Chapter IV: Fuel Standard Feasibility

A. Feasibility of Removing Sulfur from Highway Diesel Fuel

1. Sources of Diesel Fuel Sulfur

The primary sources of sulfur in diesel fuel are the sulfur-containing compounds which occur naturally in crude oil.[1] 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 percent.[1] The average amount of sulfur in crude oil refined in the U.S. is about one 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 diesel fuel produced by a given refinery is composed of one or more blendstocks from the crude oil fractionation and conversion units at the refinery. Refinery configuration and equipment, and the range and relative volumes of products manufactured (the product slate) can 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 U.S.

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[1] 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.

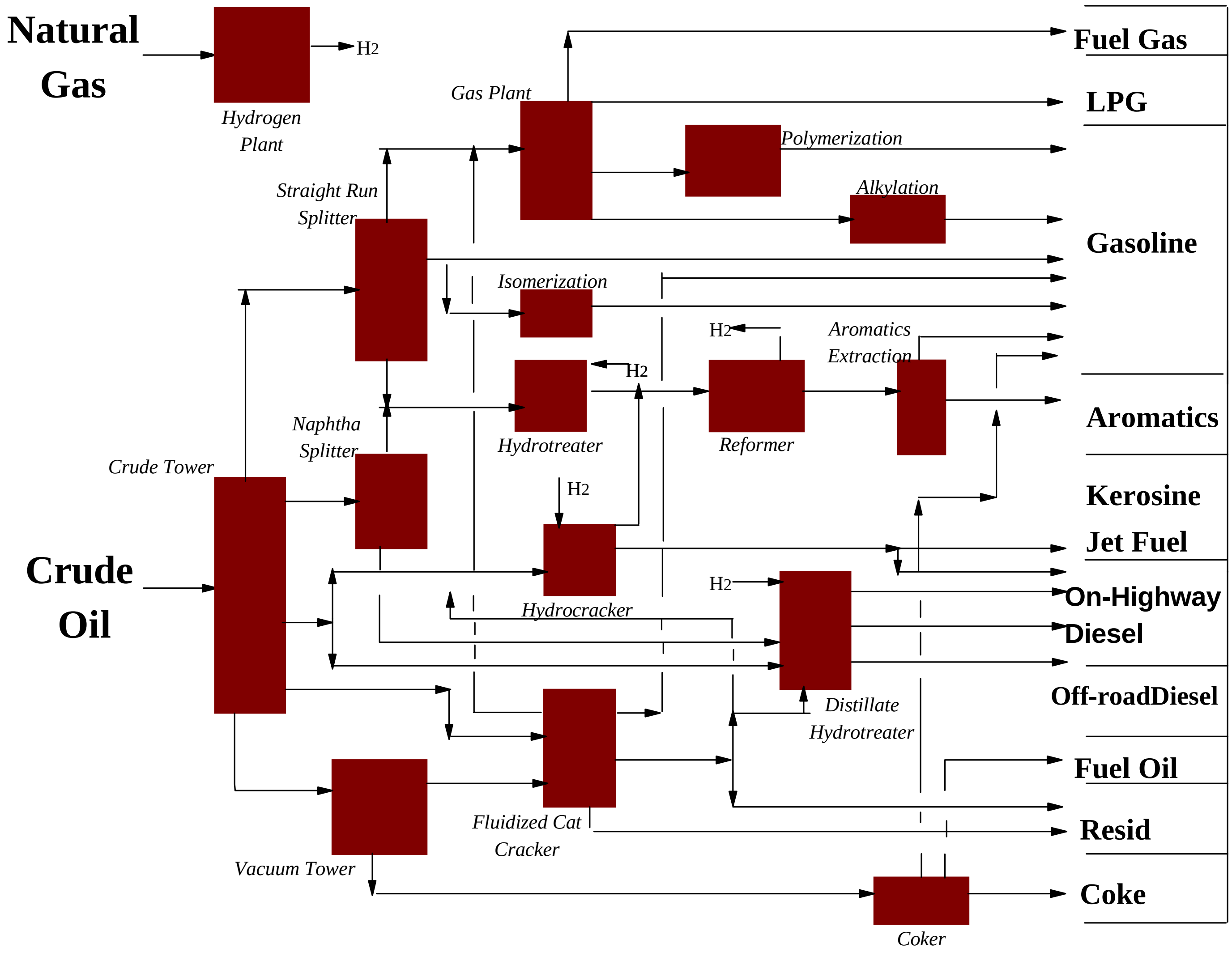


Figure IV.A-1. Diagram of a Typical Complex Refinery

Refineries differ from the model in the preceding diagram depending on the range of crude oils used, and their product slate. For example:

- Refiners that process heavier crude oils are more likely to operate coker and/or hydrocracker units.

- Refinery streams that can be used to manufacture diesel fuel can also be used in the manufacture of heating oil, kerosene and jet fuel. Much of the distillate product from the hydrocracker is often blended into jet fuel rather than diesel fuel.

On an aggregate basis, most of the highway diesel fuel volume manufactured in the U.S. comes from the straight-run product from the crude fractionation tower (called straight run). Most of the remainder comes from the fluid catalytic cracker (FCC) conversion unit (called light cycle oil). The remaining small fraction of diesel fuel volume comes from a coker conversion unit (called light coker gas oil), 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 is currently accomplished in fixed-bed hydrotreaters that operate at moderate pressures (500-700 psi), with a few exceptions at higher pressures such as the small portion of highway diesel which comes from hydrocrackers. Most of the low-sulfur diesel blendstocks come from such hydrotreaters. However, a small amount of low-sulfur diesel also comes from hydrocrackers. The sulfur levels of the various highway diesel blendstocks and the fraction of the total volume of highway diesel fuel that comes from each blendstock varies considerably from refinery to refinery. A recent 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 diesel pool as a whole.[3] The results of this survey are contained in the following tables (IV.A-1 and IV.A-2).

Table IV.A-1. Volume Fraction of U.S. Highway Diesel Pool from each Blendstock Component[4]

Diesel Blendstock	*Percent of U.S. Highway Diesel Fuel Pool per Blendstock Boiling Fraction*				
	Naphtha	*Light Distillate*	*Heavy Distillate*	*Light Gas Oil*	*All Boiling Fractions Combined*
Straight Run	0.1	6.4	4.9	1.0	12.4
Hydrotreated Straight Run	0.3	8.1	41.2	2.3	51.9
Cracked Stock	-	0.1	0.8	2.2	3.1
Hydrotreated Cracked Stock	-	2.1	15.6	1.7	19.4
Coker Gas Oil	-	-	1.0	-	1.0
Hydrotreated Coker Gas Oil	0.1	2.1	3.7	2.3	8.2
Hydrocrackate	-	1.3	2.7	-	4.0

Table IV.A-2. Sulfur Levels of Highway Diesel Blendstocks (CA Excluded)[5]

Diesel Blendstock	*Sulfur Content (ppm) by Boiling Fraction of the Blendstock*[A]				
	Naphtha	*Light Distillate*	*Heavy Distillate*	*Light Gas Oil*	*All Boiling Fractions Combined*[B]
Straight Run	827	1,770	2,269	4,980	2,218
Hydrotreated Straight Run	362	119	394	548	358
Cracked Stock	-	2,219	2,892	6,347[C]	5,322
Hydrotreated Cracked Stock	18	37	939	1,306[C]	874
Coker Gas Oil	540	1,800	3,419	-	3,419
Hydrotreated Coker Gas Oil	8[C]	25	310	400	258
Hydrocrackate	-	12	120	-	85

A The boiling ranges that define the four different boiling fractions of each diesel blendstock (naphtha, light distillate, heavy distillate, and light gas oil) varied somewhat from refiner to refiner. There was also definitional overlap in the boiling ranges provided by refiners.

B These values were derived by weighting the values for the four boiling fractions by the fraction they represent of the highway diesel fuel blendstock (see Table IV-1).

C Indicates properties that were not reported in the refiner survey. These values were calculated using the reported sulfur contents of like boiling fractions in other diesel blendstocks by assuming the same relative sulfur levels between boiling fractions. This was necessary to allow the calculation of the sulfur content of the blendstock as a whole.

As shown in Table IV.A-1, approximately 80 percent of all blendstocks used to manufacture highway diesel fuel outside of California are hydrotreated to reduce their sulfur content. Hydrocrackate is desulfurized to a substantial extent as a necessary element of the hydrocracking process and is not further processed in a hydrotreater. The table also shows that approximately 16 percent of highway diesel fuel comes from nonhydrotreated blendstocks.

The blendstocks used to manufacture highway diesel fuel used in California differ from the rest of the nation due to the unique requirements of the California market and California's specific regulatory requirements. As a result, California's highway diesel fuel averages 140 ppm sulfur.[6] Highway diesel fuel used in California is made primarily from hydrocrackate and hydrotreated straight run in roughly equal proportions, with a small volume fraction of hydrotreated cracked stock and hydrotreated coker gas oil. No high-sulfur containing blendstocks are used in the manufacture of California highway diesel fuel. California diesel fuel requirements include a limit on aromatics content which limits the amount of light-cycle oil (LCO) and light-coker gas oil (LCGO) that can be used in the manufacture of California highway diesel fuel. LCO and LCGO have a high aromatics content which is not reduced by desulfurization.

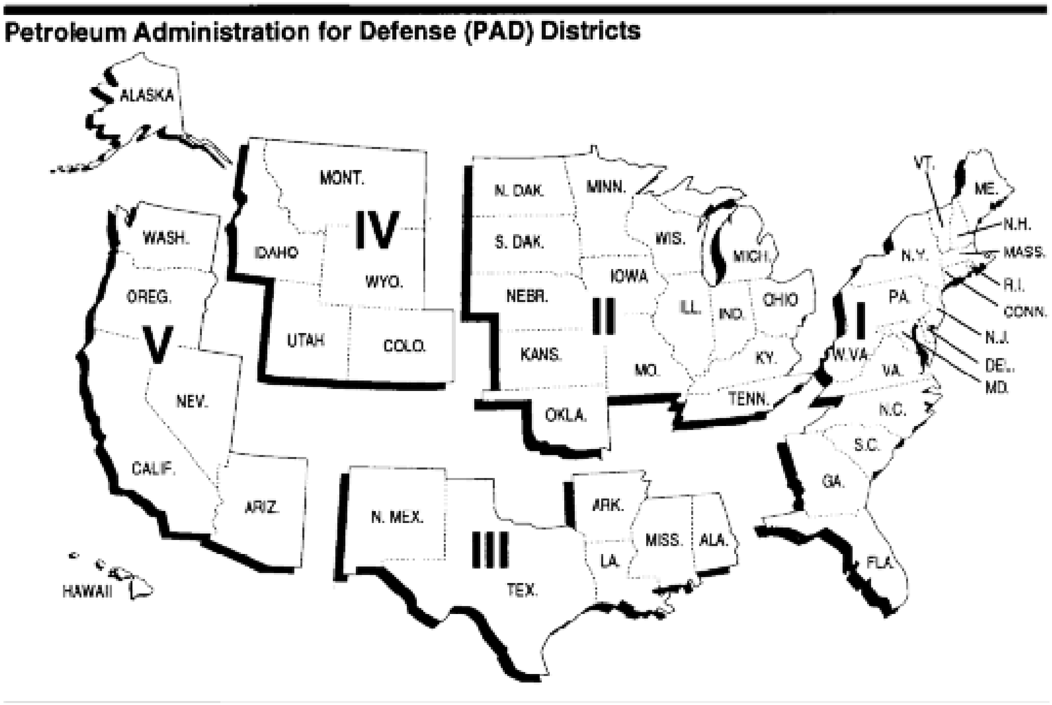
2. Current Levels of Sulfur in Highway Diesel Fuel

To determine the most cost-effective sulfur removal methods, it is important to evaluate the amount of sulfur currently in highway diesel fuel. EPA set standards for highway diesel fuel quality in 1990 (55 FR 34120, August 21, 1990). These standards have been effective since 1993. The standards limit the sulfur concentration in fuel to a maximum of 500, compared to a pre-regulation average of 2500 ppm. They also protect against a rise in the fuel's aromatics content from then-existing levels by setting a minimum cetane index of 40 (or, alternatively, a maximum aromatics level of 35 volume percent).

California set more stringent standards in 1988 for motor vehicle diesel fuels used in the South Coast air basin.[7] These standards took effect statewide in 1993. They apply to both highway and off-highway fuels (excluding marine and locomotive use), and limit sulfur levels to 500 ppm and aromatics levels to 10 volume percent, with some flexibility provisions to accommodate small refiners and alternative formulations. Under the provisions for alternate formulations, fuel manufacturers have certified highway diesel fuel for use in California with a lower maximum sulfur content than 500 ppm ppm (California highway diesel fuel actually averages 140 ppm) and a higher maximum aromatics content than 10 percent.

Alaska and certain U.S. territories currently have an exemption from federal highway diesel fuel requirements. In these areas, the) an ASTM (the American Society for Testing and Materials) specification on the maximum allowed sulfur content of diesel fuel (5,000 ppm) applies.[8] These regulatory and industry criteria set the upper bound on the sulfur content of highway diesel fuel in the U.S.

To enable our cost analysis, we compiled the data by various regions called Petroleum Administrative Districts for Defense (PADDs), as well as for California and the country as a whole.[9] The PADD regions are illustrated in the following figure (IV.A-2).



Petroleum Administration for Defense (PAD) Districts

Figure IV.A-2. Map of U.S. Petroleum Administrative Districts for Defense

Our evaluation revealed relatively little difference in the sulfur content of highway diesel fuel in PADDs 1, 2, 3, and 4. The sulfur content of highway diesel fuel in California is considerably lower than that in the rest of the nation due to regulatory requirements specific to California. The sulfur content of diesel fuel in PADD 5 outside of California and Alaska, although higher than that within California, is lower than that in PADDs 1 through 4. This is due to the fact that a large fraction of the highway diesel fuel used in PADD 5 outside of California and Alaska is manufactured by refineries that are configured primarily to supply lower-sulfur diesel fuel to the California market. Alaska currently has an exemption from federal highway diesel sulfur requirements. Please refer to Chapter IX for a discussion of diesel fuel sulfur levels in Alaska.

Table IV.A-3. Average Highway Diesel Fuel Sulfur Levels by Geographic Area

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5 O-CA&AK**	*CA*	*U.S. Avg.**
Sulfur Content (PPM)	340	350	360	330	280	140	340

* Outside of California and Alaska.

3. Current Levels of Other Fuel Parameters in Highway Diesel Fuel

The refinery process options which could be used reduce the sulfur content of highway diesel to under 15 ppm have the potential to affect other fuel parameters as well. Highway diesel fuel is required to meet specifications on a range of fuel parameters .[10] If process changes made to comply with the proposed cap on sulfur content adversely affect other fuel parameters, refiners may need to take additional steps to ensure that these other parameters meet specifications. Thus, to determine the most cost-effective sulfur removal methods, it is also important to evaluate current levels of the other fuel parameters which might be affected by refinery process changes to meet the sulfur cap. Data on the current distillation characteristics, API gravity, pour point, natural cetane level, and aromatics content of diesel fuel blendstocks are contained in the following tables (IV.A-4, IV.A-5, and IV.A-6).

Table IV.A-4. Distillation Characteristics of Diesel Blendstocks (CA Excluded)[11]

Blendstock	*Distillation Fraction*	*Distillation (°F)*				
		T10	*T30*	*T50*	*T70*	*T90*
Straight-Run	Naphtha	325	349	393	422	452
	Light Distillate	360	394	421	443	477
	Heavy Distillate	466	510	540	567	601
	Light Gas Oil	421	456	547	575	618
Hydrotreated Straight Run	Naphtha	296	375	405	432	467
	Light Distillate	383	412	429	454	484
	Heavy Distillate	431	492	543	576	621
	Light Gas Oil	457	528	584	-	595
Cracked Stock	Naphtha	-	-	-	-	-
	Light Distillate	346	357	369	384	408
	Heavy Distillate	488	-	526	541	637
	Light Gas Oil	-	508	547	599	666
Hydrotreated Cracked Stock	Naphtha	284	-	310	-	351
	Light Distillate	345	360	385	440	508
	Heavy Distillate	448	501	-	565	613
	Light Gas Oil	457	524	534	-	634
Coker Gas Oil	Naphtha	237	-	314	-	399
	Light Distillate	369	382	394	410	436
	Heavy Distillate	454	-	501	531	561
	Light Gas Oil	-	-	-	-	-
Hydrotreated Coker Gas Oil	Naphtha	188	210	245	275	305
	Light Distillate	359	375	463	494	580
	Heavy Distillate	460	-	504	534	594
	Light Gas Oil	521	564	599	-	628
Hydrocrackate	Naphtha	-	-	-	-	-
	Light Distillate	357	393	435	459	503
	Heavy Distillate	433	501	528	556	617
	Light Gas Oil	-	-	-	-	-

Table IV.A-5. Properties of Diesel Blendstocks (CA Excluded)[12]

Blendstock	*Distillation Fraction*	*Aromatics (Vol %)*	*Cetane # (Unadditized)*	*API Gravity*	*Pour Point (℉)*
Straight-Run	Naphtha	-	-	50.0	70 (additized)
	Light Distillate	15.9	40.3	42.2	-
	Heavy Distillate	15.5	-	35.2	-
	Light Gas Oil	-	45.0	30.3	11
Hydrotreated Straight Run	Naphtha	-	-	47.1	-
	Light Distillate	18.6	44.5	42.9	-
	Heavy Distillate	31.0	50.4	34.4	-
	Light Gas Oil	-	-	29.9	3
Cracked Stock	Naphtha	-	-	-	-
	Light Distillate	40.2	-	33.1	-
	Heavy Distillate	-	-	26.8	-
	Light Gas Oil	-	-	22.3	-
Hydrotreated Cracked Stock	Naphtha	-	-	52.6	-
	Light Distillate	19.0	42.7*	45.0	-
	Heavy Distillate	45.0	44.1*	30.7	-
	Light Gas Oil	-	-	-	-
Coker Gas Oil	Naphtha	8.0	-	51.7	-
	Light Distillate	-	-	42.4	-
	Heavy Distillate	-	-	32.2	-
	Light Gas Oil	-	-	-	-
Hydrotreated Coker Gas Oil	Naphtha	-	-	-	-
	Light Distillate	22.1	45.3	43.1	-
	Heavy Distillate	25.1	-	34.8	-
	Light Gas Oil	-	36.1	29.9	-
Hydrocrackate	Naphtha	-	-	-	-
	Light Distillate	-	-	41.8	-
	Heavy Distillate	24.2	50.2	32.9	-
	Light Gas Oil	-	-	-	-

* While these values are quoted directly from the API/NPRA survey, they are high compared to values found in other information sources. We understand the cetane number of light cycle oil is normally in the 20s.

Table IV.A-6. Average Highway Diesel Fuel Parameter Levels by Geographic Area[13]

Fuel Parameter		*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5 (OC)**	*CA*	*U.S. (OC)**
API Gravity		34.6	34.2	34.3	36.2	33.8	33.6	34.4
Cetane Number Unadditized		-	42.9	43.8	-	46.5	42.6	44.1
Cetane Additive (ppmv)		0	83	2	12	0	183	27
Cetane Number [additized]		-	-	-	-	-	-	-
Pour Point (°F) [additized]		[10]	[10]	[2]	0	[2]	6	[5]
Pour Point Depressant Additive (ppmw)		7	47	7	11	0	0	19
Distillation (°F)	T10	426	427	436	405	432	447	431
	T30	458	470	478	435	472	-	471
	T50	497	505	514	495	521	525	510
	T70	549	549	557	519	554	-	551
	T90	609	600	610	598	611	612	606
Aromatics (Vol %)		28.9	25.8	37.0	27.1	-	28.8	32.3

* Outside of California

4. Overview of Diesel Fuel Sulfur Control

As mentioned in Section A.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, therefore, is 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 could potentially reduce their diesel sulfur levels in 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 would fall well short of compliance with the 15 ppm sulfur cap. Thus, this analysis will not assume that this broad approach could be used to meet the new highway diesel sulfur standard.

Another method to reduce diesel fuel sulfur is to chemically remove sulfur from the hydrocarbon compounds which comprise diesel fuel. This is usually accomplished through reaction with hydrogen at moderate to high temperature and pressure. A couple of specific examples of this process are hydrotreating and hydrocracking. Another process was announced recently which 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 pressure processes being developed, such as biodesulfurization, and 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 those refinery streams which are to be blended directly into diesel fuel. Finally, another method to reduce diesel fuel sulfur is to shift sulfur-containing hydrocarbon compounds to other fuels produced by the refinery.

As discussed below, we expect that most of the sulfur reduction required by the sulfur cap standard will be chemical removal via hydrotreating. Thus, this section will begin with a relatively detailed discussion of the capabilities of this and similar processes. We also expect refiners to use the other methods to obtain cost effective sulfur reductions which will complement the primary sulfur reduction achieved via hydrotreating. These other methods, such as FCC feed hydrotreating, adsorption, biodesulfurization, chemical oxidation, and undercutting LCO, will be discussed following the primary discussion of distillate hydrotreating.

As mentioned above, this sulfur removal can occur either early or late in the refining process. The most practical place to remove sulfur early in the process is prior to the FCC unit. Hydrotreating feed to the FCC unit requires higher temperatures and pressures than hydrotreating distillate streams used to produce diesel fuel because FCC feed contains much larger and heavier molecules. Because of this, FCC feed hydrotreating is more expensive than distillate hydrotreating. We expect that most refiners will enhance or expand their current distillate hydrotreating capability to meet the sulfur cap, although the other benefits associated with FCC feed hydrotreating could lead some refiners to add this technology. The remaining discussion of hydrotreating will therefore begin with distillate hydrotreating, followed by a brief discussion of FCC feed hydrotreating.

5. Hydrotreating and Other Hydrogen-Based Processes Which Remove Sulfur

Hydrotreating and similar processes generally combine 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 a number of purposes. For example, naphtha (gasoline like material which itself 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 which 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 in order to improve the yield and quality of high value products, such as gasoline and distillate (distillate refers to a range of similar products including kerosene, diesel fuel, No. 2 heating oil and jet fuel), from the FCC unit. Nearly all refineries currently hydrotreat the refinery streams used to produce highway diesel fuel in order to remove much of the sulfur present and comply with the current 500 ppm sulfur cap. EPA expects 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.[14] These hydrotreating processes remove sulfur, nitrogen, metal and other contaminants from the hydrocarbon streams. They also can saturate some or most of the olefins present, depending on the process. However, they do not generally otherwise affect the chemical nature of the hydrocarbon compounds.

If the temperature or pressure is increased sufficiently, or a carbon-oriented 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 of the contaminants are removed and olefins and aromatics are saturated into paraffins and naphthenes. Outside the U.S., this process is commonly used to produce distillate from heavier, less marketable refinery streams. The production of distillate via hydrocracking 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 severe 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 U.S. to “upgrade” petroleum streams which are 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 which encourages aromatic saturation is used in lieu of one that simply encourages contaminant removal.

To meet the 15 ppm diesel sulfur cap, EPA expects refiners to focus as much as possible on sulfur removal. Other contaminants, such as nitrogen and metals, are already sufficiently removed by existing refinery processes. While saturation of aromatics generally improves diesel fuel quality, there is a significant additional cost involved, primarily the consumption of additional hydrogen. Consequently, we anticipate refiners will choose desulfurization processes that minimize the amount of aromatics saturation. Current diesel fuel already meets all applicable specifications, and hydrotreating to remove sulfur should not degrade quality, except possibly lubricity, as discussed in Section C. 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. Should a refiner choose to do so, it would be to improve profitability,[b] and not related to meeting the 15 ppm sulfur cap standard.

As mentioned above, this sulfur removal can occur either early or late in the refining process. The most practical place to remove sulfur early in the process is prior to the FCC unit. Hydrotreating feed to the FCC unit requires higher temperatures and pressures than hydrotreating distillate streams used to produce diesel because FCC feed contains much larger and heavier molecules. Because of this, FCC feed hydrotreating is more difficult and more expensive than distillate hydrotreating. We expect that most refiners will enhance or expand their current distillate hydrotreating capability to meet the 15 ppm sulfur diesel cap standard, although the other benefits associated with FCC feed hydrotreating will therefore begin with distillate hydrotreating, followed by a more brief discussion of FCC feed hydrotreating and other emerging diesel desulfurization technologies.

a. Fundamentals of Distillate Hydrotreating

Essentially all distillate hydrotreater designs follow the same broad format. Liquid distillate is heated and pumped to temperatures of 300-380°C and pressures of 500-700 psia with hydrogen and reacted 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 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

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[b] Refiners can choose to "upgrade" heavy refinery streams which 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.

hydrogen leaving the reactor is usually mixed with fresh hydrogen and recycled to the front of the reactor for reaction with fresh distillate feed. However, by itself, this would cause a build up of hydrogen sulfide and ammonia in the system, since it would have 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 scrubber.

Desufurization processes in use today in the U.S. generally use only one reactor, due to the need to only desulfurize diesel fuel to 500 ppm or lower. However, a second reactor can be used, particularly to meet lower sulfur levels. Instead of liquid distillate going to the diesel fuel/heating oil pool after the first reactor, it would simply be mixed with fresh hydrogen and sent to the second reactor.

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 at one or two points further down the reactor. The advantage of cocurrent design is practical, 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 and lowest at the outlet. The 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 (consisting of ABB Lummus, 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 will be co-current, while the second reactor will 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.[15] The impact of the counter-current design is even more significant when aromatics control (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 that 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 which 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 essentially 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, today's catalysts are very effective in desulfurizing dibenzothiophenes, as long as only hydrogen is attached to the carbon atoms bound directly to the sulfur atom.

However, distillate can contain dibenzothiophenes which 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 (or straight run light gas oil (SRLGO)) contains 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 more difficult to treat than straight run distillate.[16] In addition, cracked stocks, particularly LCO, have a greater tendency to form coke on the catalyst, which deactivates the catalyst and requires its 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 SRLGO.[17] 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 6 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 will be discussed later below.

Because moderate sulfur reduction is often all that is required in distillate hydrotreating, catalysts have been developed which focus almost exclusively on contaminant removal. 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 which 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 approach the catalyst surface much more easily. 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).

There are a number important issues which should be highlighted about using the hydrogenation pathway for desulfurization. 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 which results in the desulfurization of a sterically hindered compound. If the mono aromatics compounds are also saturated, there would likely be a further 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, would 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 existence of the monoaromatic compounds is at equilibrium conditions within the reactor, that the monoaromatic compounds are being both saturated and unsaturated, which helps to enable the desulfurization of these compounds.

The vendors also point out a number of reasons why the cycle length of the catalysts which catalyze hydrogenation reactions, which would likely occur in a second stage, is actually 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 higher temperatures of the first stage. The lower temperature avoids color changes 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 hydrogenation seconds stage is not degraded as quickly.

If refiners are "upgrading" their diesel fuel by converting heavy, high aromatic, low cetane, stocks to highway diesel fuel under the 15 ppm highway diesel fuel 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 reduces sulfur. The lower concentration of aromatics and improved cetane of the upgraded feedstock would then allow the product to be sold as highway diesel fuel. The much higher sales price of the highway diesel fuel compared to 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 around 15 ppm 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 which indicate that CoMo catalysts may still have an advantage over NiMo catalysts, even at sulfur levels below 50 ppm.[18]

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 strongly inhibits desulfurization reactions, as will be discussed further in the next section. It can also recombine with non-sulfur containing hydrocarbon compounds at the end of the reactor or even in subsequent piping, essentially 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 SRGO and LCO at 150 ppm sulfur and found that essentially all of the sulfur is contained in sterically hindered compounds.[19] 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 SRLGO 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 in 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.[20] They are most commonly used to more severely dearomatize distillate and increase cetane by opening up the aromatic rings, a process called ring opening.

b. Meeting a 15 ppm Cap with Distillate Hydrotreating

Using distillate hydrotreating to meet a 15 ppm sulfur cap on highway diesel fuel has been commercially demonstrated, as will be discussed below. 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 also produce off-highway diesel fuel and heating oil, which have much less stringent sulfur requirements and could, for example, provide a sink for 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 complying with a 15 ppm cap, than those processing primarily SRLGO.

To understand the types of modifications which can be made to distillate hydrotreaters in order to improve their 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.

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

where: k, K_{H2S} and K_F are various rate constants, which only vary 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
$K_F * C_F$ 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 which 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 essentially identify the types of changes which could be made to 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 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 U.S. 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 this year.[21] KF 752 can be considered to be typical of an Akzo Nobel catalyst of the 1992-93 timeframe, 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.[22] 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 which is particular 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, would produce 405, 270 and 160ppm sulfur with KF 756, KF757, and KF 842, respectively.

Haldor-Topsoe has also developed a more active catalyst. 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 SRLGO, 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.

UOP projects a similar reduction in sulfur due to improved catalyst. They estimate that a hydrotreater producing 500 ppm sulfur distillate today (20% LCO, 10% light coker gas oil) could produce 280 ppm sulfur distillate with a 50 percent more active catalyst.[23]

Over the last two years, Criterion Catalyst Company announced two new lines of catalysts. One is called Century, and the other is called Centinel.[24] These two lines of catalysts are reported to be 45 - 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 through better dispersion of the active metal on the catalyst substrate.

Thus, by itself, changing to a more active catalyst can reduce sulfur moderately. 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 4 years. Vendors have informed EPA that the cost of these advanced catalysts is very modest relative to less active catalysts. This will help to reduce the reactor size needed, but by itself would not appear to be sufficient for most refiners to meet a 15 ppm

The second type of improvement 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 15-20°C, or reduce final sulfur levels by more than two-thirds. UOP projects that scrubbing hydrogen sulfide from recycle hydrogen can reduce sulfur levels from roughly 285 to 180 ppm in an existing hydrotreater.

The third type of improvement which can be made to current distillate hydrotreaters 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 °C, which in turn would 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 25°C 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 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 would lower the temperature needed to achieve the same sulfur removal rate by eight to nine °C. Or 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 project 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 14°C while processing a mix of SRLGO and LCO with its advanced TK-574 CoMo catalyst will reduce sulfur from 120 ppm to 40 ppm.[25] UOP projects that a 20 °F 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 six 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 only decreases the necessary reactor temperature by six to eight °C. Or, temperature can be maintained and the final sulfur level reduced by 35-45 percent.

