15 ppm diesel fuel were estimated by the EPA at $1.05 billion.[91]

The EPA estimated the total cost per gallon of highway diesel of additional storage tanks at 0.7 cents. This 0.7 cents per gallon additional cost was for the 2006 to 2010 phase-in period. The EPA assumed that the additional storage tanks would be fully amortized during the phase-in period, and that service stations supplying light-duty vehicles with diesel fuel, centrally fueled fleet facilities, and card locks (unattended filling stations) would not install additional storage tanks to handle both 500 ppm diesel and ULSD. Therefore, no cost was estimated for additional storage tanks during the phase-in at service stations, centrally fueled fleet facilities, or card locks.[92]

Where an operator cannot add a tank, it may choose to drop a grade of product. (Such a strategy is not a clear winner, however, because a dropped grade of gasoline, for instance, requires the shipment and storage of greater volumes of another grade of gasoline to compensate.) A carrier might be able to drop a grade of distillate fuel oil, but not without requiring an additional, compensating volume of low-sulfur product or ULSD to meet the market need, exacerbating the draw on refiner capabilities.

The question of whether pipeline companies will be able to recover the increased costs associated either with moving ULSD or moving ULSD plus another temporary grade is a matter of conjecture. The only process for recovery will be tariff rates, and the path to structuring rates to allow that recovery is uncharted.

Overview of Tariff Rate Issues

The majority of transportation for refined petroleum products by volume or by barrel-miles is provided by common-carrier oil pipelines operating in interstate service, under rates regulated by the Federal Energy Regulatory Commission (FERC). Most oil pipeline carriers have approved tariff rates on file with the FERC covering the transportation of diesel fuel. If no other application or action were taken by an oil pipeline company, the existing tariff rates covering diesel fuel would apply to ULSD when that material is distributed to markets. As noted in other sections of this report, however, oil pipelines will incur large, incremental capital and operating costs in distributing the new diesel fuel.

For most regulated oil pipelines, the FERC uses an economic index as the basis for approving tariff rate increases. The index provides that tariff rates may increase without challenge by a percentage amount no more than the Producer Price Increase for Finished Goods, less 1 percent over an approved base rate. If an oil pipeline carrier is operating under the FERC's index method and applies its existing tariff rate to ULSD, there will be no basis for the carrier to recover its extraordinary incremental costs in the approved rate.

Some oil pipeline companies operate under alternative programs with the FERC. The second most prominent method is to administer some or all of a carrier's tariff rates under a market-based system.[93] Under this method, if various markets served by an oil pipeline are first found by the FERC to be workably competitive, the FERC then stipulates the basis by which the pipeline carrier may raise rates more flexibly, without application of the index. Many oil pipeline operators believe that market conditions under which they operate are far more competitive than their status as regulated utilities suggests. If they are correct (and the FERC's own findings of workable competition in many oil transportation markets suggests that they are), pipelines will be competitively constrained from simply passing through their higher ULSD costs to shippers.

A carrier might file a new tariff rate expressly covering ULSD. If that rate is greater than the previous rate (or the remaining tariff rate for other grades of diesel fuel), the FERC or a shipper might protest the new rate, a common occurrence. In such an event, it is possible that the new tariff rate would not be permitted to take effect or that it would be accepted subject to refund if it were later found to be excessive. Furthermore, such administrative proceedings to adjudicate tariff rates before the FERC are costly and time-consuming.

As an alternative to attempting to recover incremental costs through increasing an existing approved rate or filing new tariff rates, carriers could try to impose special charges to recover incremental capital or operating costs

[90] John Huber, Petroleum Marketers Association of America, "Letter to U.S. EPA, Re: AMS-FRL-6705-2." Submitted to the public docket on August 11, 2000.

[91] John Huber, Petroleum Marketers Association of America, "Letter to U.S. EPA, Re: AMS-FRL-6705-2." Submitted to the public docket n August 11, 2000.

[92] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-133.

[93] Other rate administration methods are available from the Commission, but they are even less frequently used.

by filing such charges as a part of the "rates and regulations" that normally cover the qualitative aspects of a tariff rate. Under this method, tariff regulations might support cost recovery in various forms, including a mandatory provision for the shipper to provide pipeline buffer material, a volume loss allowance, facility charges, or access charges. While the imposition of such special charges outside of the transportation tariff rate is possible, it is unlikely that material charges could be imposed without eliciting a shipper or FERC challenge, making this, too, an uncertain avenue for recovery of the unique costs.

Because of the difficulties presented by fitting ULSD into tariff rates, innovative approaches may be required. For instance, a pipeline carrier or an oil pipeline industry association might file an advance request with the FERC for a declaratory order either recognizing the validity of special charges or specifying the basis under which special charges would be applied to ULSD shipments. The purpose of seeking a declaratory order would be to clear a path for cost recovery before new capital or higher operating costs were actually incurred. Such an approach, with its earlier recognition of the issue, would allow the multi-year process to proceed well in advance of the collection of the new tariff rate.

The foregoing discussion suggests that higher capital and operating costs attributable to distributing ULSD will be difficult to recover, and that carriers will need to take proactive steps with the FERC and shippers in order to do so. There is no assurance that such steps will be successful, nor is there economic assurance that any such recovery will even be possible. Therefore, resistance among pipeline operators to incurring those costs should be expected.

Distribution Costs in the EIA Model

In its Regulation case analysis, EIA closely followed the EPA's assumptions about distribution costs, with the exception that EIA calculated the downgrade revenue loss within its NEMS model, using the prices of highway and non-road diesel generated from the model. From June 2006 through June 2010, EIA assumed an increased distribution cost markup of 1.2 cents per gallon on the price of highway diesel: 0.7 cents per gallon reflected the additional capital costs associated with handling two grades of highway diesel fuel during the phase-in period, 0.3 cents per gallon was the downgrade revenue loss, and 0.2 cents per gallon reflected other distribution costs, including operating and testing costs. The 1.2 cents per gallon additional distribution cost is slightly higher than the EPA's estimate of 1.1 cents per gallon. After June 1, 2010, the additional distribution cost associated with ULSD was 0.4 cents per gallon, including 0.2 cents per gallon for the downgrade revenue loss.[94]

EIA conducted a sensitivity analysis of higher distribution costs in the 10% Downgrade case. In the Regulation case, EIA followed the EPA assumption that ULSD product downgrade would be 4.4 percent of ULSD supplied. In the 10% Downgrade case, EIA assumed that 10% of ULSD would be downgraded from the highway diesel market. From June 2006 through June 2010, EIA assumed an additional distribution costs of 1.6 cents per gallon of highway diesel supplied. Of the 1.6 cents per gallon, 0.7 cents per gallon was for additional storage tanks to handle two on-highway diesel grades during the phase-in, 0.7 cents per gallon was for the revenue loss from downgrading ULSD, and 0.2 cents per gallon was for other distribution costs. After the end of the phase-in, in June 2010, the additional distribution cost was 0.9 cents per gallon: 0.7 cents per gallon for downgrade revenue loss and 0.2 cents per gallon for other distribution costs (see Chapter 6 for more detail).[95]

Summary

The Nation's refined petroleum product pipeline system is not monolithic. Pipelines are distinguished by region, type of service, mode of operation, size, how much interface material they produce, and how they dispose of it. In preparing this report, a variety of pipeline companies were consulted, representing a cross-section of size, capacity, location, markets, corporate structures, and operating modes.

It is likely that the pipeline industry can distribute ULSD successfully, but major challenges arising from the unique specifications of a new product prevent a clear assertion that pipeline distribution of the material will be successful. In successfully distributing ULSD, oil pipelines will have to surmount numerous challenges:

- Coping with a product phase-in
- Demonstrating that untested pipeline batching techniques work
- Determining for the first time that sulfur content from other refined products does not "trailback" in pipelines and will not avoidably contaminate the new fuel

[94]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-121.

[95]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-121.

9271A

- Installing product quality testing equipment (which does not yet exist)
- Recovering operating costs that are not transparently recoverable under FERC regulations or market conditions
- Collecting, transporting, reprocessing, and selling up to twice the volume of existing pipeline transmix
- Reconfiguring an undetermined number of existing stations with new piping, tanks, manifolds, or valves
- Installing new loading facilities at distribution terminals.

Protecting the integrity of 15 ppm product will be more difficult than protecting the product integrity of the current 500 ppm product. The sulfur concentration of the neighboring product will more easily lead to contamination of the ULSD. Not only is the specification lower, with less room for error, but also the "potency" of the sulfur in the nearby product is higher.

It appears that the overall proposition of transporting ULSD is feasible. More problems can be expected to arise in handling ULSD among delivering pipeline carriers than among trunk carriers. In particular, those delivering carriers that cannot support fungible operations, are already short of working tankage, have complex routing and schedules, or have small markets at their end points will have the greatest difficulty in transporting ULSD.

The market impact of a contaminated batch will be stronger, however. With such a tight specification, there is little opportunity for blending lower sulfur material into an off-specification batch or tank. With the regulation applied as a cap with no averaging aspect, an off-specification tank in a terminal with only two tanks will quickly lead to a localized shortage of highway diesel, especially in areas where the market is thin and the infrastructure sparse.

Finally, there are uncertainties about transporting ULSD that cannot be resolved without hands-on experience with this unique product.

5. Short-Term Impacts on ULSD Supply

Background

This chapter addresses the transition to ultra-low sulfur diesel fuel (ULSD) when the ULSD Rule takes effect in 2006. Whether there will be adequate supply was one of the key questions raised by the House Committee on Science in its request for analysis. The Charles Rivers Associates/Baker and O'Brien (CRA/BOB) study done for the American Petroleum Institute (API) estimated a shortfall of 320,000 barrels per day when the regulation is introduced in 2006. The issue of future supply of highway diesel fuel "received considerable attention during the comment period" on the Notice of Proposed Rulemaking (NPRM) published by the U.S. Environmental Protection Agency (EPA).[96] The EPA noted that "numerous commenters to the proposed rule indicated that they believed that the 15 ppm sulfur cap would cause shortages in highway diesel fuel supply" but that "a number of commenters also thought otherwise (i.e., that future supplies would be adequate)."[97]

While it is possible that some refiners may decide to shut down altogether because of this regulation, others might just abandon the highway diesel market. Few refineries can operate without producing gasoline because gasoline is a high-margin, high-volume product that provides significant revenue to refiners. On the other hand, it may be possible for some refineries to operate without producing ULSD. Some refineries could sell higher sulfur distillate products into the non-road, rail, ship, or heating oil markets. Some refiners could also decide to export distillate products if they are in the right location.

Because there are other markets for distillate products, some refiners may opt to delay upgrading their facilities to produce ULSD. Refiners' recent experiences with investing to meet new fuel standards have not been encouraging. As the EPA pointed out in the Regulatory Impact Analysis for this regulation, both the 500 ppm diesel fuel and reformulated gasoline standards resulted in overinvestment and oversupply of the fuels, and "of late, relatively poor refining margins have not allowed refiners to recoup the full cost of environmental standards."[98] Overly aggressive expansion to produce ULSD could result in similar oversupply of product and reduced margins, and some refiners may therefore wait to see whether adequate margins develop.

Another uncertainty is possible regulation of non-road diesel fuel. In addition, some States are proposing their own regulations for highway diesel fuel, which may add to the EPA requirements. Some refiners may wait to see whether additional requirements are established for highway or non-road diesel before investing to upgrade their refineries to produce ULSD.

The EPA has taken steps to monitor the ULSD supply situation. Its Final Rulemaking requires refiners and importers to submit a variety of information to ensure a smooth transition, and to evaluate compliance once the program begins. Refiners and importers expecting to produce highway diesel in 2006 are required to register with the EPA by December 31, 2001. Annual precompliance reports are required from 2003 through 2005, containing estimates of ULSD and 500 ppm sulfur fuel that will be produced at each refinery and projections of the numbers of credits that will be generated or needed by each refinery. A time line for compliance is also required, as well as other information.

The EPA will produce an annual report summarizing information from the precompliance reports without disclosing individual company plans. This information will give refiners a better indication of the potential market for credits and the availability of credits in each region. The EPA will also require annual reports after the program takes effect, in order to monitor production of ULSD and 500 ppm sulfur diesel fuel.[99] In addition, an independent advisory panel will be set up to look at issues of diesel supplies and related technologies, and to report to the EPA annually on the progress being made by industry to comply with the ULSD Rule.[100]

[96] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-33.

[97] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-33.

[98] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-34.

[99] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," Pre-publication Final Rulemaking (December 21, 2000), pp. 158-160.

[100] *Diesel Fuel News* (March 5, 2001), p. 3.

Cost Analysis

To assess the supply situation during the transition to ULSD in 2006, estimates of ULSD costs and supply were developed based on refinery-specific analysis of investment requirements. The relative costs can provide insights into whether refiners will make the investments to produce ULSD and give an indication of possible supply. Four scenarios describing investment behavior under different assumptions were developed to provide a range of possible responses to the ULSD Rule.

Using refinery-specific data collected by the Energy Information Administration (EIA), the ULSD product costs are estimated for each refinery based on its size, the sulfur content of the feeds, the fraction of cracked stocks in the feed, the boiling range of the feed, and the fraction of highway diesel produced. Cost curves were then developed in a three-step process. In the first step the cost of producing ULSD for each refinery was estimated for several strategies of ULSD production, based on refinery operation data for 1999. The strategies start by maintaining ULSD production at current highway diesel production levels. Then they consider both reductions and increases from current production to find the most economical level of production for individual refineries. In the second step the cost and volume information for individual refineries is used to construct cost curves for the U.S. refining industry using a variety of scenario assumptions about how refiners may respond with refinery investment in preparation for summer 2006, when ULSD requirements for highway diesel begin. The third step consists of adjusting the cost curves to reflect changes in refinery capacity from 1999 to 2006.

Appendix D describes in detail the refinery-by-refinery analysis and development of the cost model used as the basis for developing the cost curves. Table 6 provides samples of the ULSD cost model results for cases representing various refinery configurations and situations. The case descriptions in the table indicate whether the refinery in that particular case falls within the higher or lower part of the range in terms of hydrotreater unit capacity, sulfur content of the hydrotreater feed, and the fraction of cracked stock in the feed. The costs in this analysis assume a 5.2-percent after-tax return on

Table 6. Sample Results from the ULSD Cost Model

Refinery Characteristics and Costs	Case A	Case B	Case C	Case D	Case E	Case G	Case H	Case I	Case J	Case K	Case L
Hydrotreater Capacity Range[a]	H	H	H	H	H	L	L	H	H	H	HR
Feed Sulfur Content Range[a]	H	H	L	L	H	H	H	M	M	M	M
Percent Cracked Stock Range[a]	H	H	H	H	L	H	H	H	M	M	M
Revamp or New Unit[b]	N	R	N	R	R	N	R	N	N	R	R
Current Highway Diesel Production (Thousand Barrels per Day)	50.0	50.0	50.0	50.0	50.0	10.0	10.0	0.0	32.4	32.4	32.4
Hydrotreater Feeds (Thousand Barrels per Day)											
Straight-Run Distillate	34.0	34.0	34.0	34.0	50.0	6.8	6.8	33.0	25.3	25.3	18.4
Light Cycle Oil	8.0	8.0	8.0	8.0	0.0	1.6	1.6	4.0	2.1	2.1	0.0
Coker Distillate	8.0	8.0	8.0	8.0	0.0	1.6	1.6	23.0	5.1	5.1	2.3
Total	50.0	50.0	50.0	50.0	50.0	10.0	10.0	60.0	32.4	32.4	20.7
Hydrogen Consumption (Standard Cubic Feet per Barrel)	550	550	402	402	248	550	550	590	395	395	305
Feed Sulfur Content (Parts per Million)											
Straight-Run Distillate	9,000	9,000	1,100	1,100	9,000	9,000	9,000	6,000	6,000	6,000	6,000
Light Cycle Oil	25,000	25,000	3,800	3,800	0	25,000	25,000	15,000	13,000	13,000	13,000
Coker Distillate	22,000	22,000	5,700	5,700	0	22,000	22,000	14,000	14,000	14,000	14,000
ULSD Cost Components (1999 Dollars per Barrel)											
Hydrotreater											
Capacity Changes	0.73	0.55	0.70	0.55	0.36	1.21	0.74	0.72	0.81	0.55	0.49
Other	0.83	0.74	0.75	0.68	0.54	0.96	0.79	0.87	0.78	0.67	0.62
Hydrogen Production											
Capacity Changes	0.20	0.20	0.22	0.22	0.05	0.35	0.35	0.30	0.19	0.19	0.00
Other	0.52	0.53	0.55	0.54	0.12	0.56	0.57	0.88	0.40	0.41	0.13
Sulfur and Other	0.27	0.06	0.07	0.06	0.06	0.41	0.10	0.19	0.19	0.07	0.08
Total Cost (1999 Dollars per Barrel)	**2.54**	**2.08**	**2.27**	**2.05**	**1.12**	**3.49**	**2.56**	**2.97**	**2.37**	**1.88**	**1.31**
Total Cost (1999 Cents per Gallon)	**6.0**	**5.0**	**5.4**	**4.9**	**2.7**	**8.3**	**6.1**	**7.1**	**5.6**	**4.5**	**3.1**

[a]H = refinery in the higher range; M = refinery in the middle range; L = refinery in the lower range.
[b]N = new unit; R = revamped unit.
Note: Only refineries in Petroleum Administration for Defense Districts (PADDs) I-IV are included in the short-term analysis.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

9273A

investment, which is estimated to be equivalent to the 7-percent before-tax return on investment assumed in the EPA's analysis.

The cases in Table 6 were designed to represent the types of individual refinery situations that lie behind the cost curve results. Cases A and B represent refiners producing highway diesel fuel as a high fraction of their distillate pool. These refineries run a higher sulfur crude oil, do not have hydrocracking facilities, and have relatively large-scale highway diesel production. Thirty-two percent of the highway diesel they produce comes from cracked stock, which is about the average for Petroleum Administration for Defense District II (PADD II) (see Appendix D, Table D1). The cost of producing highway diesel at current production levels in the refineries of Cases A and B is 6.0 cents per gallon if a new hydrotreater is required and 5.0 cents per gallon if the current hydrotreater can be revamped. The cost of the incremental hydrogen to produce ULSD represents 28 percent of the added cost for Case A and 35 percent for Case B.

Cases C and D have the same volumes as A and B but use a lower sulfur crude oil. The cost of the added hydrogen is similar to the result for Cases A and B, because this analysis is estimating the cost to produce ULSD with 7 ppm sulfur rather than the current 500 ppm. Total costs, however, are just 0.1 cents per gallon lower for a revamped unit (Case D compared to Case B) and 0.6 cents per gallon lower for a new unit (Case C compared to Case A).

Case E shows a refinery producing ULSD only from straight-run distillate derived from a high-sulfur crude. The cost of production from a hydrotreater that has been revamped is only 2.7 cents per gallon. This is slightly more than half the cost of Case B, which has to handle 32 percent cracked stocks.

Cases G and H represent the same mix of hydrotreater feed as in Cases A and B, but the total feedstock volume is only 10,000 barrels per day, compared to 50,000 barrels per day in Cases A and B. This is the type of situation represented by comparing ULSD production in PADD IV with that in PADD II and PADD III. For a new hydrotreater unit, the ULSD cost would be 8.3 cents per gallon (2.3 cents per gallon higher than in Case A). If the unit can be revamped, the cost is 6.1 cents per gallon (1.1 cents per gallon higher than in Case B).

Some refineries currently produce high volumes of distillate product but no highway diesel. These refineries might consider entering the highway diesel market when the ULSD Rule takes effect if they anticipate that the price differential between ULSD and their other distillate products can more than offset the added investment and operating costs they would incur. Case I illustrates a non-road diesel producer converting to the production of highway diesel. The refinery runs a moderately high-sulfur crude oil and has substantial volumes of cracked distillates from the fluid catalytic cracker (FCC) and coker units. Because of quality requirements for non-road diesel products, cracked stocks still make up 45 percent of the feed to the hydrotreater for highway diesel production. The large percent of cracked stocks means a moderately high per-barrel investment and operating cost for the hydrotreater. Additionally, the per-barrel cost for hydrogen is quite high. Most of the refineries with high-volume distillate production and no highway diesel production had costs of highway diesel production in the higher portion of the cost range.

Cases J, K, and L provide an illustration of refineries achieving improved economics by reducing the volume of ULSD diesel below current highway production levels. As shown in Table 6, the cost of added hydrogen is generally a large component of the cost of producing ULSD. The cost for hydrogen grows as the fraction of cracked stocks increases, eventually requiring the construction of new hydrogen production capacity. However, if there is only a modest percent of cracked stock in the hydrotreater feed and the refiner reduces the input to the hydrotreater, then the incremental hydrogen requirement for ULSD production can be provided by existing refinery production sources.

Cases J and K show the costs for a new and revamped hydrotreater for a refinery running a medium-sulfur crude and with 22 percent cracked stock in the highway diesel production pool. Case L shows that if the input level is reduced from 32,400 barrels per day to 20,700 barrels per day when the unit is revamped, then the cost of ULSD production is reduced from 4.5 cents per gallon to 3.1 cents per gallon. Given the costs for Cases K and L, the preferred option for the refiner would be Case K if the price differential between highway and non-road diesel exceeds 6.9 cents per gallon and Case L if the differential is less than 6.9 cents per gallon.[101]

These sample cases highlight several situations that can cause refineries to have potentially high ULSD production costs and discourage them from investing to produce ULSD. Small refineries with less than 10,000 barrels per day of highway diesel production will have very high relative costs unless they can revamp an existing unit. The fraction of cracked stocks in the ULSD hydrotreater feed is extremely important. The need for hydrogen increases with the fraction of cracked stocks and may require new hydrogen production capability. If a refinery's other distillate products are primarily

[101] Calculated by taking the difference in total cost (1.88 × 32.4 − 1.31 × 20.7) divided by the change in volume (32.4 − 20.7), expressed in cents per gallon.

non-road diesel fuels with cetane requirements that limit the volume of cracked stocks, then it is often impossible for the refinery to reduce the cracked stocks going into highway diesel. Thus, refineries with moderate cracked stocks and a smaller scale will have high ULSD cost, and refineries with high cracked stocks and a moderate to large scale may also have ULSD costs that they view as uncompetitive.

Analysis of ULSD Production Decisions

Economic Considerations

Scenarios are analyzed to estimate the volumes of ULSD that refiners might produce at the beginning of the ULSD requirement in the summer of 2006. Each scenario defines a set of strategic principles that might characterize the economic rationale behind investment decisions that may be commonly made by refiners in this situation. Refiners have a choice as to how much ULSD they produce. Some refiners may decide to produce no highway diesel when the ULSD Rule comes into effect. While most refiners who are currently producers of highway diesel will likely continue to produce it, they could increase or decrease production from current levels. Because there is uncertainty associated with refiners' behavior, four supply scenarios were constructed, any one of which may turn out to be closest to the actual behavior of the refining industry in this situation.

In making the ULSD decision a refiner will look at the available options, analyze the costs to produce various levels of ULSD, and determine the impact on other distillate products. Then the refiner will try to estimate his relative competitive position for producing ULSD. The competitive assessment considers the cost of ULSD production for other refiners and looks at the mid-term competition for market share, including an analysis of current market share, regional market competition, the impact of new entrants that may have a significant cost advantage, synergies with other refineries within the same company, and potential changes in the price differential between ULSD and non-road fuels on a mid-term basis.

In a number of past instances when refiners have been required to meet new product specifications, they have not only made facility changes that would enable them to meet the demand for the product with new specifications, but have done so in such numbers and volumes that their ability to supply the market has exceeded market demand. In the case of ULSD, refiners have more choice in deciding to participate in the highway market or alternatively to produce products only for non-road distillate markets. This choice becomes a particular issue for refiners facing an expensive investment decision and the likelihood that they would be at a significant competitive cost disadvantage relative to other market competitors.

While most U.S. refiners look upon gasoline as an essential product, they could operate in the refinery business without producing any highway diesel. Thus, it is possible that some refiners will cease or significantly decrease highway diesel production when ULSD specifications take effect in 2006. This would create a transition market in which some refiners with higher costs would decrease production and be replaced by more cost-competitive refiners.

The set of more cost-competitive refiners falls into two categories—those increasing production of highway diesel from current levels and those currently producing little or no highway diesel. Will refiners in the second group jump into the market because they recognize that they would have a competitive position, or will they wait to see how the supply and margin picture unfolds before making a large-dollar commitment? Later entrants into the market could also be the beneficiaries of improved technologies that reduce the cost of compliance.

Refiners who estimate that their costs to produce ULSD are on the high end of the range will be far less likely to invest to produce ULSD. No one wants to be the marginal supplier after making a large investment, especially when the product is a secondary fuel product. The question is what differential cost will be perceived to be too high—is it 1 or 2 cents per gallon above what the refiner perceives is the average cost in the market? How does the refiner assess the possible competitive threats of a large-volume refiner who has previously not been a highway diesel producer but may now enter the market with better economics to produce highway diesel and reduce market prices? Refiners will likely try to retain highway market share, even if their relative competitive cost is modestly above the average cost in the region, rather than shifting into new markets. Refining companies with multiple refineries will view strategies in the context of their total system and could rebalance production on a system basis.

One of the key decisions in preparing to produce ULSD is whether to build a new hydrotreater or revamp an existing unit. This analysis assumes that revamps are more likely if a refinery installed new distillate hydrotreating units in the 1990s, or if the proportion of cracked stocks in the refinery's hydrotreater feed is small. New units are assumed at refineries where current hydrotreating capacity is less than highway diesel production. As shown in Table 7, the estimates indicate that 46 percent of the refineries in PADDs I-IV, accounting for 63 percent of highway diesel production capacity, would revamp existing units. PADD IV has the

9274A

Table 7. Estimate of Revamps and New Hydrotreaters for ULSD Production

Region	Number of Refineries			Percent	ULSD Production Volume (Thousand Barrels per Day)			Percent
	Revamp	New	Total	Revamp	Revamp	New	Total	Revamp
PADD I	4	7	11	36	139	77	216	64
PADD II	14	13	27	52	442	158	599	74
PADD III	22	23	45	49	603	423	1,026	59
PADD IV	5	10	15	33	46	72	117	39
Total	**45**	**53**	**98**	**46**	**1,229**	**729**	**1,957**	**63**

PADD = Petroleum Administration for Defense District.

Note: Although 98 refineries are considered in this analysis, 87 are current producers of low-sulfur diesel. Not all of these refineries are expected to produce ULSD economically.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

lowest proportion of revamps because of the larger amount of cracked stocks that refineries in that region must process. PADD II has the highest percentage of revamps because of the extensive upgrading that took place in the early 1990s and the moderate levels of cracked stocks in the feed. The EPA assumed that 80 percent of ULSD production capacity would be revamped units.

Supply Scenarios

The first of the four supply scenarios was developed based on the rationale that there is a high probability that refiners will produce at least a moderate level of ULSD. In the other three scenarios there is decreasing probability that the additional volumes would be produced. The description of the specific scenarios follows:

- **Scenario 1—Competitive Investment.** The first scenario includes only those refiners who are likely to prepare to produce ULSD in 2006. They currently hold market share and are estimated to be able to produce ULSD at a competitive cost. Refiners with highway diesel as a relatively low fraction of their distillate production are assumed to abandon the market unless their cost per unit of production is competitive at current highway diesel production levels. Some refiners are assumed to reduce highway diesel production below current levels when they have a more competitive ULSD production at a reduced production rate.

- **Scenario 2—Cautious Expansion by Competitive Producers.** In this scenario, refiners base ULSD production decisions on the assumption that the price differential between ULSD and non-road distillate products will remain wide. Current producers with competitive cost structures for ULSD production and high fractions of highway diesel production (greater than 70 percent of total distillate production) are assumed to maintain current production levels and may even push production of ULSD toward 100 percent of distillate production if only minor increases in per unit production costs occur at increased volume. Other refiners are also assumed to increase their fraction of highway production if the economics are only slightly poorer at higher volumes. Those whose current production is focused primarily on non-road markets are assumed to stay with those markets.

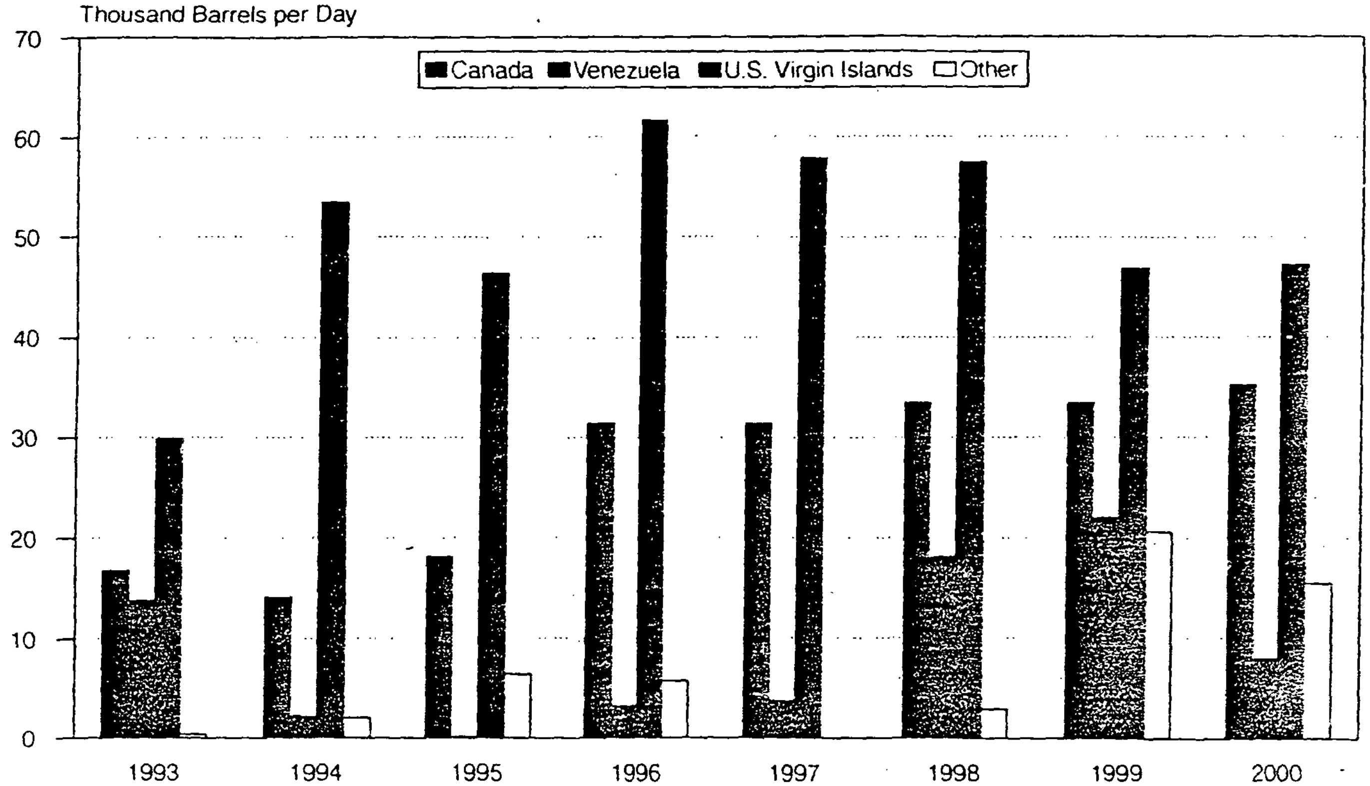
- **Scenario 3—Moderate New Market Entry.** While refineries that are currently producing little or no highway diesel may be hesitant to jump into the ULSD market, this scenario assumes that a select few will decide to take the risk. This is based on the belief that a limited number of refineries think they can gain market share without depressing the price differential between ULSD and non-road diesel to the extent of ruining margins and return on investment. These refiners are assumed to have favorable cost structures for ULSD production (probably in the lower third).

