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Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines

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Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

List of Acronyms

ABT	Averaging, Banking, and Trading
AEO	Annual Energy Outlook
AGME	Above-ground mining equipment
APA	Administrative Procedures Act
AT	Aftertreatment
BSFC	Brake Specific Fuel Consumption
CAA	Clean Air Act
CCV	Closed crankcase ventilation
CDPF	Catalyzed diesel particulate filter
CFR	Code of Federal Regulations
CI	Compression-Ignition
CMV	Commercial Marine Vessel
CO	Carbon monoxide
DF	Deterioration Factor
DI	direct injection
DOC	Diesel oxidation catalyst
EF	Emission Factor
EGR	Exhaust gas recirculation
EIA	U. S. Energy Information Administration
EIA	Economic Impact Analysis
FR	Federal Register
FTC	Federal Trade Commission
GPA	Geographic Phase-In Area
GDP	Gross domestic product
HC	Hydrocarbons
HD2007	Heavy-duty 2007 refers to the final rule setting emission standards for 2007 and later engines
hp	Horsepower
IDI	Indirect injection
IRFA	Initial Regulatory Flexibility Analysis
kW	kilowatt
L&M	Locomotive and marine
MPP	marginal physical product
NAICS	North American Industry Classification System
NDEIM	Nonroad Diesel Economic Impact Model
NMHC	Non-methane hydrocarbons

NPV	Net present value
NR	Nonroad
NRLM	Nonroad, Locomotive, and Marine diesel fuel
O&M	operating and maintenance
OMB	Office of Management and Budget
PADD	Petroleum Administration Districts for Defense
PM	Particulate matter
ppm	Parts per million
PSR	Power Systems Research
PTD	Product Transfer Document
R&D	Research and Development
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
SBA	Small Business Administration
SBAR	Small Business Advocacy Review
SBREFA	Small Business Regulatory Enforcement Fairness Act
SER	Small Entity Representative
SIC	Standard Industrial Classification
stds	standards
TAF	Transient Adjustment Factor
TPEM	Transition program for engine manufacturers (see 40 CFR 89.102 and the proposed 40 CFR
ULSD	Ultra Low Sulfur Diesel
VMP	value of marginal product
VOC	Volatile organic compounds
ZHL	Zero-Hour Emission Level

Executive Summary

The Environmental Protection Agency (EPA) is adopting requirements to reduce emissions of particulate matter (PM), oxides of nitrogen (NO_X), and air toxics from nonroad diesel engines. This rule includes emission standards for new nonroad diesel engines. The rule also reduces the level of sulfur for diesel fuels used in nonroad engines, locomotive engines, and marine engines. The reduction in sulfur for nonroad diesel fuel will enable the use of advanced emission-control technology that new nonroad diesel engines will use to achieve the emission reductions called for under the engine standards in this final rule. In addition, the reduction in sulfur will provide important public health and welfare benefits by reducing emissions of PM and SO_2 from nonroad, locomotive and marine diesel engines.

This executive summary describes the relevant air-quality issues, highlights the new Tier 4 emission standards and fuel requirements, and gives an overview of the analyses in the rest of this document.

Air Quality Background and Estimated Environmental Impact of the Final Rule

Emissions from nonroad, locomotive, and marine diesel engines contribute greatly to a number of serious air pollution problems and would continue to do so in the future absent further reduction measures. Such emissions lead to adverse health and welfare effects associated with ozone, PM, NO_X, SO_x, and volatile organic compounds, including toxic compounds. In addition, diesel exhaust is of specific concern because it is likely to be carcinogenic to humans by inhalation, as well as posing a hazard from noncancer respiratory effects. Ozone, NO_X, and PM also cause significant public welfare harm, such as damage to crops, eutrophication, regional haze, and soiling of building materials.

Millions of Americans continue to live in areas with unhealthy air quality that may endanger public health and welfare. There are approximately 159 million people living in areas that either do not meet the 8-hour ozone National Ambient Air Quality Standards (NAAQS) or contribute to violations in other counties as noted in EPA's recent nonattainment designations for part or all of 474 counties. In addition, approximately 65 million people live in counties where air quality measurements violate the $PM_{2.5}$ NAAQS. These numbers do not include the tens of millions of people living in areas where there is a significant future risk of failing to maintain or achieve the ozone or $PM_{2.5}$ NAAQS. Federal, state, and local governments are working to bring ozone and PM levels into compliance with the NAAQS attainment and maintenance plans. The reductions included in this final rule will play a critical part in these actions. Reducing regional emissions of SO_x is critical to this strategy for attaining the PM NAAQS and meeting regional haze goals in our treasured national parks. SO_x levels can themselves also pose a respiratory hazard.

In 1996, emissions from land-based nonroad diesel engines, locomotive engines, and marine diesel engines were estimated to be about 40 percent of the total mobile-source inventory of $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter) and 25 percent of the NO_X inventory. Absent this final rule, these contributions would be expected to grow to 44 percent and 47 percent by 2030 for $PM_{2.5}$ and NO_X, respectively. By themselves, land-based nonroad diesel engines are a very large part of the mobile-source $PM_{2.5}$ inventory for diesel engines, contributing about 47 percent in 1996, and growing to 70 percent by 2020 without this final rule.

The requirements in this rule will result in substantial benefits to public health and welfare and the environment through significant reductions in NO_X and PM, as well as nonmethane hydrocarbons (NMHC), carbon monoxide (CO), SO_X and air toxics. By 2030, this program will reduce annual emissions of NO_X and PM by 738,000 and 129,000 tons, respectively. We estimate these annual emission reductions will prevent 12,000 premature deaths, over 8,900 hospitalizations, 15,000 nonfatal heart attacks, and approximately 1 million days that people miss work because of respiratory symptoms. The overall quantifiable benefits will total over $83 billion annually by 2030, with a 30-year net present value of $805 billion.

A comparison of the rule's quantified costs and quantified benefits indicates that estimated benefits (approximately $80 billion per year) are much larger than estimated costs (roughly $2 billion per year). This favorable result was found to be robust in a variety of sensitivity and uncertainty analyses. The favorable net benefits are particularly impressive since there are a substantial number of health and environmental advantages of the rule that could not be quantified. In the final Regulatory Impact Analysis, the Agency has done extensive analysis to identify, describe and quantify the degree of uncertainty in the benefit estimates (see Chapter 9). This analysis suggests that the high end of the uncertainty range for this rule's estimated benefits could exceed the low end of the range by a factor of 20. In addition, illustrative calculations indicate that the uncertainty range could span two orders of magnitude using the preliminary results of an EPA-OMB collaborative study on expert judgment for the relative risk of mortality from PM exposure. Despite the uncertainty inherent in the benefit-cost analysis for this rule, the results strongly support a conclusion that the benefits will substantially exceed costs.

Engine Emission Standards

Tables 1 through 4 show the Tier 4 emission standards and when they apply. For most engines, these standards are similar in stringency to the final standards included in the 2007 highway diesel program and are expected to require the use of high-efficiency aftertreatment systems. As shown in the Table 2, we are phasing in many of the standards over time to address considerations of lead time, workload, and overall feasibility. In addition, the final rule includes other provisions designed to address the transition to meeting the long-term Tier 4 standards.

Table 1—Tier 4 PM Standards (g/bhp-hr) and Schedule

Engine Power	Model Year					
	2008	2009	2010	2011	2012	2013
hp < 25 (kW < 19)	0.30 [a]					
25 ≤ hp < 75 (19 ≤ kW < 56)	0.22 [b]					0.02
75 ≤ hp < 175 (56 ≤ kW < 130)					0.01	
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)				0.01		
hp > 750 (kW > 560)	see Table 3					

Notes:
[a] For air-cooled, hand-startable, direct injection engines under 11 hp, a manufacturer may instead delay implementation until 2010 and demonstrate compliance with a less stringent PM standard of 0.45 g/bhp-hr, subject also to additional provisions discussed in section II.A.3.a of the preamble.
[b] A manufacturer has the option of skipping the 0.22 g/bhp-hr PM standard for all 50-75 hp engines. The 0.02 g/bhp-hr PM standard would then take effect one year earlier for all 50-75 hp engines, in 2012.

Table 2—Tier 4 NOx and NMHC Standards and Schedule

Engine Power	**Standard** (g/bhp-hr)		**Phase-in Schedule**[a] (model year)			
	NOx	NMHC	2011	2012	2013	2014
25 ≤ hp < 75 (19 ≤ kW < 56)	3.5 NMHC+NOx [b]				100%	
75 ≤ hp < 175 (56 ≤ kW < 130)	0.30	0.14		50% [c]	50% [c]	100% [c]
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	0.30	0.14	50%	50%	50%	100%
hp > 750 (kW > 560)	see Table 3					

Notes:
[a] Percentages indicate production required to comply with the Tier 4 standards in the indicated model year.
[b] This is the existing Tier 3 combined NMHC+NOx standard level for the 50-75 hp engines in this category. In 2013 it applies to the 25-50 hp engines as well.
[c] Manufacturers may use banked Tier 2 NMHC+NOx credits to demonstrate compliance with the 75-175 hp engine NOx standard in this model year. Alternatively, manufacturers may forego this special banked credit option and instead meet an alternative phase-in requirement of 25/25/25% in 2012, 2013, and 2014 through December 30, with 100% compliance required beginning December 31, 2014. See sections III.A and II.A.2.b of the preamble.

Table 3 – Tier 4 Alternative NOx Phase-in Standards (g/bhp-hr)

Engine Power	NOx Standard (g/bhp-hr)
75 ≤ hp < 175 (56 ≤ kW < 130)	1.7 [a]
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	1.5

Notes:
[a] Under the option identified in footnote b of Table 2, by which manufacturers may meet an alternative phase-in requirement of 25/25/25% in 2012, 2013, and 2014 through December 30, the corresponding alternative NOx standard is 2.5 g/bhp-hr.

Table 4—Tier 4 Standards for Engines Over 750 hp (g/bhp-hr)

engines used in:	2011			2015		
	PM	NOx	NMHC	PM	NOx	NMHC
generator sets ≤1200 hp	0.075	2.6	0.30	0.02	0.50	0.14
generator sets >1200 hp	0.075	0.50	0.30	0.02	no new standard	0.14
all other equipment	0.075	2.6	0.30	0.03	no new standard	0.14

EPA has also taken steps to ensure that engines built to these standards achieve effective real-world emission control including the transient duty cycle (both cold-start and hot-start testing), steady-state duty cycles, and Not-to-Exceed standards and test procedures. The Not-to-Exceed provisions are modeled after the highway program, with which much of the industry has gained some level of experience.

Feasibility of Meeting Tier 4 Emission Standards

For the past 30 or more years, emission-control development for gasoline vehicles and engines has concentrated most aggressively on aftertreatment technologies (i.e., in-exhaust catalyst technologies). These devices currently provide as much as or more than 95 percent of the emission control on a gasoline vehicle. In contrast, the emission-control development work for highway and nonroad diesel engines has concentrated on improvements to the engine itself to limit the emissions formed in the engine (engine-out control technologies).

During the past 15 years, however, more development effort has been put into catalytic exhaust emission-control devices for diesel engines, particularly in the area of particulate matter (PM) control. Those developments, and recent developments in diesel NOx exhaust emission-control devices, make the widespread commercial use of highly efficient diesel exhaust emission controls feasible. EPA has recently set new emission standards for diesel engines installed in highway vehicles based on the emission-reduction potential of these devices. These devices will also make possible a level of emission control for nonroad diesel engines that is similar to that attained by gasoline catalyst systems. However, without the same ultra-low-sulfur diesel fuel that will be used by highway engines, these technologies cannot be implemented.

The primary focus of the Tier 4 program is the transfer of catalyst based emission control technologies developed for on-highway diesel engines to nonroad engines. This RIA summarizes extensive analyses evaluating the effectiveness of these new emission control technologies and the specific challenges to further develop these technologies for nonroad applications. The RIA concludes that for a very significant fraction of nonroad diesel engines and equipment, the application of advanced catalyst based emission control technology is feasible in the Tier 4 timeframe given the availability of 15 ppm sulfur diesel fuel.

Although the primary focus of the Tier 4 emissions program and the majority of the analyses contained in this RIA are directed at the application of catalytic emission control technologies enabled by 15 ppm sulfur diesel fuel, there are also important elements of the program based upon continuing improvements in engine-out emission controls. Like the advanced catalytic based technologies, these engine-out emission solutions for nonroad diesel engines rely upon technologies already applied to on-highway diesel engines. Additionally, these technologies form the basis for the Tier 3 emission standards for some nonroad diesel engines in other size categories.

Controls on the Sulfur Content of Diesel Fuel

We are finalizing the a two-step sulfur standard for nonroad, locomotive and marine (NRLM) diesel fuel that will achieve significant, cost-effective sulfate PM and SO_2 emission reductions. These emission reductions will, by themselves, provide dramatic environmental and public health benefits which far outweigh the cost of meeting the standards necessary to achieve them. In addition, the final sulfur standards for nonroad diesel fuel will enable advanced high efficiency emission control technology to be applied to nonroad engines. As a result, these nonroad fuel sulfur standards, coupled with our program for more stringent emission standards for new nonroad engines and equipment, will also achieve dramatic NOx and PM emission reductions. Sulfur significantly inhibits or impairs the function of the diesel exhaust emission control devices which will generally be necessary for nonroad diesel engines to meet the emission standards in this final rule. With the 15 ppm sulfur standard for nonroad diesel fuel, we have concluded that this emission control technology will be available for model year 2011 and later nonroad diesel engines to achieve the NOx and PM emission standards adopted in this final rule. The benefits of this final rule also include the sulfate PM and SO2 reductions achieved by establishing the same standard for the sulfur content of locomotive and marine diesel fuel.

The fuel sulfur requirements established under this final rule are similar to the sulfur limits established for highway diesel fuel in prior rulemakings – 500 ppm in 1993 (55 FR 34120, August 21, 1990) and 15 ppm in 2006 (66 FR 5002, January 18, 2001). Beginning June 1, 2007, refiners will be required to produce NRLM diesel fuel with a maximum sulfur content of 500 ppm. Then, beginning June 1, 2010, the sulfur content will be reduced for nonroad diesel fuel to a maximum of 15 ppm. The sulfur content of locomotive and marine diesel fuel will be reduced to 15 ppm beginning June 1, 2012. The program contains certain provisions to ease refiners' transition to the lower sulfur standards and to enable the efficient distribution of all diesel fuels.

The final program also contains provisions to smooth the refining industry's transition to the low sulfur fuel requirements, encourage earlier introduction of cleaner burning fuel, maintain the fuel distribution system's flexibility to fungibly distribute similar products, and provide an outlet for off-specification distillate product. These provisions, which will maintain, and even enhance, the health and environmental benefits of this rule, include the 2012 date for locomotive and marine diesel fuel, early credits for refiners and importers and special provisions for small refiners, transmix processors, and entities in the fuel distribution system.

Feasibility of Meeting Diesel Fuel Sulfur Standards

We conclude that it is feasible for refiners to meet the 500 ppm and 15 ppm sulfur cap standards for nonroad, locomotive and marine diesel fuel (NRLM). We project that refiners will use conventional desulfurization technology for complying with the 500 ppm sulfur standard in 2007, which is the same technology used to produce 500 ppm sulfur highway diesel fuel today. Refiners complying with the 500 ppm sulfur NRLM diesel fuel standard will have about the same amount of lead time refiners had in complying with the highway diesel fuel standard, when it took affect in 1993, and they can draw on their experience gained from complying with the 1993 highway sulfur standard. Thus we conclude that refiners producing 500 ppm NRLM diesel fuel will have sufficient leadtime. For complying with the 15 ppm sulfur cap standards applicable to nonroad diesel fuel in 2010 and to locomotive and marine diesel fuel in 2012, refiners will be able to use the experience gained from complying with the 15 ppm highway diesel fuel standard which begins to take effect in 2006. Furthermore, refiners will have ample lead time of at least six years before they will have to begin to produce 15 ppm sulfur nonroad diesel fuel. For complying with both the 15 ppm sulfur standard for nonroad diesel fuel in 2010 and the locomotive and marine diesel fuel in 2012, we expect many refiners to utilize lower cost advanced desulfurization technologies which have recently been commercialized. Others will rely on extensions of conventional hydrotreating technology which most refiners are planning on using to comply with the 15 ppm cap for highway diesel fuel in 2006. These technologies will enable refiners to achieve the 15 ppm NRLM sulfur standards.

We do not expect any new significant issues regarding the feasibility of distributing NRLM fuels that meet the sulfur standards in this rule. The highway diesel program acknowledged that limiting sulfur contamination during the distribution of 15 ppm diesel fuel would be a significant challenge to industry. Industry is already taking the necessary steps to rise to this challenge to distribute highway diesel fuel meeting a 15 ppm sulfur standard by the 2006 implementation date for this standard. Thus, we believe that any issues regarding limiting sulfur contamination during the distribution of 15 ppm sulfur nonroad, and locomotive/marine diesel fuel will have been resolved a number of years before the implementation of the 15 ppm sulfur standard for these fuels (in 2010 and 2012 respectively).

The fuel program in this rule is structured in such a way to maximize fuel fungibility and minimize the need for additional segregation of products in the fuel distribution system. Thus, this rule will only result in the need for a limited number of additional storage tanks at terminals and bulk plants in the interim, and in the long run will result in a simplified overall product slate that needs to be distributed.

Estimated Costs and Cost-Effectiveness

There are approximately 600 nonroad equipment manufacturers using diesel engines in several thousand different equipment models. There are more than 50 engine manufacturers producing diesel engines for these applications. Fixed costs consider engine research and development, engine tooling, engine certification, and equipment redesign. Variable costs include estimates for new emission-control hardware. Near-term and long-term costs for some example pieces of equipment are shown in Table 5. Also shown in Table 5 are typical prices for each piece of equipment for reference. See Chapter 6 for detailed information related to our engine and equipment cost analysis.

Table 5— Long-Term Costs for Several Example Pieces of Equipment ($2002)[a]

	GenSet	Skid/Steer Loader	Backhoe	Dozer	Agricultural Tractor	Dozer	Off-Highway Truck
Horsepower	9 hp	33 hp	76 hp	175 hp	250 hp	503 hp	1000 hp
Displacement (L)	0.4	1.5	3.9	10.5	7.6	18	28
Incremental Engine & Equipment Cost							
Long Term	$120	$790	$1,200	$2,560	$1,970	$4,140	$4,670
Near Term	$180	$1,160	$1,700	$3,770	$3,020	$6,320	$8,610
Estimated Equipment Price[b]	$4,000	$20,000	$49,000	$238,000	$135,000	$618,000	$840,000

[a] Near-term costs include both variable costs and fixed costs; long-term costs include only variable costs and represent those costs that remain following recovery of all fixed costs.

Our estimated costs related to changing to ultra-low-sulfur fuel take into account all of the necessary changes in both refining and distribution practices. We have estimated the cost of producing 500 ppm sulfur NRLM fuel to be, on average, 2.1 to 3.5 cents per gallon. Average costs for 15 ppm sulfur NR fuel during the years 2010 through 2012 are estimated to be an additional 2.5 cents per gallon for a combined cost of 5.8 cents per gallon. Average costs for 15 ppm sulfur NRLM fuel are estimated to be an additional 1.2 cents per gallon for a combined cost of 7.0 cents per gallon for the years 2014 and beyond. All of these fuel costs are summarized in Table 6. These ranges consider variations in regional issues in addition to factors that are specific to individual refiners. In addition, engines running on low-sulfur fuel will have reduced maintenance expenses that we estimate will be equivalent to reducing the cost of the fuel by 2.9

to 3.2 cents per gallon.

Table 6—Increased Cost of Providing Nonroad, Locomotive and Marine Diesel Fuel (cents per gallon of affected fuel)

Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
500 ppm NRLM	2007-10	1.9	0.2	2.1
500 ppm NRLM	2010-12	2.7	0.6	3.3
500 ppm NRLM	2012-14	2.9	0.6	3.5
15 ppm Nonroad	2010-12	5.0	0.8	5.8
15 ppm NRLM	2012-14	5.6	0.8	6.4
15 ppm NRLM	2014+	5.8	1.2	7.0

Chapter 8 describes the analysis of aggregating the incremental fuel costs, operating costs, and the costs for producing compliant engines and equipment, operating costs. Table 7 compares these aggregate costs with the corresponding estimated emission reductions to present cost-per-ton figures for the various pollutants.

Table 7—Aggregate Cost per Ton for the Proposed Two-Step Fuel Program and Engine Program—2004-2036 Net Present Values at 3% Discount Rate ($2002)

Pollutant	Aggregate Discounted Lifetime Cost per ton
NOx+NMHC	$1,010
PM	$11,200
SO_x	$690

Economic Impact Analysis

As described in Chapter 10, we prepared an Economic Impact Analysis (EIA) to estimate the economic impacts of this rule on producers and consumers of nonroad engines and equipment and fuels, and related industries. The EIA has two parts: a market analysis and a welfare analysis. The market analysis explores the impacts of the proposed program on prices and quantities of affected products. The welfare analysis focuses on changes in social welfare and explores which entities will bear the burden of the proposed program. The EIA relies on the Nonroad Diesel Economic Impact Model (NDEIM). The NDEIM uses a multi-market analysis framework that considers interactions between 62 regulated markets and other markets to estimate how compliance costs can be expected to ripple through these markets.

As shown in Table 8, the market impacts of this rule suggest that the overall economic impact on society is expected to be small, on average. According to this analysis, price increases of goods and services produced using equipment and fuel affected by this rule (the application marktets) are expected to average about 0.1 percent per year. Output decrease in the application markets are expected to average less than 0.02 percent for all years. The price increases for engines, equipment, and fuel are expected to be about 20 percent, 3 percent, and 7 percent, respectively (total impact averaged over the relevant years). The number of engines and equipment produced annually is expected to decrease by less than 250 units, and the amount of fuel produced annually is expected to decrease by less than 4 million gallons.

Table 8—Summary of Expected Market Impacts, 2013 and 2020

Market	2013			2036		
	Average engineering cost per unit	Price change	Quantity change	Average engineering cost per unit	Price change	Quantity change
Engines	$1,052	21.4%	-0.014%	$931	18.2%	-0.016%
Equipment	$1,198	2.9%	-0.017%	$962	2.5%	-0.018%
Application markets[a]	—	0.10%	-0.015%	—	0.10%	-0.016%
Nonroad Fuel Markets	$0.06	6.0%	-0.019%	$0.07	7.0%	-0.022%
Loco/Marine Transportation	—	0.01%	-0.007	—	0.01%	-0.008

[a]Commodities in the application markets are normalized; only percentage changes are presented

The welfare analysis predicts that consumers and producers in the application markets are expected to bear the burden of this proposed program. In 2013, the total social costs of the rule are expected to be about $1.5 billion. About 83 percent of the total social costs is expected to be borne by producers and consumers in the application markets, indicating that the majority of the costs associated with the rule are expected to be passed on in the form of higher prices. When these estimated impacts are broken down, 58.5 percent are expected to be borne by consumers in the application markets and 41.5 percent are expected to be borne by producers in the application markets. Equipment manufacturers are expected to bear about 9.5 percent of the total social costs. These are primarily the costs associated with equipment redesign. Engine manufacturers are expected to bear about 2.8 percent; this is primarily the fixed costs for R&D. Nonroad fuel refiners are expected to bear about 0.5 percent of the total social costs. The remaining 4.2 percent is accounted for by locomotive and marine transportation services.

Total social costs continue to increase over time and are projected to be about $2.0 billion by 2030 and $2.2 billion in 2036 ($2002). The increase is due to the projected annual growth in the engine and equipment populations. Producers and consumers in the application markets are expected to bear an even larger portion of the costs, approximately 96 percent. This is consistent with economic theory, which states that, in the long run, all costs are passed on to the consumers of goods and services.

Impact on Small Businesses

Chapter 11 discusses our Final Regulatory Flexibility Analysis, which evaluates the potential impacts of new engine standards and fuel controls on small entities. Before issuing our proposal, we analyzed the potential impacts of this rule on small entities. As a part of this analysis, we interacted with several small entities representing the various affected sectors and convened a Small Business Advocacy Review Panel to gain feedback and advice from these representatives. This feedback was used to develop regulatory alternatives to address the impacts of the rule on small businesses. Small entities raised general concerns related to potential difficulties and costs of meeting the upcoming standards.

The Panel consisted of members from EPA, the Office of Management and Budget, and the Small Business Administration's Office of Advocacy. We either proposed or requested comment on the Panel's recommendations. Chapter 11 discusses the options recommended in the Panel Report, the regulatory alternatives we considered in the proposal, and the provisions we are adopting in the final rule. We have adopted several provisions that give small engine and equipment manufacturers and small refiners several compliance options aimed specifically at educing the burden on these small entities. In general the options are similar to small entity provisions adopted in prior rulemakings where EPA set standards for nonroad diesel engines and controlled the level of sulfur in highway gasoline and diesel fuel. These provisions will reduce the burden on small entities that must meet this rule's requirements.

Alternative Program Options

In the course of developing our final program, we investigated several alternative approaches to both the engine and fuel programs. These alternative program options included variations in:

- The applicability of aftertreatment-based standards for different horsepower categories
- The phase-in schedule for engine standards
- The start date for the diesel fuel sulfur standard
- The use of a single-step instead of a two-step approach to fuel sulfur standards
- The applicability of the very-low fuel sulfur standards to fuel used by locomotives and marine engines

Chapter 12 includes a complete description of twelve alternative program options. The draft RIA contained an assessment of technical feasibility, cost, cost-effectiveness, inventory impact, and health and welfare benefits for each alternative. We refer the reader to the detailed evaluations of the options presented in the Draft Regulatory Impact Analysis.

CHAPTER 1: Industry Characterization

In understanding the impact of emission standards on regulated industries, it is important to assess the nature of the regulated and otherwise affected industries. The industries affected are the nonroad diesel engine and equipment manufacturing, oil-refining, and fuel-distribution industries. This chapter provides market share information for the above industries. This information is provided for background purposes. The information presented in this chapter will be most helpful for those unfamiliar with the engine/equipment industry and/or the oil refining and fuel-distribution industries.

Nonroad engines are generally distinguished from highway engines in one of four ways: (1) the engine is used in a piece of motive equipment that propels itself in addition to performing an auxiliary function (such as a bulldozer grading a construction site); (2) the engine is used in a piece of equipment that is intended to be propelled as it performs its function (such as a lawnmower); (3) the engine is used in a piece of equipment that is stationary when in operation but portable (such as a generator or compressor) or (4) the engine is used in a piece of motive equipment that propels itself, but is primarily used for off-road functions (such as an off-highway truck).

The nonroad category is also different from other mobile source categories because: (1) it applies to a wider range of engine sizes and power ratings; (2) the pieces of equipment in which the engines are used are extremely diverse; and (3) the same engine can be used in widely varying equipment applications (for example, the same engine used in a backhoe can also be used in a drill rig or in an air compressor).

A major consideration in regulating nonroad engines is the lack of vertical integration in this field. Although some nonroad engine manufacturers also produce equipment that rely on their own engines, most engines are sold to various equipment manufacturers over which the original engine manufacturer has minimal control. A characterization of the industry affected by this rulemaking must therefore include equipment manufacturers as well as engine manufacturers.

Sections 1.1 and 1.2 characterize the nonroad engine and equipment industries based on different manufacturers and their products and the diversity of the manufacturer pool for the various types of equipment. They describe the nonroad diesel engine market and related equipment markets by power category. Additional information related to engine/equipment profiles, including employment figures, production costs, information on engine component materials and firm characteristics, are available in the docket.[1]

1.1 Characterization of Engine Manufacturers

For purposes of discussion, the characterization of nonroad engine manufacturers is arranged by the power categories used to define the new emission standards. The information detailed in this section was derived from the Power Systems Research database and trade journals.[2] We recognize that the PSR database is not comprehensive, but have not identified a better source to provide consistent data for identifying additional companies. The sales figures presented in this chapter pertain to both mobile and stationary nonroad equipment . The former forms the bases for cost and other analyses such as included in Chapters 6 and 10.

1.1.1 Engines Rated between 0-19 kW (0 and 25 hp)

In year 2000, sales of engines in this category comprised 18 percent (approximately 135,828 units) of the nonroad market. The largest manufacturers of engines in this category are Kubota (36,601 units) and Yanmar (32,126 units). Seventy three percent of Yanmar's engines are four-cycle, water-cooled, indirect-injection models. A majority of Kubota's engines are also four-cycle, water-cooled indirect-injection models. Another major manufacturer in this category is Kukje with 21,216 units.

1.1.2 Engines Rated between 19 and 56 kW (25 and 75 hp)

This is the largest category, comprised of 38 percent of engines with approximately 281,157 units sold in year 2000. Direct-injection (DI) engines account for 59 percent of this category with 165,427 units. Yanmar has approximately 19 percent of the DI market share, followed by Deutz (16%), Kubota (13%), Hatz (12%), Isuzu(10%) ,Caterpillar/Perkins(10%) and Deere (8%). Kubota dominates the Indirect-injection (IDI) market with 51 percent of sales , followed by Daewoo Heavy Industries (12%), Ihi-Shibaura (12%), Isuzu(8%) and Caterpillar/Perkins (5%). Ag tractors, generator sets, skid-steer loaders and refrigeration and air conditioning units are the largest selling engines in this power range.

1.1.3 Engines Rated between 56 and 130 kW (75 and 175 hp)

In year 2000, manufacturers sold approximately 206,028 engines in this power range. This represents the second-largest category of nonroad engines with 28 percent of the total market. Almost all of these engines are DI. The top three manufacturers are John Deere (28%), Caterpillar/Perkins (20%) and Cummins (17%). Other manufacturers include Case/ New Holland, Deutz, Hyundai Motor, Isuzu, Toyota and Komatsu. The engines in this power range are used mostly in agricultural equipment such as ag tractors. The second-largest use for these engines is in construction equipment such as tractor/loader/backhoes and skid-steer loaders.

1.1.4 Engines Rated between 130 and 560 kW (175 and 750 hp)

Engines in this power range rank fourth (15% of the total market) in nonroad diesel engines sales with approximately 108,172 units sold in year 2000. Almost all of these are DI engines. Deere has approximately 32 percent of the DI market, followed by Caterpillar/Perkins (22%), Cummins (21%), Case/New Holland (8%),Volvo (4%), and then by Komatsu and Detroit Diesel (each 3%). The largest selling engines in this category are used in agricultural equipment (ag tractors), followed by construction equipment (wheel loaders, bulldozers, and excavators).

1.1.5 Engines Rated over 560 kW (750 hp)

This is the smallest nonroad category with approximately 5,633 engines comprising 1 percent of the total nonroad market and consist of all DI engines. Caterpillar is the largest manufacturer (44%), followed by Cummins (19%), Komatsu (18%), and Detroit Diesel (11%). Power generation is the principal application in this range, followed by large off-highway trucks and other types of construction equipment such as crawlers , wheel loaders and bulldozers.

1.2 Characterization of Equipment Manufacturers

Nonroad equipment can be grouped into several categories. This section considers the following seven segments: agriculture, construction, general industrial, lawn and garden, material handling, pumps and compressors, and welders and generator sets. Engines used in locomotives, marine applications, aircraft, recreational vehicles, underground mining equipment, and all spark-ignition engines within the above categories are not included in this rulemaking. Table 1.2-1 has examples of the types of nonroad equipment that will be impacted by this rulemaking, arranged by category.

Table 1.2-1
Sampling of Nonroad Equipment Applications

Segment	Applications		
Agriculture	Ag Tractor Baler Combine	Sprayer Windrower Other Ag Equipment	
Construction	Bore/drill Rig Crawler Excavator Grader Off-highway Tractor	Off-highway Truck Paver Plate Compactor Roller Wheel Loader/Dozer	Tamper/Rammer Scraper Skid-Steer Loader Trencher
General Industrial	Concrete/Ind. Saw Crushing Equipment	Oil Field Equipment Refrigeration/AC	Scrubber/sweeper Rail Maintenance
Lawn and Garden	Lawn and Garden Tractor	Commercial Mower	Trimmer/edger/cutter
Pumps and Compressors	Air Compressor Hydro Power Unit Pressure Washer	Pump Gas Compressor	Irrigation Set
Material Handling	Aerial Lift Crane	Forklift Terminal Tractor	Rough-Terrain Forklift
Welders and Generators	Generator Set, Welder	Lt Plant/Signal Board	

Based on power rating rating of the engines, a fraction of applications such as air compressors, generator sets, hydropower units, irrigation sets, pumps and welders is considered to be stationary and therefore not subject to EPA emission standards for nonroad engines. However, the tables in Sections 1.2.1 to 1.2.5 account for all equipment manufactured, whether stationary or mobile within an engine power category.

For purposes of discussion, nonroad equipment is grouped into five power ranges similar to those used for characterizing nonroad engines. This section explores the characteristics of nonroad equipment applications and the companies involved in manufacturing these equipment. This analysis includes several numerical summaries of different categories.

1.2.1 Equipment Using Engines Rated under 19 kW (0 and 25 hp)

The applications with the most sales are ag tractors followed by generator sets. There are about 29 total applications with engines rated under 19 kW. The six leading manufacturers produce 46 percent of the equipment in this category. Their collective sales volume over five years (1996 to 2000) was approximately 251,000 pieces of equipment in a market that has a five-year total sales volume of 551,000. These manufacturers and the major equipment types manufactured by them are shown in Table 1.2-2.

Table 1.2-2
Characterization of the Top 6 Equipment Manufacturers for Engines Rated below 19 kW

Original Equipment Manufacturer	Major Equipment Manufactured	Average Annual Sales	Percentage of Market	Engine Characterization*
Ingersoll-Rand	Refrigeration/AC, Skid-steer loaders, and Excavators	13,394	12%	W,NA, I
Deere & Company	Agricultural tractors, Commercial mowers, Lawn & garden tractors	11,042	10%	W,NA, I
Korean Gen-sets	Generator Sets	9,970	9%	W,NA, I
China Gen-sets	Generator Sets	5,559	5%	W,NA,D/ I
SDMO	Generator Sets	5,191	5%	W/A,NA, D/I
Kubota Corp.	Ag tractors,Lawn & garden tractors Commercial mowers	5,117	5%	W,NA,I

*W=water-cooled, A=air-cooled,O=oil cooled;NA=naturally aspirated,T=turbocharged;I=indirect injection,D=direct injection.

Sales for these top six OEMs are typified by generator sets, skid-steer loaders, ag tractors, commercial mowers, and refrigeration/air conditioning units. The sales of the equipment are listed in Table 1.2-3. The top six manufacturers have equipment that are typical of the market. Fifty-six OEMs produce 92 percent of the equipment in this power range.

Table 1.2-3
Equipment Sales Distribution for Engines Rated below 19 kW

Application Description	Five-year sales Volume (1996-2000)	Average Annual Sales	Percentage of Total Sales
Generator sets	171,435	34,287	31.1
Agricultural tractors	59,863	11,973	9.5
Commercial mowers	59,713	11,943	9.5
Refrigeration/AC	57,668	11,534	9.2
Welders	32,284	6,457	5.1
Light plants/Signal boards	28,239	5,648	4.5
Skid-steer loaders	23,685	4,737	3.8
Lawn & garden tractors	17,879	3,576	2.8
Pumps	16,262	3,252	2.6
Rollers	12,063	2,413	1.9
Pressure washers	11,959	2,392	1.9
Plate compactors	11,535	2,307	1.8
Utility vehicles	8,502	1,700	1.4
Aerial lifts	7,058	1,412	1.1
Excavators	6,118	1,224	1.0
Mixers	4,639	928	0.7
Scrubbers/sweepers	2,829	566	0.4
Commercial turf equipment	2,627	525	0.4
Finishing equipment	2,351	470	0.4
Other general industrial equipment	2,334	467	0.4
Tampers/rammers	2,156	431	0.3
Tractor/loader/backhoes	1,794	359	0.3
Dumpers/tenders	1,689	338	0.3
Air compressors	1,516	303	0.2
Hydraulic power units	797	159	0.1
Trenchers	776	155	0.1
Concrete/industrial saws	733	147	0.1
Irrigation sets	614	123	0.1
Wheel loaders/bulldozers	502	100	0.1
Other agricultural equipment	426	85	0.1
Surfacing equipment	362	72	0.1
Bore/drill rigs	275	55	0.0
Listed Total		110,137	91.4
Grand Total		110,289	100.0

1.2.2 Equipment Using Engines Rated between 19 and 56 kW (25 and 75 hp)

All market segments are represented within the 19 to 56 kW range. They are made up of 55 applications and about 17 percent of total sales are by Ingersoll- Rand. For the 19 to 56 kW range, the equipment uses either direct-injection or indirect-injection engines that are water-cooled or oil-cooled and are either naturally aspirated or turbocharged. The six leading manufacturers produce 53 percent of the equipment in this category. These manufacturers are listed in Table 1.2-4. They manufacture equipment typical of the market, such as agricultural tractors, generator sets, skid-steer loaders and refrigeration/AC. These top selling applications represent about 70 percent of the market as seen in Table 1.2-5. The top 90 percent of the market is supplied by 60 different companies.

Table 1.2-4
Characterization of the Top 6 Equipment
Manufacturers for Engines Rated between 19 and 56 kW

Original Equipment Manufacturer	Major Equipment Manufactured	Average Annual Sales	Percentage of Market	Engine Characterization*
Ingersoll-Rand	Refrigeration A/C, Skid-steer loaders, Air compressors	40,199	17%	W/O,NA/T,D/I
Case New Holland	Agricultural tractors, Skid-steer loaders	23,194	10%	W/O,NA/T,D/I
Thermadyne Holdings	Generator sets	19,090	8%	A,NA,D
Deere & Company	Agricultural tractors, Skid-steer loaders, Commercial mowers	17,752	7%	W,NA/T,D
Kubota Corp.	Agricultural tractors, Excavators, Wheel Loaders, Bulldozers	14,391	6%	W,NA/T,D/I
United Technologies Co.	Refrigeration/AC	12,484	5%	W,NA,D/I

*W=water-cooled, A=air-cooled,O=oil cooled;NA=naturally aspirated, T=turbocharged, I=indirect injection, D=direct injection.

Table 1.2-5
Equipment Sales Distribution across Applications between 19 and 56 kW

Application Description	Five-year sales Volume (1996-2000)	Average Annual Sales	Percentage of Total Sales
Agricultural tractors	286,295	57,259	24%
Generator sets	223,960	44,792	19%
Skid-steer loaders	177,925	35,585	15%
Refrigeration/AC	142,865	28,573	12%
Welders	60,035	12,007	5.0%
Commercial mowers	47,735	9,547	3.9%
Air compressors	33,840	6,768	2.8%
Trenchers	26,465	5,293	2.2%
Aerial lifts	25,810	5,162	2.1%
Forklifts	23,480	4,696	1.9%
Rollers	18,010	3,602	1.5%
Excavators	16,485	3,297	1.4%
Rough terrain forklifts	13,530	2,706	1.1%
Scrubbers/sweepers	11,770	2,354	1.0%
Light plants/signal boards	11,720	2,344	1.00%
Pumps	9,290	1,858	0.77%
Bore/drill rigs	9,000	1,800	0.74%
Utility vehicles	8,460	1,692	0.70%
Wheel Loaders/bulldozers	6,985	1,397	0.58%
Pressure washers	6,700	1,340	0.55%
Pavers	6,395	1,279	0.53%
Commercial turf	5,760	1,152	0.48%
Tractor/loader/backhoes	5,115	1,023	0.42%
Irrigation sets	4,300	860	0.36%
Concrete/industrial saws	3,400	680	0.28%
Other general industrial	3,400	680	0.28%
Chippers/grinders	2,625	525	0.22%
Crushing/processing equipment	2,305	461	0.19%
Hydraulic power units	1,950	390	0.16%
Terminal tractors	1,765	353	0.15%
Surfacing equipment	1,490	298	0.12%
Dumpers/tenders	1,055	211	0.09%
Listed Total		239,984	99.3%
Grand Total		241,710	100.0%

1.2.3 Equipment Using Engines Rated between 56kW and 130 kW (75 and 175 hp)

Engines rated between 56 and 130 kW are all direct-injection engines that are either water-cooled (94%), oil-cooled (4%) or air-cooled (2%). The six leading manufacturers produce 49 percent of the equipment in this category. Their collective sales volume over five years (1996 to 2000) was approximately 440,000 pieces of equipment in a market that has a five-year total sales volume of 905,000. These manufacturers are shown in Table 1.2-6.

Table 1.2-6
Characterization of the Top 6 Equipment
Manufacturers for Engines Rated between 56kW and 130 kW (75 and 175 hp)

Original Equipment Manufacturer	Major Equipment Manufactured	Average Annual Sales	Percentage of Market	Engine Characterization*
Case New Holland	Ag Tractors, Combines, Crawlers, Skid-steer loaders, Tractors/loaders/backhoes	26,717	15%	W,T,D
Deere & Company	Ag Tractors, Combines, Wheel Loaders/Dozers	25,648	14%	W,T,D
Caterpillar	Generator Sets, Scrapers, Crawlers, Excavators, Wheel loaders, bulldozers, Graders, Rough terrain fork-lifts	13,670	8%	W,T/N,D
Ingersoll-Rand	Air compressors, Rollers, Bore/drill rigs	10,169	6%	W,T,D
Agco	Agricultural tractors, Combines, Sprayers	6,182	3%	W/A,T,D
Landini Holding	Agricultural tractors	5,467	3%	W,T/N,D

*W=water-cooled, A=air-cooled,O=oil cooled;NA=naturally aspirated, T=turbocharged, I=indirect injection, D=direct injection.

Sales of these top six OEMs are typified by agricultural tractors, tractors/loaders/backhoes, generator sets, skid-steer loaders, rough terrain fork-lifts, excavators, air compressors and crawlers. The sales of these equipment are listed in Table 1.2-7. The top six manufacturers have engines that are typical of the market. Seventy-two OEMs produce 90 percent of the equipment in this power range.

Table 1.2-7
Equipment Sales Distribution across Applications between 56 and 130 kW

Application Description	Five-yr sales Volume (1996-2000)	Average Annual Sales	Percentage of Total Sales
Agricultural tractors	185,315	37,063	20%
Tractor/loader/backhoes	106,780	21,356	12%
Generator sets	103,490	20,698	11%
Skid-steer loaders	74,040	14,808	8.2%
Rough terrain forklfts	56,770	11,354	6.3%
Excavators	50,140	10,028	5.5%
Air compressors	32,080	6,416	3.5%
Crawlers	30,260	6,052	3.3%
Forklifts	29,705	5,941	3.3%
Wheel Loaders/bulldozers	27,520	5,504	3.0%
Rollers	23,195	4,639	2.6%
Commercial turf equipment	17,425	3,485	1.9%
Other general industrial	16,580	3,316	1.8%
Scrubbers/sweepers	16,005	3,201	1.8%
Irrigation sets	15,745	3,149	1.7%
Windrowers	11,385	2,277	1.3%
Pumps	10,265	2,053	1.1%
Sprayers	8,830	1,766	1.0%
Listed Total		163,108	90.1%
Grand Total		181,094	100.0%

1.2.4 Equipment Using Engines Rated between 130 and 560 kW (175 and 750 hp)

For the 130 to 560 kW range (where 560 kW is included in the range), most of the equipment uses direct-injection engines that are water-cooled and turbocharged. A few are naturally aspirated. The six leading manufacturers produce 56 percent of the equipment in this category. These manufacturers are listed in Table 1.2-8. Their products have the following applications : ag tractors, combines, generator sets, wheel loaders/bull dozers, which is typical of the market.

The 130 to 560 kW range is characterized by applications as shown in Table 1.2-9. They represent about 94 percent of the market. The top 90 percent of this market is supplied by 60 OEMs.

Table 1.2-8
Characterization of the Top 6 Equipment Manufacturers
for Engines Rated between 130 and 560 kW

Original Equipment Manufacturer	Major Equipment Manufactured	Average Annual Sales	Percentage of Market	Engine Characterization*
Deere & Company	Ag Tractors, Combines, Wheel Loaders/bulldozers	27,990	27%	W,T,D
Case New Holland	Ag Tractors, Combines, Crawlers, Generator Sets, Scrapers, Crawlers,	14,778	14%	W,T,D
Caterpillar	Excavators,wheel loaders/dozers, graders	13,151	13%	W,T/N,D
Komatsu	Crawlers, Excavators,Graders, Wheel Loaders/Dozers	4,941	5%	W,T,D
Ingersoll-Rand	Air Compressors, Rollers, Bore/Drill Rigs	3,683	4%	W,T,D
Agco	Ag Tractors, Combines, Sprayers	3,194	3%	W/A,T,D

*W=water-cooled, A=air-cooled,O=oil cooled;NA=naturally aspirated, T=turbocharged, I=indirect injection, D=direct injection.