Seventh, reactor volume can be increased. UOP projects that doubling reactor volume would reduce sulfur from 120 to 30 ppm.

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 are probably indicative of improvements which can be made in many cases, it is not likely that all of the improvements mentioned are applicable to any one unit; the degree of improvement could either be greater than, or less than the benefits that are indicated.

Therefore, many refiners may have to implement one additional technical change listed by UOP to be able to meet the 15 ppm cap standard. This last technical change is to install a complete second stage to the existing, one-stage hydrotreater. 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 a higher pressure to be used in the new second reactor. 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 of these units are already operating in refineries but may have to be expanded or enlarged.

Overall, Akzo-Nobel projects that current hydrotreaters can be modified short of a revamp to achieve 50 ppm sulfur. Acreon/IFP/Procatalyse is less optimistic, believing that more than a catalyst change will be necessary to meet this sulfur level.[26] 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.[27] 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 reductions needed to meet a 15 ppm cap would require additional measures. To assess the degree that these measures would be needed, it is useful to examine the commercial and pilot plant performance of distillate hydrotreaters to achieve very low sulfur levels.

After reviewing the technology for desulfurizing diesel fuel, and discussing the advancements in catalyst technology, it is appropriate to turn to how refiners will invest to meet the 15 ppm cap standard. Refiners have a choice of continuing to use their existing distillate hydrotreater, or to not use that equipment and design an entirely new hydrotreater. As will be shown below, numerous commercial examples exist where existing hydrotreaters have been modified to improve their sulfur removal performance. The vendors of desulfurization technology assert that refiners can meet the 15 ppm cap standard by revamping their existing diesel hydrotreating units. However, several refiners we spoke to indicated that they foresee replacing one or more of their existing diesel hydrotreaters with a brand new "grassroots" unit. One refiner stated that they plan to use the idled units in other places in the refinery.

We gathered more information on whether refiners would revamp versus install a grassroots unit during a session on diesel hydrotreating at this year's NPRA Q & A conference. The refiners on the panel and in the audience were asked if they would scrap their existing diesel hydrotreaters to install a new grassroots unit if they were faced with the proposed EPA highway diesel standard. The response by one of the refiners was that refiners would not waste good capital units in the refinery, suggesting that the refiners would revamp their existing diesel hydrotreaters with additional capital. However the refiner went on say that some refiners may choose to convert their existing diesel hydrotreaters to gasoline hydrotreaters, or to processing nonroad diesel fuel, once any nonroad requirements are known, and then put in a grassroots unit for diesel hydrotreating. That responder supposed that a refiner might choose to scrap a unit if it "was very, very old," however, when considering the tone of the commenter's remarks, he implied that few refiners would indeed scrap their existing highway diesel hydrotreaters. Another refiner said that they currently are not producing as much highway diesel fuel as they would like and that they might build a grassroots unit which would allow them to expand their highway diesel production.

Charles River and Baker and O'Brien, in a study of the cost of desulfurizing diesel fuel for API, also considered the issue of revamps versus grassroots units.[28] The API contractors used a set of assumptions to estimate how many of the desulfurization units that would be built to meet a 15 ppm cap standard would be revamped units versus brand new grassroots units. An important assumption of their analysis is that to meet a 15 ppm cap standard, both the first and second stages of diesel desulfurization require moderate to high pressure (800 psi or higher) if LCO is present in the feed to be treated. They also assume that all diesel desulfurization units installed in 1993 to meet the 500 ppm highway diesel sulfur standard are capable of this pressure, while the units which were converted over from another service are not. Finally, the study assumes that a refinery with a hydrocracker is processing its LCO in the hydrocracker and not processing it in the diesel hydrotreater. Based on these assumptions, the study assumed a refiner would revamp a diesel desulfurization unit installed in 1993, and would revamp an older unit if the refinery had a hydrocracker. By deduction, the study assumed that the refineries which had converted an existing hydrotreating unit to diesel desulfurization service in 1993 but did not have a hydrocracker, would not revamp and put in a grassroots unit. According to API's contractors, this set of assumptions would result in about 60 percent of the refineries revamping their existing desulfurization units and 40 percent of the refineries putting in new grasssroots units. The contractors did not include the information which served as the basis for their assumptions about revamps versus grassroots in their final report, and when we asked API for the information, they would not share it with us.

A cost study was conducted by the National Petroleum Council in response to a request from the Department of Energy to study the cost of desulfurizing diesel fuel.[29] This study estimated the cost to desulfurize diesel fuel down to an average of 30 ppm. An assumption of the cost study was that current diesel hydrotreaters producing 50 percent of the highway diesel fuel would be retrofitted to meet a 30 ppm sulfur standard, while the other diesel hydrotreaters producing 50 percent of highway diesel fuel would be replaced by new grassroots units. Despite that this study analyzed a much less severe diesel sulfur standard, the study assumed that the industry would have to resort to more grassroots units than the API study.

We project that some refiners will put in new grassroots units. We believe that those refiners that put in grassroots units will do so because they can most economically meet the combination of the Tier 2 gasoline sulfur standard and this highway diesel sulfur standard by converting their existing diesel desulfurization unit to meet the gasoline sulfur requirement. Or, in a few cases, refiners will put in grassroots units because the unit is too old to operate reliably enough to produce diesel on a regular basis which meets the 15 ppm cap standard. However, when we compare the assumptions made in the API and NPC studies to our discussions with refiners and with the comments made by refiners at the NPRA Q & A meeting, we believe that the API and NPC assumptions are too conservative. Regardless of the operating pressure of their existing diesel desulfurization unit, refiners are able to desulfurize distillate down to under 500 ppm to meet the existing highway diesel sulfur standard, a sulfur reduction on the order of 95 percent. In meeting a 15 ppm cap standard, this existing sulfur reduction would provide an important first stage reduction for meeting a 15 ppm sulfur cap standard. We also believe that refiners would not have much to gain by replacing this first stage with a higher pressure first stage. After considering the comments made by the refiners at the NPRA Q & A meeting, the comments made by vendors, and considering that there are few compelling reasons for going with a grassroots unit, we project that the percentage of refiners putting in grassroots units will be between 10 to 30 percent. For our cost analysis we used the average of this range, which is 20 percent.

c. Low Sulfur Performance of Distillate Hydrotreating

Data from both pilot plant studies and commercial performance are available which indicate the capability of various hydrotreating technologies to reduce distillate sulfur levels to very low levels. While many studies are available which focus on reducing sulfur to 500 ppm or below, studies of achieving lower sulfur levels (e.g., 10-50 ppm) also focus on reducing aromatics 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 cap.

Reducing aromatic content along with sulfur content is generally desirable with respect to diesel fuel quality, as aromatic reductions increase cetane levels and generally improve combustion characteristics. However, reducing aromatics consumes hydrogen and increases the cost of desulfurization relative to a case where only sulfur was being removed. A number of catalyst and engineering firms have projected the technology necessary to just reduce sulfur without a mandated aromatics reduction (and its cost) for EPA, the Engine Manufacturers Association, the American Petroleum Institute, the National Petroleum Council and others. These projections will be discussed in the next chapter on the economic impacts of this rule. 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 recent 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 advancements by catalyst manufacturers demonstrating the feasibility of producing diesel fuel which meets these levels through pilot plant testing should be considered a first-generation of technology, with new and continual advancements expected over time.

Starting with SynTechnology, as of August 2, 1999, there were 24 units either in operation or in the process of being constructed. Their purposes range from desulfurization to desulfurization plus dearomatization to mild hydrocracking. Of particular interest here is a revamp of an existing two reactor distillate hydrotreater at the Lyondell / Citgo refinery in Texas.

The revamped unit was designed to process a low-cost feed very heavily weighted towards cracked material (65-70 percent LCO and LCGO). One existing reactor was converted to SynSat Technology, while the other was used simply as a flash drum. A new first-stage reactor was added. Both reactors were designed to operate in a co-current fashion. Pilot plant studies predicted average sulfur and aromatics levels of seven ppm and 31 volume percent, respectively, based on feed sulfur and aromatics levels of 11,900 ppm and 53 volume percent, respectively. The unit exceeded expectations in the case of sulfur, producing an average sulfur level of less than five ppm from a feed sulfur level of 13,800 ppm. The actual aromatic level achieved was above the target by four volume percent, but the feed aromatic level was five volume percent higher than expected. Thus, the net reduction in aromatic content in terms of volume percent was still higher than found in the pilot plant. ABB Lummus and Criterion indicate that their catalyst technology is sufficiently flexible to focus on the deep desulfurization with or without the significant aromatics reduction seen here. This is reflected in their projection of the technology needed to meet a 15 ppm sulfur cap which is discussed in the next chapter.

While this two-stage unit initially produced less than 5 ppm product, it does not do so consistently. The primary purpose of the unit is to increase cetane so that the product can be blended directly into diesel fuel. The primary sulfur reduction requirement is to protect the noble metal catalyst in the second stage reactor. This generally requires that the product from the first stage be less than 50 ppm. Thus, if the cetane specifications are being met at less severe conditions, there is no incentive to reduce sulfur any further than necessary for catalyst protection. In addition, the unit is seeing a heavier feedstock than designed, and the desulfurization reactor is being operated at a lower temperature than designed to increase the cycle lengths.

IFP, in conjunction with various catalyst manufacturers, offers its Prime D technology for deep desulfurization, aromatics saturation and cetane improvement.[30] Using a NiMo catalyst, IFP's Prime D process can produce distillate sulfur levels of 10 ppm from SRLGO and of less than 20 ppm from distillate containing 20-100 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.[31] 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, essentially eliminate nitrogen and reduce aromatics to two to five volume percent. Hydrogen consumption was 800-971 standard cubic feet per barrel (SCFB).

Akzo Nobel recently presented a summary of the commercial experience of about a years worth of operations of their STARS catalyst for desulfurizing diesel fuel at the BP-Amoco refinery in Grangemouth, UK.[32] 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[c] into the reactor to produce 45,000 barrels per day diesel fuel at 10 - 20 ppm (to meet the 50 ppm cap standard). From the data, it was clear to see that as the space velocity changed, the sulfur level changed inversely 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.

These studies indicate the commercial feasibility of producing diesel fuel with 10 ppm or less sulfur. The primary issue remaining is to commercially demonstrate that the 15 ppm cap standard can be met using the desulfurization/hydrogenation method without saturating much of

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

the aromatics in diesel fuel, especially with a feedstock blend which contains a substantial amount of cracked material. The ease or difficulty of accomplishing this depends on the amount of cracked stocks that the refiner blends into diesel fuel and the possibility of shifting some of the sterically hindered compounds to fuels complying with less stringent sulfur standards, such as off-highway diesel fuel and heating oil.

d. Undercutting Cracked Stocks

The primary stumbling block preventing the simple desulfurization of 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. These compounds are aromatic in nature, and are found in greatest concentration in 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, it is better economically if this can be avoided. Because these compounds are inherently large in molecular weight due to their chemical structure, they distill near the high end of the diesel range of distillation temperatures. Thus, it is possible to segregate these compounds from the rest of the cracked stocks via distillation and avoid the need to desulfurize them.

Once separated, this LCO material could be mixed into the refinery streams currently being used to produce off-highway diesel fuel and heating oil. These fuels would still have to meet applicable quality specifications, such as cetane, density, sulfur and distillation. For example, the industry specification for non-road diesel fuel is a minimum of 40 cetane number, and a maximum sulfur concentration of 5,000 ppm.[33] An analysis of off-highway diesel fuel shows that off-highway diesel fuel averages 44.4 cetane number, 3,300 ppm sulfur, 34.5 API gravity, T10 of 438 °F, T50 of 517 °F, and T90 of 600 °F.[34] We anticipate that refiners would need to use cetane additives to compensate for the addition of LCO to maintain off-highway fuel cetane levels similar to those of current in-use fuels (see Section V). Additional cold-flow additives might also be necessary for off-highway diesel fuel in the winter to maintain cold-flow performance at current levels. We anticipate that refiners would allow other off-highway and heating oil properties to change as a result of the addition of LCO, while continuing to ensure that all specifications on these fuels are met.

Shifting LCO to off-highway diesel fuel and heating oil would prevent the need to desulfurize a sizeable fraction of the sterically hindered compounds currently present in highway diesel fuel. For example, Akzo Nobel studies indicate that a drop of 10 ºC in the 95th percentile distillation point (T95) of diesel fuel decreases sulfur from 50 - 60 ppm.[35] Of course, such a shift to non-highway diesel fuel markets would decrease the amount of highway diesel fuel produced, about 3 percent for the typical refinery, if more easy to hydrotreat material was not switched from non-highway diesel fuels to the highway diesel fuel pool. A decrease of T95 of this magnitude effected by undercutting only LCO would decrease sulfur even more because the sulfur levels in the heaviest portions of LCO are much greater than those in SRLGO and are the most difficult to desulfurize. Shifting only heavy LCO would increase the sulfur reduction per volume of highway diesel fuel lost, but would still result in a net loss of highway diesel fuel production if no other feedstocks replaced it.

While this heavy LCO material could be shifted to other markets, this does not necessarily have to be the case. Under certain conditions, this material can be recycled to the FCC unit.[36] For this to be feasible, the refiner must hydrotreat the FCC feed at a pressure sufficient to desulfurize the sterically hindered sulfur containing compounds and the feed hydrotreater must have sufficient excess capacity to handle the additional material. This material could also be sent to an existing hydrocracker, if sufficient capacity existed, and converted into gasoline blendstock. Or, it could be hydrotreated separately under more severe conditions to remove the sulfur, such as with SynAlliance's SynShift process. This would entail higher hydrogen consumption per barrel of treated material because of some aromatic saturation. However, the amount of material being processed would be small, so overall hydrogen consumption would still be low.

A number of vendors of distillate desulfurization processes recently developed specific projections of the technology needed to meet a range of highway diesel fuel sulfur levels. These projections were developed to support refining cost studies conducted by the Engine Manufacturers Association and the American Petroleum Institute, and the National Petroleum Council.[d] These projections addressed compliance with three different average sulfur levels: 10, 30 and 100 ppm. Generally, these projections indicate that it will be possible for refiners to meet the 10 ppm average sulfur level without resorting to catalysts and operating conditions which reduce aromatic levels dramatically. Thus, it appears that the cost of providing sufficient hydrogen to saturate these aromatics can be avoided. The specifics of these projections will be addressed in more detail in the next chapter.

6. Other Desulfurization Technologies

a. Biodesulfurization

Biodesulfurization is essentially an alternative to distillate hydrotreating. This process is being developed by Energy Biosystems. It involves the removal of sulfur-containing hydrocarbon compounds from distillate or naphtha streams using bacteria. The distillate stream is first mixed with an aqueous media containing the bacteria, caustic soda and nutrients for the bacteria. Enzymes in the bacteria first oxidize the sulfur atoms and then cleaves some of the sulfur-carbon bonds. The sulfur leaves the process in the form of hydroxyphenyl benzene sulfonate, which can be used commercially as a feedstock to produce surfactants. Designs based on pilot plant studies combine biodesulfurization with conventional hydrotreating to produce diesel fuel containing 50 ppm sulfur.

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[d] See Chapter V for additional discussion on these projections.

b. Chemical Oxidation and Extraction

Another desulfurization technology was announced by Petrostar this year which desulfurizes diesel fuel using chemical oxidation.[37] 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 catalyzed peroxyacetic acid. With an oxygen atom attached to the sulfur atom, the sulfur-containing hydrocarbon molecules becomes polar and hydrophilic and then move into the aqueous phase. Like biodesulfurization, some of the sulfones can be converted to a surfactant which could be sold to the soap industry at an economically desirable price. The earnings made from the sales of the surfactant would offset much of the cost of oxidative desulfurization.

We are aware of another chemical oxidation process which currently is in the patenting process. This process is similar to the Petrostar process, except instead of keeping the sulfone intact, this process separates the oxidized sulfur atom from the hydrocarbon immediatly after the oxidation reaction. The resulting sulfate is easily separable from the petroleum. While this process does not create a valuable byproduct, it would likely be a less capital intensive means to make the sulfur separation than the Petrostar process.

c. Sulfur Adsorption

A prospective diesel desulfurization process was recently announced by Phillips Petroleum.[38] This process is an extension of their S-Zorb process for gasoline. S-Zorb for diesel contacts highway diesel fuel (typically with about 350 ppm sulfur) with a catalyst in a reactor at relatively low pressures and temperature in the presence of hydrogen. The sulfur atom of the sulfur-containing compounds adsorbs onto the catalyst. The catalyst next cleaves the sulfur atom from the sulfur-containing hydrocarbon. To prevent the accumulation of sulfur on the catalyst, the catalyst is continually removed from the reactor. In a separate regeneration vessel, the sulfur is burned off of the catalyst and is sent to the sulfur plant. The regenerated catalyst is then recycled back to the reactor for removing more sulfur. Because the catalyst is continuously being regenerated, the catalyst should never force the unit to be shutdown, thus, Phillips estimates that the unit will be able to operate 4 - 5 years between shutdowns. Because untreated distillate can contain several percent sulfur, Phillips believes that its S-Zorb process for diesel could get overwhelmed by the amount of sulfur which is adsorbing onto the catalyst. Thus, the S-Zorb process may not be able to treat untreated distillate streams, but would likely be used to treat distillate containing 500 ppm sulfur or less.

Phillips' diesel desulfurization process has only been demonstrated in the laboratory up to this point. The laboratory testing has shown that diesel with LCO can be desulfurized down below 5 ppm. However, Phillips is on the fast track to demonstrate this process in a pilot plant and in a commercial unit. First, the company reports that its S-Zorb commercial demonstration unit for gasoline is on schedule to startup the first quarter of 2001. Since the process has never been demonstrated commercially, this demonstration unit will go a long way toward proving that the Phillips process works as designed. However, the sulfur compounds in diesel fuel are different, usually more refractory, than those in gasoline. Phillips reports, though, that the absorption catalyst more readily desulfurizes the sterically hindered sulfur compounds than the thiophenes (single ring compounds which contain sulfur) which must be desulfurized in gasoline. This suggests the possibility that S-Zorb for diesel may actually desulfurize current highway diesel fuel more easily then S-Zorb for gasoline. Phillips projects that they will have an S-Zorb diesel desulfurization pilot plant up and running by the third quarter of 2001, and a commercial unit up and running during the fourth quarter of 2003. After hearing Phillips' timeline for developing the S-Zorb diesel desulfurization process, and weighing the uncertainty associated with S-Zorb, it seems that refiners may consider this process too risky for 2006. However, this process could be far enough along in its development to be used by refiners in 2010.

d. FCC Feed Hydrotreating

At the beginning of Section 3., it was mentioned that sulfur could be removed from distillate material early or late in the refining process. Early in the process, the most practical place to remove sulfur early in the process is prior to the FCC unit. The FCC unit primarily produces gasoline, but it also produces a significant quantity of distillate, called LCO as described in Section A.1 above. LCO is high in aromatics and sulfur and contains a relatively high fraction of the sterically hindered sulfur compounds found in diesel fuel.

Many refineries already have an FCC feed hydrotreating unit. The LCO from these refineries should contain a much lower concentration of 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. 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. Economically, it 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 a more economical than distillate hydrotreating. However, these benefits are difficult to estimate in a nationwide study such as this. Thus, this study will rely on distillate hydrotreating as the primary means with which refiners would meet the 15 ppm sulfur cap. For those refiners who would choose FCC feed hydrotreating, their costs would be presumably lower than distillate hydrotreating and the costs estimated in the next chapter can then be considered to be somewhat conservative in this respect.

7. Will There Be Enough Supply of Highway Diesel Fuel?

First, in assessing the cost of desulfurizing highway diesel fuel, we began with the assumption that sufficient desulfurization equipment would have to be constructed to adequately supply diesel highway vehicles, as well as other users of highway diesel fuel. We examined historic production and demand of highway diesel fuel, factored in growth per estimates by EIA, and determined that amount of highway diesel fuel which would have to meet the 15 ppm cap both during and after the initial period during which the temporary compliance option and various hardship provisions are in effect.

The issue of future supply of highway diesel fuel was raised in the NPRM and received considerable attention during the comment period. Numerous commenters to the proposed rule indicated that they believed that the 15 ppm sulfur cap would cause shortages in highway diesel fuel supply. A number of commenters also thought otherwise (i.e., that future supplies would be adequate). These comments are summarized in Section 8.1.1 of the Response to Comments document for this rule. The factors which affect refiners' decisions on how much 15 ppm diesel fuel to produce fall into the following categories:

- Required investment per refinery
- Historic refining profit margins
- Variation in compliance costs between refiners
- Other markets for highway diesel fuel
- Uncertainty in requisite desulfurization control technology
- Likely price and import response to new sulfur standard
- Impact of desulfurization processes on fuel volume, and
- Impact of fuel transport on fuel supply

Each of these factors is addressed below. In addition, the findings of a study performed by Charles River Associates and Baker and O'Brien for API concerning the potential supply impacts of the new sulfur standard are discussed at the end of this section.

a. Required Investment per Refinery

The first issue is that the level of investment per refinery required to meet this diesel sulfur standard is more than that required to meet the recent Tier 2 gasoline sulfur standard. This is true. We projected that it would cost $44 million per refinery to meet the Tier 2 gasoline sulfur standards, while we project that it will cost $50 million per refinery to meet the diesel fuel sulfur cap. In addition, this $50 million figure represents the average of revamped units (which will cost less) and new units (which will cost more). Revamping an existing diesel hydrotreater (representing roughly 80 percent of all current units) will cost roughly $40 million, while a new diesel hydrotreater will cost $80 million. Thus, roughly 25 refineries will face twice the investment cost to meet this diesel standard as they did to meet the Tier 2 gasoline sulfur standards.

This difference in investment is to be expected. Nearly all of the sulfur in gasoline is contained in the naphtha (material boiling in the gasoline boiling range) produced in the fluidized catalytic cracker (FCC). Generally, this is the only material which needs to be hydrotreated in order to meet the 30 ppm average sulfur standard. In contrast, all diesel blendstocks, except for that from a hydrocracker (4 percent of all blendstocks) will need to be hydrotreated in order to meet the 15 ppm cap. Refiners produce roughly the same volumes of FCC naphtha and highway diesel fuel. However, diesel fuel desulfurization requires much higher temperatures and pressures, and the material must be in contact with the catalyst for longer periods of time, so the capital investment per unit volume of treated material is much higher. Finally, because refineries make 3-4 times as much gasoline as highway diesel fuel, the investment per gallon of finished fuel is 3-4 times higher for diesel fuel.

This higher investment per unit volume of product means that refiners will be putting more investment at risk relative to potential profit in the case of diesel fuel than gasoline. As will be discussed further below, the market sometimes allows refiners to recoup their full cost of meeting environmental standards (operating plus capital costs) and sometimes only allows them to recoup operating costs. The greater level of investment per unit volume of product means that refiners would have to cover 3-4 times the investment cost per gallon of fuel if the market does not reward them with a price increase which allows the recovery of capital plus a reasonable return on this investment. Directionally, this means that refiners will look much more closely at the market situation for diesel fuel before making the investment to meet the 15 ppm standard. In particular, refiners are likely to carefully assess their competitors' actions to ensure that significant overcapacity does not exist, which decreases refining margins.

The second issue is that, of late, relatively poor refining margins have not allowed refiners to recoup the full cost of environmental standards. Two examples are the 500 ppm sulfur diesel fuel standard and the RFG standards. In both cases, over-investment by the refining industry led to over-supply of these fuels and low prices.

b. Historic Refining Profit Margins

Over the past year, refining margins have improved dramatically. Domestic refineries are operating at full practical capacity and are expected to do so for the foreseeable future. Thus, the market may have begun a long term period where refining margins will be strong and reward refiners who invest in additional capacity. Refiners also know that even slight shortages in highway diesel fuel supply would lead to significant price increases and substantial profits for those in the market. Thus, as always there will be a tension between wanting to invest and reap the rewards of a potentially short market and the concern over over-investment and the inability to recover investment. The large investment per unit volume of product will make this a more difficult situation to balance than in past regulatory requirements. However, the temporary compliance option will help counter this difficulty, as it will allow many refineries currently producing highway diesel fuel to delay their investment until 2010. Thus, refiners who are in a better financial position to take the financial risk involved in such a significant investment can do so, while those which are not in as good a position can wait until 2010, buying credits in the meantime.

c. Variation in Compliance Costs Faced by Refiners

The third issue related to supply is the range of costs faced by refiners in complying with the diesel sulfur standard. Our refinery by refinery analysis indicates that refineries face a wide range of compliance costs. If each refinery currently producing highway diesel fuel invests to just maintain their current production, costs range from under 3 cents per gallon to under 12 cents per gallon. It is probably unreasonable for a refiner to expect the market to allow a long term increase in the price of diesel fuel of 12 cents per gallon.[e] However, our refinery model also indicates that some refineries can produce 15 ppm diesel fuel from their current nonroad diesel fuel blendstocks more cheaply than many refineries which currently produce highway diesel fuel.

In assessing where the additional volume of nonroad diesel fuel blendstocks would come from, we considered both refineries which produce both highway and nonroad diesel fuel today, as well as refineries which only produce nonroad diesel fuel. Based on the volume and characteristics of each refinery's nonroad diesel blendstocks, we projected which refineries could increase production of highway diesel fuel most economically. We found that many refineries could increase production of highway diesel fuel from blendstocks currently used to produce nonroad diesel fuel as or more economically than many refineries currently producing highway diesel fuel. Thus, there appears to be a plentitude of distillate blendstocks available from which to produce highway diesel fuel.

In addition to requiring that these nonroad diesel fuel blendstocks be processed to compensate for the loss of highway diesel fuel during production and distribution, we also allowed highway diesel fuel produced form these nonroad diesel fuel blendstocks to supplant highway diesel fuel produced at refineries facing higher desulfurization costs. The following table presents the maximum cost in each PADD before and after this adjustment. It should be noted that shifts of fuel production across PADDs were very limited. No transfers were allowed into or out of PADDs 4 and 5. PADD 3 was allowed to increase fuel shipments to PADD 1 and to the southern portion of PADD 2. No shifts were allowed between PADDs 1 and 2.

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[e] A few small refiners are among those facing higher compliance costs. Many of these refiners are expected to take advantage of EPA's option to delay their compliance with the Tier 2 gasoline sulfur standards. This delay in their gasoline related investment and operating costs will allow these refiners to recoup their diesel fuel-related investment with a much lower price increase than would otherwise be the case.

Table IV.A-7. Maximum Cost of Meeting the 15 ppm Cap (cents per gallon) [A]

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5 [B]*
All Current Highway Diesel Fuel Producers Continue to Produce					
2006-2010	4.8	4.6	4.2	5.5	4.3
2010 and beyond	9.6	9.7	11.9	9.1	8.9
With Minor Shifts in Production Between Highway and Nonroad Diesel Fuel					
2006-2010	4.8	4.6	4.1	5.5	4.3
2010 and beyond	5.5	7.4	5.1	8.2	5.1

[A] Excludes small refiners which we project would chose to produce 100% 15 ppm diesel fuel in 2006 and in return would be granted a three-year extension in meeting the Tier 2 gasoline sulfur standards.[f]
[B] Excludes Hawaii and Alaska, where maximum costs are 4.8-5.3 cents per gallon.

The difference between the maximum costs during the initial years are nearly identical regardless of whether shifts between highway and nonroad diesel fuel production occur. However, greater differences appear when the entire highway diesel fuel pool must meet the new standard. This occurs because it appears that a very small fraction of current highway diesel fuel production faces very high desulfurization costs, primarily because of extremely low production volumes (i.e., poor economies of scale). By shifting only 1.4 percent of current highway diesel fuel volume to nonroad diesel, the reductions in the maximum costs shown in bottom line of Table V.C-3 occur. Thus, only a very small percentage of current highway diesel fuel production volume faces costs well above the average. Likewise, it appears that ample highway diesel fuel can be produced from nonroad diesel fuel blendstocks at reasonable costs. The costs to produce highway diesel fuel from nonroad diesel fuel blendstocks assume the use of two-stage, conventional hydrotreating. Costs for those refineries not meeting the new standard until 2010 could be much lower if novel, lower cost technologies, such as Phillip's SZorb process perform as well as expected.

Also discussed in Chapter 5 of this RIA, the temporary compliance option allows a large number of refineries, roughly up to 58, to delay production of 15 ppm diesel fuel until 2010.

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[f] These refiners were excluded because the three-year delay in meeting the Tier 2 gasoline sulfur standards provides these refiners with economic benefits which can be used to compensate for the cost of meeting the 15 ppm diesel fuel sulfur cap. Thus, the actual cost of meeting the diesel sulfur cap is lower than indicated by our refinery model, which only considers the cost of diesel fuel desulfurization.

(This presumes that the roughly 63 refineries investing in desulfurization equipment in 2010 and producing 100 percent 15 ppm diesel fuel make their credits available to these other refineries.) First, these 58 refineries will be able to observe the performance of the various technologies selected by the other 63 refineries for almost 2 years before making final decisions regarding the technology they will utilize. Second, they will be able to observe the reaction of the market to the new fuel, particularly demand for use in older vehicles and to some degree, prices. However, prices during the initial years will likely differ from those once the program is fully implemented. This brings us to the third benefit of the temporary compliance option, small refiner hardship, and GPA provisions.

As indicated in Table IV.A-7, the refineries producing 15 ppm diesel fuel in 2006 should face lower costs than those delaying production until 2010. This difference in compliance cost is primarily due to lower capital-related costs. Since the biggest risk facing a refiner is the possibility that the market price increase after the implementation of the new standard will not allow the recovery of both operating and capital costs, the lower the capital cost, the lower the risk that substantial amounts will not be recovered. Also, the 75 or so refineries will only be able to delay investment until 2010 if they buy credits from those producing more than 70 percent of their highway diesel fuel under the 15 ppm cap. Thus, these 75 refineries will be subsidizing the cost of producing the 15 ppm fuel through the purchase of credits. The net cost of producing both 15 and 500 ppm fuels should be the same. This is illustrated by the following example.

