CHAPTER 5: Fuel Standard Feasibility

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In this chapter, we present an analysis of the feasibility of complying with the fuel program adopted in this final rule, including a discussion of the technology used to desulfurize and distribute ultra low diesel fuel. In Section 5.1, we discuss the sources of the blendstocks which comprise diesel fuel and summarize their reported sulfur levels. In Section 5.2, we present and evaluate a wide variety of distillate desulfurization technologies that refiners might use to meet the 500 and 15 ppm sulfur caps. In Section 5.3, we formally assess the technical feasibility of meeting the 500 ppm sulfur cap in 2007, including the sufficiency of the lead time for refiners. In Section 5.4, we assess the technical feasibility meeting the 15 ppm sulfur cap, including the sufficiency of lead time for refiners. In Section 5.5, we assess the feasibility of distributing 500 and 15 ppm sulfur fuel. In Section 5.6, we assess the feasibility of using a marker in heating oil. In Section 5.7, we evaluate the impacts of this program and other sulfur control regulations on the engineering and construction industry. In Section 5.8 we assess the impacts of this program on the supply of NRLM diesel fuel. In Section 5.9 we discuss how hydro-desulfurization is expected to affect NRLM diesel fuel properties other than sulfur. Finally, in Chapter 5.10 we assess how properties other than sulfur will be impacted by desulfurizing NRLM diesel fuel. At the end of Chapter 5 we include an Appendix summarizing EPA's authority for adopting NRLM sulfur standards.

5.1 The Blendstocks and Properties of Non-Highway Diesel Fuel

5.1.1 Blendstocks Comprising Non-highway Diesel Fuel and their Sulfur Levels

The primary sources of sulfur in diesel fuel are the sulfur-containing compounds that occur naturally in crude oil.[A] Depending on the source, crude oil contains anywhere from fractions of a percent of sulfur, such as less than 0.05 weight percent (500 ppm) to as much as several weight percent.[1] The average amount of sulfur in crude oil refined in the United States is about one weight percent.[2] Most of the sulfur in crude oil is in the heaviest boiling fractions. Since most of the refinery blendstocks that are used to manufacture diesel fuel come from the heavier boiling components of crude oil, they contain substantial amounts of sulfur.

The distillate[B] produced by a given refinery is composed of one or more blendstocks from crude oil fractionation and conversion units at the refinery. Refinery configuration and equipment, and the types and relative volumes of products manufactured (the product slate) can

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[A] Additives that contain sulfur are sometimes intentionally added to diesel fuel. For a discussion how the addition of these additives will be affected under this program, see Section IV.D.5.

[B] Distillate refers to a broad category of fuels falling into a specific boiling range. Distillate fuels have a heavier molecular weight and therefore boil at higher temperatures than gasoline. Distillate includes diesel fuel, kerosene and home heating oil. For the purposes of this discussion, we will focus on No. 2 distillate, which comprises the majority of diesel fuel and heating oil.

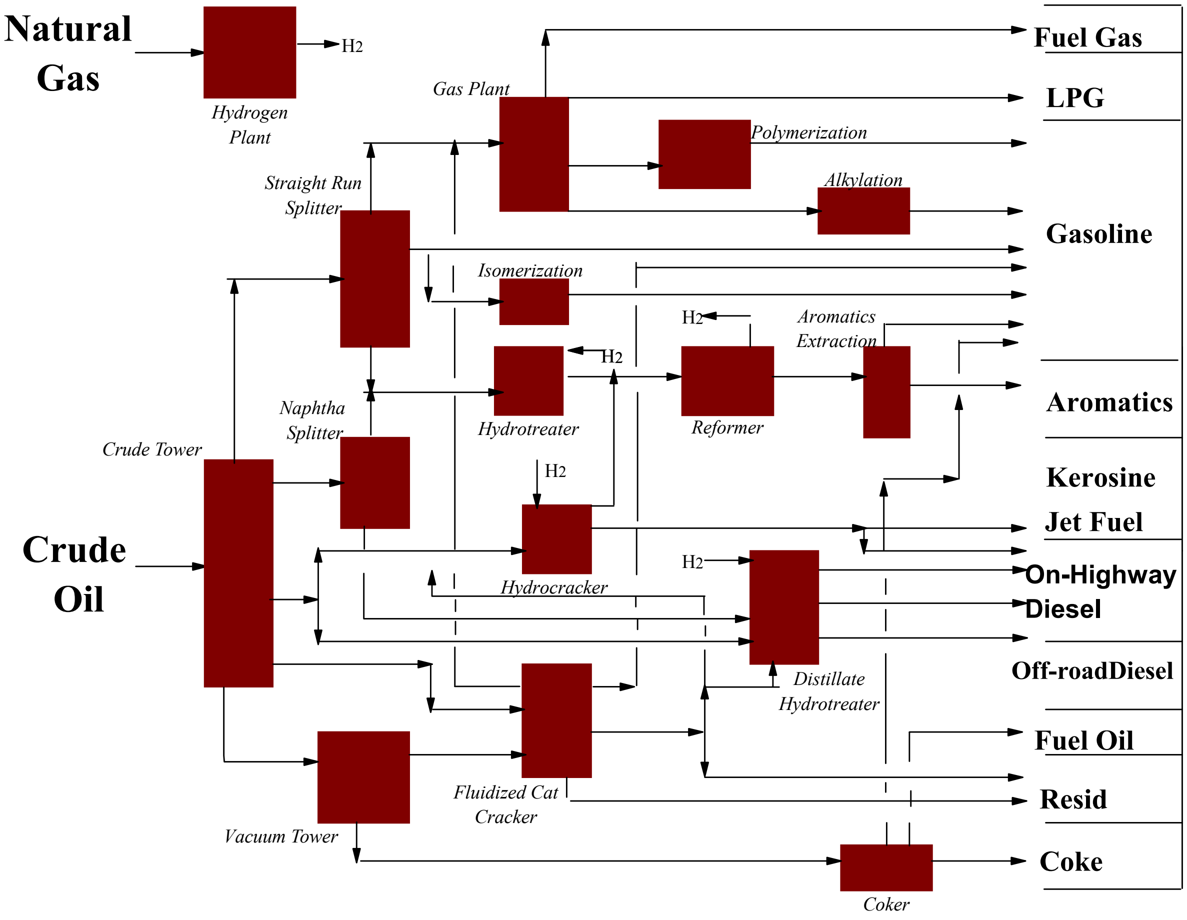

Figure 5.1-1
Diagram of a Typical Complex Refinery

significantly affect the sulfur content of diesel fuel. The diagram on the following page illustrates the configuration and equipment used at a typical complex refinery in the United States.

Refineries differ from the model in the preceding diagram depending on the characteristics of the crude oils refined, and their product slate, as illustrated in the following examples:

- Refineries that process lighter crude oils are less likely to have coker and hydrocracker units.
- Refinery streams that can be used to manufacture diesel fuel can also be used to manufacture heating oil, kerosene, and jet fuel. Much of the distillate product from the hydrocracker is often blended into jet fuel rather than diesel fuel; current highway regulations generally require that a refinery have a hydrotreater, which is usually not necessary if the refinery produces only high sulfur non-highway diesel fuel.

On an aggregate basis, most of the distillate manufactured in the United States comes from the crude fractionation tower (called straight-run or SR). Most of the remainder comes from the fluid catalytic cracker (FCC) conversion unit (called light cycle oil or LCO). The remaining small fraction of diesel fuel volume comes from a coker conversion unit or other units that crack heavy compounds such as a visbreaker or steam cracker (called other cracked stocks in this document), or from the hydrocracker conversion unit (called hydrocrackate).

To comply with the current federal regulatory requirement on the sulfur content of highway diesel fuel (500 ppm cap), the blendstock streams from these process units are typically further processed to reduce their sulfur content. Desulfurization of highway diesel blendstocks to meet the 500 ppm cap is accomplished in fixed-bed hydrotreaters that operate at moderate pressures (500 to 800 psi and higher).[3] Nearly all the low-sulfur diesel blendstocks come from such hydrotreaters. However, a small amount of low-sulfur diesel also comes from hydrocrackers operating at pressures of 500 to 3000 psi, although most operate at 1500 to 3000 psi, which naturally produces distillate fuel with sulfur levels of 100 ppm or less.

To comply with applicable non-highway sulfur requirements which range from 2000 to 5000 ppm, or the 40 cetane standard for nonroad, locomotive and marine diesel fuel, some of the distillate blendstocks used to produce non-highway diesel fuel and heating oil are hydrotreated. A significant amount of hydrocracked distillate is also blended into non-highway diesel fuel and heating oil. As discussed in Chapter 7, the use of hydrotreated blendstocks in non-highway diesel fuel has important implications for the cost of desulfurizing NRLM diesel fuel.

The distillate blendstocks used to produce non-highway diesel fuel and their sulfur content vary considerably from refinery to refinery. A survey conducted by the American Petroleum Institute (API) and National Petroleum Refiners Association (NPRA) in 1996 examined the typical blendstock properties for the U.S. highway and the non-highway diesel pools.[4] The results of this survey for the non-highway distillate pool are in Table 5.1-1.

Table 5.1-1
Average Composition and Sulfur Content of the
Non-highway Distillate Pool Outside of California in 1996[5]

Type of Distillate Stream	Diesel Blendstock	Percentage	Sulfur Content (ppm)
Unhydrotreated	Straight-Run	45	2274
	Light Cycle Oil (LCO)	12	3493
	Coker Gas Oil	1	2345
	Unhydrotreated Subtotal	58	-
Hydrotreated	Hydrotreated Straight-Run	18	353
	Hydrotreated LCO	10	1139
	Hydrotreated Coker Gas Oil	4	270
	Hydrocrackate	10	115
	Hydrotreated Subtotal	42	-
	Total	100	-

As shown in Table 5.1-1, approximately 42 percent of all blendstocks used to manufacture non-highway distillate outside of California are hydrotreated to reduce their sulfur content. This includes hydrocrackate (10 percent of the non-highway distillate pool), which is desulfurized to a substantial extent as a necessary element of the hydrocracking process and is not further processed in a hydrotreater. Table 5.1-1 also shows that approximately 58 percent of non-highway distillate comes from nonhydrotreated blendstocks. As expected, the sulfur levels of the hydrotreated blendstocks are lower than the nonhydrotreated distillate blendstocks.

In Chapter 7 of the RIA we use this blendstock information as one of the input parameters for estimating the relative difficulty and ultimately the cost for desulfurizing diesel fuel. The 1996 data is an important input for our cost analysis, and we update the mix of blendstocks to 2002 based on changes in relative unit capacities.

5.1.2 Current Levels of Other Fuel Parameters in Non-highway Distillate

It is useful to review other qualities of high-sulfur distillate, as well as sulfur content. First, some of the desulfurization technologies affect these other fuel properties. Second, as discussed further below, some sulfur compounds are more difficult to treat than others. In some cases, refiners might try to shift these more difficult compounds to fuels that face less stringent sulfur standards. Their ability to do this depends, not only on the economics of doing so, but also on the effect of such shifts on nonsulfur properties and whether or not these other properties still meet industry specifications. Thus, it is helpful to evaluate the degree to which current non-highway distillate fuels meet or exceed applicable industry standards.

Data on the current distillation characteristics, API gravity, pour point, natural cetane level, and aromatics content of diesel fuel blendstocks are in Table 5.1-2.

Table 5.1-2
Average Non-highway Distillate Fuel Property Levels by Geographic Area[6] [7]
(Data from 1997 API/NPRA Survey unless specified)

Fuel Parameter		PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (CA Excluded)	U.S. (CA Excluded)	CA
API Gravity		32.6	34.1	32.6	35.6	33.8	32.8	30.8
Cetane Number[a]		N/A	N/A	N/A	N/A	N/A	47	N/A
Pour Point (°F) [additized]		-6	-8	0	6	12	-1	4
Pour Point Depressant Additive (ppmw)		0	71	0	13	0	18	0
Distillation (°F)	T10	434	425	418	411	466	419	498
	T30	492	476	457	443	517	464	
	T50	517	508	502	499	542	503	556
	T70	545	558	536	522	570	539	
	T90	613	604	598	591	616	595	620

[a] From 1997 NIPER/TRW survey data, U.S. average includes California. N/A means not available.

The American Society for Testing Materials (ASTM) has established requirements that apply to No. 2 non-highway diesel fuel, as well as for No. 2 distillate fuel (e.g., heating oil).[8] The requirements most relevant to desulfurization are summarized in Table 5.1-3.

Table 5.1-3
ASTM Requirements that Apply to Non-Highway Distillate Fuels

	No. 2 Diesel Fuel (Non-highway)	No. 2 Fuel Oil/Heating Oil	No. 2 Marine Distillate (DMA)
T-90 Min °F	540	540	—
T-90 Max °F	640	640	—
Density max (g/cm^3) (API Gravity min)	None	0.876 (30.0)	0.890 (27.5)
Pour Point max °F		21.2	21.2
Cloud Point °F	46 to -0.4		
Sulfur max (ppm)	5000	5000	
Cetane Number min	40		40

Comparing Tables 5.1-2 and 5.1-3 shows that the average properties of current non-highway distillate are within the ASTM requirements, and for some properties, well within requirements. For example, except for California, the T90 of current non-highway diesel fuel is 25-40°F below the maximum allowed. The average cetane number of all non-highway distillate is well above the minimum of 40. Finally the pour point is well below the maximum allowed for fuel oil/heating oil and marine distillate fuel. One exception is that the API gravity of non-highway distillate fuel in PADDs 1 and 3, which includes the heating oil used in the Northeast, is just above the minimum.

While refiners might try to perform such shifts in blendstocks between fuels, note that we did not assume refineries would be shifting blendstocks between various distillate fuels to reduce the compliance costs associated with the NRLM diesel fuel sulfur standards. Instead, we projected the use of desulfurization techniques that will be sufficient to meet the new sulfur standards without shifting more difficult-to-treat sulfur compounds to other fuels. This approach appeared reasonable, given that we were evaluating the potential of over 100 refineries currently producing non-highway distillate fuel to reduce sulfur in NRLM diesel fuel. The ability to shift blendstocks between fuels to reduce costs is very refinery-specific and difficult to estimate on average across a wide range of refineries. Also, two primary types of shifts are possible and both have limits. One approach is to shift the heaviest portion of selected blendstocks such as LCO to the bunker or residual fuel pool, avoiding the need to desulfurize this material. However, the market for these heavy fuels is limited and on a national basis, this approach is generally not economically feasible. The other approach is to shift these difficult-to-treat streams and portions of streams to heating oil, which can meet less stringent sulfur standards. This would likely require the addition of additional product tankage and require more refineries to produce lower-sulfur NRLM diesel fuel. The material being shifted to heating oil could still require additional desulfurization to ensure that ASTM and state standards were still being met. Thus, there would be a cost trade-off, not just a cost reduction. Again, given the national scale of this analysis, we decided to avoid the projection of such shifts and limit our analysis to the desulfurization of current non-highway diesel fuel blendstocks. In this regard, our cost analysis as presented in Chapter 7 can be viewed as somewhat conservative.

5.2 Evaluation of Diesel Fuel Desulfurization Technology

5.2.1 Introduction to Diesel Fuel Sulfur Control

As mentioned in Section 5.1, the sulfur in diesel fuel comes from the crude oil processed by the refinery. One way to reduce the amount of sulfur in diesel fuel is therefore to process a crude oil that is lower in sulfur. Some refiners already do this. Others could switch to low- or at least lower-sulfur crude oils. However, there is limited capability worldwide to produce low-sulfur crude oil. While new oil fields producing light, sweet crude oil are still being discovered, most of the new crude oil production being brought on-line is heavier, more sour (i.e., higher sulfur) crude oils. The incentive to use low-sulfur crude oils has existed for some time and low-sulfur crude oils have traditionally commanded a premium price relative to higher-sulfur crude oils. While a few refiners with access to lower-sulfur crude oil might reduce their diesel sulfur levels this way, it is not feasible for most, let alone all U.S. refiners to switch to low-sulfur crude oils to meet a tighter diesel fuel sulfur standard. In addition, while helpful, a simple change to a low-sulfur crude oil may fall short of complying with the 500 ppm sulfur standard, and certainly fall short of the 15 ppm sulfur standard. Thus, changing to a sweeter crude oil was not considered viable for complying with the nonroad, locomotive, and marine diesel sulfur standards.

A method to reduce diesel fuel sulfur much more significantly is to chemically remove sulfur from the hydrocarbon compounds that comprise diesel fuel. This is usually accomplished through catalytically reacting the diesel fuel with hydrogen at moderate to high temperature and pressure over a fixed bed of hydrotreating catalyst. Two specific examples of this process are hydrotreating and hydrocracking. A modified version of hydrotreating that operates solely in the liquid state is now available by Process Dynamics. Another process licensed by Conoco-Phillips uses a moving bed catalyst to both remove and adsorb the sulfur using hydrogen at moderate temperature and pressure. There are other low-temperature and low-pressure processes being developed that don’t rely on hydrotreating, such as chemical oxidation. Sulfur can be removed via these processes up front in the refinery, such as from crude oil, before being processed in the refinery into diesel fuel. Or, sulfur can be removed from individual refinery streams that are to be blended directly into diesel fuel. Finally, another method to moderately reduce diesel fuel sulfur is to shift sulfur-containing hydrocarbon compounds to other fuels produced by the refinery.

After careful review of all these approaches, we expect that the sulfur reduction required by the 500 ppm sulfur standard will occur through chemical removal via conventional hydrotreating. For complying with the 15 ppm cap for NRLM diesel fuel, we expect it will be met primarily through liquid-phase hydrotreating, which is an emerging advanced desulfurization technology. This section will begin with a relatively detailed discussion of the capabilities of these various processes. Refiners may use the other methods to obtain cost-effective sulfur reductions that will complement the primary sulfur reduction achieved via hydrotreating. These other methods, such as FCC feed hydrotreating, adsorption and chemical oxidation are discussed following the primary discussion of distillate hydrotreating and liquid-phase hydrotreating. Another means for aiding the desulfurization of diesel fuel, particularly to comply with the 15 ppm standard, is undercutting, which removes the most difficult-to-treat sulfur compounds. Since undercutting can help ease the task of complying with the 15 ppm standard for any of the desulfurization technologies, we provide a discussion of undercutting below.

5.2.2 Conventional Hydrotreating

Hydrotreating generally combines hydrogen with a hydrocarbon stream at high temperature and pressure in the presence of a catalyst. Refineries currently employ a wide range of these processes for various purposes. For example, naphtha (gasoline-like material that does not meet gasoline specifications, such as octane level) being fed to the refinery reformer is always hydrotreated to remove nearly all sulfur, nitrogen and metal contaminants that would deactivate the noble metal catalyst used in the reforming process. Similarly, feed to the FCC unit is often hydrotreated to remove most of the sulfur, nitrogen and metal contaminants to improve the yield and quality of high value products, such as gasoline and distillate, from the FCC unit. Refineries currently producing highway diesel fuel to the 500 ppm standard hydrotreat their distillate to remove much of the sulfur present and to improve the cetane. That same unit or another hydrotreating unit in the refinery also hydrotreats some of the refinery streams used to blend up non-highway distillate. We expect that nearly all refiners will hydrotreat the naphtha produced by the FCC unit to remove most of the sulfur present to comply with the Tier 2 gasoline sulfur standards.[9]

If the temperature or pressure is increased sufficiently and if a noble metal catalyst is used, hydrotreating can more dramatically affect the chemical nature of the hydrocarbons, as well as remove contaminants. For example, through a process called hydrocracking, smaller, lighter molecules are created by splitting larger, heavier molecules. In the process, nearly all the contaminants are removed and olefins and aromatics are saturated into paraffins and naphthenes. Outside the United States, this process is commonly used to produce distillate from heavier, less marketable refinery streams. In the United States the hydrocracker is most often used to produce gasoline from poor quality distillate, such as LCO from the FCC unit.

A few refineries also currently hydrotreat their distillate more severely than is typical, but not as severely as hydrocracking. Their intent is to remove the sulfur, nitrogen and metallic contaminants and to also saturate most of the aromatics present. This is done primarily in Europe to meet very stringent specifications for both sulfur and aromatics applicable to certain diesel fuels and encouraged by reduced excise taxes. This severe hydrotreating process is also used in the United States to “upgrade” petroleum streams that are otherwise too heavy or too low in quality to be blended into the diesel pool, by cracking some of the material to lower molecular weight compounds and saturating some of the aromatics to meet the distillation and cetane requirements. A different catalyst that encourages aromatic saturation is used instead of one that simply encourages contaminant removal.

To meet the 500 ppm and the 15 ppm sulfur standards, we expect refiners to focus as much as possible on sulfur removal. Other contaminants, such as metals, are already sufficiently removed by existing refinery processes. While saturation of aromatics generally improves cetane, the cetane numbers of current nonroad, locomotive, and marine diesel fuels are typically already sufficient to comply with the applicable ASTM standards. Thus, refiners want to avoid saturating aromatics to avoid the additional cost of increased hydrogen consumption. Consequently, we anticipate refiners will choose desulfurization processes that minimize the amount of aromatics saturation. Current diesel fuel already meets all applicable specifications; hydrotreating to remove sulfur should not degrade quality, except possibly lubricity, as discussed in Section 5.9.1. Thus, with this one exception, there should be no need to improve diesel fuel quality as a direct result of this new diesel sulfur standard. Refiners choosing to improve fuel quality would be focusing on improved profitability, rather than meeting the 15 ppm sulfur standard.[C]

5.2.2.1 Fundamentals of Distillate Hydrotreating

Almost all distillate hydrotreater designs follow the same broad format. Liquid distillate fuel is heated to temperatures of 300 to 380°C, pumped to pressures of 500 to 700 psia, mixed with hydrogen, and passed over a catalyst. Hydrogen reacts with sulfur and nitrogen atoms contained in the hydrocarbon molecules, forming hydrogen sulfide and ammonia. The resulting vapor is then separated from the desulfurized distillate. The desulfurized distillate is usually simply mixed with other distillate streams in the refinery to produce diesel fuel and heating oil.

The vapor coming off the reactor still contains a lot of valuable hydrogen, because the reaction requires the use of a significant amount of excess hydrogen to operate efficiently and practically. However, the vapor also contains a significant amount of hydrogen sulfide and ammonia, which inhibit the desulfurization and denitrogenation reactions and must be removed from the system. Thus, the hydrogen leaving the reactor is usually mixed with fresh hydrogen and recycled to the front of the reactor for reaction with fresh distillate feed. This would cause a build up of hydrogen sulfide and ammonia in the system, since it has no way to leave the system. In some cases, the hydrogen sulfide and ammonia are chemically scrubbed from the hydrogen recycle stream. In other cases, a portion of the recycle stream is simply purged from the system as a mixture of hydrogen, hydrogen sulfide and ammonia. The latter is less efficient since it leads to higher levels of hydrogen sulfide and ammonia in the reactor, but it avoids the cost of building and operating a hydrogen sulfide scrubber.

Current desulfurization processes in the United States generally use only one reactor, due to the need to desulfurize diesel fuel only to 500 ppm or slightly lower. However, for diesel upgrading reactions or for deeper desulfurization reactions, a second reactor can be used. Instead of liquid distillate fuel going to the diesel fuel/heating oil pool after the first reactor, it would be stripped of hydrogen sulfide and ammonia and mixed with fresh hydrogen and sent to the second reactor, which is also called a second stage, after the inter stage stripping that occurs.

Traditional reactors are cocurrent in nature. The hydrogen is mixed together with the distillate at the entrance to the reactor and flow through the reactor together. Because the reaction is exothermic, heat must be removed periodically. This is sometimes done through the introduction of fresh hydrogen and distillate fuel in the middle of the reactor. The advantage of cocurrent design is practical as it eases the control of gas-liquid mixing and contact with the catalyst. The disadvantage is that the concentration of hydrogen is the highest at the front of the reactor where the easiest to remove sulfur compounds are highest in concentration and lowest at the outlet where the hardest to remove sulfur compounds are highest in concentration. The

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[C] Refiners can choose to “upgrade” heavy refinery streams that do not meet the cetane and distillation requirements for highway diesel fuel. The process for doing so is also called ring opening, since one or more of the aromatic rings of heavy, aromatic molecules are opened up, improving the value of the stream. Upgrading the heavy refinery streams to highway diesel fuel improves the stream’s market price by 10 - 30 c/gal.

opposite is true for the concentration of hydrogen sulfide. This increases the difficulty of achieving extremely low sulfur levels due to the low hydrogen concentration and high hydrogen sulfide concentration at the end of the reactor.

The normal solution to this problem is to design a counter-current reactor, where the fresh hydrogen is introduced at one end of the reactor and the liquid distillate at the other end. Here, the hydrogen concentration is highest (and the hydrogen sulfide concentration is lowest) where the reactor is trying to desulfurize the most difficult (sterically hindered) compounds. The difficulty of counter-current designs in the case of distillate hydrotreating is vapor-liquid contact and the prevention of hot spots within the reactor. The SynAlliance (Criterion Catalyst Corp., and Shell Oil Co.) has patented a counter-current reactor design called SynTechnology. With this technology, in a single reactor design, the initial portion of the reactor will follow a co-current design, while the last portion of the reactor will be counter-current. In a two reactor design, the first reactor could be co-current, while the second reactor could be counter-current.

ABB Lummus estimates that the counter-current design can reduce the catalyst volume needed to achieve 97 percent desulfurization by 16 percent relative to a co-current design.[10] The impact of the counter-current design is even more significant when aromatics reduction (or cetane improvement) is desired in addition to sulfur control.

Sulfur-containing compounds in distillate can be classified according to the ease with which they are desulfurized. Sulfur contained in paraffins or aromatics with a single aromatic ring are relatively easy to desulfurize. These molecules are sufficiently flexible so the sulfur atom is in a geometric position where it can make physical contact with the surface of the catalyst. The more difficult compounds are contained in aromatics consisting of two aromatic rings, particularly dibenzothiophenes. Dibenzothiophene contains two benzene rings that are connected by a carbon-carbon bond and two carbon-sulfur bonds (both benzene rings are bonded to the same sulfur atom). This compound is nearly flat in nature and the carbon atoms bound to the sulfur atom hinder the approach of the sulfur atom to the catalyst surface. Despite this, current catalysts are very effective in desulfurizing dibenzothiophenes, as long as only hydrogen is attached to the carbon atoms bound directly to the sulfur atom.

Distillate fuel, however, can contain dibenzothiophenes that have methyl or ethyl groups bound to the carbon atoms, which are in turn bound to the sulfur atom. These extra methyl or ethyl groups further hinder the approach of the sulfur atom to the catalyst surface. Dibenzothiophenes with such methyl or ethyl groups are commonly referred to as being sterically hindered. An example of a dibenzothiophene with a single methyl or ethyl group next to the sulfur atom is 4-methyl dibenzothiophene. An example of a dibenzothiophene with two methyl or ethyl groups next to the sulfur atom is 4,6-dimethyl dibenzothiophene. In 4,6-dimethyl dibenzothiophene, and similar compounds, the presence of a methyl group on either side of the sulfur atom makes it very difficult for the sulfur atom to react with the catalyst surface to assist the hydrogenation of the sulfur atom.

Most straight-run distillates contain relatively low levels of these sterically hindered compounds. LCO contains the greatest concentration of sterically hindered compounds, while other cracked distillate streams from the coker and the visbreaker contain levels of sterically hindered compounds in concentrations between straight-run and LCO. Thus, LCO is generally more difficult to desulfurize than coker distillate, which is in turn more difficult to treat than straight-run distillate.[11] In addition, cracked stocks, particularly LCO, have a greater tendency to form coke on the catalyst, which deactivates the catalyst and requires its regeneration or replacement.

The greater presence of sterically hindered compounds in LCO is related to two fundamental factors. First, LCO contains much higher concentrations of aromatics than typical straight run distillate.[12] All sterically hindered compounds are aromatics. Second, the chemical equilibria existing in cracking reactions favors the production of sterically hindered dibenzothiophenes over unsubstituted dibenzothiophenes. For example, in LCO, methyl substituted aromatics are twice as prevalent as unsubstituted aromatics. Di-methyl aromatics are twice as prevalent as methyl aromatics, or four times more prevalent as unsubstituted aromatics. Generally, desulfurizing 4-methyl dibenzothiophene using conventional desulfurization is six times slower than desulfurizing similar non-sterically hindered molecules, while desulfurizing 4,6-dimethyl dibenzothiophene using conventional desulfurization is 30 times slower. Slower reactions mean that either the volume of the reactor must be that much larger, or that the reaction must be somehow speeded up. The latter implies either a more active catalyst, higher temperature, or higher pressure. These alternatives are discussed below.

Because moderate sulfur reduction is often all that is required in current distillate hydrotreating, catalysts have been developed that focus almost exclusively on sulfur and other contaminant removal, such as nitrogen and metals. The most commonly used desulfurization catalyst consists of a mixture of cobalt and molybdenum (Co/Mo). These catalysts interact primarily with the sulfur atom and encourage the reaction of sulfur with hydrogen.

Other catalysts have been developed that encourage the saturation (hydrogenation) of the aromatic rings. As mentioned above, this generally improves the quality of the diesel fuel produced from this distillate. These catalysts also indirectly encourage the removal of sulfur from sterically hindered compounds by eliminating one or both of the aromatic rings contained in dibenzothiophene. Without one or both of the rings, the molecule is much more flexible and the sulfur atom can reach the catalyst surface unhindered. Thus, the desulfurization rate of sterically hindered compounds is greatly increased through the hydrogenation route. The most commonly used hydrogenation/desulfurization catalyst consists of a mixture of nickel and molybdenum (Ni/Mo).

Several important issues related to using the hydrogenation pathway for desulfurization should be highlighted. As pointed out above, one or both of the aromatics rings are being saturated, which significantly increases the consumption of hydrogen. It is important that one of the aromatic rings of a polyaromatic compound is saturated, as this is the facilitating step resulting in the desulfurization of a sterically hindered compound. If the mono aromatics compounds are also saturated, there is only a modest improvement in the desulfurization reaction rate of the sterically hindered compounds, however, at a large hydrogen cost. In addition, certain diesel fuel qualities, such as cetane, improve significantly as more of the aromatic compounds are saturated. However, the vendors of diesel desulfurization technology explained to us that if cetane improvement is not a goal, then the most cost-effective path to desulfurize the sterically hindered compounds is to saturate the polyaromatic compounds to monoaromatic compounds, but not to saturate the monoaromatic compounds. The vendors tell us that because the concentration of the monoaromatic compounds is at equilibrium conditions within the reactor, the monoaromatic compounds are being both saturated and unsaturated, which helps to enable the desulfurization of these compounds. It also means that the concentration of aromatics can be controlled by the reaction temperature and pressure.

The vendors also point out a variety of reasons why the cycle length of the catalysts that catalyze hydrogenation reactions, which likely occur in a second stage, is longer than the first stage desulfurization catalyst. First, the temperature at which the hydrogenation reactions occur to saturate the polyaromatic compounds to monoaromatic compounds, but not to saturate the monaromatic compounds, is significantly lower than the temperature of the first stage. The lower temperature avoids color change problems and reduces the amount of coke formation on the hydrogenation catalyst. Furthermore, since the first stage has somewhat “cleaned” the diesel fuel of contaminants such as sulfur, nitrogen and metals, the catalyst in this second hydrogenation stage is not degraded as quickly. Because the second stage has a cycle length as long as or longer than the first stage, adding the second stage is not expected to shorten the cycle length of the current distillate hydrotreater.

If refiners are “upgrading” their diesel fuel by converting heavy, high aromatic, low cetane, stocks to 15 ppm sulfur standard, they are intentionally reacting a lot of hydrogen with the diesel fuel. The hydrogen reactions with the diesel fuel saturates many or most of the aromatics, increases cetane number and greatly eases the reduction of sulfur. The lower concentration of aromatics and improved cetane of the upgraded feedstock then allows the product to be sold as highway diesel fuel. The much higher sales price of the highway diesel fuel compared with the lower value of the feedstock justifies the much larger consumption in hydrogen and the cost of a larger reactor.

Up to a certain level of sulfur removal, the CoMo catalyst is generally preferred. It is more active with respect to desulfurizing non-sterically hindered compounds, which comprise the bulk of the sulfur in distillate, straight-run or cracked. Below that level, the need to desulfurize sterically hindered compounds leads to greater interest in NiMo catalysts. Acreon Catalysts had indicated that NiMo are preferred for deep desulfurization due to this catalyst’s ability to saturate aromatic rings and make the sulfur atom more accessible to the catalyst. On the other hand, Haldor-Topsoe has performed studies indicating that CoMo catalysts may still have an advantage over NiMo catalysts, even at sulfur levels below 50 ppm.[13]

Two-stage processes may also be preferable to achieve ultra-low sulfur levels. Both stages could emphasize desulfurization or desulfurization could be emphasized in the first stage and hydrogenation/desulfurization emphasized in the second stage. In addition to this advantage, the main advantage of two stages lies in the removal of hydrogen sulfide from the gas phase after the first stage. Hydrogen sulfide inhibits desulfurization reactions, as discussed further in the next section. It can also recombine with nonsulfur-containing hydrocarbon compounds at the end of the reactor or even in subsequent piping, effectively adding sulfur to the desulfurized distillate. Removing hydrogen sulfide after the first stage reduces the hydrogen sulfide concentration at the end of the second stage by roughly two orders of magnitude, dramatically reducing both inhibition and recombination.

In one study, Haldor-Topsoe analyzed a specific desulfurized 50/50 blend of straight run distillate and LCO at 150 ppm sulfur and found that nearly all the sulfur is contained in sterically hindered compounds.[14] This feed contains more LCO than would be processed in the typical refinery. A refinery processing less LCO would presumably reach the point where the sulfur compounds were dominated by sterically hindered compounds at a lower sulfur level. They also compared the performance of CoMo and NiMo catalysts on a straight run distillate feed at the same space velocity. The NiMo catalyst performed more poorly than the CoMo catalyst above 200 ppm sulfur, and better below that level. This implies that much of the sulfur left at 200 ppm (and even above this level) was sterically hindered. These two studies indicate that the amount of sterically hindered compounds can exceed the 15 ppm sulfur cap by a substantial margin.

In addition to NiMo catalysts, precious metal catalysts are also very effective at desulfurizing sterically hindered compounds. An example of a precious metal catalyst is the ASAT catalyst developed by United Catalysts and Sud-Chemie AG, which uses both platinum and palladium.[15] They are most commonly used to more severely dearomatize distillate and increase cetane by opening up the aromatic rings, a process called ring opening.