Table 1.2-9
Equipment Sales Distribution across Applications between 130 and 560 kW

Application Description	Five-yr sales Volume (1996-2000)	Average Annual Sales	Percentage of Total Sales
Agricultural tractors	149,589	29,918	29.0%
Generator sets	57,400	11,480	11.0%
Wheel loaders/bulldozers	43,475	8,695	8.3%
Combines	35,743	7,149	6.8%
Excavators	35,166	7,033	6.7%
Crawlers	28,478	5,696	5.4%
Air compressors	20,884	4,177	4.0%
Graders	14,814	2,963	2.8%
Sprayers	12,193	2,439	2.3%
Terminal ractors	12,141	2,428	2.3%
Forest equipment	12,101	2,420	2.3%
Pumps	9,901	1,980	1.9%
Off-highway trucks	9,377	1,875	1.8%
Cranes	9,356	1,871	1.8%
Scrapers	7,097	1,419	1.4%
Bore/drill rigs	7,047	1,409	1.3%
Irrigation sets	6,835	1,367	1.3%
Rollers	6,055	1,211	1.2%
Other agricultural equipment	5,935	1,187	1.1%
Chippers/grinders	4,669	934	0.9%
Other construction equipment	4,142	828	0.8%
Listed Total		98,480	94.0%
Grand Total		492,398	100.0%

1.2.5 Equipment Using Engines Rated over 560 kW (750 hp)

The largest engines, those rated over 560 kW, are produced only for the nonroad market segments of construction equipment and welders and generators. As much as 35 percent of the equipment in this power range is manufactured by Caterpillar. Most equipment manufacturers must buy engines from another company. For most power categories, the Power Systems Research database estimates that between 5 and 25 percent of equipment sales are from equipment manufacturers that also produce engines. Since vertically integrated manufacturers are typically very large companies, such as John Deere and Caterpillar, the companies that make up this fraction of the market are in a distinct minority.

As in the previous category, the equipment rated over 560 kW uses mostly turbocharged, direct-injection engines that are water-cooled. The leading six manufacturers produce 81 percent of the equipment in this power range. These manufacturers are shown in Table 1.2-10. Although generator sets make up the majority of equipment sold in this range, a fraction of them are considered stationary and are therefore not impacted by this rulemaking. Off-highway trucks , wheel loaders/dozers and crawlers also have significant sales (see Table 1.2-11).

Table 1.2-10
Characterization of the Top 6 Equipment Manufacturers for Engines Rated over 560 kW

Original Equipment Manufacturer	Major Equipment Manufactured	Average Annual Sales	Percentage of Market	Engine Characterization*
Caterpillar	Generator Sets, Off-highway trucks, crawler tractors	1,857	35%	W,T,D
Komatsu	Crawlers, Wheel Loaders/Dozers, Off-Highway Trucks	1,376	26%	W,T,D
Multiquip	Generator Sets	336	6%	W,T,D
Kohler	Generator Sets	335	6%	W,T,D
Cummins	Generator Sets	325	6%	W,T,D
Onis Visa	Generator Sets	107	2%	W,T,D

*W=water-cooled, A=air-cooled,O=oil cooled;NA=naturally aspirated, T=turbocharged, I=indirect injection, D=direct injection.

Table 1.2-11
Equipment Sales Distribution across Applications over 560 kW

Application Description	Five-yr sales Volume (1996-2000)	Average Annual Sales	Percentage of Total Sales
Generator sets	14,237	2,847	54%
Off-highway trucks	4,048	810	15%
Crawlers	3,857	771	15%
Wheel loaders/bulldozers	2,567	513	9.8%
Off-highway tractors	542	108	2.1%
Excavators	371	74	1.4%
Oil field equipment	225	45	0.9%
Chippers/grinders	132	26	0.5%
Listed Total		5,196	99.1%
Grand Total		5,241	100.0%

Section 1.3 characterizes the U.S. petroleum refinery industry, market structure and trends as it pertains to distillate fuels, including nonroad diesel fuel. In addition, it covers refinery operations that are directly impacted by this final rule. Section 1.4 discusses distribution of refined petroleum products through pipelines from refineries, as well as storage operations for these products. Sections 1.3 and 1.4 are both are based on a report prepared by RTI under EPA contract, which is available in the docket.[3]

1.3 Refinery Operations

1.3.1 The Supply-Side

This section describes the supply side of the petroleum refining industry, including the current refinery production processes and raw materials used. It also discusses the need for potential changes in refinery production created by this final rule. Finally, it describes the three primary categories of petroleum products affected by the rule and the ultimate costs of production currently faced by the refineries.

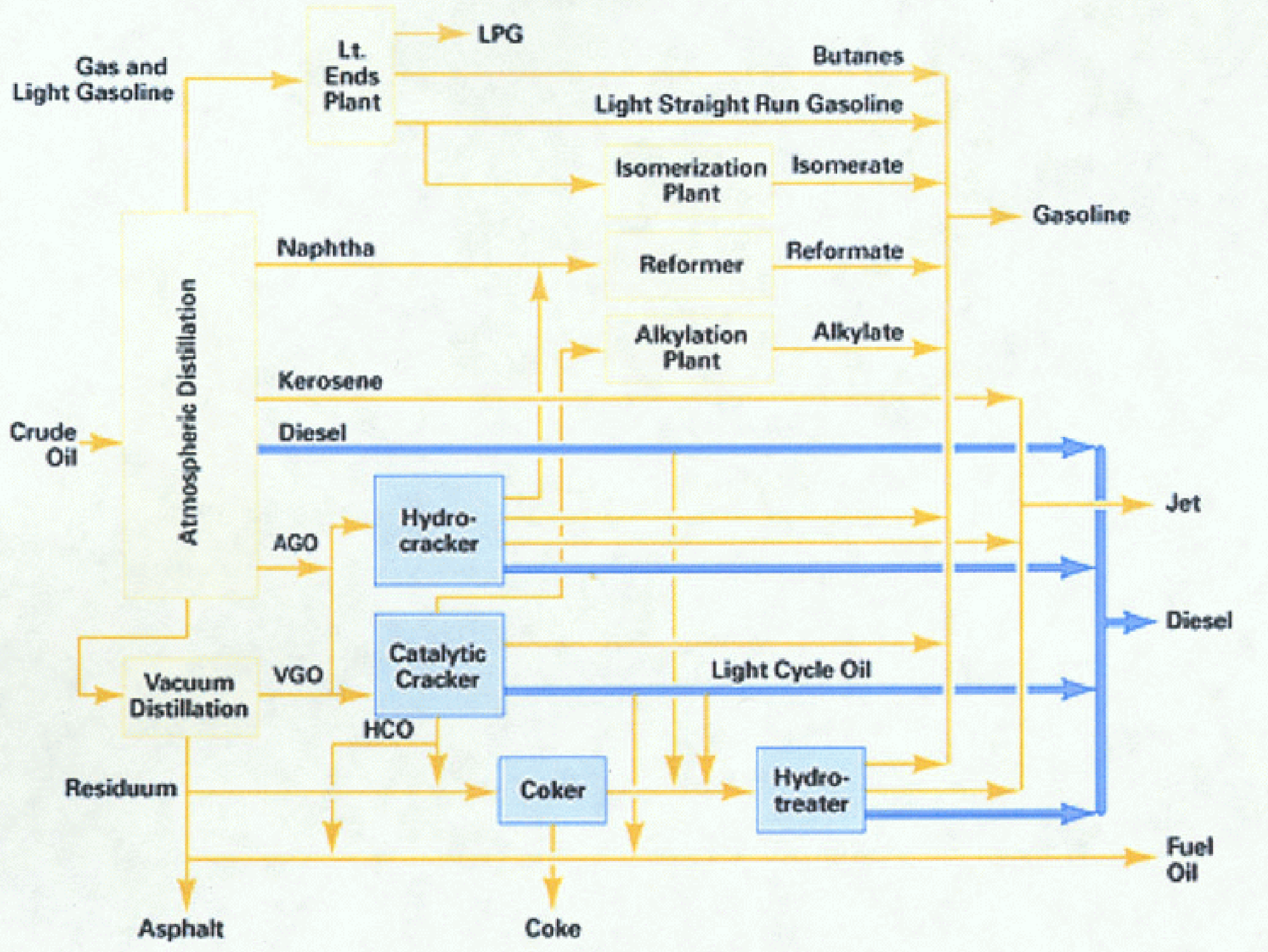
Refinery Production Processes/Technology. Petroleum refining is the thermal and physical separation of crude oil into its major distillation fractions, followed by further processing (through a series of separation and chemical conversion steps) into highly valued finished petroleum products. Although refineries are extraordinarily complex and each site has a unique configuration, we will describe a generic set of unit operations that are found in most medium and large facilities. A detailed discussion of these processes can be found in EPA's sector notebook of the petroleum refining industry (EPA, 1995); simplified descriptions are available on the web sites of several major petroleum producers (Flint Hills Resources, 2002; Chevron, 2002).

Figure 1.3-1 shows the unit operations and major product flows in a typical refinery. After going through an initial desalting process to remove corrosive salts, crude oil is fed to an atmospheric distillation column that separates the feed into several fractions. The lightest boiling range fractions are processed through reforming and isomerization units into gasoline or diverted to lower-value uses such as LPG and petrochemical feedstocks. The middle-boiling fractions make up the bulk of the aviation and distillate fuels produced from the crude. In most refineries, the undistilled liquid (called bottoms) is sent to a vacuum still to further fractionate this heavier material. Bottoms from the vacuum distillation can be further processed into low-value products such as residual fuel oil, asphalt, and petroleum coke.

A portion of the bottoms from the atmospheric distillation, along with distillate from the vacuum still, are processed further in a catalytic cracking unit or in a hydrocracker. These operations break large hydrocarbon molecules into smaller ones that can be converted to high-value gasoline and middle distillate products. Bottoms from the vacuum still are increasingly processed in a coker to produce saleable coke and gasoline and diesel fuel blendstocks. The cracked molecules are processed further in combining operations (alkylation, for example), which combine small molecules into larger, more useful entities, or in reforming, in which petroleum molecules are reshaped into higher quality species. It is in the reforming operation that the octane rating of gasoline is increased to the desired level for final sale. A purification process called hydrotreating helps remove chemically bound sulfur from petroleum products and is critically important for refineries to process their refinery streams into valuable products and to achieve the low sulfur levels required under the regulation.

For each of the major products, several product streams from the refinery will be blended into a finished mixture. For example, diesel fuel typically has a straight-run fraction from crude distillation, distillate from the hydrocracker, light-cycle oil from the catalytic cracker, and hydrotreated gas oil from the coker. Several auxiliary unit operations are also needed in the refinery complex, including hydrogen generation, catalyst handing and regeneration, sulfur recovery, wastewater treatment, and blending and storage tanks. Table 1.3-1 shows average yields of major products from U.S. refineries.

Figure 1.3-1
The Modern Refinery



Source: Chevron. 2002. Diesel Fuel Refining and Chemistry. As accessed on August 19, 2002.
www.chevron.com/prodserv/fuels/bulletin/diesel/L2_4_2rf.htm.

Table 1.3-1
Yields of Major Petroleum Products from Refinery Operations

Product	Gallons per Barrel of Crude	Percentage of Total Feed*
Crude Feed	42.0	100.0%
Gasoline	19.4	46.0%
Highway diesel fuel	6.3	15.0%
Jet Fuel	4.3	10.0%
Petroleum Coke	2.0	5.0%
Residual Fuel Oil	1.9	4.5%
LP Gas	1.9	4.5%
Home heating oil	1.6	4.0%
Asphalt	1.4	3.0%
Nonroad diesel fuel	0.8	2.0%
Other Products	4.0	9.5%
Total	43.6	104.0%

*Note: Total exceeds 100 percent due to volume gain during refining.
Source: Calculated from EIA data in Petroleum Supply Annual 2001. U.S. Department of Energy, Energy Information Administration (EIA). 2002a. Petroleum Supply Annual 2001, Tables 16, 17, and 20. Washington, DC.

Potential Changes in Refining Technology Due to the Final Rule. Regulations requiring much lower levels of sulfur for both gasoline and highway diesel fuel will come into effect over the next few years. To meet these challenges, refineries are planning to add hydrotreater units to their facilities, route more intermediate product fractions through existing hydrotreaters, and operate these units under more severe conditions to reduce levels of chemically bound sulfur in finished products. As has been documented in economic impact analyses for the gasoline and highway diesel rules, these changes will require capital investments for equipment, new piping, and in-process storage; increased use of catalyst and hydrogen; and modifications to current operating strategies.

The addition of lower sulfur limits for nonroad diesel fuel will result in additional refinery changes similar in nature to those required for highway diesel fuel. Product streams formerly sent directly to blending tanks will need to be routed through the hydrotreating operation to reduce their sulfur level. In addition, because an increasing fraction of the total volumetric output of the facility must meet ultra-low sulfur requirements, flexibility will be somewhat reduced. For example, it will become more difficult to sell off spec products if errors or equipment failures occur during operation.

Types of Products. The major products made at petroleum refineries are unbranded commodities, which must meet established specifications for fuel value, density, vapor pressure, sulfur content, and several other important characteristics. As Section 1.3.2 describes, they are transported through a distribution network to wholesalers and retailers, who may attempt to differentiate their fuel from competitors based on the inclusion of special additives or purely through adroit marketing. Gasoline and highway diesel are taxed before final sale, whereas nonroad fuel is not. To prevent accidental or deliberate misuse, nonroad diesel fuel must be dyed before final sale.

A total of $158 billion of petroleum products were sold in the 1997 census year, accounting for a nontrivial 0.4 percent of GDP. Table 1.3-2 lists the primary finished products produced; as one might expect, the percentages are quite close to the generic refinery output shown in Table 1.3-1. Motor gasoline is the dominant product, both in terms of volume and value, with almost three billion barrels produced in 1997. Distillate fuels accounted for less than half as much as gasoline, with 1.3 billion barrels produced in the United States in the same year. Data from the Energy Information Administration (EIA) suggest that 60 percent of that total is low-sulfur highway diesel, with the remainder split between nonroad diesel and heating oil. Jet fuel, a fraction slightly heavier than gasoline, is the third most important product, with a production volume of almost 600 million barrels.

Table 1.3-2
Types of Petroleum Products Produced by U.S. Refineries

Products	Total Produced (thousand barrels)	Percentage of Total
Liquified Refinery Gases	243,322	3.9%
Finished Motor Gasoline	2,928,050	46.4%
Finished Aviation	6,522	0.1%
Jet Fuel	558,319	8.8%
Kerosene	26,679	0.4%
Distillate Fuel Oil	1,348,525	21.4%
Residual Fuel Oil	263,017	4.2%
Naphtha for Feedstock	60,729	1.0%
Other Oils for Feedstock	61,677	1.0%
Special Naphthas	18,334	0.3%
Lubricants	63,961	1.0%
Waxes	6,523	0.1%
Petroleum Coke	280,077	4.4%
Asphalt and Road Oil	177,189	2.8%
Still Gas	244,432	3.9%
Miscellaneous	21,644	0.3%
Total	6,309,000	100.0%

Primary Inputs. Crude oil is the dominant input in the manufacture of refined petroleum products, accounting for 74 percent of material cost, or about $95 billion in 1997, according to the latest Economic Census (U.S. Census Bureau, 1999). The census reported almost equal proportions of imported and domestic crude in that year, with 2.5 billion barrels imported and 2.8 billion barrels originating from within the United States. More recent data published by the EIA show a higher import dependence in the most recent year, with 3.4 billion barrels, or 61.7 percent, imported out of a total of 5.5 billion barrels used by refineries during 2001 (EIA, 2002a).

Crude oil extracted in different regions of the world have quite different characteristics, including the mixture of chemical species present, density and vapor pressure, and sulfur content. The cost of production and the refined product output mix vary considerably depending on the type of crude processed. A light, sweet crude oil, such as that found in Nigeria, will process very differently from a heavy, sulfur-laden Alaska or Arabian crude. The ease of processing any particular material is reflected in its purchase price, with sweet crudes selling at a premium. The result of these variations is that refineries are frequently optimized to run only certain types of crude; they may be unable or unwilling to switch to significantly different feed materials.

In addition to crude oil, refineries may also feed to their refineries hydrocarbon by-products purchased from chemical companies and other refineries and/or semiprocessed fuel oils imported from overseas. In 1997, the Census reported that these facilities purchased $11 billion of hydrocarbons and imported $2.4 billion of unfinished oils. Other significant raw materials purchased include $600 million for precious metal catalysts and more than $800 million in additives.

Costs of Production. According to the latest Economic Census, there were 244 petroleum refining establishments in the United States in 1997, owned by 123 companies and employing 64,789 workers. Data from EIA using a more stringent definition show 164 operable refineries in 1997, a number that fell to 153 by January 1, 2002. As seen in Table 1.3-3, value of shipments in 2000 was $216 billion, up from $158 billion in the 1997 census year. The costs of refining are divided into the main input categories of labor, materials, and capital expenditures. Of these categories, the cost of materials represents about 80 percent of the total value of shipments, as defined by the Census, varying from year to year as crude petroleum prices change (see Table 1.3-4). Labor and capital expenditures tend to be more stable, each accounting for 2 to 4 percent of the value of shipments.

Table 1.3-3

Description of Petroleum Refineries—Census Bureau Data

NAICS 324110—Petroleum Refineries	Establishments	Companies	Employment	Value of Shipments ($\$10^6$)
2000	(NA)	(NA)	62229	$215,592
1999	(NA)	(NA)	63619	$144,292
1998	(NA)	(NA)	64920	$118,156
1997	244	123	64789	$157,935
1992 (reported as SIC 2911)	232	132	74800	$136,239

Sources:
1992 data from U.S. Census Bureau. 1992 Census of Manufactures, Industry Series MC920I-29A. Table 1A.
1997 data from U.S. Census Bureau, 1997 Economic Census - Manufacturing, Industry Series EC97M-3241A, Table 1.
1998-2000 data from U.S. Census Bureau, Annual Survey of Manufactures-2000, 2000, Statistics for Industry Groups and Industries M00(AS)-1, Table 2.

Table 1.3-4
Petroleum Refinery Costs of Production, 1997–2000

Petroleum Refinery Costs of Production	1997	1998	1999	2000
Cost of Materials (10^6)	$127,555	$92,212	$114,131	$178,631
as percent of shipment value	80.4%	78.0%	79.1%	82.9%
Cost of Labor (10^6)	$3,885	$3,965	$3,983	$3,995
as % of shipment value	2.4%	3.4%	2.8%	1.9%
Capital Expenditures (10^6)	$4,244	$4,169	$3,943	$4,453
as % of shipment value	2.7%	3.5%	2.7%	2.1%

Source: U.S. Census Bureau, Annual Survey of Manufactures. 2000. 2000 Statistics for Industry Groups and Industries M00(AS)-1, Tables 2 and 5.

Refinery Production Practices. Refining, like most continuous chemical processes, has high fixed costs from the complex and expensive capital equipment installed. In addition, shutdowns are very expensive, because they create large amounts of off-specification product that must be recycled and reprocessed before sale. As a result, refineries attempt to operate 24 hours per day, 7 days per week, with only 2 to 3 weeks of downtime per year. Intense focus on cost-cutting has led to large increases in capacity utilization over the past several years. A Federal Trade Commission (FTC) investigation into the gasoline price spikes in the Midwest during the summer of 2000 disclosed an average utilization rate of 94 percent during that year, and EIA data from 2001 show that a 92.6 percent utilization rate was maintained in 2001 (FTC, 2001; EIA, 2002a).

Because of long lead times in procuring and transporting crude petroleum and the need to schedule pipeline shipments and downstream storage, refinery operating strategies are normally set several weeks or months in advance. Once a strategy is established for the next continuous run, it is difficult or impossible to change it. Exact proportions of final products can be altered slightly, but at a cost of moving away from the optimal cost profile established initially. The economic and logistical drivers combine to generate an extremely low supply elasticity. One recent study estimated the supply elasticity for refinery products at 0.24 (Considine, 2002). The FTC study discussed above concluded that refiners had little or no ability to respond to the shortage of oxygenated gasoline in the Midwest in the summer of 2000, even with some advance warning that this would occur.

1.3.2 The Demand Side

This section describes the demand side of the market for refined petroleum products, with a focus on the distillate fuel oil industry. It discusses the primary consumer markets identified and their distribution by end use and PADD. This section also considers substitution possibilities available in each of these markets and the feasibility and costs of these substitutions. Figure 1.3-2 is a map of the five PADD regions.

Uses and Consumers. Gasoline, jet fuel, and distillate fuel oils account for almost 80 percent of the value of refinery product shipments, with gasoline making up about 51 percent (U.S. Census Bureau, 1999). Actual and relative net production volumes of these three major products, along with residual fuel oils, are shown in Table 1.3-5, broken out by PADD and for the country as a whole. PADD III, comprising the states of Texas, Louisiana, Arkansas, Alabama, Mississippi, and New Mexico, is a net exporter of refined products, shipping them through pipelines to consumers on the East Coast and also to the Midwest. Compared with gasoline production patterns, distillate production is slightly lower in PADD V (the West Coast) and higher in PADD II (the Midwest).

The primary end-use markets for distillate and residual fuel oils are divided by EIA as follows:

- residential—primarily fuel oil for home (space) heating;
- commercial—high-sulfur diesel fuel, low-sulfur diesel fuel, and fuel oil for space heating;
- industrial—low-sulfur diesel fuel for highway use, high-sulfur diesel fuel for nonroad use, and residual fuel oil for operating steam boilers and turbines (power generation);
- oil companies—mostly fuel oil and some residual fuel for internal use;
- farm—almost exclusively high-sulfur diesel fuel;
- electric utility—residual fuel and distillate fuel oil for power generation;
- railroad—high-sulfur diesel fuel and low-sulfur diesel fuel used for locomotives;
- vessel bunking—combination of fuel oil and residual fuel for marine engines;
- on-highway diesel—low-sulfur diesel fuel for highway trucks and automobiles; military—high-sulfur diesel fuel sales to the Armed Forces; and
- off-highway diesel—high-sulfur diesel fuel and low-sulfur diesel fuel used in construction and other industries.

Figure 1.3-2
PADD Districts of the United States

As Table 1.3-6 indicates, the highway diesel fuel usage of 33.1 billion gallons represents the bulk of distillate fuel usage (58 percent) in 2000. Residential distillate fuel usage, which in the majority is fuel oil, accounts for 11 percent of total usage in 2000. Nonroad diesel fuel is primarily centered on industrial, farm, and off-highway diesel (construction) usage. In 2000, these markets consumed about 13 percent of total U.S. distillate fuels.

To determine the regional consumption of distillate fuel usage, 2000 sales are categorized by PADDs. As shown in Table 1.3-7, PADD I (the East Coast) consumes the greatest amount of distillate fuel at 20.9 billion gallons. However, residential, locomotive, and vessel bunking consumers account for 6.4 billion gallons of the distillate fuel consumed, which means that at least one-third of the total consumed in PADD I is due to fuel oil and not to diesel fuel consumption.

Table 1.3-5
Refinery Net Production of Gasoline and Fuel Oil Products by PADD

	Motor Gasoline		Distillate Fuel Oil		Jet Fuel		Residual Fuel Oil	
PADD	Quantity (1,000 bbl)	Percent (%)	Quantity (1,000 bbl)	Percent (%)	Quantity (1,000 bbl)	Percent (%)	Quantity (1,000 bbl)	Percent (%)
I	369,750	12.6%	170,109	12.6%	30,831	5.5%	38,473	14.6%
II	641,720	21.9%	316,023	23.4%	80,182	14.4%	24,242	9.2%
III	1,306,448	44.6%	629,328	46.7%	288,749	51.7%	132,028	50.2%
IV	97,869	3.3%	54,698	4.1%	9,787	1.8%	4,151	1.6%
V	512,263	17.5%	178,367	13.2%	148,770	26.6%	64,123	24.4%
Total	2,928,050	100.0%	1,348,525	100.0%	558,319	100.0%	263,017	100.0%

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2002a. Petroleum Supply Annual 2001, Tables 16, 17, and 20. Washington, DC. Table 17.

Table 1.3-6
Distillate Fuel Oil by End Use (2000)

End Use	2000 Usage (thousand gallons)	Percentage Share (%)
Residential	6,204,449	10.8%
Commercial	3,372,596	5.9%
Industrial	2,149,386	3.8%
Oil Company	684,620	1.2%
Farm	3,168,409	5.5%
Electric Utility	793,162	1.4%
Railroad	3,070,766	5.4%
Vessel Bunking	2,080,599	3.6%
Highway Diesel	33,129,664	57.9%
Military	233,210	0.4%
Off-Highway Diesel	2,330,370	4.1%
Total	57,217,231	100.0%

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2001b. Fuel Oil and Kerosene Sales, 2000, Tables 7-12. Washington, DC.

Table 1.3-7
Distillate Fuel Oil by End Use and PADD

End Use	PADD (Thousand Gallons)				
	I	II	III	IV	V
Residential	5,399,194	628,414	1,117	38,761	136,962
Commercial	2,141,784	568,089	346,578	102,905	213,240
Industrial	649,726	600,800	420,400	241,146	237,313
Oil Company	19,101	41,727	560,905	29,245	33,643
Farm	432,535	1,611,956	552,104	220,437	351,377
Electric Utility	304,717	133,971	194,786	8,492	151,196
Railroad	499,787	1,232,993	686,342	344,586	307,059
Vessel Bunking	490,150	301,356	1,033,333	173	255,586
Highway Diesel	10,228,244	11,140,616	5,643,703	1,474,611	4,642,490
Military	70,801	36,100	9,250	4,163	112,895
Off-highway Diesel	669,923	608,307	516,989	180,094	355,056
Total	20,905,962	16,904,329	9,965,507	2,644,613	6,796,817

Table 1.3-8 presents a closer look at on-highway consumption of distillate fuel, which is entirely low-sulfur diesel fuel. PADD I (the East Coast) and PADD II (the Midwest) consume almost 65 percent of all U.S. distillate fuel sold for on-highway use.

Table 1.3-9 shows that residential consumption of distillate fuel (primarily fuel oil) is centered in PADD I (the East Coast). Fuel-oil-fired furnaces and water heaters in New York and New England consume most of this heating oil; in most of the rest of the country, residential central heating is almost universally provided by natural gas furnaces or electric heat pumps. A comparison of Tables 1.3-5 and 1.3-9 reveals that PADD I produces far less distillate fuel oil than it consumes. The balance is made up by shipments from PADD III and imports from abroad.

Tables 1.3-10, 1.3-11, and 1.3-12 focus on diesel sales for industrial, agricultural, and construction use. Industrial use of diesel fuel is fairly evenly spread across PADDs. PADD II (the Midwest) has the highest percentage of diesel usage at 28 percent, while PADD V (the West Coast) has the lowest percentage at 11 percent. In contrast, agricultural purchases of diesel are in the great majority (51 percent) centered in PADD II (the Midwest). For construction only, distillate fuel sales are available, but these sales are assumed to be principally diesel fuel. Construction usage of diesel fuel, as with industrial usage, is fairly evenly spread across PADDs, with the exception of PADD IV. PADD IV represents only 8 percent of total construction usage.

Table 1.3-8
Sales for Highway Use of Distillate Fuel by PADD (2000)

PADD	Distillate Usage (Thousand Gallons)	Share of Distillate Fuel Used
I	10,228,244	30.9%
II	11,140,616	33.6%
III	5,643,703	17.0%
IV	1,474,611	4.5%
V	4,642,490	14.0%
Total	33,129,664	100.0%

Table 1.3-9
Sales for Residential Use of Distillate Fuel by PADD (2000)

PADD	Distillate Usage (Thousand Gallons)	Share of Distillate Fuel Used
I	5,399,194	87.0%
II	628,414	10.1%
III	1,117	0.0%
IV	38,761	0.6%
V	136,962	2.2%
Total	6,204,448	100.0%

Table 1.3-10
Industrial Use of Distillate Fuel by PADD (2000)

PADD	Distillate Usage (Thousand Gallons)	Share of Distillate Fuel Used
I	649,726	30.2%
II	600,800	28.0%
III	420,400	19.6%
IV	241,146	11.2%
V	237,313	11.0%
Total	2,149,385	100.0%

Table 1.3-11
Adjusted Sales for Farm Use of Distillate Fuel by PADD (2000)

PADD	Distillate Usage (Thousand Gallons)	Share of Distillate Fuel Used
I	432,535	13.6%
II	1,611,956	50.9%
III	552,104	17.4%
IV	220,437	7.0%
V	351,377	11.1%
Total	3,168,409	100.0%

Table 1.3-12
Sales for Construction Use of Off-Highway Distillate Fuel by PADD (2000)

PADD	Distillate Usage (Thousand Gallons)	Share of Distillate Fuel Used
I	510,876	26.9%
II	549,299	28.9%
III	394,367	20.8%
IV	150,060	7.9%
V	295,235	15.5%
Total	1,899,837	100.0%

Substitution Possibilities in Consumption. For engines and other combustion devices designed to operate on gasoline, there are no practical substitutes, except among different grades of the same fuel. Because EPA regulations apply equally to all gasoline octane grades, price increases will not lead to substitution or misfueling. In the case of distillate fuels, it is currently possible to substitute between low-sulfur diesel fuel, high-sulfur diesel fuel, and distillate fuel oil, although higher sulfur levels are associated with increased maintenance and poorer performance.

With the consideration of more stringent nonroad fuel and emission regulations, substitution will become less likely. Switching from nonroad ultralow-sulfur diesel to highway ultralow-sulfur diesel is not financially attractive, because of the taxes levied on the highway product. Misfueling with high-sulfur fuel oil will rapidly degrade the performance of the exhaust system of the affected engine, with negative consequences for maintenance and repair costs.

1.3.3 Industry Organization

To determine the ultimate effects of the rule, it is important to have a good understanding of the overall refinery industry structure. The degree of industry concentration, regional patterns of production and shipment, and the nature of the corporations involved are all important aspects of this discussion. In this section, we look at market measures for the United States as a whole and by PADD region.

Market Structure—Concentration. There is a great deal of concern among the public about the nature and effectiveness of competition in the refining industry. Large price spikes following supply disruptions and the tendency for prices to slowly fall back to more reasonable levels have created suspicion of coordinated action or other market imperfections in certain regions. The importance of distance in total delivered cost to various end-use markets also means that refiners incur a wide range of costs in serving some markets; because the price is set by the highest cost producer serving the market as long as supply and demand are in balance, profits are made by the low-cost producers in those markets.

Market concentration is measured in a variety of ways by antitrust regulators in the Department of Justice (DOJ) and Federal Trade Commission (FTC), including four-firm concentration ratios (CR4) and the Herfindahl-Hirschman Index (HHI). The CR4 is simply the combined market share of the four largest sellers in a given market, a very intuitive concentration measure. The HHI, which is currently used by the DOJ's Antitrust Division and the FTC, is constructed by summing up the squared market shares, in percentage terms, of all competitors in the market. According to these agencies' 1997 Horizontal Merger Guidelines, a market with an HHI under 1,000 is considered "unconcentrated," one with an HHI between 1,000 and 1,800 is "moderately concentrated," and one with a measure over 1,800 is "highly concentrated" (DOJ, 1997).

The merger guidelines assume that high concentration offers the potential for firms to influence prices through coordinated action on prices. Still it is possible for highly concentrated markets to behave competitively if firms are unwilling or unable to coordinate their actions or if potential entry can serve to limit price increases. The RTI report presents the calculated HHI values for diesel engine markets.

There is, however, no convincing evidence in the literature that markets should be modeled as imperfectly competitive. The FTC study cited earlier concluded that the extremely low supply and demand elasticities made large price movements likely and inevitable given inadequate supply or unexpected increases in demand. Nevertheless, their economic analysis found no evidence of collusion or other anticompetitive behavior in the summer of 2000. Furthermore, the industry is not highly concentrated on a nationwide level or within regions. The 1997 Economic Census presented the following national concentration information: four-firm concentration ratio (CR) of 28.5 percent, eight-firm concentration ratio of 48.6 percent, and an HHI of 422. Merger guidelines followed by the FTC and Department of Justice consider little potential for pricing power in an industry with an HHI below 1,000.

Two additional considerations were important in making a determination as to whether we can safely assume that refineries act as price-takers in their markets. First, with greater concentration in regional or local markets than at the national level, as well as with significant transport costs, competition from across the country will not be effective in restraining prices. Secondly, several large mergers have occurred since the 1997 Economic Census was conducted, all of which have prompted action by the FTC to ensure that effective competition was retained.

To investigate these issues, RTI estimated concentration measures that are not based on refinery-specific production figures (which are not available), but rather on crude distillation capacity, which is the industry's standard measure of refinery size. We aggregated the total capacity controlled by each corporate parent, both at the PADD level and nationwide, and then calculated CR-4, CR-8, and HHI figures. The results are presented in Table 1.3-13.

Table 1.3-13
2001 Concentration Measures for Refineries Based on Crude Capacity

PADD	Quantity	CR-4	CR-8	HHI
I	1,879,400	71.6%	91.3%	1,715
II	3,767,449	54.6%	78.2%	1,003
III	8,238,044	48.8%	68.0%	822
IV (current)	606,650	59.6%	90.1%	1,310
IV (future)	606,650	45.4%	80.5%	918
V	3,323,853	61.3%	90.9%	1,199
National	17,815,396	41.89%	65.50%	644

Note: Quantity is crude distillation capacity in thousands of barrels per stream day.
Source:U.S. Department of Energy, Energy Information Administration (EIA). 2002b. Refinery Capacity Data Annual. As accessed on September 23, 2002. http://www.eia.doe.gov/ oil_gas/petroleum/data_publications/ refinery_capacity_data/refcap02.dbf. Washington, DC. See text discussion.

The data in this table provide several interesting conclusions:

- The current and future state of PADD IV shows the impact of FTC oversight to maintain competition. As part of approving the Phillips-Conoco merger, the FTC ordered the merged company to divest two refineries in PADD IV—Commerce City, Colorado, and Woods Cross, Utah. Once those divestitures take place, the concentration levels will drop below 1,000, a level that is not generally of concern.
- The only region that is highly concentrated is PADD I, which is generally dominated by two large refineries. In this case, however, imports of finished petroleum products, along with shipments from PADD III, should prevent price-setting behavior from emerging in this market. Table 1.3-14 shows imports of refined products for PADD I and the entire country. About 90 percent of total U.S. imports of gasoline and distillate fuels come into PADD I, aided by inexpensive ocean transport. It is reasonable to assume that any attempts to set prices by the dominant refineries would be defeated with increased imports.

Table 1.3-14
PADD I and Total U.S. Imports of
Gasoline and Fuel Oil Products by Top Five Countries of Origin

Top Five Countries of Origin	Finished Motor Gasoline PADD I Import	Finished Motor Gasoline Total U.S. Import	Distillate Fuel Oil PADD I Import	Distillate Fuel Oil Total U.S. Import	Residual Fuel PADD I Import	Residual Fuel Total U.S. Import
Venezuela	21,017	21,257	16,530	16,530	17,667	18,341
Brazil	8,286	8,286	1,472	1,832	8,361	9,105
Canada	41,711	43,778	30,350	35,165	9,483	11,723
Russia	869	968	10,345	10,345	174	1,051
Virgin Islands (U.S.)	38,135	38,882	30,810	31,540	13,412	13,502
Sum of Top Five	110,018	113,171	89,507	95,412	49,097	53,722
Total	153,633	165,878	112,318	125,586	91,520	107,688
Percentage of Total U.S. Imports	92.6%		89.4%		85.0%	

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2002a. Petroleum Supply Annual 2001. Tables 16, 17, and 20. Washington, DC. Table 20.

- Markets in PADDs II and III, which are not overly concentrated or geographically isolated, should behave competitively, with little potential for price-setting among its refineries.
- The four large mergers (Exxon-Mobil, BP-Amoco, Chevron-Texaco, and Phillips-Conoco) have not increased nationwide concentration to a level of concern for competitive reasons.

Market Structure—Firms and Facilities. PADD III has the greatest number of refineries affected by the final rule and will account for the largest volume of low-sulfur nonroad diesel fuel. Tables 1.3-15 and 1.3-16 present the number of operating refineries and the number of crude distillation units in each PADD; output volumes were presented in Table 1.3-5. PADD III also accounts for 45 to 50 percent of U.S. refinery net production of finished motor gasoline, distillate fuel oil, and residual fuel oil. Similarly, PADD IV has the fewest number of affected facilities and accounts for the smallest share of distillate production. Still, because compliance costs per unit of output are likely to depend on refinery scale, the small size and geographic isolation of the PADD IV refineries suggest that the financial impact may be greatest on these operations.

Table 1.3-15
Number of Petroleum Refineries by PADD

PADD	Number of Facilities	Percentage of Total
I	16	11.1%
II	28	19.4%
III	54	37.5%
IV	14	9.7%
V	32	22.2%
Total	144	100.0%

Table 1.3-16
Number of Crude Distillation Facilities by PADD

PADD	Number of Facilities	Percentage of Total
I	12	8.6%
II	26	18.7%
III	50	36.0%
IV	16	11.5%
V	35	25.2%
Total	139	100.0%

According to the EIA Petroleum Supply Annual 2001, the top three owners of crude distillation facilities are ExxonMobil Corp. (11 percent of U.S. total), Phillips Petroleum Corp. (10 percent), and BP PLC (9 percent). Table1.3-17 gives an overview of the top refineries in each PADD, in descending order of total crude distillation capacity. As operating refineries attempt to run at full utilization rates, this measure should correlate directly to total output. Information is not available on actual production of highway diesel, nonroad diesel, and other distillate fuels for each refinery. Note that PADD III has more than 50 percent of the total crude distillation capacity, as well as the three largest single facilities.

Firm Characteristics. Many of the large integrated refineries are owned by major petroleum producers, which are among the largest corporations in the United States. According to Fortune Magazine's Fortune 500 list, ExxonMobil is the second largest corporation in the world, as well as in the United States. Chevron Texaco ranks as the eighth largest U.S. corporation, placing it fourteenth in the world. The newly merged Phillips and Conoco entity will rank in the top 20 in the United States, and six more U.S. petroleum firms make the top 500. BP Amoco (fourth worldwide) and Royal Dutch Shell (eighth worldwide) are foreign-owned, as is Citgo (owned by Petroleos de Venezuela).

Many of the smallest refineries are small businesses. A total of 21 facilities owned by 13 different parent companies qualify or have applied for small business status (EPA, 2002). These small refineries are concentrated in the Rocky Mountain and Great Plains region of PADD IV, and their conversion to low-sulfur diesel fuel calls for significant flexibility.

1.3.4 Markets and Trends

There is considerable diversity in how different markets for distillate fuels have been growing over the past several years. Table 1.3-18 shows that residential and commercial use of fuel oil has been dropping steadily since 1984, while highway diesel use has nearly doubled over the same period. Farm use of distillate has been flat over the 15-year period, while off-highway use, mainly for construction, has increased by 40 percent.

Table 1.3-17
Top Refineries in Each PADD by Total Crude Distillation Capacity

	Name of Company	Location of Facilities		Crude Distillation Capacity (barrels/day)	Percentage of Total PADD Crude Distillate Capacity	Percentage of Total U.S. Crude Distillate Capacity
PADD I	Sunoco Inc. (R&M)	Philadelphia	PA	330,000	20.9%	2.0%
	Phillips 66 Co.	Linden	NJ	250,000	15.9%	1.5%
	Phillips 66 Co.	Trainer	PA	180,000	11.4%	1.1%
	Motiva Enterprises LLC	Delaware City	DE	175,000	11.1%	1.1%
	Sunoco Inc.	Marcus Hook	PA	175,000	11.1%	1.1%
	TOTAL			1,576,600	100.0%	9.7%
PADD II	BP Products North America, Inc.	Whiting	IN	410,000	12.0%	2.5%
	Phillips 66 Co.	Wood River	IL	288,300	8.4%	1.8%
	Flint Hills Resources LP	Saint Paul	MN	265,000	7.7%	1.6%
	ExxonMobil Refg & Supply Co.	Joliet	IL	235,500	6.9%	1.4%
	Marathon Ashland Petro LLC	Catlettsburg	KY	222,000	6.5%	1.4%
	Conoco Inc.	Ponca City	OK	194,000	5.7%	1.2%
	Marathon Ashland Petro LLC	Robinson	IL	192,000	5.6%	1.2%
	Williams Refining LLC	Memphis	TN	180,000	5.3%	1.1%
	TOTAL			3,428,053	100.0%	21.1%

(continued)

Table 1.3-17 (continued)
Top Refineries in Each PADD by Total Crude Distillation Capacity

	Name of Company	Location of Facilities		Crude Distillation Capacity (barrels/day)	Percentage of Total PADD Crude Distillate Capacity	Percentage of Total U.S. Crude Distillate Capacity
PADD III	ExxonMobil Refg & Supply Co.	Baytown	TX	516,500	6.8%	3.2%
	ExxonMobil Refg & Supply Co.	Baton Rouge	LA	488,500	6.4%	3.0%
	BP Products North America, Inc.	Texas City	TX	437,000	5.8%	2.7%
	ExxonMobil Refg & Supply Co.	Beaumont	TX	348,500	4.6%	2.1%
	Deer Park Refg Ltd Ptnrshp	Deer Park	TX	333,700	4.4%	2.1%
	Citgo Petroleum Corp.	Lake Charles	LA	326,000	4.3%	2.0%
	Chevron U.S.A. Inc.	Pascagoula	MS	295,000	3.9%	1.8%
	Flint Hills Resources LP	Corpus Christi	TX	279,300	3.7%	1.7%
	Lyondell Citgo Refining Co. Ltd.	Houston	TX	274,500	3.6%	1.7%
	Premcor Refg Group Inc	Port Arthur	TX	255,000	3.4%	1.6%
	Conoco Inc.	Westlake	LA	252,000	3.3%	1.6%
	Phillips 66 Co.	Belle Chasse	LA	250,000	3.3%	1.5%
	Motiva Enterprises LLC	Port Arthur	TX	245,000	3.2%	1.5%
	Marathon Ashland Petro LLC	Garyville	LA	232,000	3.1%	1.4%
	Motiva Enterprises LLC	Norco	LA	228,000	3.0%	1.4%
	Motiva Enterprises LLC	Convent	LA	225,000	3.0%	1.4%
	Phillips 66 Co.	Sweeny	TX	213,000	2.8%	1.3%
	Valero Refining Co. Texas	Texas City	TX	204,000	2.7%	1.3%
	Chalmette Refining LLC	Chalmette	LA	182,500	2.4%	1.1%
	Atofina Petrochemicals Inc.	Port Arthur	TX	178,500	2.4%	1.1%
	Total			7583080	100.0%	46.7%

(continued)

Table 1.3-17 (continued)
Top Refineries in Each PADD by Total Crude Distillation Capacity

	Name of Company	Location of Facilities		Crude Distillation Capacity (barrels/day)	Percentage of Total PADD Crude Distillate Capacity	Percentage of Total U.S. Crude Distillate Capacity
PADD IV	Conoco Inc.	Commerce City	CO	62,000	2.0%	0.4%
	Sinclair Oil Corp.	Sinclair	WY	62,000	2.0%	0.4%
	Conoco Inc.	Billings	MO	60,000	1.9%	0.4%
	TOTAL			567,370	18.4%	3.5%
PADD V	BP West Coast Products LLC	Los Angeles	CA	260,000	8.4%	1.6%
	Chevron U.S.A. Inc.	El Segundo	CA	260,000	8.4%	1.6%
	BP West Coast Products LLC	Cherry Point	WA	225,000	7.3%	1.4%
	Chevron U.S.A. Inc.	Richmond	CA	225,000	7.3%	1.4%
	Williams Alaska Petro Inc.	North Pole	AK	197,928	6.4%	1.2%
	TOTAL			3,091,198	100.0%	19.0%
Total U.S. (excluding Virgin Islands)				16,246,301		100.0%

Source:U.S. Department of Energy, Energy Information Administration (EIA). 2002b. Refinery Capacity Data Annual. As accessed on September 23, 2002. http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcap02.dbf. Washington, DC.