Assume refinery A produces 70,000 bbl/day of highway diesel fuel, all meeting the 15 ppm cap. Also assume that the cost of meeting the new standard is 4 cents per gallon. Refinery B produces 30,000 bbl/day of highway diesel fuel meeting the 500 ppm cap. Its costs do not change from today. Refinery A generates 21,000 bbl/day of credits, while refinery B needs 21,000 bbl/day of credits. The two refiners will negotiate a price for the credits, which will be a function of how many other sources of credits are available. However, if we assume that Refinery A is willing to sell its credits at cost, then Refinery A will sell 21,000 bbl/day of credits at 4 cents per gallon. Since 21,000 bbl/day represents 30 percent of its production, selling these credits reduces Refinery A's average cost to 2.8 cents per gallon. Refinery B, on the other hand, paid 4 cents per gallon for 70 percent of its production. Thus, its average cost is 2.8 cents per gallon; the same as Refinery A's average cost.

This example demonstrates that with credit trading, the refining costs of both 15 and 500 ppm fuels should be roughly the same. This should lead to the two fuels having similar prices at retail where both fuels are sold. In fact, given that 15 ppm will be the dominant fuel being produced and needs to be distributed throughout the U.S., it will likely be transported by pipeline. 500 ppm fuel, on the other hand, need not be distributed everywhere, since all vehicles can burn the 15 ppm fuel. Thus, distribution of 500 ppm fuel may be concentrated around refining areas and along major pipeline corridors. The price of 500 ppm fuel is likely to be slightly lower than that of 15 ppm fuel in these areas to encourage older vehicle owners to buy

500 ppm fuel and minimize the areas to which the 500 ppm fuel must be distributed. Thus, the risk of a large price differential encouraging misfueling should be low.

The temporary compliance option also makes this diesel fuel program more similar to the RFG program wherein not every refiner need participate, at least for the initial years. By the time that refiners need to make their final decisions on whether to construct new equipment in time to meet the new standard by 2010, the desulfurization units built for 2006 will have been operating for at least one year. This will give refiners evaluating compliance for 2010 considerable confidence in both the cost and performance of the technologies which are available. These refiners will also be able to observe the response of the market to the new fuel in terms of price. While we project that the price of 15 ppm fuel will be very similar to the price of 500 ppm fuel at refinery gates, this is due to the credit trading system. We expect that the price of both fuels will increase with the implementation of this rule. Knowledge of the cost and performance of the desulfurization technology and this market response to the new fuel should be particularly helpful to refiners needing to borrow money to fund the new equipment.

d. Other Markets for Highway Diesel Fuel

Current highway diesel fuel easily meets the specifications for nonroad diesel fuel or heating oil. However, the market for these other distillate fuels is not large enough, nor growing fast enough to absorb much highway diesel fuel. Plus, the highway diesel fuel market is currently in balance, so any decrease in domestic supply would have to made up by imports.

In order to assess the potential for refiners to sell their current highway diesel fuel or some of the blendstocks used to produce highway diesel fuel into alternative markets, EPA contracted with SwRI and Muse, Stancil to assess these other markets. Muse, Stancil found that refiners would have very limited possibilities of disposing of highway diesel fuel or its blendstocks domestically. Only PADD 1 imports significant quantities of nonroad diesel fuel or heating oil. Refineries in PADD 1 could produce more of this fuel and back out imports. However, refineries in other PADDs would have to export any fuel which they back out of the highway diesel fuel market. Based on historical prices (i.e., highway diesel fuel priced under the 500 ppm sulfur standard) , Muse, Stancil estimates that refiners outside of PADD 1 would lose 3-6 cents per gallon in revenue if they shift even 5 percent of their highway diesel fuel to the nonroad diesel fuel market. These losses increase to 4-20 cents per gallon if they shift over 5 percent of their current highway diesel fuel to these alternative markets. Refiners in PADDs 2 and 4 would be particularly hard pressed, as they would have to ship their product to the US Gulf Coast prior to exportation. This adds significant transportation costs, as there are no pipelines flowing from PADDs 2 or 4 to the Gulf.

Should refiners shift highway diesel fuel production to these other markets, it will not only affect the price of the shifted product. The price of all nonroad diesel fuel and heating oil will drop. Refiners trying to sell their highway fuel into these other markets will try to sell it locally prior to exportation. These refiners will compete with those currently producing nonroad diesel fuel and heating oil, depressing prices in the entire market. Despite lower prices, fuel demand will not increase substantially, since the use of nonroad equipment is a very weak function of fuel price. (For example, fuel costs are a small portion of the total cost of farming, mining and construction, so one would not expect that the demand in these sectors of the economy would be very responsive to fuel price.) Thus, refiners planning on shifting their highway fuel to alternative markets will not only have to consider the decrease in market value of the shifted product, but also the drop in value of their existing nonroad fuel and heating oil production. This added cost of a drop in highway diesel fuel production would vary widely from refinery to refinery since some refineries produce much more nonroad diesel fuel than highway fuel and vice versa.

This loss in market price serves as a discouragement to shift highway diesel fuel to these other markets. It basically provides refiners with a second reward for investing in desulfurization equipment in order to stay in the highway diesel fuel market. First, investment allows them to obtain the price rise of highway diesel fuel which should accompany the new sulfur standard to be achieved. Second, investment allows the price drop associated with export to be avoided, as well as reduces the potential for a drop in value in existing nonroad diesel fuel production. (This last factor is a function of other refiners' decisions, as well, in this area.) Thus, a refiner should desire to invest in meeting the new standard if he believes that the price increase in highway diesel fuel will be at least the cost of meeting the standard minus the loss associated with export. For example, if it costs up to 7 cents per gallon to meet the 15 ppm standard, then the required price increase in highway diesel fuel price may only need to be 3 cents per gallon for refineries to prefer meeting the 15 ppm standard versus taking a loss in the nonroad market of 5 cents per gallon (ignoring any price drop for existing nonroad diesel fuel production). The lack of a ready domestic alternative market for their product appears to be a strong discouragement to refiners shifting their production away from highway diesel fuel.

e. Uncertainty in Requisite Desulfurization Technology

The next factor which could affect highway diesel fuel supply is uncertainty in what technology will be required to meet the 15 ppm standard. As discussed in Section 8.1.2 below and in the RIA, uncertainty does exist concerning the requisite desulfurization technology. Most vendors project that two-stage conventional hydrotreating at low to moderate hydrogen pressure will be sufficient to achieve the new standard, even with significant quantities of LCO. Most refiners commenting on the rule, plus 1-2 vendors believe that moderate to high pressures will be needed, accompanied by more aromatic saturation and hydrogen consumption. In addition, Phillips Petroleum just announced that they have developed a new, low pressure process which promises to consume no hydrogen. This process cannot yet be licensed, but Phillips hopes to begin licensing next year. However, a commercial unit utilizing this technology will not start up until 2004.

The uncertainty in current technology which will be necessary to achieve the new standard could encourage some refiners to delay investment until the latest possible time while still allowing time to build their equipment in time for the 2006 implementation date. The promise of lower costs based on refiner's experience meeting the new standard in 2006 or with the new Phillips technology could encourage refiners to delay the construction of new equipment until beyond the 2006 implementation date. In some cases, particularly refiners located in isolated areas where hydrogen costs are high, the promise of lower long term compliance costs in one to two years could be preferable to the lower revenues obtained from selling highway diesel fuel into the nonroad diesel fuel market in the short term.

Countering the benefit of more leadtime with respect to conventional hydrotreating technology is the fact that vendors will have 2-3 years to generate both pilot plant and commercial data to convince refiners of the efficacy of their processes. While no refiners are currently required to meet a 15 ppm cap prior to 2006, numerous two-stage (and low space velocity one-stage) hydrotreating units exist world-wide. Vendors and refiners are likely to utilize these units to demonstrate their catalysts commercially. This is already being done with some units in Europe. Thus, the largest detriment to investing to meet the new standard in 2006 is the potential cost savings associated with novel technologies such as Phillips' SZorb. These technologies are sufficiently different from conventional hydrotreating that refiners are likely to require full-size commercial operation for a year or two prior to betting tens of millions of dollars on their effectiveness. With the temporary compliance option, refiners able to delay investment until 2010 should be able to utilize the newer technologies, such as SZorb.

f. Likely Price and Import Response to the New Standard

Moving onto the likely price increase which will accompany the new standard, it is very difficult to predict whether the future market price of highway diesel fuel will increase enough to cover only operating costs or operating plus capital costs. No one can predict future prices, so the real issue is what refiners project the price increase will be at the time they need to invest in order to meet the new standard. As mentioned above, the 1990's were not good to refiners; refining margins were poor. Refiners generally did not recover their capital investments which were associated with environmental programs.

However, the demand for fuel continues to grow and domestic refinery capacity is growing at only about half the rate of growth in demand. Imports of finished fuel, including highway diesel fuel are increasing. Also, refining margins during the past year have been excellent for most refiners. Integrated oil company profits have also been at record levels. The net income of individual major oil companies over the 2nd and 3rd quarters of 2000 (e.g., ExxonMobil) was sufficient to fund all of the capital investment associated with this rule. If these refining margins continue for any appreciable amount of time, the availability of capital should not be an issue, even considering other environmental programs facing refiners. These include the Tier 2 gasoline sulfur requirements and NESHAP standards for FCC units, reformers and sulfur plants. We analyze the combined capital investments associated with the gasoline and diesel fuel sulfur programs later in this chapter of the RIA. There, we found that the level of capital investment per year will be lower than that occurring in the early 1990's, when most of the programs associated with the Clean Air Act of 1990 were being implemented and when refining margins were low. Thus, from an industry wide perspective, the availability of capital should not be a problem. The temporary compliance option helps this situation substantially. A few individual refiners could have difficulty raising sufficient capital to meet the new diesel sulfur standard. We have included hardship provisions in this rule to accommodate at least some of these situations. In addition, as discussed above, not every refiner currently producing highway diesel fuel will need to continue to do so in order to meet future demand.

Overseas refiners may not be as able to produce diesel fuel under the new 15 ppm cap, as they have been under the current 500 ppm cap. The three largest exporters of diesel fuel to the U.S. are Canada, the Virgin Islands and Venezuela. The Canadian refineries which export to the U.S. are located in the far eastern portion of Canada and send the vast majority of their production to the U.S. The same is true of the largest Virgin Island refinery, which has U.S. ownership. These refineries look to the U.S. as their main market. Thus, they are as likely to invest to meet the new standard as any domestic refinery. Venezuelan refineries are in a somewhat better position to send their diesel fuel elsewhere and could be less likely than domestic refiners to invest in new desulfurization equipment. At the same time, Europe and Japan are implementing 50 ppm diesel sulfur caps and Europe is already considering a 10 ppm cap. Thus, export oriented refineries world-wide will have to invest to at least meet a 50 ppm cap and will likely prepare for even lower standards. Even a refinery designed to produce 50 ppm sulfur diesel fuel is capable of producing some 15 ppm fuel. This may require reducing volumetric throughput or cutting the endpoint of its most difficult to hydrotreat blendstocks. However, such refineries should be able to send diesel fuel to the U.S. even if they do not design to do so on a regular basis. Several overseas refiners are likely to closely observe the investment patterns of U.S. refineries to assess the economics of exporting their diesel fuel under the new standard.. Thus, overall, exporting fuel to the U.S. will be more difficult under the new standard, but supplies should be available if necessary. Again, the temporary compliance option helps this situation by allowing importers to import three gallons of 500 ppm fuel for every seven gallons of 15 ppm brought into the country.

g. Impact of Desulfurization Processes on Fuel Volume

Conventional desulfurization processes both reduce the physical and energy density of diesel fuel. Desulfurization actually increases the volume of diesel fuel produced, but each gallon of diesel fuel contains less energy. Overall, the total amount of energy leaving the hydrotreater in the form of diesel fuel decreases by roughly 1.5 percent. Vehicular fuel economy is directly proportional to fuel energy density. Thus, in order in to provide the same number of vehicle miles, refineries will need to increase the volume of blendstocks which they process by

1.5 percent. As discussed in Chapter 5, our cost projections consider this loss of diesel fuel volume in assessing the hydrotreating capacity needed by refiners.

In terms of supply, the effect is much less. Most of the energy lost to diesel fuel is in the form of naphtha or LPG. This increases the refinery's production of these products. This allows the refinery to make other adjustments which increase diesel fuel production at the expense of gasoline, bringing the net production of both products back into balance.

h. Impact of Fuel Transport on Supply

The final factor potentially affecting supply is the possibility that 15 ppm diesel fuel produced at a refinery will be contaminated during shipment and becoming unsuitable for use in 2007 and later highway vehicles. As discussed in Chapter 5 of this RIA, we expect refiners to produce diesel fuel with an average of 7 ppm under the new standard. However, some batches are likely to be higher than this. Pipelines are likely to set their own limits below 15 ppm (e.g., 10 ppm). This means that diesel fuel can only pick up 5 ppm sulfur during distribution, given the testing allowance provided in the final rule. As also discussed in Chapter 5, we estimate that current loss of highway diesel fuel to nonroad diesel market of 2.2 percent will double to 4.4 percent. This increases the production requirements for 15 ppm diesel fuel, but not for total diesel fuel, since the volume lost during distribution can be used as nonroad diesel fuel or heating oil.

As was done for the volume lost during hydrotreating, we considered that refineries would have to process 2.2 percent more diesel fuel blendstocks to produce enough highway diesel fuel to account for losses in the distribution system. This additional volume of blendstocks came from blendstocks currently being used to produce nonroad diesel fuel and heating oil.

i. Charles River Associates and Baker and O'Brien Study

The study by Charles River Associates (CRA) and Baker and O'Brien, which was commissioned by API, assessed refiners ability to maintain an adequate supply of highway diesel fuel under the 15 ppm cap. As part of this study, CRA polled refiners concerning their plans under a 15 ppm sulfur cap. Using the results of this survey, as well as other information, CRA projected refiners' costs of meeting the 15 ppm standard, as well as their likely production volumes. CRA concluded that U.S. refiners would likely reduce their highway diesel fuel production by an average of 12 percent, creating significant shortages and price spikes.

CRA's conclusions appear to have been strongly affected by their assumptions, as well as the refiner survey they conducted. For example, CRA assumed that the new sulfur standard would cause 10 percent more highway diesel fuel to be "lost" in the distribution system compared to today (i.e., downgraded to off-highway diesel fuel). We believe based on the analysis outlined in the RIA that 2.2 percent is a more accurate estimate, resulting in 9 percent more 15 ppm fuel being available than CRA estimated. This difference alone accounts for 75 percent of the potential national supply shortfall projected by CRA.

CRA also concluded, with little explanation, that 20 refineries producing highway diesel fuel today would not produce highway diesel fuel under the 15 ppm standard and that many more would reduce production. Given the lack of information provided in the study, it was not possible to evaluate CRA's criteria in selecting these 20 refineries, nor was it possible to determine how much of the shortfall was attributable to this conclusion. While CRA evaluated whether refiners currently producing highway diesel fuel would be likely to leave the market, they did not assess whether any refineries currently not producing highway diesel fuel might enter the market. EPA did conduct such an assessment. We found 2 refineries that produce essentially no highway diesel fuel today which could meet the new standard for less than 5 cents per gallon. Production from these refineries would increase highway diesel fuel production by 9 percent. We also found based on our assessment that 4 other refineries could produce highway diesel fuel from their off-highway diesel fuel blendstocks for less than 5 cents per gallon. Production from these 6 refineries would increase highway diesel fuel production by 7 percent. Together with a more reasonable estimate of downgrades in the distribution system, this would more than compensate for any potential lost production, even as estimated by CRA.

CRA also implicitly assumed that the material it projected could be removed from the highway diesel market could be sold at a reasonable price. However, CRA did not analyze the impact of this additional supply on the prices which could be obtained in these markets, or even if these alternative markets could physically absorb all of this material. Much of this material is not diesel fuel, but poor quality blendstock. It is not clear that such material could be blended into non-highway diesel fuel and CRA did not analyze this likely problem. Our analyses, supported by a study by Muse, Stancil and Co., indicate that any substantial quantities of highway diesel fuel diverted to other markets will depress prices in those markets substantially.[g] Hydrotreating diesel fuel to meet the 15 ppm standard avoids these depressed prices, reducing the net cost of meeting the new standard. Since CRA only considered the cost to desulfurize highway diesel fuel, and ignored the added cost of dumping this fuel into markets with depressed prices, CRA's conclusions must be considered to be seriously flawed in this regard.

Furthermore, CRA ignored the fact that roughly 15 percent of today's highway diesel fuel is consumed in engines and furnaces not requiring this fuel. Any shortage of highway diesel fuel would lead many of these non-essential users to switch to nonroad diesel fuel or heating oil. Only limitations in the fuel distribution system would cause these users to continue to burn highway diesel fuel.

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[g] "Alternate Markets for Highway Diesel Fuel Components," Muse, Stancil & Co., for Southwest Research Institute, for U.S. EPA, September, 2000.

These problems with CRA's analysis, plus the lack of detail available concerning the specifics of the study, lead us to reject the study's conclusions that there will be significant supply shortfalls under a 15 ppm sulfur standard.

Finally, if any potential for highway diesel fuel shortfalls exists by requiring all fuel to meet 15 ppm sulfur in 2006, as CRA's analysis suggests, we believe that allowing some continued supply of 500 ppm, as under the temporary compliance option and hardship provisions contained in today's action, addresses this concern. By allowing some transition period before the entire highway diesel pool is required to meet the 15 ppm sulfur standard, some refiners will not need to change their current operations and will be able to continue producing 500 ppm fuel during these years. Those refiners that delay production of low sulfur diesel fuel until the later years of the program will tend to be the refiners with the highest cost to comply and, thus, the greatest tendency not to invest and impact supply. Refiners that begin producing low sulfur diesel fuel in the later years of the program will be able to take advantage of ongoing improvements in desulfurization technology that will help avoid or reduce any potential losses in highway diesel fuel production when the program requires full compliance with low sulfur diesel fuel.

8. Conclusions

In order to meet the proposed 15 ppm sulfur cap, refiners are likely to further hydrotreat their highway diesel fuel in much the same way as it is being done today to meet the 500 ppm sulfur cap. Improvements to current hydrotreaters can be used to reduce diesel fuel sulfur beyond that being done to meet the 500 ppm cap. However, these improvements alone do not appear to be sufficient to provide compliance with the proposed 15 ppm cap. Based on past commercial experience, it is very possible to incorporate current distillate hydrotreaters into designs which provide compliance with the proposed 15 ppm cap. Thus, the equipment added to meet the 500 ppm standard in the early 1990's will continue to be very useful in meeting a more stringent standard.

The primary changes to refiners' current distillate hydrotreating systems would be:

1) the use of a second reactor to increase residence time, possibly incorporating counter-current flow characteristics, or the addition of a completely new second stage hydrotreater,
2) the use of more active catalysts, including those specially designed to desulfurize sterically hindered sulfur containing material,
3) greater hydrogen purity and less hydrogen sulfide in the recycle gas, and
4) possible use of higher pressure in the reactor.

Existing commercial hydrotreaters are already producing distillate with average sulfur levels below 10 ppm, which should be more than sufficient to meet a 15 ppm cap. These hydrotreaters are processing distillate with typical breakdowns of SRLGO, LCO and LCGO. Therefore, the proposed 15 ppm cap appears to be quite feasible given today's distillate processing technology. The only drawback of these commercial demonstrations is that they were designed to reduce aromatics content, or improve cetane, as well as reduce sulfur. Therefore, these units' hydrogen consumption and its associated cost are higher than that needed for simple sulfur removal. This combination of sulfur and aromatics reduction has been encouraged by fuel tax incentives in Europe. The incentive to reduce sulfur by itself to such low levels has not existed, so refiners have generally had no incentive to produce such a product commercially.

Advances continue to be made in catalyst technology, with greater amounts of sulfur being able to be removed at the same reactor size, temperature and pressure. Therefore, it is reasonable to expect that distillate hydrotreaters put into service in the 2006 timeframe will utilize even more active catalysts than those available today.

Other methods of reducing diesel fuel sulfur, such as FCC feed hydrotreating, removing the heavy end of LCO, etc. help to reduce diesel fuel sulfur levels, but will generally not be sufficient to provide compliance with a 15 ppm cap. However, we expect that a number of refiners will utilize these techniques to reduce the severity of their distillate hydrotreaters and reduce hydrogen consumption (particularly by avoiding aromatic saturation). Some of these techniques would tend to increase the supply of highway diesel fuel (e.g., FCC feed hydrotreating), while others would tend to decrease it (e.g., removing the heavy end of LCO).

Biodesulfurization technology holds promise to reduce distillate sulfur without the high temperatures and pressures involved in hydrotreating. Efforts are underway to demonstrate that this technology can achieve 50 ppm sulfur or less in the next few years. However, it is not clear whether this technology would be sufficient to meet a 15 ppm cap.

9. Fuel Availability in 2006

a. Summary

We analyzed the refining and finished products distribution industries to determine the minimum volume of 15 ppm diesel fuel that will assure it is widely available in all parts of the country by September 1, 2006 and still provide for the supply of a modest amount of 500 ppm fuel to mitigate concerns about supply shortfall. Small refiners, which contribute about 5 percent to the national highway diesel fuel supply, have been given the opportunity to defer production of 15 ppm fuel for four years. We investigated how much production of 15 ppm fuel by the remaining refiners would still assure adequate availability across the country. We determined that at least 80 percent of the highway production within each PADD by non-small refiners must be converted to 15 ppm diesel to provide those assurances.

We feel it is important to understand, to the degree possible, how well balanced and operated the refining, supply, and distribution industries in this country are. Everyday 110 million gallons (2.6 million barrels) of diesel fuel (roughly 15 percent of total finished product volume) will be produced by refineries and distributed via pipeline, truck, and other means to end-users by the year 2006. These industries have developed and maintained a very efficient and safe, albeit complex, system for converting crude oil into finished products and making them available in the market at reasonable prices, especially compared with much of the rest of the world.

b. Diesel Fuel Refining Under the Temporary Compliance Option

There are currently 124 refineries in the country that produce highway diesel. Historically, the Pacific and Gulf coasts have had the highest concentration of both large and small refineries. For example, the refineries in Texas, Louisiana, and Mississippi, most of which are located near the Gulf, produce roughly 43 percent of the highway diesel in the country. The refineries in California, mostly located near the Pacific, produce about 12.5 percent of all highway diesel. On the other hand, all the refineries located in PADD I (the Atlantic coast region) produce about 6 percent of total highway diesel, and only 18 percent of expected PADD I highway demand. The others are “scattered” across the country, although some are clustered in certain regions or states, such as the Rocky Mountains, Kansas, Oklahoma, and Illinois.

There were two key considerations in our analysis of the refining industry. First, we projected which refineries would make the investment to convert to 15 ppm diesel and which would continue to produce 500 ppm fuel. Second, we evaluated where in each PADD each of the sets of refineries are located with respect to each other, to pipelines, terminals and other major fuel consuming markets.

We used the refinery cost model described in chapter V of the Regulatory Impact Analysis to predict which refineries would most likely make the investment to produce 15 ppm fuel. Early analysis showed a concentration of low cost refineries on the Gulf coast. Consequently, restrictions on averaging and trading were necessary to prevent 15 ppm fuel from being produced in limited areas of the country if wide spread availability was to be achieved. We considered various regional restrictions, but concluded that the PADD regions provide a good differentiation of the main fuel production and distribution regions of the country. Subsequent analyses were conducted assuming averaging and trading would only take place among refineries within each of the five PADD’s. While the ABT program is PADD restricted, the transfer of fuel between PADD’s is important and refinery location with respect to other PADD’s was also considered. The small refiner hardship and GPA provisions of the rule were assumed in the base case in these analyses. With one exception, refiners were assumed to produce either 100 percent 15 ppm fuel or 100 percent 500 ppm fuel, based on our analysis of cost and on discussions with various refiners. The one exception was those refineries with hydrocrackers that can produce 15 ppm diesel very cheaply from their hydrocrackate but otherwise produced 500 ppm diesel. We assumed that the "least-expensive-to-convert" refineries in each PADD would make the investment to produce 100 percent of 15 ppm fuel and that the remaining refineries would purchase available credits from them to continue producing 500 ppm diesel fuel. We want to stress that each refinery was studied as thoroughly and equitably as the available data allowed. With the exception of small changes from PADD to PADD due to varying numbers of small refiners and their volume, the PADD specific ABT restrictions result in essentially the same volume of 15 ppm produced within each PADD. Depending on the level of 500 ppm fuel allowed to be produced, however within each PADD production of 15 ppm fuel may be limited to certain areas. At an 80 percent level for 15 ppm fuel under the temporary compliance option, production of 15 ppm fuel is projected to occur on a widespread basis across all the PADD's.

Table IV.A-8. Number of Refineries Producing 15 ppm Diesel by PADD

PADD I	3
PADD II	13
PADD III	24
PADD IV	8
PADD V	11

i. Pipelines, Terminals, and Bulk Plants

As important as it is for fuel availability for refineries to produce adequate volumes of 15 ppm fuel in all major regions of the country, it is equally important that pipelines handle that fuel. At present, large volumes of both highway (< 500 ppm total sulfur) and off-highway diesel (~3,000 ppm total sulfur) are transported long distances via pipeline to delivery or " break-out" terminals for distribution by bulk and tank truck. There are approximately 127 pipeline companies currently operating pipelines in the country. Trucking fuel over long distances is prohibitively expensive and logistically, nearly impossible. A case in point, is the transfer of fuel into PADD I from PADD III. The Plantation pipeline, which runs from Louisiana to Indiana can deliver 476,000 barrels per day. On the other hand, it would require 2,400 trucks, each carrying 200 barrels (8,400 gallons) to deliver that same volume, which includes running the trucks just one-way. The distances involved would make the cost for distribution by truck prohibitively high.

The experience and knowledge-base of the pipeline companies and shippers make it possible to ship batches of millions of gallons of different products, such as gasoline, jet fuel, kerosene, diesel, home heating oil down the same line, switching lines from time-to-time, cost-effectively, and with a minimum of problems. For example, over the course of a year, the Colonial Pipeline handles 38 different grades of gasoline, including reformulated gasoline and multiple vapor pressures for each grade, seven grades of kerosene (including two for military), 16 grades of home heating oil and diesel fuel (including marine diesel fuel for the U.S. Navy and light cycle oil) and one grade of transmix.. The Plantation Pipeline has a similar slate of finished products. While these pipelines carry multiple grades of fuel, their ability to add another fuel, especially in large volumes, is limited by tankage along the way. In that the northeast part of the country uses most of the home heating oil in the country, most other pipelines don’t usually carry it on their slate. The TEPPCO Pipeline slate includes gasolines, distillates, commercial jet fuel, military jet fuel, unfinished gasoline, and speciality blendstocks. The Explorer Pipeline system transports primarily gasoline, fuel oil, and jet fuel. The Olympic Pipeline carries gasoline, diesel, and jet fuel. Generally, from the mid-west through the west, homes and businesses are heated with natural gas which precludes the need to ship heating oil.

Pipelines vary in lengths of from as little as a few thousand feet (the shorter sections are usually referred to as stub lines) to thousands of miles, including connections. For instance the Plantation system is 3,100 miles long; the Colonial system is about 4,300 miles long; the Chevron Pipe Line Company’s network of pipelines is about 5,000 miles long, which includes their crude, chemical, and LPG capacity. The Olympic line is 400-miles, the Explorer 1,400-miles, and the Kaneb 2,075-miles long.

Pipelines vary in diameter from 6 to 48-inches. For example the Plantation pipeline varies from 6 to 30-inches; the Colonial pipeline has segments that vary from 8-inches to 48-inches. The Explorer mainline pipe size is 28-inches from Port Arthur to Tulsa and 24-inches from Tulsa to Hammond, Indiana. Most pipelines ship liquids at velocities of from 4 to 7-miles per hour, or at an average of between 5 and 6-miles per hour. Capacities can be estimated using the diameter of the pipe. Average velocities are probably most useful, because sections of many pipelines vary in diameter. Velocities are also affected by the viscosities of the various products in the line. For example, the Plantation pipeline delivers about 476,000 barrels per day through their system. The Olympic ships about 306,000 barrels per day. Colonial pipeline’s main line batch sizes vary from 75,000 to 3.2 million barrels. The smallest main line batch is 75,000 barrels. Explorer’s 28-inch section has a capacity of over 500,000 barrels per day; it’s 24-inch section can handle about 317,000 barrels per day.

Splitting the current single grade of highway diesel fuel into multiple grades raises concerns about the size of the batches that move through the pipelines. All pipelines, regardless of capacity, require minimum batch volumes to avoid the problems inherent with shipping small batches. For instance, the Colonial Pipeline has a minimum batch size of 75,000 barrels, while normal volumes range from 350,000 barrels or more per batch. The Plantation pipeline has a minimum batch size of 25,000 barrels. The Chevron pipeline from Salt Lake City, Utah to Boise, Idaho has a minimum batch size of 6,000 barrels.

One problem with small batches is the speed with which they pass through a section of pipeline. In a 48-inch pipeline, 75,000 barrels would flow past a point in the line in just one and one-quarter hours. To break-out a shipment under these conditions requires extra-ordinary care and the possibility of contamination is high. Usually, the interface volume must be raised, which results in an increase in the loss of the higher quality, more valuable fuel, either to reprocessing or downgrading.

Most pipelines are common carriers and as such have fungibility requirements, usually referred to as pipeline specifications. That is, a shipper can ship a given volume of product, but in order to maximize the batch volume, a terminal will mix or co-mingle it with fuel from other shippers, such as from other refiners, that meet the same fungibility specification. At the destination terminal, the batch volume is “broken-out” into tanks from which bulk and tank trucks make deliveries. While this fuel will have characteristics similar to the fuel the shipper sent, it will not be “exactly the same fuel”, since batches of similar fuels were mixed with it at the origin of the shipment.