- **Scenario 4—Assertive Investment.** The fourth scenario assumes that a larger number of refiners will compete to increase their shares of the ULSD market. In this scenario, refiners believe that most of their competitors are overly cautious, and that they can succeed by taking a contrary strategy (which in reality is adopted by far more refiners than anticipated).

Imports

Historically, imports have been a small part of low-sulfur diesel supply. The only significant volumes of low-sulfur diesel fuel have been imported into PADD I, which totaled 123,000 barrels per day in 1999 then declined slightly in 2000 to 106,000 barrels per day (Figure 4). Imports made up 5 percent of low-sulfur diesel product supplied for the United States as a whole in 2000 and 14 percent of product supplied in PADD I. The PADD I imports come from three main sources—Canada, the Virgin Islands, and Venezuela. Low-sulfur diesel imports from the Virgin Islands reached 62,000 barrels per day in 1996 and have fallen to 47,000 barrels per day in 2000. Imports from Canada, which have been fairly constant for the past few years, totaled 35,000 barrels per day in 2000. Imports from Venezuela grew sharply in 1998 and 1999, to 22,000 barrels per day in 1999, before falling to 8,000 barrels per day in 2000.

Figure 4. Imports of Low-Sulfur Diesel Fuel into PADD I, 1993-2000



Source: Energy Information Administration. Form EIA-814, "Monthly Imports Report."

Other countries are also planning to lower the sulfur content of diesel fuel. Canada has announced plans to require a 15 ppm sulfur diesel fuel in mid-2006, mirroring the U.S. regulation.[102] A 50 ppm ULSD becomes mandatory across Europe in 2005. The European Commission is also discussing a gradual phase-in to 10 ppm sulfur, starting with a 10-percent supply requirement in January 2007.[103]

Given these changes, Canadian refiners currently exporting to the United States may make the investment to produce ULSD for the U.S. market. The East Coast has been the main market for a large refinery in the Virgin Islands that is jointly owned by Amerada Hess and PdVSA, Venezuela's national oil company. Both of the plant's owners see the United States as a strategic market. Venezuela is planning to upgrade its domestic refineries, but because it is also interested in expanding its presence in Latin American markets,[104] it is not clear whether it would supply ULSD to the U.S. market.

Refineries worldwide will be investing to produce lower sulfur diesel fuel. Even a refinery designed to produce diesel with 50 ppm sulfur could produce some amounts at less than 15 ppm. Thus, it is conceivable that limited amounts of ULSD could be imported from other sources. In the early part of the transition to ULSD, imports beyond historical levels probably are less likely and quantities less than historical levels probably are more likely.[105]

Demand Issues

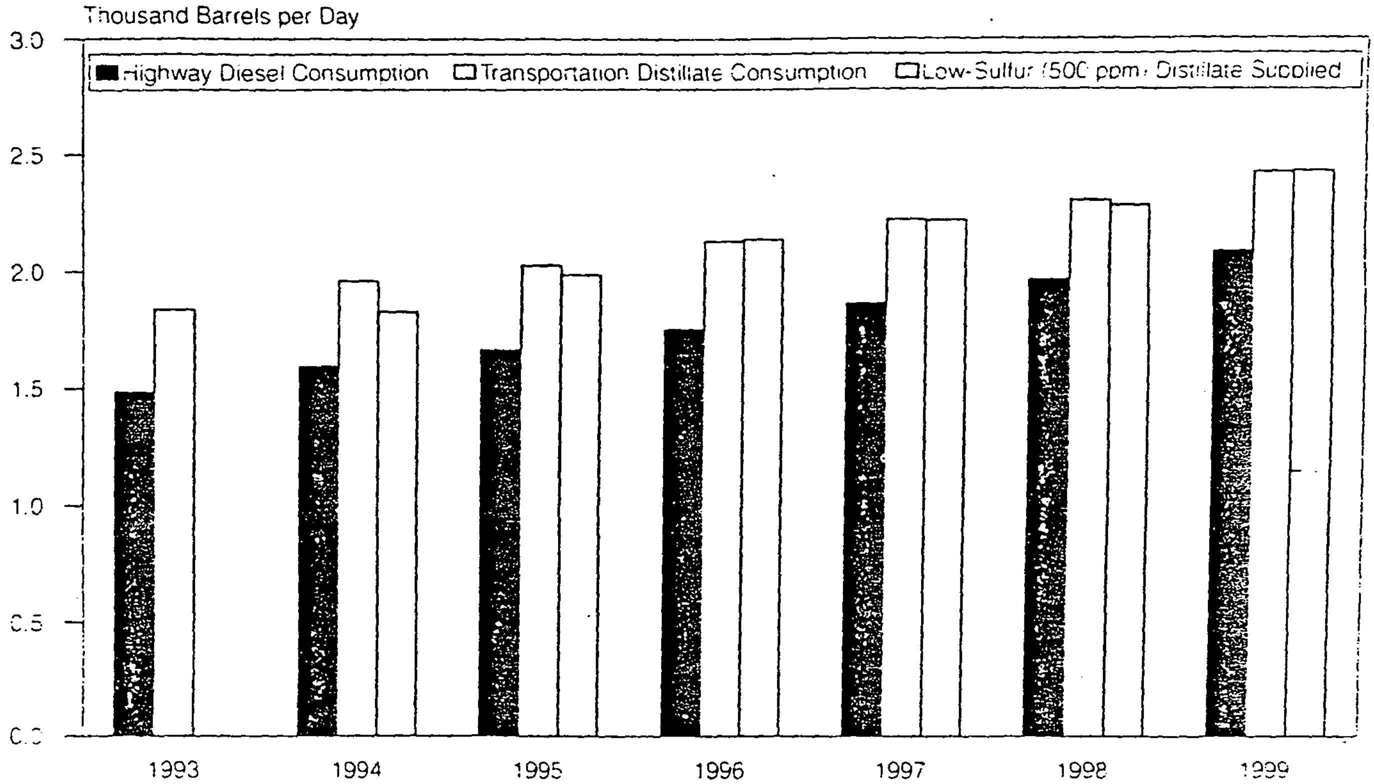
The number of vehicles that actually need ULSD when the regulation takes effect in 2006 will be small. The EPA has mandated that 80 percent of the refinery output of less than 500 ppm diesel fuel be ULSD in order to provide retail availability for the trucks that need ULSD. As a result, the supply of ULSD will be much larger than the demand provided by vehicles that need ULSD. The concern is whether enough fuel will be available to supply all highway diesel vehicles.

Current production of low-sulfur diesel fuel is greater than what is required by the market. Highway diesel fuel consumption accounted for 86 percent of transportation distillate demand in 1999. Yet low-sulfur diesel product supplied (a surrogate for demand) has nearly equaled transportation distillate demand in recent years (Figure 5). Consequently, the amount of low-sulfur

[102] Public Works and Government Services Canada, *Canada Gazette*, Vol. 135, No. 7 (February 17, 2001), p. 454.
[103] *Diesel Fuel News* (March 5, 2001), p. 11.
[104] *Oil Daily* (February 27, 2001), p. 2.
[105] EIA's Office of Oil and Gas is planning to issue a report in 2001 on the availability of product imports.

9275A

Figure 5. Low-Sulfur Diesel Consumption and Product Supplied, 1993-1999



Sources: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340, and *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, 1993-1999).

diesel fuel currently being consumed in the market is more than 15 percent higher than that required for highway vehicles. There are several reasons for this. The logistics of the distribution system dictate in some areas that only one type of fuel can be distributed. Because the price differential between low-sulfur diesel and other distillate products has been only 2 to 3 cents per gallon or less in recent years, the incentive to maintain separate product infrastructure has not been great. An important question is the extent to which the demand for ULSD will remain above that required for highway vehicles after the ULSD regulation takes effect in 2006. A larger price differential between ULSD and higher sulfur distillate products may provide some incentive to avoid consuming ULSD in markets where it is not required, but in some areas it may continue to be impractical to distribute more than one product.

It is also unclear how much 500 ppm sulfur diesel fuel will be in the market after the regulation takes effect. Refiners will be investing for the long term and not just to produce 80 percent ULSD in the transition period, and many refiners (if they invest to produce ULSD at all) may be producing 100 percent ULSD in the transition period. Some refiners could continue to supply 500 ppm diesel fuel by purchasing credits, and some small refiners could continue to produce 500 ppm sulfur fuel until 2010 (see box on page 45).

For the above reasons, the amount of ULSD actually needed to balance demand in 2006 is highly uncertain. A range of demand estimates has been developed to account for some of the uncertainty. In the mid-term analysis for this study, transportation distillate demand in PADDs I-IV[106] in the 2/3 Revamp case (see Chapter 6) amounts to about 2.7 million barrels per day. At the U.S. level, transportation distillate demand is projected to be 3.0 million barrels per day in 2006, increasing by 3.2 percent per year from the 1999 level of 2.4 million barrels per day. This compares to an average rate of increase of 3.5 percent per year from 1982 to 1999. Transportation distillate demand rose sharply from 1982 to 1989 and again from 1991 to 1999, at annual average growth rates of 4.7 and 4.0 percent, respectively, but fell in 1990 and 1991, at the time of the Iraqi invasion of Kuwait.

The probable downgrading of some ULSD to 500 ppm sulfur diesel in the distribution system was not taken into account in this part of the analysis. The requirement to produce 80 percent ULSD is at the refinery gate, and

[106] PADD V was not included in this analysis because supply concerns are less of an issue in the transition period and the requirement for CARB diesel makes the PADD V market different from PADDs I-IV.

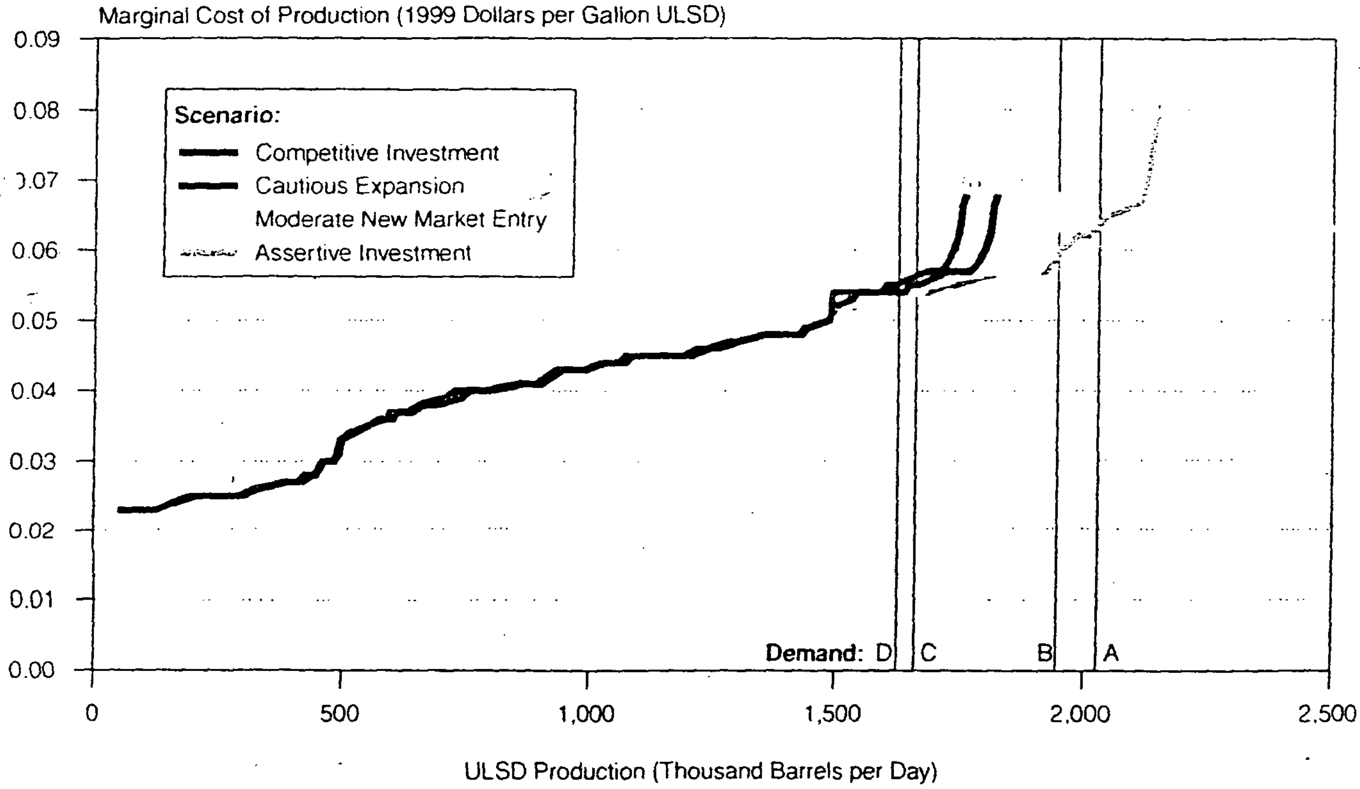
supplies that are downgraded to a higher sulfur level in the distribution system can still be sold as highway diesel during the transition period.

Cost Curves and Demand Estimates for 2006

Figure 6 shows the combined cost curves for PADDs I-IV for each of the scenarios, together with four estimates of demand.[107] The EPA estimates that, under the small refiner option, up to 5 percent of the market could delay making the transition to ULSD until 2010.[108] In addition, the temporary compliance option mandates that ULSD production must constitute 80 percent of low-sulfur diesel production. Assuming the full extent of the small refiner, temporary compliance, and credit trading provisions of the Rule, ULSD demand is estimated at just over 2.0 million barrels per day (Demand A). As indicated above, imports from the Virgin Islands and Canada are likely to continue. At their recent historical level of 80,000 barrels per day, imports would reduce domestic demand for ULSD to 1.95 million barrels per day (Demand B, which matches the demand projection in the mid-term analysis described in Chapter 6). Demand C in Figure 6 is based on the same assumptions as Demand B and, in addition, assumes that ULSD will be used only for highway consumption (86 percent of transportation distillate demand), resulting in a demand estimate of 1.7 million barrels per day. Demand D assumes a higher estimate for imports—116,000 barrels per day—which was the level for PADDs I-IV in 2000.

The cost curves in Figure 6 show the estimated volumes of ULSD that could be produced at increasing cost levels. The curves show the wide range of costs to produce ULSD across the population of U.S. refiners that might choose to become ULSD producers. There are some refiners at the upper range of the cost curves that would

Figure 6. ULSD Cost Curve Scenarios with 2006 Demand Estimates



Demand A: Small Refiner and Temporary Compliance Options
Demand B: Small Refiner and Temporary Compliance Options with Imports
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

[107] A range of demand estimates are shown in Figure 6, but no feedback effects are represented. Feedback effects are included in the mid-term analysis (Chapter 6).

[108] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

9276A

have much higher costs and could have concerns that margins in the marketplace would not be high enough to provide a satisfactory rate of return.

The cost curves in Figure 6 were developed using capital cost and return on investment assumptions consistent with those used in the EPA's analysis. Those assumptions were used in order to provide a comparison with the EPA's analysis results and should not be viewed as the assumptions that EIA considers the most likely. However, concerns about the adequacy of ULSD supply are based on the possible reluctance of higher cost producers to invest to produce ULSD in 2006. Because of the uncertainty of these assumptions, two additional sets of supply scenarios are provided, using higher capital cost assumptions and a higher required return on investment, as discussed later in this chapter.

Total ULSD production on the Scenario 1 (Competitive Investment) and Scenario 2 (Cautious Expansion) cost curves extends beyond the lower demand estimates (C and D) and would meet the highway demand estimates even if no ULSD imports were available. In Scenario 3 (Moderate New Market Entry), production just reaches the mid-term analysis demand estimate that includes imports (Demand B). In Scenario 4 (Assertive Investment), ULSD production surpasses the mid-term analysis demand estimate that does not include imports. None of the supply curves, however, provides enough supply to reach the demand estimate that does not include the temporary compliance option (see Table 8 below). Some refiners may be able to produce ULSD with a cost of about 2.5 cents per gallon; however, at the volumes needed to meet demand, costs are estimated at 5.4 to 6.8 cents per gallon.[109] ULSD prices could show an even higher differential if supply falls short of demand.

The four factors that have the strongest influence on the cost of producing ULSD are the production volume of 500 ppm diesel, the fraction of cracked stocks in the feedstock, the scale of the hydrotreater unit, and whether a new or revamped unit is required.

500 ppm Diesel Supply Issues in 2006

In 2006, 500 ppm highway diesel could come from two sources: either from refiners who produce both 500 ppm and 15 ppm highway diesel or from refiners who are now producing highway diesel but who choose not to make investments to produce ULSD and purchase credits to sell 500 ppm diesel. Few refineries are assumed to fall into the first group. Possible candidates would be refiners with large current production of highway diesel who have multiple distillate hydrotreating units and decide to revamp or replace a large unit to produce ULSD and maintain a second unit to produce 500 ppm highway diesel. This would also mean that the refiner would anticipate selling the 500 ppm diesel as non-road diesel in 2011, because building one large hydrotreater in 2006 would be more economical than building a second hydrotreater for ULSD in 2010. If the decision is made to invest to produce ULSD, a refiner is likely to invest to produce the full volume of highway diesel as ULSD. Some product that fails to meet the ULSD specifications could be downgraded to 500 ppm diesel fuel and sold as highway diesel during the transition period, but few refiners are assumed to produce both 15 ppm and 500 ppm diesel.

Production of 500 ppm highway diesel can clearly come from refiners who are now producing low-sulfur highway diesel and decide not to convert their refinery facilities in 2006. In Scenario 2, the number of non-producers of ULSD in PADDs I-IV totals 21. The characteristics of the 21 refineries that are the potential sources of 500 ppm highway diesel production in 2006 in Scenario 2 differ across the various PADDs. PADD I has 5 refineries and PADD II has 5 refineries that are assumed not to invest to produce ULSD. Nine of these ten refineries currently produce less than 10,000 barrels per day of highway diesel, and the other is under 20,000 barrels per day.

The profile of the PADD III refiners is quite different from those in the other PADDs. While PADD III has some small refineries in this group, several moderately large refineries are also included, which accounts for the fact that PADD III represents 56 percent of the total volume of PADD I-IV production that is estimated not to convert from low-sulfur diesel to ULSD in 2006. Most of these refineries are on the high end of the cost range and would have to build new units and/or deal with relatively high fractions of cracked stocks to produce ULSD.

Six refineries in PADD IV are estimated to have relatively high costs of ULSD production and are assumed not to invest to produce ULSD. The PADD IV refiners are relatively small. Most have some cracked stocks in the highway diesel feed stream and would need to build new units. The refiners not producing ULSD would need to obtain waivers or purchase credits to continue to sell 500 ppm diesel fuel into the highway market.

[109] These are marginal costs on the industry supply curve, based on average refinery costs for producing ULSD. These cost estimates do not include additional costs for distribution, estimated at 1.1 cents per gallon in the mid-term analysis. Costs were not adjusted to take sulfur credit trading into account, because of the uncertainty about whether trading would occur and the value of the credits. If credit trading occurred, costs could be reduced.

Twenty-nine refineries in Scenario 1 are in the cost range below 4 cents per gallon, and all are refineries for which it is assumed that the existing unit could be revamped. Most of these refineries have little or no cracked stocks in the hydrotreater feed to produce ULSD. For the few that do have cracked stocks, a revamped unit at a reduced throughput was found to obtain better economics of ULSD production and put them in the cost range under 4 cents per gallon. Twenty-five refineries are in the cost range from 4 to 5 cents per gallon. Thirteen are assumed to construct new units, and most of these refineries have a low percentage of cracked stocks in the hydrotreater feed. A couple of units in this cost range are assumed to reduce throughput from current highway diesel production levels. Above 5 cents per gallon, a couple of refineries with a high percentage of cracked stocks are assumed to revamp existing units. The rest, which have moderate levels of cracked stocks, are assumed to build new units. The refineries above 5 cents per gallon also include a number of smaller refineries with ULSD production under 10,000 barrels per day.

Regionally, PADD IV has the highest estimated costs for ULSD production. The refineries in PADD IV are smaller on average, have more cracked stocks to process, and have the lowest proportion of revamps. In PADD I, a large heating oil market provides an outlet for some of the more difficult streams to hydrotreat so it tends to show lower costs for producing ULSD. PADD II refineries are also toward the lower end of the cost curve. They tend to be more moderate in size (which gives better economies of scale), have moderate levels of cracked stocks, and had extensive revamps in the early 1990s to put them in a better position to upgrade to produce ULSD. PADD III has a mixture of small and large refineries with a variety of configurations and as a result shows a wide range of lower and higher cost ULSD producers. Some of the refineries in PADD III are among the highest as far as the proportion of cracked stocks in the feedstock going to the hydrotreater. Sixty-four percent of the refineries in PADD IV that are assumed to produce ULSD in Scenario 4 have estimated costs greater than 5 cents per gallon compared to 31 percent in PADD III, 22 percent in PADD II, and 17 percent in PADD I.

Scenario 1 has the lowest production volume of the four scenarios but the highest probability that production volumes of ULSD will at least reach these estimates in 2006. Of the 87 refineries in PADDs I-IV that currently produce highway diesel, only 66 are estimated to produce ULSD in Scenario 1. Of the 21 refineries that are estimated to terminate ULSD production in Scenario 1, the cost of ULSD production ranges from 6 to 13 cents per gallon.[110] Two-thirds of these refineries currently produce less than 10,000 barrels per day of highway diesel. PADD IV refineries are disproportionately in the higher cost range.

Scenario 2 assumes that the number of refineries that will produce ULSD is the same as in Scenario 1, but that these refineries will increase production if their competitive position is not greatly affected. Comparing Scenario 3 to Scenario 2, ULSD production is estimated to increase at nine refineries, and one refinery that currently produces only non-road distillate product is assumed to enter the ULSD market. All of these factors raise the estimated production level in Scenario 3 by 129,000 barrels per day over that in Scenario 2.

The probability of reaching the total volume production of Scenario 4 is the lowest. In this scenario, refineries with higher costs of production are assumed to enter the ULSD market in 2006. The added production volumes in Scenario 4 come from three types of situations. First, some refineries are assumed to expand production beyond the Scenario 3 level if unit costs are only slightly

Table 8. Supply and Demand Estimates in the Reference Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,952	2,143
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,533	-770	-709	-580	-389
Small Refiner and Temporary Compliance Options (Demand A)	2,026	-264	-203	-74	117
Small Refiner and Temporary Compliance Options with Imports (Demand B)	1,946	-184	-123	6	197
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports (Demand C)	1,662	100	161	290	481
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports (Demand D)	1,626	136	197	326	517

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043C01A.

[110] The highest estimated costs by region are 9 cents per gallon for PADD I, 13 cents per gallon for PADD II, 7 cents per gallon for PADD III, and 12 cents per gallon for PADD IV.

9277A

higher. Second, five of the refineries entering the market were viewed in Scenario 3 as having too high a cost. The third and largest portion of additional volume comes from two refineries that currently are not producers of highway diesel. All of the additional volume in Scenario 4 comes from refiners with costs of ULSD production higher than 5 cents per gallon.

Table 8 shows the differences between the demand and supply estimates. The largest shortfall, which occurs between Scenario 1 (assuming the most cautious investment strategy) and the highest demand estimate, is estimated at 770,000 barrels per day. The widest surplus, 517,000 barrels per day, is under Scenario 4 (the most aggressive investment strategy) and the lowest demand estimate that also accounts for import availability. Assuming the mid-term analysis demand estimate, which is similar to the *AEO2001* projection, Scenarios 3 and 4 project sufficient supply.

Some analysts contend that demand could exceed the estimates in this analysis that assume the temporary compliance option of 80 percent ULSD production. Most refiners that invest to produce ULSD will plan to produce 100 percent ULSD unless they have a market for the higher sulfur product after 2010. Those producing 100 percent ULSD will generate credits which can then be sold to those who decide to delay investing to produce ULSD. Credit trading programs have been successful in the utility industry, but how well credit trading will work in a less-regulated industry remains unclear. Refiners may be less than enthusiastic about selling credits to their competitors that would allow them to sell product produced at a lower cost in the same market as ULSD, possibly at a price similar to the price of ULSD.[111] Refiners who wait to invest can also take advantage of improvements in technology that could help them compete more effectively with those who invested early. Credits could increase sharply in value if markets were tight, but they would have less value if supplies were ample.

To provide a further range of demand estimates, Tables 9 and 10 show the projections for high and low macroeconomic growth cases along with the supply estimates from the cost curves. Transportation distillate demand is projected to increase by 4.0 percent per year from 1999 to 2006 in the high macroeconomic growth case and by 2.7 percent per year in the low macroeconomic growth case.

Table 9. Supply and Demand Estimates in the High Economic Growth Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,953	2,140
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,669	-906	-845	-716	[illegible]
Small Refiner and Temporary Compliance Options	2,135	-372	-311	-183	5
Small Refiner and Temporary Compliance Options with Imports	2,055	-292	-231	-103	85
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,756	7	66	196	38[illegible]
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,720	43	1[illegible]4	233	420

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run HM2001.D101600A

Table 10. Supply and Demand Estimates in the Low Economic Growth Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,953	2,140
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,447	-685	-624	-495	[illegible]
Small Refiner and Temporary Compliance Options	1,958	-195	-134	-5	18[illegible]
Small Refiner and Temporary Compliance Options with Imports	1,878	-115	-54	74	[illegible]
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,604	159	220	[illegible]	54[illegible]
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,568	195	256	385	57[illegible]

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling System, run LM2001.D101600A

[111] Many analysts contend that the prices of ULSD and 500 ppm diesel will converge in the phase-in period, because most trucks can use 500 ppm fuel but only 20 to 25 percent of production will be 500 ppm fuel. The higher demand than supply will tend to push the price to the same level as ULSD. The need to purchase credits to sell 500 ppm product will also tend to push up its price.

Two additional sets of the four supply scenarios are provided that vary the hydrotreater capital cost assumptions and the return on investment assumption. The capital costs assumed in the initial set of four scenarios in this chapter are similar to those used in the EPA analysis (see Chapter 7 for a comparison of capital cost assumptions). Because of the uncertainty associated with the cost of installing distillate hydrotreating capable of producing diesel fuel containing less than 10 ppm sulfur, a second set of scenarios was developed assuming capital costs for the hydrotreater units that are about 40 percent higher than the initial set (Figure 7). The higher capital costs in this scenario reduce the projected production of ULSD by 25,000 to 55,000 barrels per day and increase the cost estimates from 0.4 cents per gallon to 1.0 cents per gallon.

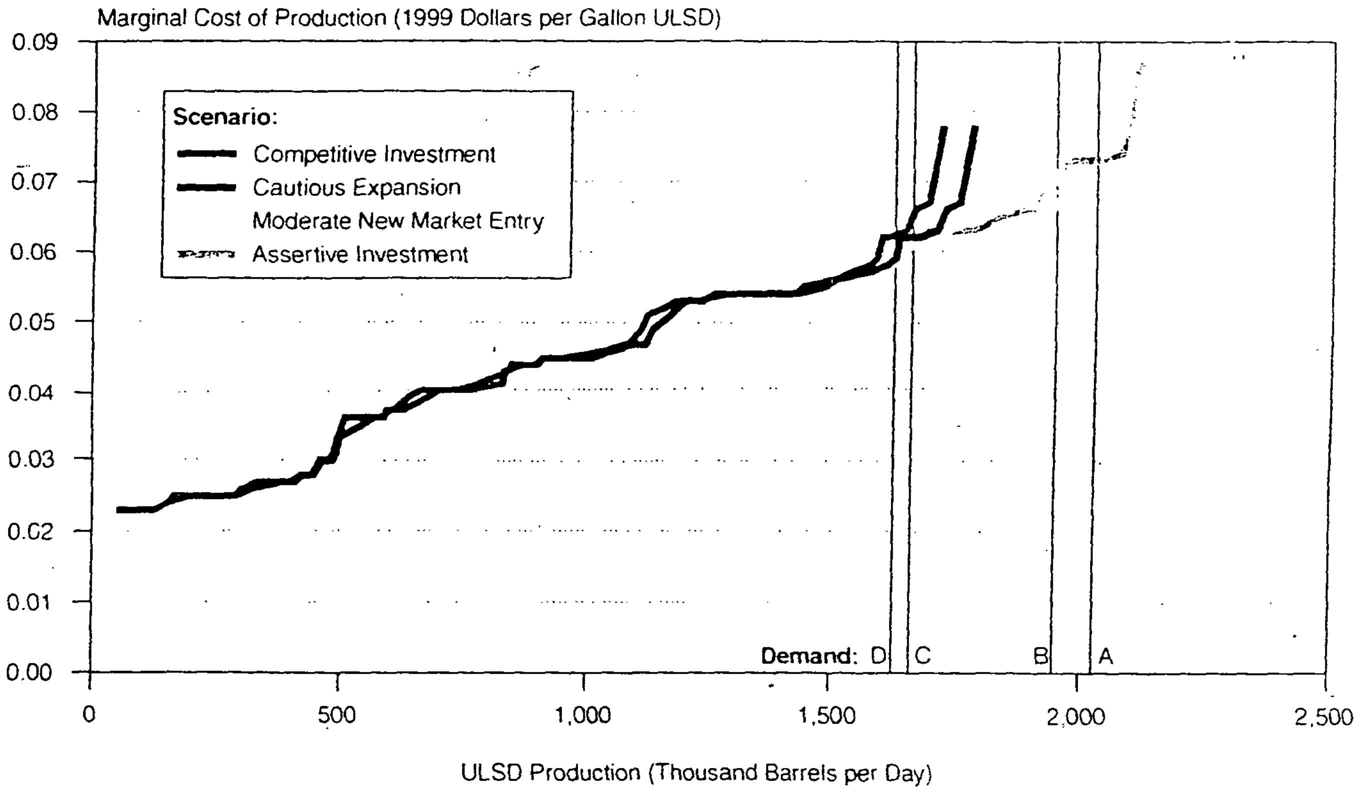
A third set of supply scenarios was developed assuming a 10-percent required return on investment (Figure 8), rather than 5.2 percent assumed in the initial set of scenarios. The higher assumed rate results in a reduction in production of 40,000 to 66,000 barrels per day across the four scenarios. The cost estimates increase by 0.8 to 1.2 cents per gallon from the first set of scenarios. Because of the reduced volumes, estimated production levels in Scenario 3 fall short of the demand level projected in the mid-term analysis (Demand B) in both the higher capital cost and higher required return on investment sensitivities (Tables 11 and 12).

Balancing Demand and Supply in 2006

These supply curves, along with the demand estimates for 2006, indicate the possibility of a tight diesel market when the ULSD Rule is implemented. Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand cenarios show adequate supply to meet estimated demand. This analysis compares supply and demand at an aggregate level. Maintaining a balance of supply and demand across regions and throughout the distribution system would be more difficult.