5.2.2.2 Meeting a 15 ppm Cap with Distillate Hydrotreating

Using distillate hydrotreating to meet a 15 ppm sulfur cap on diesel fuel has been commercially demonstrated. Thus, meeting the 15 ppm cap is quite feasible using current refining technology. Assessing the most reliable and economic means of doing so is more complicated. Refiners already hydrotreat their highway diesel fuel to meet a 500 ppm sulfur cap. These hydrotreaters use a variety of catalysts and have a range of excess capacity. Thus, refiners are not all starting from the same place. Many refiners will also be producing heating oil, which must meet only a 5000 ppm cap (lower in some states). The high-sulfur heating oil may, for example, provide a place to blend the sterically hindered sulfur-containing compounds. Finally, the amount of cracked stocks that a refiner processes into diesel fuel varies widely. Those with a greater fraction of LCO will face a more difficult task of meeting a 15 ppm cap than those processing primarily straight-run distillate.

To understand the types of possible modifications to current distillate hydrotreating to improve its performance, it is useful to better understand the quantitative relationships between the various physical and chemical parameters involved in hydrotreating. Haldor-Topsoe has developed the following algebraic expression to describe the rate of desulfurization via both direct desulfurization and hydrogenation/desulfurization.

$$\text{Rate of Desulfurization Per Catalyst Surface Area} = \frac{k \times C_s^{\,n} \times P_{H2}^{\,a}}{(1 + K_{H2S} \times P_{H2S})} + \frac{k \times C_s^{\,m} \times P_{H2}^{\,b}}{(1 + K_F \times C_F)}$$

Where:

k, K_{H2S} and K_F are various rate constants, which vary only with temperature.
C_s is the concentration of sulfur in the distillate.
P_{H2} and P_{H2S} are the partial pressures of hydrogen and hydrogen sulfide in the vapor phase.
$K_F \times C_F$ is the total inhibition due to hydrogen sulfide, ammonia, and aromatics n, m, a, and b are various constant exponents.

The first term represents the rate of direct desulfurization, such as that catalyzed by CoMo. This reaction rate increased by increasing the partial pressure of hydrogen. However, it is inhibited by increasing concentrations of hydrogen sulfide, which competes with the distillate for sites on the catalyst surface.

The second term represents the rate of desulfurization via hydrogenation of the aromatic ring next to the sulfur atom. This rate of desulfurization also increases with higher hydrogen partial pressure. However, this reaction is inhibited by hydrogen sulfide, ammonia, and aromatics. This inhibition by aromatics leads to the presence of a thermodynamic equilibrium condition that can prevent the complete saturation of aromatics. Also, this inhibition makes it more difficult to desulfurize cracked stocks, which contain high concentrations of both sterically hindered sulfur compounds and aromatics. While the literature generally expresses a preference for NiMo catalysts for desulfurizing cracked stocks, Haldor-Topsoe has found situations where this aromatics inhibition leads them to favor CoMo catalysts even for desulfurizing feeds with a high concentration of sterically hindered compounds.

These relationships identify the types of changes that could improve the performance of current distillate hydrotreaters. First, a more active catalyst can be used. This increases the “k” terms in the above equations. Second, temperature can be increased, which also increases the “k” terms in the above equations. Third, improvements can often be made in vapor-liquid contact, which effectively increases the surface area of the catalyst. Fourth, hydrogen purity can be increased. This increases the hydrogen concentration, which the P_{H2} term in the two numerator terms of the equation. Fifth, the concentration of hydrogen sulfide in the recycle stream can be removed by scrubbing. This decreases the P_{H2S} and C_F terms in the two denominator terms of the equation. Finally, more volume of catalyst can be used, which increases the surface area proportionally.

Regarding catalysts, at least two firms have announced the development of improved catalysts since the time that most distillate hydrotreaters were built in the United States to meet the 1993 500 ppm sulfur cap: Akzo Nobel / Nippon Ketjen Catalysts (Akzo Nobel) and Haldor-Topsoe. Akzo Nobel currently markets four CoMo desulfurization catalysts: KF 752, KF 756 and KF 757, which have been available for several years, and KF 848, which was announced in 2000.[16] KF 752 can be considered to be typical of an Akzo Nobel catalyst of the 1992-93 time frame, while KF 756 and 757 catalysts represent improvements. Akzo Nobel estimates that under typical conditions (e.g., 500 ppm sulfur), KF 756 is 25 percent more active than KF 752, while KF 757 is more than 50 percent more active than KF 752 and 30 percent more active than KF 756.[17] However, under more severe conditions (e.g., <50 ppm sulfur), KF 757 is 35-75 percent more active than KF 756. KF 848 is 15 - 50 percent more active than KF 757. Commercial experience exists for both advanced catalysts. KF 756 is widely used in Europe (20 percent of all distillate hydrotreaters operating on January 1, 1998), while KF 757 has been used in at least three hydrotreaters commercially. KF 757 and KF 842 utilizes what Akzo Nobel calls STARS technology, Super Type II Active Reaction Sites. Type II refers to a specific kind of catalyst site that is particularly good at removing sulfur from sterically hindered compounds.

In terms of sulfur removal, Akzo Nobel projects that a desulfurization unit producing 500 ppm sulfur with KF 752 will produce 405, 270 and 160 ppm sulfur with KF 756, KF757, and KF 842, respectively.

In 2001 and 2003, Akzo Nobel announced two new catalysts. In 2001, Akzo announced the introduction of a highly active catalyst named Nebula, which offers a different way to use coatings for catalysts. A typical catalyst is composed of two parts: an active coating containing metals and a generally inactive substrate. For Nebula, Akzo Nobel concentrated the metal coatings and omitted the substrate. Because of the very high metals content, Nebula costs several times more than conventional catalysts. The higher activity of the Nebula catalyst leads to an increased tendency for coking, which must be countered by using a high hydrogen partial pressure, resulting in a higher hydrogen consumption. (The hydrogen consumption is higher because a higher percentage of the aromatics are saturated to nonaromatic compounds.) According to Akzo Nobel, a refiner may be able to meet the 15 ppm sulfur standard by simply replacing a part of or all of its existing catalyst with Nebula and providing significantly more hydrogen (which may possibly require the addition of a hydrogen plant). Nebula may significantly reduce the capital investment for meeting the 15 ppm sulfur standard. In 2003, Akzo announced that Nebula was modified somewhat to contain 15 - 20 percent less metals, but with the same activity as the original Nebula. The updated Nebula catalyst, now called Nebula 20, can better handle heavier feeds.[18]

In 2003, Akzo Nobel announced a new catalyst named KF-760. The KF-760 catalyst is a CoMo catalyst designed for better denitrogenation of diesel fuel, in addition to the desulfurization being sought after. Where the nitrogen content is inhibiting the desulfurization of the diesel fuel, this catalyst can have 15 - 20 percent higher activity compared to their previous best, KF-757, with only a modest increase in hydrogen consumption.[19]

Haldor-Topsoe has also developed more active catalysts. Its TK-554 catalyst is analogous to Akzo Nobel's KF 756 catalyst, while its newer, more active catalyst is termed TK-574. For example, in pilot plant studies, under conditions where TK-554 produces 400 ppm sulfur in straight run distillate, TK 574 will produce 280 ppm. Under more severe conditions, TK-554 will produce 60 ppm, while TK 574 will produce 30 ppm. Similar benefits are found with a mixture of straight-run and cracked stocks. Just this year, Haldor Topsoe announced a new line of catalysts named Brim.[20] The announcement did not include information about the improvements of this line of catalysts over its previous catalysts.

UOP projects a similar reduction in sulfur due to an improved catalyst. They estimate that a hydrotreater producing 500 ppm sulfur distillate today (20 percent LCO, 10 percent light-coker gas oil) could produce 280 ppm sulfur distillate with a 50 percent more active catalyst.[21]

Over the last six years, Criterion Catalyst Company announced two new catalyst technologies. One was called Century, and the other was called Centinel.[22] These two lines of catalysts were reported to be 45 to 70 percent and 80 percent more active, respectively, at desulfurizing petroleum fuel than conventional catalysts used in the mid-90s. These improvements have come about primarily through better dispersion of the active metal on the catalyst substrate. Criterion announced a new line of catalyts in early 2004 named Ascent.[23] These catalysts are expected to be at least 20 percent more active than the Centinel line of catalysts.[24]

Axens catalysts, which is associated with IFP, offers three catalysts designed for deep desulfurization of distillate fuel. One is a CoMo catalyst named HR 406 and it is reported to be 40 percent more active than HR 306, its predecessor. Another catalyst offered by Axens is named HR 468 and it offers a mixture of CoMo with NiMo metals. The third catalyst offered by Axens is a NiMo catalyst named HR 448. The NiMo catalyst is recommended for deep desulfurization at higher pressures, while HR 468 is more recommended for use at lower pressures.[25]

This shows that changing to a more active catalyst, by itself, can reduce sulfur significantly. Based on the history of the industry, improvements in catalyst performance can be anticipated over time to result in roughly a 25 percent increase in catalyst activity every four years. Vendors have informed us that the cost of these advanced catalysts is very modest relative to less active catalysts. BP-Amoco projects that a 70 percent improvement in catalyst activity could reduce sulfur from a current hydrotreater meeting a 500 ppm sulfur specification to 30 ppm.[26] Acreon/IFP/Procatalyse is not optimistic, however, that a catalyst change alone will enable refiners to meet this sulfur level.[27] Improved catalysts will, however, reduce the reactor size needed for achieving the target sulfur level compared to a less active catalyst.

The second way to improve the hydrotreating of diesel fuel for deeper desulfurization is to reduce the concentration of hydrogen sulfide, which reduces the inhibition of the desulfurization and hydrogenation reactions. Hydrogen sulfide can be removed by chemical scrubbing. Haldor-Topsoe indicates that decreasing the concentration of hydrogen sulfide at the inlet to a co-current reactor by three to six volume percent can decrease the average temperature needed to achieve a specific sulfur reduction by 15-20ºC, or reduce final sulfur levels by more than two-thirds. UOP projects that scrubbing hydrogen sulfide from recycled hydrogen can reduce sulfur levels from roughly 285 to 180 ppm in an existing hydrotreater.

The third type of improvement to current distillate hydrotreating is to improve vapor-liquid contact. Akzo Nobel estimates that an improved vapor-liquid distributor can reduce the temperature necessary to meet a 50 ppm sulfur level by 10 ºC, which would in turn increase catalyst life and allow an increase in cycle length from 10 to 18 months. Based on the above data from Haldor-Topsoe, if temperature were maintained, the final sulfur level could be reduced by 50 percent. Similarly, in testing of an improved vapor-liquid distributor in commercial use, Haldor-Topsoe found that the new distributor allowed a 30 percent higher-sulfur feed to be processed at 25ºC lower temperatures, while reducing the sulfur content of the product from 500 to 350 ppm. Maintaining temperature should have allowed an additional reduction in sulfur of more than two-thirds. Thus, ensuring adequate vapor-liquid contact can have a major impact on final sulfur levels.

The fourth type of improvement possible is to increase hydrogen partial pressure and/or purity. As discussed above, this increases the rate of both desulfurization and hydrogenation reactions. Haldor-Topsoe indicates that increasing hydrogen purity is preferable to a simple increase in the pressure of the hydrogen feed gas, since the latter will also increase the partial pressure of hydrogen sulfide later in the process, which inhibits both beneficial reactions. Haldor-Topsoe projects that an increase in hydrogen purity of 30 percent lowers the temperature needed to achieve the same sulfur removal rate by 8 to 9ºC. Alternatively, temperature could be maintained while increasing the amount of sulfur removed by roughly 40 percent. Hydrogen purity can be increased through the use of a membrane separation system or a PSA unit. UOP projects that purifying hydrogen can reduce distillate sulfur from 180 to 140 ppm from an existing hydrotreater.

The fifth type of improvement is to increase reactor temperature. Haldor-Topsoe has shown that an increase of 14ºC while processing a mix of straight run distillate and LCO with its advanced TK-574 CoMo catalyst will reduce sulfur from 120 ppm to 40 ppm.[28] UOP projects that a 20 ºF increase in reactor temperature would decrease sulfur from 140 to 120 ppm. The downside of increased temperature is reduced catalyst life (i.e., the need to change catalyst more frequently). This increases the cost of catalyst, as well as affects highway diesel fuel production while the unit is down for the catalyst change. Still, current catalyst life currently ranges from 6 to 60 months, so some refiners could increase temperature and still remain well within the range of current industry performance. The relationship between temperature and life of a catalyst is a primary criterion affecting its marketability. Thus, catalyst suppliers generally do not publish these figures.

Sixth, additional sulfur can be removed by increasing the amount of recycle gas sent to the inlet of the reactor. However, the effect is relatively small. Haldor-Topsoe indicates that a 50 percent increase in the ratio of total gas/liquid ratio decreases the necessary reactor temperature only by 6 to 8ºC. Or, temperature can be maintained and the final sulfur level reduced by 35 to 45 percent.

Overall, Akzo-Nobel projects that current hydrotreaters can be modified short of a revamp with a second reactor to achieve 50 ppm sulfur. While this improvement is somewhat greater than the 50 percent improvement measured by Akzo Nobel at current desulfurization severity, it indicates that it may be possible to improve current hydrotreaters to produce distillate sulfur levels in the 50-100 ppm range. Thus, it appears that additional measures would be needed to meet a 15 ppm cap. This leads to the seventh means to realize deeper desulfurization, which is to increase catalyst volume through the addition of a second reactor. UOP projects that doubling the catalysts volume by adding another reactor would reduce sulfur from 120 to 30 ppm. For each refinery, refiners would need to examine how much additional sulfur control they would be able to achieve through measures one through six, and then size this second reactor to achieve the 15 ppm sulfur cap.

These individual improvements described cannot be simply combined, either additively or multiplicatively. As mentioned earlier, each existing distillate hydrotreater is unique in its combination of design, catalyst, feedstock, and operating conditions. While the improvements described above can be made in many cases, it is not likely that all the improvements mentioned are applicable to any one unit; the degree of improvement could either be greater than or less than the benefits indicated.

Some refiners may therefore have to implement one additional technical change listed by UOP to be able to meet the 15 ppm standard. This last technical change is to add a second stage to current single-stage 500 ppm hydrotreaters. This second stage would consist of a second reactor, and a high pressure, hydrogen sulfide scrubber between the first and second reactor. The compressor would also be upgraded to allow the new second reactor to be operated at a higher pressure. Assuming use of the most active catalysts available in both reactors, UOP projects that converting from a one-stage to a two-stage hydrotreater could produce 5 ppm sulfur relative to a current level of 500 ppm today.

In addition to these major technological options, refiners may have to debottleneck or add other more minor units to support the new desulfurization unit. These units could include hydrogen plants, sulfur recovery plants, amine plants and sour water scrubbing facilities. All these units are already operating in refineries but may have to be expanded or enlarged.

To assess the degree that these measures would be needed, it is useful to examine the commercial and pilot plant performance of distillate hydrotreating to achieve very low sulfur levels.

5.2.2.3 Low-Sulfur Performance of Distillate Hydrotreating

Data from both pilot plant studies and commercial performance are available indicating the capability of various hydrotreating technologies to reduce distillate sulfur levels to very low levels. While many reports of existing commercial operations focus on reducing sulfur to meet a 500 ppm sulfur standard, or somewhat below that sulfur level, studies of achieving lower sulfur levels (e.g., 10 to 50 ppm) are associated with also reducing aromatic content significantly. This combination is related to the fact that Swedish Class II diesel fuel must meet a tight aromatics specification in 2005 along with a 10 ppm sulfur standard. Other European diesel fuel must also meet a 10 ppm sulfur standard.

Another study projected the technology and resulting cost to reduce diesel fuel sulfur to comply with EPA's highway 15 ppm sulfur cap standard and sulfur standards on nonhighway distillate . The Engine Manufacturers Association retained Mathpro for this study. The projections of this study are discussed in Chapter 7. The discussion in this chapter will focus on the available pilot plant and commercial data demonstrating the achievement of low sulfur levels. It is worth noting that until the 15 ppm standard was established for highway diesel fuel in the United States and the announcements by the German government to seek sulfur levels as low as 10 ppm, there had been little effort by industry to develop technology capable of such a level across the diesel pool. Recent advances by catalyst manufacturers demonstrating the feasibility of producing diesel fuel meeting these levels through pilot plant testing and some commercial demonstrations should be considered a first-generation of technology, with new and continual advances expected over time.

As of mid 2003, Criterion Centinel and SynCat^{TM} catalysts were installed in 37 deep desulfurization units in operation in the World, including 13 Syn Technology Units. While the purpose for each unit is to desulfurize distillate to 50 ppm or below, eight of them served as a first stage of a two stage dearomatization type unit where ULSD was capable of being produced. (Lummus' licensed SynTechnology).

The other 24 hydroprocessing units operating with Criterion's Centinel's catalysts are desulfurizing distillate down to under 50 ppm sulfur, with 6 of these consistently under 15 ppm.

IFP, using Axens catalysts, offers its Prime D technology for deep desulfurization, aromatics saturation and cetane improvement.[29] Using a NiMo catalyst, IFP's Prime D process can produce distillate sulfur levels of 10 ppm from straight run distillate and of less than 20 ppm from distillate containing 20 to 100 percent cracked material using a single-stage reactor. With a two-stage process, less than one ppm sulfur can be achieved.

United Catalysts and Sud-Chemie AG have published data on the performance of their ASAT catalyst, which uses platinum and palladium.[30] The focus of their study was to reduce aromatics to less than 10 volume percent starting with a feed distillate containing up to 500 ppm sulfur and at least 100 ppm nitrogen. Starting with a feed distillate containing 400 ppm sulfur and 127 ppm nitrogen and 42.5 volume percent aromatics, the ASAT catalyst was able to reduce sulfur to eight to nine ppm, nearly eliminate nitrogen, and reduce aromatics to two to five volume percent. Hydrogen consumption was 800 to 971 standard cubic feet per barrel (SCFB).

Akzo Nobel has summarized the commercial experience of about a year's worth of operations of their STARS catalyst for desulfurizing diesel fuel at the BP-Amoco refinery in Grangemouth, UK.[31] The original unit was designed to produce 35,000 barrels per day of diesel fuel at 500 ppm treating mostly straight-run material, but some LCO was treated as well. Akzo Nobel's newest and best catalyst (KF 757 at that time) was dense-loaded into the reactor to produce 45,000 barrels per day diesel fuel at 10-20 ppm (to meet the 50 ppm standard).[D] From the data, it was clear to see that as the space velocity changed, the sulfur level changed inversely

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[D] Dense loading is a process of packing a certain volume of catalyst into a smaller space than conventional catalyst loading.

proportional to the change in space velocity. Usually when the space velocity dipped below 1.0, the sulfur level dropped below 10 ppm. At that refinery, however, it was not necessary to maintain the sulfur level below 10 ppm.

Akzo Nobel also has its STARS catalysts operating in four other units in Europe and the Middle East, three of which are producing diesel fuel with less than 10 ppm sulfur, and another unit producing diesel fuel with less than 20 ppm sulfur. Three of these units process a blend of light and heavy straight run feeds, while the other is processing a stream which is predominantly comprised of cracked stocks. Additionally, Akzo Nobel is demonstrating its Nebula catalysts commercially in three different applications in Europe producing diesel fuel ranging from 5 ppm to 50 ppm. One of those is for treating cracked stocks in addition to straight run, and the refinery is meeting a 10 ppm standard at 650 psi partial pressure.

Haldor Topsoe has their catalysts in 27 units worldwide, either as standalone desulfurization units or the first stage of a desulfurization and dearomatization unit, producing diesel fuel to under 50 ppm sulfur. While most of these are in Europe, some are also in the U.S. Of these, 17 are producing diesel fuel to under 10 ppm sulfur; some of these have cracked stocks while others do not.

Based on all this laboratory and real world experience, it is clearly feasible to produce diesel fuel with a sulfur level of 15 ppm or less even if the feedstocks contain a great deal of cracked stocks. The challenge refiners will face is how to minimize the cost of doing so. To minimize costs, refiners will have to figure out how to apply the desulfurization/hydrogenation methods on their own diesel fuels. The specifics, and thus the economics, of accomplishing this depends on the amount of cracked stocks that the refiner blends into diesel fuel. A few refiners have the possibility of shifting some of the sterically hindered compounds to fuels complying with less stringent sulfur standards, such as heating oil. However, our analysis of the feasibility of desulfurization technology did not consider the occurrence of feedstock shifting as necessary for refiners to meet the diesel sulfur standards.

5.2.3 Process Dynamics Isotherming

In the late 1990s, a professor at the University of Arkansas applied some ingenuity in reaction chemistry to diesel desulfurization. After conceiving of this process, he started a company named Process Dynamics. The reaction technology reacts diesel fuel with hydrogen, which is totally dissolved in the diesel fuel, in a plug flow reactor. Since the hydrogen gas is dissolved into the diesel fuel, the reactor needs to be designed only to handle a liquid, instead of the two phase reactors designed for conventional hydrotreating. Because only about 75 standard cubic feet of hydrogen can be dissolved into each barrel of diesel fuel and the hydrogen consumption for a particular desulfurization step can be much higher than that, this technology cannot be a once-through process. Process Dynamics solved that limitation by recycling the feed after a very short residence time in the reactor to recharge the liquid with more hydrogen and to mix this recycle with some untreated diesel fuel before sending it to the reactor. Thus, the recycled partially desulfurized diesel fuel acts like a diluent to the fresh feed controlling the hydrogen consumption, and the diesel fuel is recharged with hydrogen and sent to the reactor to be desulfurized several times as it is being treated.[32] [33]

The Process Dynamics Isotherming process has some apparent advantages over conventional desulfurization. First, since the hydrogen is already in the liquid phase, the hydrotreating reaction can occur much more quickly, because, as described by Process Dynamics, the kinetics of conventional hydrotreating are mass transfer-limited, which is the rate at which gaseous hydrogen can transfer into the liquid phase. Process Dynamics makes this point by the following reaction equations for hydrotreating diesel fuel:[34]

rg = kg (PH2 - P×H2) (rate of hydrogen mass transfer into the liquid phase)

Where:

rg = transfer rate of hydrogen gas into diesel fuel.
kg = hydrogen gas mass transfer rate.
PH2 = Partial pressure of hydrogen in the gas phase.
P×H2 = Partial pressure of hydrogen at the catalyst.

and

rs = ks T[S][P×H2] (rate of desulfurization at the catalyst site)

Where:

rs = rate of reaction of sulfur.
ks = reaction rate constant for sulfur removal.
P×H2 = partial pressure of hydrogen at the catalyst.
T = temperature in degrees absolute.
[S] = concentration of sulfur.

If the desulfurization rate of reaction (rs) is much slower than the rate at which hydrogen can dissolve into diesel fuel (rg), then there would probably not be any benefit for the Process Dynamics Isotherming process. However, according to Process Dynamics, the rate of reaction for desulfurization is faster than the rate of mass transfer, thus, the rate of reaction for diesel hydrotreating is limited by the mass transfer of hydrogen into diesel fuel. Thus, the Process Dynamics process increases the rate of reaction by dissolving the hydrogen needed for the reaction into the liquid phase before sending this liquid to the reactor. The faster rate of reaction is indicated by the fact that the Process Dynamics desulfurization process, desulfurize an unhydrotreated distillate comprised of a typical mix of distillate blendstocks down to about 500 ppm at a space velocity of 8 hour^{-1}. Conversely, conventional hydrotreating requires a space velocity of about 2 hour^{-1} to accomplish the same task. However, as you go lower and lower in sulfur levels, the rate of reaction slows due to the increased concentration of sterically hindered compounds. When the rate of reaction for desulfurization gets slower than the mass transfer rate, the Process Dynamics process loses its advantage over conventional hydrotreating. Therefore, the Process Dynamics process can be used in conjunction with conventional hydrotreating to desulfurize diesel fuel to the 15 ppm standard. The Process Dynamics unit would be inserted before the conventional hydrotreater to treat untreated distillate fuel down to 500 ppm and the conventional hydroteater would then handle the desulfurization duty from 500 ppm to 15 ppm.

There are a two important benefits to the Process Dynamics process because it has a higher space velocity. One benefit is that the Process Dynamics process requires a smaller amount of catalyst. By definition, if the same volume of feed can be treated faster than another process, the amount of catalyst needed is proportionally lower by the inverse proportion of the space velocity. The second advantage of having a faster space velocity is that the reactors are sized much smaller to hold the lower volume of catalyst. Both of these benefits result in lower costs for the Process Dynamics Isotherming deslfurization process. The lower catalyst volume required by Process Dynamics Isotherming costs proportionally less because the Process Dynamics desulfurization process uses the same catalysts as conventional hydrotreating. Similarly, the smaller reactor volume reduces the capital costs, although in this case the cost reduction is not necessarily proportionally less as smaller reactors have a poorer economy of scale compared with larger reactors.

The Process Dynamics engineers point out that the Isotherming process also has other benefits over conventional hydrotreating. When some of the aromatics in diesel fuel are saturated during the desulfurization process, heat is generated. In the case of conventional hydrotreating, much of this heat is intentionally quenched away in an attempt to avoid excessive temperature excursions. Excessive temperature excursions and local low hydrogen concentration can lead to coking, which is a constant problem with conventional hydrotreating. However, the higher space velocity of the Process Dynamics process coupled with the fact that the feed is diluted by the recycle stream allows for better control of the process temperature. Furthermore, the ready availability of hydrogen in the liquid phase along with the better temperature control prevents most of the coking from occurring. Thus, the internally generated heat can be conserved, instead of being quenched away, and used to heat the process. The conserved heat means that little to no external heating is required, which provides a savings in natural gas consumption relative to conventional hydrotreating. However, a small heater is still needed to heat the feed during start-up.

Another advantage of the Process Dynamics desulfurization process is that it does not need a hydrogen gas recycle compressor. Because the hydrogen pumped into solution and going to the reactor is either used up or remains in solution, there is no residual hydrogen gas to recycle. Compressors operating at the pressures that diesel fuel desulfurization occurs are expensive, long leadtime delivery items. Thus, by omitting the recycle gas compressor and using smaller reactors, the Process Dynamics desulfurization process not only saves substantial capital costs compared with conventional hydrotreating, but it also means a somewhat shorter construction time. The smaller reactors and heater coupled with the fact that a recycle gas compressor is not needed means that the Process Dynamics process requires a smaller footprint compared with conventional hydrotreating, facilitating the installation of the Process Dynamics unit in today's refineries which are often space-limited.

While aspects of the Process Dynamics Isotherming desulfurization process for diesel fuel desulfurization are novel compared with conventional diesel desulfurization, many aspects of the process are the same. Much of the list of required equipment is the same for the Process Dynamics process as for conventional hydrotreating. Table 5.2-1 shows both the similarities and differences between the two.

Table 5.2-1
Major Equipment Needed for Process Dynamics Isotherming and Conventional Hydrotreating

	Process Dynamics Isotherming	Conventional Hydrotreating
Heat Exchangers	Yes	Yes
Heater	Yes (small and for startup only)	Yes
Hydrogen gas compressor	Yes	Yes (for hydrogen makeup)
Mixers for dissolving hydrogen into the diesel fuel	Yes	No
Reactor (s)	Yes (2 - 4 small plug flow)	Yes (1 - 2 large trickle bed)
Reactor distributor	No	Yes
High-pressure flash drum and hydrogen separator	Yes	Yes
Low-pressure separator	Yes	Yes
Recycle hydrogen compressor	No	Yes
Recycle hydrogen gas scrubber	No	Yes

Process Dynamics has accumulated some data on the Isotherming desulfurization process from testing they have done with their pilot plant. Process Dynamics started up a pilot plant in late 2001. Recently, Process Dynamics installed a commercial demonstration unit of their technology at a Giant refinery as a revamp to an existing highway hydrotreater to demonstrate compliance with the highway diesel fuel 15 ppm sulfur standard, which begins in mid 2006. The unit was started up in September of 2002 and the Process Dynamics engineers have been working with the refinery engineers to optimize the unit for the refinery. Since early 2003, the Process Dynamics demonstration unit has consistently been producing diesel fuel under 15 ppm.

After successful demonstration of its technology at the Giant refinery, Process Dynamics is working on signing license agreements for the Process Dynamics desulfurization process. In early 2004, Process Dynamics was working on signing four additional license agreements here in the U.S.[35]

5.2.4 Phillips S-Zorb Sulfur Adsorption

A prospective diesel desulfurization process was announced by Phillips Petroleum in late 2001.[36] This process is an extension of their S-Zorb process for gasoline and thus is called S-Zorb for diesel fuel. The process is very different from conventional diesel fuel hydrotreating in which reacts the sulfur with hydrogen over a catalyst to form H2S. The S-Zorb process adsorbs the sulfur molecule, still attached to the hydrocarbon, onto a sorbent at a pressure of 275 to 500 pounds per square inch gauge (psig) and at a temperature of 700 to 800˚ F and in the presence of hydrogen in the S-Zorb reactor. The catalyst activity of the sorbent next cleaves the sulfur atom from the sulfur-containing hydrocarbon. To prevent the accumulation of sulfur on the catalyst, the sulfur containing sorbent is continually removed from the reactor. The removed sorbent is moved over to a receiving vessel by an inert lift gas, at which point the lift gas and the entrained diesel fuel is removed from the sorbent. The sorbent next drops down into a lockhopper that facilitates the movement of the sorbent to the regenerator. In the regeneration vessel, the sulfur is burned off of the sorbent with oxygen and the generated SO_2 is sent to the sulfur plant. The regenerated sorbent then drops down into a reducer vessel where the sorbent is returned back to its active state. The sorbent is then recycled back to the reactor for removing more sulfur. Because the catalyst is continuously being regenerated, Phillips estimates that the unit will be able to operate four to five years between shutdowns. Because untreated distillate can contain several percent sulfur, Phillips believes that its S-Zorb process for diesel could be overwhelmed by the amount of sulfur adsorbing onto the catalyst. Thus, the S-Zorb process may not be able to economically treat all untreated distillate streams that are high in sulfur, and is best suited to treat distillate containing 500 ppm sulfur or less. However, some refiners running sweet crudes and producing low-sulfur non-highway diesel volumes (from straight-run diesel and hydrocrackate diesel) may have lower uncontrolled nonhighway sulfur levels. These refiners may be able to use the S-Zorb process to lower their nonhighway diesel sulfur.

Phillips' S-Zorb diesel desulfurization process has been demonstrated in a pilot plant that started up in early 2002. This pilot plant has provided Phillips data on how the unit will process varying formulations of diesel fuel or diesel fuel blendstocks. The pilot plant testing data released by Phillips has shown that diesel fuels blended with LCO can be desulfurized below 5 ppm. Phillips has also shown that straight-run diesel fuel can be desulfurized below measurable levels and a 100 percent LCO stream can be desulfurized down to 10 ppm.

While the S-Zorb diesel desulfurization process has not been demonstrated commercially, Phillips has demonstrated the S-Zorb technology for desulfurizing gasoline. An S-Zorb gasoline desulfurization unit started up at Phillips' Borger refinery in April of 2001. According to Phillips, their gasoline desulfurization unit has operated as designed for the past three years. The successful demonstration of their gasoline desulfurization unit at Borger has interested many refiners in using S-Zorb gasoline desulfurization process for complying with the Tier 2 gasoline sulfur program.[E] Phillips shared with us in late 2003 that they have licensed their S-Zorb for gasoline processing for installation in 23 refineries in North America. That the Borger S-Zorb gasoline desulfurization unit has operated as designed and that there are 23 new S-Zorb gasoline units planned to start up demonstrates that there is agreement within the refining industry that the S-Zorb process works.

Most refiners, however, are very conservative and will not be willing to rely only on pilot plant testing or demonstration of a technology for another fuel as the basis for purchasing a desulfurization unit that costs tens of millions of dollars. They will want to see a particular technology operating as a commercial unit for desulfurizing diesel fuel for at least two years

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[E] Starting this year, many refiners will be starting up their gasoline desulfurization units for complying with the 30 ppm Tier 2 gasoline sulfur standard, which phases in from 2004 to 2006.

before trusting that the technology is reliable. However, Phillips is not planning to install a commercial demonstration unit of its S-Zorb diesel fuel desulfurization process, nor is Phillips planning on installing an S-Zorb for diesel unit for complying with the 15 ppm sulfur highway diesel fuel standard, which begins to take effect in mid-2006, in any of its refineries.[37] Consequently, even though S Zorb for diesel may be capable of desulfurizing diesel fuel to less than 15 ppm sulfur, it does not appear that it will factor into the mix of technologies used to meet the NRLM 15 ppm diesel fuel standards.

5.2.5 Chemical Oxidation and Extraction

Another desulfurization technology being developed by Unipure and UOP is based on chemical oxidation. For these companies, the chemical oxidation desulfurization of diesel fuel is accomplished by first forming a water emulsion with the diesel fuel. In the emulsion, the sulfur atom is oxidized to a sulfone using a strong oxidizing agent, such as catalyzed peroxyacetic acid. With an oxygen atom attached to the sulfur atom, the sulfur-containing hydrocarbon molecules become polar and hydrophilic and then move into the aqueous phase. These sulfone compounds can either be desulfurized or perhaps be converted to a surfactant that could be sold to the soap industry at an economically desirable price. The earnings made from the sales of the surfactant could offset much of the cost of oxidative desulfurization.

Unipure has set up a 50 barrel per day pilot plant which started operating in the spring of 2003. UOP is still developing its oxidation technology in the lab. Neither of these oxidation processes are available for licensing at this time.

Late in the 1990s, Petrostar had started the development of an oxidation process for desulfurizing diesel fuel. This oxidation technology was similar to that of Unipure’s. However, sometime in the last year Petrostar abandoned its work on that technology. Early in 2003, Lyondell-Citgo announced that they had recently developed a chemical oxidation desulfurization technology. This process is similar in some ways to Unipure's and Petrostar's oxidation processes, but also different in some pronounced ways. The differences are that instead of the using expensive peroxyacetic acid to create sulfones, this process uses t-butyl hydroperoxide oxidant to convert sulfur species in diesel to sulfones (this eliminates the need to recycle a co-oxidant acid). T- butyl hydroperoxide is not as corrosive as peroxyacetic acid, thus Lyondell’s process is projected to be constructed from less expensive metallurgy. Lyondell has pilot plant success desulfurizing 500 ppm diesel fuel to less than 10 ppm, but abandoned further development of this technology in late 2003.

The best opportunity for oxidation and extraction technologies to penetrate the desulfurization market my lie with smaller refineries and terminals. Terminals may find that it is cheaper to implement some sort of desulfurization technology to handle the overproduction of off spec downgrade and interface than it would be to ship it off to the nearest entity equipped to distill and hydrotreat this material. Many small refineries and terminals don’t have access to a cheap source of hydrogen and may not have sulfur plants, so having a technology which can treat their distillate material without the need to install grassroots hydrogen units and sulfur plants could make the costs associated with desulfurization reasonable to them.

5.2.6 FCC Feed Hydrotreating

As described earlier in this section, sulfur can be removed from distillate material early or late in the refining process. Early in the process, the most practical place to remove sulfur is before the FCC unit. The FCC unit primarily produces gasoline, but it also produces a significant quantity of LCO which makes up 23% of diesel fuel supply in the U.S.