Another potential problem with small batches of 15ppm fuel is the need to “wrap” the fuel more carefully and differently than other fuels. “Wrapping” refers to the choice of products that precede and follow a particular batch of fuel in a pipeline. On the Explorer pipeline, a typical sequence would be fuel oils, diesel fuels, jet fuels, and gasolines. A typical sequence on the Colonial pipeline would be reformulated gasoline, low sulfur diesel, kerosene/jet fuel, high sulfur diesel, conventional regular gasoline, all premium grades, and reformulated regular gasoline. Each fuel is essentially “wrapped” by the fuel that precedes it and follows it. An efficient way to “wrap” is to ship two products next to each other, one of which can be “downgraded” to the other to avoid losing the interface to slop and reprocessing. For instance, when Jet A is shipped either ahead of or following 500 ppm diesel. A small volume of the Jet A can usually be downgraded to 500 ppm diesel, since it fits well within the highway diesel specs. It’s total sulfur content can be significantly higher, but the total volume of interface is usually small relative to the much larger diesel volumes and the small amount of extra sulfur can be lost to dilution. However, neither 500 ppm diesel nor 15 ppm diesel can be downgraded to Jet A because the high endpoint would drive the Jet A out-of-spec. Jet A, on the other hand, cannot be downgraded to 15 ppm diesel because it’s sulfur content can range as high as 3000 ppm. As a result, it is important to maximize the batch volumes of 15 ppm fuel, to the extent possible. The volume of interface relative to the shipment volume makes the cost of shipping small batches of 15 ppm fuel prohibitively high. See Chapter IV, D.2.a of the RIA for a complete discussion of pipeline interfaces.

We also considered whether we could expect the pipelines to handle 15 ppm diesel as a “proprietary” or “specialty” fuel and thus perhaps ship small batches and still make the fuel widely and dependably available. Most pipelines will handle proprietary shipments (sometimes referred to as "tenders") of certain products, but even then, the product usually has a specification range that fits well with the specs of other products shipped on the line and can be efficiently "wrapped"; interface losses are usually larger with tenders and extra tankage fees can add as much as one-half to three-quarters of a cent per gallon. Another problem is that tenders must usually fit into an established pipeline schedule. Consequently, it is difficult to rely on regular deliveries of these products. While this is not impossible, as a practical matter it is difficult because the pipelines are usually kept full on schedules up to a month or more in advance. We expect this approach to be prohibitively expensive as well as making it difficult to have15 ppm fuel widely available at all times.

The pipelines which currently ship only one grade of diesel fuel are expected to continue doing so, until 15 ppm fuel becomes the predominant fuel. We expect them to switch to 15 ppm diesel as their only grade of fuel. A few companies, for instance the Williams, the Cenex, the Chevron, and the Pioneer pipelines in the Rocky Mountain area prefer to carry only one grade of diesel, usually highway, and simply add the required dye when the fuel is loaded on to trucks at the terminal and sell it as off-highway. Pipelines that carry highway and high-sulfur off-highway diesels are also expected to switch to 15 ppm diesel rather than carry three fuels. However, we also recognize that a few of the larger pipelines, such as the Colonial and Plantation, may choose to ship three fuels. It is important to understand that not all terminals are owned by the pipelines that deliver to or from them. Consequently, even though a pipeline may be willing to carry 15 ppm diesel in addition to 500 ppm diesel, there must be terminals in the appropriate locations along the pipeline that are capable of taking delivery of the product.

As such, an important element of this analysis is to determine at what volumes the pipelines and terminals will likely ship/handle sufficient volumes of 15 ppm diesel to make it widely available, either as the only diesel fuel or in conjunction with other higher-sulfur, diesel grade fuels. We anticipate that under the 80 percent temporary compliance option program that the vast majority of the pipelines will just carry 15 ppm fuel. Some of the larger pipelines may choose to carry both fuels, but will limit either the distance the 500 ppm fuel is carried or the number of breakout locations. For this reason, in our analysis we assumed that 500 ppm fuel will be sold in just 50 percent of the country.

Moving to terminals, an important distinction exists between the difficulties terminals face and those that pipelines face when deciding to carry 15 ppm diesel if the volume of the 15 ppm fuel is much less or even nearly equal to the volume of 500 ppm fuel. As discussed above, small batches, including minimum volume batches of 15 ppm fuel, are difficult to handle but in fact most the difficulties take place in and around the terminals. It is in fact, at the terminals where batches are sequenced into a line and broken out at delivery. Interfaces are also managed at the terminal. Once the batch of 15 ppm fuel is in the line, it travels much the same way other products do. Volume on the line does not necessarily change, since the 15 ppm fuel is displacing a matching volume of 500 ppm fuel. However, at the terminal, the 15 ppm fuel must be broken out into tankage separate from the 500 ppm, which means that unless the terminal has an extra tank somewhere of sufficient volume to handle the product, a new one must be constructed. Switching back and forth between the fuels is definitely problematic, since very small volumes of 500 ppm fuel could easily drive the 15 ppm fuel out of spec.

Today, thousands of pipeline terminals make diesel fuel accessible to thousands of bulk and tanker trucks that can easily and economically deliver smaller volumes to bulk plants or service stations, truck stops, fleets, and other end-users over distances of up to 150 to 200 miles. For instance, the Plantation pipeline is connected to 130 shipper terminals in eight states. These terminals are owned by petroleum refiners, marketers, military, and commercial fuel users. Products are "tendered" to the system from nine refineries in Mississippi and Louisiana, from other products pipeline systems, and via marine facilities on the Mississippi River. TEPPCO has 21 product delivery terminals and 31 storage facilities in 12 states. The Explorer has major tankage and terminals at Port Arthur, Greenville and Grapevine, Texas; Glenpool, Oklahoma; Wood River, Illinois, and Hammond, Indiana, and serves 70 major populations centers in 16 states. The Kaneb services parts of Wyoming, Colorado, North and South Dakota, Nebraska, Iowa, and Kansas. The TEPPCO system includes 21 product delivery terminals and 31 storage facilities in 12 states. The Olympic has 10 delivery stations between Anacortes, Washington and Portland, Oregon. These represent just a few examples of the roughly 1,400 storage facilities and terminals in the U.S.

At the production volumes and for the logistical reasons discussed above, the terminals which currently handle only one grade of diesel fuel are expected to switch to 15 ppm diesel rather than invest in the tankage and ancillary equipment necessary to carry two fuels. Discussion with and comments with industry suggest that very few, if any, terminals have unused tankage available to carry an extra fuel. A few of these companies actually supply some off-highway diesel but because they prefer to carry only one grade, usually highway, they simply add the required dye when the fuel is loaded on to trucks and sell it as off-highway. For example, some of the refineries in PADD IV supply off-highway diesel to the mining industry. Historically, most of the off-highway diesel in PADD IV has been relatively low sulfur and the refiners and shippers have simply sold dyed highway diesel into this market. We estimate that about 20 percent of the off-highway diesel in these areas is actually high sulfur fuel. Terminals that handle highway and high-sulfur off-highway diesels are also expected to switch their highway fuel to 15 ppm diesel rather than carry three fuels. However, we also recognize that the terminals on a limited number of the larger pipelines, such as the Colonial, Plantation, and perhaps the Explorer could choose to handle three fuels, and may need to build additional tankage. It is through these terminals that the remaining 500 ppm fuel would be distributed.

ii. Bulk Plants

In addition to terminals, there are roughly 10,000 bulk plant across the country which receive diesel fuel, usually by truck and then redistribute it in smaller quantities to retail outlets.

Many of the bulk plants are owned and operated by the owners of truck fleets and service stations and are major source of supply of diesel fuel, particularly in the rural areas of the country. Bulk plants typically have just one, roughly 20,000 gallon tank per product handled. As such, the introduction of another 20,000 gallon grade of diesel fuel would require the to either add tankage to carry both or specialize in supplying one or the other. At an 80 percent level for the temporary compliance option, with the 15 ppm fuel being the only fuel available except near refineries producing 500 ppm fuel or near those terminals that invest to distribute both fuels, we anticipate that most bulk plants will not add tankage and will merely switch over to 15 ppm fuel. Where available, 500 ppm fuel would likely be trucked directly from the terminal to the retail outlet or centrally fueled fleet without going through the bulk plant.

iii. Fleets & Card-locks

We expect fleet owners and card-lock companies will make the most economically reasonable choices available. They will likely purchase 500 ppm fuel, if it is available and even if it is only a penny cheaper, until they or their customers purchase a vehicle which requires 15 ppm fuel. At that time, we expect they will switch to 15 ppm fuel rather than build an extra tank, since all of their diesel powered vehicles can use the 15 ppm fuel. There was some discussion as to whether a fleet owner could arrange for a vehicle with the new emissions device to fill at a facility, i.e., another fleet owner, carrying 15 ppm fuel rather than convert his fleet to15 ppm diesel. The proposition sounds simple, but in fact there are several costs involved. It is possible that the nearest sister facility is several miles distant, at times in heavy traffic, and perhaps in the direction opposite the one to be taken by the vehicle looking for the 15 ppm fuel. Distance and time are both important factors. For example, some drivers are paid by the load and would likely demand extra pay for time spent fueling a truck. Driving loaded trucks, at 4 to 5-miles per gallon (perhaps even lower in slow or heavy stop-and-go traffic) can quickly add several cents to each gallon of fuel purchased from a distant facility. We also considered whether a fleet owner could fuel at a service station. Most service stations are designed for light vehicles only and are often located in high traffic areas, such as at intersections. Unless the station owner installs special accommodations for large trucks, fueling would be nearly impossible. Many stations also do not have around-the-clock service. It was suggested that because some larger fleets have multiple fueling depots, an owner could assign vehicles with the new emissions device to a particular depot where 15 ppm fuel would be available. Flexibility is very often the key to success for a trucking company. We do not expect owners would spend hundreds of thousands of dollars for a new truck and then restrict it’s use to a particular, confined region. Card-lock companies will likely also switch with demand for the 15 ppm fuel, rather than add facilities to handle two fuels.

iv. Truckstops

Truckstops depend on never having to turn away customers. The 15 ppm fuel can be sold to all customers while 500 ppm fuel can only be sold to the pre-2007 vehicles. Consequently, we expect that most truckstops would choose to begin carrying 15 ppm fuel at the start of the program, particularly at an 80 percent requirement under the temporary compliance option where 500 ppm fuel may be in short supply. It was suggested that truckstops could easily de-manifold their current systems and incorporate 15 ppm fuel for sale with their 500 ppm fuel. Based on discussions with truckstop owners we learned that many of them take delivery multiple times a day to prevent their tanks from running dry. Because at some point, there would be equal demand for both fuels, half the tankage would need to be available for each fuel. However, at the beginning of the program the 15 ppm fuel would likely be in low demand, which would make it nearly impossible to keep the inventory of 500 ppm fuel from running out. An additional concern, is what it would cost in lost business to take the system down for the re-manifolding period at the beginning. However, truckstops are likely to be the location most capable of and have the greatest economic incentive to make both fuels available. Regardless, however, 15 ppm fuel should be available.

v. Service Stations

We expect most retailers, such as service stations, will switch to 15 ppm fuel rather than install extra tankage to carry both fuels, especially given the magnitude and brevity of the optional compliance period. While a limited number of retailers choose to sell only 500 ppm fuel, they risk turning away customers, since the actual price differential between 15 ppm and 500 ppm fuel in most markets under the 80 percent requirement is expected to be small. The risk of losing customers would likely outweigh any economic advantage for continuing to sell 500 ppm fuel.

vi. Evaluation of Fuel Availability by PADD

Essentially, our line of thinking and analysis was that if a majority of the refineries produce the 15 ppm fuel, and given that the majority of the major pipelines connected to these refineries, the fuel will be made available in quantities sufficient to widely distribute it through the bulk plants to retailers and other end users. We began the evaluation with PADD III since it supplies fuel into most of the other PADD’s.

(1) PADD III

The total volume of diesel produced in PADD III is about 1.2 million barrels per day. Eighty percent of that or about 960,000 barrels per day of 15 ppm diesel will be produced by twenty-four refineries, most of which are located along the Gulf coast, although a few in other areas of the state will play an important role in assuring 15 ppm fuel is widely available, not only within PADD III, but also in PADD’s I, II, and IV. Movement within the PADD is handled by companies such as the Longhorn, Koch, Ultramar Diamond Shamrock, Citgo, Conoco, Shell, Chevron, Mobil, Fina, Texaco, and Trust pipeline companies. At productions volumes less than 80 percent, we estimated that at least one region of Texas may have difficulty receiving 15 ppm fuel, except by truck. At the lower production levels, the refineries in that area would likely continue producing 500 ppm fuel, most of which would be exported into PADD's I and II; small volumes are also exported into PADD's IV and V. Since most, if not all the fuel from this region is flowing by pipeline out of the area, there is limited expectation that 15 ppm fuel would flow into the area by pipeline. At 80 percent production volume and for the reasons discussed above, we expect the fuel of choice for most pipelines will be 15 ppm fuel and that most retailers will carry the fuel. As noted above, this PADD is a significant source of diesel fuel for PADD's I and II.

(2) PADD I

Three refineries are predicted to produce about 135,000 barrels per day of 15 ppm diesel, which is 80 percent of the total highway diesel produced by refineries in PADD I. Although these refineries will produce more than enough 15 ppm fuel to meet first and even second year demand in the entire PADD, most of the fuel produced in PADD I comes from the area above Virginia. As such, it is usually distributed northward, northwestwards and northeastwards within the PADD, with some short-distance distribution southward, mostly by truck. To the extent that 500 ppm diesel is already shipped, mostly by truck, into the upper northeastern states today, it should not be difficult or expensive to replace that volume with 15 ppm fuel. We expect that at the production levels most retailers will carry 15 ppm diesel. Since highway diesel demand in PADD I is approximately 820,000 barrels per day, about 82 percent of it must be imported from PADD III, via the Colonial and Plantation pipelines and through foreign imports. For instance, a shipment on the Plantation pipeline takes about 20 days and costs approximately 2 cents per gallon to travel from Baton Rouge, Louisiana to the Washington D.C. area. Shipments on the Colonial are comparable both in time and price. In order to meet overall diesel demand, the pipelines will likely carry both15 ppm and 500 ppm fuel.

(3) PADD II

The total volume of diesel produced in PADD II is about 682,000 barrels per day. Thirteen refineries, fairly strategically located in seven of the 13-PADD II states, are predicted to produce about 80 percent or 546,000 barrels per day of 15 ppm diesel. At this volume we expect the diesel of choice for the majority of pipelines will be the 15 ppm fuel and that most retailers will carry the fuel. The Kaneb, Amoco, Marathon Ashland, Buckeye, Countrymark, Conoco, Phillips, and Wolverine pipelines move much of the fuel around in this PADD. Most of the pipelines are hooked into refinery terminals but most also take delivery from and supply into the other pipelines. We found that at volumes less than 80 percent production, it was likely that two or three refineries in at least two strategic locations may not choose to produce 15 ppm fuel. In both cases these refineries were an important source of highway fuel for a fairly significant area. If they continued to produce 500 ppm fuel, it would likely stop, or at the very least hinder, the flow of sufficient 15 ppm fuel into those areas and prevent it from being widely available. At the 80 percent production level, sufficient fuel would be available in both areas. About 122,000 barrels per day of additional diesel must be imported, principally from PADD III. The Explorer, Williams, Citgo, TEPPCO, Phillips, and Conoco pipelines play an important role in this transfer. For the reasons we discussed above, we expect the 15 ppm diesel will be the fuel of choice for the pipelines from PADD III. Considering the location of the refineries in this PADD and their access to pipelines which are expected to carry 15 ppm diesel, we expect the fuel will be widely available.

(4) PADD IV

The total volume of diesel produced in PADD IV is about 127,000 barrels per day. Eighty percent of that volume or about 101,000 barrels per day of 15 ppm diesel is projected to be produced by eight refineries. The Chevron, Pioneer, Conoco, Yellowstone, Cenex, and Kaneb pipelines move most of the fuel in this PADD. This PADD makes up the majority of the GPA and has several small refineries that may choose wait until 2010 to make the investment to convert to 15 ppm fuel. We analyzed each pipeline with respect to the volume of 15 ppm fuel produced by refineries serving it. We were very concerned that, given the potential small refiner and GPA choices, there would be insufficient fuel to cause the pipelines and terminals to switch to 15 ppm fuel. We felt that parts of eastern Montana and Wyoming, western parts of North and South Dakota and an area in northeastern Montana may not receive enough 15 ppm fuel to make it widely available. At the 80 percent production requirement, we expect the fuel of choice for the pipelines will be 15 ppm diesel because it is the dominant fuel and that most retailers will carry the fuel.

(5) PADD V

PADD V has a few characteristics that make it somewhat different from the other PADD's. This is the only PADD that is really comprised of a number of separate and distinct fuel distribution systems; California, Arizona, and Nevada; Washington and Oregon, and Hawaii and Alaska. In California the SFPP, Shell, Mobil, and CalNev pipelines most of the diesel within the state. Las Vegas, Nevada is serviced via the CalNev. The southern part of Utah (PADD IV) is supplied from Las Vegas by truck. The SFPP services Reno and Fallon, Nevada in the north.

Another somewhat unusual condition exits in this PADD, in that the western halves of Washington and Oregon are somewhat isolated from service from either California or PADD IV. If PADD trading was widely permitted under a production requirement of less than 80 percent, it is possible that the refineries in the northwest could actually purchase credits and produce no 15 ppm fuel. Because the region is isolated from reasonable service out of either PADD IV or V, there would be no 15 ppm fuel in this area. At the 80 percent level, we expect that at least two refineries in the northwest will convert to produce 15 ppm fuel in volumes sufficient to meet demand for at least the first year or two. The Olympic pipeline connects the refineries in Washington with Portland, Oregon and the SFPP connects Portland to Eugene, Oregon. Due to the unique situation described earlier for this PADD, Alaska and Hawaii were split off from

PADD V and made their own trading area in order to ensure sufficient availability of 15 ppm fuel. Consequently, we expect most retailers and truckstops will switch to 15 ppm fuel for the reasons described above.

B. Interaction with Other Programs

In addition to the program proposed today, there are a number of other environmental programs that may concurrently have an impact on the refining industry. The most significant of these programs is the recently promulgated gasoline sulfur standards as part of the Tier 2 rulemaking. We have examined the impacts on engineering, construction, and capital expenditures of gasoline sulfur control in conjunction with the diesel sulfur control program .

A particular concern has been raised to the Agency regarding the capability of the engineering and construction (E&C) industries to be able to design and build diesel fuel hydrotreaters while at the same time doing the same for gasoline, as well as accomplishing their other objectives. Compliance with the 15 ppm sulfur cap for on-highway diesel fuel begins for refiners on June 1, 2006. This is within the timeframe of the phase-in of the Tier 2 sulfur standards applicable to gasoline. Thus, it is important to consider the requirements of complying with the diesel fuel sulfur cap in the context of the requirements of the Tier 2 gasoline sulfur standards. Two areas where it is important to consider the combined impact of two or more fuel quality specifications are: 1) refiners' ability to procure design and construction services and 2) refiners' ability to obtain the capital necessary for the construction of new equipment required to meet the new quality specification.

1. Design and Construction Services

We evaluated the requirement for engineering design and construction personnel, particularly three types of workers: front-end designers, detailed designers and construction workers, needed to implement the Tier 2 gasoline sulfur program and this diesel fuel sulfur cap. We developed estimates of the maximum number of each of these types of workers needed throughout the design and construction process and compare those figures to the number of personnel currently employed in these areas. It would also be useful to evaluate certain types of construction workers which might be in especially high demand, such as pipe-fitters and welders. However, good 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 diesel fuel sulfur cap might stress these specific job categories.

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 Moncrief and Ragsdale.[h] Their paper summarizes analyses performed in support of the recent National Petroleum Council study of gasoline and diesel fuel desulfurization, as well as other potential fuel quality changes. These factors are summarized in Table IV.B-1.

Table IV.B-1. Design and Construction Factors for Desulfurization Equipment

	Gasoline	*Diesel*
Number of New Pieces of Equipment per Refinery	60	15
Number of Revamped Pieces of Equipment per Refinery	0	30
Job hours per piece of new equipment *		
Front End Design	300	300
Detailed Design	1200	1200
Direct and indirect construction	9150	9150

* Revamped equipment estimated to require half as many hours per piece of equipment.

The gasoline sulfur standards as promulgated last year phase in between 2004 and 2008, with the potential for the generation of early sulfur reduction credits prior to 2004. However, a number of small refiners and refiners selling gasoline in the Geographic Phase-in Area are expected to take advantage of an option being afforded in this diesel fuel program. These refiners will be able to delay their compliance with the 30 ppm average, 80 ppm cap standards for gasoline for two years. Thus, the phase in of the Tier 2 gasoline sulfur program now extends from 2004 to as late as 2010 for GPA refiners and 2011 for qualifying small refiners.

The sulfur standards phase in at equal 12 month intervals effective on January 1 of each calendar year. Thus, it is convenient to break up the construction of gasoline desulfurization units by the year in which they have to become operational. Table IV.B-2 shows our projection of the number of gasoline desulfurization units which must be operational by January 1 of the indicated year.

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[h] 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.

Table IV.B-2. Number of Gasoline Desulfurization Units Becoming Operational on January 1 of the Indicated Year [i]

Prior to 2004	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*
Gasoline Units: After Promulgation of the Tier 2 Gasoline Sulfur Program							
10	37	6	26	9	9		
Gasoline Units: After Promulgation of the Diesel Fuel Sulfur Program							
10	37	6	26	5	3	4	6
Diesel Units							
			63				58

The diesel fuel desulfurization units are projected to start either 2006 or 2010, according to the temporary compliance and hardship provisions. With respect to the required number of job-hours per unit, all of the gasoline units were assumed to be new, grassroots units. The diesel fuel units were assumed to be 80 percent revamps and 20 percent new, grassroots units, consistent with the analysis presented earlier in this chapter.

A worse case assumption would be that all of the units scheduled to start up on a particular January 1 began and completed their design and construction at the exact same time. However, this is not reasonable for a couple of reasons. One, 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, 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 very temporary peaks in the demand for personnel. Thus, with respect to units starting up in a given year, we assumed that the design and construction of these units would be spread out throughout the year, with 25 percent of the units starting up per quarter. Given this assumption,

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[i] 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.

we developed the breakdowns of personnel requirements by month for a given project shown in Table IV.B-3.

Table IV.B-3. Distribution of Personnel Requirements Throughout the Project

	Front-End Design	*Detailed Engineering*	*Construction*
Duration per project [j]	6	11	14
Duration for projects starting up in a given calendar year	15	20	23
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

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[j] 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.

The fraction of total hours expended estimated in Table IV.B-3 was derived based on the following. Front end design typically takes six months to complete. If 25 percent of the refineries scheduled to start of 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.

Finally, we assumed that personnel were able to actively work 1877 hours per year, or at 90 percent of capacity assuming a 40 hour workweek.

Applying the above factors, we projected the maximum number of personnel needed in any given month for each type of job. The results are shown in Table IV.B-4, both assuming the availability and unavailability of the temporary compliance option. In addition to total personnel required, the percentage of the U.S. workforce currently employed in these areas is also shown.

Table IV.B-4. Maximum Monthly Demand for Personnel

	Front-End Design	***Detailed Engineering***	***Construction***
Tier 2 Gasoline Sulfur Program As Promulgated			
Number of Workers	421	1,277	8,423
Percentage of Current Workforce *	22%	13%	5%
Gasoline Plus Diesel Fuel Programs: No Temporary Compliance Option			
Number of Workers	882	2,570	15,623
Percentage of Current Workforce *	46%	27%	10%
Gasoline Plus Diesel Fuel Programs: With Temporary Compliance Option			
Number of Workers	571	1,669	10,658
Percentage of Current Workforce *	30%	17%	7%

* Based on current employment in the U.S. Gulf Coast, assuming that half of all projects occur in the Gulf Coast.

As can be seen, the diesel fuel program without the temporary compliance option would have had a large, impact on the required amount of E&C resources compared to only the Tier 2 gasoline program. Employment required in all three job categories would have essentially doubled with the addition of the diesel fuel program. However, with the temporary compliance option, the impact of the diesel fuel program is reduced dramatically, to the point where the required resources for the two programs are only about 30 percent greater than those of the Tier 2 gasoline program alone.

With the temporary compliance option, the largest impact is on front end design, where 30 percent of available U.S. resources are required. Thus, we believe that the E&C industry is capable of supplying the oil refining industry with the equipment necessary to comply with the proposed diesel fuel sulfur cap on time. We believe that this is facilitated by the extended phase-in we allowed regarding compliance with the Tier 2 gasoline sulfur standards and the diesel sulfur cap.

The second aspect of the aggregate impact of the proposed diesel fuel sulfur cap and other rules on refiners is their ability to procure adequate capital to fund the required investment in new desulfurization equipment. Estimates of previous capital investments by the oil refining industry for the purpose of environmental control are available from two sources: the Energy Information Administration (EIA) and the American Petroleum Institute (API).

According to EIA, capital investment by the 24 largest oil refiners for environmental purposes peaked at $2 billion per year during the early 1990's.[k] Total capital investment by refiners for other purposes was in the $2-3 billion per year range during this timeframe. API estimates somewhat higher capital investments for environmental purposes, with peaks of about $3 billion in 1992-1993.[l]

In the Tier 2 gasoline sulfur control rule, we estimated the expenditure of capital for gasoline desulfurization by year according to the phase in schedule described above.[m] In that analysis, we simply assumed that all of the capital investment occurred in the calendar year prior to the requirement that the unit be on-stream. Here, we developed a somewhat more sophisticated schedule for the expenditure of capital throughout a project. We projected that the capital investment would be spread evenly over a 24 month period prior to the date on which the unit must be on-stream. The results are shown in Table IV.B-5.

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[k] Rasmussen, Jon A., “The Impact of Environmental Compliance Costs on U.S. Refining profitability,” EIA, October 29, 1997.

[l] API Reported Refining and Marketing Capital Investment 1990-1998.

[m] 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.

Table IV.B-5. Capital Expenditures for Gasoline and Diesel Fuel Desulfurization

Calendar Year	*Gasoline*	*Diesel Fuel***	*Total*
2002	1.7*		1.7
2003	1.11*		1.11
2004	0.85	1.3	2.15
2005	0.59	1.9	2.49
2006	0.15	0.7	0.85
2007	0.06		0.06
2008	0.06	0.5	0.56
2009	0.02	0.9	0.92
2010		0.2	0.2

* Includes capital related to the construction of desulfurization units built prior to 2004 for the generation of early credits.

As can be seen, capital investment peaks in 2004 and 2005, at $2.15-2.49 billion. This is about two-thirds the previous high levels of refining industry investment for meeting environmental programs experienced during 1992-1994.[39] Therefore, this level of investment should be sustainable for a couple of years, particularly since the required level of investment drops off dramatically after 2006, and inflation has degraded the value of money somewhat since the early 90's. From 2002-2005, the required level of investment averages somewhat below $2.0 billion per year, or about one-half of the levels experienced during the early 1990's.

In addition to gasoline sulfur control there are other environmental programs that could also concurrently have an impact on the refining industry. The phase-down of MTBE from gasoline is currently under consideration. While the nature of the action on MTBE has not yet been determined, if EPA acts to reduce or eliminate MTBE usage, we will consider cost impacts on refiners and provide sufficient lead time to comply with such requirements.

C. The Need for Lubricity Additives

Note that much of the discussion in this section on lubricity was obtained from two Society of Automobile Engineers (SAE) Technical Papers.[40] They are referenced here once to avoid numerous repetitive references in the text. Also, some studies are noted in the text without references. These studies, unless otherwise noted, are also extracted from these two SAE papers.

1. What Impacts Will the Sulfur Change Have on Lubricity?

Diesel fuel lubricity is the characteristic of diesel fuel to provide sufficient lubrication to protect each of the many contact types within fuel pumps and injection systems for reliable performance. Unit injector systems and in-line pumps, commonly used in heavy-duty engines, are actuated by cams lubricated 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. Low fuel lubricity has been associated with low-viscosity fuels, such as No.1 diesel fuel or kerosenes, which are typically used in cold climates. As a result, many rotary fuel injection systems intended for use in cold climates contain components manufactured using improved metallurgy specifically to tolerate the use of poorer lubricity fuels.

Experience has shown that it is very rare for a naturally high-sulfur fuel to have poor lubricity, although most studies show relatively poor overall correlation between sulfur content and lubricity. One study indicated a relationship between diesel fuel lubricity and the content and composition of sulfur compounds. However, the artificial addition of sulfur compounds seems to have no effect or even a slight detrimental effect at high concentrations. Another study showed that fully-saturated hetrocyclic sulfur compounds are the most active naturally occurring fuel lubricity agents. High molecular weight components, back-end volatility, napthalenes, polyaromatics, nitrogen compounds, polar compounds (excluding sulfur and nitrogen compounds) and oxygen compounds have been identified as potential lubricity agents. There is some indicated correlation between total aromatics content and lubricity, as measured by laboratory tests. The addition of aliphatic kerosene fractions to diesel fuel, which have inherently lower lubricity, can also decrease the lubricity of the resulting blend.

Unfortunately, few consistent trends are visible in the literature, and some researchers have shown that properties such as sulfur, aromatics, acidity and olefin content cannot be used alone to predict fuel lubricity. At present, the most that can be said definitively regarding the impact of fuel composition on lubricity is that a single fuel with low viscosity, low sulfur, aromatics and acid content generally will tend to have poorer lubricity than those with higher levels. Considerable research remains to be performed regarding the fuel components most responsible for lubricity. Consequently, successful application of either a chemical test or predictive model depends on a better understanding of the fuel and additive components responsible for lubricity.

Hydrotreating, in addition to reducing sulfur content, can lead to a reduction in the concentration of various compounds which may contribute to fuel lubricity such as aromatics and high molecular weight hydrocarbons. As early as 1976, it was suggested that lowering the level of aromatics, separation of sulfur compounds and polar substances, as well as separation of surface-active substances during the hydrotreating refining process, can result in a reduction of the lubrication qualities of the fuel. One report[41] suggested that reduction in lubricity is caused by the removal of the sulfur that itself acts as a lubricant, and the removal of some compounds such a furans, pyroles and thiophenes in the refining process. In one 1992-93 study, extremely low aromatics content produced by hydrotreating caused catastrophic failure of rotary fuel injection pumps. Unfortunately, few consistent trends are visible in the literature, and some researchers have shown that properties such as sulfur, aromatics, acidity and olefin content cannot be used alone to predict fuel lubricity.