Improvements in supply could result if more refiners undertook investments to produce ULSD, if capacity expansions by refiners were greater than anticipated in

Figure 7. ULSD Higher Capital Cost Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates



Demand A: Small Refiner and Temporary Compliance Options
Demand B: Small Refiner and Temporary Compliance Options with Imports
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

9278A

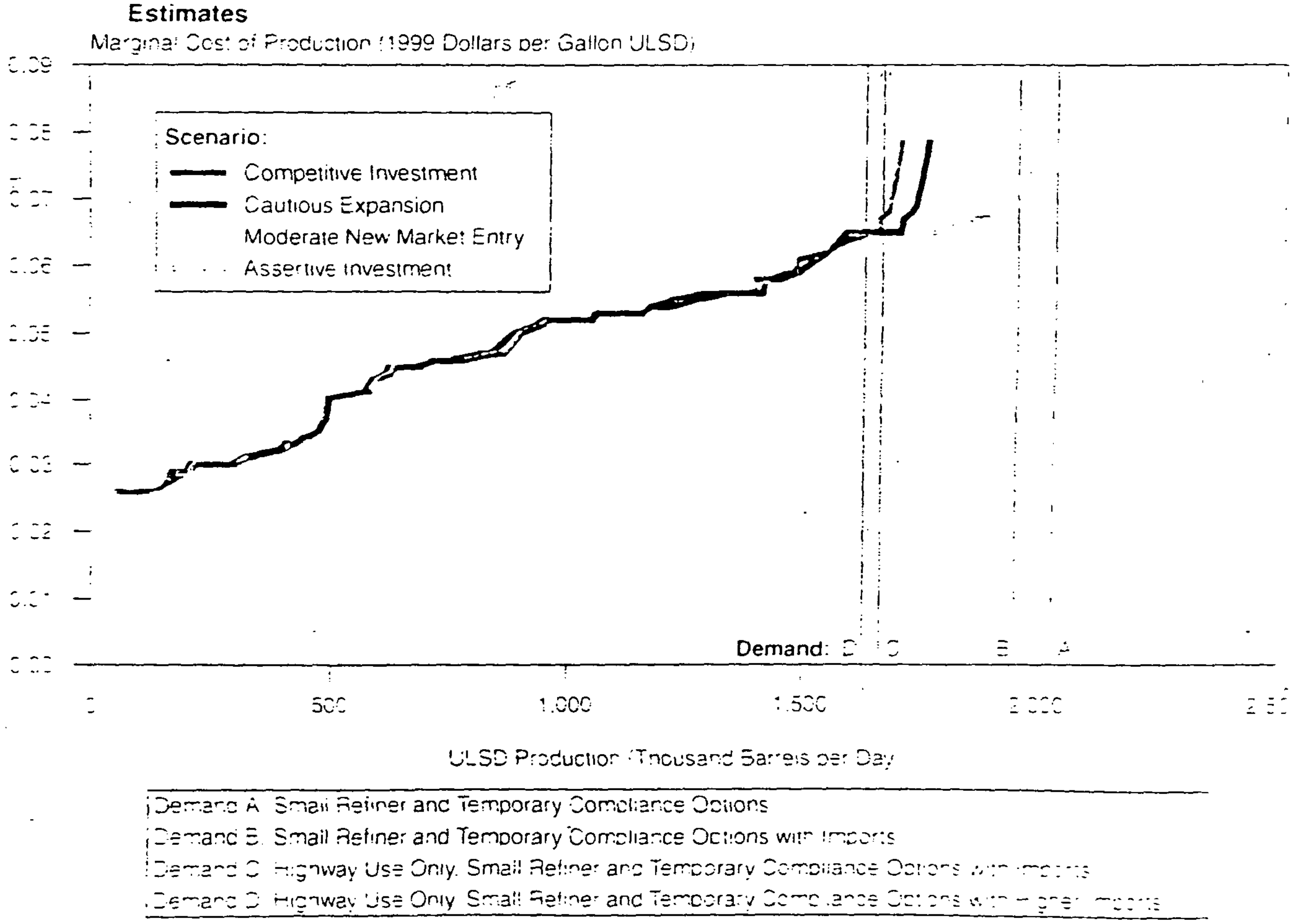
this analysis, and/or if more imports were available. On the demand side, slower growth in the highway diesel market than these demand estimates and/or curtailing of ULSD consumption for non-road uses would also improve the situation.

If supplies fall short of demand, sharp price increases could occur to balance supply and demand. That type of situation could result in a number of responses, some of which could begin to occur as soon as the price differential between ULSD and other products started to widen—possibly even before it became clear that a market supply problem existed. Refiners would attempt to maximize ULSD production. Some additional production may be possible by, for example, shifting some non-road distillate or jet fuel streams into ULSD. This would be limited, however, because only the lower sulfur streams could be used and additional hydrotreating may be necessary. Imports of jet fuel or other products could then replace the lost production of those fuels. Additional imports of ULSD could be forthcoming if there were large price differentials between markets. Such responses would require higher costs, however, because lower cost options would be exercised first.

Sharply higher prices would also curtail demand for diesel fuel. Truckers would reduce consumption to the extent possible and try to pass higher fuel costs to customers, who would then look for alternative means to transport goods.

In 2006, the quantity of fuel actually needed for vehicles requiring ULSD will be much less than the required 80 percent of diesel production. If it becomes apparent that the supply is inadequate, or that markets are becoming tight, additional low-sulfur diesel supplies could become available if the required proportion of ULSD production were reduced. Allowing more 500 ppm diesel into the highway market could alleviate some of the stress on the market. If the requirement were 70 percent instead of 80 percent, for example, the demand estimates shown in Table 8 would be reduced by 217,000 to 253,000 barrels per day, enough to eliminate the shortfalls indicated except for Demand A in Scenario 1 and the highest

Figure 8. ULSD 10% Return on Investment Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates



Sources: Cost curve scenarios: Appendix C. Demand estimates: National Energy Modeling System, run [illegible]

Table 11. Supply and Demand Estimates in the Higher Capital Cost Sensitivity Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,721	1,782	1,897	2,118
Number of Refineries Producing ULSD		61	61	61	72
Differences Between Supply and Demand					
Small Refiner Option	2,533	-812	-751	-636	-415
Small Refiner and Temporary Compliance Options	2,026	-305	-244	-130	92
Small Refiner and Temporary Compliance Options with Imports	1,946	-225	-164	-50	172
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	58	119	234	455
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,626	94	155	270	491

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

Table 12. Supply and Demand Estimates in the 10% Return on Investment Sensitivity Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,702	1,760	1,912	2,078
Number of Refineries Producing ULSD		61	61	63	71
Differences Between Supply and Demand					
Small Refiner Option	2,533	-831	-773	-621	-455
Small Refiner and Temporary Compliance Options	2,026	-325	-266	-114	51
Small Refiner and Temporary Compliance Options with Imports	1,946	-245	-186	-34	131
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	39	97	249	415
Highway Use Only. Small Refiner and Temporary Compliance Options with Higher Imports	1,626	75	133	285	451

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

demand estimate across all scenarios. However, a lower requirement for ULSD production would reduce retail availability for the vehicles that require ULSD. Other responses providing greater flexibility, increasing participation, and encouraging technological improvements would also help to alleviate supply concerns.[112]

Given the variety of responses, it is difficult to know the magnitude or duration of a possible tight market situation. Supply shifts and demand responses would require time before the effect would be felt. It would take time for additional imports to enter the market, and importers would have to believe that prices would remain high enough for long enough to make it worthwhile to divert supplies from other markets.

Summary

Whether there will be adequate supply is one of the key questions raised by the House Committee on Science in its request for analysis. To assess the supply situation during the transition to ULSD in 2006, cost curves and estimates of ULSD supply are developed based on refinery-specific analysis of investment requirements. Supply is estimated for four scenarios of investment behavior, and a range of demand is projected for comparison with the supply curves. In addition, two other sets of supply sensitivities are provided, assuming higher capital costs and higher required return on investment.

Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand cenarios show adequate supply to meet estimated demand. The two sets of supply sensitivities show even lower production estimates than the initial set. This indicates the possibility of a tight market supply situation when the ULSD Rule takes effect in 2006. While considerable uncertainty exists in both the supply and demand estimates, this analysis indicates that even though the market could see supply meet demand at a cost increase for production between 5.4 and 7.6 cents per gallon, there are a number of scenarios in which inadequate supply of ULSD could result.

[112]Short-term responses are possible, such as the regulatory response that took place when the 500 ppm diesel fuel requirements came into effect on October 1, 1993. As a result of localized outages and price spikes, the EPA sent a letter to marketers and major consumers of diesel fuel granting "enforcement discretion" in cases of extreme diffi :ulty in obtaining supplies, extending through October 22, 1993.

9279A

6. Mid-Term Analysis of ULSD Regulations

Assumptions

The National Energy Modeling System (NEMS) was used to perform petroleum market analysis of the impact of new requirements for ultra-low-sulfur diesel fuel (ULSD) from 2007 through 2015. The Petroleum Market Module (PMM) of NEMS were modified to produce a ULSD Regulation case. Analysis of the Regulation case focuses on changes relative to a reference case using the oil price and macroeconomic assumptions of the *Annual Energy Outlook 2001* (*AEO2001*) reference case but including some adjustments to provide a more accurate reflection of the diesel fuel market. The differences between the reference case for this study and the *AEO2001* reference case are discussed in Appendix B.

The projected investment costs and average marginal prices resulting from the NEMS analysis represent the investment and price levels necessary to meet all demand requirements under the new ULSD Rule. As discussed in Chapter 5, some refiners may choose to drop out of the highway diesel market or even close down instead of investing for compliance with the Rule. ULSD supply could be inadequate in the short term if enough refineries chose to forgo investment. The NEMS analysis does not capture this uncertainty of supply, because NEMS is a long-run equilibrium model. By definition, the NEMS analysis projects the level of domestic production and imports necessary to meet all demand requirements. As a result, the NEMS analysis reflects more aggressive investment behavior than that portrayed for individual refiners in the short-term analysis.

The NEMS analysis reflects the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD after June 2010. Because each model region acts as a single unit, the provision of the ULSD Rule allowing small refiners, which account for about 5 percent of current highway diesel production, to delay investment until June 2010 is not modeled explicitly. However, the production requirements are adjusted downward by 4 percent to reflect an assumption that most small refiners will choose to delay investment.[113]

The requirement for 80 percent ULSD is not phased in and begins on June 1, 2006. Therefore, the full market impact of the requirement can be expected to occur at that time. Because NEMS is an annual average model, the full economic impact of the 80/20 rule cannot be seen until 2007. In the same manner, projections for 2011 represent the first full year of 100 percent ULSD compliance. The results for 2010 reflect a partial year at the 80 percent requirement and a partial year at the 100 percent requirement. For the purpose of assessing the market impacts of the new ULSD requirements, 2007 will be discussed as the first full year of the 80/20 requirement, and 2011 will be discussed as the 100 percent requirement.

The House Committee on Science requested that, if practical, the EIA analysis use the same assumptions as those used by the U.S. Environmental Protection Agency (EPA) in its Regulatory Impact Analysis (RIA). The assumptions are compared in Table 13. The Regulation case for this study is based on the following assumptions:

- Highway diesel at the refinery gate will contain a maximum of 7 parts per million (ppm) sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process. The EPA assumed in its RIA that refineries would produce highway diesel at 7 ppm.
- The capital costs for the distillate hydrotreaters reflected in NEMS are $1,331 per barrel per day for a notional 25,000 barrel per day unit that processes low-sulfur feed streams with incidental dearomatization, and $1,849 per barrel per day for a second, 10,000 barrel per day unit that processes higher sulfur feed streams with greater aromatics improvement. A range of capital costs from a number of other studies is provided in Chapter 7. Because of differences in methodology, the sets of capital costs are not directly comparable. For instance, the EPA estimated the capital cost for a new distillate hydrotreater to range from $1,240 per barrel per day to $1,680 per barrel per day, but those estimates

[113] In its Regulatory Impact Analysis, the U.S. EnvironmentalProtection Agency included investment by small refineries in cost estimates for full compliance but not for the transition period. See U.S. Environmental Protection Agency, *Regulatory Impact Analysis Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000)

Table 13. Comparison of EIA and EPA Assumptions

Parameter	EPA	EIA	Sensitivity Analyzed
Sulfur Content at Refinery	7 ppm	7 ppm	None
Capital Costs for New Diesel Hydrotreaters	\$1,240-\$1,680 per barrel per day[a]	\$1,331-\$1,849 per barrel per day[b]	\$1,655-\$2,493 per barrel per day[b]
Percent of Production from Revamped Equipment	80 percent	80 percent	66.7 percent
Total Percentage of Downgraded ULSD	4.4 percent total	4.4 percent total	10 percent total
Revenue Loss Associated with Downgrade	0.2 to 0.3 cents per gallon for all highway diesel	0.2 to 0.3 cents per gallon ULSD based on model results	0.7 cents per gallon ULSD based on model results for 10 percent downgrade
Capital Cost for Distributing Two Highway Diesels (Excluding Above Revenue Loss)	0.7 cents per gallon through 2010	0.7 cents per gallon through 2010	None
Lubricity Additives	0.2 cents per gallon	0.2 cents per gallon	None
Loss of Energy Content	0 percent	0.5 percent	1.8 percent
Yield Loss	1.3 percent yield loss (weight) at a cost of 0.1 to 0.2 cents per gallon	Variable model result (about 1.5 percent by volume)	Variable model result (about 1.5 percent by volume)
Loss of Fuel Efficiency	None	None	4 percent loss starting in 2010, phased out by 2015
Change in Non-Road Diesel Standards	None	None	None
Change in Other Highway Diesel Properties	None	None	None
Import Availability	Not studied	Same as reference	No imports
Return on Investment	7% before tax (estimated 5.2% after tax)	5.2% after tax	10% after tax

[a]The low end of the range is for straight-run distillate; the high end is for light cycle oil.
[b]The low end of the range is for units processing low-sulfur feed with incidental dearomatization; the high end is for higher sulfur feeds with greater aromatics improvement.
Sources: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), and Energy Information Administration, Office of Integrated Analysis and Forecasting.

are associated with units processing 100 percent straight-run distillate and 100 percent light cycle oil, respectively.[114]

- Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing 80 percent of highway diesel production; the remaining refineries will build new units. Other analyses have assumed 60 percent revamps and 40 percent new builds, but the assumption of 80 percent revamps and 20 percent new units was used in the EPA's RIA. The capital cost of a revamp is assumed to be 50 percent of the cost of new equipment, which is consistent with the EPA analysis.

- The total amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 4.4 percent, an increase of 2.2 percent from the reference case. This assumption is based on the EPA's assessment that 2.2 percent of diesel fuel is currently downgraded and its assumption that the amount of downgrade will double with the new Rule. This downgrade assumption is associated with considerable uncertainty, because EPA's estimate of current downgrade was not based on a scientific survey. The EPA's estimation methodology was based on a survey by the Association of Oil Pipelines, in which six respondents provided estimates of the current diesel fuel downgrade, ranging from 0.2 percent to 10.2 percent.

- The costs associated with ULSD distribution are based in part on EPA assumptions and in part on NEMS results. This analysis uses the EPA's capital cost estimate of 0.7 cents per gallon for additional storage tanks to handle ULSD during the transition period. The capital expenditures are assumed to be fully amortized during the transition period. The ULSD Rule is assumed to increase the operating costs for distribution by 0.2 cents per gallon over the entire period. In addition, the EPA estimated a revenue loss of 0.2 to 0.3 cents per gallon for all highway diesel as a result of product downgrades. For this

[114]U.S Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Table V.C-9.

9280A

analysis, the revenue loss estimate is based on NEMS model results, at 0.3 cents per gallon of ULSD during the transition period and 0.2 cents per gallon after 2010.

- A cost of 0.2 cents per gallon is assumed for the addition of lubricity additives, consistent with estimates by the EPA and with industry analyses. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulfurization process.
- The energy content of ULSD is assumed to decline by 0.5 percent, because undercutting and severe desulfurization will result in a lighter stream composition than that for 500 ppm diesel. The EPA's analysis made no explicit adjustment to the energy content of diesel fuel but estimated a cost associated with a 1.3-percent (by weight) loss of yield. In the NEMS analysis, the yield loss is a variable model result (generally around 1.5 percent by volume). The National Petrochemical and Refining Association (NPRA) quoted a range of 1 to 4 percent energy loss in comments to the rulemaking docket. NPRA also estimated a yield loss of 1 to 5 percent.
- In accordance with the EPA's RIA, changes to engine after-treatment devices are assumed to result in no loss of fuel efficiency. Discussions with some engine and emission control technology manufacturers indicated considerable uncertainty about this assumption.
- No change in the sulfur level of non-road diesel is assumed. The EPA analysis of ULSD reflects no change in non-road standards, although the EPA is in the process of promulgating "Tier 3" non-road engine emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.[115] The level of sulfur reduction required for Tier 3 vehicles is highly uncertain because of the diversity of the non-road market.
- No changes to other highway diesel specifications, such as aromatics or cetane, are assumed. Some refiners anticipate changes to these parameters in the future because of their relationship to emissions of particulate matter (PM). The State of California already limits aromatics to 10 percent by volume, which is reflected in this analysis. Proposals for similar requirements in other States are not included.
- Imports of diesel meeting the new ULSD standard are assumed to be available to U.S. markets, but the level of imports relative to the level of product supplied by refineries in the United States is a model result. Refineries in Canada, Northern Europe, and the Caribbean Basin (including Venezuela) are assumed to make upgrades to produce diesel fuel meeting the 15 ppm sulfur cap for 2006. Canada is moving forward with plans to harmonize with diesel regulations in the United States. European refiners will reduce diesel sulfur to 50 ppm for a new European standard in 2005. Some isolated European production of diesel meeting the ULSD standard is assumed, due to tax incentives for 10 ppm diesel in some markets.[116] In order to divert ULSD from European markets, prices in the United States would have to exceed the tax incentives plus shipping costs. In 2000 less than 5 percent of U.S. imports of highway diesel came from Europe.
- In accordance with the EPA's RIA, the before-tax rate of return on investment is assumed to be 7 percent. Between 1977 and 1999 the combined before-tax return on investment for refiners and marketers averaged 7 percent, which is equivalent to a 5.2-percent after-tax rate.[117] Because NEMS operates on an after-tax basis, the 5.2-percent rate is used in the model. Most of the studies compared in Chapter 7 assumed a 10-percent after-tax return on investment.

The Committee indicated that this analysis was to be as consistent as possible with the assumptions underlying the EPA's RIA, and that sensitivity analysis should be provided for assumptions that diverge significantly from those in other studies or from expectations of industry experts.[118] In addition to the Regulation case, this report provides sensitivity analyses for five assumptions associated with a greater uncertainty, for a Severe case that combines the assumptions of the five individual sensitivities, for a No Imports case, and for a 10% Return on Investment case:

- In the Higher Capital Cost case, the capital cost of the first notional hydrotreater is 24 percent higher than in the Regulation case, and the capital cost of the second notional unit is 33 percent higher.[119]
- In the 2/3 Revamp case, two-thirds of upgrades at refineries are assumed to be accomplished by retrofitting existing equipment and one-third by construction of new units. With the exception of the

[115] U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3.

[116] Germany and the United Kingdom have proposed tax incentives for sales of 10 ppm diesel

[117] Based on financial information from Form EIA-28 (Financial Reporting System)

[118] EIA did not assess the validity of these asumptions.

[119] The capital costs used in this case are based on recent work by EnSys, with revisions based on correspondence with Mr. Martin Tallett, April 23, 2001

EPA, all other cost analyses for ULSD have used an assumption of 60 percent revamps and 40 percent new units. The two-thirds revamp assumption was developed from EIA's individual refinery analysis (see Chapter 5 and Appendix D).

- In the 10% Downgrade case, a total of 10 percent of the 15 ppm diesel is assumed to be downgraded to a lower value product because of contamination with higher sulfur products in the distribution system. Before 2010 the contaminated product is assumed to be downgraded to 500 ppm highway diesel and does not result in additional production of 15 ppm highway diesel. After 2010, when all highway diesel must meet the 15 ppm sulfur standard, refineries must produce an extra 7.8 percent of highway diesel above the reference case level, which will be sold as non-road diesel or heating oil. The EPA assumption of 4.4 percent total downgrade after the ULSD Rule takes effect in June 2006 (2.2 percent higher than in the reference case) is on the low end of downgrade estimates, which range up to 17.5 percent by Turner Mason.
- In the 4% Efficiency Loss case, manufacturers are assumed to meet the emissions requirements by installing after-treatment technology on new vehicles beginning in 2010, resulting in a 4-percent loss of fuel efficiency. The loss in new vehicle efficiency is assumed to be fully phased out by 2015 as a result of technological improvements.[120]
- In the 1.8% Energy Loss case, a greater loss of energy content is assumed than in the Regulation case, which assumed a 0.5-percent loss. The loss of energy content is associated with more severe undercutting and desulfurization due to heavier crude oil inputs.[121]
- The Severe case combines the assumptions of the four sensitivity cases above. This scenario is more in line with the assumptions used by alternative studies related to ULSD than with the EPA's RIA.
- The No Imports case assumes that no foreign imports of ULSD will be available. This assumption is not included in the Severe case because it is considered to be relatively unlikely. The greatest uncertainty for import availability is likely to occur in the early years of the program because foreign refiners may delay investment until the market outlook for ULSD is more certain. Thus far, only Canada has announced its intent to align with the final U.S. leve' and timing for reducing sulfur in highway diese. fuel.[122] Environment Canada expects to launch a public consultation process in the next few months to facilitate the rulemaking, which is similar to the U.S. ULSD Rule while taking into account issues unique to the Canadian market.[123]
- The 10% Return on Investment case uses the after-tax rate of return assumed by most other studies (10 percent), which is higher than the 5.2-percent after-tax rate used in the Regulation and other sensitivities, consistent with the EPA's assumption.

Although the assumption of non-road diesel sulfur content is also highly uncertain, a sensitivity analysis would have required significant changes to the model structure and was not within the scope of this study. Sensitivity analysis of other diesel properties was also beyond the scope of the study.

Results

Discussions of all results are framed in terms of changes from the reference case. In the Regulation case and in all the sensitivity cases, projections for 2007 reflect the first full year of the program at 80 percent ULSD and 20 percent 500 ppm highway diesel, and 2011 reflects the first full year of 100 percent ULSD. During the years requiring 80 percent ULSD, the reference case and sensitivity cases project that the greatest price increase will occur in 2007, because all investment for compliance with the "80/20" provision of the ULSD Rule must be met by that time. Similarly, a second peak in marginal prices is projected in 2011, because all investment for full compliance with the Rule must be in place by that time. Year-to-year variations in marginal prices can reflect differences in levels of demand for diesel and other products, oil price projections, the economics of domestic production versus imports, and other factors.

In the reference case, demand for transportation distillate (highway diesel) is projected to increase by 2.5 percent per year from 1999 to 2015. In the Regulation case, highway diesel demand is projected to grow at a slightly higher rate of 2.6 percent per year for the same period, largely due to the 2.2 percent additional (4.4 percent total) downgrades of highway diesel in the distribution

[120]This assumption is based on interviews with engine and technology manufacturers. Although this case reflects a scenario in which losses in efficiency from emission contol are not overcome by new technology, the considerable time available for research and development may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies.

[121]The National Petrochemical and Refining Association provided data indicating that energy loss may be greater than assumed by the ᵓA. Letter from Terrence S. Higgins to James M. Kendell, February 8, 2001.

[122]Public Works and Government Services Canada, *Canada Gazette*, Vol. 135, No. 7 (February 17, 2001), p. 454.

[123]Maureen Monaghan, Natural Resources Canada, "Canadian Sulfur Standards for Gasoline and Diesel Sulfur," presentation to the U.S. Department of Energy (March 12, 2001).

9281A

system. In other words, the additional downgrades must be offset by more ULSD production after 2010. The effect of downgrades is more pronounced in the 10% Downgrade case and the Severe case, where highway diesel demand is projected to increase by 2.9 percent and 3.1 percent per year, respectively, from 1999 to 2015.

Regulation Case

In the Regulation case, cumulative investment in distillate hydrotreating and hydrogen units is projected to be $4.2 billion higher than projected in the reference case in 2007 and $6.3 billion higher in 2011, when upgrades for meeting full compliance with the ULSD Rule will be complete (Table 14). In the early part of the transition period, upgrades for making ULSD may be constrained by specialized workforce and manufacturing limitations and access to capital, all of which will be in competition with projects for meeting the requirements for low-sulfur gasoline (see Chapter 3). The projected $2.1 billion in investment between 2007 and 2011 reflects expenditures for meeting expectations of growing demand for highway diesel, in addition to full compliance with the Rule. After 2011, incremental upgrades to meet future distillate demand are projected to continue, resulting in another $0.5 billion of investment in desulfurization equipment by 2015.

The Regulation case results in an increase in the marginal annual pump price for ULSD of 6.5 to 7.2 cents per gallon between 2007 and 2011 (Table 15). The peak differential is projected to occur in 2011, when all refiners must produce 100 percent ULSD. The projected differential declines after 2011, reaching 5.1 cents per gallon in 2015. About 0.7 cents of this decline is the result of no longer needing to include EPA's estimate of additional capital investments for distribution and storage of a second highway diesel fuel during the transition period. A drop in capital expenses for distribution systems occurs after 2010 as a reflection of the EPA's assumption that these investments will be fully amortized during the transition period. The remainder of the drop in the post-2011 differential occurs because refineries are expected to have completed the upgrades necessary for full compliance, and to be making incremental improvements that will make ULSD production less challenging. A similar decline in the price differential also occurs in all the sensitivity cases.

Through 2010, the Regulation case projections for highway diesel consumption exceed the reference case levels by up to 10,000 barrels per day, which can be attributed to the assumption of 0.5 percent loss in energy content. In 2011, the differential in consumption increases to 83,000 barrels per day, due mostly to the downgrade of 2.2 percent of ULSD to lower value non-road markets.

In a refinery, the impact of a change in the makeup or production level of a product can filter through to other

Table 14. Variation from Reference Case Projections of Cumulative Capital Expenditures for Hydrogen and Distillate Hydrotreating Units in EIA Sensitivity Cases, 2007, 2010, and 2015
(Billion 1999 Dollars)

Analysis Case	2007	2010	2015
Regulation	4.2	6.3	6.8
Higher Capital Cost	5.4	7.8	8.8
2/3 Revamp	4.6	6.9	7.6
10% Downgrade	4.2	6.7	7.3
4% Efficiency Loss	4.2	6.3	6.9
1.8% Energy Loss	4.2	6.3	6.9
Severe	5.9	9.3	10.5
No Imports	4.4	6.5	7.0

Source: National Energy Modeling System, runs DSUREF.D043001E, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, and DSU7IMP0.D043001A.

products, because it changes the mix of total refinery production. The ULSD Rule is projected to result in slightly lower yields of higher sulfur distillate used for non-road and heating purposes, because its production is replaced by ULSD that is produced by refineries but is downgraded to higher sulfur products in the distribution system. The availability of the downgraded ULSD reduces the projected prices for high-sulfur distillate by about 1 cent per gallon relative to the reference case. The analysis revealed no clear trends for other distillate products as a result of the ULSD Rule.

Higher Capital Cost Case

Because of limited experience in producing diesel containing less than 10 ppm sulfur, the capital costs for hydrotreaters able to mass produce ULSD are uncertain. The Higher Capital Cost case results in refinery investment for hydrogen and distillate hydrotreating units totaling $5.4 billion in 2007, which is $1.2 billion above the Regulation case level. By 2011 the Higher Capital Cost case is projected to require $7.8 billion of investment, $1.5 billion more than in the Regulation case. The higher investment costs translate to a higher projected price path for ULSD. Relative to the reference case, price differentials are projected to range from 7.5 to 7.8 cents per gallon between 2007 to 2010, peaking at 8.1 cents per gallon in 2011, the first full year of full compliance. These prices are 0.8 cents per gallon higher on average than those in the Regulation case.

2/3 Revamp Case

The 2/3 Revamp case results in a higher projected price path for ULSD, with price differentials ranging from 6.9 to 7.6 cents per gallon higher than in the reference case from 2007 to 2011. Prices are generally higher than in the Regulation case, with the differential between the two cases at its widest in 2011 at 0.4 cents per gallon. The 2/3

Revamp case reflects greater reliance on new equipment than in the Regulation case, resulting in an additional $600 million of investment for full compliance in 2011.

10% Downgrade Case

The 10% Downgrade case reflects a net downgrade increase of 7.8 percent over the reference case and 5.6 percent over the Regulation case. Total highway diesel consumption increases by up to 10,000 barrels per day in the transition period in both the 10% Downgrade case and the Regulation case. After 2010, the 10% Downgrade case results in an additional 289,000 barrels per day of highway diesel consumption, compared with an additional 83,000 barrels per day in the Regulation case. The greatest impact from downgrade in either the 10% Downgrade or Regulation case on refiners and consumers occurs after 2011, because until that time the contaminated product can be downgraded to 500 ppm highway diesel with no net increase in highway diesel production. Because all highway diesel supplied must meet the 15 ppm sulfur cap in June 2010, ULSD exceeding 15 ppm sulfur at some point in the distribution system must be downgraded to non-road markets and must be offset by additional ULSD production after 2010. This means that refiners must produce 212,000 barrels per day more ULSD after 2010 than in the Regulation case, which translates to an additional $500 million of investment by 2015.

Aside from the impacts on ULSD on demand and refinery investment, the 10% Downgrade case has implications for the economics of pipelines and marketers, because they incur a revenue loss when a portion of the ULSD going into the system comes out of the system as a lower value product. Table 16 shows the costs associated with ULSD distribution in the Regulation and 10% Downgrade cases. The capital costs, which are assumed to be the same in both cases, reflect additional infrastructure required for carrying a second highway diesel product during the transition period. The estimate for capital expenditures was taken from the EPA's RIA and is fully amortized over the transition period. The additional annual diesel fuel distribution costs in the Regulation case differ slightly from the EPA estimates (see Table 26 in Chapter 7), because different revenue losses associated with product downgrade are assumed.

Table 15. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015

Analysis Case	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)[a]								
Regulation	7.0	6.7	6.5	6.8	7.2	5.1	6.8	5.4
Higher Capital Cost	7.8	7.6	7.5	7.6	8.1	5.8	7.6	6.2
2/3 Revamp	7.3	6.9	6.9	7.1	7.6	5.4	7.1	5.7
10% Downgrade	7.4	7.1	6.8	7.2	9.1	5.7	7.2	6.4
4% Efficiency Loss	7.0	6.7	6.5	6.9	7.3	5.3	6.8	5.7
1.8% Energy Loss	7.3	7.0	6.6	6.9	7.4	5.2	7.0	5.5
Severe	8.8	8.4	8.4	8.6	10.7	6.8	8.6	7.4
No Imports	8.6	8.1	7.8	8.0	8.8	6.2	8.1	6.8
Total Highway Diesel Fuel Consumption (Thousand Barrels per Day)								
Regulation	10	10	8	8	83	85	9	83
Higher Capital Cost	10	9	8	7	82	83	9	82
2/3 Revamp	10	10	8	8	82	84	9	82
10% Downgrade	10	10	8	8	289	303	9	295
4% Efficiency Loss	10	10	8	19	103	108	12	107
1.8% Energy Loss	41	41	39	47	127	131	42	128
Severe	41	40	39	57	355	374	44	366
No Imports	10	9	7	7	81	83	8	81
Total Imports of Highway Diesel Fuel (Thousand Barrels per Day)								
Regulation	-36	-1	-1	0	0	0	-10	0
Higher Capital Cost	-36	-1	-1	0	0	0	-10	0
2/3 Revamp	-36	-1	-1	0	0	0	-10	0
10% Downgrade	-36	-1	-1	0	0	0	-10	0
4% Efficiency Loss	-36	-1	-1	0	0	0	-10	0
1.8% Energy Loss	-36	-1	-1	0	0	0	-10	0
Severe	-36	-1	-1	0	0	0	-10	0
No Imports	-120	-125	-125	-125	-125	-125	-124	-125

[a]End-use prices include marginal refinery gate prices, distribution costs, and Federal and State taxes but exclude county and local taxes.
Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, and DSU7IMP0.D043001A.