Many refineries already have an FCC feed hydrotreating unit. The LCO from these refineries should contain a much lower concentration of sulfur and fewer sterically hindered compounds than refineries not hydrotreating their FCC feed. Adding an FCC feed hydrotreating is much more costly than distillate hydrotreating. Just on the basis of sulfur removal, FCC feed hydrotreating is more costly than distillate hydrotreating, even considering the need to reduce gasoline sulfur concentrations, as well. This is partly due to the fact that FCC feed hydrotreating by itself is generally not capable of reducing the level of diesel fuel sulfur to those being considered in this rule, so post-treating is still necessary. However, FCC feed hydrotreating provides other environmental and economic benefits. FCC feed hydrotreating decreases the sulfur content of gasoline significantly, as well as reducing sulfur oxide emissions from the FCC unit. It also increases the yield of relatively high value gasoline and LPG from the FCC unit and reduces the formation of coke on the FCC catalyst. For individual refiners, these additional benefits may offset enough of the cost of FCC hydrotreating to make it more economical than distillate hydrotreating. However, these benefits are difficult to estimate in a nationwide study such as this. Also, feed hydrotreating is not expected to, by itself, enable a refinery to meet either the 500 or the 15 ppm standards. Thus, this study will rely on distillate hydrotreating as the primary means with which refiners will meet the 15 ppm sulfur cap. For those refiners that choose FCC feed hydrotreating, their costs will presumably be lower than distillate hydrotreating and the costs estimated in Chapter 7 can then be considered somewhat conservative in this respect.

5.3 Feasibility of Producing 500 ppm Sulfur NRLM Diesel Fuel in 2007

5.3.1 Expected use of Desulfurization Technologies for 2007

To enable our determination of whether it is feasible for the refining industry to meet the 2007 sulfur cap and to estimate the cost of complying with the sulfur standard (see Chapter 7), we needed to project the mix of available technologies that will be used for compliance. We considered several different factors for projecting the mix of technologies. First and foremost, we considered the time refiners will have to choose a new technology, which is important because of the relatively short lead time before implementation of the 500 ppm standard. Second, we considered whether the technology will be available for 2007 and, if the technology is available, how proven it is. Third, we considered whether the technology is cost-competitive by comparing it with other technologies. If a refiner finds that a technology is available at a lower cost, it is more likely to use that technology. We also considered whether the technology is available from a vendor that has proven itself to the industry by providing other successful refining technologies and particularly if the vendor has proven itself in the United States.

Finally, we considered the capability of the vendor to meet the demand of the industry. We considered all these issues for each technology but, as described below, some of these issues are more prominent than others.

To comply with the 500 ppm sulfur standard in 2007, refiners will have to decide what technology they will want to use several years before the standard needs to be met. Several years are needed to perform a preliminary design, complete a detailed design, purchase the hardware needed, obtain the air quality permits needed, and then install and start up the hardware. The timing of this final rule provides refiners three full years to comply with the 500 ppm sulfur standard. Because refiners need about three years to complete the mentioned steps to have a working new unit, there is little time to shop around for a new desulfurization technology that is just beginning to prove itself. A thorough review of a newer technology can take months, so if refiners do not have this extra time, they will tend toward technologies that are more familiar. See Section 5.3.2 for a more detailed discussion about the lead-time issues for the 2007 standard.

Of the various technologies we list above for desulfurizing diesel fuel, conventional hydrotreating is by far the most familiar to refiners. Refiners are using conventional hydrotreating to meet the current highway diesel fuel 500 ppm sulfur standard. In the United States, there are about 90 distillate hydrotreaters with virtually all of them being conventional hydrotreaters operating since 1993 or before. The one exception is a Process Dynamics Isotherming commercial demonstration unit that started up recently at a Giant refinery in New Mexico. Phillips S-Zorb for diesel and the two oxidation and extraction technologies have yet to accumulate commercial experience. However, refiners usually want to see that a refinery unit has operated successfully for at least two years to ensure that it will operate with high reliability and low maintenance requirements.[F] The Process Dynamics desulfurization unit that is installed now and has started to accrue valuable commercial experience will have accumulated somewhat less than two years of commercial experience by then.

After considering the above issues, it seems that the short lead time is the central issue of whether refiners will choose between conventional hydrotreating and other advanced desulfurization technologies for 2007. Refiners do not have the many months needed to carefully consider the advanced technologies still in development and still at the beginning of the demonstration stage, so we believe this issue is the most critical one affecting refiners' choice of desulfurization technologies for 2007. For these reasons, we believe refiners will default to what they know will work, which is conventional desulfurization. Since multiple vendors can provide the preliminary engineering design and any followup support for conventional hydrotreating, these vendors will be able to serve the refiners needing to install desulfurization units for 2007.

[F] Refiners want low-maintenance refining units because they have cut back their engineering staff to reduce their refining costs for improving their margins, and thus will seek units consistent with that strategy.

5.3.2 Lead-time Evaluation

Refiners need sufficient lead time to design, construct, and start up desulfurization technology to meet the 500 ppm standard if this standard is to be implemented in an orderly way. If one or more refiners were unable to comply in time, it would have major repercussions for the refiner and potentially for the regional fuel supply. If refiners planning on producing 500 ppm NRLM fuel could not do so in time and could not buy credits, they would have to sell their high-sulfur distillate fuel as heating oil, export it, or temporarily cease production. As discussed in Section 5.8, heating oil will no longer be widely distributed in many markets. Thus, selling large quantities of heating oil may require distressed pricing and the absorption of trucking costs. Exportation would be very costly for refiners not located on an ocean coastline. Temporary closure would result in serious financial loss. In addition, users of NRLM diesel fuel would likely face high fuel prices. Fuel prices respond quickly to supply shortages. Significant price increases would be expected if refiners were not able to fulfill demand for NRLM diesel fuel starting June 1, 2007. Thus, providing adequate lead time for refiners to design, construct, and prove out the necessary new hydrotreaters is critical to avoiding serious economic harm to both the refiners and the users of NRLM diesel fuel.

Because of this, we project that refiners will use conventional hydrotreating to meet the 500 ppm standard beginning on June 1, 2007. Of the 35 refineries projected to produce 500 ppm NRLM diesel fuel beginning in 2007, 8 are projected to do so by using recently idled highway diesel fuel hydrotreaters. These refineries are expected to idle their highway hydrotreaters in response to exiting the highway market or by installing a new grassroots diesel fuel hydrotreater. The remaining 27 refineries would need to design and construct a new hydrotreater to produce 500 ppm NRLM fuel.[G] This is roughly 20 percent of all U.S. refineries currently producing transportation fuels. Thus, the time available between the date of the final rule and June 1, 2007 must be sufficient across a wide spectrum of refiners and situations.

We have conducted two lead-time assessments for the refining industry in the past four years. One assessment supported the Tier 2 gasoline sulfur program.[H] The other assessment was part of our review of progress being made towards compliance with the 15 ppm sulfur standard for the highway diesel fuel program.[I] The results of both of these assessments are reviewed below and then applied to the new NRLM sulfur control program.

[G] Without the small-refiner provisions, an additional 20 refineries would have to produce 500 ppm NRLM fuel by June 1, 2007.

[H] Final Regulatory Impact Analysis, Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, December 1999.

[I] "Highway Diesel Progress Review," U.S. EPA, June 2002, EPA420-R-02-016.

5.3.2.1 Tier 2 Gasoline Sulfur Program

Chapter IV of the Final Regulatory Impact Analysis for the Tier 2 gasoline sulfur program presented the following table containing the results of its lead-time assessment.

Table 5.3-1
Lead-time Projections Under the Tier 2 Gasoline Sulfur Program (years)

Project Stage	Naphtha/Gasoline Hydrotreating		More Major Refinery Modification (e.g., FCC Feed Hydrotreating)	
	Time for Individual Step	Cumulative Time[a]	Time for Individual Step	Cumulative Time[a]
Scoping Studies	0.5-1.0[b]	0.5	0.5-1.0[b]	0.5
Process Design	0.5	1.0	0.5-0.75	1.0-1.25
Permitting	0.25-1.0	1.25-2.0	0.25-1.0	1.25-2.0
Detailed Engineering	0.5-0.75	1.5-2.25	0.5-1.0	1.5-2.25
Field Construction	0.75-1.0	2.0-3.0	1.0-1.5	2.5-3.5
Start-up/Shakedown	0.25	2.25-3.25	0.25	2.75-3.75

[a] Several of the steps shown can overlap.
[b] Projected to begin before Tier 2 gasoline final rule.

This table contains lead-time projections for two distinctly different approaches to gasoline sulfur control. The first, naphtha hydtrotreating, is more closely related to conventional distillate hydrotreating. In fact, several naphtha hydrotreating processes utilize fixed-bed hydrotreating, which is directly comparable to distillate hydrotreating. The second, FCC feed hydrotreating, is more complex, extensive, and costly. As discussed earlier in this chapter, some refiners might use FCC feed hydrotreating to facilitate the production of 500 ppm diesel fuel. However, this decision was likely tied to their compliance plans for the Tier 2 gasoline sulfur program, since FCC feed hydrotreating significantly reduces the sulfur content of gasoline, as well as moderately reducing the sulfur content of LCO. Since refiners will not be able to meet the sulfur standard using FCC feed hydrotreating, it is highly unlikely that a refiner would just begin considering FCC feed hydrotreating as the result of this NRLM rule. We will therefore focus only on the portion of the table that addresses the lead time for naphtha hydrotreating.

It should also be noted that the cumulative times listed in the table above are not simply the sum of the times for each step. Some steps overlap, in particular process design and permitting, permitting and detailed engineering, and detailed engineering and construction. The relationship between the time necessary for each step in the design and construction of naphtha and distillate hydrotreaters are examined in detail below. However, it is useful first to review the projected lead time related to the 15 ppm highway diesel fuel cap.

5.3.2.2 15 ppm Highway Diesel Fuel Sulfur Cap

The rulemaking implementing the 15 ppm sulfur cap for highway diesel fuel did not evaluate the lead time required for each individual step of the process. That rule provided 5.5 years of lead time between promulgation and initial implementation. This amount of lead time significantly exceeded that considered necessary to design and construct desulfurization equipment. This amount of lead time was provided, since the timing of the 15 ppm sulfur cap was set primarily by the availability of highly efficient aftertreatment technology for diesel engines and not on refiners' ability to meet the 15 ppm standard.

We reviewed the progress that refiners were making towards complying with the 15 ppm highway diesel fuel cap in 2002. Part of this review included an assessment of the tasks refiners had already completed and the length of time needed for those still remaining. The tasks considered were generally the same as those listed in Table 5.3-1 above, with one exception. That was the inclusion of the need to develop a corporate strategy towards compliance in the initial step. This strategy involved a decision regarding the degree to which refiners would continue marketing highway diesel fuel and if so, whether they would comply with the 15 ppm standard initially in 2006 or later in 2010. However, diesel fuel can be sold to the highway or non-highway markets, involving compliance with very different sulfur standards. The flexibility afforded by the rule's temporary compliance option also gave refiners a choice of when they chose to comply with the 15 ppm cap. This issue didn't arise in the Tier 2 gasoline rule, since nearly all gasoline sold in the United States meets highway quality standards and refiners have no other market for their gasoline feedstocks.

The results of the lead-time review are presented in Table 5.3-2.

Table 5.3-2
Lead-time Assessment: Progress Review of 15 ppm Highway Diesel Fuel Cap

Project Stage	Time Allotted	Latest Start Date
Strategic Planning	0.25-2 years	----------
Planning and Front-End Engineering[a]	0.5	Mid-2003
Detailed Engineering and Permits	1.0	Late 2003 - Early 2004
Procurement and Construction	1.25-2.5	October 2004
Commissioning and Start-Up	0.25-0.5	March 2006

[a] Labeled Process Design in Table 5.3-1.

By grouping several of the process steps shown in Table 5.3-1 this later assessment reduces the overlap between the various steps considerably. The primary overlap still remaining is between detailed engineering and permits and procurement and construction. While construction cannot begin until permits have been obtained, procurement can proceed. This is often essential to any time constrained refining project, due to the long lead times needed to fabricate specialized equipment.

Because the progress review was conducted more than a year after the rule was adopted, we did not add up the times associated with each step to develop a range of cumulative time requirements. Instead, we focused on the dates by which refiners should have begun each step to determine if they had indeed begun those steps that should have been started by the date of the assessment.

5.3.2.3 Lead-time Projections for Production of 500 ppm NRLM Diesel Fuel

We utilized the information for gasoline and highway diesel analyses to project the lead time necessary for a wide spectrum of refiners to start producing 500 ppm NRLM diesel fuel. Beginning with strategic planning, refiners currently producing high-sulfur diesel fuel/heating oil will have to decide whether they are going to continue producing high-sulfur heating oil or produce 500 ppm NRLM diesel fuel. This would not likely be a difficult choice for many refiners, as the heating oil market will be too small in their area to support their entire production of high-sulfur fuel. For those with a real choice, this step will likely involve discussions between the refining and marketing divisions of the firm, as well as with any common carrier pipelines used by the refiner. While many refiners prefer to be able to observe their competition’s choices and the relative production volumes and prices of 500 ppm NRLM diesel fuel and high-sulfur heating oil before making a decision, this is not possible. Given this, it seems reasonable to allow a relatively short period of time, such as three to six months, to arrive at a corporate decision to participate either in the NRLM or heating oil markets.

Scoping and screening studies refer to the process whereby refiners investigate various approaches to sulfur control. These studies involve discussions with firms supplying desulfurization and other refining technology, as well as studies by the refiner to assess the economic impacts of various approaches to meeting the sulfur standard. In the case of distillate desulfurization, refiners will likely send samples of their various distillate streams to the firms marketing desulfurization technology to determine how well each catalyst and associated hydrotreating technology removes the sulfur from that particular type of distillate (e.g., sulfur removal efficiency, yield loss, hydrogen consumption, etc.).

Under the Tier 2 rule, we projected that six to twelve months were required to evaluate the various available technologies for naphtha desulfurization. This extensive period of time was considered appropriate due to the wide range of technologies available. More importantly, however, was the fact that many of the new gasoline desulfurization technologies had not been demonstrated in actual refinery applications by the time of the final rule. Refiners naturally desire as much demonstrated experience with any new technology as possible before investing significant amounts of capital in these technologies. We believed that at a minimum, refiners should have six months after the final rule to assess their situation with respect to the final sulfur control program and select their vendor and technology. Because the Tier 2 gasoline sulfur standards phased in over two years, some refiners had more time than others before their new desulfurization equipment had to be operational. Thus, we expected refiners to take as much time as they could afford to select the particular desulfurization technology that was optimum for their situation. Thus, there was really no upper limit to the amount of time for this step.

The scoping and screening task refiners face with respect to the 500 ppm NRLM sulfur cap is both different from and similar to the situation refiners faced with the Tier 2 gasoline program. The NRLM program differs because refiners had to choose between a wide variety of gasoline desulfurization technologies to comply with the Tier 2 sulfur standards. In contrast, we project above that conventional hydrotreating will likely be the dominant choice for desulfurizing diesel fuel to 500 ppm in 2007. Furthermore, this is already a well known technology. The similarity exists, because refiners will have to consider how to comply with the 15 ppm nonroad diesel fuel cap in 2010 and 15 ppm L&M diesel fuel cap for 2012 when they design their conventional hydrotreater for 2007. While conventional hydrotreating is well understood, there are numerous ways to "conventionally hydrotreat" distillate. Variations exist in operating pressure, hydrogen purity, physical catalyst loading, etc.[J] To avoid scrapping their conventional hydrotreaters after just three to five years, we project that the refiners building new conventional hydrotreating units for 2007 will plan these units to be easily revamped to produce 15 ppm nonroad diesel fuel in 2010 and L&M diesel fuel in 2012. The specific conventional hydrotreating design selected for 2007 will therefore have to mesh with their plans for 2010 and 2012. At a minimum, this will involve selection of the operating pressure of the conventional hydrotreater, provision of physical space for additional equipment, and the capacity of hydrogen supply and treatment lines. Selecting the operating pressure is likely the most time-critical, because of the long lead times involved in procuring pressure vessels. Also, vendors need some time to assess the deep desulfurization performance of their desulfurization technologies via pilot plants testing on specific refiners' diesel fuel samples.

Fortunately, this process has been underway for some time involving refiners' highway diesel fuels. By mid-2004, this process should be nearly complete. In fact, 27 out of the 35 refineries projected to produce 500 ppm NRLM diesel fuel for 2007 have experience producing highway diesel fuel today under the 500 ppm cap. Vendors' should have ample capacity to test refiners' NRLM diesel fuel samples, as well as have developed efficient approaches to translate test results into specific process designs. Thus, six months should be more than sufficient for refiners to make the necessary, critical choices about their conventional hydrotreater design. In fact, the selection of operating pressure could be made during the process-design step, effectively reducing the amount of time to scoping and screening to three months.

The strategic decision to produce 500 ppm NRLM diesel fuel involves not only marketing, but an economic assessment of the cost of producing this fuel, both absolutely and relative to the competition. The scoping and screening studies are also not expensive to conduct. Refiners do not risk much to conduct them while they are still developing their corporate strategy. Also, the scoping and screening studies can go on concurrent with the development of a corporate strategy towards the rule. This means that the time for strategic planning (three to six months) and the time for scoping and screening (three to six months) can go on concurrently.

[J] Many of these issues are uncertainties for refiners installing a new diesel fuel hydrotreater, but would be fixed for those adapting an existing desulfurization unit or reactor.

The time required for process design of a conventional distillate hydrotreater should be no greater than that for a naphtha hydrotreater or the revamp of a diesel fuel hydrotreater (i.e., six months in both Tables 5.3-1 and 5.3-2). In fact, the design of the naphtha hydrotreater may be more complex due to the desire to avoid too great a loss in octane from olefin saturation. Avoiding octane loss may lead the refiner to treat different parts of the naphtha stream differently. Octane is not an issue with distillate hydrotreating. In general, the design of a grassroots distillate hydrotreater is more complex than that of a revamp. However, the eventual revamp in 2010 or 2012 which must follow this 500 ppm step will be is to produce 15 ppm diesel fuel, a much more challenging task than producing 500 ppm diesel fuel. Thus, some extra planning may be necessary for designing this 500 ppm hydrotreater. Regardless, six months should be sufficient for the process design of a 500 ppm NRLM unit. The cumulative time for the strategy, scoping, and process-design steps should range from nine to twelve months, as the choice of distillate hydrotreating is clear.

Regarding permitting, we have taken steps to help state and local permitting agencies to efficiently process refiners' requests for permits related to environmental-related projects such as these. Our experience with permits related to naphtha desulfurization indicates that three to nine months is a more realistic range, as opposed to the three to twelve months projected in the Tier 2 Final Regulatory Impact Analysis. There, we identified twelve months as being a worst-case scenario. Experience has confirmed this and we are not aware of any specific situations where obtaining a permit has taken this long and held up the project completion.

The detailed design and construction of a distillate hydrotreater could require some additional time relative to that for a naphtha hydrotreater due to the higher operating pressures required for distillate hydrotreating. Because fewer firms fabricate higher pressure reactors and compressors, the lead time for construction and delivery are usually longer. At the same time, less time should be required than required for a FCC feed hydrotreater. FCC feed hydrotreating usually occurs at even higher hydrogen pressures and involves much more cracking of large molecules into smaller ones. Additional equipment is necessary to handle the significant amount of gaseous product generated, etc. Interpolating between the times allocated for the detailed design and construction of a naphtha hydrotreater and a FCC feed hydrotreater results in six to nine months to design and twelve to fifteen months to construct a distillate hydrotreater. Cumulatively, the two steps would take a little more than 1 year and up to 2 years, or 1 to 1.25 years from the time permits were obtained.

This range is about three months shorter than that projected in Table 5.3-2 for the 15 ppm highway diesel fuel rule. The difference on the high end is due to the fact that 2.5 years for construction does not appear to be necessary. For this to be typical, all refiners planning to produce 15 ppm highway diesel fuel would have already been constructing their new or revamped hydrotreaters by the time of the 2003 precompliance reports. Clearly this was not the case in the precompliance report results, yet refiners considered themselves on track to meet the standard. Thus, the time periods resulting from an interpolation of the naphtha and FCC feed hydrotreating estimates of Table 5.3-1 appear reasonable for producing 500 ppm NRLM fuel.

Finally, both the Tier 2 gasoline rule and 15 ppm highway diesel fuel review allocated three months for start up for naphtha, FCC feed and highway diesel fuel hydrotreaters. Allocating the same time period for starting a distillate hydrotreater should therefore be appropriate.

Table 5.3-3 presents the results of the above assessment.

Table 5.3-3
Lead-time Projections for 500 ppm NRLM Diesel Fuel

Project Stage	Time for Individual Step	Cumulative Time
Strategic Planning	0.25-0.5	0.25-0.5
Scoping and Screening Studies	0.25-0.5	0.25-0.5
Process Design	0.5	0.75-1.0
Permitting	0.25-0.75	1.0-1.75
Detailed Engineering	0.5-0.75	1.5-2.25
Field Construction	1.0-1.25	2.0-3.0
Start-up/Shakedown	0.25	2.25-3.25

The timing of this final rule should allow some refiners to produce 500 ppm NRLM fuel as early as July 2006. This coincides with implementation of the 15 ppm highway diesel fuel cap and the ability to generate early 500 ppm NRLM credits. This analysis indicates that the last refiners should be able to produce 500 ppm NRLM fuel by July 2007. This is within a month of implementation of the 500 ppm NRLM cap. If any refiners are in the situation of needing this last month to produce 500 ppm NRLM fuel, they should be able to purchase early credits from other refiners and continue producing NRLM fuel until they are able to meet the 500 ppm cap.

5.3.2.4 Comparison with the 500 ppm Highway Diesel Fuel Program

The tasks refiners face in meeting the 500 ppm NRLM cap is very similar to the task refiners faced with meeting the 500 ppm highway diesel fuel cap by October 1, 1993. The primary difference is that refiners have ten years of experience producing 500 ppm diesel fuel commercially. This should only shorten the time required to prepare for complying with the standard relative to 1993. The 500 ppm highway diesel rulemaking was adopted in August 1990 and took effect October 1, 1993.[38] Thus, that rulemaking provided 38 months of lead time, nearly identical to that provided in this final rule for NRLM. Some price spikes occurred with the 500 ppm highway diesel fuel standard. However, these were almost exclusively in California, where a 10 volume percent aromatics standard was implemented at the same time. Also, the October implementation coincided with the annual increase in refiners' distillate production related to winter heating oil use. At that time, the United States was one of the first nation's to require 500 ppm diesel fuel, so little commercial experience was available upon which to base designs. Refiners and technology vendors currently have over ten years of commercial experience in producing 500 ppm diesel fuel. We have also shifted the implementation date away from the peak heating oil production season. Finally, the volume of highway diesel fuel affected was more than three times as much as that affected by this final rule, causing greater stress on the engineering and construction industries than we expect to result from this final rule.

Many refiners likely to produce 500 ppm NRLM diesel fuel in 2007 also have to invest to meet the Tier 2 gasoline sulfur standards and the 15 ppm highway diesel fuel cap. However, the Tier 2 program finishes phasing in in 2006 for most refiners. The 15 ppm highway diesel fuel likewise has a 2006 implementation date. This puts them at least one year ahead of the 500 ppm NRLM standard. This minimum offset of one year should ease the burden on any specific aspect of the process (e.g., raising capital funds, design personnel, construction personnel, etc.). The 1993 500 ppm highway diesel fuel cap also occurred in the midst of other fuel-quality regulations. The phase 2 gasoline Reid vapor pressure standards and the oxygenated gasoline programs took affect in 1992, while the reformulated gasoline program began in 1995. Thus, the experience with the 500 ppm highway diesel fuel program appears to be a strong confirmation that the final rule provides sufficient lead time.

5.3.2.5 Small Refiners

Small refiners may need more time to comply with a sulfur control program. Small refiners generally have a more difficult time obtaining funding for capital projects, and must plan further in advance of when the funds are needed. We contracted a study of the refining industry that assessed the time required for small refiners to obtain loans for capital investments. The simple survey revealed that small refiners need two to three months longer than large refiners to obtain funding. If small refiners are forced to or prefer to seek funding through public means, such as through bond sales, then the time to obtain funding could be longer yet, by up to one third longer.[39] In addition, because of the more limited engineering expertise of many small refiners, the design and construction process for these refineries is relatively more difficult and time consuming. We also believe the contractors that design and install refinery processing units will likely focus first on completing the more expensive upgrade projects for large refiners. This would also contribute to the additional time for design and construction of desulfurization hardware for small refiners. The three additional years being provided small refiners should be sufficient to compensate for these factors. This additional lead time should provide not only enough time for these small refiners to construct equipment, but also allow more time for them to select the most advantageous desulfurization technology. This additional time for technology selection will help to compensate for the relatively poor economy of scale inherent with adding equipment to a small refinery.

5.4 Feasibility of Producing 15 ppm Sulfur NRLM in 2010 and 2012

5.4.1 Expected use of Desulfurization Technologies in 2010 and 2012

Like the 500 ppm sulfur standard for 2007, we considered several criteria to project which desulfurization technologies will be used to meet the 15 ppm standard for nonroad in 2010 and the 15 ppm L&M standard in 2012. The criteria we considered included: (1) the time refiners will have to choose a new technology, (2) whether the technology will be available for 2010 ane 2012 and, if the technology is available, how proven it is, (3) whether the technology is cost-competitive by comparing it with other technologies, (4) whether the technology is available from a vendor that has proven itself to the industry by providing other successful refining technologies, particularly if the vendor has proven itself in the United States, and (5) whether the vendor has the capability to meet the industry demands.

Refiners will have six and eight years to meet the 2010 and 2012 standards, respectively. Refiners will have from 2 to 4 more years to evaluate the slate of technologies in addition to the usual amount of time they must have to construct and start up the necessary capital investments. Refiners are therefore not constrained when making their decisions and this particular issue did not figure into our judgment regarding projected technologies.

Next, we considered whether a technology will be available in 2010 and 2012. Conventional hydrotreating is available, as it has been used in a variety of applications to meet very stringent sulfur standards. In addition, many refiners are expected to use conventional hydrotreating to comply with the highway diesel 15 ppm cap, which applies in 2006. This would give refiners some experience with this technology before they decide which technology to use.

Process Dynamics already has a diesel fuel hydrotreating commercial demonstration unit operating which is a revamp of a 500 ppm highway diesel fuel desulfurization unit (installed before the existing highway hydrotreater). This unit demonstrates that the technology does indeed work for treating untreated diesel fuel to 500 ppm, and thus would provide a proven upgrade path through the revamp of the conventional 500 ppm units installed in 2007 to comply with the 15 ppm cap standard in 2010 or 2012. A couple more refiners may choose to revamp their refineries with the Process Dynamics technology for complying with the 15 ppm highway diesel fuel sulfur standard taking effect in 2006, thus providing several more examples of the Process Dynamics desulfurization technology being used to revamp 500 ppm treaters to meet the 15 ppm sulfur cap. Thus, refiners seeking to comply with the 15 ppm sulfur NRLM standard should be able to see at least one, and probably more examples of the Process Dynamics Isotherming process operating to desulfurize diesel fuel down to 15 ppm.

The oxidation and extraction technologies by Unipure and perhaps UOP do not have units operating now, but Unipure is projecting to have a commercial demonstration unit operating by 2006. However, an oxidation and extraction unit that begins operation in 2006 will not provide two years of operations for interested refiners before they need to choose their technology for 2010. As a result, it is unlikely to see any significant use by 2010, and use may be limited to small refineries and terminals which would take advantage of their lower costs for smaller installations. Furthermore, without a commercial demonstration unit operating along with the technology’s perceived success, it is difficult to project the penetration into the desulfurization market even for 2012.

Another issue refiners will consider is the cost of installing and operating these various technologies. Of the oxidation and extraction technologies, Unipure did provide us with desulfurization cost information based on testing at their laboratory, and that information shows that it might be cost competitive with conventional hydrotreating. Phillips also has provided us with diesel fuel desulfurization cost information from their pilot plant, which is backed up by the success they have had with their commercial gasoline desulfurization unit (see Section 7.2). That technology seems to be less expensive than conventional hydrotreating for some refineries; it appears to be suited primarily for desulfurizing low-sulfur diesel fuel down to very low sulfur levels rather than for desulfurizing higher-sulfur feedstocks. Finally, Process Dynamics provided us diesel fuel desulfurization cost information based on their pilot plant and their engineering cost estimates for the commercial demonstration unit at the Giant refinery. The Process Dynamics process seems to be less expensive than conventional hydrotreating (see Section 7.2) and has been demonstrated to meet a 15 ppm sulfur standard by revamping a conventional hydrotreater.

We next evaluated whether each diesel fuel desulfurization technology vendor is equipped to provide preliminary engineering and support the installations of its technology to a significant part of the refining industry. Conventional hydrotreating is provided by numerous vendors (Akzo Nobel, Criterion, Haldor Topsoe, IFP, and UOP) the majority of which manufacture their own line of diesel desulfurization catalysts. Also, these vendors supported the installation of many diesel fuel hydrotreaters to meet the 500 ppm highway diesel fuel sulfur standard, which went into effect in 1993, and will be working with refiners to meet the very stringent 15 ppm highway diesel fuel sulfur standard, which begins to take effect in 2006. Thus, conventional desulfurization technology is poised to make a significant contribution.

Process Dynamics has only a very small engineering staff, however, they are associated with Linde Process Plants and Roddy Engineering. Linde currently licenses several different technologies, including sulfur and olefins recovery, natural gas processing, hydrogen production, reforming, air separation. Linde has a large engineering and design department that has been active for over 30 years. Roddy Engineering has a small engineering staff for additional engineering support. Thus, Linde and Roddy Engineering are capable of providing substantial engineering support to Process Dynamics for its IsoTherming desulfurization technology for a significant penetration into the U.S. refining industry.

Phillips licenses several different technologies to refiners now, including its S-Zorb gasoline desulfurization technology and an alkylation technology, and has licensed refining technologies for over 60 years. Phillips has a robust research and development staff and also an engineering staff to support the licensing of its S-Zorb technology.

The oxidation and extraction technologies are being developed by two separate entities, one being Unipure and the other UOP. Unipure is associated with Texaco and Mustang engineering. Thus, Unipure potentially has both research and development and engineering support for its technology. UOP has substantial capacity for conducting engineering support for refiners.

After evaluating the various criteria for each technology and comparing across technologies, we developed a projection for the mix of technologies that will be used in 2010 and 2012 for meeting the 15 ppm standards. Since refiners will have plenty of time to sort through the various technologies, we believe lead time will have no bearing on refiners ability to choose an advanced desulfurization technology. Whether a technology will have accumulated at least two years of commercial experience is an important issue for the S Zorb and oxidation and extraction technologies as the developers are not expected to have a commercial demonstration unit operating for at least two years. Thus, while the Phillips S Zorb, Unipure and UOP desulfurization technologies might be selected by refiners for 2010, we are not including their technologies in our projected mix of technologies.

This leaves conventional hydrotreating and Process Dynamics Isotherming. Conventional hydrotreating will clearly have the most refining experience due to refiners' previous experience and also due to production of 15 ppm highway fuel for 2006. However, Process Dynamics already has one unit operating and perhaps more diesel fuel desulfurization commercial demonstration units will be operating for over two years. The Process Dynamics hydrotreating process is expected to be lower in cost than conventional hydrotreating providing a strong incentive to refiners seeking to reduce their capital and operating costs. Also Linde has research and development and engineering capacity to support Process Dynamics with their IsoTherming desulfurization processes, though not the same level of support as the multiple conventional hydrotreating firms. After comparing these various criteria, we believe the lower cost of Process Dynamics Isotherming will be the most important driver for these technologies. However, we also believe that some refiners will not be willing to try out a newer desulfurization technology, especially since they may already have an established relationship with another vendor. Thus, we believe the Process Dynamics process will be used to a greater extent than conventional hydrotreating, but still be somewhat market limited. We project that Process Dynamics Isotherming will capture 60 percent of the nonroad desulfurization market by 2010, with conventional hydrotreating capturing the remaining 40 percent of the nonroad desulfurization market.

Refiners will have two more years to assess which technology they will use for complying with the 15 ppm sulfur locomotive and marine standard in 2012. Despite the additional two years, though, we assume the same penetration of advanced technologies because of limiting factors for these technologies. Process Dynamics, even when associated with Linde and Roddy engineering, is expected to be limited by the engineering staff available to them and the conservative view by some refiners to new technologies. Furthermore, until a commercial demonstration unit is operating for Unipure, UOP or Phillips, it did not seem appropriate to assess potential market penetration for these advanced technologies. Thus, for 2012 we continue to assume Processed Dynamic's IsoTherming will meet 60 percent of the desulfurization demand while extensions of conventional hydrotreating will meet the remaining 40 percent.

5.4.2 Lead-time Evaluation

More lead time is needed to meet a 15 ppm sulfur standard than a 500 ppm standard. The additional time primarily involves the scoping and screening step, as the technology to achieve a 15 ppm sulfur cap is just being demonstrated on a commercial scale and some advanced technologies promising lower costs are under development. This additional time might be on the order of a few months, while the 2010 implementation date for 15 ppm nonroad and the 2012 implementation date for 15 ppm L&M fuel provides an additional three and five years of lead time, respectively. The amount of lead time available for the 15 ppm NRLM caps should therefore be more than sufficient for refiners to prepare for producing this fuel.

Of more interest is the interaction between the timing of the 15 ppm cap on highway diesel fuel and that for NRLM diesel fuel. The time periods listed in Table 5.3-3 indicate that refiners must start their process designs 2.0 to 2.75 years before first producing 15 ppm diesel fuel and complete these process designs 1.5 to 2.25 years before the implementation date. This means that process design should begin by September 1, 2007 to June 1, 2008, and be completed by March 1 to December 1, 2008. This would provide refiners planning to produce 15 ppm nonroad diesel fuel with 15 to 24 months of desulfurization experience from highway diesel fuel desulfurization units started up in mid-2006 before initiating their process design. Similarly, refiners producing 15 ppm L&M diesel fuel in 2012 are expected to have 39 to 48 months before initiating their process design. Given that catalyst cycles last two to three years, refiners could observe the performance of catalysts used to produce 15 ppm highway diesel fuel for one-third of a cycle to a full cycle before having to begin their process design for desulfurizing nonroad diesel fuel. Refiners producing L&M diesel fuel in 2012 will be able to observe the performance of highway diesel fuel desulfurization catalysts for one to two cycles. While most of the units producing highway diesel fuel in 2006 are expected to use conventional hydrotreating, as discussed above, we also expect the Process Dynamics Isotherming process to have acquired significant commercial experience and perhaps be demonstrated by more refineries choosing to commercially produce 15 ppm for the highway program. Thus, refiners planning for 2010 would be able to observe this newer process for more than three years before selecting their technology and vendor. This should be sufficient to overcome uncertainty on the part of most refiners about its performance. Overall, the available lead time allows all refiners to take advantage of the operating performance of the highway units and minimize their costs.