Similarly, the aviation community has investigated the lubricity of jet fuel. The most satisfactory explanation for wear on failed aviation components has been a simple corrosive process, involving the repeated formation and removal of metal oxides during sliding. To a lesser extent, wear has been explained by severe adhesive wear and scuffing as the component dimensions were reduced beyond tolerable limits or if contact loads were unusually high. Severe refinery treatment removes the naturally occurring corrosion inhibitors from the fuel, allowing formation of a thick oxide layer. The removal of chemically active species to upgrade thermal stability was found to be associated with poorer fuel lubricity. A number of studies by the middle to late 1960s indicated that poor performance of high-purity jet fuel appeared to be related to the availability of naturally occurring compounds, rather than gross physical or chemical properties. Other studies indicated that fully saturated hetrocyclic compounds and polynuclear aromatic hydrocarbons have a beneficial effect on lubricating characteristics. As little as two percent aromatics greatly increased the load-carrying capacity of paraffins. Mixtures of heavy aromatics and paraffins were much more effective than either compound used alone. One study also found complex esters and, to a lesser extent, high molecular weight polymers to be effective as anti-wear agents in turbine and diesel fuel. Another study found that the lubricity of severely refined fuels could be improved by the addition of trace concentrations of surface-active additives, such as corrosion inhibitors.

Some studies have indicated that the presence of water may have a significant effect on lubricity values, although apparently only humidity values were monitored and controlled for those studies. The U.S. Navy conducted a study to determine the effects of humidity and water on distillate lubricity using the BOCLE, SLBOCLE, and HFRR tests[42] (these tests are described in the next subsection). The results of this study indicated that the test fuels were not noticeably affected by any of the water introduction methods using any of the three test procedures.

Notwithstanding all these uncertainties, hydrotreating has been known to reduce the lubricity of the treated fuel, depending on the severity of the treatment and characteristics of the crude. If as anticipated, refiners increase the severity of their hydrotreating to comply with the 15 ppm sulfur standard, the lubricity of some batches of fuel may be reduced compared to today's levels. To compensate for the potential impact on fuel lubricity, we have accounted for an increased use of lubricity additives in highway diesel fuel in our cost calculations.

2. How Can One Determine Whether the Lubricity of a Fuel Is Adequate?

Many researchers have demonstrated that the correlation between the different wear mechanisms in fuel pumps is dependent on the fuel composition. This is particularly important for dissimilar wear mechanisms, such as oxidative corrosion and adhesive scuffing. The most successful wear tests appear to be those that reproduce the predominant (i.e., the most damaging) wear mechanisms. However, there is considerable disagreement as to the relevant importance of each mechanism and also to the appropriate laboratory-scale test procedure to measure lubricity. A number of studies have observed poor correlation between pump wear and the most widely used laboratory test procedures, and no single wear test provides a complete description of lubricity. In addition, these tests appear less effective when evaluating fuels that contain additives, compared to the base fuels. Several studies have reported that the laboratory tests predict negligible benefits from lubricity additives, but fuel trials indicate that lubricity additives do provide acceptable lubricity.

Many laboratory fuel tests which are designed to operate under boundary lubricating conditions are strongly correlated to viscosity. For many crude sources, a disproportionate fraction of sulfur-containing compounds are contained in the higher molecular weight fuel components, indicating an intrinsic relationship between chemical and physical fuel characteristics. One researcher successfully developed a simple empirical relationship that predicted fuel lubricity as measured using the SLBOCLE test (described below) using viscosity and di-aromatic content. Unfortunately, such a model does not account for the effects of trace constituents or lubricity additives. In 1993, the U.S. Army systematically defined the principal wear mechanisms as oxidative corrosion, chemical corrosion, adhesion, and scuffing (severe adhesion), with oxidative and scuffing predominating. In that study, the degree of pump wear seemed to be highly sensitive to the availability of dissolved moisture, indicating the presence of an oxidative mechanism.

The BOCLE (Ball-on-Cylinder Lubricity Evaluator) apparatus uses a ball-on-rotating cylinder contact geometry. The primary wear mechanism produced by this test was found to be oxidative corrosion and possibly the chemical corrosion mechanism found in high-sulfur fuels. The U.S. Army sponsored development of a modified BOCLE - the SLBOCLE (Scuffing Load Ball-on-Cylinder Lubricity Evaluator) - in 1994, to measure fuel load-carrying capacity. It measures the applied load required to produce a transition from mild boundary lubricated wear to adhesive scuffing. To minimize the effects of oxidative corrosion and abrasive wear, the SLBOCLE uses a polished test ring in place of a ground specimen. A Society of Automobile Engineers (SAE) paper concluded that the SLBOCLE test is a good tool to evaluate the lubricity of base fuels, which contain no lubricity additive.[43] However, this method can distinguish additives only if large amounts are used, well above the concentrations required to protect the equipment.

The HFRR (High Frequency Reciprocating Rig) was developed in Europe in 1986. The apparatus consists of a AISI E52100 steel ball, which reciprocates against a polished plate of the same material. The mean wear scar diameter formed on the ball is used as a measure of lubricity. This test produces a very wide range of wear mechanisms, depending on the fuel being evaluated. However, SAE paper 961948 concludes that the correlation between fuel injection pump rig and HFRR results have not been satisfactory. Many fuels which were regarded good according to a pump demerit wear rating were regarded poor according to the HFRR.

In 1991, the Society of Automotive Engineers (SAE) formed a committee to evaluate the effects of reduced fuel lubricity and to identify an effective laboratory wear test procedure. In Europe, the Coordinating European Council (CEC) was established for the same purpose. In 1992, both groups cooperated under the auspices of an International Standards Organization (ISO) working group. Following a systematic evaluation of the available test procedures, the group performed a round robin test program to compare the HFRR, two variants of the BOCLE, and the Falex BOTS (Ball-on-Three Seats) test. This work was backed up by full-scale pump tests performed by the original equipment manufacturers using a matrix of 12 fuels. A HFRR result of 450 microns was recommended by the ISO working group, and 460 microns by the CEC, as the maximum result for acceptable lubricity. No official minimum SLBOCLE result has been defined, but the ISO working group data and most studies indicate that an SLBOCLE result of approximately 3,000 grams delineates the transition between acceptable and poor lubricity. The ISO is involved in a Phase 2 study to include additized fuels, which were largely ignored in the original study. The objective is to evaluate the correlation between injection equipment rig tests and the HFRR test for additized fuels. No conclusion was reached at the time of publication of SAE 1999-01-1479 in May 1999.

The American Society for Testing and Materials (ASTM) lubricity task force evaluated the information that had been generated by previous working groups, including ISO, and recommended that the SLBOCLE and HFRR tests be adopted as ASTM test methods. However, the ASTM group chose not to adopt ISO's 450 micron specification and has not included a minimum lubricity requirement in ASTM D-975 specifications for diesel fuel quality. In addition to the additive problem, the two ASTM test methods (SLBOCLE and HFRR) suffer from poor precision and do not correlate well with each other. The ASTM group decided it needed to conduct more work to improve the precision of the test methods, resolve the discrepancy between the test results and the actual field experience, and modify the test methods to apply to additized fuels. A fuel specification will be considered after the test issues are resolved. The ASTM group is evaluating a recent BOTD (Ball on Three Disks) test, along with a modification to the existing HFRR method.

Chevron conducted a limited number of tests with additized fuels. In all cases, the HFRR test was indicated to be the least responsive to additive concentrations. This method does not recognize the existence of any additive up to levels above 100 ppm, and full benefit is indicated at levels between 200 and 500 ppm. The SLBOCLE test recognizes an additive effect between 40 and 50 ppm, and detects the full potential of the additive between 50 and 200 ppm. The BOTD test recognizes an additive effect at a level as low as 10 ppm, and detects the full additive potential at around 20 to 40 ppm. Early reports by a recent effort at Southwest Research Institute indicate that the HFRR test discrimination of additized fuels could be improved by changes to the frequency and stroke.

3. What Experience Has There Been with Low-sulfur Fuels?

***What has been the experience with aviation turbine engines*?**

Aviation turbine kerosene (Jet A, Jet A-1) is the principle fuel used by commercial airlines. A wide cut fuel spanning the gasoline and kerosene boiling range (JP-4, Jet B) has historically been used by many national air forces. A higher flash point fuel (JP-5) has been used for naval aircraft. Compared to both low and high sulfur diesel fuels, aviation kerosene fuels tend to be poor lubricants.

In 1969, the British Ministry of Defense formed a Fuel Lubricity Panel to specify a lubricity parameter for aviation turbine fuel. The Panel was unable to specify a lubricity test that would accurately reflect the lubricity requirements of an aviation turbine fuel, but it did suggest that a ball-on-cylinder machine showed promise. In the mid-1970's, the U.S. Navy began to experience durability problems on equipment operated with fuels from refineries outside the continental U.S. Failures were reported for afterburner hydrolic fuel pumps and also hang-up of fuel controls. The U.S. Navy in cooperation with the Coordinating Research Council (CRC) Aviation Fuel Lubricity Group began a detailed evaluation of the BOCLE apparatus. That study recommended that the BOCLE apparatus continue to be used to evaluate lubricity of fuels from the aircraft fleet, as well as the use of corrosion inhibitors in military aviation fuels. The study also recommended that new aircraft and fuel system components be developed to operate satisfactorily on low-lubricity fuel.

Since 1975, the approach of the commercial aviation community has been to maximize equipment durability through improved materials and design, rather than through control or measurement of fuel lubricating characteristics. However, the approach of the military has been to add corrosion inhibitors to the fuel. Currently, many military aircraft use JP-8 fuel, which is generally equivalent to Jet A-1 treated with several additives, including a corrosion inhibitor to improve lubricity. As a result of these efforts, the aviation community has reported only isolated problems related to lubricity. Research is in progress relating to future advanced turbine engines in which the incoming fuel will be exposed to temperatures reaching 163 ºC and as high as 315 ºC.

What has been the experience with compression ignition engines?

Unit injector systems and in-line pumps are actuated by cams lubricated with crankcase oil, and have minimal sensitivity to fuel lubricity. Rotary and distributor type pumps, commonly used in light- and medium-duty diesel engines, are completely fuel lubricated, resulting in high sensitivity to the effects of lubricity. As a result, the rotary fuel injection system has been the primary focus of lubricity research. As noted as far back as 1970, blending diesel fuel with a small concentration of good lubricity fuel has a disproportionately large effect on the wear characteristics of a blend. Blending or mixing different fuels minimizes the effect of isolated poor lubricity products. It has been observed that most equipment failures occur in fleets that are supplied from a single fuel source.

What has been the experience of the U.S. Military?

Military vehicles are particularly susceptible to the effects of fuel lubricity, as a given post or camp or station will use fuel from a single supplier for a minimum contract period of 12 months. As a result, little potential exists for blending of fuels from different sources. In addition, due to harsher operating conditions, engines used in military vehicles (especially tactical vehicles) are more vulnerable to lubricity problems than the equivalent engines operated in commercial vehicles.[44] In the 1970s, the Army approved JP-5 as an alternative to DF-2 (VV-F-800) diesel fuel. In the 1980s, the Department of Defense (DOD) adopted a single fuel for the battlefield and converted its tactical fleet of compression ignition powered vehicles from DF-2 to aviation turbine fuel (MIL-T-83133). In March 1988, DOD specified JP-8 as the primary fuel support for overseas ground forces, but considered it and Jet A-1 equivalent fuels. Jet A-1 does not contain the corrosion inhibitor additives of the JP-8 fuels. During Operation Desert Storm, the military experienced rotary diesel fuel pump failures on its vehicles when operated on Jet A-1. While examinations of the failed fuel injection components indicated the majority of failures were attributed to causes other than lubricity, the Jet A-1 did appear to produce increased wear in some areas of the pumps. Tests performed with rotary injection pumps on a motorized test stand indicated very severe wear was produced with Jet A-1 in as little as eight hours. Wear rate was significantly reduced by the corrosion inhibitors specified for use in JP-8. Subsequently, the U.S. military no longer considered those fuels to be equivalent.

The military noticed vehicle fuel system component wear when fuels with a SLBOCLE value of less than 2,000 grams were used consistently. The wear became significant for fuels with a SLBOCLE value of less than 1,600 grams. The DOD indicates in its comments to the proposed rule that, since the introduction of 500 ppm sulfur diesel fuel in the United States in 1993, it has experienced lubricity problems particularly in the Midwest and Northwestern portion of the United States, especially during the winter season. As a result, seven military bases require lubricity additives in the diesel fuel they procure during the winter months.

What has been the experience of the U.S. commercial sector?

According to the literature, no widespread failures associated with poor fuel lubricity have been reported in the United States, although on average, its diesel fuel has borderline lubricity, based on the HFRR test. However, a few commenters indicated experience of lubricity problems with existing diesel fuel, particularly in the United States. Fuel sulfur levels have been restricted to 500 ppm nationwide since 1993, except for Alaska and certain territories. In commercial vehicles, the beneficial effect of blending different fuels is likely to occur.

When lubricity has been a problem, failures that have been reported involved the use of No. 1 type diesel fuels with viscosities below 2.0 cSt at 40ºC. Very low ambient temperatures, aside from the obvious effect on viscosity, greatly reduces the solubility of moisture in the fuel. Dissolved moisture is necessary for the oxidative corrosion wear mechanism to occur. Many rotary fuel injection systems intended for use in cold climates contain components manufactured using improved metallurgy specifically for this reason. Many municipal bus fleets in the continental United States operate year round using low viscosity diesel fuel, such as DF-1, to minimize exhaust emissions. In practice, many operators procure aviation kerosene fuels, particularly in more temperate southern areas where low viscosity diesel fuel is not readily available. Anecdotal reports of injection system failures with these fuels are relatively common, with replacements occurring as early as 15,000 miles in some instances.

What has been California's experience?

Low sulfur (500 ppm) diesel fuels have been marketed in Southern California since 1988. Beginning October1993, diesel fuels marketed in all of California had to meet the new Federal sulfur standard of 500 ppm and a new state requirement of 10 percent aromatics by volume, or equivalent emissions. On average, the sulfur content of California's diesel fuel is about 140 ppm. In 1989, a few researchers, including fuel suppliers and engine and equipment manufacturers, recognized that the regulations to reduce the aromatics content in 1993 would have the potential to affect equipment if the fuel lubricity was reduced substantially. Of particular concern was the protection of rotary distributor pumps used in passenger cars, light vans and trucks, and much of California's agricultural equipment.[45]

A Governor's Task Force on diesel fuel was created to investigate concerns regarding lubricity and other properties of the reformulated fuel. As a result, for three years from October 1993 through 1996, staff of the California Air Resources Board monitored fuel injection system problems (and also price increases and reports of supply shortages), and recommended that fuel suppliers monitor the lubricity of their fuel using the U.S. Army's SLBOCLE test or other appropriate test and add lubricity enhancing additives to diesel fuel with a SLBOCLE test result below 3,000 grams. The 3,000 gram level was a compromise between the 2,220 gram level suggested by the American Petroleum Institute (API) and the 3,330 gram level requested by Engine Manufacturers Association (EMA). Diesel fuels marketed in California are blended from various refinery products and contain lubricity enhancers and other additives. As previously discussed, the SLBOCLE test lacks precision in evaluating additized fuels and underestimates the benefit of lubricity additives. Thus, the test results were considered an indication of the lubricity of the base fuel, and a worse case of actual fuel lubricity. Cetane-enhanced alternative formulation fuels, with aromatic content near 20 percent, were not hydrogenated as severely, and thus were not as dependent on additives for acceptable lubricity.[46]

During the three year monitoring period of 1993-1996, no lubricity-related fuel pump damage was documented for diesel vehicles using California fuel. Also, analysis of the data showed no strong correlation of lubricity with either sulfur or aromatic content. At first, only 30 percent of the fuels evaluated met or exceeded the 3,000 gram level. The average SLBOCLE results for California fuels increased from 2700 grams in 1993 to 3,300 grams in 1996. This improvement may be attributed to use of lubricity additives, combined with increasing production of alternative formulations and blended products, which perform better on the SLBOCLE test than do low aromatic products with lubricity additives.[47]

What has been Canada's experience?

Overall, Canadian fuels tend to have low density, low viscosity, and lighter distillation characteristics than those used in the United States, and are among the worst lubricity fuels in the world. Diesel fuel No. 1, as used for much of the year in Canada, is broadly similar to the kerosene fuels that caused durability problems in military vehicles, municipal buses, and aviation equipment. Even prior to the introduction of low-sulfur diesel fuel, Canada had reported problems with reduced equipment life. These failures were typically associated with winter grade diesel fuels, particularly when they were used in warmer conditions. Low-sulfur fuels have been available in Canada since the 1980s, and a maximum sulfur content of 500 ppm was mandated in 1994. Fleet testing repeatedly demonstrated catastrophic pump failure in less than 500 miles of operation on Canadian fuel. In 1997, Canada modified its low-sulfur diesel fuel specification to address the lubricity of winter fuels - those having a viscosity below 1.9 cSt at 40ºC or less and a cloud point of -30ºC or lower. A fuel supplier can "qualify" its fuel using one of several options, ranging from a field test to pump rig tests to the HFRR or BOCLE laboratory scale test. A fuel supplier must use lubricity additives if the fuel fails the selected test.

What has been Sweden's experience?

Beginning in 1991, Sweden required very low concentrations of sulfur and aromatics in its diesel fuels: maximum of 10 ppm sulfur and 5 percent by volume aromatics for Class I fuel, and maximum of 50 ppm sulfur and 20 percent by volume aromatics for Class II fuel. Field trials and research conducted by the fuel producers and equipment manufacturers indicated that these fuels, without additives, would produce unacceptable wear of light-duty injection systems. Failure of test rotary fuel pumps occurred between 5,000 and 19,000 miles for Class I fuel, and between 8,000 and 48,000 miles Class II fuel. Heavy-duty in-line pumps were less susceptible to low lubricity fuel. This experience drew more attention and interest to the possibility of a widespread fuel lubricity problem in the rest of Europe and in North America at the time they were introducing their lower sulfur and lower aromatic fuels. Since that time the use of lubricity additives in Sweden's fuel has resulted in acceptable equipment durability.[48] Beginning in 1995, Sweden required nonroad equipment, excluding commercial boats, railroads, and stationary engines, to use the very low sulfur diesel fuel (which, as noted above, includes the lubricity additives). The use of the very low sulfur diesel fuel in nonroad applications in Sweden has not resulted in any equipment durability problems.

What has been Great Britain's experience?

Since 1998, due to the use of tax incentives, nearly all highway diesel fuel in Great Britain has met a 50 ppm sulfur level. A lubricity additive is added to the fuel. The use of the low sulfur fuel in on-highway trucks in Great Britain has resulted in acceptable equipment durability. Although nonroad diesel fuel in Great Britain is not low sulfur, a limited number of applications do use the low sulfur diesel fuel. The use of low sulfur diesel fuel in nonroad applications in Great Britain has not resulted in any equipment durability problems.

What has been the Experience in Asia and in South-Pacific Countries?

In the Far East , a number of countries have already or will soon implement a 500 ppm sulfur maximum: Korea in 1996, Japan in 1997, Hong Kong in 1997, Taiwan in 1999, Thailand in 1999, Philippines in 2000 . In addition, Australia in 2003, and New Zealand in 2005 will implement a 500 ppm sulfur maximum. Research is being performed to determine the effects of Asian low-sulfur fuel on injection system durability, and except for one study in Thailand, results have not yet been published.

In Thailand, a field study was conducted to investigate the effects of low-sulfur diesel fuel (500 ppm) without lubricity additives on rotary injector pumps operating in actual driving conditions in Thailand.[49] The study involved three vehicles each for two fuels for 30,000 km. The first fuel was imported and made up of a blend of U.S. West Coast, Malaysian and locally refined fuel having a HFRR test value of 358 µm. The second fuel was the first batch of locally produced off highway fuel with a HFRR test value of 467 µm. Evidence of wear at the end of the study were within the normal acceptable range of wear at 30,000 km for all six pumps, although the pumps operated on the locally refined fuel showed nearly twice as much wear, on average, as the pumps operated on the imported blend.

4. What Can Be Done About Poor Lubricity Fuels?

Blending poor lubricity diesel fuel with a small concentration of good lubricity fuel has a disproportionately large effect on the wear characteristics of the blend. Thus, blending or mixing different batches of diesel fuel, such as that which occurs in the commercial market in the United States, minimizes the effect of isolated poor lubricity fuels.

Also, blending small amounts of lubricity enhancing additives has increased the lubricity of poor-lubricity fuels to acceptable levels. Laboratory testing, field experience and controlled pump and vehicle testing indicate that additives can be effective in reducing pump wear. The lubricity additives widely used in diesel fuels range from the corrosion inhibitors used in aviation turbine fuel to fully synthetic non-acidic products. The additives' impact on pump wear appears to be strongly influenced by fuel composition and distillation characteristics, with larger improvements observed for poorer lubricity fuels. According to contacts in the industry and an SAE report, refiners are likely blending additives to diesel fuel on a batch-to-batch basis when poor lubricity fuel is expected. In one comment to the proposal, a producer of fuel systems confirmed that much of the U.S. diesel fuel today contains lubricity enhancing additives, including military fuels.

Sweden, Canada, and the U.S. military offer examples of experiences using additives to improve the lubricity of diesel fuel. Since 1991, the use of lubricity additives in Sweden's fuel has resulted in acceptable equipment durability.[50] Since 1997, Canada has required that diesel fuel not meeting a minimum lubricity be treated with lubricity additives. The U.S. military has found that traditional corrosion inhibitor additives that it uses, such as di-linoleic acid, have been highly effective in reducing fuel system component wear. Consequently, the U.S. Army now blends 250 mg/L of MIL-I-25017E corrosion inhibitor additive to all fuels that show a SLBOCLE result below 2,000 grams, and regularly for Jet A-1, JP-5 and JP-8 fuels. In addition, seven military bases that procure commercial fuel from the Midwest and Northwestern portion of the United States require lubricity additives, especially for that fuel they procure during the winter months.

According to the literature, lubricity additives have not been found to significantly affect exhaust emissions. However, adding too much can produce unwanted side effects, such as deposits in in-line injection pumps, fuel filter plugging, injector tip deposits, plunger sticking, and water haze problems. For these reasons, the selection and treat rate of an additive are important. An SAE report indicated it is likely that the more recently developed non-acid based additives provide improved performance with reduced problems from lubricant interaction. For example, in early 1996, field problems occurred in Western Europe with vehicles fitted with in-line diesel injection pumps. Fuel filters were being blocked with black sticky gel caused by the use of lubricity additives based on a specific type of divalent acid.[51]

The literature indicates that treat rates typically vary from 20 to 200 mg/L. Higher concentrations are occasionally used, although in general, benefits appear to decrease at concentrations above 500 mg/L. Oxidative corrosion and associated sensitivity to moisture are eliminated by trace quantities of corrosion inhibitor additives. However, these additives have little or no effect on adhesion and scuffing wear mechanisms. While corrosion and rust inhibitor additives are commonly blended to distillate fuels at 10-15 ppm by the petroleum producers to protect transport pipelines, this low concentration provides little protection to consumers because of leaching during transportation and handling.

Stanadyne, the National Biodiesel Board, and West Central Soy, in comments to the proposal, indicate that blending biodiesel with low lubricity conventional diesel fuel can increase the lubricity to acceptable levels. Biodiesel is a zero sulfur diesel fuel made from domestically produced renewable fats and oils. Testing of biodiesel at Stanadyne indicated that the blending of two percent biodiesel with any conventional diesel fuel will be sufficient to address the lubricity concerns that we have with existing diesel fuels. However, more testing would be required to determine the required level of biodiesel in fuels not yet being produced, such as the 15 ppm sulfur fuel required by today's action. Stanadyne indicates the inclusion of low blends of biodiesel is desirable for two reasons. First, it would eliminate the inherent variability associated with the use of other additives, and would also eliminate the question of whether sufficient additive was used. Second, biodiesel is a fuel or a fuel component rather than an additive. It is possible to burn pure biodiesel in conventional diesel engines. Thus, if more biodiesel is added than required for adequate lubricity, there will not be any adverse consequences that might be seen if other lubricity additives are used at too high a level.

Also, it is possible for equipment producers to design new injection system equipment to tolerate lower lubricity fuels. Revised manufacturing practices to include improved materials successfully allowed commercial aircraft to operate continuously with very poor lubricity kerosene-based fuels. Studies sponsored by the U.S. Army also confirmed the possibility of reducing or eliminating the effects of poor lubricity through the use of improved metallurgy. This approach could be applied to fuel systems for commercial compression ignition engines. Conversion kits are already available to allow many pump systems to operate on low-lubricity/low viscosity fuels and are commonly used on engines in Arctic regions. For the purposes of this rule, we will assume that such conversions will not be commonplace in the commercial vehicle and vehicle engine market.

Recommendations by the commentors were largely split by industry and are briefly summarized here. They are discussed in more detail in the Response to Comments document in the public docket. The equipment manufacturers indicated that the "voluntary" approach is not adequate today, and is not likely to be adequate with the 15 ppm sulfur standard. For example, Stanadyne (and DOD) indicated that their experience with the current policy of treating fuel on an as-needed basis has fallen far short of ensuring good fuel lubricity and that a voluntary approach under the 15 ppm sulfur program will lead to wide scale lubricity problems. EMA, Cummins, the Alliance of Automobile Manufacturers and Stanadyne recommended that we specify lubricity measurement methods and set limits. DOD recommended that EPA stress to the industry the importance of having the appropriate performance requirements in the ASTM specification and to encourage the industry to develop standards by imposing a deadline for industry-wide implementation.

API, Marathon Ashland Petroleum, the American Trucking Association and Cenex Harvest States Cooperatives also expressed concern about the impact of today's action on lubricity and recommended that EPA fully explore the lubricity issue; but API and Marathon Asland Petroleum also commented that regulating lubricity is not necessary. Stanadyne and the National Biodiesel Board suggested that we could require biodiesel to be blended with the 15 ppm sulfur diesel fuel, thereby alleviating lubricity concerns otherwise apparent with the low sulfur diesel fuel. By doing so, there would be no need for us to adopt a voluntary or minimum lubricity standard.

5. Today's Action on Lubricity: A Voluntary Approach

We have decided not to establish a lubricity standard in today's action. We believe the best approach is to allow the industry and the market to address the lubricity issue in the most economical manner, avoiding an additional regulatory scheme. A voluntary approach should provide adequate customer protection from engine failures due to low lubricity, while providing the maximum flexibility for the industry. This approach will be a continuation of current industry practices for diesel fuel produced to meet the current Federal and California 500 ppm sulfur diesel fuel specifications, and benefits from the considerable experience gained since 1993. It recognizes the uncertainties of testing and measuring fuel for lubricity, and will also include any new specifications and test procedures that we expect will be adopted by the American Society for Testing and Materials (ASTM) regarding lubricity of highway diesel fuel quality. We fully expect the refining industry, engine manufacturers and end users to work together to resolve any issues as part of their normal process in dealing with customer and supplier fuel quality issues.

We do not believe that an EPA regulation is appropriate for several reasons. First, the expertise and mechanism for a lubricity standard already exist in the industry. According to the comments, the industry has been working on a lubricity specification for ASTM D-975, and low cost remedies for poor lubricity have already been proven and are already being used around the world. Although some commenters expressed concerns that the ASTM process might move too slowly to establish a lubricity specification by 2006, we fully expect that today's action will increase the urgency of those working to establish an ASTM D-975 lubricity specification, and we believe they will do so in time for the production and distribution of the low sulfur highway diesel fuel. We will do our part to encourage the ASTM process be brought to a successful conclusion.

Second, we have no firm basis to justify a lubricity specification in today's action. One such basis might be adequate demonstration that a lubricity level below or above a certain specification would either cause emissions to increase, or hinder the operation of emission control equipment. However, we have no evidence that lubricity impacts emissions, or emission control equipment. This issue is primarily a concern about equipment performance. Equipment performance is more appropriately addressed by the industry rather than government regulation by this Agency.

Third, even if we had a statutory basis to justify a lubricity standard, we are concerned that establishing an EPA lubricity regulation would provoke the same disagreements that the industry is now engaged in its efforts to establish an ASTM D-975 specification. We are in no better position to judge those issues than the industry experts who are already involved. Further, once a specification is put into the regulations and the industry subsequently determines that the specification should be changed, based on new information or circumstances, the burden would be on us to amend the mandated specification by rulemaking. This is a significant burden to put on the Agency for an engine performance issue that can and should be resolved by the industry without government intervention.

6. Are There Concerns Regarding the Impact of Diesel Desulfurization on Other Fuel Properties?

EPA is not taking action today on any fuel properties other than sulfur. We have examined the impact of fuel properties other than sulfur, such as aromatics, on the materials used in engines and fuel supply systems. We do not believe there will be impacts on materials from such other fuel properties.

While there were some problems with leaks from fuel pump O-ring seals made of a certain material (Nitrile) after the introduction of 500 ppm sulfur diesel fuel in 1993, these issues have since been addressed by equipment manufacturers who switched to materials that are compatible with low aromatic fuels. The leakage from the Nitrile seals was determined to be due to low aromatic levels in some 500 ppm fuel, not the low sulfur levels. In the process of lowering the sulfur content of some fuel, some of the aromatics had been removed. Normally, the aromatics in the fuel penetrate the Nitrile material and cause it to swell, thereby providing a seal with the throttle shaft. When low aromatic fuel is used after conventional fuel has been used, the aromatics already in the swelled O-ring will leach out into the low aromatics fuel. Consequently, the Nitrile O-ring will shrink and pull away, thus causing leaks, or the stress on the O-ring during the leaching process causes it to crack and leak. Not all off highway fuels will cause this problem, because of the amount and type of aromatics will vary. Subsequently, one engine manufacturer recommended replacement of the old O-ring seals in leaking fuel pumps with a new part of the same material, reasoning that the new part is not worn or has not taken a compression set. One fuel producer recommended switching all fuel injection pump applications to a different material (Viton) . Fuel pumps using a Viton material for the seals did not experience leakage.