9282A

4% Efficiency Loss Case

The 4% Efficiency Loss case reflects an expectation, by some engine and emission technology manufacturers, that emission requirements for new heavy-duty vehicles in 2010 will be met by installing after-treatment technology, which could result in a 4-percent loss of fuel efficiency. Technological improvements are assumed to fully offset the loss in fuel efficiency of new vehicles by 2015.[124] The combined impact of the ULSD requirement and less efficient new vehicles results in 19,000 barrels per day of additional highway diesel consumption in 2010 and 107,000 barrels per day in 2011 through 2015. The introduction of less fuel-efficient vehicles accounts for 11,000 barrels per day of the additional demand in 2010 and 24,000 barrels per day of demand after 2010. Refiners are projected to invest an additional $100 million dollars through 2015 relative to the Regulation case to provide for the slightly higher diesel demand.

The additional demand for highway diesel results in prices that are 5.7 cents per gallon above reference case prices on average between 2011 and 2015. This differential is 0.3 cents higher than when no fuel efficiency loss is assumed. Owners of vehicles purchased between 2010 and 2015 would see the greatest impact under this case, because diesel vehicles of that vintage would consume relatively more diesel fuel.

1.8% Energy Loss Case

Due to changes in refinery processing, ULSD is expected to have slightly less energy content than 500 ppm diesel. The 1.8% Energy Loss case reflects a greater loss of energy content than the Regulation case, which assumes a 0.5-percent loss per barrel. This case results in an average increase in ULSD consumption of 42,000 barrels per day between 2007 and 2010. Due to the 100 percent ULSD requirement, the impact of the lower energy content is greatest after 2010 when it widens to 128,000 barrels per day. Relative to the Regulation case, the 1.8% Energy Loss case results in an average of 33,000 barrels per day of additional demand through 2010 and 45,000 barrels per day after full compliance. This additional demand does not change refinery investment patterns relative to the Regulation case, because it can be provided through higher utilization rates.

The price differentials from the reference case average 7.0 cents per gallon between 2007 and 2010 and 5.5 cents per gallon between 2011 and 2015. In anticipation of higher demand, refineries are expected to build slightly more capacity in the transition period than they would in the Regulation case. Because of the slightly different investment pattern, prices in the 1.8% Energy Loss case are 0.2 cents per gallon higher than in the Regulation case on average through 2010 and comparable to Regulation case prices after 2010.

Severe Case

In the Severe case, the ULSD requirement in combination with the five sensitivity assumptions results in an average of 44,000 barrels per day of additional highway diesel consumption between 2007 and 2010 and an average of 366,000 barrels per day of additional demand between 2011 and 2015. The ULSD regulation by itself accounts for about 9,000 barrels per day of the additional consumption through 2010 and about 83,000 barrels per day after 2010. The combined effect of the five

Table 16. Variations from Reference Case Projections of Fuel Distribution Costs in the Regulation and 10% Downgrade Cases
(1999 Cents per Gallon)

Analysis Case and Cost Component	Average Annual Cost, June 2006 - June 2010	Average Annual Cost After June 1, 2010
Regulation		
Total	**1.2**[a]	**0.4**[a]
Capital Costs	0.7	0.0
Operating Costs	0.2	0.2
Downgrade Revenue Loss	0.3	0.2
10% Downgrade		
Total	**1.6**	**0.9**
Capital Costs	0.7	0.0
Operating Costs	0.2	0.2
Downgrade Revenue Loss	0.7	0.7

[a]The additional annual diesel fuel distribution costs in the Regulation case differ slightly from the EPA estimates (see Table 25 in Chapter 7) because different revenue losses associated with product downgrade are assumed.

Sources: **Capital Costs and Operating Costs:** U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. Operating Costs include operating, existing mix, transmix, and testing cost estimates. **Downgrade Revenue Loss:** Energy Information Administration, Office of Integrated Analysis and Forecasting, based on projected price differentials for ULSD versus 500 ppm diesel.

[124]This assumption is based on interviews with engine and technology manufacturers.

assumptions raises demand beyond that in the Regulation case by about 35,000 barrels per day through 2010 and by about 283,000 barrels per day after 2010. The higher downgrade assumption accounts for about 212,000 barrels of the additional demand after 2010. The Severe case results in a projected increase in refinery investments for hydrogen and distillate hydrotreating totaling $9.3 billion in 2011, $3.0 billion more than in the Regulation case. Higher demand in the Severe case results in marginal prices 1.7 to 3.5 cents per gallon above those in the Regulation case.

No Imports Case

In 1999, 87 percent of all imports of highway diesel went to PADD I (the East Coast), which is less self-sufficient than other regions in terms of refinery production. The East Coast is expected to continue to be the major market for imported highway diesel; however, a slight reduction in imports is projected under the ULSD Rule, because it is more economical for domestic refiners to provide the last barrel supplied. The No Imports case assumes that imports of highway diesel fuel are zero and, therefore, 120,000 to 125,000 barrels per day lower than projected in the reference case. The lack of imports means that domestic refineries must produce that much more ULSD. During the transition years, prices in the No Imports case are only slightly lower than in the Severe case, indicating the sensitivity of the market to imports. The requirement for more production results in marginal prices 1.1 to 1.6 cents per gallon higher than in the Regulation case. The higher prices in the No Imports case result in a slight dampening of demand, by up to 2,000 barrels on average when compared to the Regulation case. When imports of ULSD are not available, refineries are projected to meet the additional ULSD requirement by investing an additional $200 million in desulfurization equipment through 2015, and by reducing jet fuel production and importing more jet fuel. More ULSD is also shipped from PADDs II-IV to PADD I to compensate for the lack of imports.

10% Return On Investment Case

This case assumes that refiners will realize a higher rate of return than is assumed in the Regulation case and in all the other sensitivity cases for this analysis, which assume a 5.2-percent after-tax return on investment. Because the 10% Return on Investment case must be compared with an alternative reference case that uses a consistent rate of return, the projected price differentials are presented separately from those for the cases that are compared with the reference case (with a 5.2-percent after-tax rate (Table 17). The resulting price differentials range from 7.5 to 8.0 cents per gallon between 2007 and 2011 and are 0.9 cents per gallon higher on average than when the 5.2-percent after-tax rate is assumed. The different return on investment affects the payback of investment but does not affect the level of investment.

Regional Variations in Refining Costs

Differences between regional refinery gate prices in the analysis cases relative to those in the reference case reflect variations in the marginal costs of producing ULSD between regions (Table 18). The cost curve analysis described in Chapter 5 indicates that PADD IV, which contains relatively small refineries, can be expected to be the highest cost region; however, these costs are obscured by the aggregate model representation in NEMS. The Petroleum Market Module provides refining costs for three separate regions: PADD I (the East Coast), PADDs II-IV aggregated (mid-U.S.), and PADD V (the West Coast). In the transition years of the Regulation case, regional refining costs (excluding distribution costs) range from an average of 4.8 cents per gallon in PADD V to 5.3 cents per gallon in the other regions, with an average U.S. cost of 5.2 cents per gallon.

The relative patterns of regional costs during the transition period are similar in all the sensitivity cases, with PADD I as the highest cost region of the three NEMS regions, PADD V as the lowest cost region, and PADDs II-IV (and the U.S. average) falling in between. The relatively high ULSD production cost in PADD IV is masked in the mid-term analysis, because PADD IV is aggregated both with PADD II and with the largest and lowest cost refining region, PADD III. Average marginal refining costs generally are expected to fall by about 0.5 to 0.8 cents per gallon after 2011, as refineries make incremental improvements to meet incremental increases in demand more efficiently.

Conclusion

The ULSD Rule is projected to require total refinery investments ranging from $6.3 billion in the Regulation case to $9.3 billion in the Severe case, resulting in highway diesel fuel price increases that range from 6.5 to 10.7

Table 17. Variations from Alternative Reference Case Projections in the 10% Return on Investment Case, 2007-2015

Year	Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)[a]
2007	7.9
2008	7.5
2009	7.6
2010	7.7
2011	8.0
2015	5.7
2007-2010 Average	7.7
2011-2015 Average	6.0

[a]End-use prices include marginal refinery gate prices, distribution costs, and Federal and State taxes but exclude county and local taxes.
Source: NEMS runs DSUREF10.D043001A and DSU7PPM10.D043001A.

9283A

cents per gallon between 2007 and 2011. Because this analysis is based on results from a long-run equilibrium model, it does not capture the uncertainty of supply discussed in Chapter 5. The NEMS analysis reflects more aggressive investment than is portrayed for individual refiners in the short-term analysis. In the Regulation case, which uses many of the EPA's assumptions, prices are projected to increase by 6.5 to 7.2 cents per gallon between 2007 and 2011. The widest price differential—10.7 cents per gallon in 2011—is projected in the Severe case, which is based on assumptions more consistent with industry views. This peak price differential is associated with a requirement for additional ULSD supplies of 272,000 barrels per day above demand levels in the Regulation case, of which 206,000 barrels per day results from the 10-percent downgrade assumption.

Because NEMS is a long-run equilibrium model, it cannot address short-term supply issues; however, the No Imports case does provide some implications for short-term supply. When no availability of ULSD grade imports is assumed, the marginal price of ULSD is projected to exceed prices reflecting access to imports by about 1.2 to 1.6 cents per gallon between 2007 and 2011.

Table 18. Variations from Reference Case Projections of ULSD Marginal Refinery Gate Prices by Region in the Regulation and Sensitivity Analysis Cases, 2007-2015
(1999 Cents per Gallon)

Analysis Case and Producing Region	2007-2010 Average	2011-2015 Average	Analysis Case and Producing Region	2007-2010 Average	2011-2015 Average
Regulation			**4% Efficiency Loss** . . .		
U.S. Average	5.2	4.7	U.S. Average	5.2	5.1
PADD I	5.3	4.8	PADD I	5.3	5.3
PADDs II-IV	5.3	4.8	PADDs II-IV	5.3	5.2
PADD V	4.8	4.3	PADD V	4.8	4.5
Higher Capital Cost			**1.8% Energy Loss**		
U.S. Average	6.4	5.2	U.S. Average	5.5	4.8
PADD I	6.6	5.5	PADD I	5.6	5.3
PADDs II-IV	6.6	5.3	PADDs II-IV	5.6	4.9
PADD V	5.4	4.9	PADD V	5.2	[illegible]
2/3 Revamp			**Severe**		
U.S. Average	5.7	4.9	U.S. Average	7.0	6.4
PADD I	6.0	5.0	PADD I	7.4	6.8
PADDs II-IV	6.0	5.0	PADDs II-IV	7.4	6.3
PADD V	5.0	4.5	PADD V	5.9	5.2
10% Downgrade			**No Imports**		
U.S. Average	5.2	5.2	U.S. Average	6.6	[illegible]
PADD I	5.3	5.4	PADD I	6.9	6.8
PADDs II-IV	5.3	5.3	PADDs II-IV	6.9	6.3
PADD V	4.8	4.7	PADD V	4.6	4.3

Source: NEMS runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7D31.D043001A, DSU7TPM.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, and DSU7IMPC.D043001A.

7. Comparison of Studies on ULSD Production and Distribution

This chapter compares the methodology and results of the Energy Information Administration's (EIA's) analysis with those from a number of other studies related to ultra-low-sulfur diesel fuel (ULSD) supply and costs. Refinery costs and investments are compared with other estimates from studies by the U.S. Environmental Protection Agency (EPA), Mathpro, the National Petroleum Council (NPC), Charles River and Associates and Baker and O'Brien (CRA/BOB), EnSys Energy & Systems, Inc. (EnSys), and Argonne National Laboratory (ANL). EIA's estimates of distribution costs are compared with estimates from the EPA, ANL, and Turner, Mason and Company (TMC). A review of an analysis of alternative markets for diesel fuel components by Muse, Stancil and Company (MSC) is also provided. All cost estimates in this chapter have been converted to 1999 dollars.

Analyses of Refining Costs

The refining cost studies reviewed here represent a range of methodologies and assumptions. An understanding of some key terms is important to differentiating between the methodologies of the various studies. The studies were based on two general types of methodologies: a linear programming (LP) approach used by Mathpro, NPC, EnSys, DOE, and EIA; and a refinery-by-refinery approach used by CRA, EPA, and EIA. Within either approach, the studies used different methodologies and made different assumptions that make them difficult to compare. For instance, two different types of LP refinery models were used. The Mathpro analysis used an LP model of a "notional refinery" that represented an average refinery in a given region. In contrast, EnSys and EIA used refinery LP models that represented an aggregate refinery, or all the refineries in a region acting as one (Tables 19 and 20).

Costs estimated by the different studies are not easy to compare, because differences in estimation methodologies make them conceptually different. Both "average" and "marginal" costs can be based on LP models that operate as a single firm, or estimated from analysis of individual refineries. In general, marginal cost estimates that represent the cost of the last barrel of required supply can be seen as estimates of market prices. Much of the variation in investment and cost estimates reflects different assumptions about the cost of technologies; return on investment; the extent to which refiners will modify existing equipment or build entirely new hydrotreaters; the cost and quantity of additional hydrogen required; the extent to which some refineries may reduce highway diesel production; and the amount of highway diesel downgraded due to fuel contamination during distribution.

In EIA's refinery-by-refinery analysis (cost curves), the increased cost of producing ULSD in 2006 is estimated to be between 5.4 and 6.8 cents per gallon. Using the National Energy Modeling System (NEMS) Petroleum Market Module (PMM), the increased cost of producing ULSD is estimated to be between 4.7 and 7.3 cents per gallon from 2007 to 2010 and between 6.5 and 9.2 cents per gallon in 2011.[125] The estimated additional production costs are associated with expected increases in average marginal price increases at the pump ranging from 6.5 to 8.8 cents per gallon in the transition period and 7.2 to 10.7 cents per gallon in 2011. In the Regulation case, which uses many of the EPA's assumptions, prices are projected to increase by 6.5 to 7.2 cents per gallon between 2007 and 2011. The widest price differential—10.7 cents per gallon in 2011—is projected in the Severe case, which is based on assumptions more consistent with industry views.

For consistency with the EPA's analysis, EIA estimates are based on a 7-percent before-tax return on investment, which is estimated to equate to a 5.2-percent after-tax rate of return.[126] When a 10-percent after-tax rate of return, which was used in all the other analyses, is assumed; the refinery-by-refinery costs are about 0.8 to 1.2 cents per gallon higher than in the Regulation case, and the NEMS costs are about 0.8 to 1.1 cents per gallon higher than in the Regulation case.

[125] In the NEMS PMM projections, the U.S. price is the average of the marginal prices in the three model regions.

[126] According to financial information from Form EIA-28 (Financial Reporting System) refiners and marketers averaged a 7-percent before-tax return on investment between 1977 and 1999.

Table 19. Methodologies Used To Estimate ULSD Refining Costs

Author	Client	Date	Methodology
Mathpro	Engine Manufacturers Association	October 1999; updated August 2000	LP, notional refinery Original study: PADDs I-III average cost (aggregated) Updated study: average cost U.S. excluding California
EPA		December 2000	Refinery-by refinery analysis, average cost after credit trading
NPC	U.S. Department of Energy	June 2000	Adjusted Mathpro's LP results from original study, average cost
CRA/BOB	American Petroleum Institute	August 2000	Constructed cost curves using industry interviews, refinery-by-refinery analysis, marginal cost of PADDs I-III aggregated, PADD IV, PADD V, and U.S.
EnSys	U.S. Department of Energy	August 2000	LP, aggregate PADD III refinery, average cost by each quartile of production, marginal costs provided for one scenario
ANL	U.S. Department of Energy	November 2000	Estimated weighted average costs based on EnSys costs
EIA	U.S. House of Representatives, Committee on Science	April 2001	(1) LP; aggregate regional refineries, PADDs I, II-IV aggregate, and V; marginal cost (2) Cost curves based on individual refinery data

Sources: **EPA**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **Mathpro**: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8, Case 11. **NPC**: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. **CRA/BOB**: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **EnSys**: EnSys Energy & Systems, Inc. *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA**: Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapters 5 and 6 of this report).

Table 20. Characteristics of ULSD Cost Studies

Study	LP Model	Based on LP Results	Refinery-by-Refinery	Year-by-Year	Single Period	Multi-Region Results	Average Cost	End-Use Prices	Market Equilibrium Prices	Supply / Demand Analysis
Mathpro	X				X	X	X			
EPA			X	2006, 2010		X	X	X		
NPC		X[a]			X		X			
CRA/BOB			X		X	X		X	Short-run	X
EnSys	X				X		X			
ANL		X[b]		2006-2015[c]			X	X		
EIA NEMS	X			2007-2015		X		X	Long-run	X
EIA Refinery by Refinery			X		X	X	X			X

[a]Uses Mathpro results.
[b]Uses EnSys results.
[c]Phase-in of 8 percent ULSD to 100 percent.

Sources: **EPA**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **Mathpro**: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8, Case 11. **NPC**: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. **CRA/BOB**: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **EnSys**: EnSys Energy & Systems, Inc. *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA Refinery by Refinery**: Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapter 5 of this report). **EIA NEMS**: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

EPA Analysis

The EPA analysis was conducted in support of the final rulemaking published in December 2000.[127] The EPA analysis used a refining cost spreadsheet that included refinery-specific estimates for meeting the new highway diesel standards and aggregated them to estimate fuel cost increases at the Petroleum Administration for Defense District (PADD) and national levels. The costs of meeting the final ULSD Rule were analyzed without including possible reductions in non-road diesel sulfur. The EPA estimated that the ULSD Rule would increase average national production and distribution costs by 5.4 cents per gallon of 15 ppm diesel (4.5 cents per gallon for all highway diesel) during the temporary compliance period (2006 to 2010).[128] The total cost after full compliance in June 2010 was estimated at 5.0 cents per gallon (Table 21).

The largest component of the costs estimated by the EPA was increased refining costs (4.1 cents per gallon for 15 ppm diesel and 3.3 cents per gallon for all highway diesel between 2006 and 2010; 4.3 cents per gallon after June 1, 2010). The cost estimate for the compliance period was adjusted downward to reflect credit trading, assuming that low-cost refineries trade with high-cost refineries at the cost of production. Cost estimates for PADD IV were 30 to 40 percent higher than costs in other PADDs. The refining costs discussed above were based on a 7-percent before-tax return on investment, but the EPA also provided costs based on a 6-percent and 10-percent after-tax rate of return. The cost estimates for a 6-percent after-tax rate of return were 0.1 cents per gallon higher than the full compliance cost calculated with the 7-percent before-tax rate, and the estimates for a 10-percent after-tax rate were 0.4 cents per gallon higher.[129]

In addition to increased refining costs, the EPA estimated that the addition of lubricity additives would cost approximately 0.2 cents per gallon, and distribution costs were estimated to add another 1.1 cents per gallon during the temporary compliance period and 0.5 cents per gallon after full compliance.[130] The analysis behind the distribution cost estimates is discussed below.

Increased refining costs were expected to result from capital investment of $3.9 billion to meet the 2006 requirements and another $1.4 billion to reach full compliance in 2010, for a total investment of $5.3 billion.[131] The EPA estimated that the average refinery would spend $43 million dollars in capital expenditures and an additional $7 million per year in operating costs.

The EPA assumed that, in order to meet the 15 ppm highway diesel requirement, refiners would need to produce 7 ppm diesel fuel on average. It was assumed that 80 percent of diesel refining capacity would meet the new standards by modifications to existing hydrotreaters and the other 20 percent by building new hydrotreaters. The analysis included cost estimates under two scenarios. The first scenario assumed that all refiners currently producing highway diesel fuel would continue to do so. The second scenario assumed that some refiners would increase their production of highway diesel while making up for lost production from refiners that would drop out of the market. The EPA did not provide analysis assuming a net loss of production, but indicated that, with the inclusion of the 80/20 and small refiner provisions, no supply problems were anticipated. The EPA also performed an analysis of engineering and construction requirements and concluded that these factors should not be a problem due to the temporary compliance provisions (see Chapter 3 for more discussion).

Table 21. EPA Estimates of Increased Costs To Meet the 15 ppm Highway Diesel Standard
(1999 Cents per Gallon)

Period	Additional Refining	Lubricity Additive	Distribution[a]	Additional Distribution Tanks	Total Increase
Phase-in 2006-2010	4.1	0.2	0.4	0.7	5.4
Fully Implemented Program, 2010	4.3	0.2	0.5	0.0	5.0

[a]Not including additional distribution tanks.
Source: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), p. V-103.

[127] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[128] Total cost per gallon of 15 ppm diesel is the sum of 4.1 cents per gallon refining cost and 1.1 cent per gallon distribution cost.

[129] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-106.

[130] Distribution costs include the capital cost of additional storage tanks, additional operating costs, yield losses, product downgrades, and testing costs.

[131] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-103, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf.

Mathpro Analysis

In its original study for the Engine Manufacturers Association, Mathpro provided 5 sets of scenarios for 10 different combinations of heavy-duty, non-road, and light-duty diesel fuel standards. The scenarios were developed using a linear programming (LP) representation of a notional refinery in PADDs I through III.[132] The study was completed in October 1999 and reflected a range of uncertainty with regard to the eventual sulfur standard. The target sulfur level for highway diesel in the scenarios ranged from 150 ppm to 2 ppm. The scenarios also reflected varying assumptions about the ultimate sulfur level of non-road diesel, and about investment in upgrade (revamp) projects versus new (grassroots) projects. The scenarios resulted in an average increase in refining costs ranging from 2.5 to 9.0 cents per gallon for the 150 ppm and 2 ppm sulfur levels, respectively. The associated investment costs ranged between $0.8 billion and $3.9 billion for PADDs I through III.

In August 2000, Mathpro updated its analysis using the 15 ppm sulfur standard indicated in the June 2000 Notice of Proposed Rulemaking, assuming that the requirement would be met by producing diesel fuel with a pool average of 8 ppm or less.[133] The updated analysis provided estimates given three different assumptions about non-road diesel:

- Non-road diesel at current levels (3,500 ppm). This assumption most closely resembles the EIA and EPA cost analyses.
- Non-road diesel reduced to 350 ppm
- Non-road diesel reduced to 15 ppm.

For each of the non-road sulfur assumptions, the updated analysis provided five scenarios based on different investment and operating approaches by refineries:

- No Retrofitting-Inflexible, which requires only new unit investment
- No Retrofitting-Flexible, which requires only new unit investment but allows some flexibility in hydrocracking and jet fuel production
- Retrofitting-De-rate/Parallel, which allows modification of the existing desulfurization unit and building a parallel unit
- Retrofitting-Series, which allows expansion of the existing desulfurization unit by debottlenecking and adds a new unit in series
- Economies of Scale, which is similar to Retrofitting-Series but allows further economies of scale through inter-refinery processing arrangements.

The estimated increase in national average refining costs (excluding California) ranged between 4.0 and 7.6 cents per gallon and was associated with total investment costs between $1.8 billion and $3.3 billion (1999 dollars) over all of the non-road sulfur assumptions. Costs ranged from 4.5 to 7.1 cents per gallon and investments from $3.0 to $6.0 billion for the scenarios assuming current sulfur levels for non-road diesel (Table 22). The analysis assumed a 10-percent after-tax rate of return on investment. The scenarios with non-road diesel at 3,500 ppm were most similar to the EIA, EPA, and DOE analyses, and the scenario with non-road diesel at 350 ppm was more consistent with the CRA/BOB analysis. When non-road diesel was held at 3,500 ppm, the average cost of producing highway diesel increased by 7.1 cents per gallon in the No Retrofitting-Flexible case and by 4.5 cents per gallon in the Economies of Scale case.

Although the investment costs estimated by Mathpro were at least $195 million dollars higher when the sulfur limit for non-road diesel was assumed to decline to 350 ppm, the average costs were between 0.2 and 1.2 cents per gallon lower than in the scenarios assuming

Table 22. Mathpro Estimates of the Costs of Producing 15 ppm Highway Diesel, with Non-Road Diesel at 3,500 ppm Sulfur

Flexible	No Retrofit: Inflexible	No Retrofit: Flexible	Retrofit: De-rate	Retrofit: Series	Economies of Scale
Total Average U.S. Cost[a] (1999 Cents per Gallon)	6.8	7.1	6.7	4.6	4.5
Investment (Million 1999 Dollars)	5,950	5,900	5,370	3,330	3,040

[a]Excludes California.
Note: Costs have been converted to 1999 dollars from the 2000 dollars reported by Mathpro.
Source: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8.

[132] Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000).

[133] Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000).

9286A

3,500 ppm non-road diesel. The lower average costs were the result of spreading the investments over a larger volume of product. The scenarios with non-road diesel sulfur capped at 15 ppm required the most investment and led to the highest costs. Relative to the 3,500 ppm non-road scenarios, the 15 ppm non-road scenarios required at least $1 billion more investment and resulted in average costs between 0.1 and 0.8 cents per gallon higher.

NPC Analysis

In its report, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels*, the NPC included estimates of meeting a 30 ppm sulfur standard.[134] The estimates were based on the 30 ppm scenarios included in Mathpro's original report for the Engine Manufacturers Association in October 1999. The NPC combined the cost estimates from the "no retrofitting-inflexibility" and the "retrofitting-series" cases assuming that at 30 ppm, most refiners would retrofit. The NPC also made adjustments to the Mathpro estimates to reflect alternative assumptions of refinery economics. NPC adjusted the vendor-supplied estimates used in the Mathpro model upward by a factor of 1.2 for investments and a factor of 1.15 for hydrogen consumption and other operating expenses. The vendor data were adjusted to account for a perceived tendency of vendors to quote overly optimistic cost and performance information. The NPC analysis estimated industry investment costs at $4.1 billion at a cost of 5.9 cents per gallon (1999 dollars) and assumed 50 percent revamped and 50 percent new units. The study indicated that a sulfur standard below 30 ppm would require greater reliance on new units, as opposed to retrofits, resulting in considerably higher investments.

The NPC analysis included a discussion of limitations on engineering and construction resources and, in contrast with the EPA analysis, concluded that the overlap with gasoline sulfur projects would result in delays in meeting the diesel standards. The study suggested that highway diesel supply shortfalls might occur if the standard were required before 2007 and that even more time would be required to meet a standard below 30 ppm. (See Chapter 3 of this report for more detail on engineering and construction.)

CRA/BOB Analysis

In a study for the American Petroleum Institute, CRA/BOB developed refinery-specific cost estimates for every U.S. refinery, using the Prism refinery model.[135] The estimates and a survey of refiners intentions were used to construct a marginal cost curve that was used in an equilibrium supply and demand analysis. The initial supply and demand assumptions were from EIA's *Annual Energy Outlook 2000*. The supply curve was shifted according to the marginal cost analysis, and the demand curve was shifted based on an elasticity assumption. In contrast to all but the EIA offline analysis, the CRA/BOB study provided an analysis of a short-term supply and cost outlook.

The analysis projected a reduction in highway diesel production of 320,000 barrels per day, resulting in a supply shortfall. The EPA has estimated that 75 percent of the shortfall estimated by CRA/BOB resulted from the underlying assumption that an additional 10 percent of the highway diesel produced would be downgraded because of product degradation from distribution and storage.[136] In contrast, EIA and the EPA assumed an additional 2.2 percent of downgraded product, and TMC estimated that a total of 17.5 percent of ULSD would be downgraded.[137] The estimated increase in average refining cost was 6.7 cents per gallon to produce ULSD from 500 ppm diesel. The estimated increase in the marginal price of ULSD needed to balance supply and demand was between 14.7 and 48.9 cents per gallon, depending on the availability of imports.

The CRA/BOB analysis assumed that, in order to meet the 15 ppm standard, refiners would produce highway diesel at an average of 7 ppm.[138] The analysis also assumed that non-road diesel would be reduced to 350 ppm and jet fuel and heating oil sulfur would remain at 1999 levels. The cost estimates reflected an assumption that 40 percent of ULSD would be produced from new desulfurization units and 60 percent from revamped units, and that the return on investment would be 10 percent.

[134] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. Investment and cost estimates have been converted to 1999 dollars from 1998 dollars reported by NPC.

[135] Charles River Associates, Inc. and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000).

[136] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf.

[137] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000), *Revised Supplement* (August 2000).

[138] Telephone conversation with Ray Ory of Baker and O'Brien, January 25, 2001.

EnSys Analysis

EnSys provided a set of cost estimates to the U.S. Department of Energy's Office of Policy, using an LP model that represents PADD III refiners in the aggregate.[139] The estimates reflected a 10-percent return on investment. Unlike the previously discussed studies, EnSys did not make an assumption of how many refiners would revamp units and how many would build new desulfurization units, but instead provided cost estimates for a refinery using revamps and cost estimates for a refinery building new units. The scenarios were also based on two sets of technologies: a conservative technology set and an optimistic technology set. In order to model a phase-in of the highway diesel standard, a series of cases were run assuming different percentages of highway diesel required to meet the new standard.

EnSys developed the scenarios discussed above for the production of highway diesel at various sulfur levels, ranging from 8 ppm to 30 ppm. The results of the 10 ppm scenarios are the focus of this discussion, because they were highlighted in the EnSys report and were provided in a more uniform manner. In general, the scenarios with diesel sulfur at 8 ppm were about 0.5 cent above the 10 ppm estimates. The average incremental cost estimates for producing 10 ppm diesel ranged from 4.4 to 6.0 cents per gallon for the first 50 percent of highway diesel produced at 10 ppm, 6.0 to 7.9 cents for the next 25 percent, and 7.6 to 10.1 cents per gallon for the final 25 percent of production. The lower estimate assumed that the product was produced by 100 percent revamped units; the higher estimate assumed 100 percent new units.

The cases assumed that 25, 50, 75, and 100 percent of highway diesel would be required to meet the 10 ppm standard, while non-road diesel was capped at 360 ppm. The 360 ppm assumption was negated by the fact that the cases were compared with a reference case that also assumed 360 ppm non-road diesel. Sensitivities of reaching 360 ppm for non-road diesel were performed with other assumptions varied. Cases that assumed 100 percent highway diesel at 10 ppm and non-road and heating oil at 360 ppm resulted in average costs that were between 1.6 cents per gallon and 2.1 cents per gallon higher than in the cases assuming non-road diesel and heating oil at current sulfur levels.

The EnSys analysis also included marginal cost estimates for producing 10 ppm diesel with base technology and no revamp (all new units). The marginal cost of production was 6.6 cents per gallon for the first 25 percent of production, 7.2 cents per gallon for the first 50 percent, 7.7 cents per gallon for the first 75 percent, 9.2 cents pe gallon for the full phase-in, and 10.7 cents per gallon foı an all-at-once approach. The highway diesel volumes produced did not reflect additional production for downgraded product.

ANL Analysis

ANL provided an analysis of total incremental refining and distribution costs for seven different phase-in scenarios to the U.S. Department of Energy (DOE) in August 2000 and updated the estimates in November 2000 based on EPA comments.[140] The most recent ANL estimates were based on average incremental production cost estimates from the EnSys 10 ppm production scenarios and distribution cost estimates for 15 ppm diesel extrapolated from TMC estimates for 5 ppm and 50 ppm diesel.

The ANL analysis used average per-gallon production cost estimates taken as the weighted average of the incremental cost for each quartile of highway diesel production, provided by EnSys. The scenarios had three parameters: the type of technology, the mix of new units versus modified units, and the percent of diesel production required to be 10 ppm. EnSys estimated costs for production under two different investment scenarios: all revamped equipment and all new units. For each investment scenario, EnSys provided cost estimates for both a base technology and an optimistic technology assumption.

