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 of 50,000 barrels per day and consists of a first-stage reactor 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.

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).

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.

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.

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	49	—
NPC Scenario E	82	49	—
EPA With No Temporary Compliance Option	46	27	10
EPA With Temporary Compliance Option	30	17	7

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	9	9	—	—
After Promulgation of the ULSD Program	10	37	6	26	5	3	4	6
Diesel Units	—	—	—	63	—	—	—	58

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-2.

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.