In comments to the proposal, the EMA, American Trucking Association, API and Marathon Ashland Petroleum expressed general concerns about potential impact of 15 ppm sulfur diesel fuel on elastomer compatibility. However, these comments did not suggest that the 15 ppm sulfur diesel fuel will likely cause elastomer compatibility problems, or that any preemptive action by EPA or the industry is necessary. EMA clarified that the elastomer compatibility difficulties in the early days of the 500 ppm sulfur fuel program were likely a result of severe aromatic reductions in some of the fuels, not necessarily the removal of sulfur. We have no reason to believe that additional problems will occur with a change of fuel from 500 to 15 ppm sulfur.

D. Feasibility of Maintaining Off highway Fuel in the Distribution System

1. Overview

There are a number of potential links in the highway diesel fuel distribution system from the source of the fuel (refinery or importer) to the fuel retailer or fleet operator (hereafter referred to as the point-of-use).[n] Depending on the location of the point-of-use relative to the fuel source, the path of any given batch of highway diesel fuel through the system can include various combinations of these links. Some highway diesel fuel is transported directly from the refinery rack to the point-of-use via tank truck. However, most fuel is transported via the pipeline system to product terminals. From the storage tanks at such terminal facilities, fuel can either be trucked to the point-of-use or transferred by tank truck to bulk plants for later transfer to the point-of-use.

In some circumstances, highway diesel fuel is also transported to a terminal (or to a pipeline connection) by barge or marine tanker, such as along the eastern seaboard, from Texas to Florida, and in the case of imports. In cases where pipeline service is limited, fuel is also shipped to the terminal by rail car. Smaller tank trucks called tank wagons are used to deliver fuel to a variety of users including smaller retailers, fleet operators, and heating oil customers. Tank wagons normally have multiple tank compartments to accommodate the delivery of several different fuel types in a single delivery circuit. Most tank wagons also have a separate delivery system for each product. There is a trend towards the increased use of such separate delivery systems.

The same facilities in the fuel distribution system that are used to handle highway diesel fuel are sometimes used to handle other products, including those with a high sulfur content. As a result, there is currently some mixing of high sulfur products into highway diesel fuel. Sulfur contamination of highway diesel fuel from such mixing can occur at each link in the distribution

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[n] For additional discussion of the make-up of the highway diesel fuel distribution system, please refer to the National Petroleum Council's (NPC) report on U.S. Petroleum Refining (attachment #6 in docket item IV-D-343) and to the Draft RIA for the proposed rule.

system and is cumulative. Therefore, fuel batches whose distribution paths contain more links are subject to more instances where contamination can occur.

The pipeline system is the primary source of potential mixing of high sulfur products with highway diesel fuel in the distribution system. Transport by pipeline can involve a number of steps. For example, fuel is placed in storage tanks prior to injection into the pipeline and at transfer points between a main pipeline and branch lines or another operators pipeline. Thus, there are a number of instances when highway diesel fuel can come into contact with high sulfur products during shipment by pipeline. Pipeline systems vary greatly in the factors that can contribute to product mixing. These factors include in the pipeline diameter, length, flow rate, and number of branches off the main pipeline line. The Association of Oil Pipelines (AOPL) stated that as the complexity of the pipeline system increases, there are a greater number of potential sources of sulfur contamination.[52]

The most significant opportunity for mixing of high sulfur products into highway diesel fuel during shipment by pipeline is associated with the fact that different products are normally shipped through the same line sequentially with no physical separation between the products. The mixture between two products where they abut each other in the pipeline is referred to as interface when it can be blended into another product, and transmix when it must be returned to the refinery for reprocessing. Pipeline operators take care to sequence the different products they carry in such a way as to minimize the amount of transmix generated and the cost of downgrading interface volumes to a lower value product.

Smaller batches of highway diesel fuel are commonly drawn off from a larger batch at various points as it travels along the length of a main pipeline. A batch of fuel can also be injected into a pipeline at various points along its length. An additional volume of interface can be generated during each of these transfers. To minimize the generation of additional interface volumes, such transfers are accomplished within the "heart"[o] the batch already in the pipeline whenever possible. Additional interface volumes can also be generated when a batch of fuel is passed between different pipeline systems. This is primarily due to the need for the fuel batch to be temporally placed in a stationary storage tank to facilitate the transfer between pipeline systems.

All of the product that must be downgraded to a lower value product because of mixing in the pipeline is sometimes referred to as interface, although strictly speaking, interface is only generated when two products abut each other in the pipeline. Relatively small volumes of mixed products are commonly included in the statement of total interface volume, such as those associated with purging products contained in the manifolds at tank farms and in preparing for

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[o] The heart of a batch of fuel in a pipeline is that portion far enough from either end of the batch to ensure that no mixing occurs with other adjacent products.

the injection of a batch of fuel into the pipeline. The various concerns related to potential sulfur contamination during the distribution of highway diesel fuel by pipeline are discussed in the following section on limiting contamination in the pipeline system.

There are also significant concerns specific to limiting sulfur contamination in the other links in the distribution system (terminals / bulk plants, tank trucks / tank wagons, marine transport). These concerns include the potential for contamination of 15 ppm highway diesel fuel when it is put into a stationary storage tank, vehicle tank compartment, transfer line, or delivery line that previously held high sulfur products. Sulfur contamination can also result from leaking valves. Diesel fuel sulfur content can also be impacted by the use of additives that have a high sulfur content. These concerns are discussed in separate subsections that follow on limiting contamination at stationary storage facilities, during transport by surface vehicles, during marine transport, and from diesel fuel additives. Issues related to limiting contamination at tank farms, whether they are part of a pipeline operation or a terminal facility, are discussed in the section on limiting contamination at stationary storage facilities.

The extent to which mixing of high sulfur products into highway diesel fuel can be tolerated is dependent on the maximum allowable sulfur content for highway diesel fuel, the sulfur level of highway diesel fuel as it leaves the refinery gate, and the sulfur content of the product with the highest sulfur cap that shares the distribution system with highway diesel fuel. The highest sulfur product that presents a concern with respect sulfur contamination of highway diesel fuel from mixing in the distribution system is off highway diesel fuel, which has an industry-standard maximum sulfur content of 5,000 ppm and often averages approximately 3,000 ppm sulfur. EPA’s current cap on the sulfur content of highway diesel fuel is 500 ppm with actual sulfur level at production averaging approximately 340 ppm.[p] Thus, currently there is a 1 to 10 ratio of the maximum allowable sulfur content of highway diesel fuel to the highest sulfur content of other products in the distribution system. This ratio provides a reference regarding the current experience of the distribution industry in limiting the sulfur contamination of highway diesel fuel.

Another useful reference is provided by the ratio of the of the difference between actual highway diesel fuel sulfur levels and the 500 ppm cap to a reasonably severe sulfur level in off highway diesel fuel. The average sulfur level of current highway diesel fuel is 160 ppm below the 500 ppm cap. This difference below the sulfur cap is hereafter referred to as the “headroom” below the cap. Although the maximum sulfur level of of highway diesel fuel potentially is 5,000 ppm, fuel batches near this cap are likely to be very rare and to originate only from a very limited number of refineries. In addition, batches of of highway diesel fuel that are near the 5000 sulfur cap are likely to be diluted with batches of lower sulfur content before (or as) they are introduced in the pipeline. Based on this, we believe that 4,000 ppm is an appropriately severe sulfur level

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[p] See section IV.A.2. regarding current sulfur levels in highway diesel fuel.

to compare against the current headroom below the existing sulfur cap for highway diesel fuel. Thus, currently there is a 1 to 25 ratio of the current headroom below the highway diesel fuel sulfur standard to the highest sulfur level in a product that highway diesel fuel might reasonably be expected to come into contact with in the distribution system.

When the 15 ppm sulfur cap for highway diesel fuel is implemented, of highway diesel fuel could have a sulfur content of approximately 333 times the highway diesel fuel sulfur cap. Under our sulfur program, we expect that highway diesel fuel designated as meeting the 15 ppm cap on sulfur content will leave the refinery with an average sulfur concentration of approximately 7 ppm. Consequently, for highway diesel fuel to comply with the 15 ppm sulfur standard, sulfur contamination could contribute no more than 5 - 8 ppm to the final sulfur of the fuel. This translates to a 1/500 - 1/800 ratio of the maximum allowable sulfur contamination in highway diesel fuel to the highest sulfur level in a product that highway diesel fuel might reasonably be expected to come into contact with in the distribution system.

Based on a comparison of the above ratios, batches of highway diesel fuel meeting a 15 ppm sulfur cap will be able to tolerate much less mixing with high sulfur products than can current batches of 500 ppm highway diesel fuel. It follows that adequately limiting sulfur contamination during the distribution of highway diesel fuel meeting a 15 ppm sulfur cap may be significantly more challenging than under the current 500 ppm sulfur cap. A comparison with instances where the distribution industry has managed other difficult contamination issues is useful in evaluating the relative magnitude of the new challenge posed by the implementation of a 15 ppm cap on the sulfur content of highway diesel fuel.

In Sweden, diesel fuel meeting a 10 ppm sulfur cap has been distributed for some time. However, high sulfur fuel oils are typically distributed in a separate distribution system in Sweden. Due to this separation, Swedish 10 ppm sulfur diesel fuel is mostly segregated from high sulfur products. Therefore, it is difficult to draw inferences from the Swedish experience on how well the U.S. distribution system will accommodate 15 ppm highway diesel fuel. ARCO Petroleum currently markets highway diesel fuel meeting a 15 ppm cap in a limited fashion in California. However, this effort has yet to expand to the extent that their product is shipped in the common distribution system. Thus, current experience of marketing 15 ppm diesel fuel in the U.S. does not provide a useful reference with respect to the conditions when our sulfur program will be implemented.

The distribution system has experience in limiting contamination of other products it handles that may provide techniques useful in adequately controlling the sulfur contamination of 15 ppm sulfur highway diesel fuel. For example, the presence of small quantities of gasoline in diesel fuel can cause the industry standard flash point for diesel fuel to be exceeded.[q] This is a significant concern because diesel fuel with an inappropriately high flash point presents a explosion hazard and its use can result in driveability problems.[r] In addition, it is very difficult for a batch of diesel fuel that is out of compliance with the flash specification to be brought back into compliance by blending in a quantity of compliant diesel fuel into the noncompliant batch.[s] Consequently, extreme care is taken to prevent mixing gasoline into diesel fuel. One relevant example is that in separating a batch of diesel fuel from a batch of gasoline that it abuts in the pipeline, none of the interface is allowed into the batch of diesel fuel.

Although most of the fuels handled in the distribution system are fungible, some segregated products are carried such as high cetane diesel fuel and Amoco's clear premium gasoline. In the case of Amoco's clear gasoline, mixing with other products must be strictly limited to maintain the clarity of the product. This product is routinely transported by pipeline. Limiting contamination during the transportation of such specialty products involves unique challenges that may provide techniques useful in limiting sulfur contamination of 15 ppm highway diesel fuel.

The current experience with limiting dye contamination in highway diesel fuel provides another useful point of reference regarding a contamination concern that is currently being managed by the distribution system. EPA requires that highway diesel fuel must show no trace of the red dye which is required to be present in of highway diesel fuel by the Internal Revenue Service (IRS) to demonstrate its non-tax status. A very small quantity of dyed of highway diesel fuel mixed into highway diesel fuel can cause in a visible trace, resulting in a violation of EPA requirements. To satisfy IRS requirements at the terminal, red dye must be present in of highway diesel fuel at a concentration of at least 3.9 pounds per 1000 barrels (approximately 13 ppm).[53] Some pipeline operators commonly add a lesser amount of dye upstream in the pipeline. One operator requires that 0.75 mg per liter or approximately 0.9 ppm is added to of highway diesel fuel prior to its injection into the pipeline. This practice is followed to minimize the loss of red dye during transportation of dyed fuel and to reduce the risk of contaminating highway diesel fuel with red dye in the pipeline system. An additional quantity of dye is then added at the terminal to meet IRS requirements. Approximately 0.1 mg per liter of red dye in diesel fuel is sufficient to result in a visible trace. This translates to a ratio of 1 to 130 regarding the maximum amount of dye contamination that can be tolerated in highway diesel fuel to the minimum

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[q] The impact of mixing gasoline into diesel fuel on diesel flash point is a function of the high vapor pressure of gasoline relative to diesel fuel. In a diesel storage tank, gasoline contained in the diesel fuel will contribute a disproportionate fraction of the total fuel volume that is in the vapor phase. During the winter, this contribution can cause the vapor phase in a storage tank to be combustible, resulting in an explosion hazard.

[r] Driveability problems can result from premature ignition of the fuel-air charge in the cylinder.

[s] This procedure is the preferred method of handling noncompliant fuel batches.

concentration of red dye that must be in of highway diesel fuel to meet IRS requirements (3.9 pounds / 1000 barrels).

Since no red dye is intentionally added to highway diesel fuel, any dye that is present must originate from contamination from of highway diesel fuel. This suggests that it may be most appropriate to base a comparison of the experience in limiting dye contamination with the difficulty in limiting sulfur contamination under our program on the 1/500 - 1/800 ratio of the maximum amount of sulfur contamination that we expect could be tolerated in 15 ppm highway diesel to the highest sulfur level in a product that highway diesel fuel might reasonably be expected to come into contact with in the distribution system.

The fact that red dye is not added at the full concentration required by the IRS until after off highway diesel fuel reaches the terminal, prevents a direct comparison of the experience in limiting dye contamination with that of limiting sulfur contamination of highway diesel fuel meeting a 15 ppm sulfur cap during transport by pipeline. However, the 1/130 ratio of the concentration of dye allowed in highway diesel fuel to the minimum concentration required in of highway diesel fuel does provide a useful reference regarding a the current ability of distributors downstream of the terminal (such as tank truck and tank wagon operators) to limit contamination.

The IRS can impose a more stringent chemical test to detect red dye in highway diesel fuel at levels which do not cause a visible trace. A violation of IRS requirements can be established based on the results of such a test. While we do not have information on the concentration of red dye that could be detected by such a test, it is reasonable to assume that it would be substantially lower than 0.1 mg per liter (which causes a visible trace). Therefore, the ratio of the maximum concentration of dye allowed in highway diesel fuel to the minimum concentration required in of highway diesel may be considerably closer to the 1/500 - 1/800 ratio associated with limiting sulfur contamination of highway diesel fuel meeting a 15 ppm sulfur cap. If this is the case, it would suggest that distributors downstream from the terminal are currently coping with a level of difficulty in limiting contamination similar to that will be encountered as a result of our sulfur program.

The experience in limiting lead contamination in unleaded gasoline from leaded gasoline during the phase-out of lead in U.S. gasoline provides the most useful point of reference. The lead in leaded gasoline was added fully at the refinery, so a comparison of this experience with the difficulty of limiting sulfur contamination under our sulfur program should be valid throughout the entire distribution system. The situations where unleaded gasoline came into contact with leaded gasoline (or traces of leaded gasoline) also parallels the situations that will be encountered regarding the transportation of highway and of highway diesel fuels under our sulfur program. For example, batches of unleaded and leaded gasoline abutted each other during shipment by pipeline, and the same storage tanks and delivery equipment would sometimes be used to handle both types of gasoline. This further supports the applicability of comparing the experience in limiting lead contamination to that of limiting sulfur contamination under our sulfur program.

The maximum lead concentration in unleaded gasoline has always been 0.05 grams per gallon, with the additional requirement that no lead be intentionally added to unleaded gasoline. The maximum lead concentration in leaded gasoline was reduced in steps. In 1980, EPA adopted a “pool standard” of 0.5 grams lead per gallon. Compliance with this “pool standard” was based on evaluating the lead added to leaded gasoline by a given refiner divided by all of the gasoline that the refiner produced (unleaded and leaded). This standard resulted in typical lead levels in leaded gasoline of approximately 1 gram per gallon. In 1982, EPA adopted a 1.1 gram per gallon “leaded gallons standard”. At this time, approximately 50 percent of the gasoline pool was leaded gasoline. Compliance with this “leaded gallons standard” was based on evaluating the lead added to leaded gasoline by a given refiner divided by the volume of leaded gasoline that the refiner produced. The use of this “leaded-gallons standard” had little effect on the in-use lead concentration in leaded gasoline, which remained at approximately 1 gram / gallon until the standard was reduced to 0.5 grams of lead per gallon of leaded gasoline in 1985.

During the time when the lead content of leaded gasoline was typically 1 gram per gallon (near the maximum allowed concentration), lead levels in unleaded gasoline were typically less than 0.005 gram per gallon. This translates to approximately a 1 to 200 ratio of the typical maximum concentration of lead in unleaded gasoline to the typical maximum lead concentration in lead gasoline. Similar to the discussion above regarding dye contamination, the fact that the lead in unleaded gasoline could only have originated from contamination from leaded gasoline suggests that it is most appropriate to base our comparison with the leaded gasoline experience on the 1/500 - 1/800 ratio of the maximum amount of sulfur contamination that we expect could be tolerated in 15 ppm highway diesel to the highest sulfur level in a product that highway diesel fuel might reasonably be expected to come into contact with in the distribution system.

The various ratios discussed above are summarized in the following table IV.D-1.

Table IV.D-1. Ratios Used in Comparing the Relative Difficulty in Limiting Contamination During the Distribution of Various Fuels

500 ppm Highway Diesel Sulfur Cap 5,000 ppm Off highway Diesel Sulfur Cap	$\frac{500}{5{,}000}$	$\frac{1}{10}$
15 ppm Highway Diesel Sulfur Cap 5,000 ppm Off Highway Diesel Sulfur Cap	$\frac{15}{5{,}000}$	$\frac{1}{333}$
Current Headroom Under 500 ppm Cap Severe Sulfur Level in Product that Contacts Highway Diesel	$\frac{160}{4{,}000}$	$\frac{1}{25}$
Expected Headroom Under 15 ppm Cap Severe Sulfur Level in Product that Contacts Highway Diesel	$\frac{5 \text{ to } 8}{4{,}000}$	$\frac{1}{500}$ to $\frac{1}{800}$
Maximum Dye Concentration in Highway Diesel Required Dye Concentration in Off Highway Diesel	$\frac{0.1\text{ ppm}}{13\text{ ppm}}$	$\frac{1}{130}$
Typical Maximum Lead Concentration in Unleaded Gasoline Typical Maximum Lead Concentration in Leaded Gasoline	$\frac{0.005\text{ g/gal}}{1\text{ g/gal}}$	$\frac{1}{200}$

The Association of Oil Pipelines (AOPL) stated that their members believe the task of preventing sulfur contamination in 15 ppm highway diesel fuel will be more difficult than the transition from leaded to unleaded gasoline, the protection of the flash property of diesel fuel, or the prevention of dye contamination.[54] Comparing the ratios discussed above regarding limiting dye contamination (1/130) and limiting lead contamination (1/200), with the ratio of the anticipated headroom under the 15 ppm cap for highway diesel fuel to the highest sulfur concentration in off highway diesel fuel (severe level referenced in table IV.D-1) that is likely to contact highway diesel fuel in the distribution system (1/500 - 1/800), suggests that this is the case. However, this comparison also suggests that the challenge of limiting sulfur contamination in highway diesel fuel meeting a 15 ppm sulfur cap is not an order of magnitude different to the challenge of limiting lead contamination in unleaded gasoline that was successfully managed 25 years ago. This suggests that meeting the new challenge can be accomplished by improving upon existing techniques to limit contamination, rather than requiring a paradigm shift in the way highway diesel fuel is distributed.

Not all pipelines, terminals, and other fuel distributors handle off highway diesel fuel. At such facilities, the challenge of limiting sulfur contamination of highway diesel fuel is, and will continue to be, somewhat less difficult than at facilities that handle off highway diesel fuel. This is because other products that might share the same distribution system have a lower maximum sulfur content than off highway diesel fuel. For example, jet fuel and kerosene is subject to an industry-standard sulfur cap of 3,000 ppm. The ratio of the maximum amount of sulfur that will be allowed in highway diesel fuel under our sulfur program to the maximum concentration allowed in jet fuel or kerosene is 1 to 200. This ratio is identical to that associated with limiting lead contamination during the lead phase-down program. This suggests that the difficulty of limiting sulfur contamination during the distribution of 15 ppm highway diesel fuel at facilities that do not handle off highway diesel fuel will be of a similar magnitude to that experienced in limiting lead contamination during the lead phase-down program.

Although not within the scope of current EPA regulations, the difficulty of distributing highway diesel fuel with a 15 ppm sulfur cap would be significantly reduced if the sulfur content of nonoad diesel fuel were reduced by a future rulemaking. If this took place the product with the highest sulfur content shipped by pipeline would be jet fuel or kerosene which have a maximum sulfur content of 3,000 ppm

In the NPRM, we proposed that with relatively minor changes and associated costs, the existing distribution system would be capable of adequately limiting sulfur contamination during the distribution of highway diesel fuel with a 15 ppm sulfur cap. These projected changes included an increase in the amount of highway diesel fuel that must be downgraded to a lower value product in the pipeline system due to changes in interface handling practices, and increased terminal testing for quality control purposes. We also recognized that distributors downstream of the refinery such as tank truck operators would need to more carefully and consistently observe current industry practices to limit contamination, but projected that this could be accomplished at an insignificant cost. We proposed to hold diesel fuel additives to the same sulfur cap that would apply to diesel fuel, and projected that this could be accomplished without causing a significant burden to fuel marketers and additive manufacturers.

We received a number of comments on the proposed rule that substantial uncertainties exist regarding the ability of the distribution system to adequately limit sulfur contamination of highway diesel fuel meeting a 15 ppm sulfur cap. Some commenters stated that the only way to adequately limit sulfur contamination in the distribution of diesel fuel meeting a 15 ppm sulfur cap may be to create a completely segregated system.

Several commenters stated that EPA should conduct testing to further evaluate the ability of the distribution system to limit contamination to the very low levels necessitated by the implementation of a 15 ppm sulfur cap. The Department of Energy (DOE) called on EPA to conduct a comprehensive technology review regarding EPA's sulfur control program in the 2003 time frame, including the feasibility of distributing diesel fuel with a 15 ppm sulfur cap.[55] DOE stated that such a review is warranted because the distribution industry has never faced a similar challenge in limiting contamination and would need to take extraordinary actions to do so. DOE suggested that EPA participate in an experimental shipment of highway diesel fuel meeting a 15 ppm sulfur cap to evaluate the difficulties faced in limiting contamination.

While we acknowledge that today's rule will pose a substantial new challenge to the distribution system, we believe that the additional measures outlined in this section will sufficiently address issues associated with limiting sulfur contamination during the distribution of 15 ppm sulfur highway diesel fuel. We expect that the changes to distribution practices that may be needed will be logical outgrowths and extensions of current practices. With modest modifications, the existing distribution system will be capable of limiting contamination during the distribution of 15 ppm highway diesel fuel. The changes needed in the distribution system as a result of our sulfur program will be readily apparent once industry focuses on meeting the challenge of limiting sulfur contamination during the distribution of 15 ppm highway diesel fuel. Therefore, testing by EPA or a formal technology review of the ability of the system to limit contamination during the distribution of 15 ppm highway diesel fuel is not necessary.

It is possible that sources of sulfur contamination which did not hitherto represent a significant concern may need to be reevaluated to assess their potential impact on maintaining the 15 ppm cap on the sulfur content of highway diesel fuel. Although all of these potential minute sources of sulfur contamination in the distribution system may not have been identified and quantified, we believe that the total contamination from such sources, while made more significant by the implementation of the 15 ppm sulfur cap, is not of a sufficient magnitude to jeopardize the feasibility of distributing 15 ppm sulfur highway diesel fuel.

We anticipate that the distribution system will conduct an evaluation of the potential sources of contamination to ensure that each segment in the system has a satisfactory margin of compliance below the 15 ppm cap. As a result of this evaluation, we anticipate that industry may take measures to help adequately limit sulfur contamination in addition to those specifically identified at this time. However, we anticipate that these measures will be the exception rather than the rule. We do not anticipate that such additional measures will result in an unacceptable burden to the fuel distribution industry (see Section V.C.3.).

We anticipate that the distribution industry will resolve what minor issues that might remain while gearing up for the implementation of our sulfur program. We also anticipate that some refiners will begin producing 15 ppm diesel fuel well before the time they are required to do so. The voluntary efforts currently under way to market 15 ppm diesel are also expected to expand in the years before the implementation of our sulfur control program. This will facilitate the evaluation by the distribution system of their ability to limit sulfur contamination, and help to ensure that whatever additional changes that may be necessary are made before industry is faced with a regulatory compliance requirement. Industry will also gain experience in limiting sulfur contamination in complying with the recently finalized Tier 2 gasoline sulfur requirements.

Some commenters on the NPRM stated that tanks that handle highway diesel fuel meeting a 15 ppm cap would need to be dedicated to that purpose, necessitating the construction of a substantial number of storage tanks, tank trucks, tank wagons, and barges at unacceptably high cost and with impacts on numerous small businesses. We do not believe that our sulfur control program will cause a significant increase in the extent to which highway diesel fuel must be segregated from high sulfur products in the distribution system beyond the segregation that already exists in much of the system today. Many of the stationary storage tanks, tank trucks, tank compartments and delivery systems on tank wagons, and tank compartments on barges which are used to handle highway diesel fuel are already dedicated to this purpose. Further, we understand that there is a trend to increase this level of dedication, at least among large companies in the distribution industry. Although our program may encourage this trend, we believe that situations where our program will require equipment to be dedicated to handling highway diesel fuel will be the exception rather than the rule.

Fuel distributors commented that contamination during the distribution of fuel in tank trucks, tank wagons, barges, and rail cars could not be successfully managed simply by careful and consistent observation of current industry practices, as we asserted in the NPRM. As discussed below, we continue to believe that in most cases current industry practices will be sufficient to limit contamination if properly followed. The one exception is in the case of barges, which may need additional flushing when switching from a high sulfur product to 15 ppm highway diesel fuel (see Section IV.D.4.).

Several commenters on the NPRM stated that unavoidable contamination could cause many batches of highway diesel fuel to be noncompliant with the 15 ppm cap, resulting in shortages and high costs. These commenters also stated that the current practice of diluting batches of highway diesel fuel that do not comply with sulfur requirements with batches of fuel that have a sulfur content below the standard to bring the resultant mixture into compliance with the sulfur specification would no longer be possible when a 15 ppm cap on the sulfur content of highway diesel fuel was implemented. They related that batches of highway diesel fuel that were found to be noncompliant with the 15 ppm sulfur cap would need to be shipped by truck back to the refinery for reprocessing (treated as transmix), resulting in substantial disruption the market and cost. The Association of Oil Pipelines stated that pipeline operators may need to change the products they choose to place in the pipeline adjacent to batches of highway diesel fuel meeting a 15 ppm cap.[56] If this were the case, additional volumes of transmix could be generated.

We believe that an insignificant additional volume of transmix will be generated as a result of our sulfur program. The generation of such additional transmix volumes will be limited to circumstances related to the transfer of products through the manifolds at stationary storage facilities and in preparing for the injection of products into the pipeline (line fill). We expect that no changes will be needed in the choice of products that abut highway diesel fuel in the pipeline. Therefore, we believe that no significant additional volume of transmix associated with pipeline interface will be generated as a result of our program.

We believe that there will not be a significant increase in the volume of highway diesel fuel discovered to exceed the sulfur standard downstream of the refinery as a result of our sulfur program. Distributors will quickly optimize the distribution system using the means described in this section to avoid creating additional volumes of out of specification product. We anticipate that the preferred method of coping with batches of highway diesel fuel that are discovered to exceed the 15 ppm sulfur cap will continue to be to blend them back into compliance whenever possible. We expect that only in the infrequent instances where other options do not exist, will batches that exceed the 15 ppm cap need to be returned to the refinery for reprocessing (see Section IV.D.6). We believe that such rare circumstances will not significantly increase the difficulty (and cost) of handling out-of specification highway diesel batches under our sulfur program.

We received comments that we had underestimated the amount of highway diesel fuel that would need to be downgraded to a lower value product. Commenters stated that the amount could be so large as to contribute to difficulties in supplying sufficient quantities of highway diesel fuel.

In response to comments, we adjusted our estimate of the amount of highway diesel fuel that would need to be downgraded to a lower value product. Our analysis indicates that the magnitude of the additional volume that would need to be downgraded can be accommodated without causing supply problems or other disruptions to the market (see Section IV.A.9.).

Additive manufacturers stated that holding additives to a 15 ppm cap would result in a significant burden to additive manufacturers due to the need to reformulate their additive packages. They also stated that for certain essential types of diesel additives, no low sulfur alternatives exist.

Our analysis of the Fuel and Fuel Additive (F&FA) database indicates that additives with a sulfur content below 15 ppm are available to meet every purpose in use. However, we agree with commenters that the contribution of high sulfur additives can be adequately controlled without holding such additives to a 15 ppm sulfur cap. Therefore, we included a provision to allow the continued use of additives that exceed a sulfur content of 15 ppm provided that this does not cause the 15 ppm cap on the sulfur content of highway diesel fuel to be exceeded. This provision will prevent any significant impacts from our sulfur program related to the use of diesel fuel additives. Although our sulfur program may encourage high sulfur additives to be retired from the market, we have structured the program in a way that will not require this to happen.

A number of commenters stated that difficulties in complying with our sulfur program would be eased substantially if EPA were to include a downstream tolerance on the 15 ppm sulfur standard to reflect measurement variability. In response to comments, we incorporated a downstream tolerance on the 15 ppm sulfur standard in the compliance provisions of our program to accommodate measurement variability. As suggested in the comments, we believe this will substantially ameliorate concerns regarding the ability to comply with the 15 ppm sulfur standard downstream of the refinery. We believe this allowance will not significantly impact the average level of fuel sulfur in-use. Therefore, providing this measurement tolerance will not significantly reduce the emissions benefits of our program.

We concluded that despite the heightened challenge to the distribution industry caused by our sulfur program, it will be feasible to distribute 15 ppm highway diesel fuel with relatively minor modifications to the existing system which can be accomplished at modest additional costs. The potential sources of sulfur contamination and the additional measures that we anticipate will need to be taken to limit such contamination are discussed in the following sections. Areas where further changes may be found to be called for as a result of the anticipated process of optimizing the distribution system to limit sulfur contamination are also discussed below. Please refer to Section V.C. on the costs to the distribution system, and to the Response to Comments (RTC) document for our reply to comments on the feasibility of distributing highway diesel fuel under our sulfur program.