The ANL analysis also provided cost estimates for 60 percent revamp/40 percent no revamp given both base and optimistic technology assumptions, by blending the EnSys "all revamp" and "all new" scenarios.[141] The average estimated cost (undiscounted) of producing the first 25 percent ranged from 4.2 to 6.0 cents per gallon; the first 50 percent, 4.0 to 6.0 cents per gallon; the first 75 percent, 4.2 to 6.6 cents per gallon; for 100 percent after phase-in, 4.7 to 7.5 cents per gallon; and for 100 percent all-at-once, 6.0 to 8.1 cents per gallon.[142] Marginal costs were provided by an additional scenario resulting in a marginal cost of 6.6 cents per gallon for the first 25 percent of production, 9.2 cents per gallon for a full phase-in, and 10.7 cents per gallon if the production is required all at once. ANL developed phase-in cost series for the seven scenarios by interpolating between the cost estimates for the different levels of production mentioned above.

[139] EnSys Energy & Systems, Inc, *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000).

[140] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000).

[141] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix A.

[142] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Table 1.

9287A

Each of the phase-in cost series provided by ANL was associated with a set of distribution costs, which varied slightly in the seven scenarios. The distribution cost analysis for 15 ppm highway diesel fuel was extrapolated from TMC (early) estimates for distributing 5 ppm and 50 ppm diesel.[143] The costs included capital investment for the distribution and refueling system and for product downgrade. Distribution costs were provided for various levels of phase-in between 5 and 100 percent of the highway diesel market. The level of phase-in most consistent with the 80 percent required by the ULSD Rule for the initial years of the program was a supply of 83 percent of highway diesel, which was associated with undiscounted distribution costs between 1.5 and 2.2 cents per gallon. The costs associated with 100 percent of highway diesel at 15 ppm ranged between 1.2 and 2.1 cents per gallon.[144]

The ANL analysis concluded that, depending on the case and the stage of phase-in, the total incremental costs of a phase-in would range from 6.1 to 11.2 cents per gallon, compared to a range of 7.1 to 12.7 cents per gallon for an all-at-once strategy. Estimates of total (undiscounted) costs to consumers for the various phase-in scenarios ranged from $15.2 to $25.4 billion ($10.1 to $17.3 billion net present value). Higher expenditures were estimated for an all-at-once strategy, with expected costs totaling $30.4 to $52.8 billion ($22.3 to $38.6 billion net present value). The relatively lower distribution costs under a phase-in approach were translated into an estimated savings of $14.2 to $27.4 billion.

Summary of Investment Estimates

EPA estimated that, in order to meet the requirements of the ULSD Rule, the industry would invest a total of $5.3 billion. In comparison, DOE (by ANL) estimated between $8.1 and $13.2 billion of investment for ULSD, Mathpro estimated a range of $3.0 to $6.0 billion, CRA estimated $7.7 billion, and NPC estimated $4.1 billion to meet a 30 ppm standard and substantially higher but undefined amount to provide 15 ppm diesel (Tables 23 and 24). Because production of diesel in the appropriate sulfur range has been very limited, analysis of costs of the ULSD Rule depend heavily on vendor estimates and several critical assumptions, including refinery configuration, size, and crude oil inputs; the ratio of retrofitted units to new units; and the relative cost of retrofits versus new units.

The studies discussed above used different methodologies, economic approaches, levels of regional and annual detail, and assumptions (see Table 20). Many were completed before the Final Rule was issued and do not reflect the provisions for small refineries or the 80/20 rule. In addition, the studies were based on different assumptions about investment behavior and costs and the level of diesel demand. The capital investment estimates are difficult to compare not only because of their different methodologies and assumptions but also because their investment estimates reflect slightly different things. For instance, the EPA estimated the capital cost for a new distillate hydrotreater to range

Table 23. Comparison of ULSD Production Cost Estimates: Individual Refinery Representation

Study	Sulfur Level (ppm)	Percentage of Highway Diesel That Is ULSD	Cost Change (1999 Cents per Gallon of ULSD)	Cost Basis	Refinery Capital Investment (Billion 1999 Dollars)
EPA (temporary compliance, 2006-2010)	7	75[a]	4.[illegible]	Average, U.S.	[illegible]
EPA (full compliance, June 2010 forward)	7	100	4.3	Average, U.S.	[illegible]
CRA/BOB (August 2000 for 2006)	7[c]	100	6.7[d]	Average, U.S.[e]	--
EIA (cost curves, 2006)	7	76-100	[illegible]4-6.8	Marginal, PADDs [illegible]	

[a]Small refiners accounting for 5 percent of production are eligible to delay, but only 2 percent are assumed to delay.
[b]Cost adjusted for credit trading at cost to low cost refiners.
[c]Correspondence with Ray Orv of Baker and O'Brien. Also reflects assumption of 350 ppm non-road diesel.
[d]Average cost to produce 7 ppm diesel from 500 ppm diesel. The marginal price to balance supply and demand was estimated to be between [illegible] and [illegible] cents per gallon, depending on the availability of imports.
[e]Average based on marginal cost methodology.
[f]Marginal based on average refinery costs.

Sources: EPA: U.S. Environmental Protection Agency, *Regulatory Impact Analysis, Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site [illegible]. CRA/BOB: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). EIA: Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapter 5 of this report).

[143]Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000).
[144]M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix C.

from $1,240 per barrel per day to $1,680 per barrel per day, whereas those in EIA's refinery-by-refinery analysis ranged from $1,043 to $1,807, and in EIA's NEMS Regulation case they were $1,331 to $1,849 per barrel per day (Table 25).

The sets of capital costs used in the EIA and EPA analyses are not directly comparable. The lower-bound of EPA's capital costs represents a 25,000 barrel per day hydrotreater processing 100 percent straight-run feedstock, and the upper-bound reflects the same unit processing 100 percent light cycle oil. The EPA's upper and lower bound costs encompass a third estimate for a unit processing entirely coker distillate. The capital costs for individual refineries in the EPA analysis vary acros this range, depending on the assumptions about proportions of straight-run distillate, coker distillate, and light cycle oil processed at each refinery and the size of the hydrotreater unit. The capital cost range for EIA's refinery-by-refinery analysis also varies for the quality of the feedstock and size of each unit. EIA's short-term analysis reflects actual data about the quality of crude oil and feed streams at individual refineries. In contrast, EIA's mid-term NEMS analysis does not use refinery-specific information about feed steams but aggragates feed and crude quality information at a regional level.

Table 24. Comparison of ULSD Production Cost Estimates: LP Model or Based on LP Results

Study	Sulfur Level (ppm)	Percent of Highway Diesel That Is ULSD	Cost Change (1999 Cents per Gallon of ULSD)	Cost Basis	Refinery Capital Investment (Billion 1999 Dollars)
Mathpro (August 2000)	8	100	4.5-7.1[a]	Average U.S.	3.0-6.0[a]
NPC (June 2000)	30	100	5.9	Average PADDs I-III	4.1
EnSys (August 2000), first 50 percent of production at 10 ppm	10[b]	50	4.4-6.0[c]	Average PADD III	
EnSys (August 2000), next 25 percent of production at 10 ppm	10[b]	75	6.0-7.9[c]	Average incremental cost of next 25% PADD III	
EnSys (August 2000), final 25 percent of production at 10 ppm	10[b]	100	7.6-10.1[c]	Average incremental cost of final 25% PADD III	
EnSys (August 2000), 25% to 100%	10[b]	25-100	6.6-10.7[d]	Marginal PADD III	
ANL (November 2000), up to 50% of production at 10 ppm	10	50	4.0-6.0[d]	Average PADD III	
ANL (November 2000), 75% of production at 10 ppm	10	75	4.2-6.6[c]	Average PADD III	
ANL (November 2000), 100% of production at 10 ppm	10	100	4.7-7.5[c]	Average PADD III	8.1-13.2 (August 2000 estimate)[e]
ANL (November 2000), 100% of production at 10 ppm, all-at-once	10	100	6.0-8.1[c]	Average PADD III	
ANL (November 2000), 25% to 100%	10	25-100	6.6-9.2[d]	Marginal PADD III	
EIA (NEMS, 2007-2010)	7	76[f]	4.7-7.3[g]	Marginal, U.S. average	4.2-5.9 through 2007
EIA (NEMS, 2011)	7	100	6.5-9.2[g]	Marginal, U.S. average	6.3-9.3 through 2011

[a]Non-road 3500 ppm.
[b]Reflects assumption of 360 ppm non-road diesel but the cost impact is negated because it is compared with a reference case with non-road diesel at the same sulfur level.
[c]The higher end of the cost range reflects base technology while the lower end reflects more optimistic technology.
[d]Marginal costs at 25 percent and 100 percent 10 ppm production with base technology and all new units.
[e]U.S. Department of Energy, "Comments of the Department of Energy on the Environmental Protection Agency's May 16, 2000 Notice of Proposed Rulemaking on Heavy-Duty Engine and Vehicle Emission Standards and Highway Diesel Fuel Sulfur Control" (Washington, DC, September 2000), Enclosure 1.
[f]Small refiners accounting for 5 percent of production are eligible for the small refinery provision, but only 4 percent of production is assumed to be delayed.
[g]Average refinery gate price for individual years.

Sources: **Mathpro**: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD: August 2000). **NPC**: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000). **EnSys**: EnSys Energy & Systems, Inc, *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*. Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA**: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

9288A

The lower end cost in EIA's NEMS analysis reflects a notional unit that processes low-sulfur feed with incidental dearomatization, while the higher end cost reflects a different notional unit that processes higher sulfur feed with greater aromatics improvement. EIA also provided sensitivity analysis using higher capital cost assumptions for both the refinery-by-refinery and NEMS analyses. The Higher Capital Cost sensitivity case for EIA's refinery-by-refinery analysis is based on capital costs that are about 40 percent higher than those in the initial analysis. Both sets of capital costs were developed by the National Energy Technology Laboratory, in conjunction with Mr. John Hackworth, energy consultant. The capital costs used in the NEMS Higher Capital Cost case were provided by recent work from EnSys and are 24 percent higher for the first notional unit and 33 percent higher for the second notional unit, relative to the Regulation case.

The EPA analysis was based on estimates from two technology vendors, providing costs based on retrofits and new units.[145] EPA assumed that 80 percent of ULSD will be produced from diesel hydrotreaters that are revamped at a cost of $40 million each. These estimates reflected an assumption that new units would cost twice as much as revamps. The net result was an estimated average cost of $50 million per refinery, which equates to a little more than 4 cents per gallon of highway diesel on average.

The NPC analysis did not estimate costs for producing diesel with less than 10 ppm sulfur but indicated that even a 30 ppm sulfur standard would require reactor pressures in the range of 1,100 to 1,200 psi, which is well above the vendor estimates used by the EPA.[146] The NPC characterized vendor estimates as inherently over-optimistic;[147] however, several new technologies are under development that may reduce costs (see Chapter 3).

The ANL estimates blended the EnSys 100 percent new and 100 percent revamp refinery analysis, based on the assumption that 60 percent of ULSD would be produced from revamped units that cost an average of $40 million per unit, and the other 40 percent would come from new units at an average cost of $80 million per unit. Instead of making an assumption about the split between revamped and new units, Mathpro developed scenarios for different types of choices. Assuming no change in the non-road diesel standards, Mathpro estimated that the total investment cost would range from $6.0 billion if refineries required all new units with minimum operating flexibility to $3.0 billion if all refineries were retrofitted and economies of scale from trading were realized.

Table 25. Comparison of Key Hydrotreator Investment Assumptions for Various Refinery Models

Model	Capital Cost of New Hydrotreater (1999 Dollars per Barrel per Day, ISBL)	Revamp Cost as a Percentage of New Unit Cost	Unit Size (Barrels per Day)	Percent of ULSD Production from Revamped Units Versus New Units
Refinery-by-Refinery Models				
CRA/BOB	1,622[a]	55	25,000	60/40
EPA	1,240-1,680[b]	50	25,000	80/20
EIA Cost Curve	1,043-1,807[c]	Variable	50,000-10,000	Not an assumption
EIA Cost Curve, High Capital Cost Scenario	1,465-2,548c	Variable	50,000-10,000	Not an assumption
LP Models				
EnSys (August 2000)	2,350-3,296[d]	60	25,000	[illegible]
EIA NEMS Regulation Case	1,331-1,849[d]	50	25,000-10,000	80/20
EIA NEMS 2/3 Revamp Case	1,331-1,849[d]	50	25,000-10,000	66.7/33.3
EIA NEMS Higher Capital Cost Case	1,655-2,493[d]	50	25,000-10,000	80/20

[a]Feedstock composed of 65 percent straight-run distillate, 10 percent cracked stock, and 25 percent light cycle oil.
[b]Low end of range is for straight-run distillate and high end is for light cycle oil.
[c]Costs varied depending on unit size and feedstock.
[d]Low end of range is for units processing low-sulfur feed streams with incidental dearomatization. High end is for higher sulfur feed streams with greater aromatics improvement.

Sources: **CRA/BOB:** Correspondence with Mr. Ray Ory, April 19, 2001. **EPA:** U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, Table V.C-9, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **EIA Cost Curve and Cost Curve High Capital Cost Scenario:** National Energy Technology Laboratory, in conjunction with Mr. John Hackworth, energy consultant. **EnSys:** EnSys Energy & Systems, Inc., *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **EIA/NEMS Regulation and 2/3 Revamp Cases:** Office of Integrated Analysis and Forecasting. **EIA/NEMS High Capital Cost Case:** Revised EnSys costs based on correspondence with Mr. Martin Tallett, April 2001.

[145]EPA corroborated the vendors' cost estimates in discussions with two other vendors. E-mail from Lester Wyborny, U.S. Environmental Protection Agency, March 30, 2001.

[146]M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), p. 132.

[147]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 77.

The EIA NEMS analysis produced estimates for the refinery capital investment required to comply with the ULSD Rule for 2007 and 2010. The cumulative refinery capital investment estimated through 2007 ranged between $4.2 billion and $5.9 billion. The NEMS analysis produced an estimate of refinery capital investment between $6.3 billion and $9.3 billion through 2011.

Distribution Cost Analyses

EPA, ANL, and TMC have published estimates of distribution costs given different assumptions about the phase-in requirements for highway diesel. In general, the cost estimates for distributing a smaller percentage of 15 ppm fuel were higher than estimates assuming that 100 percent of the highway diesel market would be at 15 ppm, because a phase-in approach requires the distribution system to handle an extra product (Table 26).

Distribution cost estimates from the EPA, ANL, and TMC analyses included the capital incurred in the distribution and refueling system, as well as costs resulting from downgraded product. The EPA estimated that distribution costs would increase by 1.1 cents per gallon during the temporary compliance period, with 0.4 cents of the cost associated with the distribution and energy loss of the ULSD relative to 500 ppm diesel and 0.7 cents associated with capital expenses for handling two grades of highway diesel. EPA assumed that the capital costs would be fully amortized during the transition period (by 2010), and that revenue losses from product downgrade and other operating costs would increase distribution costs by 0.5 cents per gallon.

EIA's NEMS analysis assumed the EPA's estimated capital costs of 0.7 cents per gallon and portions of EPA's other distribution costs, including operating, transmix, and testing costs, which totaled 0.2 cents per gallon. EIA estimated the cost associated with the revenue loss of the downgraded product at 0.3 cents per gallon through 2010 and 0.2 cents per gallon after 2010 (see Chapter 6). The EIA revenue loss estimates were based on model results. A higher revenue loss estimate of 0.7 cents per gallon for all years was associated with EIA's 10% Downgrade sensitivity case, because more of the ULSD

Table 26. Comparison of ULSD Distribution Cost Estimates and Assumptions

Study	Sulfur Level (ppm)	Year	Distribution Cost Change (1999 Cents per Gallon)	Investment (Billion 1999 Dollars)	Downgrade Estimates
TMC	5		7 at 5% 4.1 at 20% 1.5 at 100%	0.215 1.05 1.08	10.0% 12.0% 19.5%
TMC	15		6.9 at 5% 4.1 at 20% 1.4 at 100%	0.215 1.05 1.08	9.5% 11.0% 17.5%
TMC	50		Costs 15% to 35% less than 5 ppm costs		8.0% 10.0% 13.5%
ANL	15		6.2 at 5% 1.6-2.2 at 74%-100% 1.2-2.1 all-at-once Costs are undiscounted and include refueling costs	50% of terminals reconfigure split between new tankage at $1 million per terminal and modified tankage at $100,000 per terminal	Same as TMC 5 ppm and 50 ppm
EPA (temporary compliance)	15	2006-2010	1.1	0.5	4.4%
EPA (full compliance)	15	Post-2010	0.5	0.3	4.4%
CRA/BOB	15				10.0% above current
EIA Regulation Case (temporary compliance)	15	2007-2010	1.2		4.4%
EIA Regulation Case (100% ULSD)	15	Post- 2010	0.4		4.4%
EIA 10% Downgrade Case (temporary compliance)	15	2007-2010	1.6		10%
EIA 10% Downgrade Case (100% ULSD)	15	Post- 2010	0.9		10%

Sources: Sources: **EPA**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **CRA/BOB**: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **TMC**: Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000). **EIA**: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

9289A

produced was projected to be downgraded to a lower value product.

The ANL estimates, which were extrapolated from previous TMC estimates for delivering 5 ppm and 50 ppm diesel,[148] ranged from 6.2 cents to 1.2 cents per gallon for delivery of 5 percent and 100 percent, respectively.[149] In August 2000, TMC provided supplemental estimates reflecting downgrade costs associated with distributing 15 ppm diesel fuel.[150] Presumably, the capital costs would remain the same as for the 5 ppm case in the previous TMC analysis. When the original TMC 5 ppm estimates are adjusted to reflect 15 ppm diesel, the total distribution cost estimates are 6.9 cents per gallon to supply 5 percent of the market; 4.1 cents per gallon to supply 20 percent of the market; and 1.4 cents per gallon to supply the entire highway diesel market.[151]

The extent to which product contamination will occur in the distribution system (and how much product must be downgraded as a result) is very uncertain. The analyses included strikingly different estimates of how much of the 15 ppm product would be downgraded in the distribution system. EIA's NEMS analysis assumed 4.4 percent downgrade for consistency with the EPA assumptions but also provided a sensitivity case assuming 10 percent downgrade. Downgrade estimates ranged from 4.4 percent of production (EPA) to 17.5 percent (TMC). Part of the uncertainty stems from not knowing the present level of downgrade occurring in the distribution system, because there is no current reporting requirement. The EPA assumed a doubling of product downgrade from current downgrade levels, which were estimated at 2.2 percent. The methodology used by the EPA to estimate current downgrade levels was highly speculative and was not based on a scientific survey. The EPA's estimation methodology was loosely based on a survey of the Association of Oil Pipelines, in which six respondents provided estimates of the current diesel fuel downgrade ranging from 0.2 percent to 10.2 percent (see Chapter 4). In the same survey some respondents expressed an expectation that the downgrade amount might be expected to double under the ULSD Rule.

The TMC analysis was based on a survey of 14 refiners (representing 38 percent of U.S. petroleum refining capacity), 3 pipeline operators (representing approximately 40 percent of U.S. highway diesel shipping capacity), and 11 terminal operators (representing 25 percent of U.S. petroleum product storage capacity). A wide range of responses was noted in the responses of pipeline operators. In the survey, some terminal operators indicated that they would not handle ULSD. Terminal operators generally anticipated a higher rate of downgrade than did pipeline operators. Terminal operators indicated that, to handle ULSD, dedicated transport trucks or compartments in transport trucks would be required to avoid sulfur contamination.[152]

The TMC analysis projected 17.5 percent downgrade when 100 percent of the highway diesel market was assumed to require the 15 ppm diesel, and slightly lower levels of downgrade were expected when smaller segments of the market were required. Although the ANL analysis did not provide the downgrade assumptions used, it was based on the TMC assumptions for downgrade of 5 ppm and 50 ppm diesel and tracked closely with the TMC assumptions. Different downgrade assumptions resulted in different cost estimates associated with downgrade. The EPA estimated a total downgrade cost of 0.2 cents per gallon for all highway diesel in the initial years and 0.3 cents per gallon after full implementation.[153] In contrast, the ANL analysis (based on the TMC assumptions of higher downgrade volumes) estimated a total downgrade cost of about 1 cent per gallon when more than half of the market was required to meet the 15 ppm standard.

The TMC, EPA, and ANL analyses also used different sets of assumptions about capital investment requirements. During the initial years of the program, when the distribution system must handle two highway diesel fuels, the EPA estimated tankage costs at refineries, terminals, pipelines, and bulk plants at $0.81 billion. In addition, investments at truck stops to handle the extra product were estimated at $0.24 billion. These costs were amortized over total highway diesel volumes (both 500 ppm and 15 ppm) during the initial 4 years at 7 percent per year, resulting in a cost of 0.7 cents per gallon. EIA used EPA's capital cost estimate of 0.7 cents per gallon in all NEMS analysis scenarios.

The ANL analysis assumed that, given a phase-in, 50 percent of terminals would add tanks or reconfigure. Of those terminals that were modified, it was assumed that

[148] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000)

[149] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix C.

[150] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000). *Revised Supplement* (August 2000).

[151] Total distribution and retail cost estimates for 5 ppm from *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* were adjusted based on update of downgrade costs for 15 ppm diesel provided in the *Revised Supplement*

[152] Telephone conversation with Bob Cunningham of Turner Mason, March 21, 2001

[153] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-124.

half would add tankage at $1 million per terminal and the other half would reconfigure at a cost of $100,000 per terminal. Bulk terminals were not assumed to make conversions for a second highway diesel fuel, because they were assumed to enter into exchange agreements with marketers during a phase-in period, rather than investing in tankage. In addition, all truck stops were assumed to be modified to provide two fuels during the phase-in, at a cost of $75,000 per truck stop.

The original TMC report provided investment estimates for distributing 5 ppm fuel to supply, 5, 20, and 100 percent of the highway diesel market. Investments at terminals and pipelines were estimated at $295 million when supplying 20 percent of the highway market and $325 million for 100 percent of the market. Retail investments were estimated at $755 million for both 20 percent and 100 percent of supply. Unlike the other two analyses, which reflected the cost of conversion to truck stops only, TMC assumed that some gasoline stations would invest to carry a second diesel fuel.[154]

Downgrade Analysis

The MSC study, *Alternative Markets for Highway Diesel Fuel Components*, conducted at the request of the EPA, provided an analysis of the potential for diverting sub-specification highway diesel to non-road or foreign markets.[155] The study compared 2007 projections for supply and demand of distillate products to assess the outlook for non-road distillate market growth and used relative relationships of highway diesel to non-road distillate prices to estimate the economic consequences of diverting to other products.

The analysis used historical industry-level distillate demands for each PADD from EIA's *Fuel Oil and Kerosene Sales* as a starting point.[156] These industry level demands were projected out to 2007, using national annual growth rates from the *Annual Energy Outlook 2000*.[157] PADD-level supply balances for distillate fuel were projected for 2007, starting with historical data from the *Petroleum Supply Annual 1999*[158] and applying growth rates from the *Annual Energy Outlook 2000*. Import and export levels were held constant in PADDs II and IV. In PADD V, inter-PADD transfers were held to historical levels and imports and exports were used as a balancing item. The study concluded that there was little potential to divert highway diesel to non-road distillate markets, and that the potential for severe market dislocations and/or price depression in the non-road markets was greatest in PADD IV and least in PADD I.

The price consequences of diverting product from the highway diesel market to non-road markets were assessed using estimated price relationships for these products derived from historical price data from various industry pricing agencies (e.g., Platts), combined with relevant transportation costs.[159] The price implications of downgrading 5 percent, 10 percent, and 15 percent of the current highway diesel supply were estimated for each PADD (Table 27). The price impact of diverting 5 percent of the highway diesel supply to other uses ranged from -3.0 cents per gallon in PADD I to -6.0 cents per gallon in PADD IV. The range widened to -3.5 to -20.0 cents per gallon in PADDs I and IV, respectively, for 10 percent of diverted product and to -3.5 to -22.0 cents per gallon for 15 percent of diverted product. The study concluded that except in PADD IV, a 5-percent diversion of product would have modest market impact. In addition, a 10- to 15-percent diversion would have a significant market impact in all areas except PADD I.

Table 27. Projected Relative Price Decrease by PADD and Percentage of Diverted Diesel
(1999 Cents per Gallon)

Diversion Level (Percent)	PADD I	PADD II	PADD III	PADD IV	PADD V
5	3.0	2.5	4.0	6.0	5.0
10	3.5	14.0	4.5	20.0	5.0
15	3.5	16.0	4.5	22.0	6.0

Source: Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000), p. 4.

[154] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000), p. 6.
[155] Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000).
[156] Energy Information Administration, *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, 1995-1998).
[157] Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washinton, DC, December 1999).
[158] Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99/1) (Washington, DC, June 2000).
[159] Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000), pp. 19-32.

9290A

Bibliography

Ackelson, D.B., and others. "Hydrotreating-Hydrocracking For Reformulated Mid-Distillate Fuels," presentation at World Conference on Refinery Processing and Reformulated Gasolines (March 1994).

Allen, L. "Economic Environmental Fuels with SynTechnologies," presented at the World Fuels Meeting, Fall 1998, Washington D.C., EAA-World Fuels-98.

Allen, L., D. Dillip, and J. Langston. *Technologies to Achieve 2000 Diesel Specifications*, PTQ, Summer 1999.

Birch, C.H. and R. Uliveri. "ULS G Diesel Refining Study" (Purvin & Gurtz, Inc., 17 November 2000).

Bjorklund, B.L. and others. *The Lower It Goes, The Tougher It Gets (The Practical Implications of Producing Ultra-Low Sulfur Diesel)*, NPRA 2000 Annual Meeting Report, AM-00-16.

California Environmental Protection Agency, Office of Health Hazard Assessment (CAL-EPA, OEHHA). *Proposed Identification of Diesel Exhaust as a Toxic Air Contaminant*. April 22, 1998.

Charles River Associates, Inc. and Baker and O'Brien, Inc. *An Assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000).

Cooper, B.H., and K.G. Knudsen. "Ultra Low Sulfur Diesel: Catalyst and Process Conditions", NPRA 1999 Annual Meeting Report, AM-99-06, March 1999.

Cooper, B.H., and K.G. Knudsen. "Refiners Have Discovered That Hydrogenation Can Be a Superior Desulfurization Process in Circumstances in Which Extraction Is Not Effective," *World Refining*, November 2000.

Cooper, B.H., and K.G. Knudsen. "What Does It Take To Produce Ultra-Low-Sulfur Diesel?" *World Refining*, November 2000.

Cooper, B.H., A. Stanislaus, and P.N. Hannerup. "Hydrotreating Catalysts for Diesel Aromatics Saturation," *Hydrocarbon Processing*, Gene Swantek Publications, June 1993.

Energy Information Administration, *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, 1995-1998).

Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0833(2000) (Washington, DC, December 1999).

Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99/1) (Washington, DC, June 2000).

Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0525(99) (Washington, DC, September 2000).

Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/index.html.

Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System, Part 1—Report and Appendix A*, DOE/EIA-M059(2000) Part 1 (Washington, DC, December 1999).

Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System, Part 2—Appendices B Through I*, DOE/EIA-M059(2000) Part 2 (Washington, DC, December 1999).

EnSys, Inc. *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000).

Federal Register. U.S. Environmental Protection Agency, 40 CFR Parts 80, 85, and 89, "Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Control Requirements" (February 10, 2000).

Federal Register. U.S. Environmental Protection Agency, 40 CFR Parts 69, 80, and 86, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Fuel Sulfur Control Requirements: Final Rule" (January 18, 2001).

Gary, J.H., and G. E. Handwerk. *Petroleum Refining—Technology and Economics* (New York, Marcel Dekker Publishing, 1994).

Gerritson, L.A. and others. "Production of Green Diesel in BP Amoco Refineries", presentation at WEFA Conference (Berlin, Germany, June 2000).

Health Effects Institute. *Diesel Exhaust: A Critical Analysis of Emissions, Exposure, and Health Effects.* April 1995.

Levy, Robert E., and others. "UniPure's ASR-2 Diesel Desulfurization Process: A Novel, Cost-effective Process for Ultra-Low Sulfur Diesel," presented at the National Petrochemical and Refiners Association 2001 Annual Meeting (New Orleans, LA March 18-20, 2001).

Manufacturers of Emission Controls Association, *Catalyst-Based Diesel Particulate Filters and NO_x Adsorbers: A Summary of the Technologies and the Effects of Fuel Sulfur* (August 14, 2000).

Maples, R.E., *Petroleum Refinery Process Economics* (Tulsa, OK, PennWell Publishing Company, 1993).

Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15 ppm Sulfur Cap* (Bethesda, MD, August 2000).

Moyse, B.M., "Process, Catalyst Choices Key to Producing 30-ppm Sulfur Fuels," *Oil & Gas Journal* (October 2000).

Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000).

National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (Washington, DC, June 2000).

National Petroleum Council, *U.S. Petroleum Refining, Meeting Requirements for Cleaner Fuels and Refineries* (August 1993).

Peters, M.S., and K.D. Timmerhaus. *Plant Design and Economics for Chemical Engineers* (New York, McGraw-Hill, 1991).

"Refining Processes 2000," *Hydrocarbon Processing* (Houston, TX: Gene Swantek Publications, November 2000).

Shiflett, W.K. "On the Road to No Sulfur: Solutions for Gasoline and Diesel Fuels" report presented at Clean Fuels 2001 (January 2001).

Shore, J. (Energy Information Administration). "Supply of Chicago/Milwaukee Gasoline Spring 2000" (August 9, 2000), web site www.eia.gov/ pub/ oil_gas/ petroleum/ presentations/ 2000/ supply_of_chicago_ milwaukee_gasoline_spring_2000/cmsupply2000.htm.

Shore, J. (Energy Information Administration). "Trip Report to London and Brussels on Import Availability Study" (February 2001).

Singh, M.K. *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel,* Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000).

Smit, C.P., "MAKFining Premium Distillates Technology: The Future of Distillate Upgrading", presentation to Petrobras (Rio de Janeiro, Brazil, August 24, 2000).

Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000).

Turner, Mason & Company, *Revised Supplement to Report: Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, August 8, 2000).

U.S. Department of Energy, Office of Transportation Technologies, "Impact of Diesel Fuel Sulfur on CIDI Emission Control Technology" (Washington, DC, August 21, 2000).

U.S. Department of Energy, Office of Transportation Technologies, "Diesel Emission Control: Sulfur Effects (DECSE) Program Phase II Summary Report: NO_x Adsorber Catalysts" (Washington, DC, October 2000).

U.S. Department of Energy, "Comments of the Department of Energy on the Environmental Protection Agency's May 16 Notice of Proposed Rulemaking on Heavy-Duty Engine and Vehicle Emission Standards and Highway Diesel Fuel Sulfur Control" (Washington, DC, September 2000).

U. S. Environmental Protection Agency, *(2000) Review of EPA's Health Assessment Document for Diesel Exhaust* (EPA/600/8-90/0-57E). Review by the Clean Air Scientific Committee (CASAC) December 2000 EPA-SAB-CASAC-01-003.

U.S. Environmental Protection Agency, Office of Research and Development. *Health Assessment Document for Diesel Exhaust: SAB Review Draft.* EPA/600/8-90/057E (Washington, DC, 2000), web site www.epa.gov/ncea/dieslexh.htm.

U.S. Environmental Protection Agency, *EPA Staff Paper on Gasoline Sulfur Issues,* EPA420-R-98-005 (Washington, DC, May 1998).

U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines,* EPA420-F-00-048 (Washington, DC, November 2000).

U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements,* EPA420-R-00-026 (Washington, DC, December 2000), web site www.epa.gov/otaq/diesel.htm#documents.