Table 1.3-18
Sales of Distillate Fuel Oils to End Users 1984-1999 (thousands of barrels per day)

Year	Resi-dential	Com-mercial	Indust-rial	Oil Co.	Farm	Electric Utility	Rail-road	Vessel Bunkering	Highway Diesel	Military	Off-Highway Diesel	All Other	Total
1984	450	319	153	59	193	45	225	110	1,093	45	109	44	2,845
1985	471	294	169	57	216	34	209	124	1,127	50	105	12	2,868
1986	476	280	175	49	220	40	202	133	1,169	50	111	9	2,914
1987	484	279	190	58	211	42	205	145	1,185	58	113	5	2,976
1988	498	269	170	57	223	52	212	150	1,304	64	119	4	3,122
1989	489	252	167	55	209	70	213	154	1,378	61	107	2	3,157
1990	393	228	160	63	215	48	209	143	1,393	51	116	(s)	3,021
1991	391	226	152	59	214	39	197	141	1,336	54	110	(s)	2,921
1992	406	218	144	51	228	30	209	146	1,391	42	113	(s)	2,979
1993	429	218	128	50	211	38	190	133	1,485	31	127	(s)	3,041
1994	413	218	136	46	209	49	200	132	1,594	34	130	(s)	3,162
1995	416	216	132	36	211	39	208	129	1,668	24	126	—	3,207
1996	436	223	137	41	217	45	213	142	1,754	24	134	—	3,365
1997	423	210	141	41	216	42	200	137	1,867	22	136	—	3,435
1998	367	199	147	37	198	63	185	139	1,967	18	142	—	3,461
1999	381	196	142	38	189	60	182	135	2,091	19	140	—	3,572

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2001a. Annual Energy Review, 2000, Table 5-13. Washington, DC.

1.4 Distribution and Storage Operations

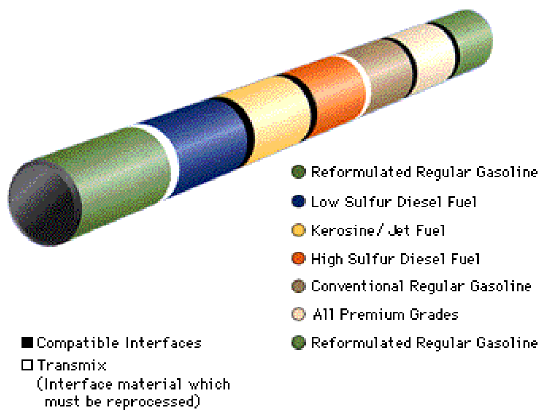
Refined petroleum products, including gasoline, distillates, and jet fuel, are transported by barge and truck and through pipelines from refineries to the wholesale and retail networks in the major markets of the United States. The most important of these routes is the 86,500-mile pipeline network, operated by nearly 200 separate companies (AOPL, 2000; FERC, 2002). Terminals and other storage facilities are located near refineries, along pipelines at breakout stations, and at bulk plants near major consumer markets. There are currently more than 1,300 terminals for refined products in the United States (API, 2002).

1.4.1 The Supply-Side

Pipelines are constructed of large-diameter welded steel pipe and typically buried underground. Pumps at the source provide motive force for the 3 to 8 miles per hour flow in the piping network (API, 1998; AOPL, 2000). Periodically, the line pressure is boosted at strategically placed pumping stations, which are often located at breakout points for intermediate distribution of various components. The product is moved rapidly enough to ensure turbulent flow, which prevents back-mixing of components. Figure 1.4-1 shows a typical configuration of several refined components on the Colonial Pipeline, a major artery connecting East Texas producing sites to Atlanta, Charlotte, Richmond, and New Jersey.

The pipelines do not change the physical form of the petroleum products that they carry and add value only by moving the products closer to markets. Operating costs of transporting products in a pipeline are quite small, so most of the cost charged to customers represents amortization of capital costs for construction. According to the 1997 Economic Census, revenues for pipeline transportation, NIACS code 48691, were $2.5 billion, of which only $288 million represented wags and salaries (U.S. Census Bureau, 2000). Almost all pipeline companies act as a common carrier (they do not take ownership of the products they transport), so their revenues and economic value added are equivalent. Census data for storage operations are not broken down in enough detail to permit estimation of revenues or value added.

Figure1.4-1
Typical Sequence in which Products are Batched While in Transit on Colonial System



The most important impact of additional EPA regulation on the distribution network has been to increase the number of different products handled by each pipeline. Although some concern has been expressed by these firms in relation to the gasoline and highway diesel regulations, the incremental effect of reducing sulfur content for nonroad diesel should be minor. The Colonial Pipeline mentioned previously currently handles 38 grades of motor gasoline, 16 grades of distillate products, 7 grades of kerosene-type fuels (including jet fuel), and an intermediate refinery product, light cycle oil (Colonial, 2002).

As Figure1.4-1 shows, these pipelines are shipping low-sulfur gasoline, low-sulfur diesel fuel, and high-sulfur nonroad fuel in the same pipeline. In most cases, the interface (mixing zone) between products is degraded to the poorer quality material. When they begin handling ultralow-sulfur diesel fuel and gasoline, they may be forced to downgrade more interface material to nonroad or fuel oil and will need to carefully prevent contamination in storage tanks and pumping stations.

Importantly, changeover to ultralow-sulfur diesel fuel for nonroad applications will not add additional complexity to their operations. We expect there to be no physical difference between 15 ppm diesel fuel destined for the highway market and 15 ppm diesel fuel destined for the off-highway market prior to the terminal level when dye must be added to off-highway diesel fuel to denote its untaxed status. This will allow pipeline operators to ship such fuels in fungible batches. Consequently, the introduction of 15 ppm off-highway diesel should not result in increased difficulty in limiting sulfur contamination during the transportation of ultra-low sulfur products. Pipeline operators will continue to have a market for the downgraded mixing zone material generated during the shipment of 15 ppm diesel fuel by pipeline. After the 15 ppm standard for highway diesel fuel and the comparable fuel standards in this final rule take effect, the pipelines that transport the majority of the nation's diesel fuel are projected to continue to carry high-sulfur diesel fuel and/or 500 ppm diesel fuel. These pipelines will blend their downgraded 15 ppm diesel into the 500 ppm and/or high-sulfur diesel fuel that they ship. A fraction of the pipelines are projected to carry only a single grade of diesel fuel (15 ppm fuel) after the HD2007 rule takes effect. These pipelines currently carry only 500 ppm highway diesel fuel. In the HD2007 rule, we projected that these pipelines will install an additional storage tank to contain the relatively low volumes of downgraded 15 ppm diesel fuel generated during pipeline transportation of the product. We projected that this downgraded material will be sold into the off-highway diesel market. The new regulation of nonroad diesel fuel will not change this practice. We expect these pipeline operators to continue finding a market for the downgraded 15 ppm fuel, either as 500 ppm off-highway diesel fuel or for use in stationary diesel engines.

1.4.2 The Demand-Side

Demand for distribution through pipelines (versus barge or truck movement) is driven by cost differentials with these alternate means of transportation. The National Petroleum Council estimated in a comprehensive 1989 report that water transport of a gallon of petroleum products was about three times as expensive per mile as transport via pipeline, and truck transportation was up to 25 times as expensive per mile (National Petroleum Council, 1989). A recent pipeline industry publication shows that pipelines handle around 60 percent of refined petroleum product movements, with 31 percent transported by water, 5.5 percent by truck, and 3.5 percent by rail (AOPL, 2001).

Pipeline transport charges make up only a small portion of the delivered cost of fuels. Industry publications cite costs of about $1 per barrel, equal to 2.5 cents per gallon, for a 1600 mile transfer from Houston to New Jersey, and about 2 cents per gallon for a shipment of 1100 miles from Houston to Chicago (AOPL, 2002; Allegro, 2001). Although average hauls are shorter and somewhat more expensive per mile, average transport rates are on the order of 0.06 to 0.18 cents per barrel per mile.

1.4.3 Industry Organization

Just as it has with other transportation modes defined by site-specific assets and high fixed costs, the federal government has traditionally regulated pipelines as common carriers. Unlike railroad and long-haul trucking, however, pipeline transport was not deregulated during the 1980s, and the Federal Energy Regulatory Commission (FERC) still sets allowable tariffs for pipeline movements. A majority of carriers, therefore, compete as regulated monopolies.

Most pipelines are permitted small annual increases in rates without regulatory approval, typically limited to 1 percent less than the increase in the producer price index (PPI). If regulatory changes caused significant cost increases, for instance from the addition of tankage to handle two grades of nonroad diesel fuel, pipeline operators would have to engage in a rate case with FERC to pass their increased costs along to consumers. If they chose not to request rate relief, the pipelines would absorb any costs above the allowable annual increases.

1.4.4 Markets and Trends

Pipeline firms have seen slowly rising demand for their services over the past several years. The latest available data, from the 1996 to 1999 period, are displayed in Table 1.4-1. Pipelines have not only captured most of the overall increase in total product movements, they have also taken some share away from water transport during the period. Railroad shipments have grown as well, but from a very small base.

Table 1.4-1
Trends in Transportation of Refined Petroleum Products

	1996	1997	1998	1999	Percentage Change 1996-1999
Pipelines	280.9	279.1	285.7	296.6	5.6%
Water Carriers	154.1	148.3	147.1	147.5	–4.3%
Motor Carriers	28.0	26.0	26.7	27.6	–1.4%
Railroads	16.0	16.2	16.2	18.2	13.8%
Totals	479.0	469.6	475.7	489.9	2.2%

Note: All figures, except percentages, in billions of ton-miles.
Source: Association of Oil Pipe Lines (AOPL). 2001. Shifts in Petroleum Transportation. As accessed on November 20, 2002. www.aopl.org/pubs/facts.html.

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CHAPTER 2: Air Quality, Health, and Welfare Effects

CHAPTER 2: Air Quality, Health, and Welfare Effects

With this rulemaking, we are acting to extend highway types of emission controls to another major source of diesel engine emissions: nonroad land-based diesel engines. This final rule sets out emission standards for nonroad land-based diesel engines - engines used mainly in construction, agricultural, industrial and mining operations - that will achieve reductions in particulate matter (PM) and NOx standards in excess of 95 percent and 90 percent, respectively. This action also regulates nonroad diesel fuel for the first time by reducing sulfur levels in this fuel more than 99 percent to 15 part per million (ppm). The diesel fuel sulfur requirements will decrease PM and sulfur dioxide (SO_2) emissions for land-based diesel engines, as well as for three other nonroad source categories: commercial marine diesel vessels, locomotives, and recreational marine diesel engines.

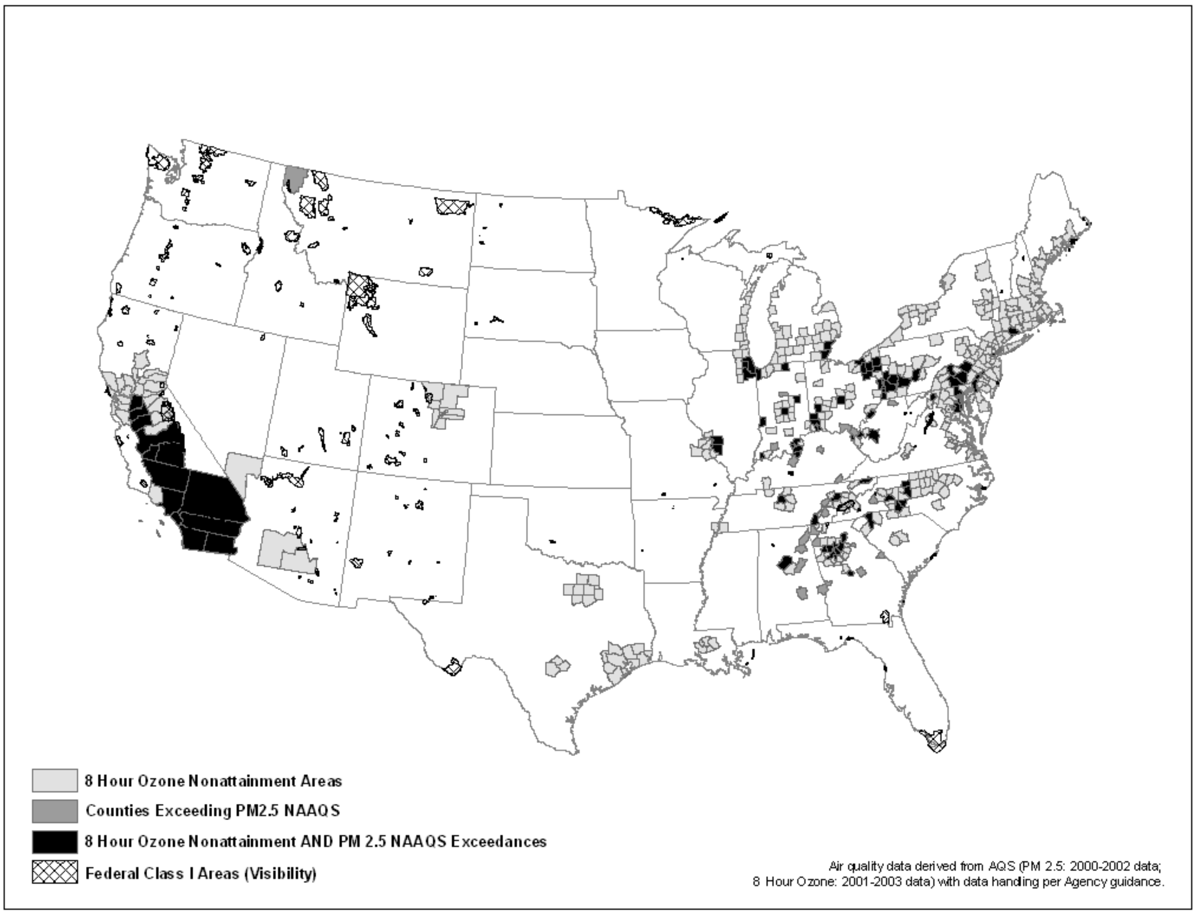
These sources are significant contributors to atmospheric pollution of (among other pollutants) PM, ozone and a variety of toxic air pollutants. In 1996, emissions from these four source categories were estimated to be 40 percent of the mobile source inventory for $PM_{2.5}$ and 25 percent for NOx. Without further control beyond those we have already adopted, by the year 2030, these sources will emit 44 percent of $PM_{2.5}$ from mobile sources, and 47 percent of NOx emissions from mobile sources. Thus, reducing emissions from nonroad sources is critically important to achieving the nation's air quality goals.

In 2030, we estimate that this program will reduce over 129,000 tons $PM_{2.5}$ and 738,000 tons of NOx. It will also virtually eliminate nonroad diesel SO_2 emissions, which amounted to approximately 236,000 tons in 1996, and would otherwise grow to approximately 379,000 tons by 2030.

These dramatic reductions in nonroad emissions are a critical part of the effort by Federal, State, local and Tribal governments to reduce the health related impacts of air pollution and to reach attainment of the National Ambient Air Quality Standard (NAAQS) for PM and ozone, as well as to improve environmental effects such as visibility. These emission reductions will be directly helpful to the 474 partial and full counties nationwide that have been recently designated as nonattainment areas for the 8-hour ozone standard and the $PM_{2.5}$ areas that will be designated later this year. Based on the most recent monitoring data available for this rule, such problems are widespread in the United States. There are almost 65 million people living in 120 counties with $PM_{2.5}$ levels exceeding the $PM_{2.5}$ NAAQS (based on 2000-2002), and about 159 million people living in 474 partial and full counties that are in nonattainment for either failing to meet the 8-hour ozone NAAQS or for contributing to poor air quality in a nearby area. Figure 2.-1 illustrates the widespread nature of these problems. Shown in this figure are counties exceeding either or both of the $PM_{2.5}$ NAAQS or designated 8-hour ozone nonattainment areas plus mandatory Federal Class I areas, which have particular needs for reductions in haze.

As described in Chapter 9, the air quality improvements expected from this rulemaking will produce major benefits to human health and welfare, with a combined value in excess of three quarters of a trillion dollars between 2007 and 2036. By the year 2030, we expect that this rule will annually prevent approximately 12,000 premature deaths and 15,000 nonfatal heart attacks. By 2030, it will also prevent 13,000 annual acute bronchitis attacks in children, 280,000 upper and lower respiratory symptoms in children, nearly 1 million lost work days among adults because of their own symptoms, and 5.9 million days where adults have to restrict their activities due to symptoms in 2030.

Figure I-1. Air Quality Problems are Widespread.



In this chapter and chapter 3, we describe in more detail the air pollution problems associated with emissions from nonroad diesel engines and air quality information that we are relying upon in this rulemaking. To meet these emission standards, engine manufacturers directly control emissions of NOx, PM, non-methane hydrocarbons (NMHC), and to a lesser extent, carbon monoxide (CO). Gaseous air toxics from nonroad diesel engines will also decrease as a consequence of the new emission standards. In addition, there will be a substantial reduction in

SO_2 emissions resulting from the decreasing sulfur level in diesel fuel. SO_2 is transformed in the atmosphere to form PM (sulfate) and can also pose a public health hazard in the gas phase.

From a public health perspective, we are primarily concerned with nonroad engine contributions to atmospheric levels of particulate matter in general (diesel PM in particular), various gaseous air toxics emitted by diesel engines, and ozone.[A] We will first review important public health effects caused by these pollutants, briefly describing the human health effects, and we will then review the current and expected future ambient levels of directly or indirectly caused pollution. Our presentation will show that substantial further reductions of these pollutants, and the underlying emissions from nonroad diesel engines, will be needed to protect public health.

Following discussion of health effects, we will discuss a number of welfare effects associated with emissions from diesel engines. These effects include atmospheric visibility impairment, ecological and property damage caused by acid deposition, eutrophication and nitrification of surface waters, environmental threats posed by polycyclic organic matter (POM) deposition, and plant and crop damage from ozone. Once again, the information available to us indicates a continuing need for further nonroad emission reductions to bring about improvements in air quality.

2.1 Particulate Matter

Particulate matter (PM) represents a broad class of chemically and physically diverse substances. It can be principally characterized as discrete particles that exist in the condensed (liquid or solid) phase spanning several orders of magnitude in size. PM_{10} refers to particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers. Fine particles refer to those particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (also known as $PM_{2.5}$), and coarse fraction particles are those particles with an aerodynamic diameter greater than 2.5 microns, but less than or equal to a nominal 10 micrometers. Ultrafine PM refers to particles with diameters of less than 100 nanometers (0.1 micrometers). The health and environmental effects of PM are in some cases related to the size of the particles. Specifically, larger particles (greater than 10 micrometers) tend to be deposited nasally and in the larger conducting airways, and they are removed by the respiratory clearance mechanisms whereas smaller particles (PM_{10}) are deposited deeper in the lungs. Also, fine particles scatter light obstructing visibility.

In addition to directly emitted particles, nonroad diesel engines currently emit high levels of NOx, which reacts in the atmosphere to form secondary $PM_{2.5}$ (namely ammonium nitrate).

[A]Ambient PM from nonroad diesel engine is associated with the direct emission of diesel PM and sulfate PM, and with PM formed indirectly in the atmosphere by NOx and SO_2 emissions (and to a lesser extent NMHC emissions). Both NOx and NMHC can participate in the atmospheric chemical reactions that produce ozone.

Nonroad diesel engines also emit SO_2 and HC, which react in the atmosphere to form secondary $PM_{2.5}$ (namely sulfates and organic carbonaceous $PM_{2.5}$). Both types of directly and indirectly formed particles from nonroad engines are found principally in the fine fraction. Thus, this discussion will focus on fine particles ($PM_{2.5}$). Ambient fine particles are a complex mixture generally composed of sulfate, nitrate, chloride, ammonium compounds, organic carbon, elemental carbon, and metals. Fine particles can remain in the atmosphere for days to weeks and travel through the atmosphere hundreds to thousands of kilometers, while coarse particles generally tend to deposit to the earth within minutes to hours and within tens of kilometers from the emission source.

2.1.1 Health Effects of Particulate Matter

Scientific studies show ambient PM concentrations (which are attributable to a number of sources including diesel) contribute to a series of adverse health effects. These health effects are discussed in detail in the EPA Air Quality Criteria Document for PM (PM Criteria Document) as well as the draft updates of this document released in the past year.[1] EPA's Health Assessment Document for Diesel Engine Exhaust (Diesel HAD) also reviewed health effects information related to diesel exhaust as a whole including diesel PM, which is one component of ambient PM.[2] We are relying on the data and conclusions in these documents regarding the effects of particulate matter. We also present additional recent studies. Taken together this information supports the conclusion that PM-related emissions from nonroad diesel engines have been associated with adverse health effects.

We received a number of public comments on specific health studies, and we are relying on the discussions and conclusions presented in the PM Criteria Document and Diesel HAD in which EPA prepared detailed evaluations of the body of scientific information and subjected those evaluations to extensive public and expert peer review. Additional information is available in the Summary and Analysis of Public Comments that accompanies this final rule.

2.1.1.1 Short-Term Exposure-Mortality and Morbidity Studies

As detailed in the PM Criteria Document, health effects associated with short-term variation in ambient PM have been indicated by numerous epidemiologic studies showing associations between exposure and increased hospital admissions for ischemic heart disease,[3] heart failure,[4] respiratory disease,[5, 6, 7, 8] including chronic obstructive pulmonary disease (COPD) and pneumonia.[9, 10, 11] Short-term elevations in ambient PM have also been associated with increased cough, lower respiratory symptoms, and decrements in lung function.[12, 13, 14] Short-term variations in ambient PM have also been associated with increases in total and cardiorespiratory daily mortality in individual cities[15, 16, 17, 18] and in multi-city studies.[19, 20, 21]

Several studies specifically address the contribution of PM from mobile sources in these time-series studies. Analyses incorporating source apportionment by factor analysis with daily time-series studies of daily death also established a specific influence of mobile source-related $PM_{2.5}$ on daily mortality[22] and a concentration-response function for mobile source-associated $PM_{2.5}$ and daily mortality.[23] Another recent study in 14 U.S. cities examined the effect of PM_{10}

exposures on daily hospital admissions for cardiovascular disease (CVD). They found that the effect of PM_{10} was significantly greater in areas with a larger proportion of PM_{10} coming from motor vehicles, indicating that PM_{10} from these sources may have a greater effect on the toxicity of ambient PM_{10} when compared with other sources.[24]

In 2002, questions were raised about the default convergence criteria and standard error calculations made using generalized additive models (GAM), which has been the statistical model of choice in many of the time-series epidemiologic studies. A number of time-series studies were reanalyzed using alternative methods, typically GAM with more stringent convergence criteria and an alternative model such as generalized linear models (GLM) with natural smoothing splines. Since then, the Health Effects Institute convened an expert panel to review the results of and the results of the reanalyses have been compiled and reviewed in a recent HEI publication.[25] In most, but not all, of the reanalyzed studies, it was found that risk estimates were reduced and confidence intervals increased with the use of GAM with more stringent convergence criteria or GLM analyses; however, the reanalyses generally did not substantially change the findings of the original studies, and the changes in risk estimates with alternative analysis methods were much smaller than the variation in effects across studies. The HEI review committee concluded the following:

a. While the number of studies showing an association of PM with mortality was slightly smaller, the PM association persisted in the majority of studies.
b. In some of the large number of studies in which the PM association persisted, the estimates of PM effect were substantially smaller.
c. In the few studies in which investigators performed further sensitivity analyses, some showed marked sensitivity of the PM effect estimate to the degree of smoothing and/or the specification of weather.

As discussed in Chapter 9, examination of the original studies used in our economic benefits analysis found that the health endpoints that are potentially affected by the GAM issues include: reduced hospital admissions, reduced lower respiratory symptoms, and reduced premature mortality due to short-term PM exposures. It is important to note that the benefits estimates derived from the long-term exposure studies, which account for a major share of the economic benefits described in Chapter 9, are not affected. Similarly, the time-series studies and case-crossover studies employing generalized linear models or other parametric methods are not affected.

2.1.1.2 Long-Term Exposure Mortality and Morbidity Studies

Short-term studies provide one way of examining the effect of short-term variations in air quality on morbidity and mortality. However, they do not allow for an evaluation of the effect of long-term exposure to air pollution on human mortality and morbidty.[26] Longitudinal cohort studies allow for analysis of such effects.

As discussed in the PM Criteria Document, the newer morbidity studies that combine the features of cross-sectional and cohort studies provide the best evidence for chronic exposure effects. The Gauderman *et al.* studies both found significant decreases in lung function growth among southern California school children to be related to $PM_{2.5}$ and/or PM_{10} levels.[27],[28] However, Peters *et al.* reported no relationship between respiratory symptoms and annual average PM_{10} levels in 12 southern California communities.[29] Long-term (months to years) exposure to PM was linked with decreased lung function and increased incidence of respiratory disease such as bronchitis (PM Criteria Document 1996, p. V-26, Abbey et al. 1995). The results of studies using long-term and short-term PM exposure data were reported to be consistent with one another. In addition, toxicology studies using surrogate particles or PM components, generally at high concentrations, and autopsy studies of humans and animals reported evidence of pulmonary effects, including morphological damage (e.g., changes in cellular structure of the airways) and changes in resistance to infection.

Additional data are available regarding long-term PM exposures and mortality. To date, four major cohorts in the U.S. have examined mortality and long-term exposure to $PM_{2.5}$. These studies are described in detail in the PM Criteria Document and we are relying on the analyses and conclusions in that document for these studies. Many of the issues raised in public comment are addressed by the Criteria Document (as detailed in the Summary and Analysis of public comments document.) In addition to the U.S. studies, there are additional data from Europe and Canada. A cohort in the Netherlands evaluated exposure to mobile source-related pollutants.[30] Another study examines exposure-mortality relationships with income in southern Ontario, Canada.[31]

Two major U.S. cohort studies, the Harvard Six Cities and the American Cancer Society studies, suggest an association between exposure to ambient $PM_{2.5}$ measured in the city of residence and premature mortality from cardiorespiratory causes.[32, 33] As discussed in the PM Criteria Document, these two prospective cohort studies tracked health outcomes in discrete groups of people over time. Subsequent reanalysis of these studies have confirmed the findings of these articles, and a recent extension of the ACS cohort study found statistically significant increases in lung cancer mortality risk associated with ambient $PM_{2.5}$.[34] This most recent finding is of special interest in this rulemaking, because of the association of diesel exhaust and lung cancer in occupational studies of varying design.

More recently, the Adventist Health Study on Smog (AHSMOG) in California indicated that long-term exposure to PM_{10} resulted in a significant risk of premature mortality in men, although risks were not elevated among women.[35] In another AHSMOG analysis, ambient $PM_{2.5}$ estimates made from visibility data at an airport were used to compare the effects of PM_{10} and $PM_{2.5}$ for the cohort.[36] No statistically significant increase in risk was observed with any component of PM. Among men, the $PM_{2.5}$ coefficient on mortality from all natural causes was consistently larger than the coarse fraction of PM_{10}. Among women, no elevation in mortality risk was found for any PM index.

Another study evaluated in the PM Criteria Document examining long-term exposure to ambient PM and mortality is the Electric Power Research Institute (EPRI)-Washington University mortality study in American Veterans.[37] The Veterans Study was originally designed as a means of assessing the efficacy of anti-hypertensive drugs in reducing morbidity and mortality in a population with pre-existing high blood pressure (in this case, male veterans) (Lipfert et al., 2000). Unlike previous long-term analyses, this study found some associations between premature mortality and ozone but found inconsistent results for PM indicators. A variety of issues associated with the study design, including sample representativeness and loss to follow up, make this cohort a poor choice for extrapolating to the general public. Furthermore, the selective nature of the population in the veteran's cohort and methodological weaknesses may have resulted in estimates of relative risk that are biased relative to a relative risk for the general population.

The Hoek et al. (2002) study examines a cohort of residents of the Netherlands who were recruited as part of the Netherlands Cohort study on Diet and Cancer (NLCS).[38] Five thousand study participants were selected at random from the larger cohort, which consisted of persons aged 55 to 69 in 1986, with follow up until 1994. In 1986, all participants filled out questionnaires on diet and other risk factors. All participants with full questionnaire data were included in the study. Each participants' home address was mapped by street address. Individual exposures to ambient pollutants were assigned by matching residential address to an exposure metric via geographic information system (GIS). "Black smoke" – widely used in Europe as a surrogate of particulate elemental carbon – and NO_2 had been previously assessed as a function of regional background, urban background, and contribution from local traffic based on proximity to busy roads.[39] Results of the survival analysis indicated that residential black smoke predicted from regional, urban, and intra-urban variation was associated with a relative risk (RR) of cardiopulmonary mortality per 10 ug/m^3 of 1.71 (with a 95 percent confidence interval (CI) of [1.10, 2.67]) and an RR for all-cause mortality of 1.31 [0.95, 1.80]. In a model including background black smoke and proximity to a major roadway, the cardiopulmonary mortality RR associated with living near a busy road was 1.95 [1.09, 3.51]. This study is of particular interest in this rule, because of the strong focus on mobile source pollutants in the exposure assessment portion of the study. This study also highlights the "near-roadway" health concerns, discussed later.

The Six Cities, ACS, AHSMOG, Veterans, and NLCS Studies are discussed in detail in the draft PM Criteria Document and revised Chapter 8. We are relying on the evaluations and conclusions presented in those documents. The long-term exposure health effects of PM are summarized in Table 2.1.1-1, which is taken directly from Table 9-11 of the draft Air Quality Criteria Document referenced earlier that was released in 2003. This document is continuing to undergo expert and public review. One study discussed below does not appear in the PM Criteria Document because it was published after the date required for inclusion in the Criteria Document.[40]

Finklestein et al. (2003) examined a cohort of 5,228 residents of the Hamilton-Burnling area of southern Ontario, Canada who had been referred for lung function testing between 1985 and 1999.[41] The study was not a random sample of the population in the Hamilton-Burlington area. Total non-accidental and cardiopulmonary mortalities between 1992 and 1999 were determined based on the Ontario Mortality Registry. The subjects' age, sex, postal code, body mass index, and pulmonary function test results were matched with disease diagnosis via the Ontario Health Insurance Plan. Canada's health insurance system allowed the investigators to determine disease diagnoses during the follow-up period. Postal codes were used to assign “ecological” variables of census-derived mean household income, 24-hour average total suspended particulate (TSP) measured every 6 days, and SO_2 measured continuously during the mid-1990's Air monitoring data came from 9 TSP and 23 SO_2 monitors, which were subject to spatial interpolation techniques. Postal code-specific pollutant concentrations were assigned using GIS. Analysis of the air quality data indicated that TSP and SO_2 tended to be higher in low-income areas. The study group was divided into higher and lower income and pollution strata, based on the median income, and TSP and SO_2 levels at the postal code level. Compared to the high-income, low-pollution group, all other groups had significantly elevated mortality relative risks with income, and each pollutant (in one-pollutant models) was associated with increased risk. Age appeared as an effect modifier, with attenuated effects at elevated age.

The 1996 PM AQCD indicated that past epidemiologic studies of chronic PM exposures collectively indicate increases in mortality to be associated with long-term exposure to airborne particles of ambient origins. The PM effect size estimates for total mortality from these studies also indicated that a substantial portion of these deaths reflected cumulative PM impacts above and beyond those exerted by acute exposure events.

Several advances have been made in terms of further analyses and/or reanalyses of several studies of long-term PM exposure effects on total, cardiopulmonary, or lung cancer mortality. The Harvard Six Cities analyses (as confirmed by the HEI reanalyses) and the recent extension of the ACS study by Pope et al. (2002) probably provide the most credible and precise estimates of excess mortality risk associated with long-term PM2.5 exposures in the United States.

2.1.1.3 Long-Term Exposures and Physiological Response in Individuals

Several studies examined in the PM Criteria Document have examined the effect of long-term exposure to air pollution on individual physiological and organ structure. These studies provide insight into the biological pathways by which air pollution may act to produce adverse health effects. The studies below provide examples of the types of studies examined in the PM Criteria Document.

Studies in Vancouver, BC, and Mexico City, Mexico, have demonstrated increased retention of $PM_{2.5}$ in the lungs of residents of the more highly polluted Mexico City.[42] More recently, comparisons of non-smoking women in Mexico City and Vancouver have shown that particle retention in the lungs of Mexico City women was associated with small airways remodeling.[43] In another study, dogs autopsied in the Mexico City and other less-polluted areas showed that dogs in more polluted areas showed greater respiratory and cardiac pathology indicative of long-term inflammatory stress.[44,45]

One recent study (not addressed in the PM Criteria Document) was conducted in Leicester, UK studying lung cells (alveolar macrophages (AM)) obtained from children undergoing elective surgery.[46] The cells were examined by electron microscope, and the study reported that in all children, some of the AMs contained particles, ranging from 1 to 16 percent of total AM collected. Of particular note, the authors found that a significantly higher fraction of the AM collected from children living on main roads contained particles as compared to children living on quiet residential roads, and that these particles were composed of single and chain aggregates of ultrafine carbon particles that appeared to be combustion-related. This study is of particular relevance to this rule, given the evidence that exposure to mobile source PM results in greater concentrations of PM in the lung. Given the elevated exposures to carbonaceous PM in occupations that work with nonroad diesel engines (discussed below), this study provides a link between nonroad PM exposure an potential lung and systemic health effects.

2.1.1.4 Studies of Short-Term Exposures and Physiological Response in Individuals

A number of studies have investigated biological processes and physiological effects that may underlie the epidemiologic findings of earlier studies. This research has found associations between short-term changes in PM exposure with changes in heart beat, force, and rhythm, including reduced heart rate variability (HRV), a measure of the autonomic nervous system's control of heart function.[47, 48, 49, 50, 51, 52] The findings indicate associations between measures of heart function and PM measured over the prior 3 to 24 hours or longer. Decreased HRV has been shown to be associated with coronary heart disease and cardiovascular mortality in both healthy and compromised populations.[53, 54, 55, 56]

Other studies have investigated the association between PM and such systemic factors such as inflammation, blood coagulability and viscosity. It is hypothesized that PM-induced inflammation in the lung may activate a "non-adaptive" response by the immune system, resulting in increased markers of inflammation in the blood and tissues, heightened blood coagulalability, and leukocyte count in the blood. A number of studies have found associations between controlled exposure to either concentrated or ambient PM or diesel exhaust exposure and pulmonary inflammation.[57, 58, 59, 60] A number of studies have also shown evidence of increased blood markers of inflammation, such as C-reactive protein, fibrinogen, and white blood cell count associated with inter-day variability in ambient PM.[61, 62, 63, 64] These blood indices have been associated with coronary heart disease and cardiac events such as heart attack.[65, 66] Studies have also shown that repeated or chronic exposures to urban PM were associated with increased severity of atherosclerosis, microthrombus formation, and other indicators of cardiac risk.[67, 68]

The recent studies examining inflammation, heart rate and rhythm in relation to PM provide some evidence into the mechanisms by which ambient PM may cause injury to the heart. New epidemiologic data have indicated that short-term changes in ambient PM mass is associated with adverse cardiac outcomes like myocardial infarction (MI) or ventricular arrythmia.[69, 70] These studies provide additional evidence that ambient $PM_{2.5}$ can cause both acute and chronic cardiovascular injury, which can result in death or non-fatal effects.

Table 2.1.1-1
Effect Estimates per Increments[a] in Long-term Mean Levels of
Fine and Inhalable Particle Indicators From U.S. and Canadian Studies

Type of Health Effect and Location	Indicator	Change in Health Indicator per Increment in PM*	Range of City PM Levels ** Means ($\mu g/m^3$)
Increased Total Mortality in Adults		**Relative Risk (95% CI)**	
Six City[B]	$PM_{15/10}$ (20 $\mu g/m^3$)	1.18 (1.06-1.32)	18-47
	$PM_{2.5}$ (10 $\mu g/m^3$)	1.13 (1.04-1.23)	11-30
	$SO_4^=$ (15 $\mu g/m^3$)	1.46 (1.16-2.16)	5-13
ACS Study[C] (151 U.S. SMSA)	$PM_{2.5}$ (10 $\mu g/m^3$)	1.07 (1.04-1.10)	9-34
	$SO_4^=$ (15 $\mu g/m^3$)	1.10 (1.06-1.16)	4-24
Six City Reanalysis[D]	$PM_{15/10}$ (20 $\mu g/m^3$)	1.19 (1.06-1.34)	18.2-46.5
	$PM_{2.5}$ (10 $\mu g/m^3$)	1.13 (1.04-1.23)	11.0-29.6
ACS Study Reanalysis[D]	$PM_{15/10}$ (20 $\mu g/m^3$) (dichot)	1.04 (1.01-1.07)	58.7 (34-101)
	$PM_{2.5}$ (10 $\mu g/m^3$)	1.07 (1.04-1.10)	9.0-33.4
ACS Study Extended Analyses[Q]	$PM_{2.5}$ (10 $\mu g/m^3$)	1.04 (1.01-1.08)	21.1 (SD=4.6)
Southern California[E]	PM_{10} (20 $\mu g/m^3$)	1.091 (0.985-1.212) (males)	51 (±17)
	PM_{10} (cutoff = 30 days/year >100 $\mu g/m^3$)	1.082 (1.008-1.162) (males)	
	PM_{10} (20 $\mu g/m^3$)	0.950 (0.873-1.033) (females)	51 (±17)
	PM_{10} (cutoff = 30 days/year >100 $\mu g/m^3$)	0.958 (0.899-1.021) (females)	
Vetrans Cohort[R]	$PM_{2.5}$ (10 $\mu g/m^3$)	0.90 (0.85, 0.954; males)	5.6-42.3
Increased Bronchitis in Children		**Odds Ratio (95% CI)**	
Six City[F]	$PM_{15/10}$ (50 $\mu g/m^3$)	3.26 (1.13, 10.28)	20-59
Six City[G]	TSP (100 $\mu g/m^3$)	2.80 (1.17, 7.03)	39-114
24 City[H]	H^+ (100 nmol/m^3)	2.65 (1.22, 5.74)	6.2-41.0
24 City[H]	$SO_4^=$ (15 $\mu g/m^3$)	3.02 (1.28, 7.03)	18.1-67.3
24 City[H]	$PM_{2.1}$ (25 $\mu g/m^3$)	1.97 (0.85, 4.51)	9.1-17.3
24 City[H]	PM_{10} (50 $\mu g/m^3$)	3.29 (0.81, 13.62)	22.0-28.6
Southern California[I]	$SO_4^=$ (15 $\mu g/m^3$)	1.39 (0.99, 1.92)	—
12 Southern California communities[J] (all children)	PM_{10} (25 $\mu g/m^3$) Acid vapor (1.7 ppb)	0.94 (0.74, 1.19) 1.16 (0.79, 1.68)	28.0-84.9 0.9-3.2 ppb
12 Southern California communities[K] (children with asthma)	PM_{10} (19 $\mu g/m^3$) $PM_{2.5}$ (15 $\mu g/m^3$) Acid vapor (1.8 ppb)	1.4 (1.1, 1.8) 1.4 (0.9, 2.3) 1.1 (0.7, 1.6)	13.0-70.7 6.7-31.5 1.0-5.0 ppb

Type of Health Effect and Location	Indicator	Change in Health Indicator per Increment in PM*	Range of City PM Levels ** Means ($\mu g/m^3$)
Increased Cough in Children		**Odds Ratio (95% CI)**	
12 Southern California communities[J] (all children)	PM_{10} (20 $\mu g/m^3$) Acid vapor (1.7 ppb)	1.05 (0.94, 1.16) 1.13 (0.92, 1.38)	28.0-84.9 0.9-3.2 ppb
12 Southern California communities[K] (children with asthma)	PM_{10} (20 $\mu g/m^3$) $PM_{2.5}$ (10 $\mu g/m^3$) Acid vapor (1.8 ppb)	1.1 (0.7, 1.8) 1.2 (0.8, 1.8) 1.4 (0.9, 2.1)	13.0-70.7 6.7-31.5 1.0-5.0 ppb
10 Canadian Communities[s]	PM_{10} (20 $\mu g/m^3$)	1.19 (1.04,1.35)	13-23
Increased Wheeze in Children			
10 Canadian Communities[s]	PM_{10} (20 $\mu g/m^3$)	1.35 (1.10,1.64)	13-23
Increased Airway Obstruction in Adults			
Southern California[L]	PM_{10} (20$\mu g/m^3$)	1.09 (0.92, 1.30)	NR
Decreased Lung Function in Children			
Six City[F]	$PM_{15/10}$ (50 $\mu g/m^3$)	NS Changes	20-59
Six City[G]	TSP (100 $\mu g/m^3$)	NS Changes	39-114
24 City[M]	H^+ (52 nmoles/m^3)	−3.45% (-4.87, -2.01) FVC	6.2-41.0
24 City[M]	$PM_{2.1}$ (15 $\mu g/m^3$)	−3.21% (-4.98, -1.41) FVC	18.1-67.3
24 City[M]	$SO_4^=$ (7 $\mu g/m^3$)	−3.06% (-4.50, -1.60) FVC	9.1-17.3
24 City[M]	PM_{10} (17 $\mu g/m^3$)	−2.42% (-4.30, -.0.51) FVC	22.0-28.6
12 Southern California communities[N] (all children)	PM_{10} (25 $\mu g/m^3$) Acid vapor (1.7 ppb)	−24.9 (-47.2, -2.6) FVC −24.9 (-65.08, 15.28) FVC	28.0-84.9 0.9-3.2 ppb
12 Southern California communities[N] (all children)	PM_{10} (25 $\mu g/m^3$) Acid vapor (1.7 ppb)	−32.0 (-58.9, -5.1) MMEF −7.9 (-60.43, 44.63) MMEF	28.0-84.9 0.9-3.2 ppb
12 Southern California communities[O] (4th grade cohort)	PM_{10} (51.5 $\mu g/m^3$) $PM_{2.5}$ (25.9 $\mu g/m^3$) $PM_{10-2.5}$ (25.6 $\mu g/m^3$) Acid vapor (4.3 ppb)	−0.58 (-1.14, -0.02) FVC growth −0.47 (-0.94, 0.01) FVC growth −0.57 (-1.20, 0.06) FVC growth −0.57 (-1.06, -0.07) FVC growth	NR
12 Southern California communities[O] (4th grade cohort)	PM_{10} (51.5 $\mu g/m^3$) $PM_{2.5}$ (25.9 $\mu g/m^3$) $PM_{10-2.5}$ (25.6 $\mu g/m^3$) Acid vapor (4.3 ppb)	−1.32 (-2.43, -0.20) MMEF growth −1.03 (-1.95, -0.09) MMEF growth −1.37 (-2.57, -0.15) MMEF growth −1.03 (-2.09, 0.05) MMEF growth	NR

Type of Health Effect and Location	Indicator	Change in Health Indicator per Increment in PM*	Range of City PM Levels ** Means (μg/m^3)
Lung Function Changes in Adults			
Southern California[P] (% predicted FEV_1, females)	PM_{10} (cutoff of 54.2 days/year >100 μg/m^3)	+0.9 % (-0.8, 2.5) FEV_1	52.7 (21.3, 80.6)
Southern California[P] (% predicted FEV_1, males)	PM_{10} (cutoff of 54.2 days/year >100 μg/m^3)	+0.3 % (-2.2, 2.8) FEV_1	54.1 (20.0, 80.6)
Southern California[P] (% predicted FEV_1, males whose parents had asthma, bronchitis, emphysema)	PM_{10} (cutoff of 54.2 days/year >100 μg/m^3)	−7.2 % (-11.5, -2.7) FEV_1	54.1 (20.0, 80.6)
Southern California[P] (% predicted FEV_1, females)	$SO_4^=$ (1.6 μg/m^3)	Not reported	7.4 (2.7, 10.1)
Southern California[P] (% predicted FEV_1, males)	$SO_4^=$ (1.6 μg/m^3)	−1.5 % (-2.9, -0.1) FEV_1	7.3 (2.0, 10.1)

*Results calculated using PM increment between the high and low levels in cities, or other PM increments given in parentheses; NS Changes = No significant changes.