5.5 Distribution Feasibility Issues

There are three considerations with respect to the feasibility of distributing NRLM diesel fuels meeting the sulfur standard’s in this final rule. The first pertains to the extent that the distribution system can reasonably accommodate the additional product segregation which might result from this final rule, given the existing limitations in the system and the potential cost of overcome such limitations. The second pertains to whether sulfur contamination can be adequately managed throughout the distribution system so fuel delivered to the end-user does not exceed the sulfur requirements in this rule. The third pertains to the ability to handle products that become mixed in the pipeline distribution system so that they can be made saleable into the distillate market. These considerations are evaluated in the following Sections 5.5.1, 5.5.2., and 5.5.3. As discussed in these sections, we have designed the NRLM fuel program to avoid significant distribution feasibility issues, and therefore have concluded that compliance with the NRLM diesel sulfur control program will represent a manageable challenge to fuel distributors that is not unduly burdensome. As a result, these issues are more correctly related to the cost of compliance rather than feasibility.

5.5.1 Ability of Distribution System to Accommodate the Need for Additional Product Segregations That Could Result from This Rule

5.5.1.1 The Diesel Fuel Distribution System Prior to Implementation of the NRLM Sulfur-Control Program

Before 1993, most No. 2 distillate fuel was produced to nearly the same specifications, shipped fungibly, and used interchangeably for highway diesel engines, nonroad diesel engines, locomotive and marine diesel engines and heating oil (e.g., furnaces and boilers) applications. Beginning in 1993, highway diesel fuel was required to meet a 500 ppm sulfur cap and be segregated from other distillate fuels as it left the refinery by the use of a visible level of dye solvent red 164 in all non-highway distillate. At about the same time, the Internal Revenue Service (IRS) similarly required non-highway diesel fuel to be dyed red (to a much higher concentration) prior to retail sale to distinguish it from highway diesel fuel for excise tax purposes (dyed non-highway fuel is exempt from this tax). This splitting up of the distillate pool necessitated costly changes in the distribution system to ship and store the now distinct products separately.

In some parts of the country where the costs to segregate non-highway diesel fuel from highway diesel fuel could not be justified, both fuels have been produced to the highway specifications. Diesel fuel produced to highway specifications but used for non-highway purposes is referred to as “spill-over.” It leaves the refinery gate and is fungibly distributed as if it were highway diesel fuel, and is typically dyed at a point later in the distribution system. Once it is dyed it is no longer available for use in highway vehicles, and is not part of the supply of highway fuel.

When the 15 ppm highway diesel fuel standard takes effect in 2006, an additional segregation of the distillate pool is anticipated. Since up to 20 percent of the highway diesel fuel pool is allowed to remain at 500 ppm until 2010, in some portions of the country as many as three grades of distillate may be distributed; 15 ppm highway, 500 ppm highway, and high-sulfur for all non-highway uses. The final highway diesel rule estimated that 500 ppm diesel fuel will be present in 40 percent of the fungible fuel distribution system including the Northeast, parts of the Midwest and in the area adjacent to the concentration of refineries in PADD 3. However, given the results of its refiner’s pre-compliance reports which suggests that more than 95 percent of highway diesel may be manufactured to a 15 ppm sulfur standard, 500 ppm fuel will likely be restricted to a much smaller portion of the distribution system in 2006.

5.5.1.2 Potential for Additional Product Segregation Under the NRLM Sulfur Program

The NRLM sulfur-control program is discussed in detail in Section IV of the preamble to the final rule. Following is a summary of these requirements and a discussion of the potential for additional product segregation which might result.

This final rule requires that NRLM fuel comply with a 500 ppm sulfur standard beginning in 2007. These provisions mirror controls on highway diesel fuel to 500 ppm in 1993. Refiners and importers can comply with the requirement either by producing NRLM fuel at or below 500 ppm or, if located outside of the Northeast/Mid-Atlantic Area and Alaska, by obtaining sufficient credits under the averaging banking and trading (ABT) provisions to cover their continued production of high-sulfur (HS) NRLM through 2010.[K] Small refiners outside of the Northeast/Mid-Atlantic Area may also continue to produce high HSNRLM until the HSNRLM small-refiner and credit-use provisions expire in June 1, 2010.

The 15 ppm sulfur standard for nonroad diesel fuel takes effect June 1, 2010 and for L&M diesel fuel takes effect June 1, 2012. The options available to comply with this 15 ppm requirement parallel those available to comply with the earlier 500 ppm NRLM requirement. Refiners and importers can produce nonroad and L&M fuel at or below 15 ppm or, if located outside of the Northeast/Mid-Atlantic Area and Alaska can obtain sufficient credits under the averaging banking and trading (ABT) provisions to cover their continued production of 500 ppm through June 1, 2014. Small refiners outside of the Northeast/Mid-Atlantic Area may also continue to produce 500 ppm NRLM until the 500 ppm NRLM small-refiner and credit-use provisions expire in June 1, 2014. After June 1 2014, all NRLM diesel fuel must meet a 15 ppm sulfur standard except for 500 ppm fuel produced in the distribution system due to pipeline interface mixing and product contamination. Outside of the Northeast/Mid-Atlantic Area and Alaska, the prescribed marker must be added to heating oil at the terminal beginning June 1, 2007 and to 500 ppm sulfur L&M diesel fuel produced at a refinery or imported from June 1 2010 through May 31, 2012.

The application of different sulfur standards to portions of the non-highway distillate pool based on end-use raises concerns regarding the potential need for additional product segregation. Currently, distillate fuel for all non-highway uses is typically drawn from a single pool that meets the most stringent specifications for any non-highway use. For example, it is our understanding that nearly all heating oil meets the cetane specification for nonroad diesel engine use despite the lack of applicability of a cetane specification for distillate fuel used as heating oil. This is because fuel manufactures and marketers have found that the potential savings from manufacturing a low cetane heating oil are typically outweighed by the additional costs of segregating an additional heating-oil-only product throughout the distribution system.

[K] The Northeast/Mid-Atlantic Area provisions are discussed in detail in Section IV.D. of the preamble to the final rule. Our determination of the boundaries of the Northeast/Mid-Atlantic Area is discussed in Section 5.5.1.4.

We anticipate that the significant cost of desulfurizing NRLM diesel fuel to meet the new sulfur standards provides a strong incentive for the fuel distribution system to evaluate whether the additional costs of distributing non-highway distillate fuels of different sulfur specifications is economically justified. This situation is analogous to that faced by industry after the 500 ppm sulfur standard for highway diesel fuel took effect in 1993.

The IRS requirement that diesel fuel used in NRLM engines be dyed before it leaves the terminal to indicate its nontaxed status also raises concerns about the potential need for additional product segregation under the NRLM sulfur program. Fuel that meets highway diesel specifications but is destined for the NRLM market can leave the terminal undyed provided that the tax is payed. Non-highway users of such fuel can then apply to the federal and applicable state revenue offices for a refund of the highway taxes payed on the fuel. In areas of the country where only 500 ppm diesel fuel is currently available by pipeline, most bulk plant operators nevertheless maintain dual tankage for dyed and undyed 500 ppm diesel fuel to meet the demands of their customers for highway-tax-free non-highway diesel fuel. Such bulk plant operators currently receive dyed diesel fuel by truck from local refineries. Thus, the IRS NRLM diesel dye requirement may result in a strong incentive for parties in the fuel distribution system downstream of the terminal to maintain segregated pools of undyed highway and dyed NRLM diesel fuel that differ in no other respect than the presence of dye (after implementation of both the 15 ppm highway diesel requirements in 2007 and the new requirements for NRLM fuel). We expect that after the NRLM standards take effect, most bulk plant operators will request that the terminal (or refinery rack) dye the fuel destined for sale into the NRLM market, so they can continue their current practice of offering untaxed diesel fuel to their NRLM customers.

We designed the NRLM sulfur program to minimize the need for additional product segregation and resulting cost to fuel distributors associated with the need for additional storage tanks, tank trucks, marker injection equipment, and other hardware and procedural factors. The designate and track provisions in this final rule allows the fungible distribution of diesel fuels that have the same sulfur content through much of the distribution system despite the fact that they are destined for different end-uses. Fuel subject to the 500 ppm and 15 ppm NRLM sulfur standards may be shipped fungibly with highway diesel fuel subject to the same sulfur standard until the fuel leaves that terminal when red dye must be added to NRLM fuel to comply with IRS fuel tax requirements. Similarly, high-sulfur and 500 ppm NRLM small-refiner and credit-use fuel can be shipped fungibly with heating oil meeting the same sulfur specification until the point when heating oil must be injected with the marker prescribed in this final rule. In addition, high-sulfur NRLM small-refiner and credit-use fuel (present until 2010) may be commingled with 500 ppm NRLM diesel fuel.

The number of possible product segregations that might exist under this rule varies temporally, geographically, and based on the location in the fuel distribution system. The variation over time is a function of the timing of the implementation dates of the two-step sulfur control program, and the implementation and sunset dates of the small-refiner and credit use provisions. In general, the number of possible segregations is the highest from 2007 - 2010, and then begins to decline thereafter as the diesel fuel standards for all highway, nonroad, and L&M diesel fuel begin to coalesce. The geographic variation is a function of limitations on where small-refiner and/or credit-use fuel can be used, and where the fuel marker requirements apply.[L] In the Northeast/Mid-Atlantic Area, the marker is not required since small-refiner and credit-use NRLM fuel can not be sold there. In areas outside of the Northeast/Mid-Atlantic Area except Alaska, the marker is required in heating oil beginning 2007 and in LM diesel fuel produced at a refinery or imported from 2010-2012. In these areas small-refiner and credit-use NRLM fuel may be sold. No marker is required in heating oil used in Alaska. However alternate requirements apply in Alaska which allow small-refiner NRLM to be sold in Alaska. The variation in the number of product segregations by location in the fuel distribution system is primarily a result of: (1) the IRS requirement that off-highway distillate be dye red to indicate its non-taxed status before leaving the terminal, (2) the requirement that heating oil outside of the Northeast/Mid-Atlantic Area and Alaska contain the marker specified under this final rule prior to leaving the terminal, and (3) the provision under this rule that the downstream standard for L&M outside of the Northeast/Mid-Atlantic Area and Alaska is 500 ppm to account for fuel generated due to mixing in the pipeline distribution system which can be sold into the locomotive and marine market after the sale of fuel above 15 ppm is otherwise prohibited.

Many of the possible product segregations are discretionary, the decision to carry an additional grade of diesel fuel being based on an economic evaluation of the associated carrying costs versus the potential market demand in their area and the additional cost associated with supplying a single fuel for multiple end-uses which meets the most stringent specifications for any of these end-uses. We expect that a substantial part of the fuel distribution system in the U.S. upstream of the terminal will carry only highway diesel fuel (for sale into both the highway and NRLM markets). As noted earlier, this is currently the case due to logistical constraints in the distribution system. We anticipate that these new NRLM sulfur standards will result in an expansion of the area in which only highway diesel fuel is supplied for sale into both the highway and NRLM markets. In such cases, the fuel is only differentiated for sale into either the highway or NRLM markets when it leaves the terminal by the addition of red dye to NRLM fuel to satisfy IRS requirements. Other segregations are unavoidable such as the segregation between 15 ppm highway and 15 ppm NRLM downstream of the terminal due to the presence of the IRS specified red dye in NRLM fuel after it leaves the terminal, and the segregation of heating oil from NRLM downstream of the terminal due to the required presence of the marker in heating oil under this final rule (outside the Northeast/Mid-Atlantic Area and Alaska).

The following tables list the possible product segregations during various stages by location in the distribution system. Table 5.5.1.2-1 lists the possible segregations outside of the Northeast/Mid-Atlantic Area and Alaska. Table 5.5.1.2-2 lists the possible segregations in the Northeast/Mid-Atlantic Area. Table 5.5.1.2-3 lists the possible segregations in Alaska. These tables represent the maximum potential number of product segregations that could result from this final rule. In most cases there will be fewer actual product segregations particularly in areas of the country that will receive pipeline shipments of only a single grade of No. 2 diesel fuel for

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[L] The fuel marker requirements are necessary to support the small-refiner and credit-use provisions. See Section IV.D of the preamble to the final rule for a discussion of the interactions between the small-refiner and credit-use provisions and the heating oil marker requirement.

use in multiple distillate fuel markets. Furthermore, it is important to note that these possible segregations are not equal in volume. As time goes by, most of the distribution system is expected to coalesce around a few segregations such that it will look much as it does today. Table 5.5.4. lists the possible number of product segregations in such areas. Section 5.5.1.3. in this RIA discusses the need for fuel distributors to invest in new storage tanks, tank trucks, injection equipment, and other hardware or to change their operating practices in response to the new product segregations caused by this rule.

Table 5.5.1.2.-1
Summary of Possible Product Segregations
Outside of the Northeast/Mid-Atlantic Area and Alaska

Time Frame	Refinery Gate June 1 - May 31	Distribution to Terminal[1] June 1 - Aug 15	Post Terminal June 1 - Sept 30
Current 2004	500 ppm Hwy HS NRLM/HO (dyed)	500 ppm Hwy HS NRLM/HO (dyed)	500 ppm Hwy 500 ppm NRLM (dyed) HS NRLM/HO (dyed)
2006-2007[2]	15 ppm Hwy 500 ppm Hwy/NRLM[7] HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy/NRLM[7] HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy 500ppm & HS NRLM/HO (dyed)
2007-2009[3]	15 ppm Hwy 500 ppm Hwy/NRLM HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy/NRLM HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy 500 ppm NRLM (dyed) HS NRLM/500ppm NRLM (dyed) HO (dyed & marked)
2009-2010[4]	15 ppm Hwy/NRLM[8] 500 ppm Hwy/NRLM HS NRLM/HO (dyed)	15 ppm Hwy/NRLM[8] 500 ppm Hwy/NRLM HS NRLM/HO (dyed)	15 ppm Hwy 15 ppm NRLM[8] (dyed) 500 ppm Hwy 500 ppm NRLM (dyed) HS NRLM/500 ppm NRLM (dyed) HO (dyed & marked)
2010-2012	15 ppm Hwy/NR 500 ppm NR/LM HS HO	15 ppm Hwy/NR 500 ppm NR/LM HS HO	15 ppm Hwy 15 ppm NR (dyed) 500 ppm NR (dyed) 500 ppm L&M (dyed and marked) HS or 500 ppm HO (dyed and marked)
2012-2014[5]	15 ppm Hwy/NRLM 500 ppm NRLM/HO[9] HS HO	15 ppm Hwy/NRLM 500 ppm NRLM/HO[9] HS HO	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm NRLM (dyed) 500 ppm HO[9] (dyed & marked) HS HO (dyed & marked)
2014 & later[6]	15 ppm Hwy/NRLM 500 ppm HO[9] HS HO	15 ppm Hwy/NRLM 500 ppm LM/HO[9] HS HO	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm L&M (dyed) 500 ppm HO[9] (dyed & marked) HS HO (dyed & marked)

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[1] The term "terminal" is used as shorthand to refer to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.

[2] The 15 ppm highway diesel program and the 500 ppm NRLM early credit provisions are effective 2006.

[3] 500 ppm NRLM program effective 2007.

[4] 15 ppm NRLM early credit generating provisions effective 2009.

[5] 15 ppm NRLM program effective 2010. HS NRLM small-refiner and credit-use provisions expire. No 500 ppm NRLM may be sold except small-refiner, credit, and pipeline interface generated 500 ppm NRLM.

[6] 500 ppm NRLM small refiner, and credit use provisions expire 2014

[7] 500 ppm early credit generating NRLM.

[8] 15 ppm early credit generating NRLM.

[9] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors

transport. Earlier, when 500 ppm NRLM was available, such fuel could have been used for heating purposes.

Table 5.5.1.2.-2:
Summary of Possible Product Segregations In the Northeast/Mid-Atlantic Area

Time Frame	Refinery Gate June 1 - May 31	Distribution to Terminal[1] June 1 - Aug 15	Post Terminal June 1 - Sept 30
Current 2004	500 ppm Hwy HS NRLM/HO (dyed)	500 ppm Hwy HS NRLM/HO (dyed)	500 ppm Hwy HS NRLM/HO (dyed)
2006 - 2007[2]	15 ppm Hwy 500 ppm Hwy/NRLM[6] HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy/NRLM[6] HS NRLM/HO (dyed)	15 ppm Hwy 500 ppm Hwy 500 ppm[6] & HS NRLM/HO (dyed)
2007 - 2009[3]	15 ppm Hwy 500 ppm Hwy/NRLM HO (dyed)	15 ppm Hwy 500 ppm Hwy/NRLM HO (dyed)	15 ppm Hwy 500 ppm Hwy 500 ppm NRLM (dyed) 500 ppm NRLM/HO (dyed)
2009 - 2010[4]	15 ppm Hwy/NRLM 500 ppm Hwy/NRLM[7] HO (dyed)	15 ppm Hwy/NRLM[7] 500 ppm Hwy/NRLM HO (dyed)	15 ppm Hwy 15 ppm NRLM[7] (dyed) 500 ppm Hwy 500 ppm NRLM (dyed) HO (dyed)
2012-2012	15 ppm Hwy/NR 500 ppm LM HO	15 ppm Hwy/NR 500 ppm LM HO	15 ppm Hwy 15 ppm NR (dyed) 500 ppm L&M (dyed) HO (dyed)
2012 & later[5]	15 ppm Hwy/NRLM 500ppm HO[9] HS HO	15 ppm Hwy/NRLM 500 ppm HO[9] HS HO	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm HO[9] (dyed) HS HO (dyed)

[1] Terminal used as shorthand refers to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.

[2] The 15 ppm highway diesel and the 500 ppm NRLM early credit provisions are effective.

[3] 500 ppm NRLM program effective 2007 and no HS NRLM may be sold except small-refiner and credit HS NRLM. HS NRLM small-refiner and credit-use fuel may not be sold in the Northeast/Mid-Atlantic Area.

[4] 15 ppm NRLM early credit provisions effective 2009.

[5] 15 ppm NRLM program effective 2010. No 500 ppm NRLM small refiner, credit use, or pipeline interface generated fuels may be sold in the Northeast/Mid-Atlantic Area.

[6] 500 ppm NRLM credit fuel.

[7] 15 ppm NRLM credit fuel.

[8] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors transport. Earlier, when 500 ppm NRLM was available, such fuel could have been used for heating purposes.

Table 5.5.1.2.-3:
Summary of Possible Product Segregations in Alaska

Time Frame	Refinery Gate	Distribution System to Terminal[1]	Post Terminal
Current 2004	500 ppm Hwy HS NRLM/HO	500 ppm Hwy HS NRLM/HO	500 ppm Hwy HS NRLM/HO
2006-2007[2]	15 ppm Hwy 500 ppm Hwy/NRLM[7] HS NRLM/HO	15 ppm Hwy 500 ppm Hwy/NRLM[7] HS NRLM/HO	15 ppm Hwy 500 ppm Hwy 500 ppm[7] & HS NRLM/HO (dyed)
2007-2009[3]	15 ppm Hwy 500 ppm Hwy/NRLM HS NRLM[10] HO	15 ppm Hwy 500 ppm Hwy/NRLM HS NRLM[10] HO	15 ppm Hwy 500 ppm Hwy/NRLM HS NRLM[10] HO
2009-2010[4]	15 ppm Hwy/NRLM[8] 500 ppm Hwy/NRLM HS NRLM[10] HO	15 ppm Hwy/NRLM[8] 500 ppm Hwy/NRLM HS NRLM[10] HS HO	15 ppm Hwy/NRLM[8] 500 ppm Hwy/NRLM HS NRLM[10] HS HO
2010-2012	15 ppm Hwy/NR 500 ppm LM 500 ppm NR[12] HO	15 ppm Hwy/NR 500 ppm LM 500 ppm NR[12] HO	15 ppm Hwy/NR 500 ppm LM 500 ppm NR[12] HO
2012-2014[5]	15 ppm Hwy/NRLM 500 ppm NRLM[11] HO	15 ppm Hwy/NRLM 500 ppm NRLM[11] HO	15 ppm Hwy/NRLM 500 ppm NRLM[11] HO
2014 & later[6]	15 ppm Hwy/NRLM 500 ppm HO[9] HO	15 ppm Hwy/NRLM 500 ppm HO[9] HO	15 ppm Hwy/NRLM 500 ppm HO[9] HO

[1] Terminal used as shorthand refers to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.

[2] The 15 ppm highway diesel and the 500 ppm NRLM early credit provisions are effective.

[3] 500 ppm NRLM program effective 2007. HS NRLM small-refiner provisions require segregation and tracking of HS NRLM.

[4] 15 ppm NRLM early credit provisions effective 2009.

[5] 15 ppm NRLM program effective 2010. HS NRLM small-refiner provisions expire in 2010. 500 ppm small-refiner NRLM provisions require segregation and tracking of 500 ppm NRLM.

[6] 500 ppm NRLM small-refiner provisions expire 2014.

[7] 500 ppm NRLM credit fuel.

[8] 15 ppm NRLM credit fuel.

[9] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors transport. Earlier, when 500 ppm NRLM was available, such fuel could have been used for heating purposes.

[10] Segregated HS NRLM small-refiner fuel only.

[11] Segregated 500 ppm NRLM small-refiner fuel only.

[12] Segregated 500 ppm NR small-refiner fuel only.

Table 5.5.1.2.-4:
Summary of Possible Product Segregations In Areas of the Country Supplied with only a Single Grade of No.2 Diesel Fuel by Pipeline (outside of the Northeast/Mid-Atlantic Area and AK)

Time Frame	Refinery Gate[1] June 1 - May 31	Distribution to Terminal[2] June 1 - Aug 15	Post Terminal June 1 - Sept 30
Current 2004	500 ppm Hwy	500 ppm Hwy	500 ppm Hwy 500 ppm NRLM (dyed) NRLM/HO (dyed)
2006-2007[3]	15 ppm Hwy	15 ppm Hwy	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm NRLM[8] (dyed) HS NRLM/HO[8] (dyed)
2007-2009[4]	15 ppm Hwy	15 ppm Hwy	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm Hwy[8] 500 ppm NRLM[8] (dyed) HS NRLM[10]/500ppm NRLM[8] (dyed) HO (dyed & marked)[8]
2009-2010[5]	15 ppm Hwy/NRLM[13]	15 ppm Hwy/NRLM[13]	15 ppm Hwy 15 ppm NRLM[10] (dyed) 500 ppm Hwy[8] 500 ppm NRLM[8] (dyed) HS NRLM[8]/500 ppm NRLM[8] (dyed) HO (dyed & marked)[8]
2010-2014[6]	15 ppm Hwy/NRLM	15 ppm Hwy/NRLM	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm NRLM[8] (dyed) 500 ppm HO[8] (dyed & marked) HS HO (dyed & marked)[8]
2014 & later[7]	15 ppm Hwy/NRLM	15 ppm Hwy/NRLM	15 ppm Hwy 15 ppm NRLM (dyed) 500 ppm L&M (dyed)[9] 500 ppm HO[8] (dyed & marked) HS HO (dyed & marked)[8]

[1] Refinery rack sales are covered under the “Post Terminal” segment.

[2] The term “terminal” is used as shorthand to refer to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.

[3] 15 ppm highway diesel program and 500 ppm NRLM early credit generating provisions are effective 2006.

[4] 500 ppm NRLM program effective 2007.

[5] 15 ppm NRLM early credit generating provisions effective 2009.

[6] 15 ppm NRLM program effective 2010. HS NRLM small-refiner and credit-use provisions expire.

[7] 500 ppm NRLM small-refiner and credit-use provisions expire 2014.

[8] Refinery rack sales or sales at terminals of segregated interface.

[9] Sales at terminals of segregated interface and from transmix processors of fuel produced from transmix.

[10] 15 ppm early credit generating NRLM.

5.5.1.3 Ability of Fuel Distributors to Handle New Product Segregations that Will Result from the NRLM Sulfur Control Program

As noted in Section 5.5.1.1, distribution feasibility concerns related to new product segregations primarily pertain to the ability of fuel distributors to bear the economic burden of installing new storage tanks and other equipment. Thus, the issue is one of cost not feasibility. Representatives of terminal and bulk plant operators stated that the physical boundaries of some of their locations and/or the local safety and environmental ordinances under which some of their facilities operate would prevent them from installing any new storage tanks. Even where the expansion of tankage facilities is limited by space or other considerations, the issue is still one of the cost of providing a fuel grade meeting a more stringent standard than necessary and not one of the feasibility of supplying fuel to a given market. These considerations and others led us to structure the NRLM program to minimize the number of additional new product segregations that would be needed. As discussed in Section 5.5.1.3, this rule allows fuels of like sulfur content to be shipped fungibly until they leave the terminal.

We also structured the fuel marker requirements to minimize the potential impact on terminal operators. One issue that concerned terminal operators is that they wished to be able to blend 500 ppm NRLM diesel fuel from high-sulfur heating oil and 15 ppm diesel fuel in order to avoid the need to install a storage tank for 500 ppm at some of their facilities (while still being able to serve the 500 ppm NRLM market). The final rule allows the marker to be added as the fuel leaves the terminal, thereby providing that terminals can blend 500 ppm diesel fuel from 15 ppm highway diesel fuel and high-sulfur heating oil subject to the anti-downgrading provisions for 15 ppm highway diesel fuel. The primary concern expressed by terminal operators regarding the potential impact of the fuel marker pertained to the cost of installing new injection equipment to add the marker to heating oil. The Northeast/Mid-Atlantic Area provisions exclude the area in which the majority of heating oil will continue to be sold after implementation of this rule, thereby minimizing this concern. Our determination of the optimal boundaries for the Northeast/Mid-Atlantic Area is discussed in Section 5.5.1.4.

The following sections evaluate the potential need for additional product segregation in each segment of the distribution system from the refinery through to the end-user due to implementation of the NRLM diesel sulfur standards. Based on the following discussion, we believe the potential impacts of this final rule on the distribution system due to the need for additional product segregation will be minimal and can be readily accommodated by industry in the lead time available. See Section 7.3 of this RIA for a discussion of the increased distribution costs that will result from this final rule.

Refineries:

Due to economies of scale involved in desulfurization, we expect that many individual refineries will choose to manufacture a single grade of diesel fuel, or perhaps two grades in some cases. We do not anticipate that individual refineries will produce substantial quantities of all the different diesel fuel sulfur grades (15 ppm fuel, 500 ppm, and heating oil). Therefore, we do not anticipate the need for additional product segregation at refineries. Because this final rule allows highway and nonroad diesel fuels to be shipped fungibly until NRLM fuel is dyed pursuant to IRS requirements at the terminal, we do not expect that the NRLM sulfur standards will require refiners to install new product storage tanks.[M]

We do not expect that the fuel marker requirements will cause the need for additional product segregation at the refinery.[N] However, refiners that market heating oil beginning in 2007 and 500 ppm L&M diesel fuel from 2010 through 2012 from their racks outside of the Northeast/Mid-Atlantic Area and Alaska will have to inject the marker into the fuel sold off their refinery racks as it is loaded into tank trucks. In the NPRM, we projected that the same equipment currently used for injection of red dye could be used to inject the fuel marker. We now recognize that due to concerns about contaminating red dyed fuel which is required to contain no marker, this will only be possible at refineries at which the only untaxed fuels that they carry are the fuels subject to the marker requirement. At other refineries, a completely new injection system will be needed so that the existing system can continue to be used to inject red dye into fuels in which this is required by IRS, but which this final rule prohibits from containing the fuelmarker. Nevertheless, we do not expect that the installation of such equipment represents a significant concern given that the cost of such equipment is modest, the number of refineries that will need to install such equipment is limited, and the space requirements and construction resource requirements are minimal.[O]

Pipelines:

Similar to refiners, we anticipate that most pipelines will carry only one or two of the sulfur level grades (e.g. 15 ppm, 15 ppm and 500 ppm, or 15 ppm and HS), although in a few instances they may carry all three. We expect that the pipelines that we projected will carry 500 ppm fuel under the 2007 highway diesel rule's temporary compliance option (TCO) will be the same pipelines that elect to carry 500 ppm diesel fuel after the NRLM diesel fuel program starts. We do not expect that any common carrier pipelines will carry 500 ppm diesel fuel after the implementation of the 15 ppm sulfur standard for nonroad diesel fuel in 2010. All product pipelines are expected to carry 15 ppm highway diesel fuel beginning in 2006. As noted earlier, the final rule provides for the fungible shipment by pipeline of highway and NRLM fuels that meet the same sulfur specification. We therefore do not expect the NRLM sulfur standards to necessitate additional product segregation in the pipeline distribution system.

There is no physical separation between product batches shipped by pipeline. When the

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[M] There will be no physical differences between highway and NRLM fuel produced by refiners to the same sulfur specification. The distinction between the two fuels is made only for accounting purposes to ensure compliance with limitations on the volume of 500 ppm highway diesel fuel that can be produced by refiners (under the highway diesel final rule) is complied with.

[N] Under this final rule, heating oil (beginning 2007) and 500 ppm sulfur L&M diesel fuel (2010-2012) must be marked before it leaves the terminal in areas outside of Alaska and the Northeast/Mid-Atlantic Area.

[O] See Section 7.4. of this RIA for a discussion of the estimated costs of marker injection equipment.

mixture that results at the interface between two products that touch each other in the pipeline can be cut into the one of these products, it is referred to as interface. When the mixture must be removed for reprocessing, it is referred to as transmix. Given that the pipeline operators will be able to combine batches of highway and NRLM diesel fuel meeting the same sulfur specification, we do not expect that the NRLM program will increase the volume of product downgrade or transmix volumes. To the contrary, there may be some opportunity for improved efficiency because of the increase in batch sizes shipped by pipeline. This potential benefit could be significant, given that the volume of NRLM shipped by pipeline represents a sizeable fraction of the total diesel fuel volume.

The marker requirements for heating oil (beginning 2007) and for 500 ppm sulfur LM diesel fuel produced by refiners or imported (2010-2012) applies prior to leaving the terminal. Furthermore, these marker requirements do not apply in the Norhteast/Mid-Atlantic Area where most heating oil is used. Therefore, we do not expect that the marker requirement will result in an increased need for product segregation in the pipeline or an increase in product downgrade or transmix volumes.

We believe the demand for heating oil will be sufficiently large only in the Northeast/Mid-Atlantic to justify the continued distribution of high-sulfur diesel fuel once nonroad, locomotive, and marine diesel fuel is removed from the potential high-sulfur diesel pool (by implementation of the NRLM sulfur standards). Heating oil will therefore unlikely be present in pipeline systems that supply areas outside of the Northeast, and Mid-Atlantic states. The pipelines that we project will handle heating oil after the requirements of this final rule take effect are those that we earlier projected to carry 500 ppm highway diesel fuel in addition to 15 ppm from 2006-10.

Under the final rule, all nonroad and L&M diesel fuel produced must meet a 15 ppm sulfur standard in 2010 and 2012 respectively. However, limited quantities of small-refiner, and credit fuel that could remain at 500 ppm until 2014. Due to the reduction in the total potential 500 ppm diesel pool in 2010 and again in 2012, it is likely that some pipelines will no longer find it economical to carry 500 ppm as well as 15 ppm diesel fuel. We are projecting that most pipelines will elect not to carry 500 ppm diesel fuel and will carry only 15 ppm diesel fuel after 2010. This could result in some overall simplification of the diesel distribution system. We expect that nonroad and L&M fuel, which is produced by refiners to a 500 ppm standard after 2010, will be distributed by the refiner to the end-user via segregated pathways. Outside of Alaska and the Northeast/Mid-Atlantic Area, limited volumes of 500 ppm fuel can continue to be produced as locomotive and marine diesel fuel from interface, and transmix indefinitely. This fuel can also be sold as heating oil within the Northeast/Mid-Atlantic Area and Alaska. We anticipate that such fuel will be distributed directly from the transmix facility or terminal that produces such fuel to the end-user. Therefore, the presence of such 500 ppm fuels in the distribution system will not result in the need for additional product segregation in pipelines.

A limited number of refiners outside of the Northeast/Mid-Atlantic Area may continue to produce high-sulfur NRLM until 2010, 500 ppm nonroad from 2010 to 2014, and 500 ppm L&M from 2012 to 2014 under the small-refiner and credit-use provisions. We expect most of this fuel will be distributed via segregated means from the refinery rack to the end-user. However, if such HS or 500 ppm nonroad or L&M is shipped by pipeline, it can be combined with heating oil meeting the same sulfur specification up to the point where it is distributed from the terminal. Therefore, we do not expect the small-refiner or credit provisions to create the need for additional tankage at any location in the fuel distribution system.

Terminals:

The product segregation needs at terminals are directly affected by the range of products that they receive by pipeline. Thus, the discussion regarding the potential impacts of this final rule on terminal operators closely parallels the preceding discussion on the potential impacts on pipeline operators. The allowance that highway and NRLM diesel fuel meeting the same sulfur specification may be shipped fungibly until NRLM diesel fuel must be dyed to indicate its non-tax status upon leaving the terminal obviates the need for additional product segregation at the terminal for NRLM fuel meeting the sulfur standards in this rule with the exception of a limited number of small additional storage tanks needed to handle “downstream flexibility” fuel created due to interface mixing in pipelines (discussed below). We expect that terminal operators will generally store NRLM and highway diesel fuel meeting the same sulfur specification in the same tank and that NRLM fuel will be injected with red dye, and LM diesel fuel produced or imported injected with the fuel marker (from 2010-2012) and red dye as it is delivered from the tank into tank trucks.

Similarly, since the marker is required to be present in heating oil (and L&M diesel fuel from 2010-2012) after it leaves the terminal, we expect that terminal operators will store heating oil and HS NRLM (allowed from 2007-2010) in the same storage tank, and 500 ppm L&M diesel fuel (2010-2012) and 500 ppm nonroad diesel fuel (allowed until 2014) in the same storage tank. Marker will be added to the heating oil and 500 ppm sulfur diesel fuel (2010-2012) when it is dispensed from the storage tank into tank trucks. A limited number of terminal operators will need to install new equipment to inject the fuel marker. As discussed in Section 5.5.1.4, we crafted the Northeast/Mid-Atlantic Area provisions to minimize the number of terminals that will need to install such equipment. We do not expect that the installation of such equipment represents a significant concern given that the cost of such equipment is modest, the number of terminal that will need to install such equipment is limited, and the space requirements and construction resource requirements are minimal.

Some terminals outside of these Northeast/Mid-Atlantic Area may market limited quantities of 500 ppm diesel fuel that was generated during the distribution of 15 ppm diesel fuel (“downstream flexibility fuel”). We expect that such fuel will be marketed directly from the terminal to the end user. Limited additional tankage will be needed at terminals to handle this 500 ppm product as discussed in Section 7.4.3.