9291A

U.S. Environmental Protection Agency, *Final Emission Standards for 2004 and Later Model Year Highway Heavy-Duty Vehicles and Engines*, EPA420-F-00-026 (Washington, DC, July 2000).

U.S. Environmental Protection Agency, *Heavy-Duty Engine and Vehicles Standards and Highway Diesel Fuel Sulfur Control Requirements*, EPA420-F-00-057 (Washington, DC, December 2000).

U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emission of Air Pollution From Highway Heavy Duty Diesel Engines*, EPA420-R-00-010 (Washington, DC, July 2000).

U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analysis*, EPA420-R-00-028 (Washington, DC, December 2000).

U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000).

van der Linde, B., and others. "SynTechnology B: An Attractive Solution for Meeting Future Diesel Specification," presented at 1999 Asian Refining Technology Conference, ARTC-99.

Appendix A

Letters from the Committee on Science, U.S. House of Representatives

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

SUITE 2320 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6301
(202) 225-6371
TTY: (202) 226-4410

July 26, 2000

Mr Lawrence A. Pettis
Acting Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Pettis:

The U.S. Environmental Protection Agency (EPA) has proposed a 15 parts per million (PPM) highway diesel sulfur cap effective at the refinery or import level beginning April 1, 2006. The same standard would be effective at the terminal level on May 1, 2006 and at the retail level on June 1, 2006. These deep sulfur reductions will require significant investments that not all refiners may choose to make. As a result, diesel fuel supplies could be affected. In addition, these extremely low sulfur levels raise serious questions about the ability of the industry to adequately distribute the fuel in a fungible pipeline system that supports an array of different fuels and sulfur levels.

We believe that the EPA has not adequately studied the potential impacts of its proposed sulfur level on diesel fuel supply or the distribution system. EPA has also not fully assessed the availability of cost-effective desulfurization technologies that would be available in time to allow compliance with the new standard. As a result, an independent and objective study is needed that addresses, at a minimum, the following questions:

- Assuming that the rule is finalized as proposed (without a phase-in of the low sulfur fuel), what are the potential impacts on highway diesel fuel supply that could result? What impacts are possible on other middle distillate products such as jet fuel, home heating oil and off-road diesel? If highway diesel fuel supply is adversely impacted, what are the potential impacts on the cost of diesel fuel to the end-users? To what extent would imports be able to fill any shortfall in supply and at what cost? How significant an effect would the 5% fuel efficiency loss associated with engine after-treatment devices have in the context of expected diesel demand under EPA's 15 PPM standard?

- EPA has proposed implementing the new diesel standard in April 2006. How would potential supply change if the effective date was later (i.e., refinery changes for diesel did not have to overlap those for gasoline sulfur)?

Mr. Lawrence A. Pettis
July 26, 2000
Page two

- What are the effects of EPA's proposal on the diesel fuel distribution system? In particular, to what extent might fuel contamination occur when shipping low sulfur diesel in common pipelines with other, higher sulfur products? What is the capability of current testing methods to accurately measure sulfur level in the context of a 15 PPM sulfur cap? What operational changes, such as batch size and product sequence changes, would be necessary and how would they contribute to likely consumer costs?

- Although not proposed in the rule, EPA has asked for comments related to the feasibility of phasing-in low sulfur highway diesel over the course of several years. Such a phase-in would require the introduction of a second grade of highway diesel fuel into the supply and distributions systems. What would be the impacts on the distribution system of a phase-in of low sulfur highway diesel? What additional investments would be needed to ensure the integrity of both the low sulfur and high sulfur product at the retail level? Would a separate infrastructure be required to adequately deliver product to market? How would these investments be recouped by the industry?

- What effect would EPA's proposed standard have on refinery operations? Would additional processing be required and would that affect refinery product yield and fuel consumption within the refinery?

- Do adequate, cost-effective technologies exist to allow refineries to adjust to the new 15 PPM standard? Are technologies in development that could reduce the costs in the future, and is there a high likelihood of their deployment into the market in a timely manner?

We are requesting that the EPA keep the proposed rule on the 15 PPM diesel sulfur cap public comment period open pending receipt of your findings. Thank you for your attention to this matter.

Sincerely,

F. JAMES SENSENBRENNER, JR.
Chairman

RALPH M. HALL
Ranking Minority Member

KEN CALVERT
Chairman
Subcommittee on Energy and Environment

JERRY F. COSTELLO
Ranking Minority Member
Subcommittee on Energy and Environment

9294A

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

SUITE 2320 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6301
(202) 225-6371
TTY: (202) 226-4410

January 24, 2001

Mr. Lawrence A. Pettis
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Pettis:

The Energy Information Administration is about to begin a study requested by the Committee on Science on July 26, 2000 regarding the effect of the Environmental Protection Agency's (EPA) 15 parts per million diesel fuel standard. I am enclosing a copy of the July 26, 2000 letter for your information.

The EPA issued the final rule on December 21, 2000, which differs in several ways from the request the Committee made in July. As such, please modify the request to take the assumptions underlying EPA's final rule into account. Where EPA's assumptions diverge meaningfully from industry assumptions please perform a sensitivity analysis as appropriate. There are some significant differences between EPA and industry assumptions in several areas including:

- the Btu content of ultra-low-sulfur diesel (ULSD);
- efficiency loss from engine after-treatment devices; and
- additional distribution costs.

Thank you for your attention to this matter. Please contact Tom Vanek of my staff at (202) 225-4778 if you have any questions.

Sincerely,

Harlan Watson

Harlan Watson
Staff Director
Energy & Environment Subcommittee

HA:tjs

Enclosure

9295

Appendix B

Differences From the *AEO2001* Reference Case

Appendix B

Differences From the *AEO2001* Reference Case

The reference case for this study was established to provide a baseline scenario representing the nominal forecast for petroleum refining and marketing without the new requirement for ultra-low-sulfur diesel fuel (ULSD). The reference case reflects the mid-term reference case forecast published by the Energy Information Administration (EIA) in its *Annual Energy Outlook 2001* (*AEO2001*).[160] Both the reference case for this study and the *AEO2001* reference case were prepared using EIA's National Energy Modeling System (NEMS).[161] Both cases reflect the "Tier 2" Motor Vehicle Emission Standards and Gasoline Sulfur Control Requirements finalized by the U.S. Environmental Protection Agency (EPA) in February 2000. Both cases also incorporate bans or reductions for the gasoline additive methyl tertiary butyl ether (MTBE) in the States where such legislation has been passed. They do not include a waiver of the Federal oxygen requirement for reformulated gasoline.

Updates in databases and assumptions that were incorporated into NEMS after the publication of *AEO2001*, however, resulted in minor differences in the reference case forecasts. Differences between the two forecasts relevant to the ULSD study are discussed in this appendix.

Return on Investment

The *AEO2001* forecast assumed a 15-percent hurdle rate in the decision to invest and a 15-percent return on investment (ROI) over the 15-year life of a refinery processing unit. To be consistent with the EPA analysis, the reference case for this study used a 10-percent hurdle rate and a 5.2-percent ROI over a 15-year financial lifespan. The revised rates do not have a significant impact on the marginal costs for producing current 500 ppm highway diesel fuel in the reference case forecast.

Diesel Fuel Consumption

The *AEO2001* reference case assumed that 85 percent of the demand for diesel fuel in the transportation sector was for highway use. More recently, however, EIA has determined that refinery production of highway diesel approximates the total demand for diesel fuel in the transportation sector. Therefore, the reference case for this study assumes that the production of 500 ppm highway diesel fuel is equal to the total demand in the transportation sector.

Two major factors account for the revised assumption. First, some of the highway diesel produced at refineries is downgraded in the distribution system. The EPA estimates that currently about 2.2 percent of highway diesel is downgraded. Second, some highway-grade diesel has been used for non-road or other uses, because the price differential between low-sulfur and high-sulfur diesel has not been large enough to make separate distribution infrastructures economical. As a result, it has been noted that some customers purchase low-sulfur diesel for non-road uses. In California, the State requires the same low sulfur standard for both highway and non-road diesel (except for railroad and maritime uses).

Import Supply Curves

The NEMS Petroleum Market Module (PMM) uses import supply curves developed from an international refinery model external to NEMS to represent the supply of available imports. In preparation for this study, new sets of crude and product import supply curves were estimated, adding supply curves for ULSD. The new import curves were used in the reference case for this study, but ULSD imports were not allowed.

Refining Technology Database

The PMM represents petroleum refining and marketing. The refining portion is a linear programming representation incorporating a detailed refining technology database that includes process options, product blending to specification, and investment costs. This database is updated annually to produce the *AEO* forecasts. There have been some minor changes since *AEO2001*, mostly associated with product blending. Although four new distillate desulfurization units were added as part of the refining technology database update, those four units were not allowed in the reference case. Therefore, the updates had minimal impact on the reference case for this study as compared with the *AEO2001* reference case.

NEMS Operation Mode

For the *AEO2001* reference case, all modules of the NEMS were executed to solve for supply and demand balance in the U.S. domestic energy market through 2020. For this study only the relevant modules were executed, including the International Energy Module, Transportation Demand Module, Industrial Demand Module, and the Petroleum Market Module. This mode of NEMS operation greatly reduced the model run time without significantly affecting the results.

[160] Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), web site www.eia.doe.gov/oiaf/aeo/. See also web sites www.eia.doe.gov/oiaf/assumption/pdf/0554(2001).pdf and www.eia.doe.gov/oiaf/supplement/index.html.

[161] Model documentation reports for NEMS and its modules as well as a summary report, *NEMS: An Overview*, are available at web site www.eia.doe.gov/bookshelf/docs.html.

Appendix C

Pipeline Regions and Operations

Appendix C

Pipeline Regions and Operations

U.S. Regions for Distribution of Petroleum and Their Key Pipelines

The supply and demand characteristics for refined petroleum products across the United States vary across regions (Petroleum Administration for Defense Districts, or PADDs). The reasons are historical, demographic, geological, and topographical.

The *East Coast* (PADD I), the most heavily populated PADD, has the highest petroleum consumption. It has virtually no indigenous crude oil production and only limited refining capacity. The Northeast is unique in its dependence on heating oil: 70 percent of all single-family homes in the Northeast are heated with oil. Hence, the Northeast has the largest market for the transportation of high-sulfur distillate, as opposed to low-sulfur diesel oil. The region covers its deficit in refined product supply with shipments from the Gulf Coast by pipeline and with imports of refined products by tanker. Colonial Pipeline (Gulf Coast to the New York area) and Plantation Pipe Line (Gulf Coast to the Washington, DC, area) are trunk lines that transport a wide product slate to the area, including distillate fuel oils. Delivering lines, such as Buckeye Pipe Line Company, distribute products within the New York Harbor and from the New York Harbor area to Pennsylvania and upstate New York. Buckeye also serves Connecticut and Massachusetts from an origin in New Haven. ExxonMobil and Sun also operate delivering product pipelines in the region.

The *Midwest* (PADD II) is less heavily populated than PADD I and has a greater balance of supply and demand for both crude oil and refined products. It receives pipeline supplies of distillate fuel oil from both the Gulf Coast and the East Coast. The main trunk carriers of refined petroleum products in the Midwest are TE Product Pipeline and Explorer Pipeline. The role of delivering carriers in the Midwest is a key to product distribution. The region's refining hubs depend on pipelines to deliver their output. As logistics hubs, as well as refining hubs, areas such as Chicago ship product output from refineries and also re-ship product received from refineries on the Gulf Coast or in Oklahoma. Pipelines serving the Chicago hub include Williams, Equilon, and Phillips (in addition to Explorer and TE Products), Citgo, Marathon Ashland, Buckeye, and Wolverine. Other refining centers or single refineries also depend on pipeline transport of their products. Kaneb and Conoco are two of the pipelines serving the western part of PADD II, the plains States, where distances are long and consumption volumes low.

The *Gulf Coast* (PADD III) is the Nation's main oil supply region. It is the largest refining area, with facility design and sophistication unrivaled in the world. It is a major crude oil producing area, with output greater than all but two members of the Organization of Petroleum Exporting Countries. It also has a low regional demand for finished petroleum products. Thus, its shipments of products to other regions are a central facet of supply east of the Rocky Mountains. The Gulf Coast is the origin of trunk carriers such as Explorer, TEPPCO (to the Midwest), Colonial, and Plantation (to the Southeast and East Coast). These pipelines also deliver to points within PADD III.

The *Rocky Mountain States* (PADD IV) are thinly populated, with a low volume of oil shipped across long transport distances. Its consumption of diesel fuel for transportation on a per capita basis is about 60 percent greater than the average in the lower 48 States, but its consumption per square mile is less than 30 percent of the lower 48 average. The region's highway consumption of diesel—a proxy for the low-sulfur diesel required—is about 60 percent of its total distillate market, but low-sulfur diesel accounts for more than 80 percent of the total distillate supplied in the region. The market is so thin that many companies have opted to market (and hence require transport and storage for) only low-sulfur diesel fuel instead of both low- and high-sulfur fuel. The pipelines serving the region distribute products from refineries in the Denver area and from refineries in Billings, MT; and Casper, WY, as well as product received from terminals in PADD II. Pipelines such as Yellowstone and Cenex distribute across the Northern Tier States. Chevron moves products out of Salt Lake City through Idaho and to western Washington, and a variety of pipelines go into and out of the Denver area (Phillips from PADD III; Chase from PADD II; and Conoco, WYCO, Sinclair, and others within the Rockies).

The *West Coast* (PADD V) is a singular oil market, separated from the rest of the country. From the earliest days, the Rockies prevented the easy transfer of oil in and out of the region. More recently, California's adoption of uniquely stringent oil product specifications has exacerbated the region's supply isolation. The region is populous as a whole because California is populous; consumption is high, but not on a per capita basis. In California, the Kinder Morgan pipeline system (formerly Santa Fe Pacific Pipeline) is the most important. It redistributes product from area refineries and, in southern California, receives product from its system in Arizona. The system in Arizona, in turn, connects with

PADD III and receives supplies from El Paso, TX. The Calnev Pipeline connects southern California with Las Vegas, NV. There are also pipelines transporting product in western Washington and Oregon from refineries in the northwest corner of Washington (Kinder Morgan and Olympic). As noted previously, Chevron supplies the eastern part of those States via pipeline from Salt Lake City, and Yellowstone delivers across Montana and Idaho into eastern Washington as well.

The East Coast is the only region where all pipelines consistently carry both diesel fuel (currently 500 ppm) and high-sulfur distillate fuel oil (heating oil). In other regions, some demand for non-road fuel is met by 500 ppm product. This is important to the demands of a phase-in.

Key Pipeline Operations

Oil pipelines operate under a range of corporate structures and face a range of operational and financial challenges. Some are independent and face capital markets on their own. Others are subsidiaries of integrated oil companies. Oil pipelines also serve their markets in different ways, and their divergent operations patterns dictate that the impact of the rule will vary across pipelines and thus across regions. The options for minimizing contamination may be different for a trunk line than for a delivering pipeline carrier, or for a pipeline in batch service versus one in fungible service. In addition, the opportunities for offsetting a supply interruption caused by a quality problem are fewer for the delivering carrier in batch service. The sequencing of product flow is central to maintaining product integrity and, possibly, reducing system flexibility by requiring changes in batch sizes or product scheduling.

Trunk Line and Delivering Pipeline Carriers

Refined petroleum products pipelines in the United States fall into two fundamental service categories. Trunk lines serve high-volume, long-haul transportation requirements; delivering pipelines transport smaller volumes over shorter distances to final market areas. Trunk pipelines provide transportation between major source points, such as the Gulf Coast, and major consumption locations, such as the East Coast. An example of a trunk pipeline is Colonial Pipeline Company, which operates from Houston to New York City. Delivering pipelines provide transportation from source points to multiple, but relatively nearby, market areas. An example of a delivering pipeline is Buckeye Pipe Line Company, which operates in the middle Atlantic and upper Midwest regions of the country from various source points, such as New York and Chicago, to markets such as Pittsburgh and Detroit. While the average haul length on Colonial Pipeline is over 1,000 miles, the average haul length on Buckeye is 125 miles.

Both trunk line and delivering pipeline carriers are necessary for meeting the Nation's demand for refined petroleum products, and each type of pipeline carrier is economically sound in performing its type of service. Many pipeline companies provide both types of service. It is clear, however, that trunk and delivering pipeline carriers encounter different operating environments and different economics. Trunk lines tend to have lower costs and revenues per barrel mile than delivering carriers. Trunk line carriers also tend to be more capital intensive than delivering carriers. Costs and revenues per unit of throughput are higher for delivering carriers than for trunk lines, and delivering carriers tend to be more labor intensive than trunk carriers. Delivering carriers also tend to operate physically smaller pipelines and to use more and smaller storage tanks than do trunk carriers.

The fundamental difference between trunk line and delivering pipeline carriers is scale. For pipelines closer to ultimate demand locations, the magnitude of operations tends to be smaller and the number of operating tasks performed tends to be larger. The trunk carriers that serve as the central arteries have flexibility to redirect product, for instance. As the system reaches its furthest capillaries, the inflexibilities imposed by the smaller scale become more apparent. The chances for "operating lockouts" increase. A lockout might occur if a terminal does not have room to accept a scheduled shipment and there are no other terminals at hand to accept the product. The pipeline is thus stalled until the product can be delivered.

Batch and Fungible Pipeline Service

Petroleum products pipelines also differ by whether they operate on a batch or fungible basis. In batch operations, a specific volume of refined petroleum products is accepted for shipment. The identity of the material shipped is maintained throughout the transportation process, and the same material that was accepted for shipment at the origin is delivered at the destination. In fungible operations, the carrier does not deliver the same batch of material that is presented at the origin location for shipment. Rather, the pipeline carrier delivers material that has the same product specifications but is not the original material.

A pipeline carrier operates in a batch or fungible mode based on its circumstances. Unless there is a more compelling reason, a pipeline operator's selection of its mode of service is based on maximizing operating and economic efficiency. In general, fungible product operation is the more efficient mode of operation. Fungible operation tends to minimize the generation of interface material (see below). Another efficiency of fungible operation is that it permits split-stream operations. In a split-stream operation, material originating at Point A and destined for Points B and C can be delivered at both distant points simultaneously; part of the stream can continue on to Point C while delivery is still underway at Point B. In a batch mode, a delivery operation to Point B means that all pipeline movements beyond Point B cease while the delivery to Point B is completed.

Fungible operations also support more efficient utilization of storage tanks. In fungible operations, large storage tanks are used to accumulate or deliver multiple consignments of identical refined products. In batch operations, only one consignment of material is typically held in each tank. Accordingly, storage tanks used in batch pipeline operations tend to be smaller (and, possibly, more numerous) and are not utilized as intensively as storage tanks used in fungible service.

Among the pipeline characteristics that determine whether a refined petroleum products pipeline operates in a batch or fungible mode, customer requirements for segregation are an important factor. (Many pipelines operating on a fungible product basis can make provision to accept a distinct batch from a shipper. In doing so the carrier might impose a higher minimum volume requirement or charge a higher tariff rate to cover the higher operating cost of providing the special service.) Nonetheless, many pipelines or pipeline segments serve areas where the structure of the market does not support the "one size fits all" character of fungible service.

Another important factor in determining a pipeline's type of service offering is the possible availability of multiple pipelines in the same service corridor. If existing practice and customer service arrangements initially mandate batch pipeline service, it is difficult for a refined petroleum products pipeline carrier to change to fungible service subsequently. On the other hand, if a pipeline carrier serves a transportation corridor using multiple pipelines, it has more flexibility to adopt fungible service.

Thus, while an oil pipeline is likely to prefer fungible service, batch service is often the only feasible choice. Like the difference between trunk and delivering carriers, the difference between fungible and batch service is one of scale for many operating parameters. An oil pipeline in batch service has considerably less flexibility to offset operating "hiccups" (such as product contamination at a shipper's terminal tank) than does an oil pipeline operating in fungible service.

Sequencing Product Flow

Refined products pipelines carry more than 60 percent of all petroleum products transported in the United States.[162] Products pipelines are routinely capable of transporting various types of products or grades of the same petroleum products in the same pipeline. For example, it is common for a single refined products pipeline to transport various grades of motor gasoline, diesel fuel, and aircraft turbine fuel in the same physical pipeline. (For the most part, oil pipelines do not transport both crude oil and refined petroleum products in the same pipeline.)

To carry multiple products or grades in the same pipeline, different petroleum products or grades are held in separate storage facilities at the origin of a pipeline and are delivered into separate storage facilities at the destination. The different types or grades of petroleum products are transported sequentially through the pipeline. While traversing the pipeline, a given refined product occupies the pipeline as a single batch of material. At the end of a given batch, another batch of material, a different petroleum product, follows. A 25,000-barrel batch of products occupies nearly 50 miles of a 10-inch-diameter pipeline.

Generally, product batches are butted directly against each other, without any means or devices to separate them. At the interface of two batches in a pipeline, some, but relatively little, mixing occurs. The actual volume of mixed material generated depends on a number of physical parameters, including pipeline diameter, distance, topography, and type of material. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material to be generated in a 10-inch pipeline over a shipment distance of 100 miles. The hydraulic flow in a pipeline is also a crucial determinant of the amount of mixing that occurs. "Turbulent flow," as occurs in most pipelines, minimizes the generation of interface, while operations that require the flow to stop and start will generate the most interface material.

Monthly Batch Scheduling

As a part of their strategy to minimize the generation of interface material, pipeline operators sequence batches on the basis of the total number of products routinely shipped and the number and capacity of storage tanks available at the origin, destination, and intermediate breakout locations. Most often, pipeline operators use a recurring monthly schedule of "cycles," shipping all the available petroleum products of the same type in sequence. For example, only gasoline grades would be shipped during the days that constitute the gasoline cycle, and only distillates would be shipped during the days that constitute the distillate cycle. The actual duration of the cycles might vary from 6 to 10 days, depending on the volume of each material to be shipped during a particular month. Operators accommodate increased seasonal demand and stock builds, for instance, by adjusting the cycle schedule. The schedule is published

[162] Based on ton-miles. See Association of Oil Pipe Lines, *Shifts in Petroleum Transportation—1999* (2001).

far in advance, however, leaving little opportunity for last-minute flexibility.

Batch sizes are determined by the availability of storage tankage (not only to pipeline operator directly, but also to originating shippers and receiving terminal operators), the batch sizes consigned by shippers, shippers' time requirements, and whether the pipeline is operated on a batch or fungible basis.

Interfaces and Transmix

The composition of the mixed (or interface) material reflects the two materials from which it is derived. While it does not conform to any standard petroleum product specification or composition, it is not lost or wasted. For interface material resulting from adjacent batches of different grades of the same product, such as mid-grade and regular gasoline, the mixture is typically blended into the lower grade. This "downgrading" reduces the volume of the higher quality product and increases the volume of the lower quality product.

The interface between two different products—gasoline and a distillate, for instance—produces a hybrid called "transmix." Transmix cannot be blended back into either of its components, as gasoline's flash point will contaminate the distillate, and distillate's higher boiling point will contaminate the gasoline. Transmix, therefore, is segregated and then reprocessed in a full-scale refinery or a purpose-built facility. When it has been separated again into its component products (gasoline and distillate, for instance), the distinct products are reintroduced into the appropriate segregated transportation and storage system. (If an operator utilizes two physical pipelines in the same corridor, it may minimize the generation of transmix by carrying only gasoline in one line and only distillates in the other. The problem of downgrade within a family of products, however, still exists.)

As shown in Figure C1, a refined products pipeline typically "wraps" the current highway diesel (at 500 ppm) with kerosene and/or jet fuel (2,000 ppm or so), and non-road diesel (up to 5,000 ppm). The chance that the 500 ppm material will be forced off-specification by sulfur contamination is low. The product tendered is around 300 ppm, leaving leeway for any minor contamination from the neighboring product.

Typically, refined oil products are transported from a source location, such as a refinery or bulk terminal, to a distribution terminal near a market area. Large aboveground storage tanks at an origin location accumulate and hold a given petroleum product pending its entry into the pipeline for transport. Petroleum products are also stored temporarily in aboveground storage tanks at destination terminals.

Storage tanks usually are dedicated to holding a single petroleum product or grade. Most storage tanks used in pipeline operation are filled and drained up to four or more times per month. Operators usually are able to place the same type of petroleum fuel in a given tank on each drain and fill cycle, and the tank is not purged and cleaned between the routine drain and fill cycles. When a tank is filled and drained with a given material, small to substantial quantities of the former material remain in the tank. To the extent that the previous material was different from new material being placed in the tank, contamination can occur. Generally, such contamination is inconsequential because the new material is substantially the same as the old material or its volume is small.

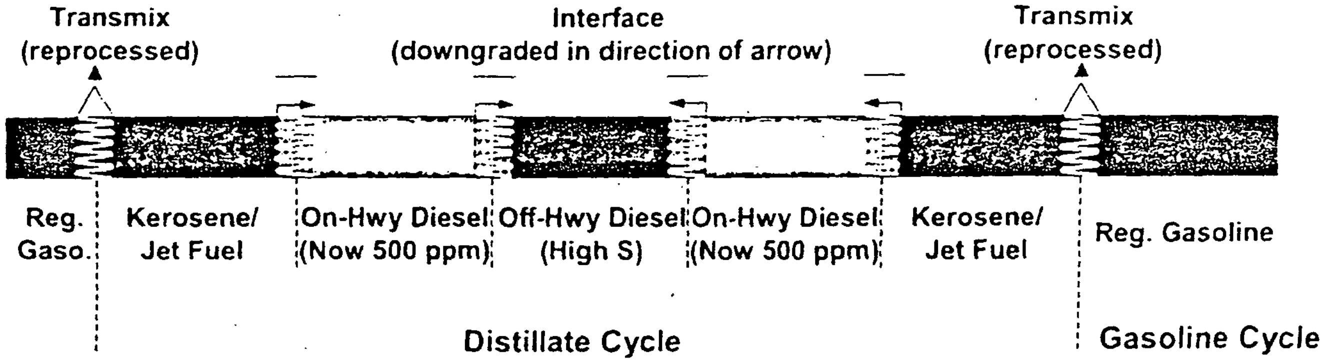
> **Making the Cut: The Mechanics of the Interface**
>
> Each petroleum product—in fact, each batch of products—has a distinct and identifiable specific gravity. Different products have widely different specific gravities. Different grades or batches of the same product have slight but measurable differences in specific gravity.
>
> Pipeline operators monitor the specific gravity of a pipeline stream as it approaches a station or terminal. A change from one specific gravity to another indicates the end of the leading batch and the beginning of the following batch. Based on this signal of the interface location, the pipeline operator "swings" batches from one pipeline to another or from mainline transit into segregated tanks. The shift in specific gravity may be too gross an indicator, however, when dealing with ULSD. By the time the shift in specific gravity is discernible, the ULSD may have been contaminated by the sulfur in its neighboring product.

In addition to tanks at the origin and destination terminals, "working" or "breakout" tanks are used in the normal course of pipeline operation. Over a pipeline route, there may be various needs to interrupt the flow of pipeline material in transit, including branching of the pipeline, change in size or capacity, mainline pumping operations, change from fungible to batch operation, and others. In each case, breakout tanks provide the flexibility to temporarily stop or buffer different flow rates of pipeline segments.

The maintenance of material in continuous pipeline transit without need for diversion into breakout tankage is known as "tightlining." A pipeline operator's ability to tightline material will prove to be a slight advantage in protecting the integrity of ULSD. Overall, however, tightlining is not an easy option to engage if facilities and operating requirements do not already permit it.

In addition to the minor creation of interface material that occurs in pipeline transit, creation of interface material also occurs in the local piping facilities (station piping) that direct petroleum products from and to respective origin and destination storage tanks and in

Figure C1. Typical Product Sequence and Interfaces in a Refined Products Pipeline



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

the tanks themselves. Essentially, station piping represents the connection between a main pipeline segment and its requisite operating tanks. The concept is simple in theory, but in practice the configuration of station piping is not. Station piping layouts become more complex as the tanks at a pipeline terminal facility become more numerous.

Configurations of station piping necessary to accommodate a given number of tanks and to provide flexibility in routing multiple products in and out of those tanks provide many possibilities for the creation of pipeline interface material. Each pipeline facility is different, not only among pipeline companies but within pipeline companies. There is no way to predict how easy or hard it will be to minimize possible sulfur contamination of ULSD in station piping, except to examine the risks on a case-by-case basis.

In fact, the interface generation in station piping and breakout tanks may be even more important than during pipeline transit. The volume of interface material thus generated is due to the physical attributes of the system. It has fewer variables but approaches being a fixed value on a barrel-per-batch, not a percentage, basis. For instance, one pipeline operator may create 25,000 barrels of high-sulfur/low-sulfur distillate interface per batch whether the batch is 250,000 barrels or 1,000,000 barrels. In addition, a given batch of product might be transported in multiple pipelines between its origin and its final destination and even within the same system might require a stop in breakout tanks, as noted above. Each segment of the journey generates additional interface.

Appendix D

Short-Term Analysis of Refinery Costs and Supply

Appendix D

Short-Term Analysis of Refinery Costs and Supply

As a result of the new regulations issued by the U.S. Environmental Protection Agency (EPA) for ultra-low-sulfur diesel fuel (ULSD) the U.S. refining industry faces two major challenges: to meet the more stringent specifications for diesel product, and to keep up with demand by producing more diesel product from feedstocks of lower quality. Some refineries in the United States and Europe currently have the capability to produce some diesel product containing less than 10 ppm sulfur, and there is no question that diesel fuel with less than 10 ppm sulfur can be produced with current technology.

U.S. refiners have demonstrated that meeting the EPA target specification of 500 ppm sulfur (1993 reduction from 5,000 ppm to 500 ppm) was easier than anticipated. The primary methods used were upgrading existing hydrotreater units by adding extra reactor volume and building new units. In contrast, the proposed change from 500 to 15 ppm represents a new and far more challenging task for the industry, because the remaining sulfur (less than 500 ppm) is likely to be contained in compounds that are difficult to desulfurize, such as 4,6-dimethyldibenzothiophene (often described as sterically hindered sulfurcontaining molecules). Furthermore, to meet growing demand for diesel fuel, some refineries will have to increase capacity, which may involve treating lower quality feedstocks (cracked distillates) that require more severe and costly process conditions.

The implications of producing ULSD are complex, not only from a unit-specific standpoint but also from a refinery standpoint. Each refinery has unique circumstances, such as existing hydrodesulfurization units, source of crude, diesel blend components, and hydrogen availability. Producing ULSD is a significant decision for most refiners, and the incremental cost per barrel could vary dramatically across the range of individual refiners. In addition, it is uncertain whether further restrictions on diesel quality will be imposed in the future. Some refiners may decide to discontinue producing highway diesel and produce only non-road diesel and heating oil as distillate products. Such decisions, coupled with increasing demand for diesel fuel, could heighten the potential for a diesel shortage in 2006.

This appendix provides details of the methods used to estimate the short-term cost per gallon to manufacture ULSD meeting the EPA sulfur specifications for 2006 and examines the variations in cost for different U.S. refineries. The analysis results in a cost curve indicative of the cost that may be incurred by U.S. refiners to produce the new fuel at various supply levels.

Estimating Components of the Distillate Blend Pool

The initial step of the analysis was to analyze the potential economics of producing ULSD for each refinery. Using input and output data submitted to the Energy Information Administration (EIA) by refiners, the current components of the distillate blend pool were estimated and allocated to the current production of highway diesel, non-road diesel, and heating oil. Volumes and sulfur content of straight-run distillate, fluid catalytic cracker (FCC) light cycle oil (LCO), coker distillate, and hydrocracker distillate were estimated on the basis of the gravity and sulfur content of crude feeds, input volumes to the FCC, coker, and hydrocracker units, and the fraction of the FCC feed that is hydrotreated.