**Range of mean PM levels given unless, as indicated, studies reported overall study mean (min, max), or mean (±SD); NR=not reported.

*** Results only for smoking category subgroups.

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2.1.1.6 Roadway-Related Exposure and Health Studies

A recent body of studies has suggested a link between residential proximity to heavily-trafficked roadways (where diesel engines are operated) and adverse health effects. While many of these studies did not measure PM specifically, they include potential exhaust exposures which include mobile source PM because they employ exposure indices such as roadway proximity or traffic volumes.

Based on extensive emission characterization studies and as reviewed in the EPA Diesel HAD (Health Assessment Document for Diesel Exhaust), diesel PM is found principally in the fine fraction (both primary and secondarily formed PM).[71, 72] In addition, in the Diesel HAD, we note that the particulate characteristics in the zone around nonroad diesel engines is likely to be substantially the same as published air quality measurements made along busy roadways. This conclusion supports the relevance of health effects associated with on-road diesel engine-generated PM to nonroad applications. Thus, near roadway studies are relevant to understanding potential health impacts of emissions from nonroad diesel engines.

Specifically, in a recent body of studies, scientists have examined health effects associated with living near major roads. As discussed above, a Dutch cohort study recently developed estimates of the relative risk of cardiopulmonary and all-cause mortality associated with living near a busy roadway.[73] The study found a statistically significant excess risk of cardiopulmonary mortality of 95 percent (i.e., a relative risk of 1.95, 95% CI: 1.09-3.52) associated with living near a busy road. A recent British ecological study examined mortality attributable to stroke in England and Wales.[74] After adjusting for potential confounders, the study found a significantly greater rate of mortality in men and women living within 200 meters of a busy road of 7 percent [95% CI on RR: 1.04 to 1.09] and 4 percent [95% CI on RR: 1.02-1.06], respectively. Risks decreased with increased distance from roadways. However, being an ecological study design, it is impossible to rule out confounding variables.

Other studies relate the incidence or prevalence of respiratory health outcomes to roadway proximity. Several studies have found positive associations between respiratory symptoms and residential roadway proximity or traffic volume. Most recently, a study in U.S. veterans living in southeastern Massachusetts found significant increases in self-reported respiratory symptoms among subjects living within 50 meters of a major road.[75]

A Dutch cohort study following infants from birth found that traffic-related pollutant concentrations found positive associations with respiratory symptoms, several illnesses, and physician-diagnosed asthma, the last of which was significant for diagnoses prior to 1 year of age.[76]

In a case-control study of children under 14 years old in San Diego, CA, with asthma diagnosis was confirmed by Medicaid claims, no associations between odds of physician diagnosis of asthma and traffic was found.[77] However, a case-based analysis of the data associated traffic flows with an increased number of medical visits among children with asthma.

A case-control study of children aged 4 to 48 months diagnosed with wheezing bronchitis included exposures predicted from traffic data, dispersion models of NO_2 as a marker of mobile source emissions, and included separate exposures for home and day care.[78] Analyses found that cases had significantly elevated NO_2 exposures compared with controls, but only among girls. A significant trend with NO_2 was reported.

Two cross-sectional studies of self-reported wheezing and allergic rhinitis symptoms in German aged 12 to 15 years found increased prevalence of wheezing and allergic rhinitis based on subject-reported frequency of truck traffic.[79],[80]

A cross-sectional study in the Netherlands examined self-reported respiratory diagnoses, allergies, and respiratory symptoms in association with annual truck and automobile density, living within 100 meters of a freeway, and indoor measures of air pollution (black smoke, NO_2).[81] The study found associations for truck traffic density with wheeze and asthma attacks in girls but not boys. Associations among girls but not boys were also found for homes within 100 m of a freeway and chronic cough, wheeze, and rhinitis. Physician-diagnosed asthma was not associated with traffic-related exposures. Physician-diagnosed allergy was inversely associated with NO_2 and black smoke.

A cross-sectional study in Surrey, England, compared city wards transected by freeways and those not transected by freeways.[82] Respiratory symptoms in the past year and self-reported diagnosis of asthma by a physician was not associated with any respiratory metric.

A recent review of epidemiologic studies examining associations between asthma and roadway proximity concluded that some coherence was evident in the literature, indicating that asthma, lung function decrement, respiratory symptoms, and atopic illness appear to be higher among people living near busy roads.[83] Other studies have shown children living near roads with high truck traffic density have decreased lung function and greater prevalence of lower respiratory symptoms compared with children living on other roads.[84]

Another recently published study from Los Angeles, CA, found that maternal residence near heavy traffic during pregnancy is associated with adverse birth outcomes, such as preterm birth and low birth weight.[85] However, these studies are not specifically related to PM, but to fresh emissions from mobile sources, which includes other components as well.

Other studies have shown that living near major roads results in substantially higher exposures to ultrafine particles. A British study found that in the lungs of children living near major roads in Leicester, UK, a significantly higher proportion of the alveolar macrophages contained PM compared with children living on quiet streets.[86] All particles observed in the lungs of children were carbon particles under 0.1 um, which are known to be emitted from diesel engines and other mobile sources. This study is consistent with recent studies of ultrafine particle concentrations around major roads in Los Angeles, CA and Minnesota, which found that concentrations of the smallest particles were substantially elevated near roadways with diesel traffic.[87, 88, 89]

The particulate characteristics in the zone around nonroad diesel engines is not likely to differ substantially from published air quality measurements made along busy roadways; thus, these studies are relevant to the diesel exhaust emissions from nonroad diesel engines. While these studies do not specifically examine nonroad diesel engines, several observations may be drawn. First, nonroad diesel engine emissions are similar in their emission characteristics to on-road motor vehicles. Secondly, exposures from nonroad engines may actually negatively bias these studies, because exposures from nonroad sources are not accounted for, and therefore reduce the study's statistical power. Third, certain populations that are exposed directly to fresh nonroad diesel exhaust are exposed at greater concentrations than those found in studies among the general population. These groups include workers in the construction, timber, mining, and agriculture industries, and members of the general population that spend a large amount of time near areas where diesel engine emissions are most densely clustered, such as residents in buildings near large construction sites.

2.1.2 Attainment and Maintenance of the PM_{10} and $PM_{2.5}$ NAAQS: Current and Future Air Quality

2.1.2.1 Current PM Air Quality

There are NAAQS for both PM_{10} and $PM_{2.5}$. Violations of the annual $PM_{2.5}$ standard are much more widespread than are violations of the PM_{10} standards. Emission reductions needed to attain the $PM_{2.5}$ standards will also assist in attaining and maintaining compliance with the PM_{10} standards. Thus, since most PM emitted by nonroad diesel engines is in the fine fraction of PM, the emission controls resulting from this final rule will contribute to attainment and maintenance of the existing PM NAAQS. More broadly, the new standards will benefit public health and welfare through reductions in direct diesel PM and reductions of NOx, SOx, and HCs that contribute to secondary formation of PM. As described above, diesel particles from nonroad diesel engines are a component of both coarse and fine PM, but fall mainly in the fine (and even ultrafine) size range.

The emission reductions from this final rule will assist States as they work with EPA through implementation of local controls including the development and adoption of additional controls as needed to help their areas attain and maintain the standards.

2.1.2.1.1 PM_{10} Levels

The current NAAQS for PM_{10} were established in 1987. The primary (health-based) and secondary (public welfare based) standards for PM_{10} include both short- and long-term NAAQS. The short-term (24-hour) standard of 150 μg/m^3 is not to be exceeded more than once per year on average over three years. The long-term standard specifies an expected annual arithmetic mean not to exceed 50 μg/m^3 averaged over three years.

Currently, 29.3 million people live in PM_{10} nonattainment areas, including moderate and serious areas. There are presently 56 moderate PM_{10} nonattainment areas with a total population of 6.6 million.[90] The attainment date for the initial moderate PM_{10} nonattainment areas, designated by law on November 15, 1990, was December 31, 1994. Several additional PM_{10} nonattainment areas were designated on January 21, 1994, and the attainment date for these areas was December 31, 2000.

There are 8 serious PM_{10} nonattainment areas with a total affected population of 22.7 million. According to the Act, serious PM_{10} nonattainment areas must attain the standards no later than 10 years after designation. The initial serious PM_{10} nonattainment areas were designated January 18, 1994 and had an attainment date set by the Act of December 31, 2001. The Act provides that EPA may grant extensions of the serious area attainment dates of up to 5 years, provided that the area requesting the extension meets the requirements of Section 188(e) of the Act. Five serious PM_{10} nonattainment areas (Phoenix, Arizona; Clark County (Las Vegas), NV; Coachella Valley, South Coast (Los Angeles), and Owens Valley, California) have received extensions of the December 31, 2001 attainment date and thus have new attainment dates of December 31, 2006.

Many PM_{10} nonattainment areas continue to experience exceedances. Of the 29.3 million people living in designated PM_{10} nonattainment areas, approximately 24.5 million people are living in nonattainment areas with measured air quality violating the PM_{10} NAAQS in 2000-2002. Among these are 8 serious areas listed in Table 1.2-1 and 6 moderate areas: Nogales, AZ, Imperial Valley, CA, Mono Basin, CA, Coso Junction, CA,[B] Ft. Hall, ID, and El Paso, TX.

[B] On August 6, 2002, EPA finalized certain actions affecting the Searles Valley, California, PM_{10} nonattainment area, which is located in the rural high desert and includes portions of Inyo, Kern, and San Bernardino Counties. The action splits the Searles Valley nonattainment area into three separate areas: Coso Junction, Indian Wells Valley and Trona. EPA's action also determines that the Trona area attained the PM-10 standards by December 31, 1994. On May 7, 2003, EPA finalized approval of the Indian Wells Moderate Area and Maintenance Plan and redesignated the area from nonattainment to attainment for particulate matter (PM-10).

Source: http://www.epa.gov/region9/air/searlespm/index.html

Table 1.2-1
Serious PM_{10} Nonattainment Areas

Area	Attainment Date	2000 Population	2000-2002 Measured Violation
Owens Valley, CA	December 31, 2006	7,000	Yes
Phoenix, AZ	December 31, 2006	3,111,876	Yes
Clark County, NV (Las Vegas)	December 31, 2006	1,375,765	Yes
Coachella Valley, CA	December 31, 2006	225,000	Yes
Los Angeles South Coast Air Basin, CA	December 31, 2006	14,550,521	Yes
San Joaquin Valley, CA	2001	3,080,064	Yes
Walla Walla, WA	2001	10,000	No
Washoe County, NV (Reno)	2001	339,486	No
Total Population	22.7 million		

In addition to these designated nonattainment areas, there are 16 unclassified areas, where 6.2 million live, for which States have reported PM_{10} monitoring data for 2000-2002 period indicating a PM_{10} NAAQS violation. An official designation of PM_{10} nonattainment indicates the existence of a confirmed PM_{10} problem that is more than a result of a one-time monitoring upset or a result of PM_{10} exceedances attributable to natural events. We have not yet excluded the possibility that one or the other of these is responsible for the monitored violations in 2000-2002 in these 16 unclassified areas. We adopted a policy in 1996 that allows areas whose PM_{10} exceedances are attributable to natural events to remain unclassified if the State is taking all reasonable measures to safeguard public health regardless of the sources of PM_{10} emissions. Areas that remain unclassified areas are not required to submit attainment plans, but we work with each of these areas to understand the nature of the PM_{10} problem and to determine what best can be done to reduce it.

2.1.2.1.2 $PM_{2.5}$ Levels

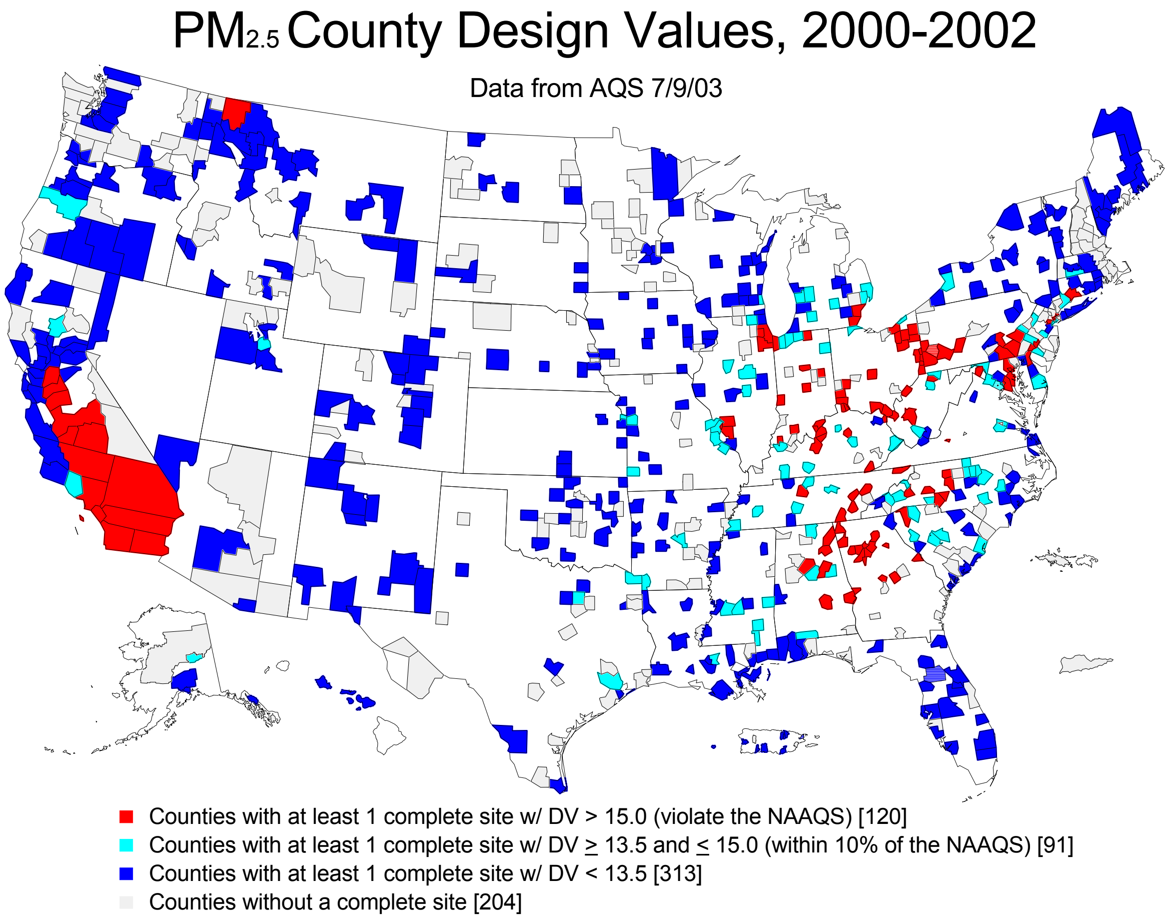
The need for reductions in the levels of $PM_{2.5}$ is widespread. Figure 2.1.1-4 below shows $PM_{2.5}$ monitoring data highlighting locations measuring concentrations above the level of the NAAQS. As can be seen from that figure, high ambient levels are widespread throughout the country. In addition, there may be counties without monitors that exceed the level of the standard. A listing of available measurements by county can be found in the air quality technical support document (AQ TSD) for the rule.

The NAAQS for $PM_{2.5}$ were established in 1997 (62 FR 38651, July 18, 1997). The short term (24-hour) standard is set at a level of 65 $\mu g/m^3$ based on the 98th percentile concentration averaged over three years. (The air quality statistic compared with the standard is referred to as the "design value.") The long-term standard specifies an expected annual arithmetic mean not to exceed 15 $\mu g/m^3$ averaged over three years.

Current $PM_{2.5}$ monitored values for 2000-2002 indicate that 120 counties in which almost 65 million people live have annual design values that violate the $PM_{2.5}$ NAAQS. In total, this represents 23 percent of the counties and 37 percent of the population with levels above the NAAQS in the areas with monitors that met completeness criteria. An additional 32 million people live in 91 counties that have air quality measurements within 10 percent of the level of the standard. These areas, though not currently violating the standard, will also benefit from the additional reductions from this rule in order to ensure long-term maintenance. There are another 204 counties where 21 million people live that had incomplete data.

Figure 2.1.2-1 is a map of currently available $PM_{2.5}$ monitoring data, highlighting monitor locations near or above the annual $PM_{2.5}$ NAAQS. As can be seen from this figure, high ambient levels are widespread throughout the East and California.

Figure 2.1.2-1


PM2.5 County Design Values, 2000-2002
Data from AQS 7/9/03
Counties with at least 1 complete site w/ DV > 15.0 (violate the NAAQS) [120]
Counties with at least 1 complete site w/ DV ≥ 13.5 and ≤ 15.0 (within 10% of the NAAQS) [91]
Counties with at least 1 complete site w/ DV < 13.5 [313]
Counties without a complete site [204]

Further insights into the need for reductions from this rule can be gained by evaluating counties at various levels above the level of the NAAQS. As shown in Table 2.1.1-3 of the 64.9 million people currently living in counties with measurements above the NAAQS, 18.8 million live in counties above 20 µg/m^3. In Section 2.1.2.2, we discuss that absent additional controls, our modeling predicts there will continue to be large numbers of people living in counties with PM levels above the standard.

Table 2.1.1-3
2000-2002 Monitored Population[a] Living in Counties with Annual Average[b] $PM_{2.5}$ Concentrations Shown

Measured 2000-2002 Annual Average $PM_{2.5}$ Concentration (µg/m3)	Number of Counties Within The Concentration Range	2000 Population Living in Monitored Counties Within The Concentration Range (Millions, 2000 Census Data)
>25	2	3.3
>20 <=25	6	15.5
>15 <=20	112	46.1
<=15	404	110.9

[a] Monitored population estimates represent populations living in counties with monitors producing data that meet the NAAQS data completeness requirements for 2000 - 2002. This analysis excludes the 204 counties whose monitoring data do not meet the completeness criteria.
[b] Annual average represents the monitor reading with the highest average in each monitored county.
[c] The monitored population is 175.7 million (or 62 percent of the U.S. Census total county-based 2000 population for the U.S. of 281.4 million).

Chemical composition of ambient $PM_{2.5}$ also underscores the contribution of emissions from the engines subject to this rule and points to the need for reductions. Data on $PM_{2.5}$ composition are available from the EPA Speciation Trends Network and the IMPROVE Network for September 2001 to August 2002 covering both urban and rural areas in numerous regions of the United States. The relative contribution of various chemical components to $PM_{2.5}$ varies by region of the country. Figure 2.1.2-2 shows the levels and composition of ambient $PM_{2.5}$ in some urban areas. Figure 2.1.2-3 shows the levels and composition of $PM_{2.5}$ in rural areas where the total $PM_{2.5}$ levels are generally lower. These data show that carbonaceous $PM_{2.5}$ makes up the major component for $PM_{2.5}$ in both urban and rural areas in the Western United States. Carbonaceous $PM_{2.5}$ includes both elemental and organic carbon. Nonroad engines, especially nonroad diesel engines, contribute significantly to ambient $PM_{2.5}$ levels, largely through emissions of carbonaceous $PM_{2.5}$. For the Eastern and middle United States, these data show that carbonaceous $PM_{2.5}$ is a major contributor to ambient $PM_{2.5}$ both urban and rural areas. In some eastern areas, carbonaceous $PM_{2.5}$ is responsible for up to half of ambient $PM_{2.5}$ concentrations.

Figure 2.1.2-2
Annual Average $PM_{2.5}$ Species and Concentrations in Selected Urban Areas
(September 2001- August 2002)

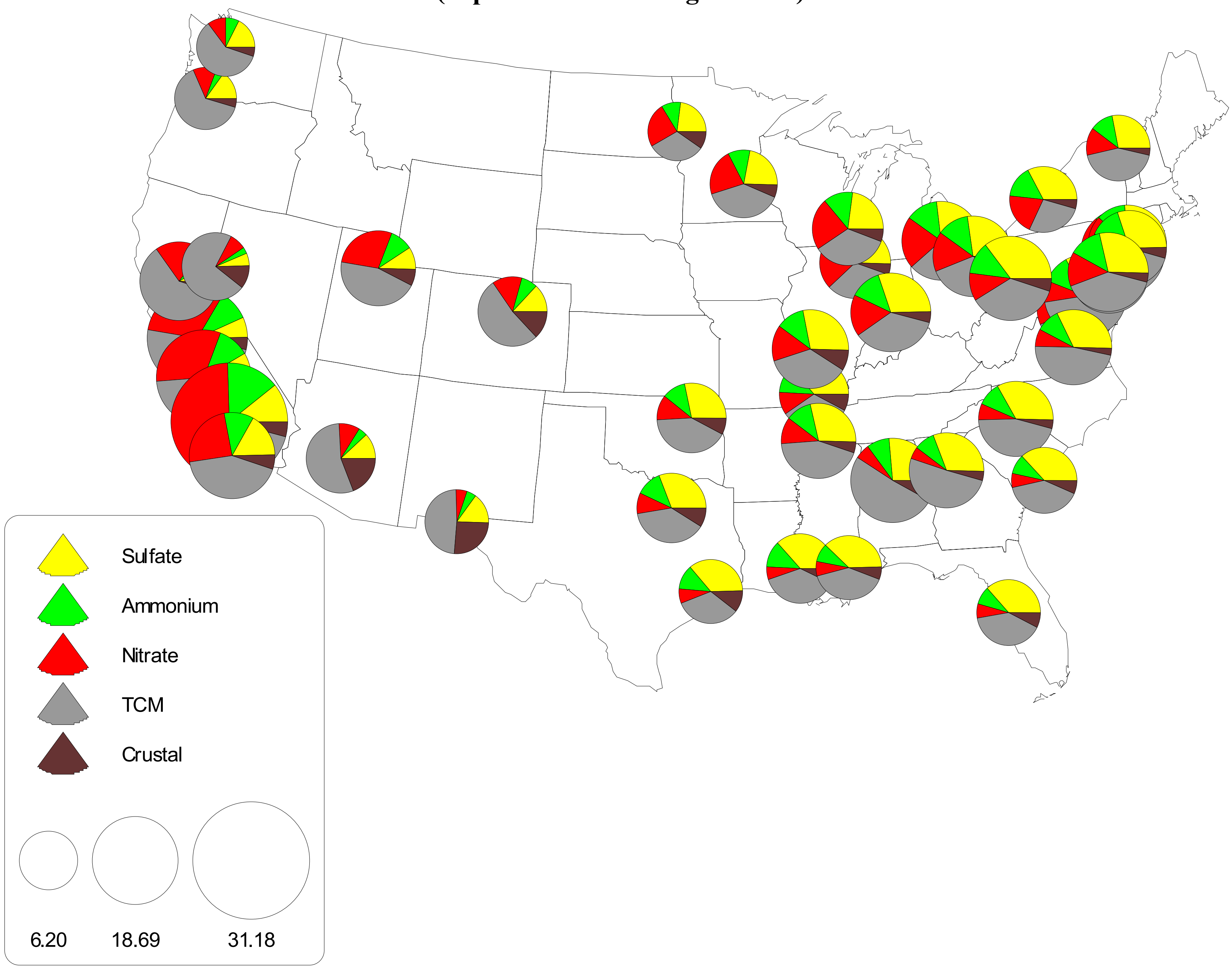
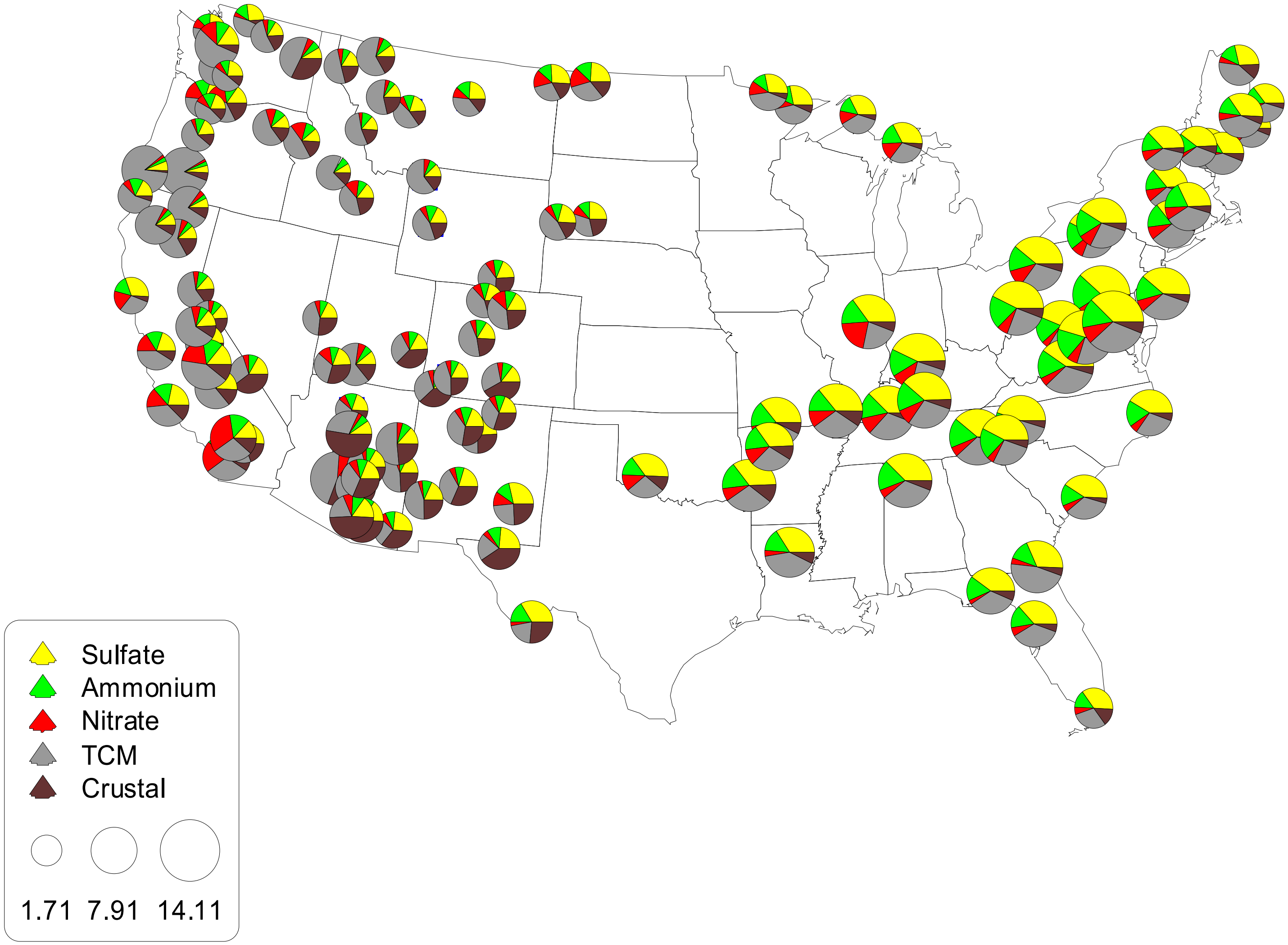


Figure 2.1.2-3
Annual Average PM2.5 Concentration and Species in Rural Areas
(September 2001 - August 2002)



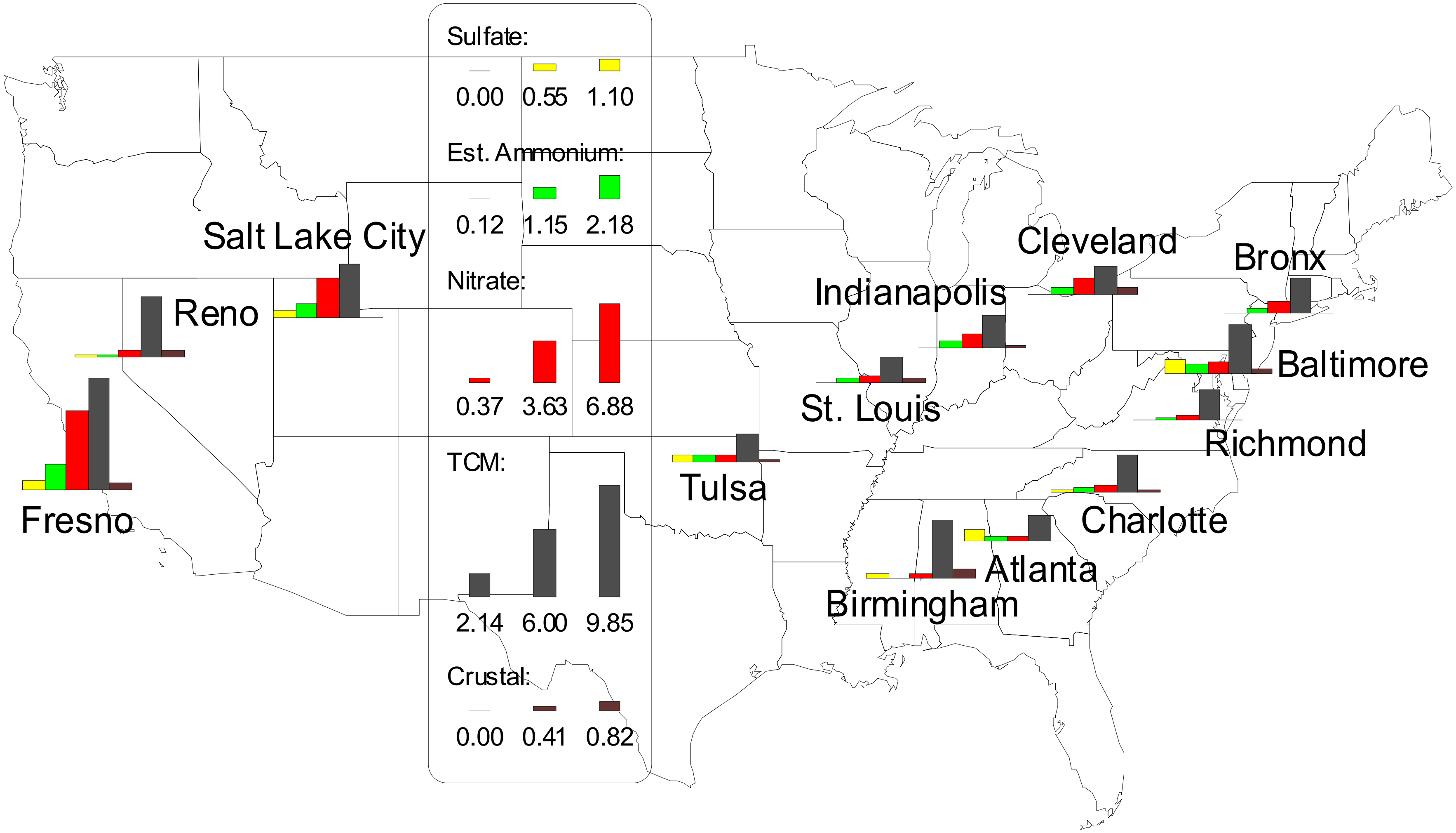
Another important component of PM in the West is nitrates, which are formed from NOx. Nitrates are especially prominent in the California area where it is responsible for about a quarter of the ambient $PM_{2.5}$ concentrations. Nonroad diesel engines also emit high levels of NOx, which reacts in the atmosphere to form secondary $PM_{2.5}$ (namely ammonium nitrate). Sulfate plays a lesser role in these western regions by mass, but it remains important to visibility impairment discussed below. Nonroad diesel engines also emit SO_2 and HC, which react in the atmosphere to form secondary $PM_{2.5}$ (namely sulfates and organic carbonaceous $PM_{2.5}$). Sulfate is also a major contributor to ambient $PM_{2.5}$ in the Eastern United States and in some areas make greater contributions than carbonaceous $PM_{2.5}$.

From Figures 2.1.2-2 and 2.1.2-3, one can compare the levels and composition of $PM_{2.5}$ in various urban areas and a corresponding rural area. This comparison, in Figure 2.1.2-4, shows that much of the excess $PM_{2.5}$ in urban areas (annual average concentration at urban monitor minus annual average concentration at corresponding rural monitor) is indeed from carbonaceous PM.[91, 92] See the AQ TSD for details.

The ambient PM monitoring networks account for both directly emitted PM as well as secondarily formed PM. Emission inventories, which account for directly emitted PM and PM precursors separately, also show that mobile source PM emissions, including that from nonroad diesel engines, is a major contributor to total PM emissions. Nationally, this final rule will significantly reduce emissions of carbonaceous PM. NOx emissions, a prerequisite for formation of secondary nitrate aerosols, will also be reduced. Nonroad diesel engines are major contributors to both of these pollutants. The new requirements in this rule will also reduce SOx and HC. Nonroad diesel engines emissions also contribute to national SOx and HC emission inventories, but to a lesser degree than for PM and NOx. The emission inventories are discussed in detail in Chapter 3.

As discussed in Sections 2.2.2.6 and 2.1, diesel PM also contains small quantities of numerous mutagenic and carcinogenic compounds associated with the particles (and also organic gases). In addition, while toxic trace metals emitted by nonroad diesel engines represent a very small portion of the national emissions of metals (less than one percent) and a small portion of diesel PM (generally less than one percent of diesel PM), we note that several trace metals of potential toxicological significance and persistence in the environment are emitted by diesel engines. These trace metals include chromium, manganese, mercury and nickel. In addition, small amounts of dioxins have been measured in highway engine diesel exhaust, some of which may partition into the particulate phase; dioxins are a major health concern but diesel engines are a minor contributor to overall dioxin emissions. Diesel engines also emit polycyclic organic matter (POM), including polycyclic aromatic hydrocarbons (PAH), which can be present in both gas and particle phases of diesel exhaust. Many PAH compounds are classified by EPA as probable human carcinogens.

Figure 2.1.2-4
Composition of Urban Excess PM2.5 at Selected Sites (September 2001 - August 2002)
(Source: U.S. EPA (2004) AQ TSD; Rao and Frank (2003))



2.1.2.2 Risk of Future Violations

2.1.2.2.1 PM Air Quality Modeling and Methods

In conjunction with this rulemaking, we performed a series of PM air quality modeling simulations for the continental U.S. The model simulations were performed for five emission scenarios: a 1996 baseline projection, a 2020 baseline projection and a 2020 projection with nonroad controls, a 2030 baseline projection and a 2030 projection with nonroad controls. Further discussion of this modeling, including evaluations of model performance relative to predicted future air quality, is provided in the AQ Modeling TSD.

The model outputs from the 1996, 2020 and 2030 baselines, combined with current air quality data, were used to identify areas expected to exceed the $PM_{2.5}$ NAAQS in 2020 and 2030. These areas became candidates for being determined to be residual exceedance areas that will require additional emission reductions to attain and maintain the $PM_{2.5}$ NAAQS. The impacts of the nonroad controls were determined by comparing the model results in the future year control runs against the baseline simulations of the same year. We note that there are significant SO_2 benefits from sulfur reductions in home heating oil fuel that are not accounted for in our modeling. This modeling supports the conclusion that there is a broad set of areas with predicted $PM_{2.5}$ concentrations at or above 15 $\mu g/m^3$ between 1996 and 2030 in the baseline scenarios without additional emission reductions.

The air quality modeling performed for this rule was based upon an improved version of the modeling system used in the HD Engine/Diesel Fuel rule (to address peer-review comments) with the addition of updated inventory estimates for 1996, 2020 and 2030.

A national-scale version of the REgional Model System for Aerosols and Deposition (REMSAD) was utilized to estimate base and future-year PM concentrations over the contiguous United States for the various emission scenarios. Version 7 of REMSAD was used for this rulemaking. REMSAD was designed to calculate the concentrations of both inert and chemically reactive pollutants in the atmosphere that affect annual particulate concentrations and deposition over large spatial scales.[C] Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, REMSAD is useful for evaluating the impacts of the final rule on PM concentrations in the United States. The following sections provide an overview of the PM modeling completed as part of this rulemaking. More detailed information is included in the AQ Modeling TSD, which is located in the docket for this rule.

[C] Given the potential impact of the final rule on secondarily formed particles it is important to employ a Eulerian model such as REMSAD. The impact of secondarily formed pollutants typically involves primary precursor emissions from a multitude of widely dispersed sources, and chemical and physical processes of pollutants that are best addressed using an air quality model that employs an Eulerian grid model design. Thus, comments from industry that EPA's methodology form computing benefits over time is based on unsupportable assumptions such as that there will be no interactions between precursors and directly emitted PM in the formation of secondary PM and that EPA excludes consideration of non-linearities in its air quality modeling are incorrect. This air quality modeling for 2020 and 2030 does incorporate the nonlinear interactions between NOx, SO_2, and direct PM.

The PM air quality analyses employed the modeling domain used previously in support of Clear Skies air quality assessment. The domain encompasses the lower 48 States and extends from 126 degrees to 66 degrees west longitude and from 24 degrees to 52 degrees north latitude. The model contains horizontal grid-cells across the model domain of roughly 36 km by 36 km. There are 12 vertical layers of atmospheric conditions with the top of the modeling domain at 16,200 meters.

The simulation periods modeled by REMSAD included separate full-year application for each of the five emission scenarios (1996 base year, 2020 base, 2020 control, 2030 baseline, 2030 control) using the 1996 meteorological inputs described below.

The meteorological data required for input into REMSAD (wind, temperature, surface pressure, etc.) were obtained from a previously developed 1996 annual run of the Fifth-Generation National Center for Atmospheric Research (NCAR) / Penn State Mesoscale Model (MM5). A postprocessor called MM5- REMSAD was developed to convert the MM5 data into the appropriate REMSAD grid coordinate systems and file formats. This postprocessor was used to develop the hourly average meteorological input files from the MM5 output. Documentation of the MM5REMSAD code and further details on the development of the input files is contained in Mansell (2000).[93] A more detailed description of the development of the meteorological input data is provided in the AQ Modeling TSD, which is located in the docket for this rule.

The modeling specified initial species concentrations and lateral boundary conditions to approximate background concentrations of the species; for the lateral boundaries the concentrations varied (decreased parabolically) with height. These initial conditions reflect relatively clean background concentration values. Terrain elevations and land use information was obtained from the U.S. Geological Survey database at 10 km resolution and aggregated to the roughly 36 km horizontal resolution used for this REMSAD application. The development of model inputs is discussed in greater detail in the AQ Modeling TSD, which is available in the docket for this rule.

2.1.2.2.2 Model Performance Evaluation

The purpose of the base year PM air quality modeling was to reproduce the atmospheric processes resulting in formation and dispersion of fine particulate matter across the United States. An operational model performance evaluation for $PM_{2.5}$ and its related speciated components (e.g., sulfate, nitrate, elemental carbon etc.) for 1996 was performed in order to estimate the ability of the modeling system to replicate base year concentrations.

This evaluation is comprised principally of statistical assessments of model versus observed pairs. The robustness of any evaluation is directly proportional to the amount and quality of the ambient data available for comparison. Unfortunately, for 1996 there were few $PM_{2.5}$ monitoring networks with available data for evaluation of the Nonroad PM modeling. Critical limitations of the existing databases are a lack of urban monitoring sites with speciated measurements and poor geographic representation of ambient concentration in the Eastern United States.

The largest available ambient database for 1996 comes from the IMPROVE network. IMPROVE is a cooperative visibility monitoring effort between EPA, federal land management agencies, and state air agencies. Data are collected at Class I areas across the United States mostly at national parks, national wilderness areas, and other protected pristine areas.[94] There were approximately 60 IMPROVE sites that had complete annual $PM_{2.5}$ mass and/or $PM_{2.5}$ species data for 1996. Using the 100th meridian to divide the Eastern and Western United States, 42 sites were located in the West and 18 sites were in the East.

The observed IMPROVE data used for the performance evaluation consisted of $PM_{2.5}$ total mass, sulfate ion, nitrate ion, elemental carbon, organic aerosols, and crustal material (soils). The REMSAD model output species were postprocessed in order to achieve compatibility with the observation species.

The principal evaluation statistic used to evaluate REMSAD performance is the "ratio of the means." It is defined as the ratio of the average predicted values over the average observed values. The annual average ratio of the means was calculated for five individual $PM_{2.5}$ species as well as for total $PM_{2.5}$ mass. The metrics were calculated for all IMPROVE sites across the country as well as for the East and West individually. Table 2.1.2-1 shows the ratio of the annual means. Numbers greater than 1 indicate overpredictions compared with ambient observations (e.g. 1.23 is a 23 percent overprediction). Numbers less than 1 indicate underpredictions.

Table 2.1.2-1
Model Performance Statistics for REMSAD $PM_{2.5}$ Species Predictions: 1996 Base Case

IMPROVE PM Species	Ratio of the Means (annual average concentrations)		
	Nationwide	Eastern U.S.	Western U.S.
$PM_{2.5}$, total mass	0.68	0.85	0.51
Sulfate ion	0.81	0.9	0.61
Nitrate ion	1.05	1.82	0.45
Elemental carbon	1.01	1.23	0.8
Organic aerosols	0.55	0.58	0.53
Soil/Other	1.38	2.25	0.88

Note: The dividing line between the West and East was defined as the 100th meridian.

When considering annual average statistics (e.g., predicted versus observed), which are computed and aggregated over all sites and all days, REMSAD underpredicts fine particulate mass ($PM_{2.5}$) by roughly 30 percent. $PM_{2.5}$ in the Eastern United States is slightly underpredicted, while $PM_{2.5}$ in the West is underpredicted by about 50 percent. Eastern sulfate is slightly underpredicted, elemental carbon is slightly overpredicted, while nitrate and crustal are largely overpredicted. This is balanced by an underprediction in organic aerosols. Overall the $PM_{2.5}$ performance in the East is relatively unbiased due to the dominance of sulfate in the observations. Western predictions of sulfate, nitrate, elemental carbon, and organic aerosols are all underpredicted.

REMSAD performance is relatively good in the East. The model is overpredicting nitrate, but less so than in previous model applications. The overpredictions in soil/other concentrations in the East can largely be attributed to overestimates of fugitive dust emissions. The model is performing well for sulfate, which is the dominant $PM_{2.5}$ species in most of the East. Organic aerosols are underpredicted in both the East and West. There is a large uncertainty in the current primary organic inventory as well as the modeled production of secondary organic aerosols.

REMSAD is underpredicting all species in the West. The dominant species in the West is organic aerosols. Secondary formation of sulfate, nitrate, and organics appears to be underestimated in the West. Additionally, the current modeling inventory does not contain wildfires, which may be a significant source of primary organic carbon in the West.

It should be noted that $PM_{2.5}$ modeling is an evolving science. There have been few regional or national scale model applications for primary and secondary PM. Unlike ozone modeling, there is essentially no database of past performance statistics against which to measure the performance of this modeling. Given the state of the science relative to PM modeling, it is inappropriate to judge PM model performance using criteria derived for other pollutants, like ozone. Still, the performance of this air quality modeling is encouraging, especially considering that the results are limited by our current knowledge of PM science and chemistry, and by the emission inventories for primary PM and secondary PM precursor pollutants. EPA and others are only beginning to understand the limitations and uncertainties in the current inventories and modeling tools. Improvements to the tools are being made on a continuing basis.

2.1.2.2.3 Results with Areas at Risk of Future $PM_{2.5}$ Violations

Our air quality modeling performed for this rulemaking also indicates that the present widespread number of counties with annual averages above 15 $\mu g/m^3$ are likely to persist in the future in the absence of additional controls. For example, in 2020 based on emission controls currently adopted or expected to be in place, we project that 66 million people will live in 79 counties with average $PM_{2.5}$ levels at and above 15 $\mu g/m^3$. In 2030, the number of people projected to live in areas exceeding the $PM_{2.5}$ standard is expected to increase to 85 million in 107 counties. An additional 24 million people are projected to live in counties with annual averages within 10 percent of the standard in 2020, and 17 million people are projected to live in counties with annual averages within 10 percent of the standard in 2030. The AQ Modeling TSD lists the specifics.

Our modeling also indicates that the reductions from this final rule will make a substantial contribution to reducing these potential exposures.[D] In 2020, we estimate that the number of people living in counties with $PM_{2.5}$ levels above the NAAQS will be reduced from 66 million to 60 million living in 67 counties. That is a reduction of 9 percent in potentially exposed population and 15 percent of the number of counties. In 2030, there will be an estimated reduction from 85 million people to 71 million living in 84 counties. This represents an even greater improvement than projected for 2020 because of the fleet turnover and corresponds to a 16 percent reduction in potentially exposed population and a 21 percent of the number of counties. Furthermore, our modeling also shows that the emission reductions will assist areas with future maintenance of the standards.