Bulk Plants:

Bulk plants are secondary distributors of refined petroleum products. They typically receive fuel from refinery racks or terminals by tank truck and distribute off-highway diesel fuel in bulk by truck to end users, serving the role of the retailer. Bulk plants are one point in the distribution system where we anticipate some additional tankage will likely be needed as a result of this final rule. However, we project that only a small subset of the bulk plants will be faced with the choice of adding additional tankage. In most areas of the country, a distinct grade of heating oil will no longer be carried, and bulk plant operators can simply switch the tank that they previously devoted to high-sulfur service to 500 ppm NRLM service in 2007 and supply their HO needs out of this same tank.

In areas where heating oil is anticipated to remain as a separate grade, we anticipate that bulk plants will face the choice of adding a new tank and perhaps demanifolding their delivery truck(s) to distribute dyed 500 ppm NRLM diesel fuel in addition to high-sulfur heating oil.[P] In this context demanifolding refers to the process of separating a single storage tank on a delivery tank truck (or trucks) to make two compartments. Some bulk plants that face the choice of installing the facilities to allow additional product segregation may find the cost of a new storage tank and demanifolding their delivery truck(s) is too high, or may not have the space or capability to add new tank. However, such bulk plants have other options. If they own another bulk plant facility in the area, they may choose to optimize use of available tankage by carrying one of the grades at each facility. Even if they do not own another facility, they may be able to establish a similar arrangement with a terminal or other bulk plant in the area. They could choose to supply heating oil only during the winter months, and supply NRLM during the summer months to both markets. Finally, they could simply choose not to distribute one of the fuel grades. For example, either sell NRLM for both uses or sell only heating oil and allow other fuel distributors in the area to satisfy the NRLM market. We anticipate that approximately 1,600 bulk plants will face the decision of adding new tankage or finding some other means of continuing to serve both heating oil and nonroad markets. This is the number of bulk plants that we project will be located in the areas of the country where heating oil will continue to be carried by the fungible distribution system after the NRLM standards take effect and where 500 ppm fuel will also be carried. Of these, we expect no more than 1,000 will choose to install a new tank. Given the ample lead time to prepare for implementation of the NRLM sulfur standards, the installation of additional tanks at bulk plants is an economic issue rather than a feasibility issue. Even where the expansion of tankage facilities is limited by space or other considerations, the issue is still one of the cost of providing a fuel grade meeting a more stringent standard than necessary and not one of the feasibility of supplying fuel to a given market.

We do not anticipate that bulk plants will invest to carry a separate 500 ppm grade of NRfuel in addition to 15 ppm nonroad fuel after 2010. The majority of the nonroad volume will meet the15 ppm sulfur standard. We expect that few, if any, bulk plants will carry 500 diesel L&M diesel fuel since this market is not a substantial one for bulk plants. Unless a bulk plant had existing tankage available or supplied a majority of its fuel to NRLM uses, 500 ppm nonroad and L&M will therefore likely be limited to refinery and terminal distribution. This is how the bulk of the distribution of locomotive and marine diesel fuel occurs today.

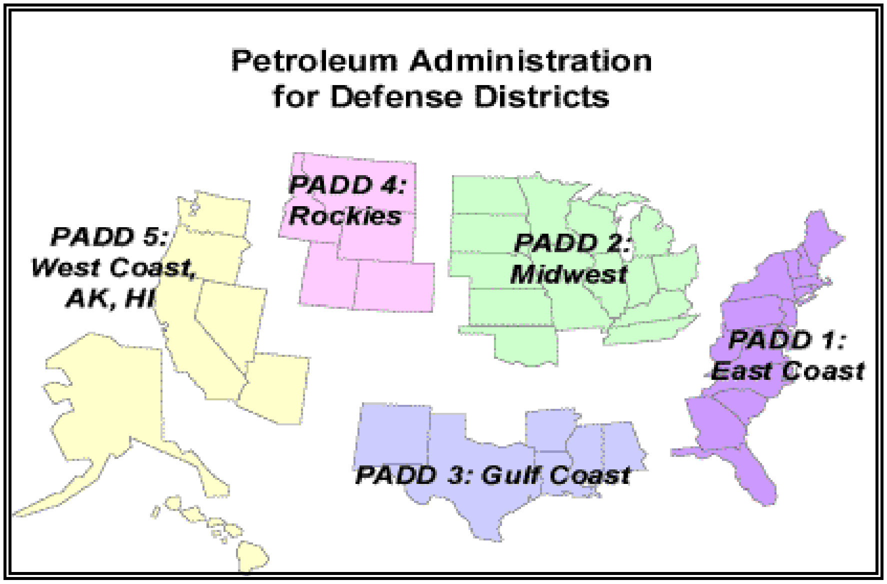
[P] In the Northeast/Mid-Atlantic Area heating oil would be dyed. Outside of the Northeast/Mid-Atlantic Area and Alaska, heating oil would be dyed and marked. In Alaska, heating oil will neither be dyed or marked.

5.5.1.4 Determining the Boundaries for the Northeast/Mid-Atlantic Area

Our goal in adopting the Northeast/Mid-Atlantic Area approach is to minimize the number of terminals that will need to install new injection equipment and the amount of fuel that will need to be marked, while preserving to the maximum extent possible the flexibilities for refiners and importers. The key to balancing these somewhat competing concerns of refiners and terminal operators is the selection of where to draw the boundary of the Northeast/Mid-Atlantic Area.

The Northeast/Mid-Atlantic Area approach was first suggested in comments from the National Oil Heat Research Alliance (NORA).[Q] NORA suggested that limiting the small-refiner and credit-use provisions to Petroleum Administration for Defense Districts (PADDs) 2,3,4 & 5 would make the marker requirement for heating oil unnecessary in PADD 1. Excluding PADD 1 from the heating oil marker requirement could then eliminate nearly all costs associated with the marker requirement, and might not impose any limits on refiners who may wish to take advantage of the small-refiner and credit flexibilities. The definition of the 5 PADDs is illustrated in Figure 5.5.1.4.-1.

Figure 5.5.1.4.-1: Definition of PADDs



NORA presented a PADD by PADD analysis of data from the Energy Information Administration (EIA) regarding the volume of diesel fuel used for heating purposes compared to the volume of fuel used in other non-highway distillate end-uses which it used to support its suggested exclusion of PADD 1 from the marker requirement for heating oil. Selected results of this analysis are presented in Table 5.5.1.4-1.

[Q] Comments from John Huber of the National Oil Heat Research Alliance (NORA), Docket ID No. OAR-2003-0012-0840.

Table 5.5.1.4-1
Ratio of Heating Oil to Other Non-Highway

Area	Ratio of Non-Highway Diesel Fuel Used for Heating Purposes to Non-Highway Diesel Used for Other Purposes
PADD I (Total)	3.57
PADD IA[1]	16.73
PADD IB	6.73
PADD IC	0.31
PADD II	0.34
PADD III	0.09
PADD IV	0.22
PADD V	0.31

[1] The sub-regions that make up PADD I are illustrated in Figure 5.5.1.4-3.

NORA stated that the number of heating oil gallons paying for the application of the small-refiner and credit provisions in PADD I would be much greater than the potential number of gallons that might use the provisions.[R] NORA stated that this indicated that the application of the small refiner and credit provisions in PADD I was not a good value. NORA stated that an evaluation of the cost of the marker requirement versus the potential benefits of the small-refiner and credit provisions indicates that the application of these provisions should be limited to PADDs in which the ratio of non-highway diesel fuel used as heating oil to non-highway diesel fuel used for other purposes, essentially NRLM, was less than 1.

To assess where to draw the boundaries of the Northeast/Mid-Atlantic Area we evaluated the area supplied by the pipeline distribution systems that are expected to continue to ship heating oil after implementation of this rule, evaluated the magnitude of heating oil demand by state, evaluated where the terminals are located that are likely to carry heating oil, evaluated the distribution area of small refiner(s) for high-sulfur NRLM diesel fuel and refiner expectations regarding the market for high-sulfur NRLM, and solicited input from the potentially affected parties.

The marker requirement for 500 ppm sulfur L&M diesel fuel that will be effective outside of the Northeast/Mid-Atlantic Area and Alaska from June 1, 2010, through May 31, 2012, was not a significant factor in our evaluation how to define the boundary of the Northeast/Mid-Atlantic Area. We expect that locomotive and marine diesel fuel subject to the marker requirements will primarily be distributed via segregated pathways from a limited

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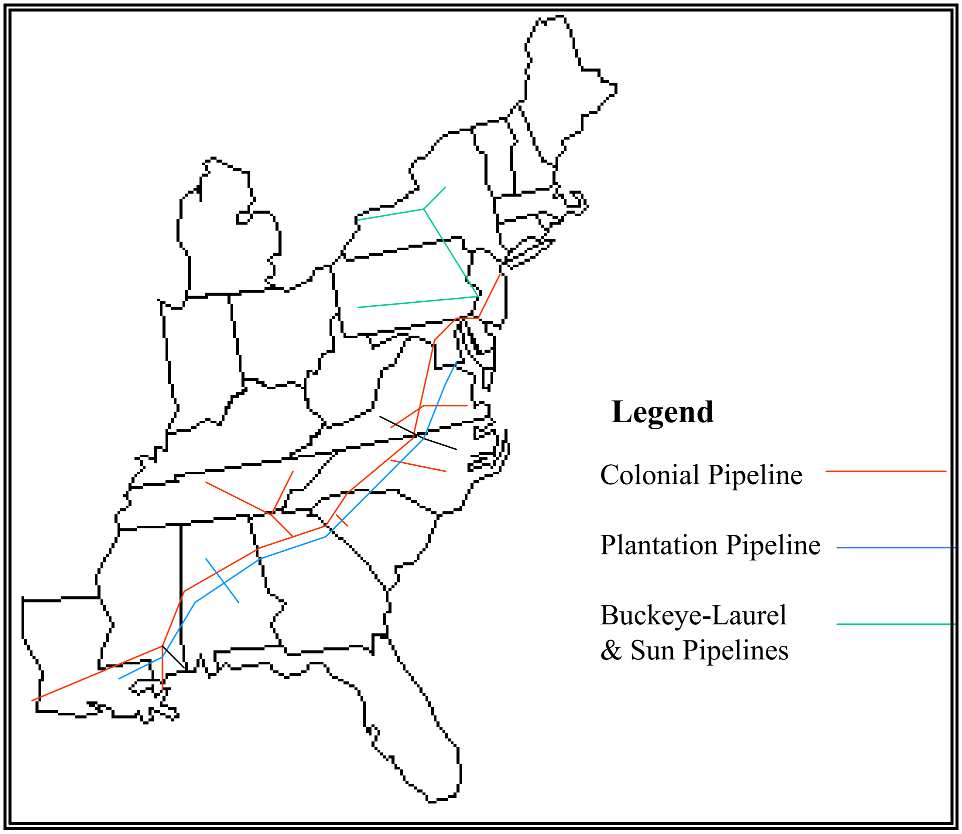
[R] "Paying for" refers to the volume of heating oil bearing the costs related to the marker requirements where these requirements are needed to make the small refiner and credit provisions enforceable.

number of refineries. Therefore, a significant number of terminals will not need to handle L&M diesel fuel that is subject to the marker requirement. Thus, the potential cost of installing injection equipment to add the marker to 500 ppm sulfur L&M diesel fuel which is subject to the marker requirement will be limited to only a few refineries and terminals (i.e. approximately 15, see section 7.4.4. of this RIA).

Area Supplied by Pipelines that are Expected to Continue to Ship Heating Oil, and Location of Terminals that Will Carry Heating Oil:

After implementation of the NRLM program, we expect that the demand for heating oil outside of the Northeast and Mid-Atlantic States will be insufficient to justify its continued shipment as a segregated product by pipeline. Heating oil that is shipped by pipeline into the Northeast and Mid-Atlantic states primarily originates in the cluster of refineries located in PADD III (e.g. in Texas and Louisiana) and is shipped on the Colonial and Plantation pipelines North. The Buckeye/Laurel pipeline receives fuel from these pipelines for shipment North and West into New York state and Pennsylvania. Some heating oil shipped by pipeline in this area will also likely originate from refineries within PADD I and from imports into New York harbor. No heating oil flows by pipeline from PADD I into PADD II. The Buckeye/Laurel has a pipeline through Southern Pennsylvania that ends in Pittsburgh and a pipeline in New York that runs West to Buffalo South of the Lake Erie shore. The Sun pipeline also runs West from Philadelphia to Pittsburgh. A simplified illustration of these pipeline systems is presented in Figure 5.5.1.4-2. We anticipate that the branch lines off of the main pipelines South of North Carolina may no longer find it economical to distribute a separate grade of heating oil.

Figure 5.5.1.4-2: Simplified Illustration of the Pipeline Distribution System that Supplies the Northeast and Mid-Atlantic States*



*All branch lines are not shown in this figure, and in some cases a more complex local system is condensed into a single line. The location of the lines are approximate. Product flows from the South to the end of the lines.

Magnitude of Heating Oil Demand:

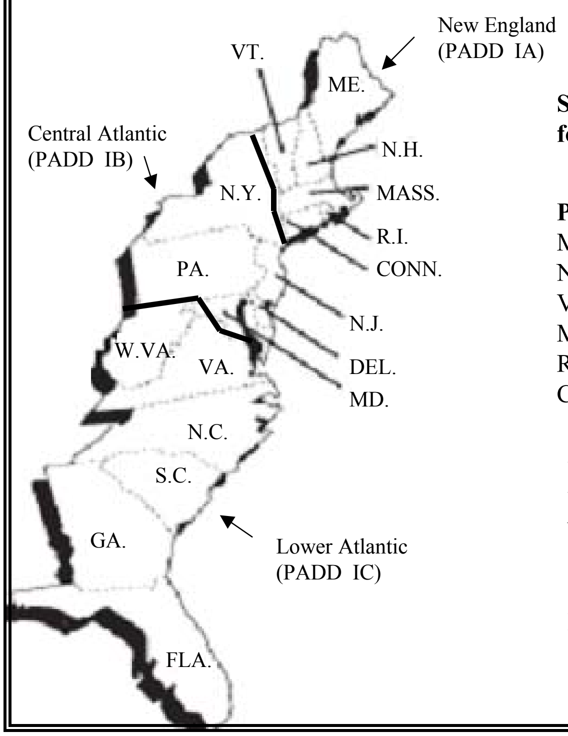
Figure 5.5.1.4-3 shows the residential heating oil use in PADD I by state and by the sub-districts in PADD I.[S]

[S] Energy Information Administration Fuel Oil and Kerosene Sales 2002.

Figure 5.5.1.4-3: Residential Use of Heating Oil in PADD I

Residential Use of No. 2 Distillate in PADD I

PADD I Refining District



Sales of No. 2 Distillate Fuel Oil for Residential Use
(Thousand Gallons)

PADD IA		**PADD IB**	
ME.	271,855	N.Y.	1,330,288
N.H.	167,740	PA.	351,645
VT.	85,505	N.J.	366,112
MASS.	892,675	DEL.	40,038
R.I.	135,745	MD	178,006
CONN.	529,648	D.C.	14,234

PADD IC	
W.VA.	19,948
VA.	196,518
NC.	113,584
SC.	15,585
GA	2,225
FLA	3,785

PADD I Summary

PADD 1 Total	5,192,749	
PADD 1A	2,083,168	(40%)
PADD 1B	2,757,936	(53%)
PADD 1C	351,645	(7%)

The data summary presented by NORA indicated that PADD IC was more similar to the other PADDs than to PADDs IA and IB with respect to the volume of heating oil used in relation to the use of NRLM fuel. However, a review of the levels of heating oil by state (in Figure 5.5.1.4-1) reveals that the level of heating oil use in Virginia and North Carolina is more similar in magnitude to that in the PADD IA and PADD IB states than to the other states in PADD IC. This suggests that assigning Virginia, North Carolina, and the areas in PADD IA and IB to the Northeast/Mid-Atlantic Area but not the remaining states in PADD IC might best balance the criteria of excluding areas with high heating oil demand from the marker requirement while preserving the widest possible area in which refiners could use the small-refiner and credit provisions.

However, a review of the pipeline map in Figure 5.5.1.4-2 and the topography of West Virginia suggests that the Eastern panhandle of West Virginia should also be in the Northeast/Mid-Atlantic Area. The topography of West Virginia has dictated that in some ways the state's Eastern panhandle is more closely linked with the surrounding states than to the rest of West Virginia.[T] This also suggests that Eastern panhandle may receive its fuel from the pipelines that serve the northeast and Mid-Atlantic states. Discussion with the West Virginia Petroleum Marketers Association confirmed that the counties in the Eastern panhandle of West Virginia do receive their fuel from sources that draw from the Colonial and Plantation pipelines, while the remainder of the state receives its fuel from other sources.[U] Therefore, we believe that it is appropriate to assign the counties in the Eastern panhandle of West Virginia to the Northeast/Mid-Atlantic Area but not the rest of the state.

We believe that states outside of PADD I should not be assigned to the Northeast/Mid-Atlantic Area for several reasons. The first reason is that heating oil users are predominately located in PADD I. Therefore, assigning areas outside of PADD 1 to the Northeast/Mid-Atlantic Area would provide relatively little relief with respect the burden of the marker requirement for heating oil, while substantially eroding the potential benefits of the small refiner and credit provisions under today's rule. Table 5.5.1.4-2 illustrates that the great majority of heating oil use is localized in PADD IA and IB.

Table 5.5.1.4-2
Residential Heating Oil Use in the U.S.

Area	Residential Heating Oil Use[1] (thousand gallons)	Percent of U.S. Total
U.S. Total	5,830,179	-
PADD I	5,192,749	89.1%
PADD IA	2,083,168	35.7%
PADD IB	2,757,936	47.3%
PADD IC	351,645	6.0%
PADD II	473,972	8.1%
PADD III	3,138	0.1%
PADD IV	19,796	0.3%
PADD V	140,524	2.4%

[1] Energy Information Administration (EIA), Fuel Oil and Kerosene Sales 2002, Table 19, Adjusted Sales for Residential Use: Distillate Fuel Oil and Kerosene.

The estimates in Table 5.5.1.4-2 are based on the reported use and do not speak to the sulfur content of the fuel. A sizeable fraction of the fuel reported as used as heating oil may be spillover from the highway diesel pool. This is most likely in areas where heating oil is currently

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[T] West Virginia University: The Sources of the Political Agenda: Geography, History and Economy, and Political Culture (of West Virginia), http://www.polsci.wvu.edu/faculty/dilger/PS321/CHAP-1.htm#N_3_

[U] Phone conversation with the Western Virginia Petroleum Marketers Association.

not distributed by pipeline. As noted earlier, we anticipate that after implementation of the NRLM program, heating oil will only be distributed by pipeline to supply the Northeast and Mid-Atlantic states. Therefore, it is likely that this rule will result in a greater proportion of the fuel used for heating purposes outside of PADD I to come from the highway diesel and NRLM pools. Though used for heating purposes, such spillover would be designated as highway and NRLM, would meet the applicable sulfur standards, and thus would not be subject to the marker requirement. The marker requirement is associated with the sulfur content of the fuel rather than its designation.

The second reason is that we expect that the heating oil which is sold outside of the Northeast and Mid-Atlantic states will primarily be distributed directly from refiner racks. We expect that the vast majority of terminals that will continue to carry heating oil will be supplied by the pipeline systems illustrated in Figure 5.5.1.4-2 and by marine shipments into Northern PADD I and thus will be located adjacent to these sources. Only a few entities, primarily refiners, would need to install new injection equipment for the heating oil marker if the marker requirement were to apply only to areas outside of the Northeast and Mid-Atlantic states.

Limited volumes of heating oil produced from segregated pipeline interface may be sold at some terminals outside of the Northeast and Mid-Atlantic states.[V] However, we anticipate that for many of the terminal operators that occasionally receive such fuel, the number of such fuel batches will not be great enough to justify the installation of marker injection equipment. Instead of adding the marker, such terminals would have the option of designating it as NRLM through May 31, 2010, 500 ppm nonroad through May 31, 2012, 500 ppm NRLM from June 1, 2012 through May 31, 2014, or 500 ppm L&M beyond 2014. Any fuel designated as such could still be sold as heating oil.

The final reason is that we believe that assigning areas outside of Northeast and Mid-Atlantic states to the Northeast/Mid-Atlantic Area would significantly diminish the intended relief of the refinery flexibility provisions. Thus, we believe that implementation of the heating oil marker requirement outside of the Northeast and Mid-Atlantic states would allow implementation of refiner flexibilities that would be of substantial value to refiners in reducing their compliance burden, especially small refiners who might otherwise find the burden of compliance prohibitive, while resulting in an acceptably small burden to industry.

Based on our assessment discussed above, the following areas seemed the best candidates for assignment to the Northeast/Mid-Atlantic Area: PADD 1A, PADD 1B, Virginia, North Carolina, and the Eastern Panhandle of West Virginia. The following section discusses how we further refined the definition of the Northeast/Mid-Atlantic Area based on our evaluation of the distribution area of small refiners and additional input from the potentially affected industries.

[V] We project that the majority of this segregated interface will meet a 500 ppm specification. Under the provisions of the final rule, such 500 ppm diesel fuel could be sold directly into the NRLM market from 2007 - 2014 and into the locomotive and marine diesel markets after 2014.

Input from refiners and other parties on the appropriate boundary of the Northeast/Mid-Atlantic Area.

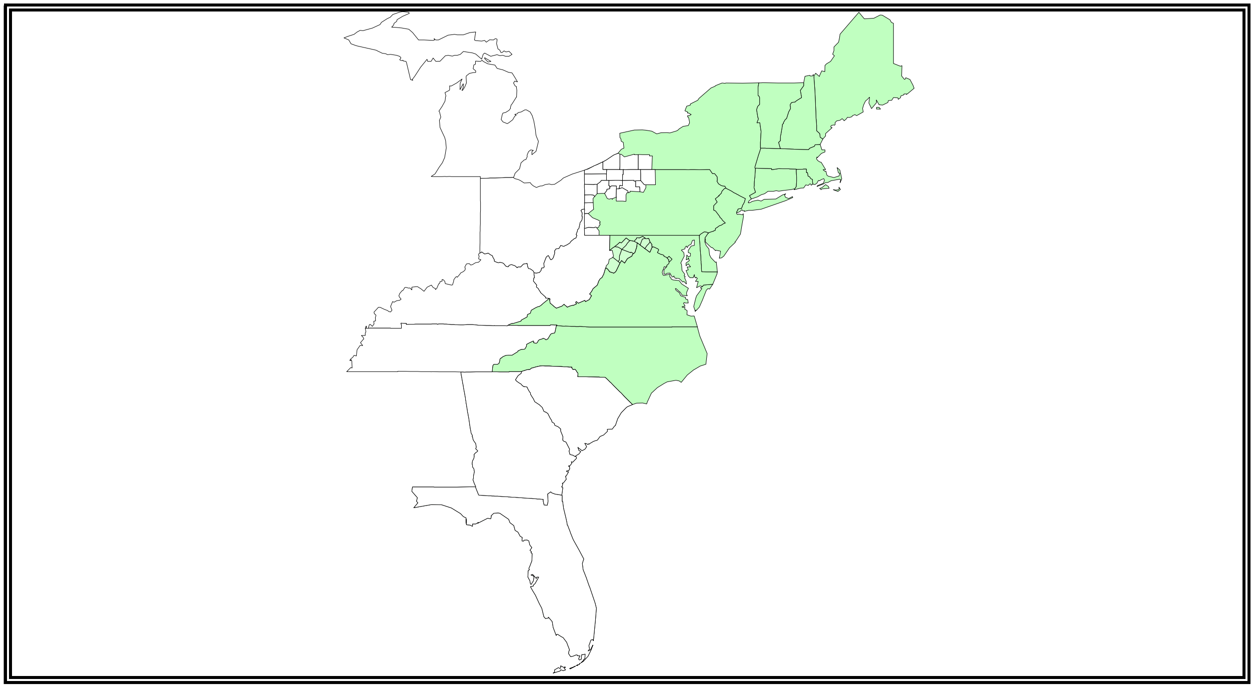
A critical factor in defining the boundary of the Northeast/Mid-Atlantic Area is evaluating its impact on small refiners' access to the small-refiner provisions. Our evaluation of the location of small refiners who will likely use these provisions indicates that one such small refiner's distribution area, in Northwestern Pennsylvania, is located within the aforementioned areas. With the exception of this refinery, our evaluation indicated that assigning these areas to the Northeast/Mid-Atlantic Area would not interfere with the use of the small-refiner provisions or significantly reduce the value of the NRLM credit provisions. We sought input from the range of potentially affected parties on this assessment and on how we might accommodate the needs of the small refiner to have access to the small-refiner provisions while maintaining our goal of minimizing the potential number of entities that would need to install injection equipment and the volume of heating oil that would need to be marked. The parties that we solicited input from include: the American Petroleum Institute, the National Petroleum Refiners Association, the Ad Hoc Coalition of Small Refiners, the Independent Fuel Terminal Operators Association (IFTOA), the Association of Oil Pipelines, the National Oil-heat Research Alliance, Colonial Pipeline, Buckeye Pipeline, the American Refining Group, and Marathon-Ashland Petroleum.

Based on these discussions, we determined that they the small-refiner flexibilities would remain intact if the following counties were not assigned to the Northeast/Mid-Atlantic Area: Chautauqua, Cattaraugus, and Allegany counties in New York, and Erie, Crawford, Warren McKean, Potter, Mercer, Venango, Forest, Clarion, Elf, Jefferson, and Cameron counties in Pennsylvania. These counties are located between the two arms of the Buckeye/Laurel pipeline that project West into New York and Pennsylvania (see Figure 5.5.1.4.-2). There are many terminals along the paths of these pipelines but none to our knowledge in the aforementioned counties. Our review also indicates that it would be most consistent with current distribution patterns to not assign the Pennsylvania border counties of Lawrence and Greene to the Northeast/Mid-Atlantic Area. Thus, it appears that not assigning these counties to the Northeast/Mid-Atlantic Area would not substantially increase the burden to terminal operators and most closely conforms to the current patterns of product distribution. Input from the all the parties we contacted was favorable to not assigning these counties to the Northeast/Mid-Atlantic Area.

Conclusion:

Based on the above, we determined that the Northeast/Mid-Atlantic Area defined below would minimize the number of terminals that would need to install new injection equipment and the amount of fuel that would need to be marked, while preserving the benefits of the small-refiner and credit high-sulfur NRLM provisions. All the industry representatives we contacted stated that the definition of the Northeast/Mid-Atlantic Area in the final rule represents the best balance of the various selection criteria and meets our stated goals in adopting the exclusion-area approach. The areas excluded from the marker requirement and where the sale of fuel manufactured under the credit and hardship provision is prohibited are: North Carolina, Virginia, Maryland, Delaware, New Jersey, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, Maine, Washington D.C., New York (except for the counties of Chautauqua, Cattaraugus, and Allegany), Pennsylvania (except for the counties of Erie, Warren, Mc Kean, Potter, Cameron, Elk, Jefferson, Clarion, Forest, Venango, Mercer, Crawford, Lawrence, Beaver, Washington, and Greene), and the eight Eastern-most counties in West Virginia (namely: Jefferson, Berkely, Morgan, Hampshire, Mineral, Hardy, Grant, and Pendleton). The Northeast/Mid-Atlantic Northeast/Mid-Atlantic Area is illustrated in Figure 5.5.1.4-1.[W]

Figure 5.5.1.4.-1: Northeast/Mid-Atlantic Area



5.5.2 Limiting Sulfur Contamination

The physical hardware and distribution practices for NRLM fuel does not differ significantly from those for current highway diesel fuel. Therefore, we do not anticipate any new issues with respect to limiting sulfur contamination during the distribution of 500 ppm NRLM fuel that would not have already been accounted for in distributing highway diesel fuel. Highway diesel fuel has been required to meet a 500 ppm sulfur standard since 1993. Thus, we expect that limiting contamination during the distribution of 500 ppm non-highway diesel engine fuel can be readily accomplished by industry.

In the highway diesel rule, we acknowledged that meeting a 15 ppm sulfur specification would pose a substantial new challenge to the distribution system. Refiners, pipelines and terminals would have to pay careful attention to and eliminate any potential sources of

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[W] The Northeast/Mid-Atlantic Area is shaded.

contamination in the system (e.g., tank bottoms, dead legs in pipelines, leaking valves, interface cuts, etc.) In addition, bulk plant operators and delivery truck operators would have to carefully observe recommended industry practices to limit contamination, including things as simple as cleaning out transfer hoses, proper sequencing of fuel deliveries, and parking on a level surface. The necessary changes to distribution hardware and practices and the associated costs are detailed in the RIA to the highway diesel final rule.[40]

We are continuing to work with industry to ensure a smooth transition to the 15 ppm sulfur standard for highway diesel fuel. In November of 2002, a joint industry-EPA Clean Diesel Fuel Implementation Workshop was held in Houston, Texas. This workshop was co-sponsored by a broad cross-section of trade organizations representing the diesel fuel producers and distributors who will be responsible for compliance with the 15 ppm highway diesel standard: the National Petroleum Refiners Association (NPRA), the Association of Oil Pipelines (AOL), the Independent Fuel Terminal Operators Association (IFTOA), the National Association of Conveniences Stores (NACS), the Society of Independent Gasoline Marketers of America, and the Petroleum Marketers Association of America (PMAA). The workshop featured over 20 presentations by industry the topic of distributing 15 ppm diesel fuel, as well as a questions and answers discussion.[41] Some of these presentations contained the results of the first test programs conducted by the pipeline industry to develop procedures and identify the changes needed to limit sulfur contamination. These initial test programs did not resolve all of industry's concerns related to the ability to limit sulfur contamination during the distribution of 15 ppm diesel fuel. However, the results were promising and indicated that with further testing and development the distribution industry can successfully manage sulfur contamination during the distribution of 15 ppm diesel fuel. We understand that the fuel distribution industry is in the process of conducting such additional work and that there are plans to develop standard industry practices for each segment of the distribution industry to limit sulfur contamination. We will keep abreast of developments in this area.

Due to the need to prepare for compliance with the highway diesel program, we anticipate that issues related to limiting sulfur contamination during the distribution of 15 ppm NRLM diesel fuel will be resolved well in advance of the proposed 2010 implementation date for 15 ppm sulfur standard for nonroad fuel. We are not aware of any additional issues that might be raised unique to nonroad fuel. If anything we anticipate limiting contamination will become easier. We expect that 15 ppm nonroad diesel fuel will be distributed in fungible batches with 15 ppm highway diesel fuel up to the point when it leaves the terminal and nonroad diesel fuel must be dyed per IRS requirements. The resulting larger batch sizes as a percentage of the total 15 ppm diesel throughput may make it somewhat easier to limit sulfur contamination and could reduce losses to product downgrade during transportation by pipeline. We also expect that the projected absence of high-sulfur diesel fuel and heating oil in many pipeline systems will lessen the opportunity for sulfur contamination. As a result, if anything the opportunity for contamination should decline with the expansion of the 15 ppm pool to include nonroad and L&M in addition to highway diesel fuel.

5.5.3 Handling Practices for Distillate Fuels that Become Mixed in the Pipeline Distribution System

The NRLM sulfur program in this rule raises two issues regarding the potential impact on the current handling practices for diesel fuel that become mixed with other distillate fuels or with gasoline during transport by pipeline (pipeline interface). The first pertains to whether there will be suitable market for the diesel fuel that is recovered from these mixed products. The second pertains to whether the requirements in this rule would interfere with the operations of transmix processors. As discussed in the following sections, we included provisions in the NRLM program to address these potential concerns.

Ensuring a Suitable Market for Diesel Fuel Recovered from Pipeline Interface

Fuel batches shipped by pipeline abut each other with no physical separation between the batches. Consequently, mixing between the fuel batches that abut each other in the distribution is unavoidable. When the volume in the mixing zone (interface) meets the specifications of one of the two fuels being shipped next to each other, the interface is simply added to the batch of that fuel. For example, the interface between regular and premium gasoline is added to the regular grade batch. Or, the interface between jet fuel and heating oil is added to the heating oil batch. One interface which is never added to either adjacent batch is a mixture of gasoline and any distillate fuel, such as jet or diesel fuel. If this interface was added to the distillate batch, the gasoline content in the interface would result in a violation of the distillate's flash point specification. If this interface was added to the gasoline batch, it would cause the gasoline to violate its end point specification. Therefore, this interface must be shipped to a transmix processor to separate the mixture into naphtha (a sub-octane gasoline) and distillate. The 2007 highway diesel fuel program will not change this practice. Most of the naphtha produced by transmix processors from gasoline/distillate mixtures is usually blended with premium gasoline to produce regular grade gasoline. The heaviest portion of this naphtha is typically cut into the distillate fuel produced so as to lessen the impact on octane (and the resulting need to blend in premium gasoline to make regular gasoline). The distillate produced is an acceptable high-sulfur diesel fuel or heating oil, though if the feed material was primarily low-sulfur distillate and gasoline it will likely also meet the current 500 ppm highway fuel cap.

The interface between jet fuel and highway diesel can not be cut into jet fuel due to end point and other concerns. However, it can usually be cut into 500 ppm diesel fuel as long as the sulfur level of the jet fuel is not too high. With the lowering of the highway standard to 15 ppm, however, this will no longer be possible. We expect that pipelines minimize this interface by abutting jet fuel and high-sulfur distillate in the pipeline whenever possible. However, it will be unavoidable under many circumstances. A substantial part of the pipeline distribution system currently does not handle high-sulfur distillate. We expect that the highway program and this final rule will cause additional pipeline systems to discontinue carrying high-sulfur distillate. Pipelines that do not carry high-sulfur distillates will generate this interface whenever they ship jet fuel. Under the highway program and this final rule, we project that pipeline operators will segregate this interface by cutting it into a separate storage tank. Because this interface can be sold as 500 ppm NRLM fuel or heating oil without reprocessing, and because these markets exist nationwide, there is little impact beyond the need for refiners to produce more 15 ppm highway diesel fuel to offset the downgraded volume, which was considered as part of the refining costs in the highway diesel rule.

With control of nonroad diesel fuel to 15 ppm sulfur in 2010, and L&M in 2012, the opportunities to downgrade interface to another product become increasing limited. Where limited this will increase costs due to the need to transport the interface to where it can be marketed or to a facility for reprocessing. In areas with large heating oil markets, such as the Northeast and the Gulf Coast, the control of NRLM sulfur content will still have little impact on the sale of this interface. However, in areas lacking a large heating oil market, the sale of this distillate interface will be more restricted. Because this interface will be composed of 15 ppm diesel fuel and jet fuel, we estimate that the distillate interface created should nearly always meet a 500 ppm cap. Thus, this interface can be added to 500 ppm NRLM batches (as well as heating oil, where it is present at the terminal) through 2014. After 2014, this 500 ppm interface fuel can only be sold as L&M fuel or heating oil.

