Appendix D

Short-Term Analysis of Refinery Costs and Supply

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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
Murban	Abu Dhabi	39	0.9	58	40	22
Saudi Arabia Light	Saudi Arabia	34	1.7	58	32	18
Forcados	Nigeria	31	0.2	39	25	<15
Forties	North Sea	37	0.3	52	37	20
Maya	Mexico	22	3.3	47	25	15
Boscan	Venezuela	10	5.5	39	21	<15
North Slope	Alaska	27	1.0	45	30	17
Gibson Mix	Louisiana	36	0.3	55	40	22
West Texas Sour	Texas	32	2.4	47	32	18

Note: It was assumed that 650-1050F vacuum gas oil was cracked at 60 percent or 80 percent volume conversion. Properties of the vacuum gas oil and cetane number of straight-run diesel are from the Ethyl Corporation crude oil database.

Source: G.H. Unzelman, "Diesel Fuel Demand: A Challenge to Quality," Presentation to the Energy Economics Group, Institute of Petroleum (London, UK, October 10, 1983).

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:

$$-\mathrm{d}S / \mathrm{d}t = kS^n P_{H_2} / (1 + K_s S_o) \,.$$

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.

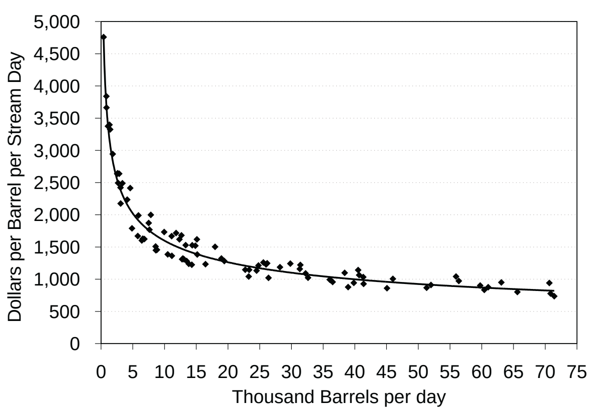
In the view of many refiners with whom discussions were held, an estimate of $1,600 per barrel per stream day is believed to be a more representative ISBL investment cost to produce ULSD. Therefore, the model was rerun using a basis of $1,600 per barrel per stream day for a unit with 30,000 barrels per 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.

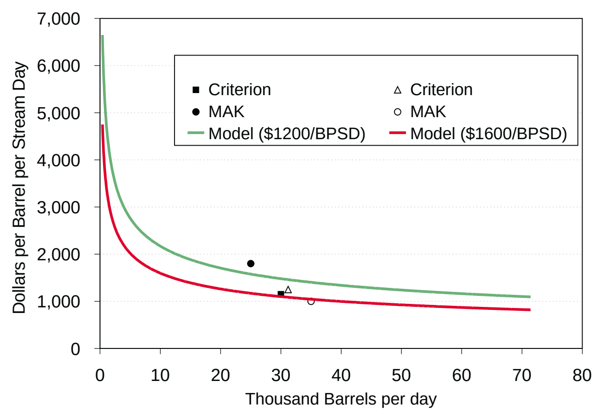
Hydrotreater Catalyst: Catalyst cost (in dollars per barrel) is a function of space velocities and is calculated assuming a 2-year life, with CoMo in the first reactor and NiMo in the second reactor. CoMo is more reactive in removing sulfur from the less challenging sulfur-containing molecules. Below 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)



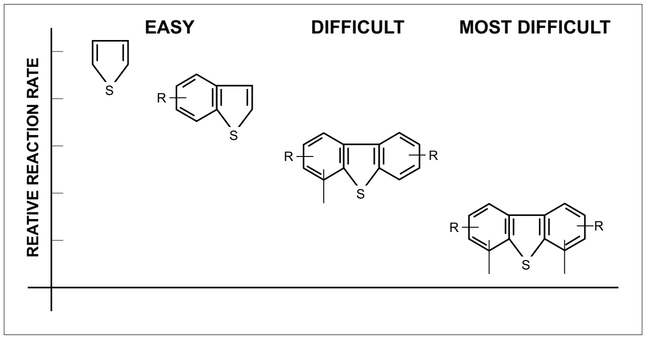
Source: National Energy technology Laboratory.

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.