Table 2.1.2-2 lists the counties with 2020 and 2030 projected annual $PM_{2.5}$ design values that violate the annual standard. Counties are marked with an "V" in the table if their projected design values are greater than or equal to 15.05 $\mu g/m^3$. The current 3-year average design values of these counties are also listed. Recall that we project future design values only for counties that have current design values, so this list is limited to those counties with 1999-2001 ambient monitoring data sufficient to calculate current 3-year design values.

[D]The results illustrate the type of PM changes for the preliminary control option, as discussed in Section 3.6. The analysis differs from the modeled control case based on public comment and updated information; however, we believe that the net results would approximate future emissions, though we anticipate the PM reductions might be smaller. We also note that our modeling does not account for substantial reductions in SO_2 associated with sulfur reductions in home heating oil.

Table 2.1.2-2
Counties with 2020 and 2030 Projected Annual PM2.5
Design Values in Violation of the Annual PM2.5 Standard.[a, b]

State	County	1999 - 2001 Design Value (ug/m^3)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
AL	De Kalb	16.8			V	V	64,452
AL	Houston	16.3	V		V	V	88,787
AL	Jefferson	21.6	V	V	V	V	662,047
AL	Mobile	15.3			V	V	399,843
AL	Montgomery	16.8	V	V	V	V	223,510
AL	Morgan	19.1	V	V	V	V	111,064
AL	Russell	18.4	V	V	V	V	49,756
AL	Shelby	17.2	V	V	V	V	143,293
AL	Talladega	17.8	V	V	V	V	80,321
CA	Fresno	24	V	V	V	V	799,407
CA	Imperial	15.7			V		142,361
CA	Kern	23.7	V	V	V	V	661,645
CA	Los Angeles	25.9	V	V	V	V	9,519,338
CA	Merced	18.9	V	V	V	V	210,554
CA	Orange	22.4	V	V	V	V	2,846,289
CA	Riverside	29.8	V	V	V	V	1,545,387
CA	San Bernardino	25.8	V	V	V	V	1,709,434
CA	San Diego	17.1	V	V	V	V	2,813,833
CA	San Joaquin	16.4			V		563,598
CA	Stanislaus	19.7	V	V	V	V	446,997
CA	Tulare	24.7	V	V	V	V	368,021
CT	New Haven	16.8	V	V	V	V	824,008
DE	New Castle	16.6	V	V	V	V	500,265
DC	Washington	16.6	V	V	V	V	572,059
GA	Bibb	17.6	V	V	V	V	153,887
GA	Chatham	16.5	V	V	V	V	232,048
GA	Clarke	18.6	V	V	V	V	101,489
GA	Clayton	19.2	V	V	V	V	236,517
GA	Cobb	18.6	V	V	V	V	607,751
GA	De Kalb	19.6	V	V	V	V	665,865
GA	Dougherty	16.6	V	V	V	V	96,065
GA	Floyd	18.5	V	V	V	V	90,565
GA	Fulton	21.2	V	V	V	V	816,006
GA	Hall	17.2	V		V	V	139,277
GA	Muscogee	18	V	V	V	V	186,291
GA	Paulding	16.8	V	V	V	V	81,678
GA	Richmond	17.4	V	V	V	V	199,775

State	County	1999 - 2001 Design Value (ug/m^3)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
GA	Washington	16.5	V	V	V	V	21,176
GA	Wilkinson	18.1	V	V	V	V	10,220
IL	Cook	18.8	V	V	V	V	5,376,741
IL	Du Page	15.4			V		904,161
IL	Madison	17.3	V	V	V	V	258,941
IL	St Clair	17.4	V	V	V	V	256,082
IL	Will	15.9	V		V	V	502,266
IN	Clark	17.3	V	V	V	V	96,472
IN	Lake	16.3	V	V	V	V	484,564
IN	Marion	17	V		V	V	860,454
IN	Vanderburgh	16.9			V		171,922
KY	Jefferson	17.1	V	V	V	V	693,604
KY	Kenton	15.9			V		151,464
LA	East Baton Rouge	14.6			V	V	412,852
LA	West Baton Rouge	14.1			V		21,601
MD	Baltimore	16			V		754,292
MD	Prince Georges	17.3	V	V	V	V	801,515
MD	Baltimore City	17.8	V	V	V	V	651,154
MA	Suffolk	16.1	V		V		689,807
MI	Wayne	18.9	V	V	V	V	2,061,162
MS	Jones	16.6	V		V	V	64,958
MO	St Louis City	16.3	V		V	V	348,189
MT	Lincoln	16.4	V	V	V	V	18,837
NJ	Hudson	17.5	V	V	V	V	608,975
NJ	Union	16.3			V	V	522,541
NY	Bronx	16.4	V		V	V	1,332,650
NY	New York	17.8	V	V	V	V	1,537,195
NC	Catawba	17.1	V		V	V	141,685
NC	Davidson	17.3	V	V	V	V	147,246
NC	Durham	15.3			V		223,314
NC	Forsyth	16.2			V	V	306,067
NC	Gaston	15.3			V		190,365
NC	Guilford	16.3	V		V	V	421,048
NC	McDowell	16.2			V		42,151
NC	Mecklenburg	16.8	V	V	V	V	695,454
NC	Wake	15.3			V		627,846
OH	Butler	17.4	V		V	V	332,807
OH	Cuyahoga	20.3	V	V	V	V	1,393,978
OH	Franklin	18.1	V	V	V	V	1,068,978
OH	Hamilton	19.3	V	V	V	V	845,303
OH	Jefferson	18.9	V	V	V	V	73,894
OH	Lawrence	17.4	V	V	V	V	62,319
OH	Lucas	16.7	V	V	V	V	455,054

State	County	1999 - 2001 Design Value (ug/m^3)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
OH	Mahoning	16.4			V		257,555
OH	Montgomery	17.6	V	V	V	V	559,062
OH	Scioto	20	V	V	V	V	79,195
OH	Stark	18.3	V	V	V	V	378,098
OH	Summit	17.3	V	V	V	V	542,899
OH	Trumbull	16.2			V		225,116
PA	Allegheny	21	V	V	V	V	1,281,666
PA	Delaware	15			V		550,864
PA	Philadelphia	16.6	V	V	V	V	1,517,550
PA	York	16.3			V		381,751
SC	Greenville	17	V	V	V	V	379,616
SC	Lexington	15.6			V		216,014
TN	Davidson	17			V	V	569,891
TN	Hamilton	18.9	V	V	V	V	307,896
TN	Knox	20.4	V	V	V	V	382,032
TN	Shelby	15.6			V		897,472
TN	Sullivan	17			V		153,048
TX	Dallas	14.4			V		2,218,899
TX	Harris	15.1	V	V	V	V	3,400,578
UT	Salt Lake	13.6			V		898,387
VA	Richmond City	14.9			V		197,790
WV	Brooke	17.4	V	V	V	V	25,447
WV	Cabell	17.8	V	V	V	V	96,784
WV	Hancock	17.4	V	V	V	V	32,667
WV	Kanawha	18.4	V	V	V	V	200,073
WV	Wood	17.6	V		V	V	87,986
WI	Milwaukee	14.5			V		940,164
Number of Violating Counties [b]			79	67	107	84	
Population of Violating Counties[c]			65,821,000	60,453,500	85,525,600	71,375,600	

[a] As described in Chapter 3, the final control case differs from the modeled control case based on public comment and updated information; however, we believe that the net results would approximate future emissions, although we anticipate the design value improvements would be smaller. In our modeling, we do not account for SO2 reductions related to sulfur reductions in home heating oil.

[b] Projections are made only for counties with monitored design values for 1999-2001. These were the most current data at the time the analyses were performed. Counties with insufficient data or lacking monitors are excluded.

[c] Populations are based on 2020 and 2030 estimates rounded to nearest hundred. See the AQ Modeling TSD for details.

Table 2.1.2-3 lists the counties with 2020 or 2030 projected annual $PM_{2.5}$ design values that do not violate the annual standard, but are within 10 percent of it. Counties are marked with an "X" in the table if their projected design values are greater than or equal to13.55 $\mu g/m^3$, but less than 15.05 $\mu g/m^3$. Counties are marked with an "V" in the table if their projected design values are greater than or equal to 15.05 $\mu g/m^3$. The 1999-2001 design values of these counties are also listed. These are counties that are not projected to violate the standard, but to be close to it, so the final rule will help ensure that these counties continue to meet the standard in either the base or control case for at least one of the years analyzed.

Table 2.1.2-3
Counties with 2020 and 2030 Projected Annual PM2.5 Design Values within Ten Percent of the Annual PM2.5 Standard.[a, b]

State	County	1999 - 2001 Design Value (ug/m^3)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
AL	Alabama	15.5	X	X	X	X	14,254
AL	De Kalb	16.8	X	X	V	V	64,452
AL	Houston	16.3	V	X	V	V	88,787
AL	Madison	15.5			X		276,700
AL	Mobile	15.3	X	X	V	V	399,843
AR	Crittenden	15.3	X	X	X	X	50,866
AR	Pulaski	15.9	X	X	X	X	361,474
CA	Butte	15.4			X	X	203,171
CA	Imperial	15.7	X	X	V	X	142,361
CA	Kings	16.6	X		X	X	129,461
CA	San Joaquin	16.4	X	X	V	X	563,598
CA	Ventura	14.5	X	X	X	X	753,197
CT	Fairfield	13.6			X		882,567
DE	Sussex	14.5			X		156,638
GA	Hall	17.2	V	X	V	V	139,277
IL	Du Page	15.4	X	X	V	X	904,161
IL	Macon	15.4	X	X	X	X	114,706
IL	Will	15.9	V	X	V	V	502,266
IN	Elkhart	15.1	X		X	X	182,791
IN	Floyd	15.6	X	X	X	X	70,823
IN	Howard	15.4	X		X	X	84,964
IN	Marion	17	V	X	V	V	860,454
IN	Porter	13.9			X		146,798
IN	Tippecanoe	15.4	X		X	X	148,955
IN	Vanderburgh	16.9	X	X	V	X	171,922
KY	Bell	16.8	X	X	X	X	30,060
KY	Boyd	15.5	X	X	X	X	49,752
KY	Bullitt	16			X		61,236
KY	Campbell	15.5	X		X	X	88,616
KY	Daviess	15.8	X		X	X	91,545
KY	Fayette	16.8	X	X	X	X	260,512
KY	Kenton	15.9	X	X	V	X	151,464
KY	Pike	16.1	X	X	X	X	68,736
LA	Caddo	13.7			X	X	252,161
LA	Calcasieu	12.7			X		183,577
LA	East Baton Rouge	14.6	X	X	V	V	412,852
LA	Iberville	13.9	X		X	X	33,320

State	County	1999 - 2001 Design Value (ug/m^3)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
LA	Jefferson	13.6			X	X	455,466
LA	Orleans	14.1	X		X	X	484,674
LA	West Baton Rouge	14.1	X	X	V	X	21,601
MD	Baltimore	16	X	X	V	X	754,292
MA	Hampden	14.1			X		456,228
MA	Suffolk	16.1	V	X	V	X	689,807
MI	Kalamazoo	15	X		X	X	238,603
MS	Forrest	15.2	X	X	X	X	72,604
MS	Hinds	15.1	X		X	X	250,800
MS	Jackson	13.8			X	X	131,420
MS	Jones	16.6	V	X	V	V	64,958
MS	Lauderdale	15.3	X	X	X	X	78,161
MO	Jackson	13.9			X		654,880
MO	Jefferson	15	X	X	X	X	198,099
MO	St Charles	14.6	X		X	X	283,883
MO	St Louis	14.1			X		1,016,315
MO	St Louis City	16.3	V	X	V	V	348,189
NJ	Mercer	14.3	X		X	X	350,761
NJ	Union	16.3	X	X	V	V	522,541
NY	Bronx	16.4	V	X	V	V	1,332,650
NC	Alamance	15.3	X	X	X	X	130,800
NC	Cabarrus	15.7	X	X	X	X	131,063
NC	Catawba	17.1	V	X	V	V	141,685
NC	Cumberland	15.4	X		X	X	302,963
NC	Durham	15.3	X	X	V	X	223,314
NC	Forsyth	16.2	X	X	V	V	306,067
NC	Gaston	15.3	X	X	V	X	190,365
NC	Guilford	16.3	V	X	V	V	421,048
NC	Haywood	15.4	X		X	X	54,033
NC	McDowell	16.2	X	X	V	X	42,151
NC	Mitchell	15.5	X		X	X	15,687
NC	Orange	14.3			X		118,227
NC	Wake	15.3	X	X	V	X	627,846
NC	Wayne	15.3			X		113,329
OH	Butler	17.4	V	X	V	V	332,807
OH	Lorain	15.1	X		X	X	284,664
OH	Mahoning	16.4	X	X	V	X	257,555
OH	Portage	15.3	X	X	X	X	152,061
OH	Trumbull	16.2	X	X	V	X	225,116
PA	Berks	15.6	X	X	X	X	373,638
PA	Cambria	15.3			X		152,598
PA	Dauphin	15.5	X		X	X	251,798
PA	Delaware	15	X	X	V	X	550,864

State	County	1999 - 2001 Design Value (ug/m³)[b]	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
PA	Lancaster	16.9	X	X	X	X	470,658
PA	Washington	15.5			X		202,897
PA	York	16.3	X	X	V	X	381,751
SC	Georgetown	13.9			X		55,797
SC	Lexington	15.6	X	X	V	X	216,014
SC	Richland	15.4	X	X	X	X	320,677
SC	Spartanburg	15.4	X	X	X	X	253,791
TN	Davidson	17	X	X	V	V	569,891
TN	Roane	17	X	X	X	X	51,910
TN	Shelby	15.6	X	X	V	X	897,472
TN	Sullivan	17	X	X	V	X	153,048
TN	Sumner	15.7	X		X	X	130,449
TX	Dallas	14.4	X	X	V	X	2,218,899
UT	Salt Lake	13.6	X		V	X	898,387
VA	Bristol City	16			X	X	17,367
VA	Richmond City	14.9	X	X	V	X	197,790
VA	Roanoke City	15.2			X		94,911
VA	Virginia Beach Cit	13.2			X		425,257
WV	Berkeley	16	X	X	X	X	75,905
WV	Marshall	16.5	X	X	X	X	35,519
WV	Ohio	15.7	X		X	X	47,427
WV	Wood	17.6	V	X	V	V	87,986
WI	Milwaukee	14.5	X	X	V	X	940,164
WI	Waukesha	14.1			X		360,767
Number of Counties within 10%[b]			70	62	64	70	
Population of Counties within 10%[c]			23,836,400	24,151,800	16,870,300	24,839,600	

[a] As described in Chapter 3, the final control case differs from the modeled control case based on public comment and updated information; however, we believe that the net results would approximate future emissions, although we anticipate the design value improvements would be smaller. In our modeling, we do not account for SO2 reductions related to sulfur reductions in home heating oil.
[b] Projections are made only for counties with monitored design values for 1999-2001. These were the most current data at the time the analyses were performed. Counties with insufficient data or lacking monitors are excluded.
[c] Populations are based on 2020 and 2030 estimates rounded to nearest hundred. See the AQ Modeling TSD for details.

We estimate that the reduction of this final rule will produce nationwide air quality improvements in PM levels. On a population-weighted basis, the average change in future-year annual averages is projected to decrease by 0.42 $\mu g/m^3$ in 2020, and 0.59 $\mu g/m^3$ in 2030.

While the final implementation process for bringing the nation's air into attainment with the $PM_{2.5}$ NAAQS is still being completed in a separate rulemaking action, the basic framework is well defined by the statute. EPA has requested that States and Tribes submit their recommendations by February 15, 2004. EPA's current plans call for designating $PM_{2.5}$ attainement and nonattainment areas in December 2004. Following designation, Section 172(b) of the Clean Air Act allows states up to 3 years to submit a revision to their state implementation plan (SIP) that provides for the attainment of the $PM_{2.5}$ standard. Based on this provision, states could submit these SIPs in late-2007. Section 172(a)(2) of the Clean Air Act requires that these SIP revisions demonstrate that the nonattainment areas will attain the $PM_{2.5}$ standard as expeditiously as practicable but no later than 5 years from the date that the area was designated nonattainment. However, based on the severity of the air quality problem and the availability and feasibility of control measures, the Administrator may extend the attainment date "for a period of no greater than 10 years from the date of designation as nonattainment." Based on section 172(a) provisions in the Act, we expect that areas will need to attain the $PM_{2.5}$ NAAQS in the 2010 (based on 2007 - 2009 air quality data) to 2015 (based on 2012 to 2014 air quality data) time frame, and then be required to maintain the NAAQS thereafter.

Since the emission reductions from this final rule will begin in this same time frame, the projected reductions in nonroad emissions will be used by states in meeting the $PM_{2.5}$ NAAQS. States and state organizations have told EPA that they need nonroad diesel engine reductions in order to be able to meet and maintain the $PM_{2.5}$ NAAQS as well as visibility regulations, especially in light of the otherwise increasing emissions from nonroad sources without more stringent standards.[95, 96, 97] The following are sample comments from states and state associations on the proposed rule, which corroborate that this rule is a critical element in States' NAAQS attainment efforts. Fuller information can be found in the Summary and Analysis of Comments.

- "Unless emissions from nonroad diesels are sharply reduced, it is very likely that many areas of the country will be unable to attain and maintain health-based NAAQS for ozone and PM." (STAPPA/ALAPCO)
- "Adoption of the proposed regulation ... is necessary for the protection of public health in California and to comply with air quality standards." (California Air Resources Board)
- "The EPA's proposed regulation is necessary if the West is to make reasonable progress towards improving visibility in our nation's Class I areas." (Western Regional Air Partnership (WRAP))
- "Attainment of the NAAQS for ozone and $PM_{2.5}$ is of immediate concern to the states in the northeast region....Thus, programs ... such as the proposed rule for nonroad diesel engines are essential." (NESCAUM)

Furthermore, this rule ensures that nonroad diesel emissions will continue to decrease as the fleet turns over in the years beyond 2014; these reductions will be important for maintenance of the NAAQS following attainment. The future reductions are also important to achieve visibility goals, as discussed below.

2.1.3 Environmental Effects of Particulate Matter

In this section, we discuss public welfare effects of PM and its precursors including visibility impairment, acid deposition, eutrophication and nitrification, POM deposition, materials damage, and soiling.

2.1.3.1 Visibility Degradation

Visibility can be defined as the degree to which the atmosphere is transparent to visible light.[98] Visibility impairment has been considered the "best understood and most easily measured effect of air pollution."[99] Fine particles are the major cause of reduced visibility in parts of the United States. Haze obscures the clarity, color, texture, and form of what we see. Visibility is an important effect because it has direct significance to people's enjoyment of daily activities in all parts of the country. Visibility is also highly valued in significant natural areas such as national parks and wilderness areas, because of the special emphasis given to protecting these lands now and for future generations.

Scattering and absorption by both gases and particles decrease light transmittance. Size and chemical composition of particles strongly affects their ability to scatter or absorb light. The same particles (sulfates, nitrates, organic carbon, smoke, and soil dust) comprising $PM_{2.5}$, which are linked to serious health effects and environmental effects (e.g., ecosystem damage), can also significantly degrade visual air quality. (For data on chemical composition of particles in slected urban and rural areas, see Figures 2.1.2-2 and 2.1.2-3 above.) Sulfates contribute to visibility impairment especially on the haziest days, accounting in the rural Eastern United States for more than 60 percent of annual average light extinction on the best days and up to 86 percent of average light extinction on the haziest days. Nitrates and elemental carbon each typically contribute 1 to 6 percent of average light extinction on haziest days in rural locations in the Eastern United States.[100]

To quantify changes in visibility, the analysis presented in this chapter computes a light-extinction coefficient, based on the work of Sisler, which shows the total fraction of light that is decreased per unit distance.[101] This coefficient accounts for the scattering and absorption of light by both particles and gases, and accounts for the higher extinction efficiency of fine particles compared with coarse particles. Visibility can be described in terms of visual range, light extinction or deciview.[E] Visibility impairment also has a temporal dimension in that impairment might relate to a short-term excursion or to longer periods (e.g., worst 20 percent of days or annual average levels). More detailed discussions of visibility effects are contained in the EPA Criteria Document for PM.[102]

Visibility effects are manifest in two principal ways: (1) as local impairment (e.g., localized hazes and plumes) and (2) as regional haze. The emissions from engines covered by this rule contribute to both types of visibility impairment.

[E] Visual range can be defined as the maximum distance at which one can identify a black object against the horizon sky. It is typically described in miles or kilometers. Light extinction is the sum of light scattering and absorption by particles and gases in the atmosphere. It is typically expressed in terms of inverse megameters (Mm^{-1}), with larger values representing worse visibility. The deciview metric describes perceived visual changes in a linear fashion over its entire range, analogous to the decibel scale for sound. A deciview of 0 represents pristine conditions. The higher the deciview value, the worse the visibility, and an improvement in visibility is a decrease in deciview value.

Local-scale visibility degradation is commonly in the form of either a plume resulting from the emissions of a specific source or small group of sources, or it is in the form of a localized haze such as an urban "brown cloud." Plumes are comprised of smoke, dust, or colored gas that obscure the sky or horizon relatively near sources. Impairment caused by a specific source or small group of sources has been generally termed as "reasonably attributable."

The second type of impairment, regional haze, results from pollutant emissions from a multitude of sources located across a broad geographic region. It impairs visibility in every direction over a large area, in some cases over multi-state regions. Regional haze masks objects on the horizon and reduces the color and contrast of nearby objects.[103]

On an annual average basis, the concentrations of non-anthropogenic fine PM are generally small when compared with concentrations of fine particles from anthropogenic sources.[104] Anthropogenic contributions account for about one-third of the average extinction coefficient in the rural West and more than 80 percent in the rural East.[105] In the Eastern United States, reduced visibility is mainly attributable to secondarily formed particles, particularly those less than a few micrometers in diameter (e.g., sulfates). While secondarily formed particles still account for a significant amount in the West, primary emissions contribute a larger percentage of the total particulate load than in the East. Because of significant differences related to visibility conditions in the Eastern and Western United States, we present information about visibility by region. Furthermore, it is important to note that even in those areas with relatively low concentrations of anthropogenic fine particles, such as the Colorado plateau, small increases in anthropogenic fine particle concentrations can lead to significant decreases in visual range. This is one of the reasons mandatory Federal Class I areas have been given special consideration under the Clean Air Act. The 156 mandatory Federal Class I areas are displayed on the map in Figure 2-1 above.

EPA determined that emissions from nonroad engines significantly contribute to air pollution that may be reasonably anticipated to endanger public health and welfare for visibility effects in particular (67 FR 68242, November 8, 2002). The primary and PM-precursor emissions from nonroad diesel engines subject to this rule contribute to these effects. To demonstrate this, in addition to the inventory information in Chapter 3, we present information about both general visibility impairment related to ambient PM levels across the country, and we also analyze visibility conditions in mandatory Federal Class I areas. Accordingly, in this section, for both the nation and for mandatory Federal Class I areas, we discuss the types of effects, current and future visibility conditions absent the projected emission reductions, and the changes we anticipate from the projected emission reductions. We conclude that the projected emission reductions will improve visibility conditions across the country and in particular in mandatory Federal Class I areas.

2.1.3.1.1 Visibility Impairment Where People Live, Work and Recreate

Good visibility is valued by people throughout the country - in the places they live, work, and enjoy recreational activities. However, unacceptable visibility impairment occurs in many areas throughout the country. In this section, in order to estimate the magnitude of the visibility problem, we use monitored $PM_{2.5}$ data and modeled air quality accounting for projected emissions from nonroad diesel engines absent additional controls. The air quality modeling is discussed in Section 2.1.2 above and in the AQ Modeling TSD.[106] The engines covered by this rule contribute to $PM_{2.5}$ levels in areas across the country with significant visibility impairment.

The secondary PM NAAQS is designed to protect against adverse welfare effects such as visibility impairment. In 1997, the secondary PM NAAQS was set as equal to the primary (health-based) PM NAAQS (62 Federal Register No. 138, July 18, 1997). EPA concluded that PM can and does produce adverse effects on visibility in various locations, depending on PM concentrations and factors such as chemical composition and average relative humidity. In 1997, EPA demonstrated that visibility impairment is an important effect on public welfare and that visibility impairment is experienced throughout the United States, in multi-state regions, urban areas, and remote Federal Class I areas.

The updated monitored data and air quality modeling presented below confirm that the visibility situation identified during the NAAQS review in 1997 is still likely to exist. Specifically, there will still likely be a broad number of areas that are above the annual $PM_{2.5}$ NAAQS in the Northeast, Midwest, Southeast and California , such that the determination in the NAAQS rulemaking about broad visibility impairment and related benefits from NAAQS compliance are still relevant. Thus, levels above the fine PM NAAQS cause adverse welfare impacts, such as visibility impairment (both regional and localized impairment). EPA recently confirmed this in our determination about nonroad engines significant contribution to unacceptable visibility impairment (67 FR 68251, November 8, 2002).

In addition, in setting the PM NAAQS, EPA acknowledged that levels of fine particles below the NAAQS may also contribute to unacceptable visibility impairment and regional haze problems in some areas, and Clean Air Act Section 169 provides additional authorities to remedy existing impairment and prevent future impairment in the 156 national parks, forests and wilderness areas labeled as mandatory Federal Class I areas (62 FR at 38680-81, July 18, 1997).

In making determinations about the level of protection afforded by the secondary PM NAAQS, EPA considered how the Section 169 regional haze program and the secondary NAAQS would function together.[107] Regional strategies, such as this rule, are expected to improve visibility in many urban and non-Class I areas as well. Visibility impairment in mandatory Federal Class I areas is discussed in Section 2.1.4.

2.1.3.1.1.1 Current Areas Affected by Visibility Impairment: Monitored Data

The need for reductions in the levels of $PM_{2.5}$ is widespread, as discussed above and shown in Figure 2-1. Currently, high ambient $PM_{2.5}$ levels are measured throughout the country. Fine particles may remain suspended for days or weeks and travel hundreds to thousands of kilometers, and thus fine particles emitted or created in one county may contribute to ambient concentrations in a neighboring region.[108]

Without the effects of pollution, a natural visual range is approximately 120 to 180 miles

(200 to 300 kilometers) in the West and 45 to 90 miles (75 to 150 kilometers) in the East.[109] However, over the years, in many parts of the United States, fine particles have significantly reduced the range that people can see. In the West, the visibility range is 33 to 90 miles (53 to 144 kilometers), and in the East, the current range is only 14 to 24 miles (22 to 38 kilometers).[110]

Current $PM_{2.5}$ monitored values for 2000-2002 indicate that almost 65 million people in 120 counties live in areas where design values of $PM_{2.5}$ annual levels are at or above the $PM_{2.5}$ NAAQS. This represents 23 percent of the counties and 37 percent of the population in the areas with monitoring data that met completeness requirements and had levels above the NAAQS. Thus, at least these populations (plus others who travel to these areas) would likely be experiencing visibility impairment that is unacceptable. Emissions of PM and its precursors from nonroad diesel engines contribute to this unacceptable impairment.

An additional 32 million people live in 91 counties that have air quality measurements for 2000-2002 within 10 percent of the level of the PM standard. These areas, though not currently violating the standard, will also benefit from the additional reductions from this final rule to ensure long-term maintenance of the standard and to prevent deterioration in visibility conditions.

Although we present the annual average to represent national visibility conditions, visibility impairment can also occur on certain days or other shorter periods. As discussed below, the Regional Haze program targets the worst 20 percent of days in a year. The projected emission reductions from this rule are also needed to improve visibility on the worst days.

2.1.3.1.1.2 Areas Affected by Future Visibility Impairment

Because the chemical composition of PM and other atmospheric conditions affect visibility impairment, we used the REMSAD air quality model to project visibility conditions in 2020 and 2030 to estimate visibility impairment directly as changes in deciview. One of the inputs to the PM modeling described above is a projection of future emissions from nonroad diesel engines absent additional controls. Thus, we are able to demonstrate that the nonroad diesel emissions contribute to the projected visibility impairment and that there continues to be a need for reductions from those engines.

As described above, based on this modeling and absent additional controls, we predicted that in 2020, there will be 79 counties with a population of 66 million where annual $PM_{2.5}$ levels are above 15 µg/m3.[111] In 2030, this number will rise to 107 counties with a population of 85 million in the absence of additional controls. Section 2.1.2 and the AQ Modeling TSD provides additional details.

Based upon the light-extinction coefficient, we also calculated a unitless visibility index or deciview. As shown in Table 2.1.3-1, in 2030 we estimate visibility in the East to be about 20.54 deciviews (or visual range of 50 kilometers) on average, with poorer visibility in urban areas, compared with the visibility conditions without man-made pollution of 9.5 deciviews (or visual range of 150 kilometers). Likewise, we estimate visibility in the West to be about 8.83

deciviews (or visual range of 162 kilometers) in 2030, compared with the visibility conditions without anthropogenic pollution of 5.3 deciviews (or visual range of 230 kilometers). Thus, in the future, a substantial percent of the population may experience unacceptable visibility impairment in areas where they live, work and recreate.

Table 2.1.3-1
Summary of Future National (48 state) Baseline Visibility Conditions Absent Additional Controls (Deciviews)

Regions[a]	Predicted 2020 Visibility (annual average)	Predicted 2030 Visibility (annual average)	Natural Background Visibility
Eastern U.S.	20.27	20.54	9.5
Urban	21.61	21.94	
Rural	19.73	19.98	
Western U.S.	8.69	8.83	5.3
Urban	9.55	9.78	
Rural	8.5	8.61	

[a] Eastern and Western Regions are separated by 100 degrees north longitude. Background visibility conditions differ by region.

The emissions from nonroad diesel engines contribute to this visibility impairment as discussed in Chapter 3. Nonroad diesel engines emissions contribute a large portion of the total PM emissions from mobile sources and anthropogenic sources, in general. These emissions occur in and around areas with PM levels above the annual $PM_{2.5}$ NAAQS. The nonroad engines subject to this rule contribute to these effects as well as localized visibility impairment. Thus, the emissions from these sources contribute to the unacceptable current and anticipated visibility impairment.

2.1.3.1.1.3 Future Improvements in Visibility from the Projected Emission Reductions

For this rule, we also modeled a preliminary control scenario that illustrates the likely emission reductions. As public comment and additional data regarding technical feasibility and other factors became available, our judgment about the controls that are feasible has evolved. Thus, the preliminary control option differs from what we are proposing, as summarized in Section 3.6. It is important to note that these changes would not affect our estimates of the baseline conditions without additional controls described above. In our air quality modeling, we did not account for SO_2 reductions from reductions in sulfur levels in home heating oil. We anticipate that the nonroad diesel emission reductions from this final rule together with other strategies would improve the projected visibility impairment, and we conclude that there continues to be a need for reductions from those engines.

Based on our modeling, we predict that in 2020, there will be 12 counties with a population of 6 million that come into attainment with the annual $PM_{2.5}$ because of the improvements in air quality from the emission reductions resulting from this final rule. In 2030, an estimated total of 24 counties (12 additional counties) with a population of 14 million (8 million additional people) will come into attainment with the annual $PM_{2.5}$ because of the improvements in air quality from this final rule. There will also be emission reductions in counties with levels close to the air quality standards that will improve visibility conditions and help them maintain the standards. All of these areas and their populations will experience improvements in visibility as well as health effects, as described earlier.

We estimate that the emission reductions resulting from this final rule will produce nationwide air quality improvements in PM levels. On a population-weighted basis, the average change in future-year annual averages will be a decrease of 0.33 $\mu g/m^3$ in 2020, and 0.46 $\mu g/m^3$ in 2030. These reductions are discussed in more detail in Section 2.1.2 above.

We can also calculate these improvement in visibility as decreases in deciview value. As shown in Table 2.1.3-2, in 2030 we estimate visibility in the East to be about 20.54 deciviews (or visual range of 50 kilometers) on average, with poorer visibility in urban areas. Emission reductions from this final rule in 2030 will improve visibility by an estimated 0.33 deciviews. Likewise, we estimate visibility in the West to be about 8.83 deciviews (or visual range of 162 kilometers) in 2030, and we estimate that emission reductions from this final rule in 2030 will improve visibility by 0.25 deciviews. These improvements are needed in conjunction with other sulfur reduction strategies in the East and a combination of strategies in the West to make reasonable progress toward visibility goals.[112] Thus, this final rule is an important part of strategies to improve visibility in areas where they live, work and recreate.

Table 2.1.3-2
Summary of Future National Visibility Improvements
from Nonroad Diesel Emission Reductions (Annual Average Deciviews)

Regions[a]	2020		2030	
	Predicted Baseline 2020 Visibility	Predicted 2020 Control Visibility[b]	Predicted Baseline 2030 Visibility	Predicted 2030 Control Visibility[b]
Eastern U.S.	20.27	20.03	20.54	20.21
Urban	21.61	21.37	21.94	21.61
Rural	19.73	19.49	19.98	19.65
Western U.S.	8.69	8.51	8.83	8.58
Urban	9.55	9.3	9.78	9.43
Rural	8.5	8.33	8.61	8.38

[a] Eastern and Western Regions are separated by 100 degrees north longitude. Background visibility conditions differ by region.
[b] The results illustrate the type of visibility improvements for the preliminary control option, as discussed in Section 3.6. The analysis in Chapter 3 differs based on updated information; however, we believe that the net results would approximate future PM emissions, although we anticipate the annual average visibility improvements would be smaller.

2.1.3.1.2 Visibility Impairment in Mandatory Federal Class I Areas

Achieving the annual $PM_{2.5}$ NAAQS will help improve visibility across the country, but it will not be sufficient to meet the statutory goal of no manmade impairment in the mandatory Federal Class I areas (64 FR 35722, July 1, 1999 and 62 FR 38680, July 18, 1997). In setting the NAAQS, EPA discussed how the NAAQS in combination with the regional haze program, is deemed to improve visibility consistent with the goals of the Act.[113] In the East, there are and will continue to be sizable areas above 15 $\mu g/m^3$ and where light extinction is significantly above natural background. Thus, large areas of the Eastern United States have air pollution that is causing and will continue to cause unacceptable visibility problems. In the West, scenic vistas are especially important to public welfare. Although the annual $PM_{2.5}$ NAAQS is met in most areas outside of California, virtually the entire West is in close proximity to a scenic mandatory Federal Class I area protected by 169A and 169B of the Act.

The 156 Mandatory Federal Class I areas are displayed on the map in Figure 2-1 above. These areas include many of our best known and most treasured natural areas, such as the Grand Canyon, Yosemite, Yellowstone, Mount Rainier, Shenandoah, the Great Smokies, Acadia, and the Everglades. More than 280 million visitors come to enjoy the scenic vistas and unique natural features including the night sky in these and other park and wilderness areas each year.

In the 1990 Clean Air Act amendments, Congress provided additional emphasis on regional haze issues (see section 169B). In 1999 EPA finalized a rule that calls for States to establish goals and emission reduction strategies for improving visibility in all 156 mandatory Class I national parks and wilderness areas. In this rule, EPA established a "natural visibility" goal.[114] In that rule, EPA also encouraged the States to work together in developing and implementing their air quality plans. The regional haze program is focused on long-term emissions decreases from the entire regional emission inventory comprised of major and minor stationary sources, area sources and mobile sources. The regional haze program is designed to improve visibility and air quality in our most treasured natural areas so that these areas may be preserved and enjoyed by current and future generations. At the same time, control strategies designed to improve visibility in the national parks and wilderness areas will improve visibility over broad geographic areas, including other recreational sites, our cities and residences. In the PM NAAQS rulemaking, EPA also anticipated the need in addition to the NAAQS and Section 169 regional haze program to continue to address localized impairment that may relate to unique circumstances in some Western areas. For mobile sources, there may also be a need for a Federal role in reduction of those emissions, in particular, because mobile source engines are regulated primarily at the Federal level.

The regional haze program calls for states to establish goals for improving visibility in national parks and wilderness areas to improve visibility on the haziest 20 percent of days and to ensure that no degradation occurs on the clearest 20 percent of days (64 FR 35722. July 1, 1999). The rule requires states to develop long-term strategies including enforceable measures designed to meet reasonable progress goals toward natural visibility conditions. Under the regional haze program, States can take credit for improvements in air quality achieved as a result of other Clean Air Act programs, including national mobile-source programs.[F]

2.1.3.1.2.1 Current Mandatory Federal Class I Areas Affected by Visibility Impairment: Monitored Data

Detailed information about current and historical visibility conditions in mandatory Federal Class I areas is summarized in the EPA Report to Congress and the recent EPA Trends Report.[115] The conclusions draw upon the Interagency Monitoring of Protected Visual Environments (IMPROVE) network data.[116] The National Park Service report also describes the state of national park visibility conditions and discusses the need for improvement.[117]

As described in the EPA Trends Report 1999, most of the IMPROVE sites in the intermountain West and Colorado Plateau have annual average impairment of 12 deciviews or

[F] Although a recent court case, American Corn Growers Association v. EPA, 291F.3d 1(D.C .Cir 2002), vacated the Best Available Retrofit Technology (BART) provisions of the Regional Haze rule, the court denied industry's challenge to EPA's requirement that state's SIPS provide for reasonable progress towards achieving natural visibility conditions in national parks and wilderness areas and the "no degradation" requirement. Industry did not challenge requirements to improve visibility on the haziest 20 percent of days. The court recognized that mobile source emission reductions would need to be a part of a long-term emission strategy for reducing regional haze. A copy of this decision can be found in Docket A-2000-01, Document IV- A-113.

less, with the worst days ranging up to 17 deciviews (compared with 5.3 deciviews of natural background visibility).[118] Several other western IMPROVE sites in the Northwest and California experience levels on the order of 16 to 23 deciviews on the haziest 20 percent of days. Many rural locations in the East have annual average values exceeding 21 deciviews, with average visibility levels on the haziest days up to 32 deciviews.

Although there have been general trends toward improved visibility, progress is still needed on the haziest days. Specifically, as discussed in the EPA Trends Report, in the 10 Class I areas in the Eastern United States, visibility on the haziest 20 percent of days remains significantly impaired with a mean visual range of 23 kilometers for 1999, as compared with 84 kilometers for the clearest days in 1999. In the 26 Class I reported areas in the Western United States, the conditions for the haziest 20 percent of days degraded between 1997 and 1999 by 17 percent. However, visibility on the haziest 20 percent of days in the West remains relatively unchanged over the 1990s with the mean visual range for 1990 (80 kilometers) nearly the same as the 1990 level (86 kilometers).

2.1.3.1.2.2 Mandatory Federal Class I Areas Affected by Future Visibility Impairment

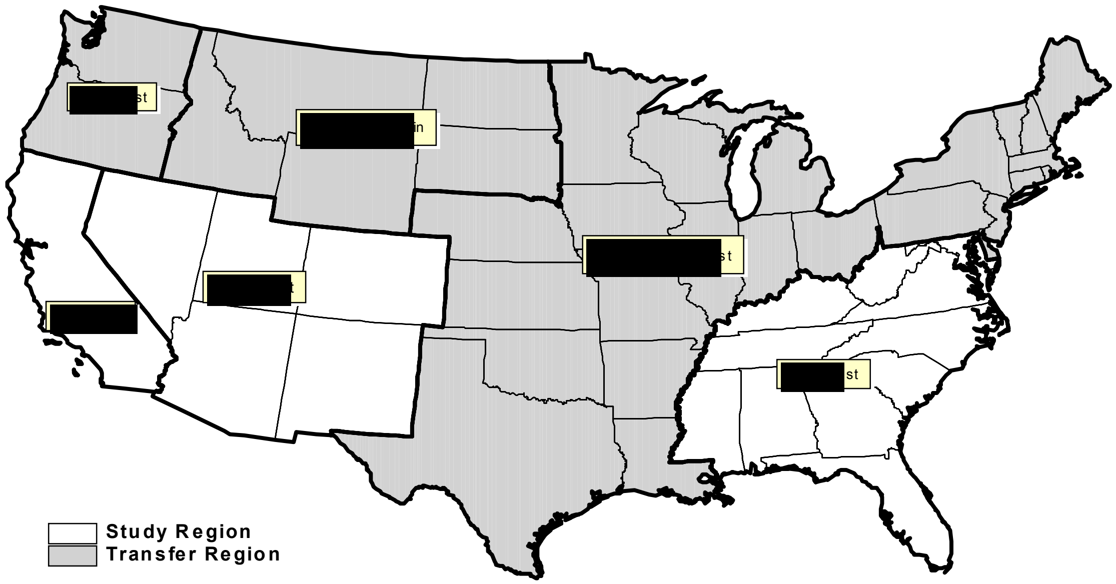
As part of the PM air quality modeling described above, we modeled future visibility conditions in the mandatory Federal Class I areas absent additional controls. The results by region are summarized in Table 2.1.3-3. In Figure 2.1.3-1, we define the regions used in this analysis.[119] These air quality results show that visibility is impaired in most mandatory Federal Class I areas and additional reductions from engines subject to this rule are needed to achieve the goals of the Clean Air Act of preserving natural conditions in mandatory Federal Class I areas.

Table 2.1.3-3
Summary of Future Baseline Visibility Conditions in Mandatory Federal Class I Areas Absent Additional Emission Reductions (Annual Average Deciview)

Class I Regions [a]	Predicted 2020 Visibility	Predicted 2030 Visibility	Natural Background Visibility
Eastern	19.72	20.01	9.5
Southeast	21.31	21.62	
Northeast/Midwest	18.30	18.56	
Western	8.80	8.96	5.3
Southwest	6.87	7.03	
California	9.33	9.56	
Rocky Mountain	8.46	8.55	
Northwest	12.05	12.18	
National Class I Area Average	11.61	11.80	

[a] Regions are depicted in Figure 1-5.1. Background visibility conditions differ by region based on differences in relative humidity and other factors: Eastern natural background is 9.5 deciviews (or visual range of 150 kilometers) and in the West natural background is 5.3 deciviews (or visual range of 230 kilometers).

Figure 2.1.3-1
Visibility Regions for the Continental United States



Note: Study regions were represented in the Chestnut and Rowe (1990a, 1990b) studies used in evaluating the benefits of visibility improvements.

2.1.3.1.2.3 Future Improvements in Mandatory Federal Class I Visibility from the Projected Emission Reductions

The overall goal of the regional haze program is to prevent future and remedy existing visibility impairment in mandatory Federal Class I areas. As shown by the future deciview estimates in Table 2.1.3-4, additional emission reductions will be needed from the broad set of sources that contribute, including the emissions from engines subject to this rule. The table also presents the results from our modeling of a preliminary control scenario that illustrates the likely reductions from the final rule. Emission reductions from nonroad diesel engines are needed to achieve the goals of the Act of preserving natural conditions in mandatory Federal Class I areas. These reductions are a part of the overall strategy to achieve the visibility goals of the Act and the regional haze program.

Table 2.1.3-4
Summary of Future Visibility Improvements[b] in Mandatory Federal Class I Areas from Nonroad Diesel Emission Reductions (Annual Average Deciviews)

Mandatory Federal Class I Regions[a]	2020		2030	
	Predicted Baseline 2020 Average Visibility	Predicted 2020 Control Average Visibility[b]	Predicted Baseline 2030 Average Visibility	Predicted 2030 Control Average Visibility[b]
Eastern	19.72	19.54	20.01	19.77
Southeast	21.31	21.13	21.62	21.38
Northeast/Midwest	18.30	18.12	18.56	18.32
Western	8.80	8.62	8.96	8.72
Southwest	6.87	6.71	7.03	6.82
California	9.33	9.12	9.56	9.26
Rocky Mountain	8.46	8.31	8.55	8.34
Northwest	12.05	11.87	12.18	11.94
National Class I Area Average	11.61	11.43	11.80	11.56

[a] Regions are presented in Figure 2.1.3-1 based on Chestnut and Rowe (1990a, 1990b) study regions.
[b] The results illustrate the type of visibility improvements for the preliminary control option, as discussed in Section 3.6. The final control scenario described in Chapter 3 differs from the modeled scenario based on public comment and updated information; however, we believe that the net results would approximate future PM emissions, although we anticipate the annual average visibility improvements would be smaller.