In Chapter 7 of the Final RIA, we estimate the costs related to handling this interface fuel during the three time periods (2007-2010, 2010-2014[X], and 2014 and beyond). We project that there will be no additional costs prior to 2010, as 500 ppm fuel will be the primary NRLM fuel and be widely distributed. Beyond 2010, we estimate that some terminals will have to add a small storage tank (or dedicate an existing tank) for this fuel, as 500 ppm highway diesel fuel and the majority of 500 ppm nonroad disappears from the distribution system. In many places, this interface will be the primary, if not sole source of 500 ppm fuel, so existing tankage for this interface will be limited. We have also added shipping costs to transport this fuel to NRLM and heating oil users. The volume of this interface is significant, sometimes a sizeable percentage of the combined NRLM fuel and heating oil markets. In the post-2014 period, the volume of this interface fuel is larger than the combined L&M fuel and heating oil markets in certain PADDs. Also, the volume of interface received at each terminal will vary substantially, depending on where that terminal is on the pipeline. The advantage of this is that where the interface accumulates it may be of sufficient volume to justify marketing as a separate grade of fuel. Conversely, the potential users of this 500 ppm interface fuel may not be located near the terminals with the fuel necessitating additional transportation costs.

Prior to 2014, 500 ppm fuel can be used as NRLM fuel and heating oil. Additional storage tanks will be needed in some cases, as this will be the only source of 500 ppm fuel in the marketplace. There will also be additional costs associated with transporting this 500 ppm to an appropriate end-user. Starting in 2014, this interface fuel can no longer be sold to the nonroad fuel market. Since the interface volume does not change, this increases the proportion which gets sold to the L&M and heating oil markets. Thus, overall, transportation distances and costs will likely increase. We also estimate that some fuel will have to be shipped back to refineries and reprocessed to meet a 15 ppm cap and shipped out a second time.

[X] The costs are not significantly different from 2010-2012 than they are from 2012-2014.

By allowing the 500 ppm fuel to continue to be sold into the NRLM market until 2014 and into the L&M market thereafter, the final rule removes issues regarding the feasibility of handling this material. Without these provisions, a substantial portion of this fuel would need to be returned to the refinery for reprocessing raising significant cost issues, since the material would need to be transported by truck in many cases and it might be difficult to locate refiners willing to reprocess all of the volume. As discussed above there will be some additional transportation costs to deliver such 500 ppm to a suitable market and a limited volume will need to be reprocessed starting in 2014. However, as discussed in Chapter 7 of this RIA, we expect the associated costs will be modest and can be accommodated by fuel distributors.

The Potential Impact on Transmix Processors

There are two issues regarding the potential impact of this rule on transmix processors. The first pertains to whether a transmix processor should be subject to the requirements applicable to all refiners. The second pertains to whether the heating oil marker requirements will restrict their ability sell the distillate fuels they produce into non-heating oil markets

As discussed above, some pipeline interfaces do not meet the specifications for sale into any end-use market. In such cases the interface is referred to as transmix and delivered to a transmix processor for separation into marketable products. Transmix processors operate distillation towers that separate the gasoline/distillate mixture into their component parts: gasoline and distillate fuel (as discussed above). Transmix processors possess no facilities with which to remove sulfur from fuel and it currently would be burdensome for them to install such equipment. For example, they do not have access to any hydrogen for desulfurization like at a typical refinery. Based on these realities, we believe that it would be inappropriate to treat transmix processors as refiners with respect to compliance with the sulfur standards under this rule. Consequently, the final rule provides that transmix processors may produce fuels for sale into the NRLM markets that meet the applicable small-refiner provisions as long as they remain in effect. After the NRLM small-refiner provisions expire in 2014, transmix processors may continue to sell 500 ppm fuel into the L&M market as discussed above. This allows 500 ppm fuel produced by transmix processors to stay in the diesel fuel market and avoids the costs that would accrue other wise. The final rule also amends the highway program to allow similar flexibility for transmix processors. Consequently, there are no feasibility issues associated with transmix processors.

Transmix processors stated that the presence of a marker in heating oil would limit the available markets for their reprocessed distillates. The feed material for transmix processors primarily consists of the interface mixing zone between batches of fuels that abut each other during shipment by pipeline where this mixing zone can not be cut into either of the adjacent products. If marked heating oil was shipped by pipeline, the source material for transmix processors fed by pipelines that carry heating oil would contain SY-124. Transmix processors stated that it would be prohibitively expensive to segregate pipeline-generated transmix containing the marker from that which does not contain the marker prior to processing, and that they could not economically remove the marker during reprocessing. Thus, in cases where the marker would be present in a transmix processor's feed material, they would be limited to marketing their reprocessed distillate fuels into the heating oil market. Since the final rule requires that the marker be added at the terminal gate (rather than at the refinery gate), the feed material that transmix processors receive from pipelines will not contain the marker. Hence, they will not typically need to process transmix containing the heating oil marker, and today's marker requirement is not expected to significantly alter their operations. There is little opportunity for marker contamination of non-heating oil fuel to occur at the terminal and further downstream. In the rare instances where this might occur, the fuel contaminated would likely also be a distillate fuel, and thus could be sold into the heating oil market without need for reprocessing.

5.6 Feasibility of the Use of a Marker in Heating Oil

As discussed in Section IV.D. of the preamble, to ensure that heating oil is not shifted into the NRLM market, we need a way to distinguish heating oil from high-sulfur NRLM produced under the small-refiner and credit provisions. Currently, there is no differentiation today between fuel used for NRLM uses and heating oil. Both are typically produced to the same sulfur specification, and both are required to have the same red dye added prior to distribution from downstream of the terminal. Based on recommendations from refiners, in the NPRM, we concluded that the best approach to differentiate heating oil from high-sulfur NRLM would be to require that a marker be added to heating oil at the refinery gate. Since the proposal we received additional information which allows us to rely upon recordkeeping and reporting provisions to differentiate heating oil from high-sulfur NRLM up the point where it leaves the terminal (see Section IV.D. of the preamble to the final rule). The final rule therefore requires that a marker be added to heating oil before it leaves the terminal, rather than proposed approach of requiring it to be added at the refinery gate.[Y]

Terminal operators suggested that we might also be able to rely on recordkeeping and reporting downstream of the terminal to differentiate heating oil from high-sulfur NRLM, thereby eliminating any need for a marker in heating oil. However, we believe such recordkeeping and reporting mechanisms would be insufficient to keep heating oil out of the NRLM market downstream of the terminal under typical circumstances. We can rely on such measures before the fuel leaves the terminal, because it is feasible to require all the facilities in the distribution system to send us reports describing their fuel transfers. As discussed in Section IV.D of the preamble to the final rule, we can compare these electronic reports to identify parties responsible for shifting heating oil into the NRLM market. Downstream of the terminal the parties involved in the fuel distribution system become far too numerous for such a system to be implemented and enforced (including jobbers, bulk plant operators, heating oil dealers, retailers, and including farmers. Reporting errors for even a small fraction would require too many resources to track down and correct and would eliminate the effectiveness of the system.

Our proposal envisioned that a fuel marker would be required in heating oil from June 1,

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[Y] Heating oil sold inside the Northeast/Mid-Atlantic Area finalized under today's rule does not need to contain a marker (see Section IV.D. of today's preamble).

2007 through May 31, 2010, and that the same marker would be required in locomotive and marine fuel from June 1, 2010 through May 1, 2014. As a consequence of finalizing a 15 ppm sulfur standard for locomotive and marine fuel in 2012 we are now requiring the use of a marker in locomotive and marine fuel from 2010-2012. However, we are also requiring the continued use of the marker in heating oil indefinitely (see Section IV of the preamble to the final rule).

We proposed and are finalizing that solvent yellow 124 (SY-124) must be added to heating oil beginning June 1, 2007, and to 500 ppm sulfur L&M diesel fuel produced or imported from June 1, 2010 through May 31, 2012 at a concentration of 6 milligrams per liter (mg/l). The chemical composition of SY-124 is as follows: N-ethyl-–[2-[1-(2-methylpropoxy)ethoxyl]-4-phenylazo]-benzeneamine.[Z] This concentration is sufficient to ensure detection of SY-124 in the distribution system, even if diluted by a factor of 50. Any fuel found with a marker concentration of 0.10 milligrams per liter or more will be presumed to be heating oil from June 1, 2007 through May 31, 2010, and after May 31, 2012. From June 1, 2010 through May 31, 2012, any fuel found to contain a marker concentration of 0.10 milligrams per liter or less will be considered heating oil if its sulfur content is above 500 ppm, or L&M diesel fuel if its sulfur content is below 500 ppm. Below a concentration of 0.10 mg/L, the prohibition on the use of fuel containing the marker does not apply.

There are a number of other types of dyes and markers. Visible dyes are most common, are inexpensive, and are easily detected. Using a second dye in addition to the red dye required by IRS in all non-highway fuel for segregation of heating oil based on visual identification raises certain challenges. The marker that we require under today's rule must be different from the red dye currently required by IRS and EPA and not interfere with the identification of red dye in distillate fuels. Invisible markers are beginning to see more use in branded fuels and are somewhat more expensive than visible markers. Such markers are detected either by the addition of a chemical reagent or by their fluorescence when subjected to near-infra-red or ultraviolet light. Some chemical-based detection methods are suitable for use in the field. Others must be conducted in the laboratory due to the complexity of the detection process or concerns regarding the toxicity of the reagents used to reveal the presence of the marker. Near-infra-red and ultra-violet fluorescent markers can be easily detected in the field using a small device and after brief training of the operator. There are also more exotic markers available such as those based on immunoassay, and isotopic or molecular enhancement. Such markers typically need to be detected by laboratory analysis.

We selected SY-124, however, for a number of reasons:

1) There is considerable data and experience with it which indicates there are no significant issues with its use.
2) It is compatible with the existing red dye
3) Test methods exist to quantify its concentration, even if diluted by a factor of 50 to 1

[Z] Opinion on Selection of a Community-wide Mineral Oils Marking System, ("Euromarker"), European Union Scientific Committee for Toxicity, Ecotoxicity and the Environment plenary meeting, September 28, 1999.

4) It is reasonably inexpensive
5) It can be produced and provided by a number of sources

Effective in August 2002, the European Union (EU) enacted the requirement that SY-124 be added at 6 mg/l to diesel fuel that is taxed at a lower rate in all EU member states.[AA] Solvent yellow 124 is referred to as the "Euromarker" in the EU. The EU has found this treatment rate to be sufficient for their enforcement purposes while not interfering with the identification of the various different colored dyes required by different EU member states (including the same red dye that is required in the U.S.). Despite its name, solvent yellow 124 does not impart a strong color to diesel fuel when used at a concentration of 6 mg/l. Most often it is reportedly nearly invisible in distillate fuel given that the slight yellow color imparted is similar to the natural color of many distillate fuels.[BB] In the presence of red dye, SY-124 can impart a slight orange tinge to the fuel. However, it does not interfere with the visual identification of the presence of red dye or the quantification of the concentration of red dye in distillate fuel. Thus, the use of SY-124 at 6 mg/l in diesel fuel should not interfere with the use of the red dye by IRS to identify non-taxed fuels.

Solvent yellow 124 is chemically similar to other additives used in gasoline and diesel fuel, and EPA has registered it as a fuel additive under 40 CFR part 79. Therefore, we expect that its products of combustion would not have an adverse impact on emission control devices, such as a catalytic converter. Extensive evaluation and testing of solvent yellow 124 was conducted by the European Commission. This included combustion testing which showed no detectable difference between the emissions from marked and unmarked fuel. Norway specifically evaluated the use of distillate fuel containing solvent yellow 124 for heating purposes and determined that the presence of the Euromarker did not cause an increase in harmful emissions from heating equipment. Based on the European experience with solvent yellow 124, we do not expect that there would be concerns regarding the compatibility of solvent yellow 124 in the U.S. fuel distribution system or for use in motor vehicle engines and other equipment such as in residential furnaces.

Our evaluation of the process conducted by the EU in selecting the SY-124 for use in the EU convinced us that SY-124 was also the most appropriate marker to propose for use in heating oil under the final rule. We received a number of comments expressing concern about the use of SY-124. Based on our evaluation of these comments (summarized below and in the Summary and Analysis of Comments), we continue to believe that SY-124 is the most appropriate marker to specify for use under today's rule. The final rule therefore requires that, beginning June 1, 2007, SY-124 be added to heating oil, and from June 1, 2020 through May 31, 2012, SY-124 be added to LM diesel fuel produced at a refinery or imported at a concentration of 6 mg/l before the fuel leaves the terminal, except in the Northeast/Mid-Atlantic Area and Alaska.

[AA] The European Union marker legislation, 2001/574/EC, document C(2001) 1728, was published in the European Council Official Journal, L203 28.072001.

[BB] The color of distillate fuel can range from near water white to a dark blackish brown but is most frequently straw colored.

The concerns regarding the use of SY-124 primarily pertained to: the potential impact on jet engines if jet fuel were contaminated with SY-124; the potential health effects of SY-124 when used in fuel for heating purposes, particularly for unvented heaters; the potential cost impact on fuel distributors and transmix processors; and the potential conflict with IRS red dye requirements.

The American Society of Testing and Materials (ASTM), the Coordinating Research Council (CRC), and the Federal Aviation Administration (FAA) requested that we delay finalizing the selection of a specific marker for use in this final rule. They requested that selection of a specific marker should be deferred until testing could be conducted regarding the potential impact of SY-124 on jet engines. The Air Transport Association stated that we should conduct an extensive study regarding the potential for contamination, determine the levels at which the marker will not pose a risk to jet engines, and seek approval of SY-124 as a jet fuel additive. Other parties, including the Department of Defense (DoD), also stated that we should refrain from specifying marker under this rule until industry and other potentially affected parties can recommend an appropriate marker. Representatives of the heating oil industry expressed a concern that we had not conducted an independent review regarding the safety/suitability of SY-124 for use in heating oil.

We met and corresponded with numerous and diverse parties to evaluate the concerns expressed regarding the use of SY-124, and to determine whether it might be more appropriate to specify a different marker for use under today's rule. These parties include IRS, FAA, ASTM, CRC, various marker/dye manufacturers, European distributors of fuels containing the Euromarker, marker suppliers, and members of all segments in the U.S. fuel distribution system.

We believe that concerns related to potential jet fuel contamination have been sufficiently addressed for us to finalize the selection of SY-124 as the required marker in this rule.[CC] As discussed in Section IV.D of the preamble to the final rule, changes in the structure of the fuel program since the proposal have allowed us to move the point where the marker must be added to from the refinery gate to the terminal. The vast majority of concerns regarding the potential for contamination of jet fuel with SY-124 pertained to the shipment of marked heating oil by pipeline. All parties were in agreement that nearly all the potential for marker contamination of jet fuel would disappear if the point of marker addition was moved to the terminal. We spoke with terminal operators, both large and small, who confirmed that they maintain strictly segregated distribution facilities for red dyed fuel and jet fuel because of jet fuel contamination concerns. The same type of segregation practices can be readily adapted regarding the handling of marked heating oil and jet fuel, and would be equally effective in limiting contamination of jet fuel with SY-124. Downstream of the terminal, the only other chance for marker contamination of jet fuel pertains to bulk plant operators and jobbers that handle marked fuel and jet fuel. For the most part, these parties also currently maintain strict segregation of the facilities used to transport jet fuel and heating oil (or L&M fuel that will be marked under toady's rule). The one

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[CC] See the Summary and Analysis of Comments for a more detailed discussion of our response to concerns about the possible contamination of jet fuel with the heating oil marker.

exception is that small bulk plant operators that supply small airports sometimes use the same tank truck to alternately transport jet fuel and heating oil. In such cases, they flush the tank compartment prior to transporting jet fuel to remove any residual heating oil left behind after the tank is drained. We do not expect that bulk plant operators will handle marked L&M diesel fuel.

The final rule requires that fuel which is required to contain the marker must also contain red dye. Therefore, the "white bucket" test that distributors currently use to detect red dye contamination of jet fuel can also be relied upon to detect marker contamination of jet fuel. Based on the above discussion, we concluded that the marker requirements under today's rule would not significantly increase the likelihood of jet fuel contamination, and that when such contamination might occur, it could be readily identified without the need for additional testing. Our finalization of the Northeast/Mid-Atlantic Area in (see Section IV.D. of the preamble to the final rule) also minimizes potential concerns regarding the potential that jet fuel may become contaminated with the marker since no marker is required in heating oil (or 500 ppm L&M diesel fuel produced by refiners or imported from 2010-2012) in this area and there is expected to be little heating oil used outside of the Northeast/Mid-Atlantic Area.

This final rule requires addition of the marker at the terminal rather than the refinery gate as proposed. Based on this change, ASTM withdrew its request to delay finalization of the marker requirements in this rule. However, ASTM stated that some concern remains regarding jet fuel contamination downstream of the terminal (due to the limited use of the same tank wagons to alternately transport jet fuel and heating oil discussed above). Nevertheless, ASTM related that these concerns need not delay finalization of the marker requirements in this rule. ASTM intends to support a CRC program to evaluate the compatibility of markers with jet fuel. FAA is also undertaking an effort to identify fuel markers that would be compatible for use in jet fuel. We commit to a review of the use of SY-124 in the future based on the findings of the CRC and the FAA, experience with the use of SY-124 in Europe, and future input from ASTM or other concerned parties. If alternative markers are identified that do not raise concerns regarding the potential contamination of jet fuel, we will initiate a rulemaking to evaluate the use of one of these markers in place of SY-124.

After 2010, today's rule removes the current EPA refinery gate requirement that any diesel fuel that not meet the specifications for highway diesel fuel must contain visible evidence of red dye (40 CFR § 80.520(b)(2)). This requirement means that diesel fuel which does not meet highway diesel specifications must currently be dyed before it is shipped by pipeline from the refinery. As a result of the implementation of today's rule, we do not expect that any red dyed fuel will be shipped by pipeline due to the need to comply with EPA requirements after 2010. Based on this change, we expect that today's rule will actually result in an overall reduction in the potential for jet fuel to become contaminated with azo dyes such as red dye and SY-124.

Since the NPRM, no new information has been provided which indicates that the combustion of SY-124 in heating equipment would result in more harmful emissions than when combusted in engines, or would result in more harmful emissions than combustion of unmarked heating oil. The European experience with the use of solvent yellow 124 and the evaluation process it underwent prior to selection by the EU, provides strong support regarding the compatibility of SY 124 in the U.S. fuel distribution system, and for use in motor vehicle engines and other equipment such as in residential furnaces. We believe that hypothesized concerns regarding health impacts from the use of SY-124 do not present sufficient cause to delay finalization of the marker requirements under today's rule.

The European Union intends to review the use of Solvent yellow 124 after December 2005, but may undertake the review earlier if any health and safety or environmental concerns about its use are raised. We intend to keep abreast of such activities and may initiate our own review of the use of solvent yellow 124 depending on the European Union's findings, or other relevant information. There will be nearly four years of accumulated field experience with the use of SY-124 in Europe at the time of the review by the EU and nearly 5 years by implementation of the marker requirement under this rule. This will provide ample time to identify any new issues with SY-124 and to choose a different marker if warranted.

Commenters stated that potential health concerns regarding the use of SY-124 might be exacerbated with respect to its use in unvented space heaters. Commenters further stated that there are prohibitions against the dying of kerosene (No. 1 diesel) used in such heaters. No information was provided to support these concerns, however, and we have no information to suggest any health concerns exist regarding the use of SY-124 in unvented heaters. Nevertheless, even if there were such concerns, this rule will not require SY-124 to be used in the fuel used in unvented heaters. Furthermore, this rule does not require that SY-124 be added to kerosene. This resolves most of what concern might remain regarding this issue, since kerosene is the predominate fuel used in unvented heaters. However, the DoD stated that diesel fuel is sometimes used in its tent heaters and expressed concern regarding the presence of SY-124 in fuel used for this purpose. We understand that to simplify the DoD fuel distribution system, it is DoD policy to use a single fuel called JP-8 for multiple purposes where practicable, including space heating. Neither JP-8 not diesel fuel used for such a purpose would not be subject to the heating oil marker requirement in this rule.

We believe that the concerns expressed regarding the potential impact on distributors and transmix processors from the presence of SY-124 in heating oil have been addressed by moving the point of marker addition to the terminal. Terminal operators stated that they desire the flexibility to blend 500 ppm diesel fuel from 15 ppm diesel fuel and heating oil. This practice would have been prevented by the proposed addition of the marker at the refinery gate. Under the final rule, terminal operators will have access to unmarked high-sulfur fuel with which to manufacture 500 ppm diesel fuel by blending with 15 ppm diesel fuel.[DD]

Transmix processors stated that the presence of a marker in heating oil would limit the available markets for their reprocessed distillates. The feed material for transmix processors

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[DD] Terminals that manufacture 500 ppm diesel fuel by blending 15 ppm and high-sulfur fuel are treated as a refiner under the final rule. They must also comply with all applicable designate and track requirements, anti-downgrading provisions, and other applicable requirements (see Section IV.D of the preamble to the final rule).

primarily consists of the interface mixing zone between batches of fuels that abut each other during shipment by pipeline where this mixing zone can not be cut into either of the adjacent products. If marked fuel was shipped by pipeline, the source material for transmix processors fed by pipelines that carry heating oil (or marked L&M diesel fuel) would contain SY-124. Transmix processors stated that it would be prohibitively expensive to segregate pipeline-generated transmix containing the marker from that which does not contain the marker prior to processing, and that they could not economically remove the marker during reprocessing. Thus, in cases where the marker would be present in a transmix processor's feed material, they would be limited to marketing their reprocessed distillate fuels into the heating oil market (or the L&M market from 2010-2012 if the fuel met a 500 ppm sulfur specification). Since the final rule requires that the marker be added at the terminal gate (rather than at the refinery gate), the feed material that transmix processors receive from pipelines will not contain the marker. Hence, they will not typically need process transmix containing the marker, and the marker requirement is not expected to significantly alter their operations. There is little opportunity for marker contamination of fuels that are required to be marker free to occur at the terminal and further downstream. In the rare instances where this might occur, the fuel contaminated would likely also be a distillate fuel, and thus could be sold into the heating oil market (or the L&M market from 2010-2012 if the fuel met a 500 ppm sulfur specification) without need for reprocessing.

We do not expect that the marker requirement will result in the need for additional fuel storage tanks or tank trucks in the distribution system. As discussed in Section VI.A of the preamble to the final rule, we project that implementation of the NRLM sulfur standards will result in the need for additional storage tanks and tank truck demanifolding at a limited number of bulk plant facilities. The marker requirement does not add another criteria apart from the sulfur content of the fuel which would force additional product segregation.

As discussed above, industry has expressed concern about the use of the same tank trucks to alternately transport marked fuel and jet fuel. We do not expect that the addition of marker to heating oil (and 500 ppm sulfur diesel fuel produced by refiners or imported from 2010-2012) will exacerbate these concerns. However, depending on the outcome of the aforementioned CRC program, the fuel marker requirements under today's rule may hasten the current trend to avoid the use of tank trucks to alternately transport jet fuel and heating oil (or L&M diesel fuel to the extent that this occurs today). To the extent that this does occur, we do not expect that it would result in substantial additional costs since few tank truck operators currently use the same tank truck compartments to alternately transport heating oil and jet fuel and we are aware of no instances where tank truck operators currently use the same tank truck compartments to alternately transport L&M diesel fuel and jet fuel.

Through our discussions with the IRS, we have confirmed that the presence of SY-124 will not interfere with enforcement of their red dye requirement.[EE] Although, SY-124 may impart a slight orange tint to red-dyed diesel fuel, this will not complicate the identification of the presence of the IRS red dye. In fact, IRS has determined that the presence of SY-124 may

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[EE] Phone conversation between Carl Dalton, IRS and Jeff Herzog, EPA February 19, 2004.

even enhance enforcement of their fuel tax program.[FF] However, as identified in the comments, implementation of the marker requirement for heating oil arguably may be in conflict with IRS regulations at 26 CFR 48.4082-1(b), which states that no dye other than the IRS-specified red dye must be present in untaxed diesel fuel. IRS is evaluating what actions might be necessary to clarify that the addition of SY-124 to heating oil would not be in violation of IRS regulations. IRS related that they are investigating a family of markers for potential use in addition to red dye under their diesel tax program which might be compatible with jet fuel. IRS stated that the use of one of the markers in this family under this rule might result in a reduced burden on industry. Given the changes reflected in the final rule, the marker provisions will not impose a significant burden. However, if the IRS program were to develop alternate markers that would be compatible with jet fuel, we will initiate a rulemaking to evaluate the use of one of these markers in place of SY-124 for heating oil.

Commenters also expressed concerns regarding the proprietary rights related to the manufacture and use of SY-124, and stated that we should adopt a nonproprietary marker if possible. The proprietary rights related to SY-124 expire several months after implementation of the marker requirements in this rule. Therefore, we do not expect that the current proprietary rights regarding SY-124 are a significant concern. Commenters also stated that our estimated cost of SY-124 in the NPRM (0.2 cents per gallon of treated fuel) was high compared to other markers that cost hundredths of a cent a gallon. Since the proposal we have obtained more accurate information which indicates that the current cost of bulk quantities of SY-124 is approximately 0.03 cents per gallon of treated fuel (see Section 7.4. of this RIA). Based on conversations with various marker manufacturers, this cost is comparable to or less than other fuel markers.

5.7 Impacts on the Engineering and Construction Industry

An important aspect of the feasibility of any fuel quality program is the ability of the refining industry to design and construct any new equipment required to meet the new fuel quality standard. In this section we assess the impact of the final NRLM fuel program on engineering design and construction personnel needs. Specifically, we focus on three types of workers: front-end designers, detailed designers and construction workers needed to design and build new desulfurization equipment. In doing this, we consider the impacts of the Tier 2 gasoline sulfur and the 2007 highway diesel sulfur programs on these same types of personnel. We compare the overall need for these workers to estimates of total employment in these areas. In general, it would also be useful to expand this assessment to specific types of construction workers which might be in especially high demand, such as pipe-fitters and welders. However, estimates of the number of people currently employed in these job categories are not available. Thus, it is not possible to determine how implementing the nonroad diesel fuel sulfur cap and other programs might stress the number of personnel needed in specific job categories.

To accomplish this task, we first estimated the level of design and construction resources

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[FF] ibid

related to revamped and new desulfurization equipment. We next projected the number of revamped and new desulfurization units which would be needed under the final NRLM fuel program. Then, we developed a schedule for how desulfurization projects due to be completed at the same time might be spread out during the year. We next developed a time schedule for when the various resources would be needed throughout each project. Finally, we project the level of design and construction resources needed in each month and year from 2004 and 2014 and compare this to the number of people employed in each job category.

5.7.1 Design and Construction Resources Related to Desulfurization Equipment

The number of job-hours necessary to design and build individual pieces of equipment and the number of pieces of equipment per project were taken from an NPRA technical paper by Moncrief and Ragsdale.[42] Their study was performed to support a recent National Petroleum Council study of gasoline and diesel fuel desulfurization, as well as other potential fuel quality changes.[43] These estimated job hours are summarized in Table 5.7-1.

Table 5.7-1
Design and Construction Factors for Desulfurization Equipment

	Gasoline[a]	Highway and Nonroad Diesel Treaters	Highway and Nonroad Diesel Treaters
	New Hydrotreater	New Hydrotreater	Revamp Existing Hydrotreater
Number of Pieces of Equipment per Refinery	60	60	30
Job hours per piece of equipment[a]			
Front End Design	300	300	150
Detailed Design	1200	1200	600
Direct and indirect construction	9150	9150	4575

[a] Revamped equipment estimated to require half as many hours per piece of equipment. All gasoline treaters for Tier 2 compliance are assumed to be new.

As discussed in Section 5.3.2, we projected that the lead time for NRLM hydrotreater modifications can be shortened relative to that required by other fuel programs due to refiners combining their efforts to comply with this NRLM fuel rule with those for the 2007 highway diesel fuel program. These tasks include scoping and corporate screening studies, technology evaluation and permit approvals. We did not, however, reduce the level of E&C personnel required for the NRLM fuel program to reflect these synergies. Thus, the above resource requirements are conservative in this regard. The primary reason for the lack of impact is that the 2007 implementation date for the 500 ppm NRLM standard is later than the primary 2004-2006 phase-in period for the Tier 2 gasoline and the 2006 implementation date for the 15 ppm highway diesel fuel standard.

5.7.2 Number and Timing of Revamped and New Desulfurization Units

In the Final Regulatory Impact Analysis for the 2007 highway diesel program, we estimated the number of new and revamped desulfurization units projected for both the Tier 2 and highway diesel fuel programs.[44] We subsequently received pre-compliance reports for each refinery in the country regarding their plans for complying with the highway diesel program. In most cases the information was preliminary, but never the less sufficient to provide a better estimate of the number and timing of new diesel desulfurization units becoming operational, as shown in Table 5.7-2. We simplified our highway program analysis by assuming that refineries who comply early and produce 15 ppm fuel before 2006 will invest to produce highway fuel in year 2006.

Table 5.7-2
Number of Gasoline and Highway Diesel Desulfurization Units Becoming Operational[a][45]

Fuel Type and Stage	Before 2004	2004	2005	2006	2007	2008	2009	2010
New gasoline desulfurization units	10	37	6	26	5	3	4	6
Highway Diesel Desulfurization Units (80% revamps, 20% new)				96				5

[a] Units become operational on January 1st for gasoline desulfurization and June 1st for highway diesel desulfurization units.

The next step was to estimate the types of equipment modifications necessary to meet the final rule NRLM fuel requirements. This was a complex task, due to the overlap of the highway and NRLM fuel programs and the fact that refiners' relative production of highway and high-sulfur distillate fuel varies dramatically. In our assessment of the cost of this rule (see Chapter 7), we separated refineries which produce high-sulfur distillate into three categories and assessed their need for new or revamped desulfurization equipment separately. These three categories (as also discussed in Section 7.2.1) are: highway refiners (95% or more of their no. 2 distillate production meets highway diesel fuel specifications), high-sulfur refiners (5% or less of their no. 2 distillate production meets highway diesel fuel specifications), and mix refiners (producers of high-sulfur distillate fuel not falling into one of the other categories). In Section 7.2.2.2, we describe in detail how we projected the number of refiners which would build new hydrotreaters or revamp existing hydrotreaters by calendar year in response to the final NRLM sulfur program.

In applying the results of the cost analysis, we assumed that new hydrotreaters designed to produce 500 ppm NRLM fuel would utilize the level of personnel for a new unit listed in the table above. In those cases where a refiner produced 15 ppm NRLM fuel in one step, they would utilize this same level of personnel. However, when a hydrotreater capable of producing 500 ppm was modified to produce 15 ppm NRLM fuel, either using conventional or Process

Dynamics technology, we assumed that the personnel levels for a revamp applied.

Table 5.7-3 presents the results of this analysis for the 63 refineries which we project will produce 500 ppm and 15 ppm NRLM diesel fuel under the final program.

Table 5.7-3
Number and Timing of NRLM Desulfurization Units

	2007	2008	2009	2010	2011	2012	2013	2014
Revamped Hydrotreater	0			17		9		14
New Hydrotreater	28			24		6		2

5.7.3 Timing of Desulfurization Projects Starting up in the Same Year

A worst-case assumption would be that all the units scheduled to start up on January 1 for gasoline and June 1 for diesel would begin and complete their design and construction at the exact same time. However, this is not reasonable for a couple of reasons. Our early credit programs for gasoline, highway and nonroad diesel production will entice some refiners to make treater modifications ahead of our program startup dates thus shifting E&C workload ahead for these refiners. Also, an industry-wide analysis such as this one assumes that all projects take the same amount of effort and time. This means that each refinery is using every specific type of resource at exactly the same time as other refineries with the same start-up date. However, in reality, refineries' projects will differ in complexity and scope. Even if they all desired to complete their project on the same date, their projects would begin over a range of months. Thus, two projects scheduled to start up at exactly the same time are not likely to proceed through each step of the design and construction process at the same time. Second, the design and construction industries will likely provide refiners with economic incentives to avoid temporary peaks in the demand for personnel.

For these reasons, we spread out the design and construction of units expected to start up in the same calendar year. We assumed that 25 percent of the units would initiate design and thus, start up each quarter leading up to the date upon which they had to be operating.

5.7.4 Timing of Design and Construction Resources Within a Project

The next step in this analysis was to estimate how the engineering and construction resources are spread out during a project. We developed a distribution of each type of resource across the duration of a project for the Tier 2 gasoline and 2007 highway diesel sulfur programs. The fractions of total hours expended each month were derived as follows.

Per Moncrief and Ragsdale, front end design typically takes six months to complete.[46] If 25 percent of the refineries scheduled to start up in a given year start their projects every quarter, each subsequent group of the refineries starts when the previous group is halfway through their front end design. Overall, front end design for the four groups covers a period of 15 months, or 6 months for the first group plus 3 months for each of the three subsequent groups. In spreading this work out over the 15 months, we assumed that the total engineering effort would be roughly equal over the middle 9 months. The effort during the first and last 3 month period would be roughly two-thirds of that during the peak middle months. The same process was applied to the other two job categories. The reader is referred to the Final RIA for the 2007 highway diesel rule for a more detailed description of the methodology used.

The distribution of resources is summarized in Table 5.7-5.

Table 5.7-5
Distribution of Personnel Requirements Throughout the Project

	Front-End Design	***Detailed Engineering***	***Construction***
Duration per project	6 months	11 months	14 months
Duration for projects starting up in a given calendar year	15 months	20 months	23 months
Month	*Fraction of total hours expended per month from start of that portion of the project*		
1	0.050	0.020	0.030
2	0.050	0.030	0.030
3	0.050	0.040	0.030
4	0.078	0.040	0.040
5	0.078	0.040	0.040
6	0.078	0.050	0.040
7	0.078	0.050	0.040
8	0.078	0.060	0.050
9	0.078	0.065	0.050
10	0.078	0.075	0.055
11	0.078	0.075	0.055
12	0.078	0.075	0.060
13	0.050	0.060	0.060
14	0.050	0.060	0.055
15	0.050	0.050	0.055
16		0.050	0.050
17		0.040	0.050
18		0.040	0.040
19		0.030	0.040
20		0.020	0.040
21			0.030
22			0.030
23			0.030

The initiation of each of these three tasks relative to the start-up of the new equipment and relative to each other was discussed above in Section 5.3.2.3, where we discuss the leadtime necessary to meet the 2007, 2010 and 2012 NLRM sulfur caps. The following table summarizes the relative position of the first month shown in Table 5.7-5 above relative to the June 1 start date for the two standards.