2. Feasibility of Limiting Sulfur Contamination in the Pipeline System

The primary source of potential sulfur contamination in the pipeline system is associated with the handling practices for interface volumes associated with shipments of highway diesel. The Association of Oil Pipelines (AOPL) stated that other potential sources of sulfur contamination include pipeline dead legs, line fill, tank heels, tank manifolds, and the fact that some valves designed to facilitate batch changes take as long as 45 seconds or more to close.[57] There may also be a heightened level of concern regarding leaking valves. AOPL also expressed concern that their current physical methods[t] of evaluating when to make a cut between adjacent batches in the pipeline may not be adequate for determining when a cut should be made between a batch of 15 ppm diesel fuel and another product batch adjacent to it in the pipeline. The Department of Energy (DOE) stated that sulfur contamination from internal surface accumulation of high sulfur product along the sides of pipes and within tanks, which currently is considered negligible, might become significant given the small amount of contamination that could be tolerated in fuel that must meet a 15 ppm sulfur cap.[58]

Each potential source of contamination in the pipeline system is discussed in turn below. Some of the concerns discussed in this section, such as those related to the interface handling practices regarding pipeline shipments of highway diesel fuel that abut batches of jet fuel or kerosene, line-fill, and leaking valves are also pertinent to limiting contamination in other parts

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[t] Pipeline operators often discern the interface between two products in the distribution system based on a change in fuel density and/or a change in color. Tracking information from upstream in the pipeline is used to help identify the approximate time when the interface between batches will arrive at a given point in the system.

of the distribution system such as terminals and bulk plants. These concerns are discussed here because they are integral facets of the pipeline distribution system.

Pipeline owners operate storage tanks where product is fed into the pipeline, at points along the line where product is exchanged, and at the juncture between two pipelines. These storage tanks are necessary to facilitate the exchange of products in the various lines and to ensure that the pipeline remains in steady operation. Interface and transmix can be generated during this exchange. Concerns related to limiting sulfur contamination in storage tanks used to facilitate pipeline operation are discussed in the section on limiting contamination in stationary storage tanks.

Several commenters stated that our sulfur program would cause a substantial increase the volume of transmix that is generated during the shipment of highway diesel fuel, resulting in an unacceptable burden to industry. This concern is addressed within the sections that address the various potential contamination sources.

a. Interface Handling Practices

i. Current Downgrade Volume

Some pipeline operators currently cut as much as 25 percent of the interface volume generated during the shipment of highway diesel fuel into the highway diesel batch. The other 75 percent of the interface volume is cut into the high sulfur product which abuts the batch of highway diesel fuel in the pipeline. This practice is currently possible because of the large over-compliance with the current 500 ppm standard by refiners.[u] By allowing some high sulfur product to mix with highway diesel fuel, the amount of highway diesel fuel that is downgraded to a lower value product is reduced, thereby minimizing cost.

In addition to the amount of interface that is generated during the actual transport of fuel through the pipeline, relatively minor volumes of interface are also generated during the transfer of products into and out of storage tanks associated with pipeline (and terminal) operation, and in preparing to inject a batch of fuel into the pipeline. Given the small diameter of the piping that connects storage tanks and is used to “lay down” a batch of fuel prior to injection into the pipeline relative to the diameter of the pipeline, and the short length of such lines compared to

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[u] Highway diesel fuel sulfur levels currently average 340 ppm in the United States outside of California. California has its own requirements on highway diesel fuel sulfur content which result in an average sulfur content of 140 ppm within the State of California. See section IV.A.3.

length of pipelines, the amount of interface generated during such product transfers is relatively small compared to that generated in the pipeline.[v]

The Association of Oil Pipelines (AOPL) related that the current downgrade accounting system does not provide a ready means to estimate the current volume of highway diesel fuel downgrade.[59] AOPL stated that this raises concerns regarding the accuracy of the estimates of current downgrade provided by their members and cautioned against their use in estimating the economic impact of our sulfur program. They also stated that the diversity in the characteristics of their members operations led to a wide range in the estimates of the current downgrade volume (ranging from 0.2 percent to 10.2 percent of the total volume of low sulfur diesel fuel shipped by pipeline). These estimates included all of the sources of downgraded highway diesel fuel.

It is worth noting that some commenters on the proposed rule apparently used the upper bound in this range of individual estimates and the assumption that downgrade volumes would double under our program to estimate that 20 percent of 15 ppm highway diesel fuel supplied would need to be downgraded to a lower value product due to mixing with high sulfur products in the distribution system. This approach substantially overestimates the additional highway diesel fuel that would need to be downgraded to a lower value product as a result of our sulfur program because it assumes that the worst case condition with respect to the current downgrade volume is applicable for the entire range of pipeline operators. This does not take into account the diversity in the characteristics of pipeline owner's operations that AOPL related was linked to the wide range in the estimates of the current downgrade volumes that they received from their members.

We believe that the estimates provided by AOPL members provides an adequate characterization of the range of current downgrade volumes across the diverse pipeline distribution system. To derive an estimate of the average downgrade for the pipeline system as a whole today, we used the range of downgrade estimates from AOPL and a characterization of the pipeline distribution system in terms of pipeline diameter and length derived from the PennWell[w] pipeline database. Due to the characteristics of fluids as they travel through a pipeline, the larger the pipeline diameter and the longer a batch of product is pumped through a pipeline, the greater degree of mixing with adjacent batches that will take place. Furthermore, larger diameter pipelines tend to be relatively more complex than smaller diameter lines (i.e. have more tank

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[v] The amount of interface generated is dependent on a number of factors, most prominent of which are the diameter and length of the line through which the product flows. Issues related to "line fill" are specifically discussed in a later section.

[w] A proprietary database of information on pipeline and terminal facilities in the United States produced by PennWell MAPsearch Inc., P.O. Box 5237, Durango Colorado, mapsearch.com.

farms and connections to other lines) leading to a larger number of interface volumes being generated for any given batch of fuel as it travels to its ultimate destination.

We assigned a specific estimate of percent downgrade from those provided by AOPL members to each pipeline diameter included in the PennWell database, ranging from 10.2 percent for the largest diameter pipeline to 0.2 percent for the smallest diameter line. In doing so, we assumed that downgrade increases linearly with the cross sectional area of the pipeline. To account for the impact of pipeline length on downgrade volume, we weighted the downgrade estimate for each pipeline diameter by the fraction of total pipeline system length represented by that diameter. By this method, we estimated that the average downgrade for the pipeline system as a whole currently is approximately 2.5 percent of the highway diesel fuel shipped by pipeline.

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

ii. Downgrade Volume with 15 ppm Sulfur Standard for Highway Diesel Fuel

We are assuming that when the 15 ppm cap on highway diesel fuel sulfur content is implemented, it will no longer be possible to cut any of the interface volume into highway diesel fuel. This is referred to as a protective interface cut, and corresponds to a doubling of the volume of highway diesel interface volume downgraded to a lower value product compared to the 25 percent / 75 percent cut described above. Some individual AOPL members stated that a protective interface cut would be necessary to limit sulfur contamination during the shipment of 15 ppm highway diesel fuel. Some AOPL members also stated that the amount of highway diesel fuel that would need to be downgraded to a lower value product would likely double as a result of our sulfur program. However, they cautioned that actual losses may be higher depending on the extent to which sulfur from preceding batch trails back into a batch of 15 ppm fuel.

Some pipeline operators currently make a protective interface cut when separating a batch of highway diesel fuel from other products which it abuts in the pipeline. This suggests that our assumption that the amount of highway diesel fuel downgraded to a lower value product will double as a result of the implementation of the 15 ppm cap on the sulfur content of highway diesel fuel will yield a conservatively high estimate of our program’s impact. However, given the uncertainties regarding the various sources of highway diesel fuel that must be downgraded to a lower value product, we believe that the use of this assumption provides an appropriate level of confidence that we are not underestimating the impact of our sulfur program. This estimate is also in agreement with that provided by several commenters.

We believe that it is highly unlikely that any difference that might exist in the physical properties of 15 ppm diesel fuel (e.g. density, viscosity) versus those of current highway diesel fuel will cause a substantial change in the extent to which sulfur from preceding batches trails back into batches of highway diesel fuel. Regardless, our estimate that downgrade volumes will double will help to account for various unknowns that may cause downgrade volumes to increase.

By applying the assumption that highway diesel fuel volumes will double as a result of our sulfur program to the estimate of the current downgrade volume (2.2 percent of highway diesel fuel supplied) we estimated that an additional 2.2 percent of the highway diesel supplied will need to be downgraded to a lower value product to adequately limit sulfur contamination as a result of the implementation of the 15 ppm sulfur standard under our program. In gaining experience with the distribution of 15 ppm highway diesel fuel, we anticipate the pipeline operators may cut a somewhat greater portion of highway diesel fuel batches into products that they abut in the pipeline in order to ensure that no volume of interface is cut into the highway diesel fuel batch. This may result in somewhat more highway diesel fuel being downgraded until pipeline operators become more confident in their ability to make a protective interface cut. However, we do not expect that the additional volumes will be significant and believe that pipeline operators will quickly optimize their interface handling practices to limit the volume of highway diesel fuel that must be downgraded. We anticipate that the expansion of voluntary efforts to market 15 ppm diesel fuel will facilitate such fine tuning of the pipeline system to handle 15 ppm highway diesel fuel prior to the implementation of our sulfur program. We attributed costs for this optimization process in our cost analysis (see section V.C.3).

iii. Changes to the Interface Handling Practices when Highway Diesel Fuel Abuts Shipments of Jet Fuel or Kerosene

The industry specification for the end boiling point of kerosene and jet fuel is much lower that the specification for the end boiling point of diesel fuel. Since the measured end boiling point of a fuel is much more related to the presence of high boiling point fuel species rather than their concentration, a small quantity of diesel fuel mixed into kerosene or jet fuel can cause the end boiling point specification for these product to be exceeded. The current practice when a batch of highway diesel fuel abuts a batch of jet fuel or kerosene in the pipeline is to cut all of the interface generated into the batch of highway diesel fuel. Discussion at a recent industry conference highlighted the fact that this practice will no longer be possible when all highway diesel fuel is required to meet a 15 ppm sulfur cap because of the relatively high sulfur content of jet fuel and kerosene (as high as 3000 ppm). It was stated that as a result the mixture of highway diesel fuel meeting a 15 ppm sulfur cap and jet fuel or kerosene would need to be returned from the terminal to the refinery for reprocessing, at high cost (i.e. would need to be treated as transmix).

While we agree that handling procedures for this mixture will need to change, we believe that it will not be necessary to treat it as transmix. We believe that there will be opportunity for the mixture to be sold from the terminal into the off highway diesel pool or 500 ppm highway diesel pool during the period when the temporary compliance option is available. We have concluded that the increased volume of downgrade can be accommodated without disruption to the fuel market. The increased cost associated with downgrading this mixture is included in our analysis of distribution costs. The need for this additional downgrade results in an effective reduction in the supply of highway diesel fuel. The increased cost of supplying an additional volume of highway diesel fuel to compensate for this reduction is incorporated in our analysis of refinery costs. Additional storage tanks will be needed to handle the mixture at those terminals that currently do not handle off highway diesel fuel. The cost of these tanks has been fully accounted for in the calculation of costs during the time period when the optional compliance program is available.

iv. Conclusion

We conclude that the primary change needed to current distribution practices to limit sulfur contamination of 15 ppm highway diesel fuel in the pipeline system (and for the distribution system as a whole) will be the elimination of discretionary mixing of a fraction of the interface volume associated with pipeline shipments of highway diesel fuel into the highway diesel fuel pool. When the temporary compliance option expires, the additional volume of highway diesel fuel that will need to be downgraded to a lower value product as a result of this change will be sold into the off highway diesel fuel market. During the period when the temporary compliance option is available, we estimated that a fraction of this volume would be sold into the 500 ppm highway diesel fuel market. The relative volumes of downgrade that we expect will be sold into the off highway vs the 500 ppm highway diesel market and the costs associated this downgrade are discussed in section V.C. We concluded that the additional downgrade can be accepted without significant disruption to either the off highway or highway diesel fuel markets (see section IV.D.2.).

The need to produce an additional volume of 15 ppm highway diesel fuel to compensate for the additional downgrade is accounted for in both our feasibility and cost analysis (see Section IV.D.2. and V.C.). Given that in all cases there will be opportunity to downgrade the volume of interface which currently is blended into highway diesel fuel to a lower value product, we believe that the changes outlined above can be implemented without the generation of any significant additional volumes of transmix from this source. The Association of Oil Pipelines stated that pipeline operators may more frequently abut batches of highway diesel fuel with batches of low sulfur gasoline in an attempt to limit sulfur contamination of highway diesel fuel meeting a 15 ppm cap.[60] If this were the case, additional volumes of transmix would be generated since mixtures of gasoline and diesel fuel must typically be returned to the refinery for reprocessing. The changes to pipeline interface practices described in this section will be sufficient to limit sulfur contamination from high sulfur products that abut batches of 15 ppm highway diesel fuel in the pipeline. Pipeline operators will not be forced to increase the frequency that batches of gasoline abut batches of highway diesel fuel in the pipeline. Since we expect that no changes will be needed in the choice of products that abut highway diesel fuel in the pipeline, we believe that no significant additional volume of transmix associated with pipeline interface will be generated as a result of our program.

During the time period when the temporary compliance option is available, the ability to abut some batches of 15 ppm highway diesel fuel with batches of 500 ppm highway diesel fuel in pipelines that carry both fuels may ease the difficulty limiting sulfur contamination of 15 ppm fuel. We believe that it will still be necessary to cut all of the interface between such products into the 500 ppm fuel batch. Nevertheless, the lower sulfur content of 500 ppm highway diesel fuel relative to off highway diesel fuel would mean that whatever mixing that does take place from would have less impact on the sulfur content of 15 ppm highway diesel fuel.

b. Identifying the Location of the Interface Between Fuel Batches

The Association of Oil Pipelines (AOPL) expressed concern that their current physical methods of evaluating when to make a cut between adjacent batches in the pipeline may not be adequate for determining when a cut should be made between a batch of 15 ppm diesel fuel and a batch of a different product adjacent to it in the pipeline.[61] AOPL related that pipeline operators currently do not use the measurement of fuel sulfur content to help determine when such a cut should be made. They related that there would be no time to conduct a lab evaluation of fuel sulfur content and that appropriate on-line sulfur measurement equipment is currently not available. The recent National Petroleum Council (NPC) clean fuels report stated that they did not expect that field test equipment such as that which might be used to measure the sulfur content of fuel as it flows through the pipeline would be available by the time our sulfur control program is implemented.[62]

We do not believe that pipeline operators will need to substantially change the methods used to detect the interface between highway diesel fuel and adjacent products in the pipeline. We believe that the difference between the physical properties of highway diesel fuel and other products carried in the pipeline will continue to be as identifiable as they currently are. Therefore, pipeline operators will have the same ability to discern the interface between two products in the distribution system based on a change in fuel density and/or a change in color. In addition, pipeline operators are already coping with instances where the physical properties of fuels in the pipeline is very similar. When the normal methods of detecting an interface between batches are thought to provide insufficient differentiation between batches, pipeline operators in some cases today inject a small amount of dye or other fuel marker at the start of a new batch to distinguish it from a previous batch. We expect this practice will continue in the future.

Tracking information from upstream in the pipeline is also used to help identify the approximate time when the interface between batches will arrive at a given point in the system. This helps to focus the attention of technicians who make the cuts between pipeline batches during the time when the interface is expected to pass their observation post.

Making a protective interface cut will likely be critical to adequately limit sulfur contamination during the distribution of 15 ppm diesel fuel. This may force additional measures to ensure that there will be will be adequate time for the cut to be made. Such measures may include: more rapid communication between the station at which the fuel is sampled in the line and the control room where the valves are operated, providing means to control the valves at the point where the product in the pipeline is measured, or moving the sampling point further upstream in the pipeline. We believe that the need for such changes will be made within the context of optimizing the distribution system to limit contamination. The costs of these changes are accounted for in our cost estimate for this optimization process and should not cause a significant disruption to pipeline operations.

c. Dead Legs

Dead legs are lengths of pipeline extending off from a main line (e.g. to serve a terminal tank farm) that have a valve situated some distance from the junction of the two lines. There is potential for some mixing of the fuel left in the dead leg (e.g. after an exchange of products between a terminal and the pipeline) with other batches of fuel as it passes in the main pipeline. If such mixing occurs quickly, the product left in the dead leg would tend to be included in the interface between adjacent products in the pipeline. For short dead legs, we believe that the turbulence at the junction of the two lines will ensure that this is the case. If a dead leg was long enough, some product might remain trapped near the valve in the dead leg. During the operation of a pipeline it is common for pressure fluctuations to occur. Such fluctuations could cause product trapped in a long dead leg to be drawn out into the pipeline stream over time, resulting in some contamination of a batch as it passes the dead leg. Commenters stated that the sulfur contamination of highway diesel fuel from dead legs could be significant when the 15 ppm cap on sulfur content is implemented.

We believe that existing concerns about limiting contamination has ensured that existence of long dead legs is the exception rather than the rule. Such concerns will have already provided a strong incentive to keep the volume of fuel contained in a dead leg to an minimum by careful placement of the valve close to the junction of the lines. To the extent that there may still be some long dead legs in the system, compliance with the Tier 2 gasoline sulfur requirements will encourage their elimination well before the implementation of our diesel sulfur program. To the extent that long dead legs exists when our diesel sulfur program is implemented, the problem can be rectified by properly repositioning the valve. Given the limited extent that such instances are likely to exist, this should not be a significant burden to the pipeline industry. The potential cost of such valves is small enough to be accommodated in the costs we have attributed to the optimization of the distribution system to limit sulfur contamination (see section V.C.3.). We believe that any instances where long dead legs do exist, will be identified and rectified before the 15 ppm sulfur standard for highway diesel fuel is implemented. Given that most, if not all dead legs, are already relatively short, and the fuel in such dead legs is exchanged in the interface between fuel batches as they pass the leg in the pipeline, the highway diesel fuel downgrade volume from such sources is already factored into our analysis of downgrade volumes (see section IV.D.2.a.).

d. Line-Fill

Prior to the injection of fuel into a pipeline, the feed line from the terminal or refinery tanks holding the batch of fuel to be injected must be "layed down" (filled) with the product to be injected. There is a like situation at the tank farms where product is transferred from a main pipeline to a branch line or to another operators pipeline. The term line-fill refers to the amount of fuel in the feed line(s) from a tank farm to a pipeline. When product is received at a terminal from the pipeline, the product which is resident in the feed line must be purged. To facilitate the exchange of products in the feed line, most facilities have at least two lines from the pipeline to the tank farm. When possible, the fuel that must be displaced from the feed line is directed to a tank that contains the same product. However, inevitably some fuel will need to be directed into a "slop tank" to be treated as transmix. Pipeline operators keep records of the products resident in the various line segments to ensure proper routing and separation of product when the line is being layed down.

Line-fill volume is fixed and will not increase as a result of our program. Pipeline and terminal operators will need to exercise additional care to limit the mixing of high sulfur products into highway diesel fuel when preparing for the injection of a batch of highway diesel fuel into the pipeline. However, given the relatively small diameter and length of lines used in this process, there should be little or no increase in the amount of interface or tranmix generated. Thus, there should be no need for additional tanks to handle transmix and little or no impact on the difficulty and costs associated with the line-fill process.

An analogous situation occurs when product is drawn off of the pipeline into a stationary storage facility (terminal or pipeline brake out facility). The product contained in the receiving line (which can also be used to inject products into the pipeline) must be properly directed when receiving a batch of highway diesel fuel. For the reasons discussed above, the implementation of our sulfur program should also not result in the a significant impact related to drawing fuel off of the pipeline.

e. Leaking Valves

Contamination from leaking valves is a greater concern from single-seal valves. Existing concerns about product contamination has encouraged the increased use of double-seal valves throughout the distribution industry. As a result, much of the system already uses such valves and there is an increasing trend towards their use. In addition, it is common practice to monitor valves to ensure their proper operation. Therefore, there should be little potential for sulfur contamination of 15 ppm highway diesel fuel from leaking valves. We anticipate that at those locations where double-seal valves are not already utilized, distributors may be encouraged to install such valves by the implementation of the Tier 2 gasoline sulfur requirements. To the extent that single-seal valves continue to be in use when our diesel sulfur program is implemented, our diesel program may further accelerate their replacement with double-seal valves.[x] We expect that the locations where such replacement is advised will be identified during the process of optimizing the distribution system to limit sulfur contamination in 15 ppm highway diesel fuel, and that their installation where needed will not be burdensome.

f. Surface Accumulation of Sulfur-Containing Substances

The specter was raised in the comments on the NPRM that sulfur contamination from the accumulation of substances on the walls of the pipeline and on the surfaces of stationary storage tanks and the tank compartments in tank trucks, tank wagons, rail cars, and barges could jeopardize the ability to comply with the 15 ppm cap on highway diesel fuel. No other information was provided to substantiate this concern. We believe there is no reason to surmise that contamination from surface accumulation in pipelines will represent a significant concern under our sulfur program. To the extent that sulfur-containing molecules in a fuel batch adhere to the wall of a pipeline, they would tend to be flushed back into the pipeline flow in the interface between products. Whatever amount that might tend to tenaciously adhere to pipeline walls would tend to remain in an aggregate formation rather than dissolving back into the stream. Such accumulation would either be removed as part of normal pipeline cleaning processes, or if flaked off into the pipeline flow, would be removed during the normal filtration process. To the extent that products accumulated on pipeline walls might dissolve back into the pipeline flow, this would be more likely to occur into lighter products which act as solvents such as gasoline. Based on the above discussion, we believe that contamination from surface accumulation in pipelines will not represent a significant concern. For these same reasons, we expect that surface accumulation in storage tanks will not pose a significant contamination concern. In addition, to the extent that contamination from surface accumulation may be a concern, it seems reasonable to conclude that this issue would already be an issue since highway diesel fuel is very sensitive to dye contamination from off highway diesel fuel.

To adequately limit sulfur contamination, it may become more important to allow sufficient time for high sulfur fuel clinging to the walls of tanks to drain completely before

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[x] Double valves were used to help prevent lead contamination from leaded to unleaded gasoline during the phase-out of lead in U.S. gasoline. The lead phase-out presented perhaps the most difficult situation with respect to limiting contamination up to this time.

refilling the tank 15 ppm highway diesel fuel. However, this represents only more careful observation of what is current industry practice and should not impose a significant burden. Such concerns are discussed further in the section on limiting sulfur contamination at stationary storage facilities and during transportation by surface vehicles and marine vessels.

3. Limiting Sulfur Contamination at Stationary Storage Facilities

This section addresses the following concerns related to limiting sulfur contamination at stationary storage facilities such as terminals, bulk plants, and pipeline break-out tank farms:

- Quality control testing
- Switching products contained in storage tanks:
  Contamination from high sulfur product left behind in a storage tank that will be used to contain highway diesel
- Tank manifolds:
  Contamination from high sulfur product contained in lines that connect various storage tanks to a common fuel transfer point such as a terminal rack

Because of their crosscutting nature, the following concerns regarding the limitation of sulfur contamination at stationary storage facilities were addressed in the previous section on limiting contamination in the pipeline system:

- The need for additional storage tanks at certain terminals to accommodate a needed change in the interface handling practices with respect to batches of highway diesel fuel that abut batches of jet fuel or kerosene in the pipeline
- Line fill
- Leaking valves
- Surface accumulation of high sulfur product

a. Quality Control Testing

We believe that a modest level of additional quality control testing will be needed at the terminal level to ensure compliance with the 15 ppm sulfur cap. Further, we believe that such additional testing can be conducted using existing equipment and will not represent a substantial burden to industry. For additional discussion regarding the extent and costs of this testing please see section V.C.3 in this RIA. For a discussion of the test procedures we expect will be used to measure the sulfur content of highway diesel fuel please see section VII in the preamble the final rule for our diesel sulfur program.

b. Product Switching in Stationary Storage Tanks

In some instances, different products are held in the same tanks at different times. This can occur at the tank facilities which are a part of the pipeline system, such as the facilities which feed product into pipelines and at break-out tank facilities.[y] During the switching of products held in a storage tank, sulfur contamination may result from high-sulfur product left behind in the tank before being filled with highway diesel fuel. The foremost potential source of residual product left behind during such switching operations is the tank heel. A tank heel is the amount of product that remains in a tank after no additional product can be removed by normal means. Pipeline operators have expressed concern that a tank heel volume of off highway diesel fuel that today can be mixed with an incoming batch of highway diesel fuel without causing the current 500 ppm cap to be exceeded, would cause the 15 ppm cap to be exceeded.[63] In such cases the tank would need to be flushed before 15 ppm diesel fuel could be placed in it. This concern was expanded upon by the Independent Fuel Terminal Operators Association (IFTOA) who stated that storage tanks would need to be chemically cleaned before being used to store 15 ppm diesel and be dedicated to holding only 15 ppm highway diesel fuel thereafter.[64]

The amount of tank heel varies depending on the type of tank floor. Some tanks have a conical shaped floor typically constructed of concrete with a drain at the lowest point. The tank heel for such a tank is nearly zero. New tanks are typically constructed with such a floor so that they will drain completely. This greatly facilitates tank maintenance and facilitates the easy removal of water that settles at the bottom of the tank.

Some (primarily older) tanks have a roughly level sand floor on which a liner rests. Such tanks may or may not have a number of drains at various low points in the tank to facilitate the elimination of water that settles to the bottom. The floors of such tanks can be quite irregular and contain a number of low areas where fuel pools and can not readily be removed. This volume is the tank heel. In addition, such tanks may have a side drain rather than a floor drain, which can contribute further to the volume of the tank heel. The volume of the tank heel for such tanks can be substantial. Therefore, high sulfur product in the tank heel could be a significant source of sulfur contamination.

One fact which tends to limit the potential sulfur contamination from residual high sulfur products in the flat bottom tanks is that water tends to settle into stagnant areas at the bottom of a tank. This limits the volume of petroleum products that can reside in such stagnant areas since

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[y] An example of a break-out tank facility is one that holds products the are stripped off of a main pipeline before injection into another line.

they tend to be filled with water. The water trapped in stagnant pools on the bottom of a tank is a concern in and of itself. Biological organisms can grow at the interface between water and petroleum products, especially diesel fuel. The residue from such organisms can cause significant contamination. These concerns have contributed to the trend away from the use of tanks with an irregular flat bottom. More importantly, the majority of storage tanks used to hold highway diesel fuel are currently dedicated to this purpose and there is an increasing trend towards this practice. It seems reasonable that due to the difficulty in switching the products contained in storage tanks with irregular flat bottoms, such tanks would be the first tanks to be dedicated to a single fuel. In the infrequent cases where this is not already the case, it seems reasonable that where practicable the tank would be dedicated to a single fuel. In such cases, only a one time cleaning would be required.

To the extent that some additional dedicated tankage will be necessary, we have more than compensated for this in our analysis of the additional tanks that will be needed to facilitate the presence of two grades of highway diesel fuels during the period covered by the temporary compliance option. We have assumed that such tanks will be constructed at a number of stationary storage facilities and anticipate that most storage facilities will have a dedicated tank to handle 15 ppm diesel fuel. We also estimated that additional storage tanks may be needed at some tank farms that service the pipeline system due to a change in the interface handling practices regarding batches of highway diesel fuel and jet fuel or kerosene that abut each other in the pipeline (see section IV.D.2.a. in this RIA). This also helps to compensate for whatever additional tanks might be needed to address contamination concerns. The costs for these tanks is incorporated in our estimation of tank costs to facilitate handling two grades of highway diesel fuel during the period when

It seems likely that storage tanks would need to be flushed with highway diesel fuel prior to being switched from containing off highway diesel fuel, jet fuel, or kerosene to 15 ppm highway diesel fuel. We do not believe that there is any reason to suspect that the tank would need to be chemically cleaned to remove residual high-sulfur products clinging to the interior surfaces of the tank.[z] It should be noted that due to concerns about dye contamination from off highway diesel fuel and the impact of gasoline on the flash point of highway diesel fuel, properly emptying a tank to hold highway diesel fuel is already a significant concern. Consequently, it is not uncommon currently for a storage tank to be flushed with a quantity of highway diesel fuel prior to being filled with highway diesel fuel if the previously held gasoline or off highway diesel fuel. We believe that following such normal business practices when switching products contained in a storage tank in most cases would provide sufficient protection against sulfur contamination in 15 ppm highway diesel fuel. Some additional volume of highway diesel fuel may need to be used in flushing tanks before switching a storage tank to highway diesel fuel

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[z] See the earlier discussion on potential contamination from high sulfur products clinging to the walls of pipelines (IV.D.1.e.).

service when our 15 ppm sulfur cap is implemented. However, because such switching occurs infrequently, we believe that additional amount of downgrade caused by tank flushing will be insignificant. In addition, our use of conservative assumptions in estimating the additional downgrade volume from the changes needed in interface handling practices will more than offset any additional downgrade volume that may result from tank flushing.

c. Tank Manifolds

The array of tanks at tank farms is connected by a network of pipes that resemble the network of rail lines at a railroad yard. At the juncture between the feed lines from the pipeline and the tank manifold system, a branching takes place such that products directed toward two different tanks may flow down a single connecting line for a time. Similar to the line fill situation, product downgrade and transmix can result from different products sharing the same line. To the extent that the tank that contains highway diesel fuel is located at the end of the pipe network, there may be more opportunity for mixing of high sulfur products into a batch of highway diesel fuel as it moves through the manifold to and from the storage tank.

When off highway diesel fuel abuts highway diesel fuel in a tank manifold, it is common practice to make a protective interface cut between the two batches (i.e.: all of the mixed product is cut into the off highway diesel fuel). This practice is followed because the interface volumes in manifold pipes are small and there is little incentive or ability to fine tune the amount of interface which is cut into the different fuel batches. We expect that this procedure will continue in the future and will be sufficient to limit the sulfur contamination of 15 ppm highway diesel fuel in tank manifold systems. Therefore, we believe that the handling of 15 ppm highway diesel fuel in tank manifold systems will not result in the generation of significant volumes of additional product that must be downgraded to a lower value product or treated as transmix. Another factor which tends to minimize concerns related to tank manifolds is that only a small volume of product resident in the pipe networks must be displaced when moving a batch of highway diesel fuel, even in those cases where the storage tank that holds the highway diesel fuel is at the end of the manifold system.