The estimates for volumes of full-range straight-run distillate, LCO from the FCC, and coker distillate were adjusted according to reported refinery data. Because kerosene and jet fuel are made from the straight-run distillate and hydrocracked material, those distillate pool components were reduced accordingly. If a hydrocracker was available at a refinery, volumes of LCO and coker distillate were allocated to the hydrocracker by comparing available distillate boiling range components to distillate product volumes. A final adjustment was made, based on the relative production of gasoline and distillate products.

The initial estimate of straight-run distillate volume for a given refinery was based on a typical cut point range for a crude oil with the gravity of the crude oil charged to that refinery. If the available distillate pool volumes exceeded the distillate product produced, the volume of the straight-run distillate component was reduced, based on the typical variation in distillation cut points. (The light end of the kerosene boiling range material may be included in the reformer feed for gasoline production, and the heavy end (high end) of the boiling range may be included in the FCC feedstock. Either or both of these adjustments will reduce the straight-run distillate volume.) The adjustments resulted in estimated distillate pool volumes approximately equal to the reported volumes of distillate production. The distillate pool components were then allocated to the production of highway diesel, non-road diesel, and heating oil.

Allocating Blend Pool Components to Distillate Products

Specifications for the various diesel and heating oil products determine how refiners allocate the distillate component to the products. In 1997, the American Petroleum Institute (API) and National Petrochemical and Refining Association published a survey of blend patterns used by U.S. refiners in 1996 for gasoline and distillate products.[163] The compositions of the distillate products for Petroleum Administration for Defense Districts (PADDs) I-IV reported in the API/NPRA survey for 1996 are summarized in Table D1.

According to the API/NPRA survey, the fraction of cracked stocks (LCO and coker distillate) is about one-third of the total for both highway and non-road diesel fuels. PADD II has the highest percentage of cracked stock components: 34.7 percent for highway diesel and 27.3 percent for non-road diesel. Only PADDs I and III have significant production of heating oil, and the cracked stock content is 44.7 percent in PADD I and 40.9 percent in PADD III. While highway diesel has a lower sulfur limit than non-road diesel, both have the same minimum cetane number requirement of 40, which limits the fraction of cracked stock that can be included in either product. Cracked stocks are poor-quality diesel blend components, because of their high aromatics content and low cetane numbers (Table D2).

A refiner cannot consider options for producing ULSD without considering the impact on other diesel and heating oil products. Thus, while cracked stocks have a combination of high aromatics and higher sulfur that make them difficult materials to convert to ULSD, for most refiners it is not possible to shift more of these cracked stocks to non-road diesel because of the non-road cetane requirement. A few refiners in PADDs I and III could potentially allocate more cracked stocks to heating oil, but as the relative volumes in Table D1 indicate, this would help only a small number of refiners.

The EPA analysis of the feasibility of producing ULSD[164] discussed the difficulty of desulfurizing cracked stocks compared to straight-run distillate to meet ULSD standards. Commentary indicated that, if hydrocracking capacity were available, some cracked stock could be sent to the hydrocracker. In estimating the distillate pool components as described above, the volume balances indicated that in many refineries with hydrocrackers, the LCO was likely being consumed as hydrocracker feed. The EPA also suggested that, because non-road diesel fuel has an average cetane number of 44.4, more cracked stock could be allocated to non-road diesel and still achieve the 40 minimum standard.

In analyzing each specific refinery, EIA found that refineries fall into three groups with respect to cracked stocks. One group has a relatively small fraction of cracked stocks (such as those with hydrocrackers) and hence produces highway and non-road diesel fuels with relatively high cetane. For a second group, cetane constraints offer little chance for allocating more cracked stocks to non-road diesel. The third group, using heavy crude oil feeds to produce large volumes of cracked stocks from FCC units and cokers, must treat distillate

Table D1. API/NPRA Survey of Distillate Product Compositions, 1996

Region	Product	Product Components (Percent by Volume)				Total Volume (Million Barrels)
		Straight-Run Distillate	Cracked Light Cycle Oil	Cracked Coker Distillate	Hydrocracked Distillate	
PADD I	Highway Diesel	67.7	16.5	0.0	15.8	12.1
	Heating Oil	54.2	44.7	0.0	1.1	10.4
PADD II	Highway Diesel	62.7	28.8	5.9	2.6	59.9
	Heating Oil	66.9	11.6	21.5	0.0	2.1
	Non-Road Diesel	72.7	27.3	0.0	0.0	19.2
PADD III	Highway Diesel	66.0	18.8	10.7	4.5	104.5
	Heating Oil	57.8	29.6	11.3	1.3	6.5
	Non-Road Diesel	56.9	12.8	3.2	27.1	28.9
PADD IV	Highway Diesel	71.0	22.6	4.2	2.2	11.0
	Non-Road Diesel	80.9	19.1	0.0	0.0	2.1

Note: The survey included reports from 9 PADD I refineries, 25 PADD II refineries, 42 PADD III refineries, and 12 PADD IV refineries and accounted for 80 percent of the volume that EIA reported was produced in that period.

Source: *Final Report: 1996 American Petroleum Institute/National Petrochemical and Refining Association Survey of Refining Operations and Product Quality* (July 1997).

[163] *Final Report: 1996 American Petroleum Institute/National Petrochemical and Refining Association Survey of Refining Operations and Product Quality* (July 1997).

[164] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, web site www.epa.gov/otaq/regs/hd2007/frm/ria-iv.pdf.

components to reduce aromatics and improve cetane in order to produce acceptable products.

In the longer term, increased movement of cracked distillates between refineries could occur, with more undercutting of cracked stock to remove the high-aromatic, high-sulfur material at the high end of the boiling range. Such industry optimization avenues would take time to establish, however, because they are based on component price differentials that may grow over time to provide incentives for such activities. During the transition period starting in 2006, based on past experience, it is assumed that most refiners would base their strategies on analyses of specific refinery situations. Possible exceptions are multiple refineries within a single company system having logistical connections that permit practical and economical movement of refinery streams.

Identifying Refinery Options for Producing ULSD

The objective of this step of the analysis was to generate estimates of the incremental cost for each refinery to produce ULSD. The incremental cost will vary for each refinery, depending on the volume of ULSD produced; the type of blend components from which it is produced; the sulfur, aromatics, and boiling range content of those blend components; whether the refinery can revamp an existing hydrotreater or must build a new one; and the cost for catalyst, hydrogen, and other requirements to produce the ULSD. Moreover, each refinery must decide how much ULSD it will produce in 2006. Because the volume of ULSD produced will affect the incremental cost of production, the incremental cost of ULSD production for each refinery was first estimated at current production levels, assuming both the revamp of a current hydrotreating unit and the addition of a new unit. Then, additional options for reducing or expanding the refinery's ULSD production were estimated.

Several factors may cause a refiner to maintain, contract, or expand highway diesel production when the ULSD regulation takes effect in 2006. Maintaining current production of highway diesel has the appeal of keeping the refinery production in balance with current distillate markets sales for the company. Either increasing or decreasing the highway diesel production will mean finding markets for more highway diesel, more heating oil, or more non-road diesel products. Reducing ULSD production may result in a lower per barrel incremental cost for ULSD production.

ULSD production requires added hydrogen usage in the distillate hydrotreater, thereby increasing hydrogen consumption per unit of distillate feed. Some refiners may choose to reduce feed input in order to continue to operate within existing hydrogen supply constraints and avoid building new hydrogen production capacity. Reducing hydrotreater throughput may also enhance the practicality of revamping a current hydrotreater to avoid building a new unit. The 1996 API/NPRA survey showed that at the 500 ppm sulfur limit level, about 15 percent of untreated material was placed in highway diesel in PADDs I-IV. Producing ULSD will require that all the diesel product must be hydrotreated. This means that some refiners who seek to revamp will be working with a unit that has less capacity than indicated by current highway production. Some additional capacity may be made available by increasing the utilization rates of existing units that are currently operating at lower utilization rates.

If a refiner has to build a new hydrotreater, expansion of highway diesel production is an obvious consideration.

Table D2. Cetane Number of Light Cycle Oil From Some World Crude Oils

Crude Oil	Source	Gravity (Degrees API)	Sulfur Content (Percent by Weight)	Cetane Number: Straight-Run Diesel	Cetane Number: Light Cycle Oil at 60 Percent Conversion	Cetane Number: Light Cycle Oil at 80 Percent Conversion
[illegible]	Abu Dhabi	39	[illegible]	58	[illegible]	[illegible]
[illegible]	Saudi Arabia	34	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Nigeria	[illegible]	0.2	[illegible]	[illegible]	[illegible]
Forties	North Sea	37	0.3	52	[illegible]	[illegible]
Maya	Mexico	22	3.3	47	[illegible]	[illegible]
Boscan	Venezuela	10	5.5	[illegible]	[illegible]	[illegible]
North Slope	Alaska	27	1.0	45	[illegible]	[illegible]
[illegible]	Louisiana	39	[illegible]	[illegible]	[illegible]	[illegible]
West Texas Sour	Texas	32	[illegible]	[illegible]	[illegible]	[illegible]

Note: [illegible] vacuum gas oil was cracked at 60 percent or 80 percent [illegible] database.

Source: [illegible]

Expansion can provide economies of scale for a new unit and may mean lower costs per unit; however, if new hydrogen production capacity is required, the cost per unit may be higher. There is also the risk of having to find additional markets for the added highway diesel production.

The EPA analysis[165] and a study by Charles River Associates, Inc., and Baker and O'Brien, Inc. (CRA/BOB)[166] have attempted to determine which refineries could be revamped; however, it is highly uncertain which refineries have hydrotreaters that could be revamped and maintain current production volumes. The present study also makes such an estimate, using a rationale similar to that used in the CRA/BOB analysis. The process construction literature for the past decade was reviewed for distillate hydrotreater projects, and it was assumed that revamps would be more likely for refineries that carried out major distillate projects in the 1990s, especially those that installed new units. It was also assumed that revamps would be practical for refineries using a small percentage of cracked stock to produce ULSD. In addition, it was assumed that new units would be built at refineries with current hydrotreater capacity less than their highway diesel production (although revamps would also be feasible at reduced production levels).

Estimating Costs for Individual Refineries

A semi-empirical model was developed to size and cost new and revamped distillate hydrotreating plants for production of ULSD. Sulfur removal was predicted using a kinetic model tuned to match the limited literature data available on deep distillate desulfurization. Correlations were used in the model to relate hydrogen consumption, utility usage, etc., to the three major constituents of the distillate pool: straight-run distillate, light cycle oil, and coker gas oil.

Model Assumptions

New ULSD Unit

- Sulfur removal from the existing refinery distillate pool, utilizing a dual-reactor hydrodesulfurization unit with interstage H_2S removal.
- Hydrogen consumption includes hydrogen required to desulfurize the distillate pool to 7 ppm and to saturate aromatics and olefins in the distillate.
- Cost estimates include capital for a new hydrotreating plant, sulfur plant, and expansion of utilities. Depending on the feedstock, the model decides whether or not to construct a new hydrogen plant.
- Operating costs include utilities, maintenance, catalyst and chemicals makeup and natural gas used for hydrogen generation. A small credit is taken for the sale of the sulfur byproduct.

Revamped ULSD Unit

- Sulfur removal from the existing refinery diesel pool, utilizing existing hydrodesulfurization unit with a new second-stage reactor and interstage H_2S removal.
- Incremental hydrogen consumption for revamp based on decreasing the sulfur level from 500 ppm to 7 ppm.
- Cost estimates include capital for new hydrotreating reactor, heater, heat exchanger, H_2S absorber, and expansion of utilities. Existing refinery sulfur and hydrogen plants are assumed to have sufficient excess capacity to handle increased throughputs. Depending on the feedstock, the model decides whether of not to construct a new hydrogen plant.
- Operating costs include incremental utilities, maintenance, catalyst and chemical makeup, and natural gas used for hydrogen generation. No credit is taken for the sale of the additional sulfur byproduct.

Model Description

The ULSD model considers hydrotreating three different types of refinery feeds: straight-run distillate from the atmospheric column, LCO from the FCC, and coker gas oil from the coker. The model is in a spreadsheet format and contains Visual Basic coded functions for some complex calculations. It consists of seven main sections: (1) Economic Factors, (2) Refinery Input Data, (3) Manual Variables, (4) Hydrotreater Kinetics, (5) Hydrotreater Plant, (6) Hydrogen Plant, and (7) Sulfur Plant. The model consists of seven Microsoft Excel® worksheets: a raw data worksheet that contains refinery-specific information used by the other worksheets, five refinery scenario worksheets that contain the detailed step-by-step calculations for the revamp and new unit cost projections, and a summary worksheet.

Model Options

The costs to produce ULSD for five investment options are estimated from the compiled data for each refinery. Costs vary for each refinery, depending on the volume of ULSD produced, the blend components from which it is produced, the sulfur, aromatics, and boiling range of the blend components, whether the refinery can revamp an existing hydrotreater or must build a new one, and the cost of the catalyst, hydrogen, etc. required to

[165]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000).

[166]Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000).

produce ULSD. The volume of ULSD a refiner decides to produce will affect the cost. For each refinery, the cost for ULSD production is estimated at current production levels, both assuming the addition of a new hydrotreating unit and assuming the revamping of an existing hydrotreating unit (options 1 and 2 below). Three additional options are considered (reductions from current highway diesel production assuming new and revamped hydrotreater units and increases from current production assuming new units) to find the most economical production levels for individual refineries.

Option 1 (Baseline New Hydrotreater): This "business-as-usual" option is modeled using the current refinery production capacities for highway and non-road diesel. The model estimates the cost to produce highway and non-road diesel at the proposed sulfur limits (7 ppm and 5,000 ppm, respectively) while maintaining the same hydrotreater throughput. A new hydrotreater plant is estimated.

Option 2 (Baseline Revamped Hydrotreater): This option is identical to Option 1 except that the existing hydrotreater plant is assumed to be revamped. The revamp option considers the cost of installing an additional hydrotreater reactor (not an entire plant) and interstage amine scrubber. The additional reactor is sized to decrease the existing diesel sulfur content from 500 ppm to 7 ppm.

Options 3 and 4 (Reduced ULSD New and Revamp Hydrotreater): These options consider the cost impacts of decreasing highway diesel production and increasing non-road diesel production. Because ULSD production will require more hydrogen consumption (especially for refineries with lower quality feedstocks), reducing ULSD production may permit the refinery to operate within existing hydrogen capacity and avoid the necessity of building a costly new hydrogen plant. Furthermore, reducing hydrotreater throughput may also enhance the practicality of revamping the current hydrotreater and avoiding the need to invest in a new unit.

Option 5: Increased ULSD New Hydrotreater: This option considers expanding highway diesel production while decreasing non-road diesel production; thus increasing throughput to the hydrotreater and creating the need for a new hydrotreater. A particular refiner might consider this option for several reasons: (1) the refinery has a high volume of cracked stocks, and a new hydrotreater plant is needed anyway; (2) a new unit may provide economies of scale and lower per-unit production cost; (3) there may be a perceived opportunity to expand highway diesel production as demand increases and "challenged" refineries discontinue diesel production. A corresponding revamp case was not considered, because it was assumed that current refineries were at maximum production rate with existing equipment, and both new hydrotreater and hydrogen plants would be needed.

Worksheet Environment

Economic Factors: The capital charge factor is assumed to be 12.0 percent (corresponding to a 5.2-percent after-tax rate of return on investment), contingency 20.0 percent, on-site maintenance 4.0 percent, off-site maintenance 2.0 percent, taxes and insurance 1.5 percent (included in the capital charge factor), and miscellaneous 0.6 percent, all as a percentage of capital investment. Sensitivity cases using a 17.2-percent capital charge were also analyzed.

Refinery Input Data: The cost model requires two input data sets for each scenario. The first set of input data is the baseline data, consisting of the current refinery diesel capacities from which all scenarios are developed. The baseline data consist of the API gravity, highway and non-road diesel blend component flow rates, and sulfur content of each stream to the hydrotreater. The second set of input data contains the blend component flow rates for the optional expanded or reduced hydrotreater.

Manual Variables: Some variables are not available in the original refinery-by-refinery specific database and require some engineering judgment and estimation. Whether or not the FCC feed is hydrotreated affects the hydrogen consumption for desulfurizing the LCO stream. Pretreatment of the FCC feed results in products (LCO in this case) with higher API gravities (lower sulfur and aromatic content), which will in turn require less hydrogen to remove the remaining sulfur during hydrotreating. The geographic location factor is utilized in the cost estimates for each refinery process; the location basis used in the model is the U.S. Midwest. The pressure input (in pounds per square inch absolute [psi]) affects both the kinetic and hydrotreater portions of the model. It is assumed that the maximum pressure for the revamp options is 650 psi, and the average length-of-run pressure for the new hydrotreater options is 900 psi. The estimated process temperature has a direct impact on the kinetic performance.

Hydrotreater Kinetics: The kinetic model used in this study has the general form:

$$-dS/dt = kS^{n}P_{H_2}/(1 + K_sS_e).$$

An Arrhenius form is used for the temperature dependence of k. For the Langmuir-Henshelwood factor, it is assumed that sulfur species in the feed and H_2S are equally strongly absorbed on catalyst sites. The constants in the equation were fit using the best available data from the literature. The best fit was obtained with n equal to 1.5. The equation was integrated to give space velocity as a function of feed properties and operating conditions. The value of k used reflects the higher severity required to process cracked feedstocks. When two reactors are used in series with interstage H_2S removal, the intermediate sulfur level is adjusted to give approximately equal space velocities in the two reactors. When utilized for the revamp situations, the intermediate sulfur level (500 ppm) is manually placed in the kinetic model, and only the second space velocity is used for hydrotreater cost estimating.

Hydrotreater Plant: The total on-site capital cost estimate for a new hydrotreater plant (see Chapter 3) consists of three parts: a two-reactor system (in series) with interstage H_2S stripping, hydrogen makeup compressors, and remaining on-site capital equipment. The cost of the reactor system and makeup compressors are a function of the percent of cracked stocks present in the hydrotreater feed pool, whereas the cost of the remaining on-site equipment is a function of capacity. The combined flow rates, space velocities calculated from the kinetic model, and pressure are used to size each reactor, with the restrictions that the reactor length-to-diameter ratio must be greater than or equal to 5, and the diameter must be less than or equal to 15 feet. The cost of each reactor is a function of the wall thickness and reactor weight. Next, the hydrogen makeup compressor costs are calculated based on the hydrogen consumption. The remaining on-site capital for a new plant (inside battery limit [ISBL] equipment) is estimated by using vendor data supplied in a recent NPC study as a basis (30,000 barrels per stream day, $1,200 per barrel per stream day). Figure D1 shows the predicted ISBL costs for each refinery studied, using a basis of $1,200 per barrel per stream day, and a best-fit curve through the data. Differences in capital costs at a given capacity level are the result of variations in the fractions of the different types of feeds (e.g., straight run versus cracked stocks) and the sulfur level of the feed to the hydrotreater.

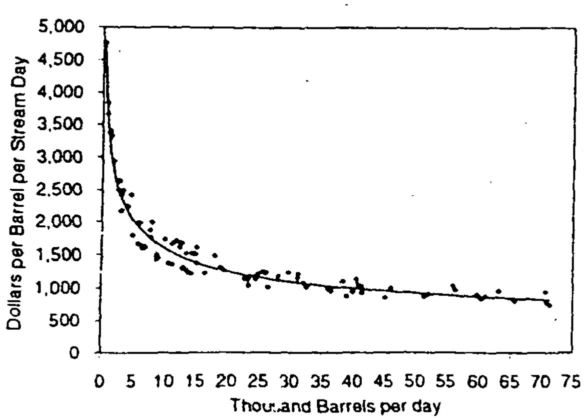
In the view of many refiners with whom discussions were held, an estimate of $1,600 per barrel per stream day is believed to be a more representative ISBL investment cost to produce ULSD. Therefore, the model was rerun using a basis of $1,600 per barrel per stream day for a unit with 30,000 barrels per stream day capacity. Figure D2 shows the relation of vendor-supplied data to the model results for both ISBL baseline costs ($1,200 per barrel per stream day and $1,600 per barrel per stream day).

The revamped hydrotreater on-site capital portion of the model utilizes only the space velocity calculated for the second reactor used to lower the diesel pool sulfur content from 500 ppm (manually specified) to 7 ppm. The revamped hydrotreater capital cost includes only an additional reactor, heater, and separator and assumes that the existing inside battery limit equipment will remain unchanged.

The on-site capital costs for the new and revamped hydrotreater plants include the initial catalyst charge. The off-site capital cost for a new plant is assumed to be 45 percent of the on-site capital cost, and the off-site capital cost for a revamped plant is assumed to be 30 percent of the on-site capital cost.

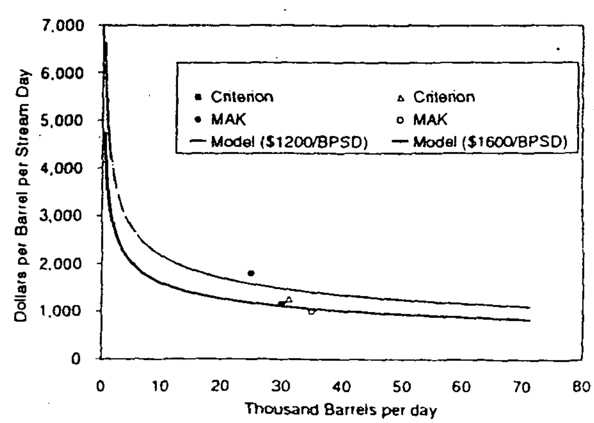
Hydrotreater Catalyst: Catalyst cost (in dollars per barrel) is a function of space velocities and is calculated assuming a 2-year life, with CoMo in the first reactor and NiMo in the second reactor. CoMo is more reactive in removing sulfur from the less challenging sulfur-containing molecules. Below 500 ppm, however, the sulfur present is more likely to be contained in sterically hindered molecules and is more difficult to remove using a CoMo catalyst (Figure D3). In contrast, NiMo has higher activity on more challenging sulfur-containing molecules. Published data have shown that the costs of both catalysts are approximately $10 per pound, including royalty.

Figure D1. Cost Curve for Ultra-Low-Sulfur Diesel ($1,200 Baseline ISBL Costs)



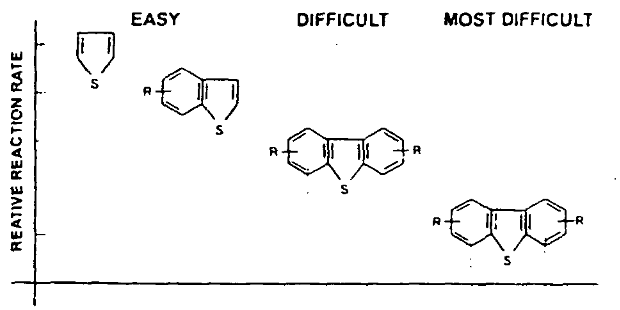
Source: National Energy technology Laboratory.

Figure D2. Cost Curve for Ultra-Low-Sulfur Diesel ($1,200 and $1,600 Baseline ISBL Costs)



Source: National Energy technology Laboratory.

Figure D3. Impact of Sulfur Species on Reaction Rate



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Hydrotreater Utilities: The main utilities for the hydrotreater plant included in the model are power, steam, cooling water, and fuel. All utility requirements were estimated from published correlations or actual data. The revamp option utility requirements are the incremental utilities to remove the remaining sulfur present in the diesel. The incremental additional power was estimated to be 40 percent of the existing power usage due to additional hydrogen consumption and potentially higher system pressure drops.

Hydrotreater Yields and Energy Content: The volume and weight percent yields of ULSD produced by the distillate hydrotreater can vary considerably, depending on the fraction of cracked stocks in the feed and the level of aromatics saturation. An average yield and energy content were estimated for this study, based on the Criterion data in a June 2000 study by the National Petroleum Council.[167] The yield of hydrotreater product in the distillate boiling range was assumed to be 98 percent by weight, and the API gravity was assumed to increase by 2 numbers, which means that the volume yield was 99.2 percent. There was also a small increase in the Btu content of the product on a weight basis (98.2 percent of the feed energy content in 98.0 weight percent of the feed). The energy content declines on a volume basis, because the heat content of the product is 0.989 times the heat content of the feed on a volume basis.

Hydrogen Plant: The same hydrogen consumption and hydrogen plant cost estimation methodologies are used for both the new and revamp cases. The goal of the hydrogen plant portion of the model is to determine the hydrogen consumption and associated costs to reduce the current sulfur level (500 ppm) down to 7 ppm, whether it is a new or revamp situation (see Table 6 in Chapter 6). The incremental H_2 is calculated as the difference between the baseline H_2 consumption (for highway diesel at 500 ppm sulfur and non-road diesel at 5,000 ppm) and the predicted required H_2 consumption (highway diesel at 7 ppm, non-road at 5,000 ppm). If the incremental H_2 consumption value is greater than 25 percent of the baseline H_2 capacity, then the model calculates the H_2 costs based on a new plant.

Simple nonlinear correlations based on the flow rate and sulfur concentration of each cut, including the non-road streams to the hydrotreater, were developed using data compiled from multiple sources. The H_2 consumption correlations are as follows:

Straight-run highway baseline:

$$\text{SCF } H_2 = \text{SR Flowrate} * (((120 * \text{SRSulPercent}) + 40) + 50)$$

Straight-run highway required:

$$\text{SCF } H_2 = \text{SR Flowrate} * (((120 * \text{SRSulPercent}) + 40) + 50 + 50)$$

Straight-run non-road baseline and required:

$$\text{SCF } H_2 = \text{SR NonHighway Flowrate} * ((120 * \text{SRSulPercent}) + 40)$$

LCO highway baseline:

$$\text{SCF } H_2 = \text{LCO Flowrate} * (((150 * \text{LCOSulPercent}) + 40) + 150)$$

LCO and coker distillate highway required:

$$\text{SCF } H_2 = \text{LCO Flowrate}* (((150 * \text{LCOSulPercent}) + 40) + 150 + 650)$$

LCO and coker distillate non-road baseline and required:

$$\text{SCF } H_2 = \text{LCO NonHighway Flowrate} * ((150 * \text{LCOSulPercent}) + 40).$$

After the total baseline, required, and incremental hydrogen capacities are calculated, the model then decides whether to build a new hydrogen plant. If the existing H_2 plants capacity is determined to be sufficient (no build), only the variable cost associated with the required capacity is calculated. If a new H_2 plant is necessary, the on-site capital cost is estimated (scaled) using published data (60 million standard cubic feet per day plant at $50 million). The off-site capital cost is assumed to be 40 percent of the on-site capital cost. The total hydrogen cost per barrel of distillate treated includes the cost of the natural gas feed to the hydrogen plant.

Sulfur Plant: The new sulfur plant estimates are based on the amount of sulfur removed from the diesel pool and are a function of whether the FCC feed was pre-treated, the flow rate and percent sulfur of each stream, and the API gravity of the crude. The estimate

[167] National Petroleum Council, U.S. *Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000)

includes an interstage H_2S absorber for the new unit case. The on-site capital, off-site capital, and fixed and variable operating costs are calculated by scaling off published data. The only difference in the total sulfur cost on a per barrel basis is the credit from the sale of the sulfur at $27.50 per long ton. The revamp case assumes that the existing sulfur plant can handle the additional 500 ppm sulfur removed from the diesel stream. The sulfur section of the revamp worksheet calculates the cost of an additional absorber, which is a function of the overall flow rate to the hydrotreater and the hydrogen recirculation rate. In the sample cases, the sulfur costs ranged from $0.08 to $0.55 per barrel.

9306A

Appendix E

Model Results

Appendix E

Model Results

This appendix provides mid-term projections for end-use prices and total supplies of ultra-low-sulfur diesel fuel (ULSD), based on the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) Petroleum Market Module (PMM). Historical data for 1999 prices and supplies of highway diesel (500 ppm sulfur) are also provided for comparison (Tables E1 and E2).

The projected end-use (pump) prices are lower than the current prevailing prices for highway diesel fuel for several reasons. The end-user prices include crude oil costs, processing costs, taxes, and marketing costs.[168] Therefore, variations in the costs and taxes affect the projected end-user prices. The reference case, the Regulation case, and all sensitivity cases were based on mid-term projections for world crude oil prices used in *Annual Energy Outlook 2001 (AEO2001)*. After the steep increase in world crude oil prices in 1999 and 2000, EIA projected that crude oil prices would decline initially (through 2003), then slowly increase through 2020.[169] EIA's *Weekly Petroleum Status Report* for March 23, 2001, estimated the February 2001 price at $24.60 per barrel ($0.577 per gallon) in 1999 dollars for U.S. imported crude oil. In comparison, NEMS projects a world crude oil price of $21.37 per barrel ($0.509 per gallon) in 2010 (in 1999 dollars). The lower 2010 oil price projections from *AEO2001* thus account for a difference of 6.8 cents per gallon in the projected end-use prices for ULSD.

In addition, the end-use diesel prices include a nominal Federal tax of $0.24 per gallon in 1999, which decreases in value (in real terms) in the forecast years. The differential in Federal taxes between 1999 and 2010 is about 4 cents per gallon. The PMM reference case projects an end-use price of $1.238 per gallon in 2010. After upward adjustment to account for the differentials in world crude oil price and Federal taxes (a total of 10.8 cents), the end-use price would be $1.346 per gallon at the current world crude oil price level.

The U.S. prices of most petroleum fuel products fluctuate between seasons and in response to world crude oil prices. The higher-than-normal diesel prices in 2000 and in the early part of 2001 reflect the low distillate inventory and high world crude oil prices. Since February 2001, the average price of U.S. highway diesel has been dropping steadily, to a level around $1.40 per gallon. According to the *Weekly Petroleum Status Report* for March 23, 2001, the average U.S. price of highway diesel was $1.338 per gallon (in 1999 dollars), comparable to the price projection of $1.346 per gallon from the PMM.

[168] Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), Figure 112.

[169] Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), Figure 88.

Table E1. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 5-Percent Return on Investment

Analysis Case	1999	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
End-Use Prices of Highway Diesel (1999 Cents per Gallon)[a]									
Reference (500 ppm)	114.0	121.6	122.3	123.0	123.6	124.1	124.3	122.6	124.3
Regulation (ULSD)	NA	128.6	129.0	129.5	130.4	131.3	129.4	129.4	129.7
Higher Capital Cost (ULSD)	NA	129.4	129.9	130.5	131.2	132.2	130.1	130.3	130.5
2/3 Revamp (ULSD)	NA	128.9	129.2	129.9	130.7	131.7	129.7	129.7	130.0
10% Downgrade (ULSD)	NA	129.0	129.4	129.9	130.8	133.2	130.0	129.8	130.7
4% Efficiency Loss (ULSD)	NA	128.6	129.0	129.5	130.5	131.4	129.6	129.4	130.0
1.8% Energy Loss (ULSD)	NA	128.9	129.3	129.6	130.5	131.5	129.5	129.6	129.8
Severe (ULSD)	NA	130.4	130.7	131.4	132.2	134.8	131.1	131.2	131.7
No Imports (ULSD)	NA	130.2	130.4	130.8	131.6	132.9	130.5	130.8	131.1
Total Highway Diesel Supplied (Million Barrels per Day)									
Reference									
Total (500 ppm)	**2.43**	**3.09**	**3.15**	**3.21**	**3.27**	**3.32**	**3.55**	**3.18**	**3.43**
Regulation									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.28**	**3.40**	**3.63**	**3.19**	**3.51**
Higher Capital Cost									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.28**	**3.40**	**3.63**	**3.19**	**3.51**
2/3 Revamp									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.28**	**3.40**	**3.63**	**3.19**	**3.51**
10% Downgrade									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.61	3.85	2.59	3.72
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.28**	**3.61**	**3.85**	**3.19**	**3.72**
4% Efficiency Loss									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.03	3.42	3.65	2.59	3.53
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.29**	**3.42**	**3.65**	**3.19**	**3.53**
1.8% Energy Loss									
500 ppm	2.43	0.71	0.72	0.73	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.42	2.47	2.52	3.06	3.45	3.68	2.62	3.55
Total	**2.43**	**3.13**	**3.19**	**3.25**	**3.32**	**3.45**	**3.68**	**3.22**	**3.55**
Severe									
500 ppm	2.43	0.71	0.72	0.73	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.42	2.47	2.52	3.07	3.67	3.92	2.62	3.79
Total	**2.43**	**3.13**	**3.19**	**3.25**	**3.33**	**3.67**	**3.92**	**3.22**	**3.79**
No Imports									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	**2.43**	**3.10**	**3.16**	**3.22**	**3.28**	**3.40**	**3.63**	**3.19**	**3.51**

[a]Highway diesel prices (both 500 ppm and ULSD) include Federal and State taxes but exclude county and local taxes.
NA = not available.
Sources: **1999:** Energy Information Administration, *Petroleum Supply Annual 1999*, Vol. 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000). **Projections:** National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, and DSU7IMP0.D043001A.