Table 5.7-6
Initiation of Activity (Number of Months Prior to Standard Implementation (June 1))

	2007	2010	2012
Front End Design	30	42	66
Detailed Engineering	24	36	60
Construction	24	36	60

As can be seen from Table 5.7-6, we assumed that the design and construction of new hydrotreaters for the 2007 500 ppm NRLM standard would occur in a somewhat compressed time frame due to the relatively short lead time available between the promulgation of the NRLM rule and June 1, 2007.

5.7.5 Projected Levels of Design and Construction Resources

We calculated the number of workers in each of the three categories required in each month by applying the distributions of the various resources per project (Table 5.7-5) to the number of new and revamped hydrotreaters projected to start up in each calendar year (Tables 5.7-2 and -3) and the number of person-hours required per project (Table 5.7-1). We converted hours of work into person-years by assuming that personnel were able to actively work 1877 hours per year, or at 90 percent of capacity assuming a 40 hour work week. We then determined the maximum number of personnel needed in any specific month over the years 2004-2010 for each job category both before and after the NRLM diesel fuel program. The results are shown in Table 5.7-6. In addition to total personnel required, the percentage of the U.S. workforce currently employed in these areas is also shown. These percentages were based on estimates of the most recently available employment levels on the Gulf Coast for the three job categories: 1920 front end design personnel, 9585 detailed engineering personnel and roughly 160,000 construction workers (taken from Moncrief and Ragsdale). We assumed that half of all refining projects occurred on the Gulf Coast.

Table 5.7-7
Maximum Monthly Demand for Personnel

Program	Parameter	Front-End Design	Detailed Engineering	Construction
Tier 2 Gasoline Sulfur Program Plus Highway Diesel Fuel Program	Number of Workers	383 (Jan 04)	2,720 (Apr 04)	17,646 (Nov 04)
	Current Workforce [1]	20%	28%	11%
With Final NRLM Program	Number of Workers	383 (Jan 04)	2,720 (April 04)	17,646 (Nov 04)
	Current Workforce [1]	20%	28%	11%

[1] Based on recent employment in the U.S. Gulf Coast, assuming that half of all projects occur in the Gulf Coast. The year and month of maximum personnel demand is shown in parenthesis.

As can be seen from Table 5.7-7, the final NRLM diesel fuel program has no impact on the maximum monthly personnel requirements for the front end, detailed design and construction personnel.

Table 5.7-8 presents a summary of the average annual personnel demand for the demand for front end engineering in each year.

Table 5.7-8
Annual Front End Engineering Personnel Demand

Calendar Year	Gasoline + Highway Diesel Baseline	Plus Final NRLM Program
2002	159	159
2003	651	651
2004	97	97
2005	32	261
2006	47	87
2007	55	320
2008	2	49
2009	0	86
2010	0	23
2011	0	73
2012	0	13
2013	0	0
2014	0	0

The impact of the NRLM program on annual front end engineering demand in Table 5.7-8 reveals that the front end engineers will be needed for the three fuel programs considered here for over a decade. Prior to this NRLM rule, the peak impact occurs in 2003 and decreases thereafter. After this NRLM rule, the peak still occurs in 2003, but lesser peaks occur in 2005 2007 related to the design of new hydrotreaters in 2007 and 2010. Because the level of front end engineering after 2003 is much less than that in 2003, we do not expect that refiners will experience any difficulties in obtaining the necessary front end engineering required to meet the NRLM sulfur caps.

Table 5.7-9 presents a summary of the average annual personnel demand for the detailed end engineering in each year.

Table 5.7-9
Annual Detailed Engineering Personnel Demand

Calendar Year	Gasoline + Highway Diesel Baseline	Plus Final NRLM Program
2002	682	682
2003	1,315	1,315
2004	2,031	2,031
2005	400	690
2006	345	1,076
2007	370	760
2008	193	1,041
2009	5	176
2010	0	273
2011	0	113
2012	0	235
2013	0	17
2014	0	0

The impact of the NRLM program on annual detailed engineering demand in Table 5.7-9 reveals that the detailed engineers will be needed for the three fuel programs considered here for over a decade. Prior to this NRLM rule, the peak impact occurs in 2004 and decreases thereafter. After this NRLM rule, the peak still occurs in 2004, but lesser peaks occur in 2006 and 2008 related to the design of new hydrotreaters for 2007 and 2010. Because the level of front end engineering after 2004 is much less than that in 2004, we do not expect that refiners will experience any difficulties in obtaining the necessary front end engineering required to meet the 2007 or 2010 NRLM sulfur caps.

Table 5.7-10 presents a summary of the average annual personnel demand for construction workers in each year.

Table 5.7-10
Construction Worker Personnel Demand

Calendar Year	Gasoline + Highway Diesel Baseline	Plus Final NRLM Program
2002	7,574	7,574
2003	5,040	5,040
2004	14,778	14,778
2005	9,422	11,469
2006	249	5,326
2007	390	3,830
2008	1,474	7,370
2009	593	2,596
2010	0	1,904
2011	0	1,057
2012	0	1,632
2013	0	342
2014	0	0

The impact of the NRLM program on annual construction worker demand in Table 5.7-10 reveals that construction workers will be needed for the three fuel programs considered here for over a decade. Prior to this NRLM rule, the peak impact occurs in 2004 and decreases thereafter. After this NRLM rule, the peak still occurs in 2004, from which demand for construction workers decreases less gradually to 2007. There is another relative peak in 2008, related to the design of new hydrotreaters 2010. Because the level of front end engineering after 2004 is much less than that in 2004, we do not expect that refiners will experience any difficulties in obtaining the necessary front end engineering required to meet the NRLM sulfur caps.

Thus, we believe that the E&C industry is capable of supplying the refining industry with the equipment necessary to comply with our final nonroad diesel fuel program. We believe that this is facilitated by the synergies obtained with highway diesel rule implementation and the later phase in dates for nonroad compliance.

5.8 Supply of Nonroad, Locomotive, and Marine Diesel Fuel (NRLM)

We have developed the fuel program in this final rule to minimize the impact on the distillate fuel supply. For example, the final rule transitions the fuel sulfur level down to 15 ppm in two steps, providing an estimated six years of leadtime for the final step for nonroad diesel fuel and eight years for L&M diesel fuel (up to ten years for small refiners). Banking and trading provisions provide flexibility to refiners and hardship provisions are available for qualifying refiners. To evaluate the effect of the new fuel standards on supply, we evaluated four possible cases: (1) whether the new standards could cause refiners to remove certain blendstocks from the fuel pool, (2) whether the new standards could require chemical processing that loses fuel in the process, (3) whether the cost of meeting the new standards could lead some refiners to leave a particular market, and (4) whether the cost of meeting the new standards could lead some refiners to stop operations altogether (i.e., shut down). In all cases, as discussed below, we have concluded that the answer is no. Therefore, consistent with our findings made during the HD2007 rule, we do not expect this rule to cause any supply shortages of nonroad, locomotive, or marine diesel fuel.

Blendstock Shift: As mentioned above, we first evaluated whether certain blendstocks or portions of blendstocks may need to be removed from the NRLM diesel fuel pool. Technology exists to desulfurize any commercial diesel fuel to less than 10 ppm sulfur. Technologies, such as hydro-dearomatization, have been used on a commercial scale. More direct, desulfurization technologies are just now being demonstrated fairly widely as refiners in both the United States and Europe are producing No. 2 diesel fuel at 15 ppm sulfur or less. Pilot plant studies have demonstrated that diesel fuels consisting of a wide range of feedstocks and containing high levels of sulfur can be desulfurized to less than 15 ppm. Such studies and experience have reliably demonstrated that at pressures within the range of many current conventional hydrotreaters, the single most important variable that limits desulfurization to very low sulfur levels is the length of time the fuel is in contact with hydrogen and the catalyst. This "residence time" is primarily a function of reactor volume. Therefore, we believe there is no technical reason to remove certain feedstocks from the diesel fuel pool. It may cost more for refiners to process certain blendstocks, such as light cycle oil, than others. Consequently, there may be economic incentives for refiners to move these blendstocks out of the diesel fuel market to reduce compliance costs. However, that is an economic issue, not a technical issue and is addressed next. Thus, this rulemaking should not result in any long-term reduction in the volume of products derived from crude oil available for blending into diesel fuel or heating oil.

As mentioned above, certain feedstocks are more expensive to desulfurize than others. The primary challenge of desulfurizing distillate to sulfur levels meeting the 15 ppm cap is the presence of sterically hindered compounds, particularly those with two methyl or ethyl groups blocking the sulfur atom.[GG] These compounds are aromatic in nature, and are found in greatest concentration in light cycle oil (LCO), which itself is highly aromatic. These compounds can be desulfurized readily if saturated. However, due to the much higher hydrogen cost of doing so, could be better economically if this can be avoided. Because these compounds are large in size and high in molecular weight due to their chemical structure, they distill near the high end of the diesel range of distillation temperatures. Thus, it is technically possible to segregate these compounds from the rest of the LCO via distillation to avoid the need to desulfurize them. One

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[GG] Meeting a 500 ppm standard can be met without desulfurizing much or any of the sterically hindered compounds.

option would be to construct a separate distillation column to keep this stream separate from other refinery streams, however, this would lead to significant capital costs and operating costs in the form of heat input. Another likely more cost-effective option would be to use the existing FCC fractionator to shift these heavy molecules out of the LCO pool. They would be shifted to slurry oil, which eventually becomes part of residual fuel. Once there, it would be very difficult to recover them for blending into heating oil.

Residual fuel is priced well below diesel fuel. The residual fuel oil market is also not growing in the U.S. and growing only slowly worldwide. We investigated several sources of price information, including EIA, LCM online and BP publications. According to EIA, spot heating oil prices averaged roughly 75 cents per gallon from 2000-2003. According to the above sources, residual fuel averaged 25-35% less, or 48-55 cents per gallon. Thus, shifting LCO or heavy LCO to residual fuel would involve a significant long-term reduction in revenue (and profits), ranging from 20-27 cents per gallon. Thus, we believe refiners will generally not attempt to reduce the cost of desulfurizing diesel fuel in this way.

To evaluate this possibility, using the distillate desulfurization model described in Section 7.2 above, we estimated the incremental cost of processing LCO (the worse of the two blendstocks) into 15 ppm diesel fuel for each domestic refinery. On average, desulfurizing LCO to 15 ppm sulfur cost 11.4 cents per gallon. However, in some cases, this cost reached 15 cents per gallon. The model is not able to estimate the cost of processing heavy LCO. In fact, the quality of LCO and especially heavy LCO is very crude oil dependent. However, the cost for heavy LCO could be twice these amounts, since the concentration of both total sulfur and the most difficult to remove sulfur are concentrated in the heaviest molecules. Thus, the upper end of the range of incremental desulfurization costs for heavy LCO could potentially exceed the loss in revenue from shifting this material to the residual fuel market. The U.S. residual fuel market is small relative to the distillate fuel market, flat, and already being fulfilled. Thus, any significant shift would likely depress residual fuel prices and increase the reduction in profits, further discouraging the shift. Worldwide, the residual fuel market is growing slowly. Thus, it is unlikely that large volumes of LCO could leave the NRLM fuel market. However, we cannot rule out the possibility that some LCO, particularly that produced by capital-strapped refiners, could be shifted to residual fuel.

To estimate the upper limit of this shift, we estimated the volume of heavy LCO produced by refineries whose LCO processing costs exceeded 12 cents per gallon and which were not owned by large, integrated oil companies or small refiners. We excluded refineries located in PADDs 2 and 4, since these refineries face sizeable transportation costs to get this material to a residual fuel market, such as marine. This costly, heavy LCO represents 0.4% of total NRLM fuel demand, a very small volume. In this case, we would expect that this loss could easily be made up by increased imports of 15 ppm diesel fuel or domestic refiners facing lower 15 ppm NRLM fuel costs.

It is possible that refiners could exchange material between the NRLM and heating oil markets to reduce the cost of meeting a 15 ppm cap, while still maintaining their NRLM fuel production volume. In our cost projections, we projected that individual refineries will produce either 15 ppm, 500 ppm or high-sulfur distillate with their existing slate of blendstocks to avoid additional tankage and maximize economies of scale for the desulfurization equipment. Thus, we did not assume that refiners would reduce costs by exchanging feedstocks around, such as sending LCO to heating oil and straight-run from heating oil to NRLM diesel fuel. Despite this, the costs appear to be reasonable. Thus, some refiners with adequate tankage and access to the heating oil market may be able to reduce costs with such an exchange of feedstocks. However, we did not factor these savings into our cost projections. Even if there were such exchanges, they would not reduce the supply of NRLM diesel fuel.

Processing Losses: We evaluated whether the new fuel standards might require chemical processing that results in fuel losses. Conventional desulfurization processes do not reduce the energy content of feedstocks, although the feedstock composition may be slightly altered. A conventional hydrotreater used to produce 15 ppm sulfur diesel converts about 98 percent of its feedstock to finished diesel fuel. About 1.5 percent of the remaining two-percent leaves the unit as naphtha or light-crackate (i.e., gasoline feedstock), while the last 0.5 percent is split about evenly between liquified petroleum gas (LPG) and refinery fuel gas. Both naphtha and LPG are valuable liquids used to produce other finished products including gasoline. Refiners can easily adjust the relative amounts of gasoline and diesel fuel produced by a unit, especially at the process level under discussion. This additional naphtha can displace other gasoline or kerosene blendstocks, which can then be shifted to the diesel fuel pool. LPG, on the other hand, is used primarily for space-heating, but depending on where it's produced and how it's cut, can be used as a feedstock in the petrochemical industry. Because LPG can be used for space heating, it will likely displace some volume of heating oil, which in turn could be shifted to the diesel pool. Currently, heating oil or high-sulfur fuel, has the same basic composition as highway diesel, other than its sulfur content, and can be used to fuel nonroad, locomotive, and commercial marine equipment. Thus, the desulfurization process usually has little or no direct impact on a refinery's net fuel production. The volume-shift from diesel fuel to fuel gas is very small (0.25 percent) and the gas can be used to reduce consumption of natural gas within the refinery. This discussion applies to the full effect of the new fuel standards (i.e., the reduction in sulfur content from 3000 ppm to 500 ppm and from 500 ppm to 15 ppm). For the first step of fuel standards the impacts are only about 40 percent of those described above.

The conversion rate of a given feedstock to light products is reportedly much lower for the emerging or advanced technologies than for conventional hydrotreaters. For the purposes of this rulemaking, the newer or advanced technologies are projected to be used only as a second step to reduce the fuel to 15 ppm sulfur after it has been reduced from 3000 ppm to 500 ppm using conventional hydrotreating technology.[HH] We project that the Process Dynamics process might reduce the conversion to light products for the second step by 55 percent.

Exit the NRLM Diesel Fuel Market: We evaluated whether the compliance costs

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[HH] While the addition of the Process Dynamics process would facilitate the desulfurization to 15 ppm, the Process Dynamics unit is expected to be installed as a revamp before the existing conventional hydrotreater handling the 3000 to 500 ppm step while the conventional hydrotreater would be moved to address the 500 ppm to 15 ppm step.

associated with this rulemaking might cause some refiners to consider reducing their production of NRLM or to leave those markets altogether. As mentioned above, diesel fuel and heating oil are chemically and physically similar, except for sulfur level. Thus, beginning in mid-2007, a refiner may shift his high-sulfur distillate from NRLM fuel to the heating oil market and avoid the need to invest in new desulfurization equipment. Likewise, beginning in mid-2010 or mid-2012, a refiner may shift part or all of its supply to heating oil. The result would be a potential oversupply of heating oil beginning in 2007. We expect such an oversupply of these fuels to result in a substantial drop in their market price and would consequently increase the cost for a given refiner to exit the NRLM diesel fuel markets. Furthermore, refiners may be forced to find new export markets for their excess high-sulfur fuel. Overseas market prices are often no higher and are occasionally lower than those in the United States. We believe these low market differentials combined with the additional transportation costs will encourage most refiners to comply with the NRLM program to remain in the domestic low-sulfur fuel markets.

We addressed this same issue during the development of the highway diesel rule (66 FR 5002). We contracted with Southwest Research Institute (SwRI) and with Muse, Stancil & Company, an engineering firm involved primarily in economic studies and evaluations concerning the refining industry to help us assess the potential for refiners to sell their highway diesel fuel (< 500 ppm) or the blendstocks used to produce it into alternative markets. At that time, Muse, Stancil & Company found that most refiners had few domestic alternatives for accommodating highway diesel fuel or its blendstocks. PADD I imports significant quantities of high-sulfur fuel for use as nonroad diesel fuel and heating oil. Muse, Stancil & Company concluded that PADD I refineries could produce less highway fuel and more high-sulfur fuel and still avoid over supplying the market by reducing imports. However, refineries in other PADDs that import little, if any, high-sulfur fuel would be forced to find other, less valuable markets, including new markets for export, if they exited the highway diesel fuel market. We concluded that, at current production levels, refiners faced greater economic losses trying to avoid meeting the 15 ppm cap than by trying to comply with it, even if the market did not allow them to recover their capital investment. We believe a similar conclusion can be drawn from an analysis of this final rule for the following six reasons:

1. Approximately one-half of what is currently the U.S. high-sulfur diesel fuel market will have become part of the 500 ppm and 15 ppm markets by the time the HD2007 program and the sulfur caps on NRLM fuel have been implemented. Within that same time frame we expect few, if any, of the common carrier pipelines, except perhaps those serving the Northeast, to carry high-sulfur heating oil. Therefore, the sale of high-sulfur distillate may be limited to markets that a refiner can serve by truck.

2. The technology to desulfurize fuel, including refractory feedstocks, to less than 500 ppm sulfur has been used commercially for over a decade. The technology to reduce fuel to less than 15 ppm sulfur will have been commercially demonstrated in mid-2006, a full four years before the 15 ppm sulfur standard for nonroad diesel fuel takes effect.

3. The volume of fuel affected by the 15 ppm nonroad diesel fuel standard in 2010 and L&M standard in 2012 will be a small fraction of that affected by the HD2007 program. This dramatically reduces the required capital investment.

4. Canada, Europe and Japan are implementing rules to reduce sulfur levels in highway and nonroad diesel fuel to the 10-15 ppm range, which will effectively eliminate these regions as alternative export markets for high-sulfur fuel.

5. Refineries outside of the United States and Europe are operating at a lower percentage of their capacity than U.S. refineries.[II] Capacity utilization rates at U.S. refineries are well over 90 percent. Historically, if refinery utilization rates approached their maxima, it was usually a strong indication that demand for finished products was high. In this environment, product prices usually rose and held until the demand pressure was reduced or eliminated. Foreign refinery utilization rates as well as wholesale prices tend to be well below domestic rates, again, a reflection of lower demand relative to the potential output of finished products. The preceding condition can have at least two effects on the marketing decisions domestic refiners may face. First, if foreign margins are low and U.S. market prices high, a foreign refiner can, and most likely will, sell his products into the U.S. market, thereby reducing the upward pressure on prices and likely reducing domestic refinery margins. And, second, it is highly unlikely that a domestic refiner will decide to further reduce his margins by adding the cost to ship his product into a foreign market with a less stringent sulfur standard where wholesale prices are already lower than in the United States. Consequently, we believe U.S. refiners will not have a reasonable opportunity to export their high-sulfur fuel.

6. One measure of the overall fiscal well-being of a refining operation is its margin. Refinery profit margins[JJ] during the 1990s were not very encouraging until about 1997. In fact, in 1994, the net margin was less than $0.50 per refined barrel. By 1997 it had nearly tripled and by 2000 had increased to nearly five times the 1994 average. Margins leveled out again during 2001 and decreased somewhat during 2002, but recovered during the last few months of 2002 and in early 2003. Current industry projections into the future indicate the expectation for continued high profit margins.

[II] Europe currently imports diesel fuel and is expected to continue to do so. However, European sulfur caps will be equivalent to those in the United States. Therefore, exporting distillate fuel to Europe is not an option for U.S. refiners to avoid complying with stringent sulfur caps here. Likewise, imports from European refiners are not likely.

[JJ] The terms "margin" or the plural "margins" are often used in the petroleum industry in reference to several different variables including "spread" or "spreads," "net margin" or "cash margin," "gross margin," and "profit margin." The numbers these terms represent are all basically a measure of a revenue minus the cost to produce that revenue, expressed on a per barrel-basis of either crude oil or finished product(s).

Once refiners have made their investments to meet the NRLM diesel fuel standards, or have decided to produce high-sulfur heating oil, we expect the various distillate markets to operate very similar to current markets. When fully implemented in 2014, there will be three distillate fuels in the market, 15 ppm highway and NRLM diesel fuel[KK] and high-sulfur heating oil. The resulting options are similar to the current situation in which there are two fuels—500 ppm and high-sulfur distillate. In this case, refiners with the capability of producing 15 ppm diesel fuel have the most flexibility, since they can sell their fuel to any of the three markets. Those refiners capable of producing only high-sulfur distillate will be able to participate in only the heating oil market. Generally, we do not expect one market to provide vastly different profit margins than the others, as high profit margins in one market will attract refiners from another via investment in desulfurization equipment.

Refinery Closure: There are several reasons why we believe refineries will not completely close down as a result of this final rule. One reason is that the regulations include a provision to adjust the sulfur caps for small refiners, as well as any refiner facing unusual financial hardship. Another reason is that nonroad, locomotive, and marine diesel fuel is usually the third or fourth most important product produced by the refinery from a financial perspective. A total shutdown would mean losing all the revenue and profit from these other products. Gasoline is usually the most important product, followed by highway diesel fuel and jet fuel. A few refineries do not produce either gasoline or highway diesel fuel, so jet fuel and high-sulfur diesel fuel and heating oil are their most important products. The few refiners in this category likely face the biggest financial challenge in meeting the requirements in this final rule. However, those refiners will also presumably be in the best position to apply for the special hardship provisions, presuming they do not have readily available source of investment capital. The additional time afforded by these provisions should allow the refiner to generate sufficient cash flow to invest in the required desulfurization equipment. Investment here could also provide them the opportunity to expand into more profitable (e.g., highway diesel) markets.

A quantitative evaluation of whether the cost of the fuel program in this final rule could cause some refineries to cease operations completely would be very difficult, if not impossible to perform. A major factor in any decision to shut down is the refiner’s current financial situation. It is very difficult to assess an individual refinery’s current financial situation. This includes a refiner’s debt, as well as its profitability in producing fuels other than those affected by a particular regulation. It can also include the profitability of other operations and businesses owned by the refiner.

Such an intensive analysis can be done to some degree in the context of an application for special hardship provisions, as discussed above. However, in this case, we may request detailed financial documents that are not normally available. Prior to such application, as is the case now, this financial information is usually confidential. Even when it is published, the data

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[KK] There will also be 500 ppm locomotive and marine diesel fuel produced from transmix in the distribution system which can be used to satisfy the locomotive and marine demand, although this 500 ppm fuel will be produced downstream at terminals.

usually apply to more than just the operation of a single refinery.

Another factor is the need for capital investments other than for this rule. We can roughly project the capital needed to meet other new fuel-quality specifications, such as the Tier 2 or highway diesel sulfur standards. However, we cannot predict investments to meet local environmental and safety regulations, nor other investments needed to compete economically with other refiners.

Finally, any decision to close in the future must be based on some assumption of future fuel prices. Fuel prices are very difficult to project in absolute terms. The response of prices to changes in fuel-quality specifications, such as sulfur content, as is discussed in the next section, are also very difficult to predict. Thus, even if we had complete knowledge of a refiner's financial status and its need for future investments, the decision to stay in business or close would still depend on future earnings, which are highly dependent on prices.

Some studies in this area point to fuel pricing over the past 20 years or so and conclude that prices will increase only to reflect increased operating costs and will not reflect the cost of capital. In fact, the rate of return on refining assets has been poor until the late 1990s and until recently, there has been a steady decline in the number of refineries operating in the United States. However, this may have been due to circumstances specific to that time period. The primary reason is that refinery capacity utilization was less than 80 percent in 1985.

Current refinery capacity utilization in the United States is generally considered to be at its maximum sustainable rate. There are no regulatory mandates on the horizon that will increase production capacity significantly, even if ethanol use in gasoline increases substantially.[LL] Consistent with this, refining margins have been much better over the past few years than during the previous 15 years and the refining industry itself is projecting good returns for the foreseeable future.

Conclusion: Therefore, consistent with our findings made during the HD2007 rule and the nonroad NPRM, we do not expect this final rule to cause any supply shortages of nonroad, locomotive, or marine diesel fuel.

5.9 Desulfurization Effect on Other Non-Highway Diesel Fuel Properties

5.9.1 Fuel Lubricity

Engine manufacturers depend on diesel fuel lubricity properties to lubricate and protect moving parts within fuel pumps and injection systems for reliable performance. Unit injector systems and in-line pumps, commonly used in diesel engines, are actuated by cams lubricated

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[LL] The U.S. Congress is considering legislation that would require the increased use of renewables, like ethanol, in gasoline and diesel fuel. While the amount of renewables could be considerable, it is well below the annual growth in transportation fuel use.

with crankcase oil, and have minimal sensitivity to fuel lubricity. However, rotary and distributor type pumps, commonly used in light and medium-duty diesel engines, are completely fuel lubricated, resulting in high sensitivity to fuel lubricity. The types of fuel pumps and injection systems used in nonroad diesel engines are the same as those used in highway diesel vehicles. Consequently, nonroad and highway diesel engines share the same need for adequate fuel lubricity to maintain fuel pump and injection system durability.

The state of California currently requires the use of the same diesel fuel in nonroad equipment as in highway equipment. Outside of California, highway diesel fuel is often used in nonroad equipment when logistical constraints or market influences in the fuel distribution system limit the availability of high-sulfur fuel. Thus, nonroad equipment has been using federal 500 ppm sulfur diesel fuel and California diesel fuel, some of which may have been treated with lubricity additives for nearly a decade. During this time, there has been no indication that the level of diesel lubricity needed for fuel used in nonroad engines differs substantially from the level needed for fuel used in highway diesel engines.

Diesel fuel lubricity concerns were first highlighted during implementation of the federal 500 ppm sulfur highway diesel program and the state of California's diesel program circa 1993.[47] The diesel fuel requirements in the state of California differ from the federal requirements by substantially restricting the aromatics content of diesel fuel in addition to the sulfur content. Considerable research remains to better understand which fuel components are most responsible for fuel lubricity. Nevertheless, there is evidence that the typical process used to reduce diesel fuel sulfur content or aromatics content of diesel fuel (i.e., hydrotreating) can reduce fuel lubricity. Consequently, implementing the sulfur standards in this final rule will likely require some action to maintain the lubricity of non-highway diesel fuel.

The potential impacts on fuel lubricity from NRLM sulfur standards are associated solely with the additional refinery processing that is necessary to meet these standards. Although we are extending the cetane index/aromatics content specification to NRLM diesel fuel, we do not expect this to have a significant impact on fuel lubricity. We require that highway diesel fuel meet a minimum cetane index level of 40 or, as an alternative, contain no more than 35 volume percent aromatics. ASTM already applies a cetane number specification of 40 to NRLM diesel fuel, which is generally more stringent than the similar 40 cetane index specification. Because of this, the vast majority of current NRLM diesel fuel already meets the EPA cetane index/aromatics specification for highway diesel fuel. Thus, the new requirement will have an impact only on a limited number of refiners and there will be little overall impact on other diesel fuel qualities (including fuel lubricity) associated with producing fuel to meet the cetane/aromatic requirement.

Blending small amounts of lubricity-enhancing additives increases the lubricity of poor-lubricity fuels to acceptable levels. These additives currently are available in the market, are effective, and are in widespread use around the world. Several commenters on our final rule setting a 15 ppm sulfur standard for highway diesel fuel indicated that biodiesel can be used to increase the lubricity of conventional diesel fuel to acceptable levels. Some testing suggested that only two volume percent is necessary. However, more testing may be required to determine the necessary level of biodiesel for fuels not yet being produced, such as the 15 ppm fuel required under this final rule.

In the United States, there is no government or industry standard for diesel fuel lubricity. Therefore, specifications for lubricity are determined by the market. Since the beginning of the 500 ppm sulfur highway diesel program in 1993, fuel system producers, engine and engine manufacturers, and the military have been working with the American Society for Testing and Materials (ASTM) to develop protocols and standards for diesel fuel lubricity in its D-975 specifications for diesel fuel. ASTM is working towards a single lubricity specification that would apply to all diesel fuel used in any type of engine. The ASTM development process has reached an agreement on the High Frequency Reciprocating Rig (HFRR) lubricity test method and an initial lubricity level of 520 micron Wear Scar Diameter (WSD) for its lubricity specification. The specification has been balloted four times in recent years and the current hold up on the passing of the specification is the lack of an implementation date. ASTM is hoping to overcome implementation date issues by allowing an implementation date of 1/1/2005 in the next ballot or by not putting the specification to a vote until late in 2004. In light of this, the California Air Resources Board (CARB) has decided to regulate lubricity starting in August 2004. Initial lubricity levels will require diesel fuel to have a WSD of < 520 microns for the HFRR. CARB also has provisions in its regulation to lower the required lubricity level to < 460 micron WSD, HFRR pending the outcome of the work being performed by the CRC Diesel Performance Group. CARB may withdraw this specification if ASTM reaches a consensus and passes it’s lubricity standard before the CARB implementation date. We will follow suit with a separate lubricity rulemaking similar to CARB’s if ASTM does not reach a consensus on its lubricity standard in reasonable time.

Although ASTM has not yet adopted specific protocols and standards, refiners that supply the U.S. market have been treating diesel fuel with lubricity additives on a batch to batch basis, when poor lubricity fuel is expected. Other evidence of how refiners are ensuring adequate fuel lubricity can be found in Sweden, Canada, and the U.S. military. The U.S. military has found that traditional corrosion inhibitor additives have been highly effective in reducing fuel system component wear. Since 1991, the use of lubricity additives in Sweden's 10 ppm sulfur Class I fuel and 50 ppm sulfur Class II fuel has resulted in acceptable equipment durability.[48] Since 1997, Canada has required that its 500 ppm sulfur diesel fuel not meeting a minimum lubricity be treated with lubricity additives.

The potential need for lubricity additives in diesel fuel meeting a 15 ppm sulfur specification was evaluated during the development of EPA’s highway diesel rule. The final highway diesel rule did not establish a lubricity standard for highway diesel fuel. We believe the issues related to the need for diesel lubricity in fuel used in non-highway diesel engines are not substantially different from those related to the need for diesel lubricity for highway engines. Consequently, we are relying on the same industry-based voluntary approach to ensuring adequate lubricity in non-highway diesel fuels that we relied upon for highway diesel fuel. Consistent with the highway diesel final rule, we believe the best approach is to allow the industry and the market to address the lubricity issue in the most economical manner. We expect that a voluntary approach will provide adequate customer protection from engine failures due to low lubricity, while providing the maximum flexibility for the industry. We expect that the American Society for Testing and Materials (ASTM) will finalize a fuel lubricity standard for use by industry that could be applied to low-sulfur NRLM diesel fuel.

The degree to which removing the sulfur content from diesel fuel may impact fuel lubricity depends on the characteristics of the blendstocks used as well as the severity of the treatment process. Based on our comparison of the blendstocks and processes used to manufacture non-highway diesel fuels, we project that the potential decrease in the lubricity of non-highway diesel fuel that might result from the new sulfur standards will be substantially the same as that experienced in desulfurizing highway diesel fuel to meet the same sulfur standard.

A refiner of diesel fuel for use in California and for much of the rest of the United States as well evaluated the impacts on fuel lubricity of the current federal and California diesel fuel requirements.[49] This refiner concluded that, reducing the aromatics content of diesel fuel requires more severe hydrotreating than reducing the sulfur content to meet a 500 ppm standard. Consequently, concerns regarding diesel fuel lubricity have primarily been associated with California diesel fuel and some California refiners treat their diesel fuel with a lubricity additive as needed. The subject refiner stated that outside of California, hydrotreating to meet the current 500 ppm sulfur specification seldom results in a sufficient reduction in fuel lubricity to require the use of a lubricity additive. We expect that the same hydrotreating process currently used to produce highway diesel fuel will be used to reduce the sulfur content of non-highway diesel fuel to meet the 500 ppm sulfur standard during the first step under this final rule. We therefore estimate that there will be only a marginal increase in the use of lubricity additives in NRLM diesel fuel meeting the 500 ppm sulfur standard for 2007.

The highway diesel program projected that hydrotreating will be the process most frequently used to meet the 15 ppm sulfur standard for highway diesel fuel in 2006. However, we project that the 2010 and 2012 implementation dates for the 15 ppm standard for NRLM diesel fuel will allow the use of advanced technologies to remove sulfur from 60 percent of the affected diesel pool. The use of such developing desulfurization processes is discussed in Section 5.5. These new processes have less of a tendency to affect other fuel properties than does hydrotreating. Therefore, the use of such new desulfurization technologies might tend to have less of an impact on fuel lubricity. However, we have no specific information with which to quantify the impacts of the developing technologies on fuel lubricity. To provide a conservatively high estimate of the potential impact of meeting the 15 ppm standard for nonroad diesel fuel, we assumed that the potential impact on fuel lubricity of the new desulfurization processes will be the same as that experienced when hydrotreating diesel fuel to meet a 15 ppm sulfur standard. We therefore assumed, as we did for 15 ppm highway diesel fuel, that all 15 ppm NRLM diesel fuel must be treated with lubricity additives. The cost associated with the increased use of lubricity additives in 500 ppm NRLM diesel fuel and in 15 ppm NRLM diesel fuel is discussed in Chapter 7.

Railroads and locomotive manufacturers have expressed concern that low-sulfur fuel might damage existing locomotives. Locomotives already use a significant amount of low-sulfur fuel, especially in California, and there has not been any evidence of sulfur-related problems.

Low-sulfur locomotive diesel fuel meeting the soon to be specified lubricity requirements will provide adequate protection to these engine and fuel systems.

5.9.2 Volumetric Energy Content

Some of the projected desulfurization processes for meeting the non-highway diesel sulfur standards tend to reduce the volumetric energy content (VEC) of the fuel during processing. Desulfuization also tends to result in a swell in the total volume of fuel. These two effects tend to cancel each other out so there is no overall loss in the energy content in a given batch of fuel that is subjected to desulfurization. Thus, we do not expect the potential reduction in VEC that might result from the new sulfur standards to affect the refiners' ability to supply sufficient quantities of non-highway diesel fuel. The potential impacts on diesel supply are discussed in Section 5.8.

Since a greater volume of fuel must be consumed in the engine to produce the same amount of power, however, a larger volume of fuel is needed to meet the same level of demand. The potential increase in the distribution costs associated with a reduction in NRLM diesel VEC is discussed in Section 7.3.