As discussed in the previous section, we estimated that many facilities will construct an additional tank dedicated to 15 ppm diesel fuel. To the extent that contamination concerns exist regarding the placement of highway diesel fuel storage tanks in the manifold system, we anticipate that new tanks will be located in a way that minimizes these concerns.

4. Limiting Sulfur Contamination During Transport by Surface Vehicles

Highway diesel fuel is transported by the following types of surface vehicles: tank truck, tank wagon, and rail car. Tank trucks are the largest capacity road haul vehicles that carry petroleum products. They deliver product to truck stops, service stations, and large fleet operators, as well engaging in other road movement of petroleum products as needed. Tank wagons usually serve smaller customers, such as centrally-fueled fleets, smaller service stations, and in certain circumstances heating oil customers such as homeowners. Tank wagons normally have multiple tank compartments to accommodate the delivery of several different fuel types in a single delivery circuit. Tank wagons have a smaller total capacity than tank trucks. In cases where pipeline service is limited, fuel is sometimes shipped to the terminal by rail car.

In the proposed rule, we stated that concerns related to limiting sulfur contamination during the transport of 15 ppm diesel fuel by tank truck, tank wagon, and rail car could be adequately addressed by careful and consistent observation of current industry practices used to limit contamination. Based on this assessment, we concluded that our program would result in a significant additional burden regarding the transportation of highway diesel fuel by such vehicles.

The Independent Fuel Terminal Operators Association (IFTOA) stated that all storage tanks, including those on surface transport vehicles would need to be chemically cleaned before being used to store 15 ppm diesel and would need to be dedicated to this purpose thereafter. [65] The American Petroleum Institute (API) stated that it is unlikely that “consistent and careful” observation of current practices will be sufficient to limit sulfur contamination during transport of 15 ppm diesel fuel as EPA asserted in the proposed rule.[66] The American Trucking Association (ATA) stated that our assertion that enhanced observation of current industry practices by truckers that distribute highway diesel fuel was incorrect.[67] ATA argued that an additional burden results whenever a trucker must alter current handling practices and that this additional burden would impact truckers who are small businesses the most. ATA offered no additional detail on the nature of the potential burdens. We did not receive information to substantiate the concerns raised in these comments.

In their comments on the Advance Notice of Proposed Rulemaking (ANPRM), the Petroleum Marketers Association of America (PMAA) stated that contamination concerns would cause a large number of tank wagon operators to purchase new trucks with dedicated tank compartments for 15 ppm highway diesel fuel and dedicated delivery systems.[68] PMAA stated that this would cause much disruption to the fuel distribution industry and an unacceptable burden to its members. We responded to these comments from PMAA in the Draft Regulatory Impact Analysis (DRIA) for the proposed rule.[69]

We continue to believe that sulfur contamination during the transport of 15 ppm diesel fuel by tank truck, tank wagon, and rail car can be adequately controlled by the careful and consistent observation of current industry practices used to limit contamination. These practices include making sure that the tank truck, tank wagon, or rail car is properly leveled and allowing sufficient time for the tank compartment to drain completely prior to filling with 15 ppm highway diesel fuel. The tank compartments in such vehicles are designed to drain completely. As discussed earlier (see section IV.D.2.e.), we do not believe that the accumulation of high sulfur products on the walls of storage tanks will be significant source of sulfur contamination. Therefore, assuring that such compartments drain completely will be sufficient to limit sulfur contamination. There are no unique concerns related to limiting contamination during the transport of 15 ppm highway diesel fuel by tank trucks and rail car.

PMAA stated that it would not be possible to adequately limit sulfur contamination when delivering 15 ppm highway by a tank wagon that has a common delivery system. In such cases, the delivery system would need to be purged of high-sulfur product prior to its use to delivery 15 ppm highway diesel fuel. Current industry practice is to switch the product flow just prior to the end of the delivery so that the delivery system is charged with the product intended for delivery at the next stop. PMAA stated that this is not always feasible because the receiving tank may fill more quickly than was expected, or the next customer may not need the product that has been put into the hose. We believe such occurrences will be rare and can be further limited by more careful filling and delivery scheduling practices. Tank wagon operators currently schedule deliveries of highway diesel fuel as a first stop in the delivery circuit whenever possible to help minimize contamination concerns.

In transitioning from the delivery of off highway diesel fuel to highway diesel fuel, PMAA related that after switching to highway diesel fuel at the end of the delivery of off highway diesel, tank wagon operators typically observe the color of the product being delivered and do not turn off the flow until the stream is clear. Since off highway diesel (including heating oil) typically contains a red dye, a clear stream indicates that the delivery system is completely flushed of off highway diesel fuel. This practice will continue to be sufficient to ensure that the delivery system is charged with highway diesel fuel since a minute quantity of dye causes a visible trace in highway diesel fuel (see section IV.D.1).

Since the practices described above are currently in common use due to existing product contamination concerns, we continue to believe that there should be not be a significant additional burden associated with ensuring their consistent and careful observance. Some marketers may need to reeducate their employees regarding the importance of these practices. To the extent that such employee education is needed at all, we anticipate that it might be accomplished in regular employee meetings or employee bulletins at negligible cost.

In any event, the concerns discussed above should represent the exception rather than rule. Most highway diesel fuel is distributed to retail facilities and centrally fueled fleets where off highway diesel fuel is not used. Thus, the circumstances where the same tank compartment is used to alternately handle off highway and highway diesel fuels are limited. This also means that cases where a tank wagon’s delivery circuit includes off highway diesel fuel would be limited. Such cases would primarily be limited to areas where diesel fuel oil is used for home heating, such as in the North-East during the home heating season.

More importantly, the tank compartments in tank trucks and tank wagons are for the most part dedicated to carry a single fuel. In addition, most tank wagons have a separate delivery system for each product. Further, there is an increasing industry trend towards dedicating such equipment to handle a single fuel. In cases where such dedication exists, sulfur contamination will not be a concern. Thus, the circumstances under which the concerns discussed above arise are expected to be uncommon and to decrease over time.

5. Limiting Sulfur Contamination During Transport by Marine Vessels

The Independent Fuel Terminal Operators Association (IFTOA) stated that the current practice of flushing tanks on a barge with fuel when a supplier switches from a fuel with a higher sulfur content to highway diesel fuel would no longer be possible when the 15 ppm cap on the sulfur content of highway diesel fuel is implemented.[70] IFTOA stated that it would be necessary to clean the tank compartments with high powered water jets which is a difficult and expensive process ($30,000 to $50,000 per barge).

During the three month transition period between the time when refiners are require to produce 15 ppm highway diesel fuel and when it is required downstream, we anticipate that distributors stationary storage tanks will gradually be blended down so that any residual product is removed. Thus, for dedicated stationary storage tanks we expect that contamination from residual high sulfur fuel will not be a significant concern. Similar to stationary storage tanks, we expect that barges will experience sufficient turn overs of the fuel contained in their tank compartments to ensure that sulfur contamination from residual high sulfur product is not a significant concern.

It may be reasonable to presume that barges are equipped with sumps from which the residual product can be completely removed. If this were the case, one might conclude a barge cold be made ready to carry 15 ppm highway diesel fuel by allowing sufficient time for fuel to drain into these sumps to be removed. If this were not sufficient, flushing the barge with 15 ppm diesel fuel might provide the necessary cleaning action. If this were so, the situation would be similar to that discussed above for stationary storage tanks, for which we concluded that sulfur contamination from residual product should not be a significant concern.

Due to existing contamination concerns, most tank compartments in marine vessels used to transport highway diesel fuel are already dedicated to this purpose and there is an increasing trend toward such dedication. Some barges plying the eastern seaboard may on occasion switch seasonally between highway diesel and heating oil. However, this is the exception rather than the rule. Consequently, we expect that there would be few instances when this concern would arise which would decrease in time. To the extent that such instances might occur, we believe that the associated tank cleaning costs would not substantially add to the cost of our program. In addition, the volume of heating oil shipped under such circumstances is small fraction of the total volume shipped by barge. Hence, any impact would be insignificant in the context of our entire program.

We received no comments to suggest that there are unique concerns for other marine vessels such as coastal tankers.

6. Limiting Sulfur Contamination from Diesel Fuel Additives

Diesel fuel additives include corrosion inhibitors, cold-operability improvers, and static dissipaters. Use of such additives is distinguished from the use of kerosene by the low concentrations at which they are used and their relatively more complex chemistry.[aa] We proposed that diesel fuel additives used in highway diesel fuel meet the same cap on sulfur content required for the fuel itself. Additive manufacturers commented that there was no need to impose a 15 ppm sulfur cap on such additives in order to effectively limit the sulfur content of finished diesel fuel.[71] They asserted that imposing such a cap would result in unjustified costs and disruptions to the producers and users of diesel additives. Additive manufacturers also stated that for certain additives, such as static dissipaters needed to prevent explosion hazards at terminal facilities, there are currently no effective alternatives that comply with a 15 ppm cap on sulfur content.

In response to these comments, we are allowing the use of diesel fuel additives with a sulfur content greater than 15 ppm provided their use does not result in an exceedence of the 15 ppm cap on the sulfur content of highway diesel fuel.

Our review of data submitted by additive and fuel manufacturers to comply with EPA's Fuel and Fuel Additive Registration (F&FAR) requirements (40 CFR Part 79), which is summarized below, indicates that additives to meet every purpose (including static dissipation) are currently in common use which meet a 15 ppm cap on sulfur content. The ability of industry to provide additives for use in 15 ppm highway diesel fuel is further supported by the fact that diesel fuel meeting a 10 ppm cap on sulfur content has been marketed in Sweden for some time, and ARCO Petroleum recently began marketing fuel meeting a 15 ppm sulfur cap in California. Even if low sulfur additives were not yet available for certain purposes, we believe that it is reasonable to assume that they would become available before our sulfur program is implemented in 2006. The summary of the data in the F&FAR database also indicates that the

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[aa] Diesel fuel additives are used at concentrations commonly expressed in parts per million. Diesel fuel additives can include specially-formulated polymers and other complex chemical components. Kerosene is used at much higher concentrations, expressed in volume percent. Unlike diesel fuel additives, kerosene is a narrow distillation fraction of the range of hydrocarbons normally contained in diesel fuel. See Section VII.C.4. above regarding the requirements associated with the addition of kerosene to diesel fuel.

industry could adapt to use only additives that contain less than 15 ppm sulfur. However, we agree that it is not necessary to force the additives that contain greater than 15 ppm sulfur to be retired. By allowing their continued use, we avoid any significant impacts from our sulfur program related to diesel fuel additives.

Summary of Information Contained in the F&FAR Database on Diesel Fuel Additives

- Most sulfur containing additives registered with the EPA currently meet the 15 ppm cap.
  - There are approximately 3500 diesel additives registered with the EPA.
  - Of the diesel additives registered with EPA, 463 additives manufactured by 104 companies contain sulfur.
  - Of the sulfur-containing additives, 176 additives (38 of such additives) manufactured by 51 companies (49 of companies that manufacture sulfur-containing additives) have a sulfur content greater than 15 ppm
  - There are 226 sulfur-containing additives manufactured by 65 companies that have a sulfur content less than 5 ppm.

- In 1999, 5.5 percent of the total volume the additives used in diesel fuel contained sulfur.

- In 1999, 47 percent of the diesel fuels registered by fuel manufacturers had sulfur containing additives listed (of all purposes in-use). These fuel formulations represent 65 percent of the total diesel fuel volume.

- Several dozen different additives registered with EPA have anti-static (static dissipater) listed as a purpose in-use (PIU). EPA data shows that there are 40 additives that list anti-static as a PIU.
  - 64 percent of these additives have an elemental sulfur level greater than 15 ppm.
  - Nearly a dozen different anti-static additives registered with the EPA have zero amount of sulfur in their formulations.

Since such off highway additives are currently in widespread use side-by-side with high-sulfur additives, it is reasonable to conclude that there is not a significant difference in their cost.

The unusually high sulfur content of a few additives may discourage their use in diesel fuel that meets a 15 ppm sulfur cap. However, it will generally continue to be possible for additive manufacturers to market additives that contain greater than 15 ppm sulfur for use in highway diesel fuel. Such additives can also continue to be used in off highway diesel fuel. Additive manufacturers that market such additives and blenders that use them in highway diesel fuel will have additional requirements to ensure that the 15 ppm sulfur cap on highway diesel fuel is not exceeded. Although our sulfur program may encourage the gradual retirement of additives that do not meet a 15 ppm sulfur cap for use in highway diesel fuel, we do not anticipate that this will result in disruption to additive users and producers or a significant increase in cost. Additive manufactures commonly reformulate their additives on a periodic basis as a result of competitive pressures. We anticipate that any reformulation that might need to occur to meet a 15 ppm sulfur cap will be substantially accommodated within this normal cycle.

In some cases, blenders may not find it feasible to conduct testing, or otherwise obtain information on the sulfur content of the fuel either before or after additive blending, without incurring substantial cost. Without such information, a blender would not have documentation with which to evaluate what impact the use of an additive which exceeds 15 ppm would have on the fuel's final sulfur content.[bb] We anticipate that blenders will manage the risk associated with the use of additives above 15 ppm in sulfur content under such circumstances with actions such as the following:

- selecting an additive with minimal sulfur content above 15 ppm that is used at a low concentration, and

- working with their upstream suppliers to provide fuel of sufficiently low sulfur content to accommodate the small increase in sulfur content which results from the use of the additive.

This is similar to the way distributors will manage contamination from their distribution hardware (tank trucks, etc.). Distributors will not necessarily test for fuel sulfur content after each opportunity for contamination, but rather will rely on mechanisms set up to minimize the contamination, and to obtain fuel sufficiently below the standard to accommodate the increase in sulfur content from the contamination.

7. Handling Batches of Highway Diesel Found to Exceed the Sulfur Standard Downstream of the Refinery

We believe that there will not be a significant increase in the volume of highway diesel fuel discovered to exceed the sulfur standard downstream of the refinery as a result of today's rule. We believe this will be the case both during the transition of the program and after the sulfur requirements are fully implemented. We anticipate that distributors will quickly optimize their practices to avoid sulfur contamination. We also anticipate that distributors will gain some

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[bb] The transfer of an additive with a sulfur content greater than 15 ppm will be required to be accompanied by a product transfer document which provides information in the sulfur content of the additive and the extent to which its use at the maximum recommended concentration would increase the sulfur content of the finished fuel. This information will allow the blender to assess the potential impact of the additive's use on their compliance with the requirement that the use of additives not cause the 15 ppm cap on the sulfur content of highway diesel fuel to be exceeded.

experience in reducing sulfur contamination in the distribution system through complying with the recently finalized Tier 2 low sulfur gasoline requirements (65 FR 6698, February 10, 2000). While outside the scope of this final rule, it is worth pointing out that potential difficulties in distributing 15 ppm diesel fuel would be lessened if the sulfur content of off highway diesel fuel is reduced by a future rulemaking. We anticipate that the batches of highway diesel fuel that are discovered to exceed the 15 ppm sulfur cap will be coped with as follows:

- When possible, by blending highway diesel fuel that is below the 15 ppm cap with the out of specification batch to bring the resulting mixture into compliance. This practice will be more difficult than it is currently because the amount of fuel needed to blend the out of specification batch into compliance may increase. However, we expect it to continue to be the method of choice for handling out of specification highway diesel whenever possible.

- By downgrading the batch either to off highway diesel fuel or to 500 ppm highway diesel during the initial years of our program when the temporary compliance option is available.

- By reprocessing the batch to meet the 15 ppm cap, but only in those infrequent instances where the previous options do not exist.

We do not believe that the cost of handling out-of specification highway diesel batches will increase significantly as a result of our sulfur program.

E. Misfueling

1. Introduction

As noted in the feasibility discussion of Chapter III, we believe that, in order to comply with the 2007 and later model year heavy-duty diesel engine emission standards, low sulfur diesel fuel is needed. For this reason, refiners will be required to begin producing 15 ppm sulfur highway diesel fuel starting in mid-2006. Once 2007 and later model year heavy-duty vehicles are sold and operated in the fleet, it will be very important that these vehicles are refueled with low sulfur fuel to ensure proper operation of the emission control systems. Misfueling a 2007 and later model year heavy-duty vehicle with a fuel that has a sulfur level above 15 ppm could poison the emission control system and eliminate any emissions benefit from the 2007 standards.

There is the potential for misfueling a 2007 and later heavy-duty vehicle because there are a number of situations where vehicle owners could have access to diesel fuels with sulfur levels significantly above 15 ppm. First, hardship provisions allow small refiners to continue producing and selling as highway fuel, current highway diesel fuel (which can have a sulfur level of up to

500 ppm) until mid-2010. Second, we are adopting a temporary compliance option that allows refiners to continue producing current highway diesel during the transition of the program. Third, even without the temporary compliance option for highway diesel fuel, off highway diesel fuel (which can have a sulfur level of up to 5,000 ppm) will continue to be available in the market. Last, United States vehicles operated in Canada or Mexico may have access to fuels that do not meet the 15 ppm sulfur limit being adopted for the United States.

Misfueling can happen for a number of reasons. A vehicle owner may choose to misfuel deliberately if they perceive there would be an economic benefit to doing so. For example, misfueling was a significant problem during the transition from leaded gasoline to unleaded gasoline in the mid-1970s and 1980s when unleaded gasoline was required to be used in 1975 and later model year cars. On average, leaded gasoline was significantly cheaper than unleaded gasoline at the retail level and provided a strong incentive for some owners to misfuel with the wrong fuel. A vehicle owner may also misfuel accidentally, and not even realize they are using the wrong fuel. This situation could happen currently at those retail outlets which carry both highway and off highway diesel fuel, and could happen during the transition period to low sulfur diesel fuel when both 15 ppm and 500 ppm sulfur will be available.

Depending on the level of concern over misfueling, there are a range of options that could be taken to limit the occurrence of misfueling. Options include simple, low cost programs that require labels on the fuel pump and labels on the vehicle that specify what fuel should be used in a vehicle, or color-coding nozzles to alert operators to what fuel is being pumped. More complicated and higher cost options include setting fuel nozzle size limits and fuel inlet restrictors, or requiring computer chips on fuel pumps and vehicles that allow the vehicle and fuel pump to “talk to each other” and ensure that the vehicle is getting the appropriate fuel.

The following section presents the steps being taken in this rule to ensure that 2007 and later model year heavy-duty diesel vehicles will be fueled with 15 ppm sulfur fuel. We then present our analysis of whether the steps being taken are sufficient to address concerns over misfueling. The misfueling discussion is divided into two sections addressing deliberate misfueling and accidental misfueling separately.

2. What Provision Are We Adopting to Ensure 2007 and Later Heavy-Duty Diesel Vehicles Use 15 ppm Sulfur Fuel?

As noted above, there are a number of situations where vehicle owners could have access to diesel fuels with sulfur levels significantly above 15 ppm. In order to ensure that operators of 2007 and later model year heavy-duty diesel vehicles are able to identify the proper fuel needed in their vehicle when they refuel, we are adopting the following provisions. First, model year 2007 and later heavy-duty diesel vehicles must be equipped with labels on the dashboard and near the refueling inlet that say: “Use Low Sulfur Diesel Fuel Only.” Second, heavy-duty vehicle manufacturers must notify each purchaser of a model year 2007 or later diesel-fueled vehicle that the vehicle must be fueled only with low sulfur diesel fuel. We believe this requirement is necessary to alert vehicle owners to avoid high sulfur fuel that will be available in this country and outside the United States as well. Third, all highway diesel fuel pumps and co-located nonroad diesel fuel pumps must be prominently labeled to identify what type of fuel is dispensed from the pump.

3. Are Additional Requirements Necessary to Address Deliberate Misfueling?

A vehicle operator who deliberately misfuels will do so because they expect to realize some type of benefit from using the wrong fuel in the vehicle. The benefit the operator expects to realize might be economic (if the required fuel is more expensive than other fuels available) or it might be a performance benefit (if the operator believes the required fuel is inferior in some property to the other fuels available). For many heavy-duty diesel vehicles, particularly line-haul trucks, fuel costs can be as much as 20 percent of annual operating costs, so operators have a strong incentive to save on fuel costs. Therefore, one factor that would stongly encourage deliberate misfueling would be if there was a price differential between the 15 ppm sulfur diesel fuel (required for 2007 and later model year heavy-duty vehicles) and 500 ppm sulfur highway diesel fuel.

As described in Chapter V, the cost of producing 15 ppm sulfur fuel will be more expensive than current highway diesel fuel by approximately 4 cents per gallon. However, given the requirements adopted today, we believe there should not be a large price differential between the 15 ppm sulfur fuel and the 500 ppm sulfur fuel at retail outlets. Under the credit trading program, to produce 500 ppm fuel, most refiners will have to purchase credits from other refiners producing 15 ppm fuel, increasing the cost of the 500 ppm fuel, while decreasing the cost of the 15 ppm fuel. At the refinery gate, the cost of both fuels should be approximately the same. In addition, given the amount of 15 ppm fuel required under the temporary compliance option, 15 ppm fuel will be distributed through essentially the entire pipeline system. The distribution of 500 ppm fuel, on the other hand, will be more limited, due to its much lower volume. We expect that the 500 ppm fuel will be distributed by truck in the areas nearby refineries producing this fuel and through a few major pipelines to a limited number of major fuel consuming areas. Overall, the better economies of scale of transporting 15 ppm fuel should compensate for any additional handling cost due to the need to more carefully avoid contamination with high sulfur fuels. For these reasons, we expect the price to consumers of 500 ppm sulfur fuel to be generally close to that of 15 ppm sulfur fuel and, therefore, there should not be a significant economic incentive to misfuel with 500 ppm sulfur fuel. Nevertheless, any price differential could cause some operators to consider misfueling. Therefore, it is important to examine how price differential has affected misfueling in past fuel programs.

The main experience with any significant level of misfueling in the past was during the unleaded gasoline fuel phase-in that began in the mid-1970s. Throughout the early years of the unleaded gasoline phase-in, the retail price of unleaded fuel was typically around 7 to 8 cents per gallon more than leaded gasoline. This price differential represented ten percent or more of the average retail price of gasoline at the time.[cc] Primarily because of this significant price difference, deliberate misfueling of cars with leaded fuel was a significant problem, resulting in poisoned catalytic converters and a loss of emission benefits. Based on the current retail price for highway diesel fuel from the Energy Information Agency of approximately $1.60 per gallon, the small price difference expected under today's program between 15 ppm sulfur and 500 ppm sulfur fuels is expected to be significantly less (i.e., a price difference of around one to two percent) than the difference that existed between leaded and unleaded gasoline. With such a small difference in price between the 15 ppm and 500 ppm sulfur fuels, we do not believe there will be any significant short-term economic benefit for operators to misfuel 2007 and later heavy-duty vehicles.

Beyond the lack of an economic incentive, we believe there are several factors that will likely serve as deterrents to deliberate misfueling. First, the potential risk associated with voiding any manufacturer emission warranty or damaging the engine and exhaust system on an expensive vehicle might cause owners and operators of heavy-duty trucks to be more careful in ensuring that their vehicles are fueled properly. Second, as discussed in Section III.F. of this RIA, misfueled vehicles could experience a loss in performance, such as poor acceleration or engine stalling. Third, under our fuels regulations it is unlawful for any person to fuel a 2007 and later model year heavy-duty diesel vehicle with any fuel other than low sulfur highway diesel fuel.

With respect to the likelihood that operators would deliberately misfuel with nonroad diesel fuel, we do not believe the new fuel requirements will increase this likelihood. Nonroad diesel fuel is taxed significantly less than highway diesel fuel (approximately 24 cents per gallon less), so there is already a large price difference between the two fuels. Under the requirements of the new highway diesel fuel program, the price differential between highway and nonroad diesel fuels will stay the same or get slightly larger. However, any increase should be relatively minor and shouldn't result in any large increase in the likelihood of people deliberately misfueling with nonroad fuel.

The likelihood of deliberate misfueling in Canada is minimal and lessened by the prospects for eventual harmonization of standards. Canada has recently expressed its intent to

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[cc] DOE Comments on the NPRM, docket item IV-G-28, Enclosure 1.

harmonize its fuel regulations with our fuels standards.[dd] This would offer vehicle owners the option of refueling with low sulfur fuel there. Even if Canada were to lag behind the U.S. in mandating low sulfur fuels, there is less potential for U.S. commercial vehicles needing low sulfur fuel to refuel in Canada because Canadian diesel fuel is currently much more costly than U.S. fuel due to higher fuel taxes. As a result, most vehicle owners will prefer to purchase fuel in the U.S., prior to entering Canada, whenever possible. This is facilitated by large tractor-trailer trucks that have long driving ranges of up to 2,000 miles per tankful and the fact that most of the Canadian population lives within 100 miles of the United States/Canada border. Consequently, most U.S. diesel vehicles would not have a critical need to refuel in Canada, and for those that do, low sulfur fuel would likely become available along major through routes to serve the needs of U.S. commercial traffic that have the need to purchase it.

With regard to Mexico, the entrance of U.S. trucks beyond the border commercial zone has been prohibited since before the conclusion of the North American Free Trade Agreement (NAFTA) in 1994. This prohibition applies in the U.S. as well, as entrance of Mexican trucks into the U.S. beyond the border commerce zone is also not allowed. Because these prohibitions are contrary to the intent of the Free Trade Agreement, a timetable was established to eliminate them.[ee] However, these prohibitions remain in force at this time. As a result, there is little opportunity or need for misfueling in Mexico.

The NAFTA negotiations included creation of a “corridor” where commercial truck travel occurs, and where Mexico is obligated to provide “low sulfur” fuel. At the time of the NAFTA negotiations, “low sulfur” fuel was considered 500 ppm, which was the level needed to address the needs of engines meeting the 1994 emission standards. The travel prohibition currently in place may be lifted at some point. At that time, the issue of assuring, for U.S. vehicles, the availability of 15 ppm sulfur fuel needed by the 2007 and later heavy-duty vehicles may need to be addressed.

In summary, for the reasons described above, we do not believe there is cause for concern over any significant level of deliberate misfueling of 2007 and later heavy-duty vehicles. Although there is likely to be a limited amount of deliberate misfueling, we believe that people who are intent on deliberately misfueling will quickly find ways around any requirements

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[dd] "Process Begins to Develop Long Term Agenda to Reduce Air Pollution from Vehicles and Fuels", Environment Canada press release, May 26, 2000.

[ee] See NAFTA, Volume II, Annex I, Reservations for Existing Measures and Liberalization Commitments, Pages I-M-69 and 70, and Pages I-U-19 and 20.

designed to limit misfueling. For example, based on our experience with unleaded gasoline[ff], many car owners physically removed the fuel inlet restrictor from their vehicles (which were meant to prevent an owner from refueling with the larger sized leaded fuel nozzles) so that they could refuel with cheaper leaded gasoline. We believe the best approach for minimizing the level of deliberate misfueling is making sure operators of 2007 and later model year heavy-duty diesel vehicles are educated about the negative effects on vehicle performance from using diesel fuel with a sulfur level above 15 ppm.

4. Are Additional Requirements Necessary to Address Accidental Misfueling?

There is also the possibility that a truck operator may misfuel accidentally, and not realize they are refueling with the wrong fuel. As noted above, there are a number of reasons a truck operator may find fuel other than 15 ppm sulfur highway diesel fuel when they pull into a retail outlet to refuel. First, the temporary compliance option and hardship provisions will allow refiners to produce two highway diesel fuels during the transition compliance period. Second, there are a number of retail outlets that carry both highway diesel fuel and nonroad diesel fuel at the same location.

With regard to the potential for accidental misfueling of 2007 and later heavy-duty vehicles with 500 ppm sulfur highway diesel fuel during the transition to low sulfur fuel, we believe the labeling requirements described earlier will lower the potential for accidental misfueling. The labels should help vehicle operators identify which fuel is required for their vehicle and help the operator identify the appropriate fuel when they refuel. Although the possibility exists that an operator would not see the fuel pump label and accidentally misfuel with 500 ppm sulfur fuel, we do not believe this will be a common occurrence. Most retail outlets (except truck stops) will likely only carry one grade of highway fuel, and because 15 ppm sulfur fuel is the predominate fuel required even at the start of the program, it will likely be 15 ppm sulfur fuel. Furthermore, the small refiner option lasts for only four years when the number of vehicles needing 15 ppm fuel is relatively small but the majority of fuel out there will be 15 ppm fuel. Last of all, as discussed in Chapter III, Section A.7., a one time misfueling event with 500 ppm fuel will not necessarily irreversibly destroy the emissions control equipment. For these reasons, we believe that a labeling program for both vehicles and fuel pumps will satisfactorily address any concerns over accidental misfueling.

[ff] "An Analysis of the Factors Leading to the Use of Leaded Gasoline in Automobiles Requiring Unleaded Gasoline," September 29, 1978, Sobotka & Company, Inc., "Motor Vehicle Tampering Survey – 1983," July 1984, U.S. EPA, Office of Air and Radiation, and "Anti-Tampering and Anti-Misfueling Programs to Reduce In-Use Emissions From Motor Vehicles," May 25, 1983 (EPA/AA/83-3). All contained in Docket A-99-06.

With regard to the potential for accidental misfueling with nonroad diesel fuel, few retail outlets currently carry both nonroad and highway diesel fuel. Those retail outlets that do also carry nonroad diesel fuel, the nonroad fuel pump is often located away from the highway fuel pump. Thus, it would be difficult to accidentally misfuel with nonroad diesel fuel. Therefore, we do not believe there will be any significant amount of accidental misfueling of 2007 and later model year heavy-duty diesel vehicles with nonroad diesel fuel. However, as noted earlier, we are requiring that all nonroad fuel pumps at retail outlets carrying both nonroad diesel fuel and highway diesel fuel be labeled. We believe the label requirements are sufficient to address concerns over the potential for misfueling with nonroad diesel fuel.

In summary, for the reasons noted above, we believe that the simple labeling requirements being adopted will help vehicle owners identify and use the correct fuel and will be sufficient to address the level of concern regarding accidental misfueling.

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