2.1.3.2 Other Effects

2.1.3.2.1 Acid Deposition

Acid deposition, or acid rain as it is commonly known, occurs when SO_2 and NOx react in the atmosphere with water, oxygen, and oxidants to form various acidic compounds that later fall to earth in the form of precipitation or dry deposition of acidic particles.[120] It contributes to damage of trees at high elevations and in extreme cases may cause lakes and streams to become so acidic that they cannot support aquatic life. In addition, acid deposition accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's cultural heritage. To reduce damage to automotive paint caused by acid rain and acidic dry deposition, some manufacturers use acid-resistant paints, at an average cost of $5 per vehicle—a total of near $80 million per year when applied to all new cars and trucks sold in the United States each year.

Acid deposition primarily affects bodies of water that rest atop soil with a limited ability to neutralize acidic compounds. The National Surface Water Survey (NSWS) investigated the effects of acidic deposition in over 1,000 lakes larger than 10 acres and in thousands of miles of streams. It found that acid deposition was the primary cause of acidity in 75 percent of the acidic lakes and about 50 percent of the acidic streams, and that the areas most sensitive to acid rain were the Adirondacks, the mid-Appalachian highlands, the upper Midwest and the high elevation West. The NSWS found that approximately 580 streams in the Mid-Atlantic Coastal Plain are acidic primarily due to acidic deposition. Hundreds of the lakes in the Adirondacks surveyed in the NSWS have acidity levels incompatible with the survival of sensitive fish species. Many of the over 1,350 acidic streams in the Mid-Atlantic Highlands (mid-Appalachia) region have already experienced trout losses due to increased stream acidity. Emissions from U.S. sources contribute to acidic deposition in Eastern Canada, where the Canadian government has estimated that 14,000 lakes are acidic. Acid deposition also has been implicated in contributing to degradation of high-elevation spruce forests that populate the ridges of the Appalachian Mountains from Maine to Georgia. This area includes national parks such as the Shenandoah and Great Smoky Mountain National Parks.

A study of emission trends and acidity of water bodies in the Eastern United States by the General Accounting Office (GAO) found that from 1992 to 1999 sulfates declined in 92 percent of a representative sample of lakes, and nitrate levels increased in 48 percent of the lakes sampled.[121] The decrease in sulfates is consistent with emission trends, but the increase in nitrates is inconsistent with the stable levels of nitrogen emissions and deposition. The study suggests that the vegetation and land surrounding these lakes have lost some of their previous capacity to use nitrogen, thus allowing more of the nitrogen to flow into the lakes and increase their acidity. Recovery of acidified lakes is expected to take a number of years, even where soil and vegetation have not been "nitrogen saturated," as EPA called the phenomenon in a 1995 study.[122] This situation places a premium on reductions of SOx and especially NOx from all sources, including nonroad diesel engines, in order to reduce the extent and severity of nitrogen saturation and acidification of lakes in the Adirondacks and throughout the United States.

The SOx and NOx reductions from this rule will help reduce acid rain and acid deposition, thereby helping to reduce acidity levels in lakes and streams throughout the country and help accelerate the recovery of acidified lakes and streams and the revival of ecosystems adversely affected by acid deposition. Reduced acid deposition levels will also help reduce stress on forests, thereby accelerating reforestation efforts and improving timber production. Deterioration of our historic buildings and monuments, and of buildings, vehicles, and other structures exposed to acid rain and dry acid deposition also will be reduced, and the costs borne to prevent acid-related damage may also decline. While the reduction in sulfur and nitrogen acid deposition will be roughly proportional to the reduction in SOx and NOx emissions, respectively, the precise impact of this rule will differ across different areas.

2.1.3.2.2 Eutrophication and Nitrification

Eutrophication is the accelerated production of organic matter, particularly algae, in a water body. This increased growth can cause numerous adverse ecological effects and economic impacts, including nuisance algal blooms, dieback of underwater plants due to reduced light penetration, and toxic plankton blooms. Algal and plankton blooms can also reduce the level of dissolved oxygen, which can also adversely affect fish and shellfish populations.

In 1999, the National Oceanic and Atmospheric Administration (NOAA) published the results of a five year national assessment of the severity and extent of estuarine eutrophication. An estuary is defined as the inland arm of the sea that meets the mouth of a river. The 138 estuaries characterized in the study represent more than 90 percent of total estuarine water surface area and the total number of U.S. estuaries. The study found that estuaries with moderate to high eutrophication conditions represented 65 percent of the estuarine surface area. Eutrophication is of particular concern in coastal areas with poor or stratified circulation patterns, such as the Chesapeake Bay, Long Island Sound, or the Gulf of Mexico. In such areas, the "overproduced" algae tends to sink to the bottom and decay, using all or most of the available oxygen and thereby reducing or eliminating populations of bottom-feeder fish and shellfish, distorting the normal population balance between different aquatic organisms, and in extreme cases causing dramatic fish kills.

Severe and persistent eutrophication often directly impacts human activities. For example, losses in the nation's fishery resources may be directly caused by fish kills associated with low dissolved oxygen and toxic blooms. Declines in tourism occur when low dissolved oxygen causes noxious smells and floating mats of algal blooms create unfavorable aesthetic conditions. Risks to human health increase when the toxins from algal blooms accumulate in edible fish and shellfish, and when toxins become airborne, causing respiratory problems due to inhalation. According to the NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms – an indication that eutrophication is well developed in more than half of U.S. estuaries.

In recent decades, human activities have greatly accelerated nutrient inputs, such as nitrogen and phosphorous, causing excessive growth of algae and leading to degraded water quality and associated impairments of freshwater and estuarine resources for human uses.[123] Since 1970, eutrophic conditions worsened in 48 estuaries and improved in 14. In 26 systems, there was no trend in overall eutrophication conditions since 1970.[124] On the New England coast, for example, the number of red and brown tides and shellfish problems from nuisance and toxic plankton blooms have increased over the past two decades, a development thought to be linked to increased nitrogen loadings in coastal waters. Long-term monitoring in the United States, Europe, and other developed regions of the world shows a substantial rise of nitrogen levels in surface waters, which are highly correlated with human-generated inputs of nitrogen to their watersheds.

Between 1992 and 1997, experts surveyed by National Oceanic and Atmospheric Administration (NOAA) most frequently recommended that control strategies be developed for agriculture, wastewater treatment, urban runoff, and atmospheric deposition.[125] In its Third Report to Congress on the Great Waters, EPA reported that atmospheric deposition contributes from 2 to 38 percent of the nitrogen load to certain coastal waters.[126] A review of peer reviewed literature in 1995 on the subject of air deposition suggests a typical contribution of 20 percent or higher.[127] Human-caused nitrogen loading to the Long Island Sound from the atmosphere was estimated at 14 percent by a collaboration of federal and state air and water agencies in 1997.[128] The National Exposure Research Laboratory, U.S. EPA, estimated based on prior studies that 20 to 35 percent of the nitrogen loading to the Chesapeake Bay is attributable to atmospheric deposition.[129] The mobile source portion of atmospheric NOx contribution to the Chesapeake Bay was modeled at about 30 percent of total air deposition.[130]

Deposition of nitrogen from nonroad diesel engines contributes to elevated nitrogen levels in waterbodies. The new emission standards for nonroad diesel engines will reduce total NOx emissions by 738,000 tons in 2030. The NOx reductions will reduce the airborne nitrogen deposition that contributes to eutrophication of watersheds, particularly in aquatic systems where atmospheric deposition of nitrogen represents a significant portion of total nitrogen loadings.

2.1.3.2.3 Polycyclic Organic Matter (POM) Deposition

EPA's Great Waters Program has identified 15 pollutants whose deposition to water bodies has contributed to the overall contamination loadings to the these Great Waters.[131] One of these 15 compounds, a group known as polycyclic organic matter (POM), are compounds that are mainly adhered to the particles emitted by mobile sources and later fall to earth in the form of precipitation or dry deposition of particles. The mobile source contribution of the seven most toxic POM is at least 62 tons/year and represents only those POM that are adhered to mobile source particulate emissions.[132] The majority of these emissions are produced by diesel engines.

POM is generally defined as a large class of chemicals consisting of organic compounds having multiple benzene rings and a boiling point greater than 100° C. Polycyclic aromatic hydrocarbons are a chemical class that is a subset of POM. POM are naturally occurring substances that are byproducts of the incomplete combustion of fossil fuels and plant and animal biomass (e.g., forest fires). Also, they occur as byproducts from steel and coke productions and waste incineration.

Evidence for potential human health effects associated with POM comes from studies in animals (fish, amphibians, rats) and in human cells culture assays. Reproductive, developmental, immunological, and endocrine (hormone) effects have been documented in these systems. Many of the compounds included in the class of compounds known as POM are classified by EPA as probable human carcinogens based on animal data.

The new emission standards will reduce not only the PM emissions from land-based nonroad diesel engines, but also the deposition of the POM adhering to the particles, thereby reducing health effects of POM in lakes and streams, accelerating the recovery of affected lakes and streams, and reviving adversely affected ecosystems.

2.1.3.2.4 Materials Damage and Soiling

The deposition of airborne particles can also reduce the aesthetic appeal of buildings and culturally important articles through soiling, and can contribute directly (or in conjunction with other pollutants) to structural damage by means of corrosion or erosion. Particles affect materials principally by promoting and accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Particles contribute to these effects because of their electrolytic, hygroscopic, and acidic properties, and their ability to sorb corrosive gases (principally sulfur dioxide). The rate of metal corrosion depends on a number of factors, including the deposition rate and nature of the pollutant; the influence of the metal protective corrosion film; the amount of moisture present; variability in the electrochemical reactions; the presence and concentration of other surface electrolytes; and the orientation of the metal surface.

Paints undergo natural weathering processes from exposure to environmental factors such as sunlight, moisture, fungi, and varying temperatures. In addition to the natural environmental factors, studies show particulate matter exposure may give painted surfaces a dirty appearance. Several studies also suggest that particles serve as carriers of other more corrosive pollutants, allowing the pollutants to reach the underlying surface or serve as concentration sites for other pollutants. A number of studies have shown some correlation between particulate matter and damage to automobile finishes. A number of studies also support the conclusion that gaseous pollutants contribute to the erosion rates of exterior paints.

Damage to calcareous stones (i.e., limestone, marble and carbonated cemented stone) has been attributed to deposition of acidic particles. Moisture and salts are considered the most important factors in building material damage. However, many other factors (such as normal weathering and microorganism damage) also seem to play a part in the deterioration of inorganic building materials. The relative importance of biological, chemical, and physical mechanisms has not been studied to date. Thus, the relative contribution of ambient pollutants to the damage observed in various building stone is not well quantified. Under high wind conditions, particulates result in slow erosion of the surfaces, similar to sandblasting.

Soiling is the accumulation of particles on the surface of an exposed material resulting in the degradation of its appearance. When such accumulation produces sufficient changes in reflection from opaque surfaces and reduces light transmission through transparent materials, the surface will become perceptibly dirty to the human observer. Soiling can be remedied by cleaning or washing, and depending on the soiled material, repainting.

2.2 Air Toxics

2.2.1 Diesel Exhaust PM

A number of health studies have been conducted regarding diesel exhaust including epidemiologic studies of lung cancer in groups of workers, and animal studies focusing on non-cancer effects specific to diesel exhaust. Diesel exhaust PM (including the associated organic compounds that are generally high molecular-weight hydrocarbon types, but not the more volatile gaseous hydrocarbon compounds) is generally used as a surrogate measure for diesel exhaust.

2.2.1.1 Potential Cancer Effects of Diesel Exhaust

In addition to its contribution to ambient PM inventories, diesel exhaust is of specific concern because it has been judged to pose a lung cancer hazard for humans as well as a hazard from noncancer respiratory effects such as pulmonary inflammation.

In 2001, EPA completed a rulemaking on mobile source air toxics with a determination that diesel particulate matter and diesel exhaust organic gases be identified as a Mobile Source Air Toxic (MSAT).[133] This determination was based on a draft of the Diesel HAD on which the Clean Air Scientific Advisory Committee (CASAC) of the Science Advisory Board had reached closure. Including both diesel PM and diesel exhaust organic gases in the determination was made in order to be precise about the components of diesel exhaust expected to contribute to the observed cancer and non-cancer health effects. Currently available science, while suggesting an important role for the particulate phase component of diesel exhaust, does not attribute the likely cancer and noncancer health effects independently to diesel particulate matter as distinct from the gas phase components (EPA, 2001). The purpose of the MSAT list is to provide a screening tool that identifies compounds emitted from motor vehicles or their fuels for which further evaluation of emission controls is appropriate.

EPA released its final "Health Assessment Document for Diesel Engine Exhaust" (the EPA Diesel HAD), referenced earlier. There, diesel exhaust was classified as likely to be carcinogenic to humans by inhalation at environmental exposures, in accordance with the revised draft 1996/1999 EPA cancer guidelines.[134] In accordance with earlier EPA guidelines, diesel exhaust would be similarly classified as a probable human carcinogen (Group B1).[135, 136] A number of other agencies (National Institute for Occupational Safety and Health, the International Agency for Research on Cancer, the World Health Organization, California EPA, and the U.S. Department of Health and Human Services) have made similar classifications.[137,138,139,140,141] The Health Effects Institute has also made numerous studies and report on the potential carcinogenicity of diesel exhaust.[142, 143, 144] Numerous animal and bioassay/genotoxic tests have been done on diesel exhaust.[145, 146] Also, case-control and cohort studies have been conducted on railroad engine exposures[147,148,149] in addition to studies on truck workers.[150, 151,152] Also, there are numerous other epidemiologic studies including some studying mine workers and fire fighters.[153, 154]

It should be noted that the conclusions in the EPA Diesel HAD were based on diesel engines currently in use, including nonroad diesel engines such as those found in bulldozers, graders, excavators, farm tractor drivers and heavy construction equipment. As new diesel engines with significantly less PM exhaust emissions replace existing engines, the conclusions of the EPA Diesel HAD will need to be reevaluated.

More specifically, the EPA Diesel HAD states that the conclusions of the document apply to diesel exhaust in use today including both highway and nonroad engines. The EPA Diesel HAD acknowledges that the studies were done on engines with older technologies generally for highway applications and that "there have been changes in the physical and chemical composition of some DE [diesel exhaust] emissions (highway vehicle emissions) over time, though there is no definitive information to show that the emission changes portend significant toxicological changes." The EPA Diesel HAD further concludes that "taken together, these considerations have led to a judgment that the hazards identified from older-technology-based exposures are applicable to current-day exposures." The diesel technology used for nonroad diesel engines typically lags that used for highway engines, which have been subject to PM standards since 1988. Thus, the conclusions from the EPA Diesel HAD continue to be relevant to current nonroad diesel engine emissions.

Some of the epidemiologic studies discussed in the EPA Diesel HAD were conducted specifically on nonroad diesel engine emissions. In particular, one recent study examined bulldozer operators, graders, excavators, and full-time farm tractor drivers finding increased odds of lung cancer.[155] Another cohort study of operators of heavy construction equipment also showed increased lung cancer incidence for these workers.[156]

For the EPA Diesel HAD, EPA reviewed 22 epidemiologic studies in detail, finding increased lung cancer risk in 8 out of 10 cohort studies and 10 out of 12 case-control studies. Relative risk for lung cancer associated with exposure range from 1.2 to 2.6. In addition, two meta-analyses of occupational studies of diesel exhaust and lung cancer have estimated the smoking-adjusted relative risk of 1.35 and 1.47, examining 23 and 30 studies, respectively.[157,158] That is, these two studies show an overall increase in lung cancer for the exposed groups of 35 percent and 47 percent compared with the groups not exposed to diesel exhaust. In the EPA Diesel HAD, EPA selected 1.4 as a reasonable estimate of occupational relative risk for further analysis.

EPA generally derives cancer unit risk estimates to calculate population risk more precisely from exposure to carcinogens. In the simplest terms, the cancer unit risk is the increased risk associated with average lifetime exposure of 1 $\mu g/m^3$. EPA concluded in the Diesel HAD that it is not possible currently to calculate a cancer unit risk for diesel exhaust due to a variety of factors that limit the current studies, such as a lack of standard exposure metric for diesel exhaust and the absence of quantitative exposure characterization in retrospective studies.

However, in the absence of a cancer unit risk, the EPA Diesel HAD sought to provide additional insight into the possible ranges of risk that might be present in the population. Such insights, while not confident or definitive, nevertheless contribute to an understanding of the possible public health significance of the lung cancer hazard. The possible risk range analysis was developed by comparing a typical environmental exposure level to a selected range of occupational exposure levels and then proportionally scaling the occupationally observed risks according to the exposure ratio's to obtain an estimate of the possible environmental risk. If the occupational and environmental exposures are similar, the environmental risk would approach the risk seen in the occupational studies whereas a much higher occupational exposure indicates that the environmental risk is lower than the occupational risk. A comparison of environmental and occupational exposures showed that for certain occupations the exposures are similar to environmental exposures while, for others, they differ by a factor of about 200 or more.

The first step in this process is to note that the occupational relative risk of 1.4, or a 40 percent from increased risk compared with the typical 5 percent lung cancer risk in the U.S. population, translates to an increased risk of 2 percent (or 10^{-2}) for these diesel exhaust exposed workers. The Diesel HAD derived a typical nationwide average environmental exposure level of 0.8 $\mu g./m^3$ for diesel PM from highway sources for 1996. This estimate was based on national exposure modeling; the derivation of this exposure is discussed in detail in the EPA Diesel HAD. Diesel PM is a surrogate for diesel exhaust and, as mentioned above, has been classified as a carcinogen by some agencies.

The possible environmental risk range was estimated by taking the relative risks in the occupational setting, EPA selected 1.4 and converting this to absolute risk of 2% and then ratioing this risk by differences in the occupational vs environmental exposures of interest. A number of calculations are needed to accomplish this, and these can be seen in the EPA Diesel HAD. The outcome was that environmental risks from diesel exhaust using higher estimates of occupational exposure could range from a low of 10^{-4} to 10^{-5} or be as high as 10^{-3} if lower estimates of occupational exposure were used. Note that the environmental exposure of interest (0.8 $\mu g/m^3$) remains constant in this analysis, while the occupational exposure is a variable. The range of possible environmental risk is a reflection of the range of occupational exposures that could be associated with the relative and related absolute risk levels observed in the occupational studies.

While these risk estimates are exploratory and not intended to provide a definitive characterization of cancer risk, they are useful in gauging the possible range of risk based on reasonable judgment. It is important to note that the possible risks could also be higher or lower and a zero risk cannot be ruled out. Some individuals in the population may have a high tolerance to exposure from diesel exhaust and low cancer susceptibility. Also, one cannot rule out the possibility of a threshold of exposure below which there is no cancer risk, although evidence has not been seen or substantiated on this point.

Also, as discussed in the Diesel HAD, there is a relatively small difference between some occupational settings where increased lung cancer risk is reported and ambient environmental exposures. The potential for small exposure differences underscores the concerns about the potential public hazard, since small differences suggest that environmental risk levels may be close to those observed in the occupational setting.

EPA also assessed air toxic emissions and their associated risk (the National-Scale Air Toxics Assessment or NATA for 1996), and we concluded that diesel exhaust ranks with other substances that the national-scale assessment suggests pose the greatest relative risk.[159] This national assessment estimates average population inhalation exposures to diesel PM in 1996 for nonroad as well as highway sources. These are the sum of ambient levels in various locations weighted by the amount of time people spend in each of the locations. This analysis shows a somewhat higher diesel exposure level than the 0.8 $\mu g/m^3$ used to develop the risk perspective in the Diesel HAD. The average nationwide NATA mobile exposure levels are 1.44 $\mu g/m^3$ total with highway source contribution of 0.46 $\mu g/m^3$ and a nonroad source contribution of 0.98 $\mu g/m^3$. The average urban exposure was 1.64 $\mu g/m^3$ and the average rural exposure was 0.55 $\mu g/m^3$. In five percent of urban census tracts across the United States, average exposures were above 4.33 $\mu g/m^3$. The EPA Diesel HAD states that use of the NATA exposure estimates instead of the 0.8 $\mu g/m^3$ estimate results in a similar risk perspective.[G]

In summary, even though EPA does not have a specific carcinogenic potency with which to accurately estimate the carcinogenic impact of diesel exhaust, the likely hazard to humans together with the potential for significant environmental risks leads us to conclude that diesel exhaust emissions need to be reduced from nonroad engines in order to protect public health. The following factors lead to our determination.

1. EPA has officially designated diesel exhaust as a likely human carcinogen due to inhalation at environmental exposure. Other organizations have made similar determinations.
2. The entire U.S. population is exposed to various levels of diesel exhaust. The higher exposures at environmental levels is comparable to some occupational exposure levels, so that environmental risk could be the same as, or approach, the risk magnitudes observed in the occupational epidemiologic studies.
3. The possible range of risk for the general U.S. population due to exposure to diesel exhaust is 10^{-3} to 10^{-5} although the risk could be lower and a zero risk cannot be ruled out.

Thus, the concern for a carcinogenicity hazard resulting from diesel exhaust exposures is longstanding based on studies done over many years. This hazard may be widespread due to the

[G]It should be note that, as with any modeling assessment, there are a number of significant limitations and uncertainties in NATA. These uncertainties and limitations include use of default values to model local conditions, limitations in emissions data, uncertainties in locating emissions spatially and temporally, and accounting for atmospheric processes. NATA limitations and uncertainties are discussed at the following website: http://www.epa.gov/ttn/atw/nata/natsalim2.html ubiquitous nature of exposure to diesel exhaust.

2.2.1.2 Other Health Effects of Diesel Exhaust

The acute and chronic exposure-related effects of diesel exhaust emissions are also of concern to the Agency. The Diesel HAD established an inhalation Reference Concentration (RfC) specifically based on animal studies of diesel exhaust. An RfC is defined by EPA as "an estimate of a continuous inhalation exposure to the human population, including sensitive subgroups, with uncertainty spanning perhaps an order of magnitude, that is likely to be without appreciable risks of deleterious noncancer effects during a lifetime." EPA derived the RfC from consideration of four well-conducted chronic rat inhalation studies showing adverse pulmonary effects.[160, 161, 162, 163] The diesel RfC is based on a "no observable adverse effect" level of 144 $\mu g/m^3$ that is further reduced by applying uncertainty factors of 3 for interspecies extrapolation and 10 for human variations in sensitivity. The resulting RfC derived in the Diesel HAD is 5 $\mu g/m^3$ for diesel exhaust as measured by diesel PM. This RfC does not consider allergenic effects such as those associated with asthma or immunologic effects. There is growing evidence that diesel exhaust can exacerbate these effects, but the exposure-response data are presently lacking to derive an RfC.

While there have been relatively few human controlled exposure studies associated specifically with the noncancer impact of diesel PM alone, diesel PM is frequently part of the ambient particles studied in numerous epidemiologic studies. Conclusions that health effects associated with ambient PM in general are relevant to diesel PM are supported by studies that specifically associate observable human noncancer health effects with exposure to diesel PM. As described in the Diesel HAD, these studies include some of the same health effects reported for ambient PM, such as respiratory symptoms (cough, labored breathing, chest tightness, wheezing), and chronic respiratory disease (cough, phlegm, chronic bronchitis and suggestive evidence for decreases in pulmonary function). Symptoms of immunological effects such as wheezing and increased allergenicity are also seen. Studies in rodents, especially rats, show the potential for human inflammatory effects in the lung and consequential lung tissue damage from chronic diesel exhaust inhalation exposure. The Diesel HAD notes that acute or short-term exposure to diesel exhaust can cause acute irritation (e.g., eye, throat, bronchial), neurophysiological symptoms (e.g., lightheadedness, nausea), and respiratory symptoms (cough, phlegm). There is also evidence for an immunologic effect such as the exacerbation of allergenic responses to known allergens and asthma-like symptoms.[164,165,166,167] The Diesel HAD lists numerous other studies as well. Also, as discussed in more detail previously, in addition to its contribution to ambient PM inventories, diesel PM is of special concern because it has been associated with an increased risk of lung cancer.

The Diesel HAD also briefly summarizes health effects associated with ambient PM and the EPA's annual NAAQS of 15 $\mu g/m^3$. There is a much more extensive body of human data showing a wide spectrum of adverse health effects associated with exposure to ambient PM, of which diesel exhaust is an important component. The RfC is not meant to say that 5 $\mu g/m^3$ provides adequate public health protection for ambient $PM_{2.5}$. In fact, there may be benefits to reducing diesel PM below 5 μg/m^3 since diesel PM is a major contributor to ambient $PM_{2.5}$.[H]

Also, as mentioned earlier in the health effects discussion for $PM_{2.5}$, there are a number of other health effects associated with PM in general—and motor vehicle exhaust, including that from diesel engines in particular—that provide additional evidence for the need for significant emission reductions from nonroad diesel sources.

As indicated earlier, a number of recent studies have associated living near roadways with adverse health effects. Two of the studies cited earlier will be mentioned again here as examples of the type of work that has been done. A Dutch study (discussed earlier by G. Hoek et al., 2002) of a population of people 55-69 years old found that there was an elevated risk of heart and lung related mortality among populations living near high traffic roads. A review discussed earlier of studies (by R. Delfino et al., 2002) of the respiratory health of people living near roadways included a publication indicating that the risk of asthma and related respiratory disease appeared elevated in people living near heavy traffic.[168] These studies offer evidence that people exposed most directly to emissions from mobile sources, including those from diesel engines, face an elevated risk of illness or death.

All of these health effects plus the designation of diesel exhaust as a likely human carcinogen provide ample health justification for control.

Public comments from the Building and Construction Trades Department, AFL-CIO, and International Union of Operating Engineers supported the need to adopt the nonroad rule noting that exposure to diesel emissions from nonroad diesel engine poses a great risk to workers in the construction industry and other occupations, but are highest among construction workers because they work in close proximity to the exposure source, and are exposed daily to the hazards of nonroad diesel pollution. In their comments, BCTD noted that construction workers may be exposed to hazards generated from work performed by other trades employed by other contractors because sources of diesel exposure are scattered throughout the site. They noted further that in an exposure study, railway workers, heavy equipment operators and miners had

[H]It should again be noted that recent epidemiologic studies of ambient $PM_{2.5}$ do not indicate a threshold of effects at low concentrations. For example, the authors of the Pope reanalysis note that, for the range of exposures considered in their reanalysis, the slope of the concentration-response function appears to be monotonic and nearly linear, although they cannot exclude the potential for a leveling off or steepening at higher exposure levels. The EPA Science Advisory Board's Advisory Council for Clean Air Compliance, which provides advice and review of EPA's methods for assessing the benefits and costs of the Clean Air Act under Section 812 of the Act, has advised that there is currently no scientific basis for assuming any specific threshold for the PM-related health effects considered in typical benefits analyses (EPA-SAB-Council-ADV-99-012, 1999). Also, the National Research Council, in its own review of EPA's approach to benefits analyses, has agreed with this advice. This advice is supported by the recent literature on health effects of PM exposure (Daniels et al., 2000; Pope, 2000; Pope et al., 2002, Rossi et al., 1999; Schwartz, 2000, Schwartz, Laden, and Zanobetti 2002 [Schwarz, J.; Laden, F.; and Zanobetti, A. (2002) The Concentration-Response Relation between PM2.5 and Daily Deaths. Environ Health Perspect 110(10): 1025-1029]) which generally finds no evidence of a non-linear concentration-response relationship and, in particular, no evidence of a distinct threshold for health effects. The most recent draft of the EPA Air Quality Criteria for Particulate Matter (U.S. EPA, 2002) reports only one study, analyzing data from Phoenix, AZ, that reported even limited evidence suggestive of a possible threshold for $PM_{2.5}$ (Smith et al., 2000).

higher mortality rates from lung cancer and all causes than workers without diesel exposure. Heavy equipment operators and miners had comparable relative risk for lung cancer, both of which were over 2.5 times that of non-exposed workers (Boffetta, 1988).

2.2.1.3 Diesel Exhaust PM Ambient Levels

Because diesel PM is part of overall ambient PM and cannot be easily distinguished from overall PM, we do not have direct measurements of diesel PM in the ambient air. Diesel PM concentrations are estimated instead using one of three approaches: 1) ambient air quality modeling based on diesel PM emission inventories; 2) using elemental carbon concentrations in monitored data as surrogates; or 3) using the chemical mass balance (CMB) model in conjunction with ambient PM measurements. (Also, in addition to CMB, UNMIX/PMF have also been used). Estimates using these three approaches are described below. In addition, estimates developed using the first two approaches above are subjected to a statistical comparison to evaluate overall reasonableness of estimated concentrations from ambient air quality modeling. It is important to note that, while there are inconsistencies in some of these studies on the relative importance of gasoline and diesel PM, the studies discussed in the Diesel HAD all show that diesel PM is a significant contributor to overall ambient PM. Some of the studies differentiate nonroad from highway diesel PM.

2.2.1.3.1 Toxics Modeling and Methods

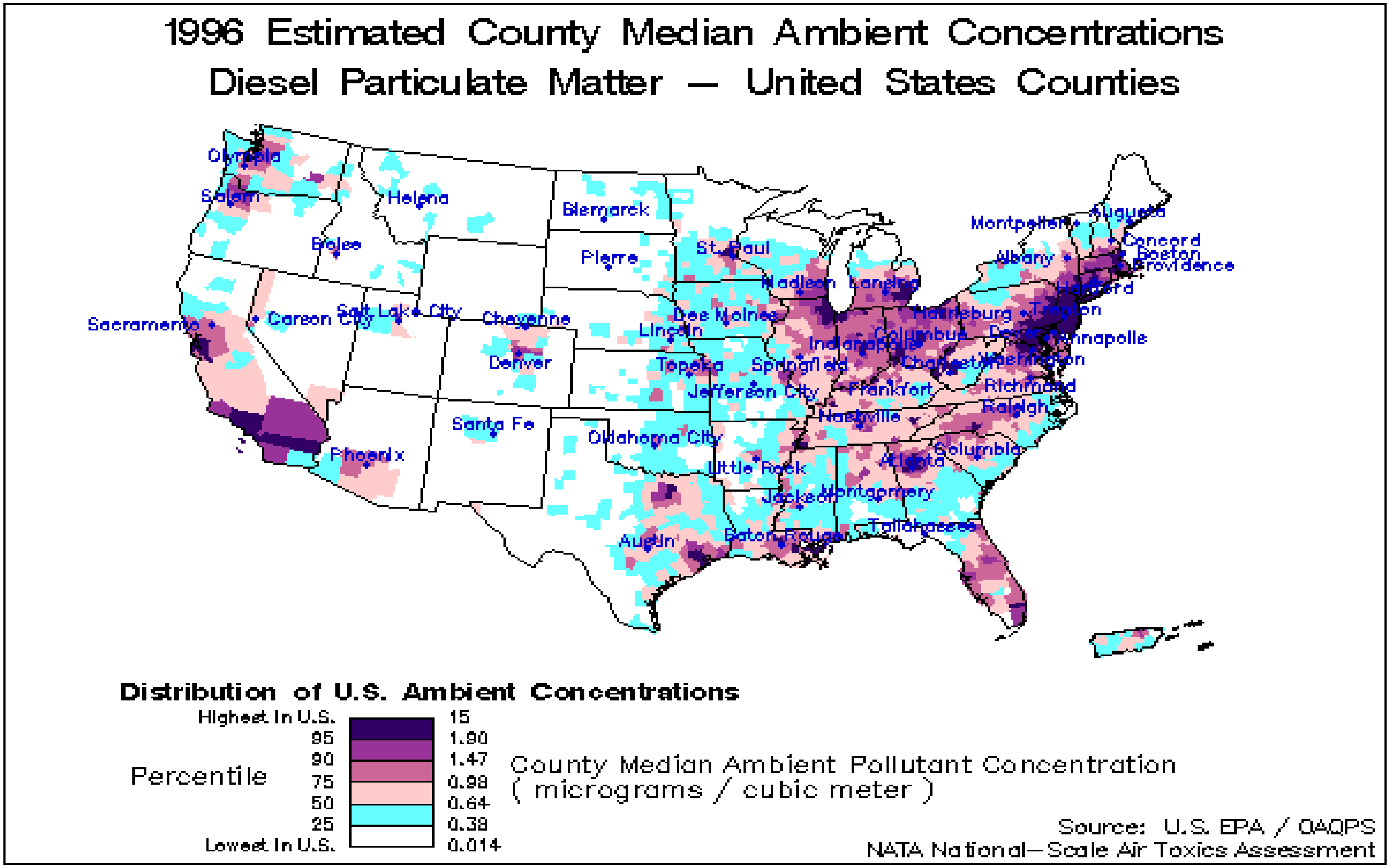
In addition to the general ambient PM modeling conducted for this rulemaking, diesel PM concentrations for 1996 were estimated as part of the National-Scale Air Toxics Assessment (NATA; EPA, 2002). In this assessment, the PM inventory developed for the recent regulation promulgating 2007 heavy duty vehicle standards was used (EPA, 2000). Note that the nonroad inventory used in this modeling was based on an older version of the draft NONROAD Model that showed higher diesel PM than the current version, so the ambient concentrations may be biased high. Ambient impacts of mobile source emissions were predicted using the Assessment System for Population Exposure Nationwide (ASPEN) dispersion model.

From the NATA 1996 modeling, overall mean annual national ambient diesel PM levels of 2.06 $\mu g/m^3$ were calculated with a mean of 2.41 in urban counties and 0.74 in rural counties. Table 2.2.1-1 below summarizes the distribution of average ambient concentrations to diesel PM at the national scale. Over half of the diesel PM can be attributed to nonroad diesel engines. A map of county median concentrations (median of census tract concentrations) from highway and nonroad sources is provided in Figure 2.2.1-1. We have not generated a map depicting the estimated geographic distribution of nonroad diesel PM alone. While the high median concentrations are clustered in the Northeast, Great Lake States and California, areas of high median concentrations are distributed throughout the United States.

Table 2.2.1-1
Distribution of Average Ambient Concentrations of
Diesel PM at the National Scale in the 1996 NATA Assessment.

	Nationwide ($\mu g/m^3$)	Urban ($\mu g/m^3$)	Rural ($\mu g/m^3$)
5th Percentile	0.33	0.51	0.15
25th Percentile	0.85	1.17	0.42
Average	2.06	2.41	0.74
75th Percentile	2.45	2.7	0.97
95th Percentile	5.37	6.06	1.56
Onroad Contribution to Average	0.63	0.72	0.27
Nonroad Contribution to Average	1.43	1.69	0.47

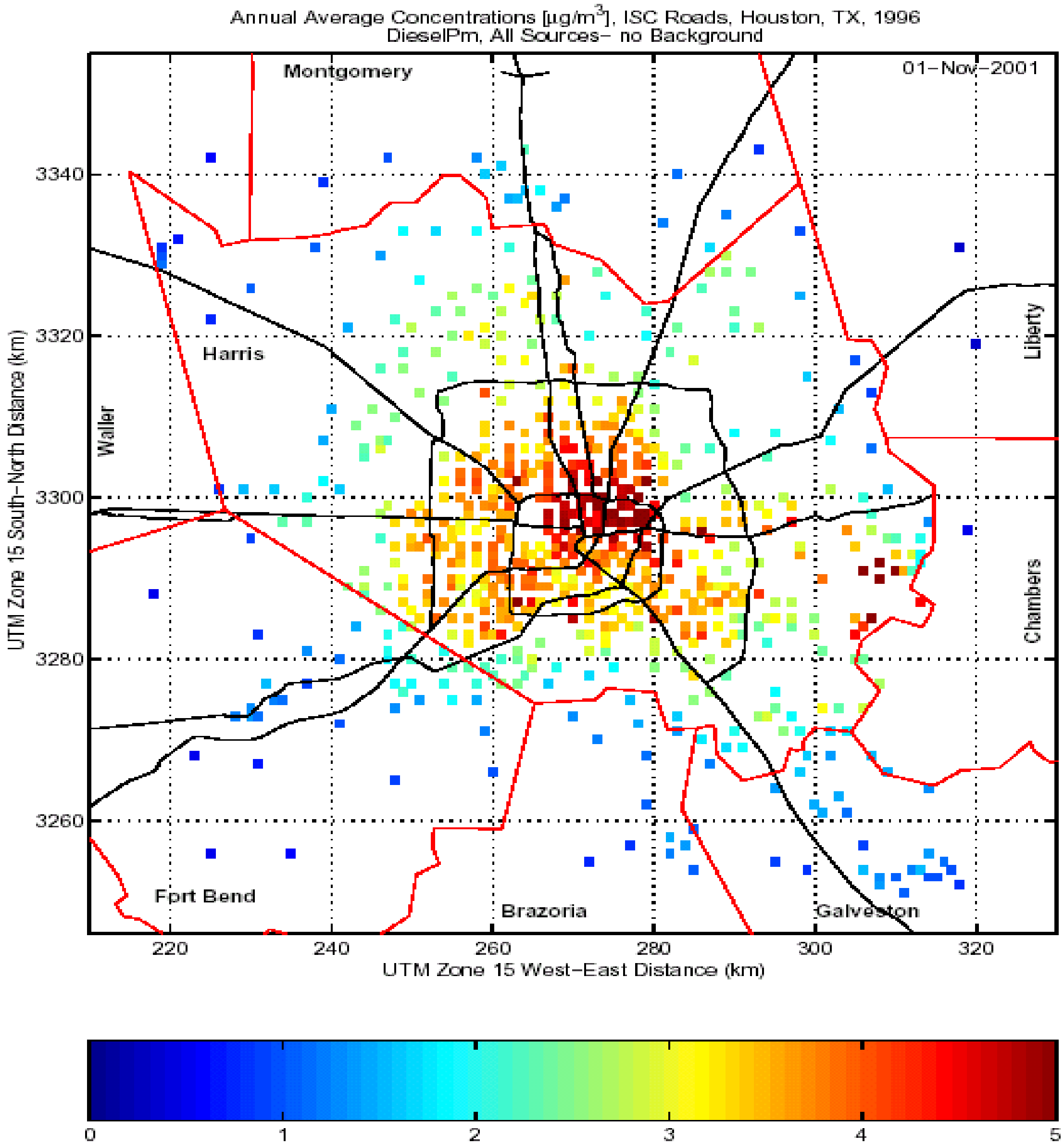
Figure 2.2.1-1
Estimated County Median Concentrations of Diesel Particulate Matter



Source: EPA National-Scale Air Toxics Assessment for 1996. Results should not be used to draw conclusions about local concentrations. Results are most meaningful at the Regional or National level.

Diesel PM concentrations were also recently modeled across a representative urban area, Houston, Texas, for 1996, using the Industrial Source Complex Short Term (ISCST3) model.[169] The methodology used to model diesel PM concentrations is the same as the methodology used for benzene and other hazardous air pollutants, as described in a recent EPA technical report.[170] For Harris County, which has the highest traffic density in Houston area, link-based diesel PM emissions were estimated for highway mobile sources, using diesel PM emission rates developed for the recent EPA 2007 heavy duty engine and highway diesel fuel sulfur control rule.[171] This link-based modeling approach is designed to specifically account for local traffic patterns within the urban center, including diesel truck traffic along specific roadways. For other counties in the Houston metropolitan area, county level emission estimates from highway vehicles were allocated to one kilometer grid cells based on total roadway miles. Nonroad diesel emissions for Houston area counties were obtained from the inventory done for the 2007 heavy duty rule, and allocated to one kilometer grid cells using activity surrogates. The modeling in Houston suggests strong spatial gradients (on the order of a factor of 2-3 across a modeling domain) for diesel PM and indicates that "hotspot" concentrations can be very high. Values as high as 8 $\mu g/m^3$ at were estimated at a receptor versus a 3 $\mu g/m^3$ average in Houston. Such "hot spot" concentrations suggest both a high localized exposure plus higher estimated average annual exposure levels for urban centers than what has been estimated in assessments such as NATA 1996, which are designed to focus on regional and national scale averages. Figure 2.2.1-2 depicts the spatial distribution of diesel PM concentrations in Houston.

Figure 2.2.1-2
Annual Average Ambient Concentrations of Diesel PM in Houston, 1996, based on Dispersion Modeling Using Industrial Source Complex Short Term (ISCST3) model.



2.2.1.3.2 Elemental Carbon Measurements

As shown in Figures 2.1.1-1 to 3, the carbonaceous component is significant in ambient PM. The carbonaceous component consists of organic carbon and elemental carbon. Monitoring data on elemental carbon concentrations can be used as a surrogate to determine ambient diesel PM concentrations. Elemental carbon is a major component of diesel exhaust, contributing to approximately 60-80 percent of diesel particulate mass, depending on engine technology, fuel type, duty cycle, lube oil consumption, and state of engine maintenance. In most areas, diesel engine emissions are major contributors to elemental carbon, with other potential sources including gasoline exhaust, combustion of coal, oil, or wood, charbroiling, cigarette smoke, and road dust. Because of the large portion of elemental carbon in diesel particulate matter, and the fact that diesel exhaust is one of the major contributors to elemental carbon in most areas, ambient diesel PM concentrations can be bounded using elemental carbon measurements.

The measured mass of elemental carbon at a given site varies depending on the measurement technique used. Moreover, to estimate diesel PM concentration based on elemental carbon level, one must first estimate the percentage of PM attributable to diesel engines and the percentage of elemental carbon in diesel PM. Thus, there are significant uncertainties in estimating diesel PM concentrations using an elemental carbon surrogate. Also, there are issues with the measurement methods used for elemental carbon. Many studies used thermal optimal transmission (TOT), the NIOSH method developed at Sunset laboratories. Other studies used thermal optical reflectance (TOR), a method developed by Desert Research Institute. EPA has developed multiplicative conversion factors to estimate diesel PM concentrations based on elemental carbon levels.[172] Results from several source apportionment studies were used to develop these factors.[173, 174, 175, 176, 177, 178, 179] Average conversion factors were compiled together with lower and upper bound values. Conversion factors (CFs) were calculated by dividing the diesel $PM_{2.5}$ concentration reported in these studies by the total organic carbon or elemental carbon concentrations also reported in the studies. Table 2.2.1-2 presents the minimum, maximum, and average EC conversion factors as a function of:

- Measurement technique
- Eastern or Western United States
- Season
- Urban or rural

The reported minimum, maximum, and average values in Table 2.2.1-2 are the minima, maxima, and arithmetic means of the EC conversion factors across all sites (and seasons, where applicable) in the given site subset. For the TOT data collected in the East, the minimum, maximum, and average conversion factors are all equal. This is because these values were based only on one study where the data were averaged over sites, by season.[180] Depending on the measurement technique used, and assumptions made in converting elemental carbon concentration to diesel PM concentration, average nationwide concentrations for current years of diesel PM estimated from elemental carbon data range from about 1.2 to 2.2 μg/m^3. EPA has compared these estimates based on elemental carbon measurements with modeled concentrations in the NATA for 1996. Results of comparisons of mean percentage differences are presented in Table 2.2.1-3. These results show that the two sets of data agree reasonably well, with estimates for the majority of sites within a factor of 2, regardless of the measurement technique or methodology for converting elemental carbon to diesel PM concentration. Agreement was better when modeled concentrations were adjusted to reflect recent changes in the nonroad inventory. The best model performance based on the fraction of modeled values within 100 % of the monitored value is for the DPM-maximum value, which reflects changes to the nonroad inventory model. The corresponding fractions of modeled values within 100 % of the monitored value are 73 % for TOR sites, 80 % for TOT sites, and 92 % for TORX sites. All in all, this performance compares favorably with the model to monitor results for other pollutants assessed in NATA, with the exception of benzene, for which the performance of the NATA modeling was better.

2.2.1.3.3 Chemical Mass Balance Receptor Modeling and Source Apportionment

The third approach for estimating ambient diesel PM concentrations uses the chemical mass balance (CMB) model for source apportionment in conjunction with ambient PM measurements and chemical source "fingerprints" to estimate ambient diesel PM concentrations. The CMB model uses a statistical fitting technique to determine how much mass from each source would be required to reproduce the chemical fingerprint of each speciated ambient monitor. Inputs to the CMB model applied to ambient $PM_{2.5}$ include measurements made at an air monitoring site and measurements made of each of the source types suspected to affect the site. The CMB model uses a statistical fitting technique ("effective variance weighted least squares") to determine how much mass from each source would be required to reproduce the chemical fingerprint of each speciated ambient monitor. This calculation is based on optimizing the sum of sources, so that the difference between the ambient monitor and the sum of sources is minimized. The optimization technique employs "fitting species" that are related to the sources. The model assumes that source profiles are constant over time, that the sources do not interact or react in the atmosphere, that uncertainties in the source fingerprints are well-represented, and that all sources are represented in the model.