The impact of desulfurization on diesel fuel VEC varies depending on the type of blendstocks and desulfurization process used. A comparison of the blendstocks used to produce high-sulfur diesel fuel with those used to produce highway diesel fuel shows that both pools contain similar fractions of each type of blendstock.[50] Based on this comparison, we believe a comparable level of severity in the desulfurization process is required to produce NRLM diesel fuel meeting a given sulfur specification as will be required to produce highway diesel fuel meeting the same sulfur specification. Refiners with experience in the use of hydrodesulfurization to manufacture both 500 ppm and 15 ppm highway diesel fuel provided us with information that we used to estimate the accompanying reduction in VEC. Using this information, we estimate that hydrodesulfurization of NRLM diesel fuel to meet a 500 ppm sulfur standard will result in a reduction in volumetric energy content of 0.7 percent.

The 15 ppm sulfur standard for nonroad diesel fuel does not start until 2010 and for L&M diesel fuel until 2012. The additional lead time allows refiners to take advantage of several less-expensive desulfurization technologies currently under development to produce diesel fuel complying with the 15 ppm sulfur standard in addition to conventional hydrotreating. Of the advanced desulfurization technologies which refiners may consider, we believe that only Process Dynamics Isotherming will be used extensively (see Section 5.3). We project that Process Dynamics Isotherming will be used by 60% of the NRLM market, while conventional hydrotreating will be used by the remaining 40%. The Process Dynamics engineers estimate that the Isotherming desulfurization process will have less of an impact on diesel fuel volumetric energy content than does hydrodesulfurization. Using the mix of desulfurization technologies we expect to be available, we estimate that desulfurizing NRLM diesel fuel from 500 ppm to 15 ppm will reduce the volumetric energy content by an additional 0.5 percent (0.7% conventional hydrotreating and 0.4% for IsoTherming). Thus, reducing the sulfur content of nonroad diesel fuel from the current maximum 5,000 ppm sulfur cap to the 15 ppm sulfur standard is estimated to result in a 1.2 percent reduction in VEC. Table 5.9-1 summarizes the projections for estimating the impact of the new sulfur standards on VEC, including: (1) the percentage of the applicable NRLM diesel fuel pool that we expect will be desulfurized using each of the available desulfurization processes and (2) the projected impact of each desulfurization process on VEC.

Table 5.9-1
Projections Used in Estimating the in Reduction in
Volumetric Energy Content Associated with Meeting the New Sulfur Standards

Desulfurization Process[a]	Percent of Diesel Pool Desulfurized Using a Given Process to Meet the Applicable Sulfur Standard			Reduction in Volumetric Energy Content Associated with a Given Desulfurization Process	
	NRLM[b] 500 ppm in 2007	NR 15 ppm in 2010	L&M 15 ppm in 2012	Reduction in Sulfur Content	
				HS[c] to 500 ppm	500 ppm to 15 ppm
Conventional Desulfurization	100 %	40%	40%	0.7%	0.7 %
Process Dynamics Isotherming	NA	60%	60%	NA	0.4 %
Over-all Impact on VEC of All Desulfurization Processes Used	-		-	0.7%	0.5%

[a] See Section 5.3 regarding the use of conventional hydrodesulfurization , and the Process Dynamics Isotherming process to meet the new sulfur standards.

[b] NR = nonroad diesel fuel, L = locomotive diesel fuel, and M = marine diesel fuel.

[c] HS refers to high-sulfur diesel fuel at the current uncontrolled average sulfur level of approximately 3000 ppm.

It is important to remember that the anticipated reduction in VEC discussed above applies only to those gallons of NRLM diesel fuel that currently have a high sulfur content. Due to logistical constraints in the fuel distribution system, much of the fuel used in NRLM engines meets highway diesel fuel standards (see Section 7.1). The costs related to the reduction in NRLM diesel fuel VEC accompanying the new sulfur standards are discussed in Section 7.3.

5.9.3 Fuel Properties Related to Storage and Handling

In addition to fuel lubricity additives, a range of other additives are also sometimes required in diesel fuel to compensate for deficiencies in fuel quality. These additives include cold flow improvers, static dissipation additives, anti-corrosion additives, and anti-oxidants. The highway diesel fuel program projected that, except for an increase in the fuel lubricity additives, reducing the sulfur content of highway diesel fuel to meet a 15 ppm standard will not result in an increase in the use of diesel performance additives. Since that time, we have identified no new information to alter that projection. Consequently, our estimate of the increase in additive use resulting from this final rule parallels that under the highway program. We estimate that the use of lubricity additives will increase and that the use of other additives will be unaffected.

5.9.4 Cetane Index and Aromatics

We require that nonroad, locomotive, and marine diesel fuel comply with the current highway diesel fuel requirements for cetane index or aromatics. Thus, these non-highway diesel fuels must meet either a 40 minimum cetane index, or a 35 percent maximum aromatics limit. In this section, we present information on what these properties are currently for non-highway diesel fuel, then we estimate how much they are likely to change when these streams are desulfurized.

We have reports of non-highway diesel fuel cetane index values from refinery samples from 1997 to 2001. The 1997 and 1998 reports were published by the National Institute for Petroleum and Energy Research (NIPER), Bartlesville, OK, and then this organization changed their name to TRW Petroleum Technologies, which published the reports for 1999 through 2001. The reports divided the country into the Eastern, Southern, Central, Rocky Mountain, and Western Regions. The samples, which averaged about 17 per year, were pooled from the various regions. The range of cetane index values for the 85 total samples is 39.4 - 57.0. Out of the 85 samples, 5 samples were under the cetane index value of 40 and potentially would not comply with the cetane index minimum of 40. However, those that were below the 40 cetane index minimum, were barely below it (i.e., 39.4 versus 40). Since the aromatics levels were not provided for these 5 samples, we could not verify if these samples would also not comply with the aromatics part of the specification.

As refiners desulfurize their NRLM diesel fuel to comply with the 500 ppm standard in 2007 and then again to comply with the 15 ppm standard in 2010 and 2012, we expect them to see increased cetane levels in their NRLM diesel fuel. Vendors of the desulfurization technologies either provided information on the impact that their technologies have on the cetane index of diesel fuel, or we were able to estimate the impact using changes to API gravity and the T-50 distillation point. While the changes in cetane index were provided for the desulfurization of highway diesel fuel, they apply to NRLM diesel fuel as well, as it is similar in quality and composition to highway diesel fuel. The estimated impact of the desulfurization technologies on cetane index summarized in the following table. As described in Chapter 7, much of the high-sulfur diesel pool is already hydrotreated (on the order of 50 percent in some PADDs) and will therefore not be impacted by the first step of fuel control to 500 ppm, so the cetane index is expressed as a range for the high-sulfur to 500 ppm step. The lower value of the range reflects the fact that refiners will have to hydrotreat only half their existing high-sulfur pool to produce 500 ppm sulfur fuel, while the upper value reflects the fact that refiners will have to treat their entire pool. For conventional hydrotreating, a range in the amount of increase in cetane index values is also reflected in the 500 ppm to 15 ppm sulfur reduction step, which reflects the different estimates for the two vendors that provided us the desulfurization information.

Table 5.9-2
Impact of Desulfurization Technologies on Diesel Fuel Cetane Index

	Conventional Hydrotreating	Process Dynamics Isotherming
High-Sulfur to 500 ppm	+2 to +4	+2 to +4
500 ppm to 15 ppm	+1 to +2	+2
Total High-Sulfur to 15 ppm	+3 to +6	+4 to +6

As summarized in the above table, conventional hydrotreating improves the cetane index of diesel fuel by 2 to 4 numbers for the 500 ppm sulfur standard, and 1 to 2 numbers for the 15 ppm sulfur standard incremental to the 500 ppm standard. If the lowest cetane index values of non-highway diesel fuel are indeed between 39 and 40 as the NIPER/TRW data suggest, then the desulfurization of that pool to comply with the 500 ppm sulfur standard, which we expect to be accomplished using conventional desulfurization technology, is expected to increase the cetane index to a value above the 40 minimum, thus we do not expect refiners to be constrained by a cetane index requirement.

Aromatics should also decrease, although this decrease is expected to occur mostly through the saturation of polynuclear aromatics to monoaromatics.

5.9.5 Other Fuel Properties

Desulfurization is expected to impact other qualities of non-highway diesel fuel. The concentration of nitrogen in current high-sulfur diesel fuel is on the order of several hundred parts per million. The desulfurization technologies projected to be used for compliance with the 500 ppm sulfur standard are expected to lower nitrogen levels down to under 100 ppm, although they may still be above 50 ppm. These same desulfurization technologies are expected to lower nitrogen levels down to under 10 ppm when achieving compliance with the 15 ppm sulfur standard.

Conventional desulfurization and Process Dynamics Isotherming are expected to affect the distillation temperature of NRLM diesel fuel. For desulfurizing high-sulfur diesel fuel down to 15 ppm, one vendor of conventional hydrotreating technology estimates that each distillation point (T-10 - T-90) will experience a 5˚F decrease. Consistent with that, API gravity is expected to increase by 4 numbers, with density decreasing commensurately. Process Dynamics Isotherming is expected to impact the distillation temperature less than conventional hydrotreating due to the lower API gravity increase caused by Process Dynamics compared with conventional hydrotreating.

Appendix 5A: EPA's Legal Authority for Adopting Nonroad, Locomotive, and Marine Diesel Fuel Sulfur Controls

We are adopting diesel fuel sulfur controls under our authority in section 211(c)(1) of the Clean Air Act. This section gives us the authority to "control or prohibit the manufacture, introduction into commerce, offering for sale, or sale" of any fuel or fuel additive for use in an off-highway engine or vehicle (1) whose emission products, in the judgment of the Administrator, cause or contribute to air pollution which may reasonably be anticipated to endanger the public health or welfare or (2) whose emission products will impair to a significant degree the performance of any emission control device or system which is in general use, or which the Administrator finds has been developed to a point where in a reasonable time it would be in general use were the fuel control or prohibition adopted.

We currently do not have regulatory requirements for sulfur in nonroad, locomotive, or marine diesel fuel. Beginning in 1993, highway diesel fuel was required to meet a sulfur cap of 500 ppm and be segregated from other distillate fuels as it left the refinery by the use of a visible level of dye solvent red 164 in all non-highway distillate. Any fuel not dyed is treated as highway fuel. Beginning in 2006, highway diesel fuel will be required to start meeting a sulfur cap of 15 ppm.

We are adopting controls on sulfur levels in off-highway diesel fuel based on both of the Clean Air Act criteria described above. Under the first criterion, we believe that emission products of sulfur in nonroad, locomotive, and marine diesel fuel used in these engines contribute to PM and SOx pollution. As discussed in Chapter 2, emissions of these pollutants cause or contribute to ambient levels of air pollution that endanger public health and welfare. Control of sulfur to 15 ppm for NRLM fuel will lead to significant, cost-effective reductions in emissions of these pollutants, with the benefits to public health and welfare significantly outweighing the costs. In the proposal and Draft RIA EPA discussed controlling sulfur through a first step to 500 ppm for NRLM fuel, based on the public health and welfare benefits from such a fuel control, with a second step to 15 ppm for nonroad fuel, based on technology enablement for associated nonroad engine standards. EPA also discussed various alternatives, such as a second step to 15 ppm for locomotive and marine fuel as well as a single step to 15 ppm for NRLM fuel, both based on the public health and welfare benefits from such a fuel sulfur control.

Adopting a 15 ppm standard for locomotive and marine fuel makes it clear that for purposes of section 211(c)(1)(A) the most appropriate way to view the final fuel control program adopted in this rule is as a complete program, covering all of NRLM fuel. This is because the reduction to 15 ppm for nonroad fuel is in essence no different from the reduction to 15 ppm for locomotive and marine fuel. Basically, the same desulfurization technology is used, the same per-gallon desulfurization costs are incurred, and the same per gallon emissions reductions and benefits are achieved from the fuel control. The only significant difference is the magnitude of total actual reductions and costs, based on the volume of diesel fuel controlled. Therefore for purposes of section 211(c)(1)(A), EPA has analyzed and justified the reduction of NRLM fuel sulfur from current sulfur levels to 15 ppm as a complete program, without drawing any distinction between nonroad and locomotive and marine fuel.

Under the second criterion, we believe that sulfur in nonroad diesel fuel will significantly impair the emission-control systems expected to be in general use in nonroad engines designed to meet the emission standards adopted in this rule. Chapter 4.1.7 describes the substantial adverse effect of high fuel-sulfur levels on the emission-control devices or systems for diesel engines meeting the proposed emission standards. Controlling sulfur levels in nonroad diesel fuel to 15 ppm will enable emission-control technology that will achieve additional significant, cost-effective reduction in emissions of NOx, NMHC and PM pollutants, beyond that achieved by the fuel control itself. The following sections summarize our analysis of the various issues related to adopting fuel-sulfur controls for nonroad, locomotive, and marine diesel fuel.

5A.1 Health and Welfare Concerns of Air Pollution Caused by Sulfur in Diesel Fuel

At the current unregulated levels of sulfur in this diesel fuel, the emission products from the combustion of diesel sulfur in these engines can reasonably be anticipated to endanger public health and welfare. Sulfur in nonroad, locomotive and marine diesel fuel leads directly to emissions of SO2 and sulfate PM from the exhaust of diesel vehicles, both of which cause adverse health and welfare impacts, as described in Chapter 2. SO2 emissions from nonroad, locomotive and marine engines are directly proportional to the amount of sulfur in the fuel. SO2 is oxidized in the atmosphere to SO3 which then combines with water to form sulfuric acid (H2SO4) and further combines with ammonium in the atmosphere to form ammonium sulfate aerosols. These aerosols are what is often referred to as sulfate PM. This sulfate PM comprises a significant portion of the “secondary” PM that does not come directly from the tailpipe, but is nevertheless formed in the atmosphere from exhaust pollutants. Exposure to secondary PM may be different from that of PM emitted directly from the exhaust, but the health concerns of secondary PM are just as severe as for directly emitted particulate matter, with the possible exception of the carcinogenicity concerns with diesel exhaust.

Approximately 1-2% of the sulfur in nonroad, locomotive and marine diesel fuel is not converted into SO2, but is instead further oxidized into SO3 which then forms sulfuric acid aerosols (sulfate PM) as it leaves the tailpipe. While only a small fraction of the overall sulfur is converted into sulfate emissions in the exhaust, it nevertheless accounts for approximately 10% of the total PM emissions from diesel engines today. This sulfate PM is also directly proportional to the sulfur concentration in the fuel. The health and welfare implications of emissions of PM and SO2 and the need for reductions in these emissions are discussed in Chapter 2.

The reduction in the sulfur level of nonroad, locomotive, and marine diesel fuel to 15 ppm would achieve in excess of 99 percent reduction in the emissions of SO_2 and sulfate PM emissions from nonroad, locomotive, and marine diesel engines compared with today’s levels. The first step to 500 ppm would achieve about a 90% reduction and the second step to 15 ppm would achieve in excess of a 99 percent reduction in these pollutants.

EPA has evaluated the technical feasability of achieving these sulfur levels, including the cost of the reductions and the impact on fuel supply. EPA has concluded that these reductions are feasible in the lead time provided, and should not have an adverse impact on the adequacy of NRLM fuel supply to meet demand; see RIA Chapter 5.

EPA also evaluated the emissions reductions achieved by controlling NRLM sulfur levels and compared them to the benefits and the costs to achieve these reductions. EPA evaluated the monetary value of many of the public health and welfare benefits that will be achieved by these reductions in emissions; see RIA Chapter 9. The monetized value of the health and welfare benefits of the emissions reductions obtained by lowering sulfur in NRLM diesel fuel from current levels to 15 ppm are expected to significantly exceed the costs of this reduction in sulfur levels. This is the case for the complete fuel program (going from current levels of sulfur in NRLM to 15 ppm for NRLM), as well as for each of the two steps used to achieve the complete fuel program (going from current levels to 500 ppm, and then going from 500 ppm to 15 ppm). The costs per gallon are also reasonable for going from current sulfur levels to 15 ppm.[MM] EPA also evaluated the cost per ton of emissions reduced for lowering sulfur in NRLM from current levels down to 15 ppm, the complete program. The results are comparable to the cost per ton of the entire engine and fuel program adopted in this final rule, as well as for other control programs designed to reduce emissions of the same pollutants; see RIA Chapter 8. The most appropriate way to evaluate the cost per ton is to consider the complete fuel program adopted in the final rule, since that is the action we are taking. However, we have also evaluated the cost per ton considering the two steps separately. The cost per ton of emissions reduced in the first step to 500 ppm is comparable to other control programs. The cost per ton for the second step, when considered in isolation, is somewhat high compared to the cost per ton of other control programs, however the monetized benefits from the reduction in emissions achieved by the second step are greater than the costs to achieve these reductions. In sum, EPA concludes that the entire body of evidence strongly supports the view that controlling sulfur in NRLM fuel to 15 ppm, through a two step process, is quite reasonable in light of the emissions reductions and benefits achieved, taking costs into consideration.

The rationales for the two-step approach to fuel sulfur control and the levels associated with each step are discussed in Chapters 5 and 12. Aside from its dramatic and immediate in-use emission benefits, the proposed sulfur level of 500 ppm for the first step was chosen primarily due to its consistency with the current highway diesel fuel standard. The magnitude of the distribution system costs would virtually prohibit the widespread distribution of any other grades of diesel fuel, as discussed in Section IV.B of the preamble to the proposed rule. The 15 ppm level was chosen as the final level for the same reasons, as well as for the reasons discussed below concerning the need for 15 ppm sulfur fuel to enable the use of advanced emissions

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[MM] The cost per gallon to go from current levels to 15 ppm is the same cost per gallon to go from current sulfur levels to 500 ppm plus the cost per gallon to go from 500 to 15 ppm. The cost per gallon for each of the separate steps is by definition less than the cost for the combined steps of the total fuel program.

control technology. Consequently, the choice of sulfur level was limited to one of the existing three grades; 15 ppm, 500 ppm, or uncontrolled. A reduction in the sulfur directly to 15 ppm was inconsistent with the proposed 2-step approach to diesel fuel sulfur control. Therefore, given the need to achieve reductions, the 500 ppm level was selected for this temporary first step of control.

Section 211(c)(2)(A) requires that, prior to adopting a fuel control based on a finding that the fuel's emission products contribute to air pollution that can reasonably be anticipated to endanger public health or welfare, EPA consider "all relevant medical and scientific evidence available, including consideration of other technologically or economically feasible means of achieving emission standards under [section 202 of the Act]." EPA's analysis of the medical and scientific evidence relating to the emissions impact from nonroad, locomotive and marine engines, which are impacted by sulfur in diesel fuel, is described in more detail in Chapter 2 of the RIA.

EPA has also satisfied the statutory requirement to consider "other technologically or economically feasible means of achieving emission standards under section [202 of the Act]." This provision has been interpreted as requiring consideration of establishing emission standards under section 202 prior to establishing controls or prohibitions on fuels or fuel additives under section 211(c)(1)(A). See *Ethyl Corp. v. EPA*, 541 F.2d. 1, 31-32 (D.C. Cir. 1976). In *Ethyl*, the court stated that section 211(c)(2)(A) calls for good faith consideration of the evidence and options, not for mandatory deference to regulation under section 202 compared to fuel controls. *Id*. at 32, n.66.

EPA recently set emissions standards for heavy-duty highway diesel engines under section 202 (66 FR 5002, January 18, 2001). That program will reduce particulate matter and oxides of nitrogen emissions from heavy duty engines by 90 percent. In order to meet these more stringent standards for diesel engines, the program requires a 97 percent reduction in the sulfur content of diesel fuel. EPA does not believe it is appropriate to seek further reductions at this time from these engines. Also, section 211(c)(2)(A) refers to standard setting under section 202 for highway engines or vehicles, and does not refer to standard setting under section 213. In any case, EPA is adopting stringent new standards for nonroad diesel engines under section 213.

The two-step reduction of sulfur to 15 ppm for nonroad, locomotive and marine diesel fuel represents an appropriate exercise of the Agency's discretion under section 211(c)(1)(A). The control of NRLM fuel down to 15 ppm provides significant reductions in emissions of PM and SO2, producing reductions in excess of 99% of these emissions. The fuel program is cost effective and produces benefits to public health and welfare whose value significantly outweighs the costs. These reductions can be achieved in a manner that is technologically feasible, will not disrupt fuel supply, and is harmonized with the similar fuel controls for highway diesel fuel. Using two steps to reduce the level of NRLM sulfur to 15 ppm allows for a short lead time for implementation, enabling the environmental benefits to begin as soon as possible.

5A.2 Impact of Diesel Sulfur Emission Products on Emission-Control Systems

EPA is restricting the sulfur content of nonroad diesel fuel nationwide to no more than 15 ppm beginning in 2010, to enable compliance with new emission standards based on the use of advanced emission control technology that will be available to nonroad diesel engines. It is apparent that sulfur in nonroad diesel fuel significantly impairs the emission-control technology of nonroad engines designed to meet the final emission standards. As discussed in Chapter 4.1, existing aftertreatment technologies will be capable of achieving dramatic reductions in NOx and PM emissions from nonroad engines when the standards based on use of advanced aftertreatment devices take effect in the 2011 and later model years. The aftertreatment technology for PM is already in an advanced state of development and being tested in fleet demonstrations in the U.S. and Europe. The NOx aftertreatment technology is in a less-advanced, but still highly promising, state of development, and, as discussed in Chapter 4.1, EPA believes the lead time between now and 2011 will provide sufficient opportunity to adapt this technology for use on nonroad engines. EPA believes these aftertreatment technologies will be in general use beginning in 2011, with the diesel sulfur controls adopted in this rule.

At today's typical sulfur concentrations, these aftertreatment technologies cannot be introduced widely into the marketplace. Not only does their efficiency at reducing emissions fall off dramatically at elevated fuel sulfur concentrations, but engine operation impacts and permanent damage to the aftertreatment systems are also possible. To ensure regeneration of the diesel particulate filter at exhaust temperatures typical of nonroad diesel engines as described in Chapter 4.1.1.3, we are expecting that precious group metals (primarily platinum) will be used in their washcoat formulations. There are two primary mechanisms by which sulfur in nonroad diesel fuel can limit the effectiveness or robustness of diesel particulate filters which rely on a precious metal oxidizing catalyst. The first is inhibition of the oxidation of NO to NO_2 and the second is the preferential oxidation of SO_2 to SO_3, forming a precursor to sulfate particulate matter. With respect to NOx aftertreatment, all the NOx aftertreatment technologies discussed in Chapter 4.1.2 that EPA believes will generally be available to meet the standards are expected to utilize platinum to oxidize NO to NO2 to either improve the NOx reduction efficiency of the catalysts at low temperatures or, as in the case of the NOx adsorber, as an essential part of the process of NOx storage and regeneration. This reliance of NO2 as an integral part of the reduction process means that the NOx aftertreatment technologies, like the PM aftertreatment technologies, would be significantly impaired by the sulfur in nonroad diesel fuel. This is because sulfur, in the form of SOx, competes with NOx to be stored by the aftertreatment device. The resulting sulfate is harder to break down than the stored NOx, and is not normally released during the regeneration phase (i.e. SOx is stored preferentially to NOx by the device). The sulfur therefore continues to build up, preventing storage of NOx, and rendering the device ineffective. Further, although this problem can be addressed by adding a "desulfation" phase to aftertreatment operation, the number of these desulfation events needs to be minimized in order to prevent damage to the aftertreatment device.

Current sulfur levels also impair performance and durability of diesel oxidation catalysts

(DOCs), which some of the 0-75 hp nonroad engines may utilize to achieve the 2008 emission standards for PM. See chapter II. A of the preamble and Chapter 4.1.1.2 of this RIA. Although EPA would not justify its decision to reduce sulfur levels in nonroad diesel fuel to 500 ppm for this reason alone, it is worth pointing out the benefits to these PM emission control technologies which result from the reduction.

5A.3 Sulfur Levels that Nonroad Engines Can Tolerate

As discussed in Chapter 4, there are three key factors which, taken together, lead us to conclude that a nonroad diesel sulfur cap of 15 ppm is necessary so the NOx and PM aftertreatment technology on nonroad engines will function properly and be able to meet the emission standards. These factors are the impact of higher sulfur levels on the efficiency and reliability of the control systems, and on the engine's fuel economy.

The efficiency of emission control technologies at reducing harmful pollutants is directly impacted by sulfur in nonroad diesel fuel. Initial and long term conversion efficiencies for NOx, HC, CO and diesel PM emissions are significantly reduced by catalyst poisoning and catalyst inhibition due to sulfur. NOx conversion efficiencies with the NOx adsorber technology in particular are dramatically reduced in a very short time due to sulfur poisoning of the NOx storage bed. In addition, total PM control efficiency is negatively impacted by the formation of sulfate PM. The formation of sulfate PM is likely to be in excess of the total PM standard , unless nonroad diesel fuel sulfur levels are below 15 ppm. When sulfur is kept at these low levels, both PM and NOx aftertreatment devices are expected to operate at high levels of conversion efficiency, allowing compliance with the PM and NOx emission standards.

The reliability of the emission control technologies to continue to function as required under all operating conditions for the life of the engine is also directly impacted by sulfur in nonroad diesel fuel. As discussed in Chapter 4, sulfur in nonroad diesel fuel can prevent proper operation and regeneration of both NOx and PM advanced aftertreatment control technologies leading to permanent loss in emission control effectiveness and even catastrophic failure of the systems. For example, if regeneration of a PM filter does not occur, catastrophic failure of the filter can occur in less than a single tank full of high-sulfur nonroad diesel fuel. For NOx adsorbers, keeping sulfur levels no higher than 15 ppm is needed to minimize the number of desulfation events to provide a high efficiency operation over the useful life of the engine. It is only through the availability of nonroad diesel fuel with sulfur levels less than 15 ppm that these technologies can reliably be used to achieve the 90+ % emission reductions of PM and NOx on which the 2011 and later model year standards are based. We believe that diesel fuel sulfur levels of 15 ppm are needed and would allow these technologies to operate properly throughout the life of the vehicle, including proper periodic or continuous regeneration.

The sulfur content of nonroad diesel fuel will also impact the fuel economy of nonroad engines equipped with NOx and PM aftertreatment technologies. As discussed in detail in Chapter 4.1.7, NOx adsorbers are expected to consume nonroad diesel fuel in order to cleanse themselves of stored sulfates and maintain efficiency. The larger the amount of sulfur in nonroad diesel fuel, the greater this adverse impact on fuel economy. As sulfur levels increase above 15 ppm, the fuel economy impact quickly changes from merely noticeable to unacceptable. Likewise PM trap regeneration is inhibited by sulfur in nonroad diesel fuel. This leads to increased PM loading in the diesel particulate filter, increased exhaust backpressure, and poorer fuel economy. Thus for both NOx and PM technologies, the lower the fuel sulfur level, the better the fuel economy of the vehicle.

As a result of these factors, we find that 15 ppm represents an upper threshold of acceptable nonroad diesel fuel sulfur levels for use with nonroad engines using generally available advanced aftertreatment for PM and for NOx.

5A.4 Sulfur Sensitivity of Other Emission Control Devices or Systems

Section 211(c)(2)(B) requires that, prior to adopting a fuel control based on a significant impairment to vehicle emission-control systems, EPA consider available scientific and economic data, including a cost benefit analysis comparing emission-control devices or systems which are or will be in general use that require the proposed fuel control with such devices or systems which are or will be in general use that do not require the proposed fuel control. As described below, we conclude that the aftertreatment technology expected to be used to meet the nonroad standards would be significantly impaired by operation on high-sulfur (greater than 15 ppm) nonroad diesel fuel. Our analysis of the available scientific and economic data can be found elsewhere in this document, including an analysis of the environmental benefits of the emission standards (Chapter 3), an analysis of the costs and the technological feasibility of controlling sulfur to the levels established in the final rule (Chapter 7), and a cost-effectiveness analysis of the sulfur control and nonroad emission standards (Chapter 8). Under section 211(c)(2)(B), as just noted, EPA is also required to compare the costs and benefits of achieving emission standards through emission-control systems that would not be sulfur-sensitive, if any such systems are or will be in general use.

We have determined that there are not (and will not be in the foreseeable future) emission control devices available for general use in nonroad engines that can meet the nonroad emission standards and would not be significantly impaired by nonroad diesel fuel with high sulfur levels. NOx and PM emissions cannot be reduced anywhere near the magnitude contemplated by the final emission standards without the application of aftertreatment technology. As discussed in Chapter 4, there are a number of aftertreatment technologies that are currently being developed for both NOx and PM control with varying levels of effectiveness, sulfur sensitivity, and potential application to nonroad engines.

As discussed in Chapter 4.1, all the aftertreatment technologies that could be used to meet the PM or NOx standards are significantly impaired by the sulfur in diesel fuel. For PM control, all PM aftertreatment t technology that is capable of meeting the PM aftertreatment-based Tier 4 standards would need the level of sulfur control adopted in this rule. In addition, the NOx aftertreatment technologies evaluated by EPA all rely on the use of catalytic processes to increase the effectiveness of the device in reducing NOx emissions. For example both NOx adsorbers and compact SCR would rely on noble metals to oxidize NO to NO_2, to increase NOx conversion efficiency at the lower exhaust temperatures found in diesel motor vehicle operation. This catalytic process, however, produces sulfate PM from the sulfur in the diesel fuel, and these NOx aftertreatment devices therefore need the level of sulfur control adopted in this rule in order for the vehicle to comply with the PM standard.

In addition, compact SCR is not a technology that would be generally available by the model year 2011 time frame. SCR systems require refilling with urea on a regular basis in order to operate. Significant and widespread changes to the fuel distribution system infrastructure thus would have to be made, and there is no practical expectation that this would occur, with or without the low-sulfur standard adopted in this final rule. While it is feasible and practical to expect that compact SCR may have a role in specific controlled circumstances, such as certain centrally fueled fleets, or for generator sets using greater than 750 hp engines, it is not realistic at this time to expect that the fuel distribution system infrastructure changes needed for widespread and general use of compact SCR on nonroad engines will be in place by the model year 2011 time frame. Finally, for NOx control, both NOx adsorbers and compact SCR are significantly impaired by sulfur in diesel fuel, and (as explained above) both technologies would need very large reductions in sulfur from current levels to meet the NOx standard adopted in this final rule. EPA believes that the requirement of a cost benefit analysis under section 211(c)(2)(B) is not aimed at evaluating emission-control technologies that would each require significant additional or different EPA fuel control regulations before the technology could be considered generally available.

Moreover, it is undisputed that any generally available technology capable of achieving the PM aftertreatment-based standards requires 15 ppm sulfur fuel. Thus,15 ppm sulfur fuel will be needed in any event.

In sum, EPA believes that both PM and NOx aftertreatment technologies require 15 ppm sulfur fuel.

As described in Chapter 4, EPA anticipates that all the nonroad engine technologies expected to be used to meet the final nonroad standards will require the use of nonroad diesel fuel with sulfur levels capped at 15 ppm. If we do not control diesel sulfur to the finalized levels, we would not be able to set nonroad standards as stringent as those we are finalizing in this final rule. Consequently, EPA concludes that the benefits that would be achieved through implementation of the engine and sulfur control programs cannot be achieved through the use of emission control technology that does not need the sulfur control adopted in this rule, and would be generally available to meet the emission standards adopted in this rule.

This also means that if EPA were to adopt emission standards without controlling diesel sulfur content, the standards would be significantly less stringent than those finalized in this rule, based on what would be technologically feasible with current or 500 ppm sulfur levels.

5A.5 Effect of Nonroad Diesel Sulfur Control on the Use of Other Fuels or Fuel Additives

Section 211(c)(2)(C) requires that prior to prohibiting a fuel or fuel additive, EPA establish that such prohibition will not cause the use of another fuel or fuel additive "which will produce emissions which endanger the public health or welfare to the same or greater degree" than the prohibited fuel or additive. This finding is required by the Act only prior to prohibiting a fuel or additive, not prior to controlling a fuel or additive. Since EPA is not prohibiting use of sulfur in nonroad, locomotive or marine fuel, but rather is controlling the level of sulfur in these diesel fuels, this finding is not required for this rulemaking. However, EPA does not believe that the sulfur control will result in the use of any other fuel or additive that will produce emissions that will endanger public health or welfare to the same or greater degree as the emissions produced by nonroad diesel with uncontrolled sulfur levels.

Unlike the case of unleaded gasoline in the past, where lead performed a primary function by providing the necessary octane for the vehicles to function properly, sulfur does not serve any useful function in nonroad, locomotive or marine diesel fuel. It is not added to diesel fuel, but comes naturally in the crude oil into which diesel fuel is processed. Were it not for the expense of sulfur removal, it would have been removed from diesel fuel years ago to improve the maintenance and durability characteristics of diesel engines. EPA is unaware of any function of sulfur in nonroad, locomotive or marine diesel fuel that might have to be replaced once sulfur is removed, with the possible exception of lubricity characteristics of the fuel. As discussed in Chapters 4 and 5, there is some evidence suggesting that as sulfur is removed from diesel fuel the natural lubricity characteristics of diesel fuel may be reduced. Depending on the crude oil and the manner in which desulfurization occurs some low-sulfur diesel fuels can exhibit poor lubricity characteristics. To offset this concern lubricity additives are sometimes added to the diesel fuel. These additives, however, are already in common use today and EPA is unaware of any health hazards associated with the use of these additives in diesel fuel, which would merely be used in larger fractions of the diesel fuel pool. We do not anticipate that their use would produce emissions which would reduce the large public health and welfare benefits that this rule would achieve.

EPA is unaware of any other additives that might be necessary to add to nonroad, locomotive or marine diesel fuel to offset the existence of sulfur in the fuel. EPA is also unaware of any additives that might need to be added to nonroad, locomotive or marine diesel fuel to offset any other changes to the fuel which might occur during the process of removing sulfur.

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43. National Petroleum Council, " U.S. Petroleum Assuring Adequacy and Affordability of Cleaner Fuels", June 2000 pages 118-133.

44. Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: The Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, December 1999, EPA 420-R-99-023.

45. Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: The Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, December 1999, EPA 420-R-99-023.

46. Moncrief, Philip and Ralph Ragsdale, "Can the U.S. E&C Industry Meet the EPA's Low Sulfur Timetable," NPRA 2000 Annual Meeting, March 26-28. 2000, Paper No. AM-00-57.

47.Chapter IV of the Regulatory Impact Analysis for the Final Highway Diesel Rule contained a substantial background discussion regarding past experience in maintaining adequate fuel

lubricity in low-sulfur fuels, EPA Air docket A-99-06.

48. Letter from L. Erlandsson, MTC AB, to Michael P. Walsh, dated October 16, 2000. Docket A-99-06, item IV-G-42.

49. Chevron Products Diesel Fuel Technical Review provides a discussion of the impacts on fuel lubricity of current diesel fuel compositional requirements in California versus the rest of the nation. http://www.chevron.com/prodserv/fuels/bulletin/diesel/l2%5F7%5F2%5Frf.htm

50. Final Report, 1996 American Petroleum Institute / National Petroleum Refiners Association, Survey of Refining Operations and Product Quality, July 1997.