9303A

Table E2. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 10-Percent Return on Investment

Analysis Case	1999	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
End-Use Prices of Highway Diesel (1999 Cents per Gallon)[a]									
Reference with 10% Return on Investment (500 ppm)	114.0	121.9	122.5	123.3	123.8	124.4	125.4	[illegible]	[illegible]
Regulation with 10% Return on Investment (ULSD)	NA	129.8	130.0	[illegible]	131.5	132.4	[illegible]	[illegible]	[illegible]
Total Highway Diesel Supplied (Million Barrels per Day)									
Reference with 10% Return on Investment									
Total (500 ppm)	**2.43**	**3.10**	**3.16**	**3.22**	**3.27**	**3.33**	**3.56**	**3.19**	**3.44**
Regulation with 10% Return on Investment									
500 ppm	2.43	0.70	0.71	0.73	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.41	2.46	2.50	3.02	3.41	3.64	2.60	[illegible]
Total	**2.43**	**3.11**	**3.17**	**3.23**	**3.28**	**3.41**	**3.64**	**3.20**	**3.52**

[a]Highway diesel prices (both 500 ppm and ULSD) include Federal and State taxes but exclude county and local taxes.

NA = not available.

Sources: 1999: Energy Information Administration, *Petroleum Supply Annual 1999*, Vol. 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000). Projections: National Energy Modeling System, runs DSUREF10.D043001A and DSU7PPM10.D043001A.

Sensitive! B5

Stanley Calvert 04/06/2001 10:43 AM

To: MaryBeth Zimmerman/EE/DOE@DOE
cc:

Subject: Wind Success Inputs

Stan Calvert
X68021

--- Forwarded by Stanley Calvert/EE/DOE on 04/06/2001 10:39 AM ---

Phil Dougherty 04/06/2001 10:04 AM

To: Stanley Calvert/EE/DOE@DOE
cc:

Subject:

Marybeth:

9310

I hope this information helps,
PJD

Stanley Calvert 04/06/2001 11:11 AM

To: MaryBeth Zimmerman/EE/DOE@DOE
cc: Phil Dougherty/EE/DOE@DOE

Subject: Re: Wind Success Inputs

Stan

MaryBeth Zimmerman

MaryBeth Zimmerman 04/06/2001 10:59 AM

To: Stanley Calvert/EE/DOE@DOE
cc: Phil Dougherty/EE/DOE@DOE

Subject: Re: Wind Success Inputs

Thanks. I worked with your last bullet and added the final reference on growth in production from EIA's Renewable Energy Annual 2000 (March 2001):

Stanley Calvert 04/06/2001 10:43 AM

Stanley Calvert 04/06/2001 10:43 AM

To: MaryBeth Zimmerman/EE/DOE@DOE
cc:

Subject: Wind Success Inputs

Stan Calvert
X68021

MaryBeth Zimmerman 02/23/2001 03:15 PM

To: David Rodgers/EE/DOE@DOE
cc: Buddy Garland/EE/DOE@DOE, John Sullivan/EE/DOE@DOE

Subject: Re: Incoming letters regarding NEP

David Rodgers 02/23/2001 01:49 PM

David Rodgers 02/23/2001 01:49 PM

To: MaryBeth Zimmerman/EE/DOE@DOE, Darrell Beschen/EE/DOE@DOE
cc:

Subject: Incoming letters regarding NEP

Dear Folks,

Thanks, david

David Rodgers 02/23/2001 01:49 PM

To: MaryBeth Zimmerman/EE/DOE@DOE, Darrell Beschen/EE/DOE@DOE
cc:

Subject: Incoming letters regarding NEP

Dear Folks,

Thanks, david

9316

From: Bill Babiuch/NRELDC/NRELEX@NRELExchange on 02/21/2001 10:45 AM

To: Darrell.Beschen@ee.doe.gov@SMTP@NRELExchange
cc: MaryBeth Zimmerman/EE/DOE@DOE

Subject: RE: need print out for Buddy

Darrell,

—Bill

DOE R&D Budgets FY80-FY00.ppt

-----Original Message-----
From: Darrell.Beschen@ee.doe.gov [SMTP:Darrell.Beschen@ee.doe.gov]
Sent: Wednesday, February 21, 2001 8:29 AM
To: Babiuch, Bill
Subject: RE: need print out for Buddy

yes please make a one or two pager with the chart and the data.....constant dollars..
you can send it to me email and i will print it here....we are busting ass on the WH NEP.....d.

Sarah Kirchen
06/06/2001 03:27 PM

To: MaryBeth Zimmerman/EE/DOE@DOE, Gloria Elliott/EE/DOE@DOE, Patrick Booher/EE/DOE@DOE, Tina Kaarsberg/EE/DOE@DOE
cc: Sam Baldwin/EE/DOE@DOE, Nancy Jeffery/EE/DOE@DOE, Debbie Stroud/EE/DOE@DOE, Annette West/EE/DOE@DOE

Subject: Congressional Q&As from Senate Energy and Natura. Resources Committee Hearing, May 24, 2001

Thank you.

Gail McKinley
05/25/2001 06:38 PM

To: Randy Steer/EE/DOE@DOE
cc: MaryBeth Zimmerman/EE/DOE@DOE, Darrell Beschen/EE/DOE@DOE, Buddy Garland/EE/DOE@DOE, Sam Baldwin/EE/DOE@DOE, John Sullivan/EE/DOE@DOE, Mark Ginsberg/EE/DOE@DOE, Jerry Dion/EE/DOE@DOE, Gregory Reamy/EE/DOE@DOE, Thomas Heavey/EE/DOE@DOE

Subject: Re: Ten-Year Funding Increase for Weatherization

From: Randy Steer on 05/25/2001 12:40 PM

From: Randy Steer on 05/25/2001 12:40 PM
To: MaryBeth Zimmerman/EE/DOE@DOE
cc: Gail McKinley/EE/DOE@DOE, Darrell Beschen/EE/DOE@DOE, Buddy Garland/EE/DOE@DOE, Sam Baldwin/EE/DOE@DOE, John Sullivan/EE/DOE@DOE

Subject: Re: Ten-Year Funding Increase for Weatherization

Randy.

Williams, Ronald L

B: 5

From: Ball, Crystal A - KN-DC [caball@bpa.gov]
Sent: Monday, March 26, 2001 9:56 AM
To: Anderson, Margot; Carrier, Paul
Cc: 'Seifert, Roger - KN-DC'; 'Stier, Jeffrey K - KN-DC'
Subject: RE: BPA DSI information

Crystal

-----Original Message-----
From: Anderson, Margot [mailto:Margot.Anderson@hq.doe.gov]
Sent: Friday, March 23, 2001 5:54 PM
To: 'Stier, Jeffrey K - KN-DC'; 'Ball, Crystal A - KN-DC'; Carrier, Paul
Cc: 'Seifert, Roger - KN-DC'
Subject: RE: BPA DSI information

Thank you. Any help you could give on economic impacts would be most helpful.

-----Original Message-----
From: Stier, Jeffrey K - KN-DC [mailto:jkstier@bpa.gov]
Sent: Friday, March 23, 2001 3:59 PM
To: Anderson, Margot; 'Ball, Crystal A - KN-DC'; Carrier, Paul
Cc: 'Seifert, Roger - KN-DC'
Subject: RE: BPA DSI information

-----Original Message-----
From: Anderson, Margot [mailto:Margot.Anderson@hq.doe.gov]
Sent: Friday, March 23, 2001 12:46 PM
To: 'Ball, Crystal A - KN-DC'; Carrier, Paul
Cc: 'Stier, Jeffrey K - KN-DC'; 'Seifert, Roger - KN-DC'
Subject: RE: BPA DSI information

Crystal,

B5

9320

DOE015-2663

Margot

-----Original Message-----
From: Ball, Crystal A - KN-DC [mailto:caball@bpa.gov]
Sent: Friday, March 23, 2001 12:35 PM
To: Anderson, Margot; Carrier, Paul
Cc: Stier, Jeffrey K - KN-DC; Seifert, Roger - KN-DC
Subject: RE: BPA DSI information
Importance: High

> <<DSI paul info.doc>> <<McCook pr final.doc>>

Williams, Ronald L

From:	MaryBeth Zimmerman
Sent:	Monday, March 26, 2001 10:01 AM
To:	Anderson, Margot
Cc:	Parks, William; Kaarsberg, Tina; York, Michael; Garland, Buddy; BP Sullivan/OU=SMTP/O=NRELEX@NRELExchange@DOE%HQ-NOTES; Haspel, Abe; Jeffery, Nancy
Subject:	Re: Chapter 8 (Increased production of U.S. Energy Resources).

ch 8 march 24.doc

B5

On first quick perusal here:

Thanks for the review copy. I will forward any comments received by others on this distribution list.

Margot Anderson@HQMAIL on 03/24/2001 10:40:57 AM

To: Abe Haspel/EE/DOE@DOE@HQMAIL, MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL, Michael York/EE/DOE@DOE@HQMAIL, John Conti@HQMAIL, Andrea Lockwood@HQMAIL, William Breed@HQMAIL, Michael Whatley@HQMAIL, Douglas Carter@HQMAIL, Jay Braitsch@HQMAIL, Elena Melchert@HQMAIL, TREVOR COOK@HQMAIL, 'jkstier@bpa.gov'@internet@HQMAIL, Christopher Freitas@HQMAIL, Mark FRIEDRICHS@HQMAIL, David Pumphrey@HQMAIL, Kevin Kolevar@HQMAIL, ANDY KYDES@HQMAIL
cc: Joseph Kelliher@HQMAIL

Subject: Chapter 8 (Increased production of U.S. Energy Resources).

Chapter 8 (Increased production of U.S. Energy Resources).

Task Force Charlie: This can go out to other Agencies for review. Includes comments from meeting on 2/21.

DOE: FE took the pen and I edited and inserted new material from NE. Also selected the graphics from FE's menu of options. Graphics are a little thin toward the back of the chapter. Who can help?

EIA - please take a fact-check look.

<akmeier@lbl.gov> on 05/24/2001 02:23:20 PM

Please respond to akmeier@lbl.gov@Internet@HQMAIL
To: MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL
cc:

Subject: Re: my electricity chart

- alan

MaryBeth Zimmerman wrote:

>
>
>
>
>
>
>
>

9323

> - alan
>
> --
> ==========
> Alan Meier
> Berkeley Lab (LBNL), Building 90-2000
> Berkeley, California 94720 USA
> Tel. +1 (510) 486-4740 Fax +1 (510) 486-4673
> e-mail: AKMeier@LBL.gov
> http://www.lbl.gov/~akmeier
> ==========

--
==========
Alan Meier
Berkeley Lab (LBNL), Building 90-2000
Berkeley, California 94720 USA
Tel. +1 (510) 486-4740 Fax +1 (510) 486-4673
e-mail: AKMeier@LBL.gov
http://www.lbl.gov/~akmeier
==========

John.Sullivan@ee.doe.gov on 05/23/2001 08:54:44 AM

To: MaryBeth Zimmerman/EE/DOE@DOE, Sam Baldwin/EE/DOE@DOE, Buddy Garland/EE/DOE@DOE, Brian Connor/EE/DOE@DOE, Randy Steer/EE/DOE@DOE, Steven Lee/EE/DOE@DOE, MSHAPIRO43@cs.com
cc: Abe Haspel/EE/DOE@DOE
Subject: Re: Program Reviews Discussion Paper

MaryBeth.Zimmerman@ee.doe.gov on 05/22/2001 02:51:12 PM

To: Brian Connor/EE/DOE@DOE

cc: John Sullivan/EE/DOE@DOE, sam.baldwin@hq.doe.gov, Buddy Garland/EE/DOE@DOE, Steven Lee/EE/DOE@DOE, Randy Steer/EE/DOE@DOE, mshapiro43@cs.com

Subject: Re: Program Reviews Discussion Paper

BRIAN CONNOR
05/22/2001 11:54 AM

To: john.sullivan@ee.doe.gov @ DOE, sam.baldwin@hq.doe.gov @ DOE, buddy.garland@ee.doe.gov, Steven Lee/EE/DOE@DOE, MaryBeth Zimmerman/EE/DOE@DOE, Randy Steer/EE/DOE@DOE, mshapiro43@cs.com
cc:

Subject: Program Reviews Discussion Paper

(See attached file: NEP Program Review Discussion Paper.wpd)

- NEP Program Review Discussion Paper.wpd

9336

"Macauley, Molly" <Macauley@rff.org> on 05/22/2001 04:25:00 PM

To: MaryBeth Zimmerman/EE/DOE@DOE
cc: "Toman, Mike" <Toman@rff.org>
Subject: RE: Follow-up to this morning

The project referenced below can be properly considered an approach to "measuring the contribution of investments in renewable energy: consumer welfare gains." As such, it is conceivably a planning tool and has been used as such at NASA and DoC.

-----Original Message-----
From: MaryBeth.Zimmerman@ee.doe.gov
[mailto:MaryBeth.Zimmerman@ee.doe.gov]
Sent: Tuesday, May 22, 2001 4:17 PM
To: Macauley, Molly; Toman, Mike; Gruenspecht, Howard; Newell, Richard
Cc: Sam.Baldwin@ee.doe.gov; Buddy.Garland@ee.doe.gov;
Philip.Patterson@ee.doe.gov; Phillip.Tseng@ee.doe.gov;
Michael.York@ee.doe.gov; Tom.Kimbis@ee.doe.gov;
Darrell.Beschen@ee.doe.gov; Tina.Kaarsberg@ee.doe.gov;
Eldon.Boes%NRELExchange@ee.doe.gov;
Bill.Babiuch%NRELExchange@ee.doe.gov;
Larry.Goldstein%NRELExchange@ee.doe.gov; Jerry.Dion@ee.doe.gov;
Kenneth.Friedman@ee.doe.gov; Peggy.Podolak@ee.doe.gov;
Ellyn.Krevitz@ee.doe.gov
Subject: Follow-up to this morning

I wanted to thank you again for coming by today and discussing area of possible areas of research. The timing was perfect, following up on the NEP release, for identifying areas of analytical need and opportunity. I apologize again for having to leave a bit early, but I am pleased we finally got a chance to have everyone in the room together.

Phil Tseng and I would like to get back to you soon regarding Planning office analysis needs. I would also like to get copies of the quarterly reports from the work that Molly Macauley is doing for us from the competitive solicitation so we can discuss that in more detail. I have concerns about describing the approach as a budget decision tool at its apparent current point of

application
to these programs and technologies, but I'll need to learn more.

I hope you got a good sense of the items we are most interested in. The way EERE is structured, we can fund analysis through my office (Planning, Analysis, and Evaluation), or through any of the sector offices. The lead analysts for each sector are:

Buildings:	Jerry Dion (586-9470)
Industry:	Ken Friedman (586-0379) or Peggy Podolak (586-6430)
Power:	Tina Kaarsberg (586-3802) [at the meeting]
Transportation	Phil Patterson (586-9121) [at the meeting]
Federal	Ellyn Krevitz (586-4740)

Phil Tseng, Darrell Beschen, and Mike York are in the Planning office. Tim Kimbis is from TMS and on-site with us full time for on-the-spot analysis. For your information, I've cc:ed everyone from EERE & NREL who were present.

John Sullivan
04/27/2001 08:38 AM

To: Randy Steer/EE/DOE@DOE, MaryBeth Zimmerman/EE/DOE@DOE, Sam Baldwin/EE/DOE@DOE, Buddy Garland/EE/DOE@DOE, #EE-DAS, #EE-ADAS
cc: Abe Haspel/EE/DOE@DOE

Subject: Re: Additional Materials for S-1: Fuel Cell/Hydrogen Economy

------------------------ Forwarded by John Sullivan/EE/DOE on 04/27/2001 08:30 AM ------------------------

William Parks
04/27/2001 08:13 AM

To: Randy Steer/EE/DOE@DOE
cc: John Sullivan/EE/DOE@DOE, Robert Dixon, Buddy Garland

Subject: Re: Additional Materials for S-1: Fuel Cell/Hydrogen Economy

thanks
Bill
From: Randy Steer on 04/26/2001 03:20 PM

From: Randy Steer on 04/26/2001 03:20 PM
To: James Daley/EE/DOE@DOE, Richard Budzich/EE/DOE@DOE, Nancy Jeffery/EE/DOE@DOE, Robert Dixon/EE/DOE@DOE, William Parks/EE/DOE@DOE, Sigmund Gronich/EE/DOE@DOE
cc:

Subject: Re: Additional Materials for S-1: Fuel Cell/Hydrogen Economy

Randy.

hydrogen-economy_fog.wp

Abe.Haspel@ee.doe.gov on 05/18/2001 07:23:05 AM

To: MaryBeth Zimmerman/EE/DOE@DOE
cc:
Subject: Next CERA briefing at DOE

Marybeth:.

Michael Ortmeier@HQMAIL on 05/17/2001 04:16:57 PM

To:
cc:

Subject: Next CERA briefing at DOE

Folks, please see the attachment for information on the next CERA briefing on Mexico/Latin American energy issues on

---

Thursday, 24 May @ 10:00 to 11:30 in Rm.
GJ-015 Forrestal Bldg. Regards, Mike O

- CERA7mex.DOC

Williams, Ronald L

From: Kelliher, Joseph
Sent: Monday, March 26, 2001 10:48 AM
To: Anderson, Margot
Subject: questions

Importance: High

A few questions to help winnow down our list even more --

9342

DOE015-2685

Tom Kimbis
02/15/2001 03:56 PM

To: Joel Rubin/EE/DOE@DOE
cc:

Subject: Re: graphics please

here's the first graph

Household Gvt Asstance Gas P
JOEL

JOEL RUBIN
02/15/2001 12:49 PM

To: Tom Kimbis/EE/DOE@DOE
cc:

Subject: graphics please

NEPA_Chap 2 Outline.doc

MaryBeth Zimmerman 02/16/2001 06:40 PM

To: czmb;
cc:

Subject: NEP, draft 1

---------------- Forwarded by MaryBeth Zimmerman/EE/DOE on 02/16/2001 06:39 PM ----------------

Margot Anderson@HQMAIL on 02/16/2001 05:48:00 PM

To: Abe Haspel/EE/DOE@DOE@HQMAIL, John Sullivan/EE/DOE@DOE@HQMAIL, MaryBeth Zimmerman/EE/DOE@DOE@HQMAIL, Robert Kripowicz@HQMAIL, Robert Porter@HQMAIL, WILLIAM MAGWOOD@HQMAIL, David Pumphrey@HQMAIL, James HART@HQMAIL, Paula Scalingi@HQMAIL, Michael Whatley@HQMAIL, LARRY PETTIS@HQMAIL, jkstier@bpa.gov@internet@HQMAIL, cball@bpa.gov@internet@HQMAIL
cc: Joseph Kelliher@HQMAIL

Subject: NEP, draft 1

Here are sections 1,2, 4, and 5.

Thank you all for pushing so hard - we have a lot of very good material here.

Attending Monday
Larry Pettis (FE)
Cook (NE)
Mary Beth Zimmerman, John Sullivan (EE)
Bob Kripowicz (FE)
Margot Anderson (PO)
Paula Scalingi (SO)
Joe Kelliher (OSEC)
Joe Stier or Crystal Ball (BPA)

What did I miss?

Margot

section 1 draft 1 section 2 draft Section 4 draft Section 5 draft

Williams, Ronald L

From: MaryBeth Zimmerman
Sent: Monday, March 26, 2001 10:57 AM
To: Anderson, Margot
Subject: 1 small change in efficiency graphic

revised refrigerator.ppt

9350

DOE015-2693

Martin, Adrienne Release

From: Braitsch, Jay
Sent: Monday, May 07, 2001 5:14 PM
To: Anderson, Margot
Subject: Citations

The attached three documents cover citations for different parts of Chapter 5. I tried to merge them into one document but got totally fouled up with the MS Word draft feature, which I don't understand. Some cites were missed in obscure sections (e.g., hydro, oil power), but they don't look controverial to me.

Citation Check FE2 - CH 5.do... | Citation Check - FE - CH 5.doc... | Citation Check - NE - CH 5.doc...

9352

DOE015-0001

Martin, Adrienne

Release

From: Tom Kimbis
Sent: Monday, May 07, 2001 5:29 PM
To: Anderson, Margot
Cc: Zimmerman, MaryBeth
Subject: chapter 6

CitationsCHAPTER 6-with sites ...

Citations are done on Chapter 6. See attached.

-- Mike York and Tom

9373

DOE015-0022

Martin, Adrienne

From: KYDES, ANDY
Sent: Tuesday, May 08, 2001 11:42 AM
To: Anderson, Margot
Subject: FW: citations update

CITATI~2.DOC 0413CH.DOC CITATI~1.DOC

Margot here's a resend of chapter 2, the last attachment on this page.

Andy

-----Original Message-----
From: Kydes, Andy
Sent: Monday, May 07, 2001 11:10 AM
To: 'Margot Anderson_at_HQ-EXCH at X400PO'
Cc: MARYBETH ZIMMERMAN; JAY BRAITSCH
Subject: RE: citations update

Margot,

I didn't have Bill Breeds(SP?) email. Please forward to him.

We have alot of the information responded to alraedy. I will merge Chapter
1
together and simply forward the rest. I'll attach our reviews so far for 2,
4,
5. Chapter one to follow shortly.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Monday, May 07, 2001 10:37 AM
To: Kydes, Andy; TREVOR COOK_at_HQ-EXCH at X400PO; William Breed_at_HQ-EXCH at X400PO; Jay Braitsch_at_HQ-EXCH at X400PO; Douglas Carter_at_HQ-EXCH at X400PO; MaryBeth Zimmerman_at_HQ-NOTES at X400PO
Subject: citations update

Can I get an update on how things are going and do we need to bring more folks in on this?

9402

DOE015-0051

b(5)

White, Eric

From: Ellis, Dina
Sent: Thursday, April 19, 2001 8:52 AM
To: Gerardi, Geraldine; Weinberger, Mark
Subject: FW: energy tax proposals

Importance: High

-----Original Message-----
From: Kelliher, Joseph [mailto:Joseph.Kelliher@hq.doe.gov]
Sent: Thursday, April 19, 2001 8:45 AM
To: 'MPeacock@OMB.EOP.gov'; 'mweatherly@omb.eop.gov';
'Bruce.Davie@do.treas.gov%internet'; 'Dina.Ellis@do.treas.gov'
Subject: energy tax proposals
Importance: High

9462

DOE015-0111

b(5) email + attachment

Kelliher, Joseph

From: Cook, Trevor
Sent: Tuesday, May 22, 2001 9:21 AM
To: Kelliher, Joseph
Cc: Magwood, William
Subject: reprocessing paper

Importance: High

Joe,

Here is the paper, its just over a page.

Trevor.

ONE PAGER ON REPROCESSING.doc

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, May 21, 2001 3:15 PM
To: Magwood, William; Cook, Trevor
Subject: hearing prep: reprocessing

9876

DOE015-0525

01 0085

2001-010085 4/12/01 3:40

April 8, 2001

(b)(6)

The Honorable Spencer Abraham
Secretary
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Secretary Abraham,

During your interview last Sunday on This Week, you confirmed that cutting funding for energy efficiency and renewable energy programs by as much as 30 percent is being considered. I assume that this is happening, at least in part, in an Energy Task Force headed by Vice President Cheney. My concern, based on your further remarks, is that you and this task force are not receiving the information necessary to make well-informed decisions, "We're going to look at these programs which have been widely scorned and criticized of not having returned a very good investment for the taxpayers..." I know of program examples that deserve scorn and criticism however; I also know of programs that have demonstrated great present and potential future value. My concern is that the only group being heard is a group that has *only* scorn and criticism.

Your goal is appropriate (U.S. Chamber of Commerce, National Energy Summit), "...to make sure that America's energy needs of the next 20 years are met; that we succeed in—in confronting that challenge." You also indicated the need for a diverse energy supply policy; "It will be founded on the understanding that diversity of supply means security of supply ... and that a broad mix of supply options – from coal to windmills, nuclear to natural gas – will help protect consumers against price spikes and supply disruptions." This timeframe is also appropriate for further development of diverse energy supplies. I have direct experience with photovoltaic programs that have been highly successful. Photovoltaic power generation has unique benefits including supplying clean power at the point of use during times of peak demand. Photovoltaic power generation is in its infancy relative to all other energy options. Even so, photovoltaic technology has demonstrated successes for present energy generation and, more importantly, demonstrated development successes indicating that photovoltaic technology will continue to meet DOE near-term and long-term (20 year) goals.

I request your support in all possible ways to insure well-informed decisions regarding our energy future. The photovoltaic option is one of multiple renewable energy technologies that deserve to be considered in the broad mix of energy supply options.

Best regards,

Dale E. Tarrant

(b)(6)

9879

DOE015-0528

Williams, Ronald L

(b)(5)

From: Breed, William
Sent: Thursday, March 08, 2001 5:32 PM
To: Anderson, Margot
Subject: NEP ideas

M:

Bill

template for policy ideas.doc

9880

DOE015-0529

Williams, Ronald L

B - 5

From: Kelliher, Joseph
Sent: Saturday, March 10, 2001 1:13 PM
To: Anderson, Margot
Subject: S. 72

9881

DOE015-0530

(b)(5)

Williams, Ronald L

From: Braitsch, Jay
Sent: Thursday, March 08, 2001 5:36 PM
To: Anderson, Margot
Cc: Kripowicz, Robert; DeHoratiis, Guido; Johnson, Nancy; Melchert, Elena; Rudins, George; Carter, Douglas; Furiga, Richard; Shages, John; Porter, Robert; Bajura, Rita; Carabetta, Ralph
Subject: FE's NEP 2pagers

Margot -

9895

DOE015-0544

Williams, Ronald L P - 5

From: Kelliher, Joseph
Sent: Saturday, March 10, 2001 5:50 PM
To: Fygi, Eric; Haspel, Abe; Anderson, Margot
Subject: Appliance Standards

9896

DOE015-0545

Williams, Ronald L

From: Kelliher, Joseph
Sent: Sunday, March 11, 2001 11:48 AM
To: Haspel, Abe; Conti, John; Zimmerman, MaryBeth
Cc: Anderson, Margot
Subject: California questions

Importance: High

I want to revisit a few matters we discussed a month ago, but did not wrap up:

Please call if you have questions.

9897

DOE015-0546

b(5)

Martin, Adrienne

From: Kelliher, Joseph
Sent: Thursday, April 12, 2001 8:37 PM
To: Anderson, Margot; Kripowicz, Robert; Haspel, Abe; Magwood, William
Cc: Kolevar, Kevin
Subject: energy tax proposals

Importance: High

9898

DOE015-0547

Williams, Ronald L

From: MaryBeth Zimmerman
Sent: Friday, March 09, 2001 7:43 AM
To: Anderson, Margot
Subject: EERE NEP summaries

EERE Summary Submission.doc

attached. one-pagers will follow as finalized

9936

DOE015-0585

b(5)

Martin, Adrienne

From: Breed, William
Sent: Friday, April 13, 2001 11:05 AM
To: Anderson, Margot; Conti, John
Subject: RE: energy tax proposals

Margot: any idea for format or length? does Joes want a full one-pager, or more of a short para or 2 description?

...of course we have ideas...

Bill

William Breed
Acting Director, Office of Energy Efficiency,
Alternative Fuels, and Oil Analysis (PO-22)
202-586-4763

-----Original Message-----
From: Anderson, Margot
Sent: Friday, April 13, 2001 8:31 AM
To: Conti, John; Breed, William
Subject: FW: energy tax proposals
Importance: High

Bill and John,

-----Original Message-----
From: Kelliher, Joseph
Sent: Thursday, April 12, 2001 8:37 PM
To: Anderson, Margot; Kripowicz, Robert; Haspel, Abe; Magwood, William
Cc: Kolevar, Kevin
Subject: energy tax proposals
Importance: High

b(5) Sanitize

9942

DOE015-0591

(b)(5)

Williams, Ronald L

From:	Kelliher, Joseph
Sent:	Monday, March 12, 2001 1:29 PM
To:	Anderson, Margot
Subject:	prices
Importance:	High

9943

DOE015-0592

(b)(5)

Williams, Ronald L

From: Scalingi, Paula
Sent: Friday, March 09, 2001 11:54 AM
To: Anderson, Margot
Subject: RE: NEP goals

Margot,

Hi. I'm back.

—–Original Message—–
From: Anderson, Margot
Sent: Friday, March 09, 2001 11:43 AM
To: Rogers, Cecellia
Cc: Scalingi, Paula
Subject: RE: NEP goals

Cecellia,

Margot

—–Original Message—–
From: Rogers, Cecellia
Sent: Thursday, March 08, 2001 5:24 PM
To: Anderson, Margot
Cc: Scalingi, Paula; Kelliher, Joseph
Subject: RE: NEP goals
Importance: High

Margot,
Here are Paula's notes:

9944

DOE015-0593

(b)(5)

She will be back in the office tomorrow.
Ceil

-----Original Message-----
From: **Anderson, Margot**
Sent: Tuesday, March 06, 2001 4:24 PM
To: Scalingi, Paula
Subject: NEP goals

Paul,

Margot

9945

DOE015-0594

Williams, Ronald L

From: Kelliher, Joseph
Sent: Monday, March 12, 2001 9:20 AM
To: Anderson, Margot
Subject: RE: NEP Policy Options

-----Original Message-----
From: Anderson, Margot
Sent: Monday, March 12, 2001 9:12 AM
To: Kelliher, Joseph
Subject: RE: NEP Policy Options

We provide our options on Wednesday (3/14). We will need to whittle down the proposals to date. Did you get my eralier e-mail with the list of options?

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, March 12, 2001 8:56 AM
To: Anderson, Margot
Subject: RE: NEP Policy Options

When do we provide our options to the Task Force? I can't remember. This week?

-----Original Message-----
From: Anderson, Margot
Sent: Monday, March 12, 2001 8:43 AM
To: Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea; Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch, Jay; Melchert, Elena; Cook, Trevor; 'jkstier@bpa.gov'; O'Donovan, Kevin; Kolevar, Kevin; Scalingi, Paula
Cc: Kelliher, Joseph
Subject: NEP Policy Options

All,

<< File: Short titles.doc >>

9946

DOE015-0595