This source apportionment technique presently does not distinguish between highway and nonroad but, instead, gives diesel PM as a whole. One can allocate the diesel PM numbers based on the inventory split between highway and nonroad diesel, although this allocation was not done in the studies published to date. This source apportionment technique can though distinguish between diesel and gasoline PM. Caution in interpreting CMB results is warranted, as the use of fitting species that are not specific to the sources modeled can lead to misestimation of source contributions. Ambient concentrations using this approach are generally about 1 $\mu g/m^3$ annual average. UNMIX/PMF models show similar results.

Table 2.2.1-2
Summary of Calculated Elemental Carbon (EC) Conversion Factors
(Conversion factors to convert total EC to diesel $PM_{2.5}$ concentration)

Ambient Measurement Technique: TOT or TOR	East or West	Season	Location Type General	MIN[a]	MAX[a]	AVERAGE[a]	Recommended Conversion Factors	
							EAST	WEST
TOT	East	Fall (Q4)	Mixed	2.3	2.3	2.3	X	
	East	Spring (Q2)	Mixed	2.4	2.4	2.4	X	
	East	Summer (Q3)	Mixed	2.1	2.1	2.1	X	
	East	Winter (Q1)	Mixed	2.2	2.2	2.2	X	
	West	Unknown	Urban	1.2	2.4	1.6		X
TOT Total				1.2	2.4	2.0		
TOR		Winter	Rural	0.6	1.0	0.8	X	X
		Winter	Urban	0.5	1.0	0.7	X	X
	Winter Total			0.5	1.0	0.8		
TOR Total				0.5	1.0	0.8		
Grand Total				0.5	2.4	1.3		

Source: ICF Consulting for EPA, 2002, Office of Transportation and Air Quality. Report No. EPA420-D-02-004.
[a] Minimum, maximum, or average value across all sites of the estimated conversion factors.

TOT = thermal optimal transmission, the NIOSH method developed at Sunset laboratories.
TOR = thermal optical reflectance, a method developed by Desert Research Institute.

Table 2.2.1-3
Summary of Differences Between the Nearest Modeled Concentration
of Diesel Pm from the National Scale Air Toxics Assessment and Monitored Values
Based on Elemental Carbon Measurements (Diesel PM model-to-measurement comparison)

Modeled Variable[a]	Monitored Variable[b]	N	Mean Modeled Value	Mean Monitored Value	Mean Difference	Mean % Difference	Fraction of Modeled Values Within			
							10%	25%	50%	100%
concnear	TOR	15	1.56	0.94	0.63	100	0.07	0.13	0.53	0.53
concnear2	TOR	15	1.20	0.94	0.26	56	0.07	0.13	0.47	0.60
concnear	TORH	15	1.56	1.16	0.40	62	0.00	0.07	0.40	0.60
concnear2	TORH	15	1.20	1.16	0.04	26	0.00	0.07	0.33	0.73
concnear	TORL	15	1.56	0.64	0.92	190	0.13	0.40	0.47	0.53
concnear2	TORL	15	1.20	0.64	0.55	126	0.07	0.33	0.47	0.53
concnear	TOT	95	2.61	1.73	0.88	80	0.12	0.21	0.45	0.68
concnear2	TOT	95	2.05	1.73	0.32	42	0.11	0.37	0.53	0.77
concnear	TOTH	95	2.61	2.10	0.52	61	0.11	0.22	0.46	0.74
concnear2	TOTH	95	2.05	2.10	-0.05	27	0.11	0.35	0.53	0.80
concnear	TOTL	95	2.61	1.52	1.09	101	0.09	0.17	0.43	0.63
concnear2	TOTL	95	2.05	1.52	0.52	58	0.09	0.32	0.52	0.72
concnear	TORX	88	2.31	1.70	0.61	47	0.10	0.30	0.59	0.78
concnear2	TORX	88	1.81	1.70	0.11	15	0.17	0.30	0.59	0.85
concnear	TORXH	88	2.31	2.23	0.08	13	0.11	0.26	0.60	0.84
concnear2	TORXH	88	1.81	2.23	-0.42	-12	0.08	0.22	0.52	0.92
concnear	TORXL	88	2.31	1.19	1.12	110	0.10	0.26	0.41	0.65
concnear2	TORXL	88	1.81	1.19	0.62	65	0.14	0.31	0.52	0.74

Source: ICF Consulting for EPA, 2002, Office of Transportation and Air Quality. Report No. EPA420-D-02-004.

[a] Modeled variable:
- concnear Nearest modeled DPM concentration from the 1996 NATA
- concnear2 Nearest modeled DPM concentration with NATA concentrations adjusted to be consistent with changes to the nonroad inventory model

[b] Monitored variable:
- TOR EC value multiplied by TOR average correction factor
- TORH EC value multiplied by TOR maximum correction factor
- TORL EC value multiplied by TOR minimum correction factor
- TOT EC value multiplied by TOT average correction factor
- TOTH EC value multiplied by TOT maximum correction factor
- TOTL EC value multiplied by TOR minimum correction factor
- TORX TOR values plus the TOR equivalent values multiplied by TOR average correction factor
- TORXH TOR values plus the TOR equivalent values multiplied by TOR maximum correction factor
- TORXL TOR values plus the TOR equivalent values multiplied by TOR minimum correction factor

Because of the correlation of diesel and gasoline exhaust PM emissions in time and space, chemical molecular species that provide markers for separation of these sources have been sought. Recent advances in chemical analytical techniques have facilitated the development of sophisticated molecular source profiles, including detailed speciation of organic compounds, which allow the apportionment of particulate matter to gasoline and diesel sources with increased certainty. As mentioned previously, however, caution in interpreting CMB results is warranted. Markers that have been used in CMB receptor modeling have included elemental carbon, polycyclic aromatic hydrocarbons (PAHs), organic acids, hopanes, and steranes.

It should be noted that since receptor modeling is based on the application of source profiles to ambient measurements, this estimate of diesel PM concentrations includes the contribution from on-highway and nonroad sources of diesel PM, although no study to date has included source profiles from nonroad engines. Engine operations, fuel properties, regulations, and other factors may distinguish nonroad diesel engines from their highway counterparts.

In addition, this model accounts for primary emissions of diesel PM only; the contribution of secondary aerosols is not included. The role of secondarily formed organic PM in urban $PM_{2.5}$ concentrations is not known, particularly from diesel engines.

The first major application of organic tracer species in applying the CMB model evaluated ambient $PM_{2.0}$ in Los Angeles, CA sampled in 1982.[181] This study was the first to distinguish gasoline and diesel exhaust. CMB model application at four sites in the Los Angeles area estimated ambient diesel $PM_{2.0}$ concentrations to be 1.02-2.72 $\mu g/m^3$. Note that diesel PM estimates are derived from source profiles measured on in-use diesel trucks.

Another major study examining diesel exhaust separately from gasoline exhaust and other sources is the Northern Front Range Air Quality Study (NFRAQS).[182] This study was conducted in the metropolitan Denver, CO area during 1996-1997. The NFRAQS study employed a different set of chemical species, including PAHs and other organics to produce source profiles for a diverse range of mobile sources, including “normal emitting” gasoline vehicles, cold start gasoline vehicles, high emitting gasoline vehicles, and diesel vehicles. Average source contributions from diesel engines in NFRAQS were estimated to be 1.7 $\mu g/m^3$ in an urban area, and 1.2 $\mu g/m^3$ in a rural area. Source profiles in this study were based on highway vehicles.

The CMB model was applied in California’s San Joaquin Valley during winter 1995-1996.[183] The study employed similar source tracers as the earlier study of Los Angeles PM2.0, in addition to other more specific markers. Diesel PM source contribution estimates in Bakersfield, CA were 3.92 and 5.32 during different measurement periods. Corresponding estimates in Fresno, CA were 9.68 and 5.15 $\mu g/m^3$. In the Kern Wildlife Refuge, diesel PM source contribution estimates were 1.32 and 1.75 $\mu g/m^3$ during the two periods.

The CMB model was applied in the Southeastern United States on data collected during the Southeastern Aerosol Research and Characterization (SEARCH) study (Zheng et al., 2002). Modeling was conducted on data collected during April, July, and October 1999 and January 2000. Examining ambient monitors in urban, suburban, and rural areas, the modeled annual average contribution of primary diesel emissions to ambient $PM_{2.5}$ was 3.20-7.30 $\mu g/m^3$ in N. Birmingham, AL, 1.02-2.43 $\mu g/m^3$ in Gulfport, MS, 3.29-5.56 $\mu g/m^3$ in Atlanta, GA, and 1.91-3.07 $\mu g/m^3$ in Pensacola, FL, which together represented the urban sites in the study. Suburban sites in the study were located outside Pensacola, FL (1.08-1.73 $\mu g/m^3$). Rural sites were located in Centreville, AL (0.79-1.67 $\mu g/m^3$), Oak Grove, MS (1.05-1.59 $\mu g/m^3$), and Yorkville, GA (1.07-2.02 $\mu g/m^3$).

The CMB model was applied to ambient $PM_{2.5}$ data collected during a severe photochemical smog event during 1993 in Los Angeles using organic tracers.[184] Modeled concentrations of diesel contributions to $PM_{2.5}$ during this episode were conducted for Long Beach (8.33 μg/m^3), downtown Los Angeles (17.9 μg/m^3), Azusa (14.9 μg/m^3), and Claremont, CA (7.63 μg/m^3).

While these studies provide an indication that diesel exhaust is a substantial contributor to ambient $PM_{2.5}$ mass, they should still be viewed with caution. CMB modeling depends on ensuring the use of highly specific tracer species. If sources, such as nonroad diesel engines, are chemically different from other sources, including highway diesel trucks, the CMB model can misestimate source contributions. Nevertheless, these studies provide information that is complementary to source-oriented air quality modeling (discussed above). From these studies, it is apparent that diesel exhaust is a substantial contributor to ambient $PM_{2.5}$, even in remote and rural areas.

2.2.1.4 Diesel Exhaust PM Exposures

Exposure of people to diesel exhaust depends on their various activities, the time spent in those activities, the locations where these activities occur, and the levels of diesel exhaust pollutants (such as PM) in those locations. While ambient levels are specific for a particular location, exposure levels account for such factors as a person moving from location to location, proximity to the emission source, and whether the exposure occurs in an enclosed environment.

2.2.1.4.1 Occupational Exposures

Diesel particulate exposures have been measured for a number of occupational groups over various years but generally for more recent years (1980s and later) rather than earlier years. Occupational exposures had a wide range varying from 2 to 1,280 μg/m^3 for a variety of occupational groups including miners, railroad workers, firefighters, air port crew, public transit workers, truck mechanics, utility linemen, utility winch truck operators, fork lift operators, construction workers, truck dock workers, short-haul truck drivers, and long-haul truck drivers. These individual studies are discussed in the Diesel HAD.

The highest exposure to diesel PM is for workers in coal mines and noncoal mines, which are as high a 1,280 μg/m^3, as discussed in the Diesel HAD. The National Institute of Occupational Safety and Health (NIOSH) has estimated a total of 1,400,000 workers are occupationally exposed to diesel exhaust from on-road and nonroad equipment.

Many measured or estimated occupational exposures are for on-road diesel engines and some are for school buses.[185, 186, 187,188] Also, some (especially the higher ones) are for occupational groups (fork lift operator, construction workers, or mine workers) who would be exposed to nonroad diesel exhaust. Sometimes, as is the case for the nonroad engines, there are only estimates of exposure based on the length of employment or similar factors rather than a μg/m^3 level. Estimates for exposures to diesel PM for diesel fork lift operators have been made that range from 7 to 403 μg/m^3 as reported in the Diesel HAD. In addition, the Northeast States for Coordinated Air Use Management (NESCAUM) measured occupational exposures to particulate and elemental carbon near the operation of various diesel non-road equipment. Exposure groups include agricultural farm operators, grounds maintenance personnel (lawn and garden equipment), heavy equipment operators conducting multiple job tasks at a construction site, and a saw mill crew at a lumber yard. Samples will be obtained in the breathing zone of workers. In a recently released interim report on occupational health risks from diesel engine exposure, pollution inside the cabs of heavy diesel equipment were shown to be up to 16 times higher than federal health recommendations. The diesel PM was estimated to exist at levels that pose risk of chronic inflammation and lung damage in exposed individuals (NESCAUM, 2003).

In public comments from the Building and Trade Department, AFL-CIO, they note their research center, the Center to Protect Workers' Rights, has sponsored research conducted by the Construction Occupational Health Program (COHP) at University of Massachusetts at Lowell which documents diesel emissions exposure among a number of trades employed on a major highway project underway in Boston, MA. Over 260 personal samples of diesel exposure were collected among laborers (116); operating engineers (113) and other trades including ironworkers (15), carpenters (9), piledrivers (5), boilermakers (1), plumbers (1) and surveyors (1). Exposures associated with specific work processes were also documented. Using the American Conference of Governmental Industrial Hygienists Threshold Limit Value (TLV) for diesel exhaust as elemental carbon of 20 ug/m^3 as proposed in 2002, the percentage of samples exceeding the TLV overall was 14 percent (Woskie, 2002; ACGIH, 2002). It should be noted that much of this project involves construction of underground tunnels. However, work in enclosed and/or poorly ventilated work areas is common in construction.

One recent study found that construction workers in Ontario are exposed to elevated concentrations of elemental carbon (EC) measured by thermal-optical transmission (TOT), which the authors used as a surrogate for diesel exhaust.[189] Task-based exposure measurements were made corresponding to engine use. Demolition laborers were exposed to between 4.9 to146 ug/m3 of EC-TOT while operating compressors, performing excavation and cleanup, and in tearing down structures. Construction equipment operating engineers were exposed to 4.3 to 7.8 ug/m3 EC-TOT while operating their machinery. Painters in new commercial construction were exposed to between 3.6 to 9.0 ug/m3 EC-TOT, as a result of operating mixers. While these concentrations are substantially higher than those seen in typical urban air, it is difficult to assign these EC-TOT measurements to diesel engines, and the study authors did not indicate the fuel source of the equipment used. However, it is likely that many of the engines in this study were diesel engines.

2.2.1.4.2 Ambient Exposures in the General Population

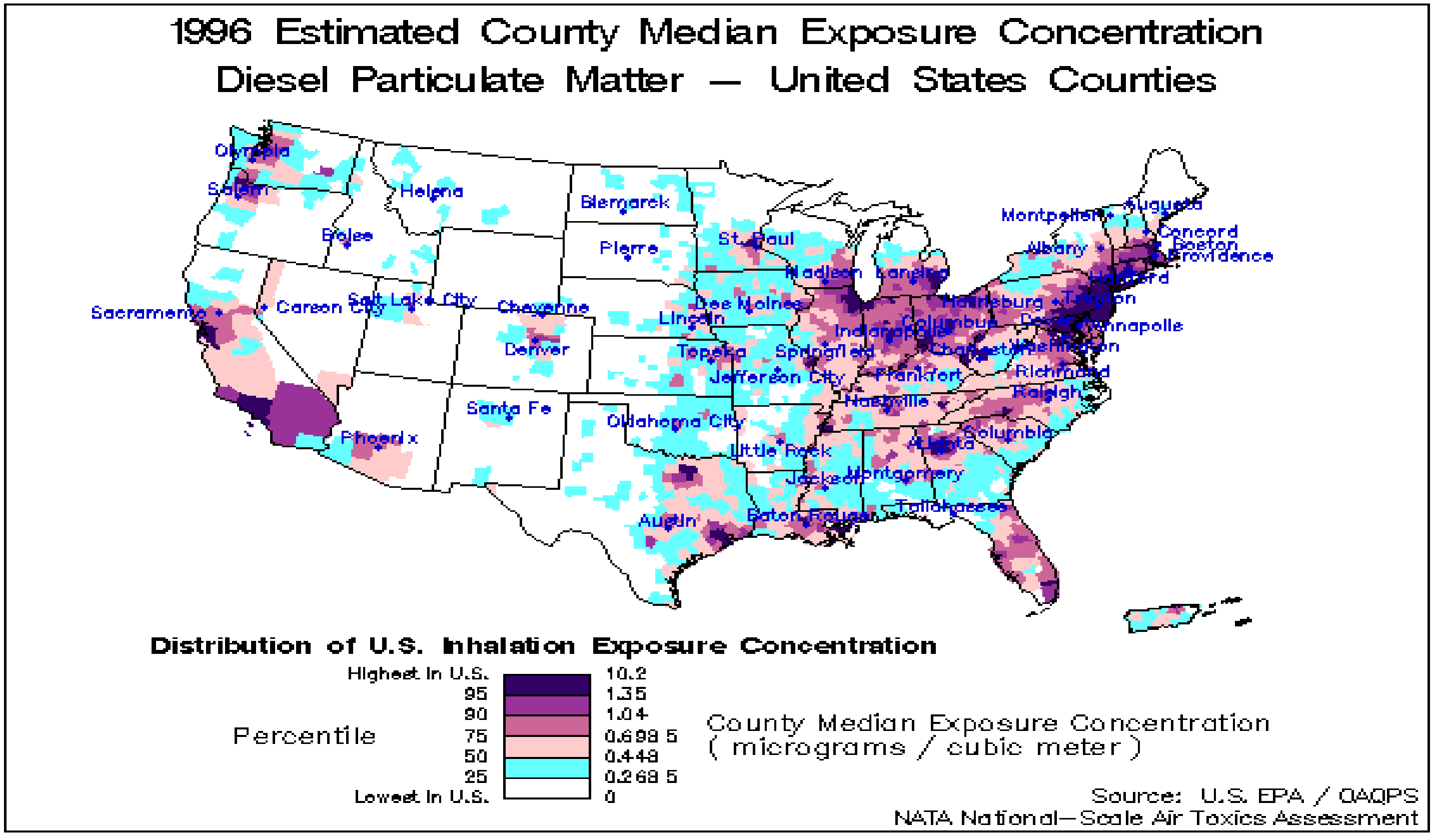
Currently, personal exposure monitors for PM cannot differentiate diesel from other PM. Thus, we use modeling to estimate exposures. Specifically, exposures for the general population are estimated by first conducting dispersion modeling of both highway and nonroad diesel emissions, described above, and then by conducting exposure modeling. The most comprehensive modeling for cumulative on-road and non-road exposures to diesel PM is the NATA. This assessment calculates exposures of the national population as a whole to a variety of air toxics, including diesel PM. As discussed previously, the ambient levels are calculated using the ASPEN dispersion model. As discussed above, the preponderance of modeled diesel PM concentrations are within a factor of 2 of diesel PM concentrations estimated from elemental carbon measurements.[190] This comparison adds credence to the modeled ASPEN results and associated exposure assessment.

The modeled concentrations for calendar year 1996 are used as inputs into an exposure model called the Hazardous Air Pollution Exposure Model (HAPEM4) to calculate exposure levels. Average exposures calculated nationwide are 1.44 μg/m^3 with levels of 1.64 μg/m^3 for urban counties and 0.55 μg/m^3 for rural counties. Again, nonroad diesel emissions account for over half of the this exposure. Table 2.2.1-4 summarizes the distribution of average exposure concentrations to diesel PM at the national scale in the 1996 NATA assessment. Figure 2.2.1-3 presents a map of the distribution of median exposure concentrations for U.S. counties.

Table 2.2.1-4
Distribution of Average Exposure Concentrations to
Diesel PM at the National Scale in the 1996 NATA Assessment.

	Nationwide (μg/m^3)	Urban (μg/m^3)	Rural (μg/m^3)
5th Percentile	0.16	0.29	0.07
25th Percentile	0.58	0.81	0.29
Average	1.44	1.64	0.55
75th Percentile	1.73	1.91	0.67
95th Percentile	3.68	4.33	1.08
Onroad Contribution to Average	0.46	0.52	0.21
Nonroad Contribution to Average	0.98	1.12	0.34

Figure 2.2.1-3
Estimated County Median Exposure Concentrations of Diesel Particulate Matter



Source: EPA National-Scale Air Toxics Assessment for 1996. Results should not be used to draw conclusions about local exposure concentrations. Results are most meaningful at the Regional or National level.

As explained earlier, the fact that these levels are below the 5 μg/m^3 RfC (which is based on limited animal studies on diesel PM) does not necessarily mean that there are no adverse health implications from overall $PM_{2.5}$ exposure. The health studies for the $PM_{2.5}$ NAAQS are far more encompassing than the limited animal studies used to develop the RfC for diesel exhaust, and, also, the NAAQS applies to $PM_{2.5}$ regardless of its composition.

2.2.1.4.3 Ambient Exposures to Diesel Exhaust PM in Microenvironments

One common microenvironment for ambient exposures to diesel exhaust PM is beside freeways. Although freeway locations are associated mostly with highway rather than nonroad diesel enignes, there are many similarities between highway and nonroad diesel emissions, as discussed in the Diesel HAD. Also, similar spatial gradients in concentrations would be expected where nonroad equipment is used. The California Air Resources Board (California ARB) has measured elemental carbon near the Long Beach Freeway in 1993.[191] Levels measured ranged from 0.4 to 4.0 μg/m^3 (with one value as high as 7.5 μg/m^3) above background levels. Microenvironments associated with nonroad engines would include construction zones. PM and elemental carbon samples are being collected by NESCAUM in the immediate area of the nonroad engine operations (such as at the edge or fence line of the construction zone). Besides PM and elemental carbon levels, various toxics such as benzene, 1,3-butadiene, formaldehyde, and acetaldehyde will be sampled. The results should be especially useful since they focus on microenvironments affected by nonroad diesel engines.

Also, EPA is funding research in Fresno, California to measure indoor and outdoor PM component concentrations in the homes of over 100 asthmatic children. Some of these homes are located near agricultural, construction, and utility nonroad equipment operations. This work will measure infiltration of elemental carbon and other PM components to indoor environments. The project also evaluates lung function changes in the asthmatic children during fluctuations in exposure concentrations and compositions. This information may allow an evaluation of adverse health effects associated with exposures to elemental carbon and other PM components from on-road and nonroad sources.

2.2.2 Gaseous Air Toxics

Nonroad diesel engine emissions contain several substances known or suspected as human or animal carcinogens, or have noncancer health effects. These other compounds include benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, dioxin, and polycyclic organic matter (POM). Mobile sources, including nonroad diesel engines, contribute significantly to total emissions of these air toxics. All of these compounds were identified as national or regional "risk" drivers in the 1996 NATA. That is, these compounds pose a significant portion of the total inhalation cancer risk to a significant portion of the population. As discussed later in this section, this final rule will significantly reduce these emissions.

Nonroad engines are major contributors to nationwide cancer risk from air toxic pollutants, as indicated by the NATA 1996.[192] In fact, this study and the National Toxics Inventory (NTI) for 1996 are used throughout this section for toxics inventory information for nonroad sources.[193]

Also, a supplemental paper provides more detail on nonroad diesel exhaust.[194] In addition, a paper published by the Society of Automotive Engineers gives future projections to 2007 for these air toxics.[195] These references form the basis for much of what will be discussed in this section.

Figure 2.2.2-1 summarizes the contribution of nonroad engines to average nationwide lifetime upper bound cancer risk from outdoor sources in the 1996 NATA. These data do not include the cancer risk from diesel PM since EPA does not presently have a potency for diesel particulate/exhaust. Figure 2.2.2-2 depicts the nonroad engine contribution to average nationwide inhalation exposure for benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein. These compounds are all known or suspected human carcinogens, except for acrolein, which has serious noncancer health effects. All of these compounds were identified as national or regional risk drivers in the 1996 NATA, and mobile sources contribute significantly to total emissions in NATA. As indicated previously, NATA exposure and risk estimates are based on air dispersion modeling using the ASPEN model. Comparisons of the predicted concentrations from the model to monitor data indicate good agreement for benzene, where the ratio of median modeled concentrations to monitor values is 0.92, and results are within a factor of two at almost 90 percent of monitors.[196] Comparisons with aldehydes indicate significantly lower modeled concentrations than monitor values. Comparisons with 1,3-butadiene have not been done. Previously, extensive work was done on gaseous air toxic emissions including those from nonroad diesel and reported in EPA's 1993 Motor Vehicle-Related Air Toxics Study.[197] This final rule will reduce these emissions. Dioxin and some POM compounds have also been identified as probable human carcinogens and are emitted by mobile sources, although nonroad sources are less than 1% of total emissions for these compounds.

Figure 2.2.2-1

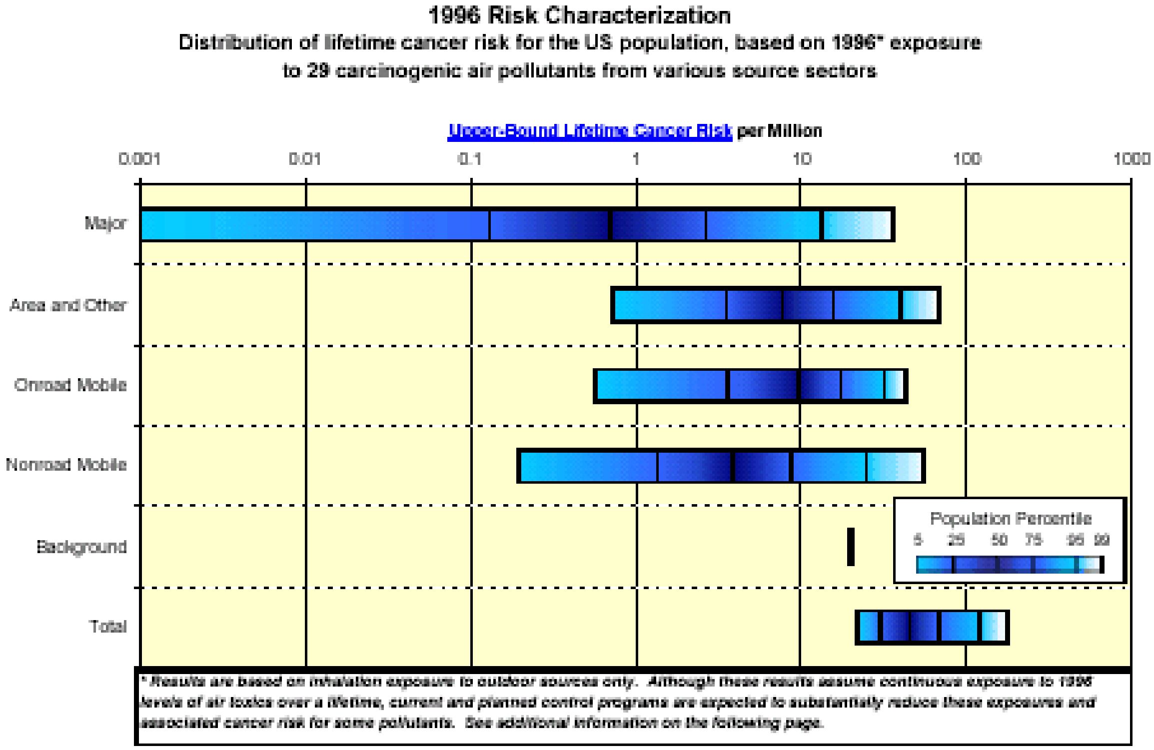
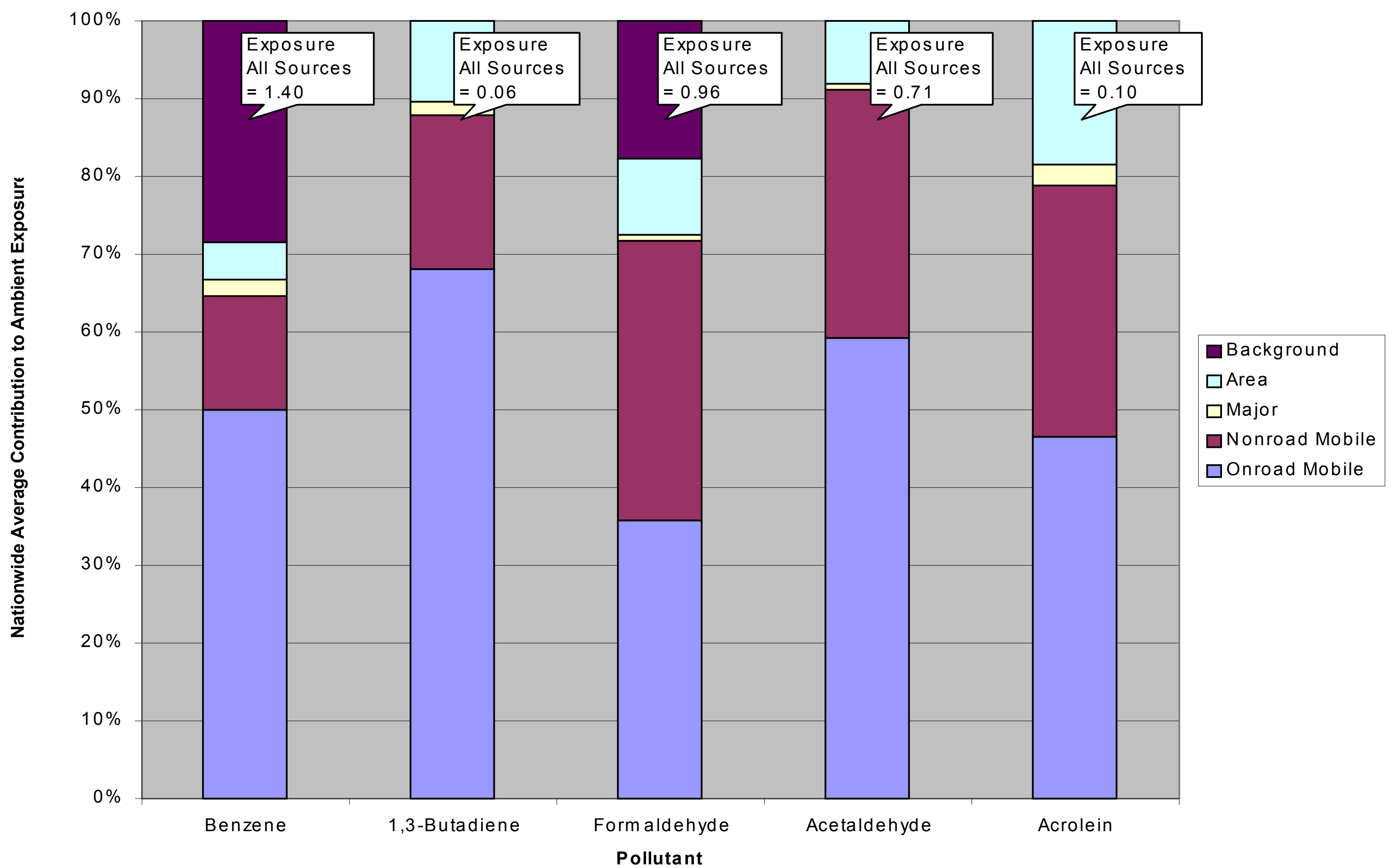

1996 Risk Characterization
Distribution of lifetime cancer risk for the US population, based on 1996* exposure to 29 carcinogenic air pollutants from various source sectors
Upper-Bound Lifetime Cancer Risk per Million
0.001
0.01
0.1
1
10
100
1000
Major
Area and Other
Onroad Mobile
Nonroad Mobile
Background
Total
Population Percentile
5
25
50
75
95
99
* Results are based on inhalation exposure to outdoor sources only. Although these results assume continuous exposure to 1996 levels of air toxics over a lifetime, current and planned control programs are expected to substantially reduce these exposures and associated cancer risk for some pollutants. See additional information on the following page.

Figure 2.2.2-2
Contribution of Source Sectors to Average Annual Nationwide Inhalation Exposure to Air Toxics in 1996



Source: National Scale Air Toxics Assessment.

2.2.2.1 Benzene

Benzene is an aromatic hydrocarbon that is present as a gas in both exhaust and evaporative emissions from mobile sources. Benzene accounts for one to two percent of the exhaust hydrocarbons, expressed as a percentage of total organic gases (TOG), in diesel engines.[198, 199] For gasoline-powered highway vehicles, the benzene fraction of TOG varies depending on control technology (e.g., type of catalyst) and the levels of benzene and other aromatics in the fuel, but is generally higher than for diesel engines, about three to five percent. The benzene fraction of evaporative emissions from gasoline vehicles depends on control technology and fuel composition and characteristics (e.g., benzene level and the evaporation rate) and is generally about one percent.[200]

Nonroad engines account for 28 percent of nationwide emissions of benzene with nonroad diesel accounting for about 3 percent in 1996. Mobile sources as a whole account for 78 percent of the total benzene emissions in the nation. Nonroad sources as a whole account for an average of about 17 percent of ambient benzene in urban areas and about 9 percent of ambient benzene in rural areas across the U.S, in the 1996 NATA assessment. Of ambient benzene levels due to mobile sources, 5 percent in urban and 3 percent in rural areas come from nonroad diesel engines (see Figure 2.2.2-3).

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure.[201] It is associated with additional health effects including chromosomal changes in human and animal cells and increased proliferation of bone marrow cells in mice.[202, 203] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term occupational exposure to benzene.

Inhalation is the major source of human exposure to benzene in the occupational and non-occupational setting. At least half of this exposure is attributable to gasoline vapors and automotive emissions. Long-term inhalation occupational exposure to benzene has been shown to cause cancer of the hematopoetic (blood cell) system. Among these are acute nonlymphocytic leukemia,[I] chronic lymphocytic leukemia and possibly multiple myeloma

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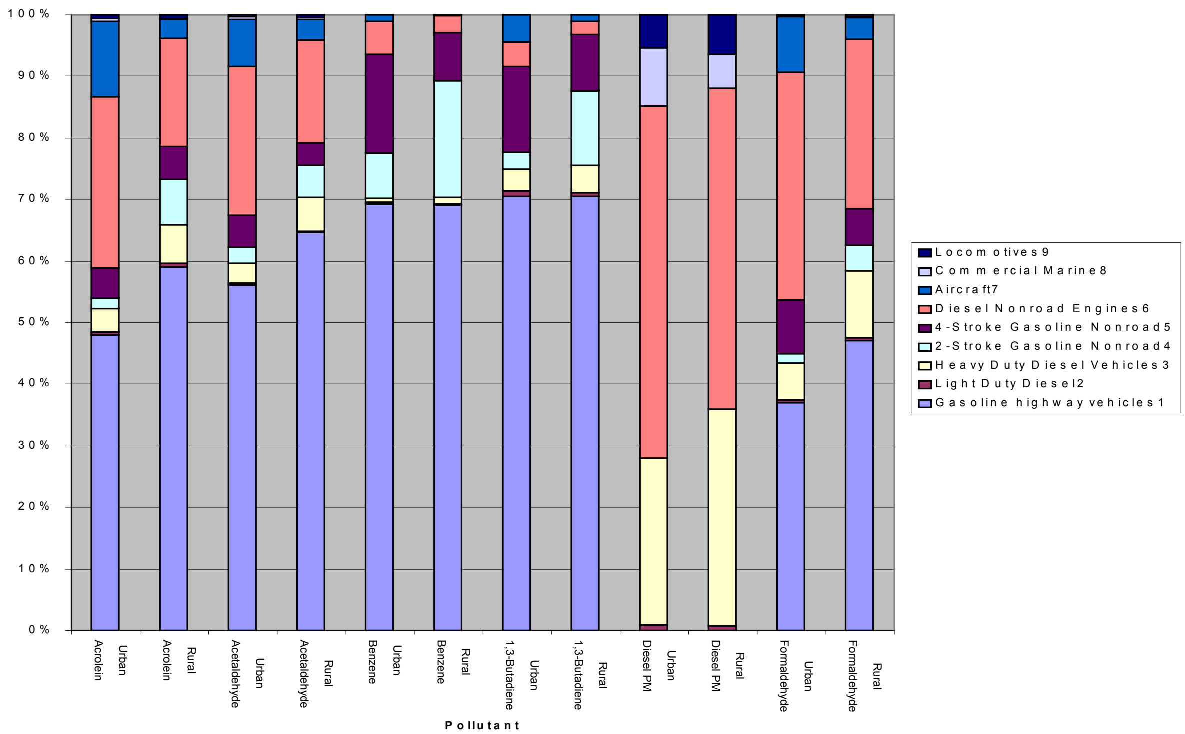
[I] Leukemia is a blood disease in which the white blood cells are abnormal in type or number. Leukemia may be divided into nonlymphocytic (granulocytic) leukemias and lymphocytic leukemias. Nonlymphocytic leukemia generally involves the types of white blood cells (leukocytes) that are involved in engulfing, killing, and digesting bacteria and other parasites (phagocytosis) as well as releasing chemicals involved in allergic and immune responses. This type of leukemia may also involve erythroblastic cell types (immature red blood cells). Lymphocytic leukemia involves the lymphocyte type of white bloods cell that are responsible for the immune responses. Both nonlymphocytic and lymphocytic leukemia may, in turn, be separated into acute (rapid and fatal) and chronic (lingering, lasting) forms. For example; in acute myeloid leukemia (AML) there is diminished production of normal red blood cells (erythrocytes), granulocytes, and platelets (control clotting), which leads to death by anemia, infection, or hemorrhage. These events can be rapid. In chronic myeloid leukemia (CML) the leukemic cells retain the ability to differentiate (i.e., be responsive to stimulatory factors) and perform function; later there is a loss of the ability to respond.

Figure 2.2.2-3
Contribution of Source Sectors to Total Average
Nationwide Mobile Source Ambient Concentrations in 1996



(primary malignant tumors in the bone marrow), although the evidence for the latter has decreased with more recent studies.[204,205] Leukemias, lymphomas, and other tumor types have been observed in experimental animals exposed to benzene by inhalation or oral administration. Exposure to benzene and/or its metabolites has also been linked with chromosomal changes in humans and animals[206] and increased proliferation of mouse bone marrow cells.[207]

The latest assessment by EPA places the excess risk of developing acute nonlymphocytic leukemia at 2.2×10^{-6} to 7.8×10^{-6} per µg/m^3. In other words, there is a risk of about two to eight excess leukemia cases in one million people exposed to 1 µg/m^3 over a lifetime (70 years).[208] This range of unit risks are the maximum likelihood estimate (MLE) calculated from different exposure assumptions and dose-response models that are linear at low doses. It should be noted that not enough information is known to determine the slope of the dose-response curve at environmental levels of exposure and to provide a sound scientific basis to choose any particular extrapolation model to estimate human cancer risk at low doses. In fact, recent data[209] suggest that because genetic abnormalities occur at low exposure in humans, and the formation of toxic metabolites plateaus above 25 ppm (80,000 µg/m^3), the dose-response curve could be supralinear below 25 ppm. Thus, EPA believes the use of a linear extrapolation model as a default approach is appropriate.

Based on average population exposures in the 1996 NATA Assessment, upper bound cancer risk (using the upper end of the MLE range) from inhalation of benzene from ambient sources is above 10 in a million across the entire United States. These results are best interpreted as upper estimates of risks to typical individuals (provided exposure estimates are not underestimated). Thus most individuals are likely to have risks that are equal to or lower than these estimates, but some individuals may have risks which are higher. EPA projects a median nationwide reduction in ambient concentrations of benzene from mobile sources of about 46 percent between 1996 and 2007, as a result of current and planned control programs based on the analysis referenced earlier examining these pollutants in the 1996 to 2007 time frame based on the analysis of hazardous air pollutants in the 1996 to 2007 time frame referenced earlier.

A number of adverse noncancer health effects, blood disorders such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[210, 211] People with long-term occupational exposure to benzene have experienced harmful effects on the blood-forming tissues, especially in bone marrow. These effects can disrupt normal blood production and suppress the production of important blood components, such as red and white blood cells and blood platelets, leading to anemia (a reduction in the number of red blood cells), leukopenia (a reduction in the number of white blood cells), or thrombocytopenia (a reduction in the number of blood platelets, thus reducing the ability of blood to clot). Chronic inhalation exposure to benzene in humans and animals results in pancytopenia,[J] a condition characterized by decreased numbers of circulating erythrocytes (red blood cells), leukocytes (white blood cells), and thrombocytes (blood platelets).[212,213] Individuals that develop pancytopenia and have continued exposure to benzene may develop aplastic anemia,[K] whereas others exhibit both pancytopenia and bone marrow hyperplasia (excessive cell formation), a condition that may indicate a preleukemic state.[214, 215] It should be noted that these health effects occur in human and animal studies at concentrations well above those typically found in the ambient environment. The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[216] EPA's inhalation reference concentration (RfC, i.e., a chronic exposure level presumed to be "without appreciable risk" for noncancer effects) for

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[J]Pancytopenia is the reduction in the number of all three major types of blood cells (erythrocytes, or red blood cells, thrombocytes, or platelets, and leukocytes, or white blood cells). In adults, all three major types of blood cells are produced in the bone marrow of the vertebra, sternum, ribs, and pelvis. The bone marrow contains immature cells, known as multipotent myeloid stem cells, that later differentiate into the various mature blood cells. Pancytopenia results from a reduction in the ability of the red bone marrow to produce adequate numbers of these mature blood cells.

[K]Aplastic anemia is a more severe blood disease and occurs when the bone marrow ceases to function, i.e.,these stem cells never reach maturity. The depression in bone marrow function occurs in two stages - hyperplasia, or increased synthesis of blood cell elements, followed by hypoplasia, or decreased synthesis. As the disease progresses, the bone marrow decreases functioning. This myeloplastic dysplasia (formation of abnormal tissue) without acute leukemias known as preleukemia. The aplastic anemia can progress to AML (acute mylogenous leukemia).

benzene is 30 µg/m^3, based on suppressed absolute lymphocyte counts as seen in humans under occupational exposure conditions.

The average inhalation exposure concentration to benzene from ambient sources in the 1996 NATA assessment is 1.4 µg/m^3, and the 95th percentile exposure concentration is about twice as high (U. S. EPA, 2002). However, the assessment does not account for localized hotspots. In these hot spots, such as in close proximity to roadways, inhalation exposures from ambient sources are likely to be much higher.[217, 218, 219, 220, 221, 222] As mentioned above, nonroad diesel engines are small but significant contributors to the ambient concentrations resulting in these exposures.

2.2.2.2 1,3-Butadiene

1,3-Butadiene is formed in engine exhaust by the incomplete combustion of fuel. It is not present in engine evaporative emissions, because it is not present in any appreciable amount in fuel. 1,3-butadiene accounts for less than one percent of total organic gas exhaust from mobile sources.

Nonroad engines account for 18 percent of nationwide emissions of 1,3-butadiene in 1996 with nonroad diesel accounting for about 1.5 percent based on the NATA, NTI, and supplemental information already discussed in the previous section. Mobile sources account for 63 percent of the total 1,3-butadiene emissions in the nation as a whole. Nonroad sources as a whole account for an average of about 21 percent of ambient butadiene in urban areas and about 13 percent of ambient 1,3-butadiene in rural areas across the United States. Of ambient butadiene levels due to mobile sources, 4 percent in urban and 2 percent in rural areas come from nonroad diesel (see Figure 2.2.2-3).

EPA earlier identified 1,3-butadiene as a probable human carcinogen in its IRIS database.[223] EPA characterized 1,3-butadiene as carcinogenic to humans by inhalation.[224,225,226] The specific mechanisms of 1,3-butadiene-induced carcinogenesis are not fully characterized. However, the data strongly suggest that the carcinogenic effects are mediated by genotoxic metabolites of 1,3-butadiene. Animal data suggest that females may be more sensitive than males for cancer effects; but more data are needed before reaching definitive conclusions on potentially sensitive subpopulations.

The cancer unit risk estimate is 0.08/ppm or 3×10-5 per µg/m3 (based primarily on linear modeling and extrapolation of human data). In other words, it is estimated that approximately 30 persons in one million exposed to 1 µg/m^3 1,3-butadiene continuously for their lifetime (70 years) would develop cancer as a result of this exposure. The human incremental lifetime unit cancer risk (incidence) estimate is based on extrapolation from leukemias observed in an occupational epidemiologic study.[227] This estimate includes a twofold adjustment to the epidemiologic-based unit cancer risk applied to reflect evidence from the rodent bioassays suggesting that the epidemiologic-based estimate may underestimate total cancer risk from 1,3-butadiene exposure in the general population. Based on average population exposure from the 1996 NATA Assessment, upper bound lifetime cancer risk from inhalation of 1,3-butadiene is above 10 in a million across the entire United States. Most individuals are likely to have risks that are equal to or lower than these estimates, but some individuals may have risks which are higher. EPA projects a median nationwide reduction in ambient concentrations of butadiene from mobile sources of about 46 percent between 1996 and 2007, as a result of current and planned control programs.

1,3-Butadiene also causes a variety of reproductive and developmental effects in mice; no human data on these effects are available. The most sensitive effect was ovarian atrophy observed in a lifetime bioassay of female mice.[228] Based on this critical effect and the benchmark concentration methodology, an RfC was calculated. This RfC for chronic health effects was 0.9 ppb, or about 2 $\mu g/m^3$. The average inhalation exposure from outdoor sources in the 1996 NATA assessment was 0.08 $\mu g/m^3$, with a 95th percentile concentration of 0.2 $\mu g/m^3$ (U. S. EPA, 2002). As is the case with benzene, in some hot spots, such as in close proximity to roadways, inhalation exposures from ambient sources are likely to be much higher. As mentioned above, nonroad diesel engines are small but significant contributors to the ambient concentrations resulting in these exposures.

2.2.2.3 Formaldehyde

Formaldehyde is the most prevalent aldehyde in engine exhaust. It is formed from incomplete combustion of both gasoline and diesel fuel. In a recent test program that measured toxic emissions from several nonroad diesel engines, ranging from 50 to 480 horsepower, formaldehyde consistently accounted for well over 10 percent of total exhaust hydrocarbon emissions.[229] Formaldehyde accounts for far less of total exhaust hydrocarbon emissions from gasoline engines, although the amount can vary substantially by duty cycle, emission control system, and fuel composition. It is not found in evaporative emissions.

Nonroad engines account for 29 percent of nationwide emissions of formaldehyde in 1996, with nonroad diesel accounting for about 22 percent based on the NATA, NTI, and supplemental information already discussed. Mobile sources as a whole account for 56 percent of the total formaldehyde emissions in the nation. Of ambient formaldehyde levels due to mobile sources, 37 percent in urban and 27 percent in rural areas come from nonroad diesel. Nonroad sources as a whole account for an average of about 41 percent of ambient formaldehyde in urban areas and about 10 percent of ambient formaldehyde in rural areas across the U.S, in the 1996 NATA assessment. These figures are for tailpipe emissions of formaldehyde. Formaldehyde in the ambient air comes not only from tailpipe (of direct) emissions but is also formed from photochemical reactions of hydrocarbons. Mobile sources are responsible for well over 50 percent of total formaldehyde including both the direct emissions and photochemically formed formaldehyde in the ambient air, according to the NATA for 1996. EPA projects a median nationwide reduction in ambient concentrations of formaldehyde from mobile sources of about 43 percent between 1996 and 2007, as a result of current and planned control programs (Cook et al., 2002).

EPA has classified formaldehyde as a probable human carcinogen based on limited evidence for carcinogenicity in humans and sufficient evidence of carcinogenicity in animal studies, rats, mice, hamsters, and monkeys.[230, 231] Epidemiological studies in occupationally exposed workers suggest that long-term inhalation of formaldehyde may be associated with tumors of the nasopharyngeal cavity (generally the area at the back of the mouth near the nose), nasal cavity, and sinus.[232] Studies in experimental animals provide sufficient evidence that long-term inhalation exposure to formaldehyde causes an increase in the incidence of squamous (epithelial) cell carcinomas (tumors) of the nasal cavity.[233, 234, 235] The distribution of nasal tumors in rats suggests that not only regional exposure but also local tissue susceptibility may be important for the distribution of formaldehyde-induced tumors.[236] Research has demonstrated that formaldehyde produces mutagenic activity in cell cultures.[237]

The agency is currently conducting a reassessment of risk from inhalation exposure to formaldehyde based on new information including a study by the CIIT Centers for Health Research.[238, 239] The CIIT information and other recent information, including recently published epidemiological studies, are being reviewed and considered in the reassessment of the formaldehyde unit risk estimate. The epidemiological studies examine the potential for formaldehyde to cause cancer in organs other than those addressed by the CIIT model. We plan to bring this reassessment to the Science Advisory Board in the summer of 2004.

Formaldehyde exposure also causes a range of noncancer health effects. At low concentrations (e.g. 60 – 2500 $\mu g/m^3$), irritation of the eyes (tearing of the eyes and increased blinking) and mucous membranes is the principal effect observed in humans. At exposure to 1200-14,000 $\mu g/m^3$, other human upper respiratory effects associated with acute formaldehyde exposure include a dry or sore throat, and a tingling sensation of the nose. Sensitive individuals may experience these effects at lower concentrations. Forty percent of formaldehyde-producing factory workers reported nasal symptoms such as rhinitis (inflammation of the nasal membrane), nasal obstruction, and nasal discharge following chronic exposure.[240] In persons with bronchial asthma, the upper respiratory irritation caused by formaldehyde can precipitate an acute asthmatic attack, sometimes at concentrations below 6200 $\mu g/m^3$.[241] Formaldehyde exposure may also cause bronchial asthma-like symptoms in non-asthmatics.[242, 243]

Immune stimulation may occur following formaldehyde exposure, although conclusive evidence is not available. Also, little is known about formaldehyde's effect on the central nervous system. Several animal inhalation studies have been conducted to assess the developmental toxicity of formaldehyde: The only exposure-related effect noted in these studies was decreased maternal body weight gain at the high-exposure level. No adverse effects on reproductive outcome of the fetuses that could be attributed to treatment were noted. An inhalation reference concentration (RfC), below which long-term exposures would not pose appreciable noncancer health risks, is not available for formaldehyde at this time. The Agency is currently conducting a reassessment of risk from inhalation exposure to formaldehyde.

Average inhalation exposure from outdoor sources in the 1996 NATA assessment was 0.9 $\mu g/m^3$, with a 95th percentile concentration of 2.3 $\mu g/m^3$.

2.2.2.4 Acetaldehyde

Acetaldehyde is a saturated aldehyde that is found in engine exhaust and is formed as a result of incomplete combustion of both gasoline and diesel fuel. In a recent test program that measured toxic emissions from several nonroad diesel engines, ranging from 50 to 480 horsepower, acetaldehyde consistently accounted for over 5 percent of total exhaust hydrocarbon emissions (Southwest Research, 2002). Acetaldehyde accounts for far less of total exhaust hydrocarbon emissions from gasoline engines, although the amount can vary substantially by duty cycle, emission control system, and fuel composition. It is not a component of evaporative emissions.

Nonroad engines account for 43 percent of nationwide emissions of acetaldehyde with nonroad diesel accounting for about 34 percent based on the NATA, NTI, and supplemental information. Mobile sources as a whole account for 73 percent of the total acetaldehyde emissions in the nation. Nonroad sources as a whole account for an average of about 36 percent of ambient acetaldehyde in urban areas and about 21 percent of ambient acetaldehyde in rural areas across the U.S, in the 1996 NATA assessment. Of ambient acetaldehyde levels due to mobile sources, 24 percent in urban and 17 percent in rural areas come from nonroad diesel.. Also, acetaldehyde can be formed photochemically in the atmosphere. Counting both direct emissions and photochemically formed acetaldehyde, mobile sources are responsible for the major portion of acetaldehyde in the ambient air according to the NATA for 1996.

Based primarily on nonhuman animal model studies, acetaldehyde is classified by EPA as a probable human carcinogen. Studies in experimental animals provide sufficient evidence that long-term inhalation exposure to acetaldehyde causes an increase in the incidence of nasal squamous cell carcinomas (epithelial tissue) and adenocarcinomas (glandular tissue).[244, 245, 246, 247, 248] The upper confidence limit estimate of a lifetime extra cancer risk from continuous acetaldehyde exposure is about 2.2×10^{-6} per $\mu g/m^3$. In other words, it is estimated that about 2 persons in one million exposed to 1 $\mu g/m^3$ acetaldehyde continuously for their lifetime (70 years) would develop cancer as a result of their exposure. The Agency is currently conducting a reassessment of risk from inhalation exposure to acetaldehyde. Based on the current unit risk and average population exposure from the 1996 NATA Assessment, upper bound cancer risk from inhalation of acetaldehyde from ambient sources is above one in a million for more than one hundred million Americans. Most individuals are likely to have risks that are equal to or lower than these estimates, but some individuals may have risks which are higher. EPA projects a median nationwide reduction in ambient concentrations of acetaldehyde from mobile sources of about 36 percent between 1996 and 2007, as a result of current and planned control programs

EPA's IRIS database states that noncancer effects in studies with rats and mice showed acetaldehyde to be moderately toxic by the inhalation, oral, and intravenous routes (EPA, 1988). Similar conclusions have been made by the California Air Resources Board.[249] The primary acute effect of exposure to acetaldehyde vapors is irritation of the eyes, skin, and respiratory tract. At
high concentrations, irritation and pulmonary effects can occur, which could facilitate the uptake of other contaminants. Little research exists that addresses the effects of inhalation of

acetaldehyde on reproductive and developmental effects. Long-term exposures should be kept below the reference concentration of 9 µg/m^3 to avoid appreciable risk of these noncancer health effects (EPA, 1988). The average inhalation exposure from outdoor sources in the 1996 NATA assessment was 0.7 µg/m^3, with a 95th percentile concentration of 1.8 µg/m^3 (U. S. EPA, 2002). As is the case with other air toxic compounds emitted by mobile sources, in some hot spots, such as in close proximity to roadways, inhalation exposures are likely to be much higher. As mentioned above, nonroad diesel engines are significant contributors to the ambient concentrations resulting in these exposures.

Acetaldehyde has been associated with lung function decrements in asthmatics. In one study, aerosolized acetaldehyde caused reductions in lung function and bronchoconstriction in asthmatic subjects.[250]

2.2.2.5 Acrolein

In a recent test program that measured toxic emissions from several nonroad diesel engines, ranging from 50 to 480 horsepower, acrolein accounted for about 0.5 to 2 percent of total exhaust hydrocarbon emissions (Southwest Research, 2002). Acrolein accounts for far less of total exhaust hydrocarbon emissions from gasoline engines, although the amount can vary substantially by duty cycle, emission control system, and fuel composition. It is not a component of evaporative emissions.

Nonroad engines account for 25 percent of nationwide emissions of acrolein in 1996 with nonroad diesel accounting for about 17.5 percent based on NATA, NTI, and the supplemental information Mobile sources as a whole account for 43 percent of the total acrolein emissions in the nation. Of ambient acrolein levels due to mobile sources, 28 percent in urban and 18 percent in rural areas come form nonroad diesel according to NATA.

Acrolein is intensely irritating to humans when inhaled, with acute exposure resulting in substantial discomfort and sensory irritancy, mucus hypersecretion, and congestion. These effects have been noted at acrolein levels ranging from 390 µg/m^3 to 990 µg/m^3.[251] The intense irritancy of this carbonyl has been demonstrated during controlled tests in human subjects who suffer intolerable eye and nasal mucosal sensory reactions within minutes of exposure.[252] The irritant nature of acrolein provides the basis for the OSHA Permissible Exposure Limit (PEL) for the workplace of 0.1 ppm (230 µg/m^3) for an 8-hour exposure period. Acrolein has an odor threshold of about 0.16 ppm (370 µg/m^3),[253] and acute inhalation exposure of humans to 10 ppm (23,000 µg/m^3) may result in death over a short period of time.[254]

Acrolein is an extremely volatile vapor, and it possesses considerable water solubility.[255] As such, it readily absorbs into airway fluids in the respiratory tract when inhaled. Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters exposed to acrolein formed the basis of the reference concentrations for inhalation (RfC) developed in 2003.[256] The RfC of acrolein is 0.02 µg/m^3. Average population inhalation exposures from the 1996 NATA assessment are between 0.02 µg/m^3 and 0.2 µg/m^3. Thus, the hazard quotient (inhalation exposure divided by the RfC) is greater than one for most of the U.S. population, indicating a potential for adverse noncancer health effects.

The toxicological data base demonstrating the highly irritating nature of this vapor has been consistent regardless of test species. Animal inhalation studies revealed early on that acrolein induces damage throughout the respiratory tract at 0.7 ppm (1600 $\mu g/m^3$) [257] in concordance with data showing similar vapor uptake along isolated upper and lower lung regions of animals.[258] At levels that humans may encounter incidentally, acrolein has been shown to alter breathing mechanics[259, 260] and airway structure in animals[261] as well as to interfere with macrophage function and to alter microbial infectivity.[262, 263, 264] As with many other irritants, acrolein has the potential to induce adaptation to its own irritancy with repeated exposures to low concentrations (1260 $\mu g/m^3$)[265] -- a phenomenon consistent with the apparent human adaptation to the high spikes of acrolein emanating in mainstream smoke from cigarettes.[266] Hence, sensory awareness of exposure to low levels of acrolein may diminish the apparent acute discomfort, while exposure and the potential for longer term impacts persist. Prolonged exposure to acrolein has been shown in animals to have an impact on pulmonary structure and function that can be quantified.[267] Over the range of 0.4 to 4.0 ppm (920 to 9200 $\mu g/m^3$) acrolein, distinct dose-dependent changes in the degree of injury/disease are apparent, which have lung function consequences. There are clear changes in the cell lining of the airways, including mucus cell hyperplasia, as well as changes in the underlying supportive matrix of the airways. These changes parallel changes in airway hyperreactivity (sometimes referred to as "twitchiness"). Such changes are similar to those observed with asthma. The structural changes in the larger airways, likewise, are reminiscent of those associated with chronic exposure to tobacco smoke.

Irritant effects in humans can be seen at levels encountered industrially that are below the odor threshold and thus may be erroneously thought to be safe. Over time, these same occupational levels of exposure in rats appear to alter airway structure and function. As those in the workplace generally do not reflect the more sensitive groups of the public, the potential for persistent, low level exposures eliciting health outcomes among susceptible groups, including asthmatics who have sensitive airways is a concern.[268]

EPA has concluded that the potential for carcinogenicity of acrolein cannot be determined either for oral or inhalation routes of exposure.[269]

2.2.2.6 Polycyclic Organic Matter

POM is generally defined as a large class of chemicals consisting of organic compounds having multiple benzene rings and a boiling point greater than 100 degrees C. Polycyclic aromatic hydrocarbons (PAHs) are a chemical class that is a subset of POM. POM are naturally occurring substances that are byproducts of the incomplete combustion of fossil fuels and plant and animal biomass (e.g., forest fires). They occur as byproducts from steel and coke productions and waste incineration. They also are a component of diesel PM emissions. As mentioned in Section 2.1.2.1.2, many of the compounds included in the class of compounds known as POM are classified by EPA as probable human carcinogens based on animal data. In particular, EPA obtained data on 7 of the POM compounds, which we analyzed separately as a class in the NATA for 1996. Nonroad engines account for only 1 percent of these 7 POM compounds with total mobile sources responsible for only 4 percent of the total; most of the 7 POMs come from area sources. For total POM compounds, mobile sources as a whole are responsible for only 1 percent. The mobile source emission numbers used to derive these inventories are based only on particulate-phase POM and do not include the semi-volatile phase POM levels. Were those additional POMs included (which is now being done in the NATA for 1999), these inventory numbers would be substantially higher. A study of indoor PAH found that concentrations of indoor PAHs followed the a similar trend as outdoor motor traffic, and that motor vehicle traffic was the largest outdoor source of PAH.[270]

A recent study found that maternal exposures to polycyclic aromatic hydrocarbons (PAHs) in a multiethnic population of pregnant women were associated with adverse birth outcomes, including low birth weight, low birth length, and reduced head circumference.[271]

2.2.2.7 Dioxins

Exposure to dioxins are recognized by several authoritative bodies, including the International Agency for Research on Cancer, the National Institute of Environmental Health Sciences, the Agency for Toxic Substances and Disease Registry, EPA and some State health and environmental agencies, to present a human health hazard for cancer and non-cancer effects. Recent studies have confirmed that very small amounts of dioxins are formed by and emitted from diesel engines (both heavy-duty diesel trucks and nonroad diesel engines). In an inventory for dioxin sources in 1995, such emissions accounted for only about 1 percent of total dioxin emissions. These nonroad rules will have minimal impact on overall dioxin emissions since these are a very small part of total emissions.

2.3 Ozone

This section reviews health and welfare effects of ozone and describes the air quality information that forms the basis of our conclusion that ozone concentrations in many areas across the country face a significant risk of exceeding the ozone standard into the year 2030. Information on air quality was gathered from a variety of sources, including monitored ozone concentrations from 1999-2001, air quality modeling forecasts conducted for this rulemaking and other state and local air quality information.

Ground-level ozone, the main ingredient in smog, is formed by the reaction of volatile organic compounds (VOCs) and nitrogen oxides (NOx) in the atmosphere in the presence of heat and sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources, including highway and nonroad motor vehicles and engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller "area" sources. VOCs are also emitted by natural sources such as vegetation. Oxides of nitrogen are emitted largely from motor vehicles, off-highway equipment, power plants, and other sources of combustion.

The science of ozone formation, transport, and accumulation is complex. Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions involving NOx, VOC, heat, and sunlight. Many of the chemical reactions that are part of the ozone-forming cycle are sensitive to temperature and sunlight. When ambient temperatures and sunlight levels remain high for several days and the air is relatively stagnant, ozone and its precursors can build up and produce more ozone than typically would occur on a single high-temperature day. Further complicating matters, ozone also can be transported into an area from pollution sources found hundreds of miles upwind, resulting in elevated ozone levels even in areas with low VOC or NOx emissions. As a result, differences in NOx and VOC emissions and weather patterns contribute to daily, seasonal, and yearly differences in ozone concentrations and differences from city to city.

These complexities also have implications for programs to reduce ozone. For example, relatively small amounts of NOx enable ozone to form rapidly when VOC levels are relatively high, but ozone production is quickly limited by removal of the NOx. Under these conditions, NOx reductions are highly effective in reducing ozone while VOC reductions have little effect. Such conditions are called "NOx-limited." Because the contribution of VOC emissions from biogenic (natural) sources to local ambient ozone concentrations can be significant, even some areas where man-made VOC emissions are relatively low can be NOx-limited.

When NOx levels are relatively high and VOC levels relatively low, NOx forms inorganic nitrates (i.e., particles) but relatively little ozone. Such conditions are called "VOC-limited." Under these conditions, VOC reductions are effective in reducing ozone, but NOx reductions can actually increase local ozone under certain circumstances. Even in VOC-limited urban areas, NOx reductions are not expected to increase ozone levels if the NOx reductions are sufficiently large. The highest levels of ozone are produced when both VOC and NOx emissions are present in significant quantities on clear summer days.

Rural areas are almost always NOx-limited, due to the relatively large amounts of biogenic VOC emissions in such areas. Urban areas can be either VOC- or NOx-limited, or a mixture of both, in which ozone levels exhibit moderate sensitivity to changes in either pollutant.

Ozone concentrations in an area also can be lowered by the reaction of nitric oxide with ozone, forming nitrogen dioxide (NO_2); as the air moves downwind and the cycle continues, the NO_2 forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of NOx, VOC, and ozone, all of which change with time and location.

2.3.1 Health Effects of Ozone

Exposure to ambient ozone contributes to a wide range of adverse health effects, which are discussed in detail in the EPA Air Quality Criteria Document for Ozone.[272] Effects include lung function decrements, respiratory symptoms, aggravation of asthma, increased hospital and emergency room visits, increased medication usage, inflammation of the lungs, as well as a variety of other respiratory effects. People who are particularly at risk for high ozone exposures inclue healthy children and adults who are active outdoors. Susceptible subgroups include children, people with respiratory disease, such as asthma, and people with unusual sensitivity to ozone. More information on health effects of ozone is also available at http://www.epa.gov/ttn/naaqs/standards/ozone/s_03_index.html.

Based on a large number of scientific studies, EPA has identified several key health effects caused when people are exposed to levels of ozone found today in many areas of the country. Short-term (1 to3 hours) and prolonged exposures (6 to 8 hours) to higher ambient ozone concentrations have been linked to lung function decrements, respiratory symptoms, increased hospital admissions and emergency room visits for respiratory problems.[273, 274, 275, 276, 277, 278] Repeated exposure to ozone can make people more susceptible to respiratory infection and lung inflammation and can aggravate preexisting respiratory diseases, such as asthma.[279, 280, 281, 282, 283] It also can cause inflammation of the lung, impairment of lung defense mechanisms, and possibly irreversible changes in lung structure, which over time could lead to premature aging of the lungs and/or chronic respiratory illnesses, such as emphysema and chronic bronchitis.[284, 285, 286, 287]

Adults who are outdoors and active during the summer months, such as construction workers and other outdoor workers, also are among those most at risk of elevated exposures.[288] Thus, it may be that children and outdoor workers are most at risk from ozone exposure because they typically are active outside, playing and exercising, during the summer when ozone levels are highest.[289, 290] For example, summer camp studies in the Eastern United States and Southeastern Canada have reported significant reductions in lung function in children who are active outdoors.[291, 292, 293, 294, 295, 296, 297, 298] Further, children are more at risk of experiencing health effects than adults from ozone exposure because their respiratory systems are still developing. These individuals, as well as people with respiratory illnesses such as asthma, especially asthmatic children, can experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during prolonged periods of moderate exertion.[299, 300, 301, 302]

The 8-hour NAAQS is based on well-documented science demonstrating that more people are experiencing adverse health effects at lower levels of exertion, over longer periods, and at lower ozone concentrations than addressed by the 1-hour ozone standard.[303] Attaining the 8-hour standard greatly limits ozone exposures of concern for the general population and populations most at risk, including children active outdoors, outdoor workers, and individuals with pre-existing respiratory disease, such as asthma.

There has been new research that suggests additional serious health effects beyond those that had been know when the 8-hour ozone standard was set. Since 1997, over 1,700 new health and welfare studies have been published in peer-reviewed journals.[304] Many of these studies have investigated the impact of ozone exposure on such health effects as changes in lung structure and biochemistry, inflammation of the lungs, exacerbation and causation of asthma, respiratory illness-related school absence, hospital and emergency room visits for asthma and other respiratory causes, and premature mortality. EPA is currently in the process of evaluating these and other studies as part of the ongoing review of the air quality criteria and NAAQS for ozone. A revised Air Quality Criteria Document for Ozone and Other Photochemical Oxidants will be prepared in consultation with the EPA's Clean Air Scientific Advisory Committee (CASAC).

Key new health information falls into four general areas: development of new-onset asthma, hospital admissions for young children, school absence rate, and premature mortality. Examples of new studies in these areas are briefly discussed below.

Aggravation of existing asthma resulting from short-term ambient ozone exposure was reported prior to the 1997 decision and has been observed in studies published since.[305, 306] More recent studies now suggest a relationship between long-term ambient ozone concentrations and the incidence of new-onset asthma. In particular, such a relationship in adult males (but not in females) was reported by McDonnell et al. (1999).[307] Subsequently, McConnell et al. (2002) reported that incidence of new diagnoses of asthma in children is associated with heavy exercise in communities with high concentrations (i.e., mean 8-hour concentration of 59.6 ppb) of ozone.[308] This relationship was documented in children who played 3 or more sports and was not statistically significant for those children who played one or two sports.[L] The larger effect of high activity sports than low activity sports and an independent effect of time spent outdoors also in the higher ozone communities strengthened the inference that exposure to ozone may modify the effect of sports on the development of asthma in some children.

Previous studies have shown relationships between ozone and hospital admissions in the general population. A new study in Toronto reported a significant relationship between 1-hour maximum ozone concentrations and respiratory hospital admissions in children under two.[309] Given the relative vulnerability of children in this age category, we are particularly concerned about the findings from the literature on ozone and hospital admissions.

Increased respiratory disease that are serious enough to cause school absences has been associated with 1-hour daily maximum and 8-hour average ozone concentrations in studies conducted in Nevada in kindergarten to 6th grade[310] and in Southern California in grades 4 to 6.[311] These studies suggest that higher ambient ozone levels may result in increased school absenteeism.

The <u>ambient</u> air pollutant most clearly associated with premature mortality is PM, with dozens of studies reporting such an association. However, repeated ozone exposure may be a contributing factor for premature mortality, causing an inflammatory response in the lungs that may predispose elderly and other sensitive individuals to become more susceptible to the adverse health effects of other air pollutants, such as PM.[312, 313] Although the findings in the past have been mixed, the findings of three recent analyses suggests that ozone exposure is associated with increased mortality. Although the National Morbidity, Mortality, and Air Pollution Study (NMMAPS) did not find an effect of ozone on total mortality across the full year, Samet et al. (2000), who conducted the NMMAPS study, did report an effect after limiting the analysis to summer when ozone levels are highest.[314] Similarly, Thurston and Ito (1999) have reported associations between ozone and mortality.[315] Toulomi et al., (1997) reported that 1-hour maximum ozone levels were associated with daily numbers of deaths in 4 cities (London, Athens, Barcelona, and Paris), and a quantitatively similar effect was found in a group of 4 additional cities (Amsterdam, Basel, Geneva, and Zurich).[316]

[L] In communities with mean 8-hour ozone concentration of 59.6 ppb, the relative risk of developing asthma in children playing three or more sports was 3.3. (95% CI 1.9 - 5.8) compared with children playing no sports.

As discussed in Section 2.1 with respect to PM studies, the Health Effects Institute (HEI) reported findings by health researchers that have raised concerns about aspects of the statistical methodology used in a number of older time-series studies of short-term exposures to air pollution and health effects.[317]

2.3.2 Attainment and Maintenance of the 1-Hour and 8-Hour Ozone NAAQS

As shown earlier in Figure 2-1, unhealthy ozone concentrations (i.e., those exceeding the 8-hour standard, which is requisite to protect public health with an adequate margin of safety) occur over wide geographic areas, including most of the nation's major population centers. These areas include much of the eastern half of the United States and large areas of California. Nonroad engines contribute a substantial fraction of ozone precursors in metropolitan areas.

Emission reductions from this rule will assist nonattainment and maintenance areas in reaching the standard by each area's respective attainment date and help maintaining the standard in the future. We discuss both the 1-hour and the 8-hour NAAQS, which are based on air quality measurements, called design values and other factors.

An ozone design value is the concentration that determines whether a monitoring site meets the NAAQS for ozone. Because of the way they are defined, design values are determined based on 3 consecutive-year monitoring periods. For example, an 8-hour design value is the fourth highest daily maximum 8-hour average ozone concentration measured over a three-year period at a given monitor. The full details of these determinations (including accounting for missing values and other complexities) are given in Appendices H and I of 40 CFR Part 50. As discussed in these appendices, design values are truncated to whole part per billion (ppb). Due to the precision with which the standards are expressed (0.08 parts per million (ppm) for the 8-hour), a violation of the 8-hour standard is defined as a design value greater than or equal to 0.085 ppm.

For a county, the design value is the highest design value from among all the monitors with valid design values within that county. If a county does not contain an ozone monitor, it does not have a design value. Thus, our analysis may underestimate the number of counties with design values above the level of NAAQS. For the purposes of identifying areas likely to have an ozone problem in the future, we used the 1999-2001 because these data were the most current at the time we performed the modeling (i.e, 2003 data were not yet available). In the recent designations, the 2001-2003 data were used. The 1999-2001, the 2000-2002, and the 2001-2003 sets of design values are listed in the AQ TSD, which is available in the docket to this rule.

A number of States and local areas in their public comments discussed their need for the rule to reduce ozone levels. The California Air Resources Board noted, "Adoption of the proposed regulations outlined in the NPRM by US EPA is necessary for the protection of public health in California to comply with air quality standards." In addition, the South Coast Air Quality Management District (SCAQMD) requested more federal reductions, citing their need: "In 2010, federal sources including non-road engines, ships, trains, aircraft, and 49-state vehicles would contribute to 34% of the NOx emissions in the South Coast Air Basin (Basin). Of this amount, non-road engines account for 14% or 108 tons per day of NOx in the Basin. ... without aggressive regulations which would achieve substantial reductions by 2010 for non-road engines, as well as other sources under federal jurisdiction, attainment of the federal 1-hour ozone and PM2.5 standards could be seriously jeopardized. ...Where EPA has exclusive or nearly exclusive jurisdiction, EPA must achieve the maximum feasible reductions to enable states to attain federal standards. Therefore, it is incumbent upon EPA to craft its proposed regulation in a manner that would provide maximum emissions benefit in the near term as well as on a long-term basis."

The City of Houston commented that as the largest city with a severe 1-hour ozone nonattainment area and a near-nonattainment area for PM that they had a need for "huge emission reductions from all sectors in the 8-county area to reach attainment... While diesel engines constitute less than 25% of the city's vehicle fleet, they account for over 40 percent of our mobile source emissions and almost 35% of our overall emissions. The non-road portion of our fleet alone produces 26% of our mobile source, and 21% of the city's overall emissions."

Comments from Illinois Lieutenant Governor comments supported the need for reductions in ozone: "Working to relieve the affects of asthma is of particular importance in Illinois where the mortality rate is the highest in the country and is the number one reason for children missing school."

Similarly, New York State Department of Environmental Conservation "strongly supports EPA's proposed rule to control emissions of air pollution from nonroad diesel engines and fuels. We believe that these regulations, when fully implemented, will provide substantial environmental and public health benefits. ..Nonroad diesel equipment is a major source of NOx, SOx and PM emissions and this proposal will help the state of New York attain and maintain the NAAQS for ozone and PM."

2.3.2 Attainment and Maintenance of the 1-Hour and 8-Hour Ozone NAAQS

As shown earlier in Figure 2-1, nonattainment with the ozone NAAQS occur over wide geographic areas, including most of the nation's major population centers. These areas include much of the eastern half of the United States, industrial midwest, and large areas of California. Nonroad diesel engines contribute a substantial fraction of ozone precursors in metropolitan areas.

Emission reductions from this rule will assist nonattainment and maintenance areas in reaching the standard by each area's respective attainment date and help maintaining the standard in the future. We discuss both the 1-hour, an exceedance-based standard, and the 8-hour NAAQS, which is based on air quality measurements, called design values, as well as other factors.

An ozone design value is a calculated ozone concentration that is used in determining whether a monitoring site meets the NAAQS. Because of the way they are defined, design values are determined based on 3 consecutive-year monitoring periods. For example, an 8-hour ozone design value is the average of the annual fourth highest daily maximum 8-hour average ozone concentrations measured over a three-year period at a given monitor. Determination of whether an area attains the 1-hour NAAQS is based on the number of "exceedances" of the standard over a three year period. The full details of these determinations (including accounting for missing values and other complexities) are given in Appendices H and I of 40 CFR Part 50. As discussed in these appendices, design values are truncated to whole part per billion (ppb). Due to the precision with which the standards are expressed (0.08 parts per million (ppm) for the 8-hour), a violation of the 8-hour standard is defined as a design value greater than or equal to 0.085 ppm.

For a county, the design value is the highest design value from among all the monitors with valid design values within that county. A nonattainment area may contain counties both with and without monitors. The highest design value of any county monitor representing the nonattainment area would determine the design value for that nonattainment county. For the purposes of identifying areas likely to have an ozone problem in the future, we performed modeling and used the 1999-2001 air quality data as described below because these data were the most current at the time we performed the modeling (i.e, 2003 data were not yet available). In the 8-hour designations and classifications, we used the 2001-2003 data in addition to considering other factors. The 1999-2001, the 2000-2002, and the 2001-2003 sets of design values are listed in the AQ TSD, which is available in the docket to this rule.

A number of States and local areas in their public comments discussed their need for the rule to reduce ozone levels. For example, the California Air Resources Board noted, "Adoption of the proposed regulations outlined in the NPRM by US EPA is necessary for the protection of public health in California to comply with air quality standards." In addition, the South Coast Air Quality Management District (SCAQMD) requested more federal reductions, citing their need: "In 2010, federal sources including non-road engines, ships, trains, aircraft, and 49-state vehicles would contribute to 34% of the NOx emissions in the South Coast Air Basin (Basin). Of this amount, non-road engines account for 14% or 108 tons per day of NOx in the Basin. ... without aggressive regulations which would achieve substantial reductions by 2010 for non-road engines, as well as other sources under federal jurisdiction, attainment of the federal 1-hour ozone and $PM_{2.5}$ standards could be seriously jeopardized. ...Where EPA has exclusive or nearly exclusive jurisdiction, EPA must achieve the maximum feasible reductions to enable states to attain federal standards. Therefore, it is incumbent upon EPA to craft its proposed regulation in a manner that would provide maximum emissions benefit in the near term as well as on a long-term basis."

The City of Houston commented that as the largest city with a severe 1-hour ozone nonattainment area and a near-nonattainment area for PM that they had a need for "huge emission reductions from all sectors in the 8-county area to reach attainment... While diesel engines constitute less than 25% of the city's vehicle fleet, they account for over 40 percent of our mobile source emissions and almost 35% of our overall emissions. The non-road portion of our fleet alone produces 26% of our mobile source, and 21% of the city's overall emissions."

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Similarly, New York State Department of Environmental Conservation "strongly supports EPA's proposed rule to control emissions of air pollution from nonroad diesel engines and fuels. We believe that these regulations, when fully implemented, will provide substantial environmental and public health benefits. ..Nonroad diesel equipment is a major source of NOx, SOx and PM emissions and this proposal will help the state of New York attain and maintain the NAAQS for ozone and PM."

2.3.2.1 1-Hour Ozone Nonattainment and Maintenance Areas and Concentrations

Currently, there are 110 million people living in 53 1-hour ozone nonattainment areas covering 219 counties.[318] Of these areas, there are one extreme and 13 severe 1-hour ozone nonattainment areas with a total affected population of 74 million as shown in Table 2.3-1. We focus on these classifications of designated areas because the timing of their attainment dates relates to the timing of the new emission standards. Five severe 1-hour ozone nonattainment areas have attainment dates of November 15, 2007. The Los Angeles South Coast Air Basin is designated as an extreme nonattainment area and has a compliance date of November 15, 2010. While all of these areas are expected to be in attainment before the emission reductions from this rule are fully realized, these reductions will be important to assist these areas in achieving the health and welfare protections of the standards and maintaining compliance with air quality standards.

Table 2.3-1
1-Hour Ozone Extreme and Severe Nonattainment Areas

Nonattainment Area	Attainment Date	2000 Population (millions)	2000-2002 Measured Violation?
Los Angeles South Coast Air Basin, CA[a]	November 15, 2010[a]	14.6	Yes
Chicago-Gary-Lake County, IL-IN	November 15, 2007	8.8	Yes
Houston-Galveston-Brazoria, TX	November 15, 2007	4.7	Yes
Milwaukee-Racine, WI	November 15, 2007	1.8	Yes
New York-New Jersey-Long Island, NY-NJ-CT	November 15, 2007	19.2	Yes
Southeast Desert Modified AQMA, CA	November 15, 2007	1.0	Yes
Atlanta, GA	2005	3.7	Yes
Baltimore, MD	2005	0.8	Yes
Baton Rouge, LA	2005	0.6	Yes
Philadelphia-Wilmington-Trenton, PA-NJ-DE-MD	2005	6.3	Yes
Sacramento, CA	2005	2.0	Yes
San Joaquin Valley, CA	2005	3.2	Yes
Ventura County, CA	2005	0.7	No
Washington, DC-MD-VA	2005	4.5	Yes
Total Population	74million		

[a] Extreme 1-Hour nonattainment areas. All other areas are severe nonattainment areas.
Source: US EPA, Air Quality TSD 2004

Many 1-hour ozone nonattainment areas continue to experience exceedances. Approximately 53 million people are living in 73 counties with measured air quality violating the 1-hour NAAQS in 2000-2002.[M] See the AQ TSD for more details about the counties and populations experiencing various levels of measured 1-hour ozone concentrations.

[M]Typically, county design values (and thus exceedances) are consolidated where possible into design values for consolidated metropolitan statistical areas (CMSA) or metropolitan statistical areas (MSA). Accordingly, the design value for a metropolitan area is the highest design value among the included counties, and counties that are not in metropolitan areas would be treated separately. However, for this section, we examined data on a county basis, not consolidating into CMSA or MSA. Designated nonattainment areas may contain more than one county, and some of these counties have experienced recent exceedances, as indicated in the table. Further, the analysis is limited to areas with ozone monitors.

The ability of states to maintain the ozone NAAQS once attainment is reached has proved challenging, and the recent recurrence of violations of the NAAQS in some other areas increases the Agency's concern about continuing maintenance of the standard. Recurrent nonattainment is especially problematic for areas where high population growth rates lead to significant annual increases in vehicle trips and VMT. Moreover, ozone modeling conducted for this rule predicted exceedances in 2020 and 2030 (without additional controls), which adds to the Agency's uncertainty about the prospect of continued attainment for these areas. The reductions from this final rule will help areas attain and maintain the 1-hour standards.

2.3.2.2 8-Hour Ozone Levels: Current Nonattainment and Future Concentrations

EPA has recently designated nonattainment areas for the 8-hour NAAQS by calculating air quality design values (using 2001-2003 measurements) and considering other factors (www.epa.gov/ozonedesignations).

As described above in Section 2.3.1, the 8-hour NAAQS is based on well-documented science demonstrating that more people are experiencing adverse health effects at lower levels of exertion, over longer periods, and at lower ozone concentrations than addressed by the 1-hour ozone standard.[319] The 8-hour standard greatly limits ozone exposures of concern for the general population and sensitive populations. This section describes the current nonattainment with the 8-hour ozone NAAQS and describes our modeling to predict future 8-hour ozone concentrations, which demonstrate a need for reductions in emissions from this final rule.

2.3.2.2.1 Current 8-Hour Ozone Nonattainment

All or part of 474 counties are in nonattainment, as shown in Figure 2-1, for either failing to meet the 8-hour ozone NAAQS or for contributing to poor air quality in a nearby area. About 159 million people live in the 126 areas that do not meet the 8-hour NAAQS. Based upon the measured data from years 2001-2003 and other factors, these areas were recently designated and classified by EPA.). The nonattainment areas covered under subpart 1 will be required to attain the standard no later than 5 years after designation and, in limited circumstances, they may apply for an additional extension of up to 5 years (e.g., 2009 to 2014). The areas classified under subpart 2 have attainment dates ranging from up to 3 years for marginal areas (2007) to up to 20 years for extreme areas (2024). .

Table 2.3-2 presents the areas, their design values for the 8-hour and 1-hour standards and their category or classification. The reductions from this rule will contribute to these areas' overall strategy to attain and maintain the standards.

Table 2.3-2. 8-Hour Ozone Nonattainment Areas

EPA Region	Area Name	Design Value ppb (2001-2003 data) 8-Hr	1-Hr	Category/Classification
2	Albany-Schenectady-Troy, NY	87	115	Subpart 1
5	Allegan Co, MI	97	115	Subpart 1
3	Allentown-Bethlehem-Easton, PA	91	114	Subpart 1
3	Altoona, PA	85	107	Subpart 1
9	Amador and Calaveras, CA(Central Mtn Co)	91	117	Subpart 1
4	Atlanta, GA	91	125	Subpart 2 Marginal
3	Baltimore, MD	103	143	Subpart 2 Moderate
6	Baton Rouge, LA	86	131	Subpart 2 Marginal
6	Beaumont-Port Arthur, TX	91	129	Subpart 2 Marginal
5	Benton Harbor, MI	91	117	Subpart 1
5	Benzie Co, MI	88	116	Subpart 1
3	Berkeley and Jefferson Counties, WV	86	105	EAC Subpart 1
4	Birmingham, AL	87	113	Subpart 1
1	Boston-Lawrence-Worcester (E. MA), MA	95	124	Subpart 2 Moderate
1	Boston-Manchester-Portsmouth(SE),NH*	95	124	Subpart 2 Moderate
2	Buffalo-Niagara Falls, NY	99	116	Subpart 1
5	Canton-Massillon, OH	90	109	Subpart 1
5	Cass Co, MI	93	124	Subpart 2 Moderate
3	Charleston, WV	86	107	Subpart 1
4	Charlotte-Gastonia-Rock Hill, NC-SC	100	129	Subpart 2 Moderate
4	Chattanooga, TN-GA	88	113	Subpart 1
5	Chicago-Gary-Lake County, IL-IN	101	134	Subpart 2 Moderate
9	Chico, CA	89	102	Subpart 1
5,4	Cincinnati-Hamilton, OH-KY-IN	96	118	Subpart 1
4	Clarksville-Hopkinsville, TN-KY	85	99	Subpart 1
3	Clearfield and Indiana Cos, PA	90	106	Subpart 1
5	Cleveland-Akron-Lorain, OH	103	128	Subpart 2 Moderate
4	Columbia, SC	89	108	EAC Subpart 1
5	Columbus, OH	95	117	Subpart 1
6	Dallas-Fort Worth, TX	100	135	Subpart 2 Moderate
5	Dayton-Springfield, OH	90	117	Subpart 1
8	Denver-Boulder-Greeley-Ft Collins-Love., CO	87	114	EAC Subpart 1
5	Detroit-Ann Arbor, MI	97	127	Subpart 2 Moderate
5	Door Co, WI	94	113	Subpart 1
3	Erie, PA	92	114	Subpart 1
2	Essex Co (Whiteface Mtn) NY	91	113	Subpart 1
5	Evansville, IN	85	106	Subpart 1
4	Fayetteville, NC	87	108	EAC Subpart 1
5	Flint, MI	90	103	Subpart 1

EPA Region	Area Name	Design Value ppb (2001-2003 data) 8-Hr	1-Hr	Category/Classification
5	Fort Wayne, IN	88	106	Subpart 1
3	Franklin Co, PA	93	114	Subpart 1
3	Frederick Co, VA	85	106	EAC Subpart 1
3	Fredericksburg, VA*	99	140	Subpart 2 Moderate
5	Grand Rapids, MI	89	110	Subpart 1
1	Greater Connecticut, CT	95	139	Subpart 2 Moderate
5	Greene Co, IN	88	102	Subpart 1
3	Greene Co, PA	89	107	Subpart 1
4	Greensboro-Winston Salem-High Point, NC	93	121	EAC Subpart 2 Moderate
4	Greenville-Spartanburg-Anderson, SC	87	114	EAC Subpart 1
1	Hancock, Knox, Lincoln and Waldo Cos, ME	94	120	Subpart 1
3	Harrisburg-Lebanon-Carlisle, PA	88	111	Subpart 1
4	Haywood and Swain (Great Smoky NP), NC	85	104	Subpart 1
4	Hickory-Morganton-Lenoir, NC	88	105	EAC Subpart 1
6	Houston-Galveston-Brazoria, TX	102	175	Subpart 2 Moderate
3,4	Huntington-Ashland, WV-KY	91	115	Subpart 1
5	Huron Co, MI	87	109	Subpart 1
9	Imperial Co, CA	87	142	Subpart 2 Marginal
5	Indianapolis, IN	96	119	Subpart 1
5	Jackson Co, IN	85	100	Subpart 1
2	Jamestown, NY	94	115	Subpart 1
2	Jefferson Co, NY	97	121	Subpart 2 Moderate
4	Johnson City-Kingsport-Bristol, TN	86	110	EAC Subpart 1
3	Johnstown, PA	87	106	Subpart 1
5	Kalamazoo-Battle Creek, MI	86	102	Subpart 1
3	Kent and Queen Anne's Co, MD	95	122	Subpart 2 Moderate
9	Kern Co (Eastern Kern), CA	98	118	Subpart 1
5	Kewaunee Co, WI	93	110	Subpart 1
4	Knoxville, TN	92	114	Subpart 1
5	La Porte Co, IN	93	135	Subpart 2 Moderate
3	Lancaster, PA	92	124	Subpart 2 Moderate
5	Lansing-East Lansing, MI	86	102	Subpart 1
9	Las Vegas, NV	86	107	Subpart 1
5	Lima, OH	89	108	Subpart 1
9	Los Angeles South Coast Air Basin, CA	131	180	Subpart 2 Severe 17
9	Los Angeles-San Bernardino (W Mojave),CA	106	138	Subpart 2 Moderate
4,5	Louisville, KY-IN	92	120	Subpart 1
4	Macon, GA	86	113	Subpart 1
3	Madison and Page Cos (Shenandoah NP), VA	87	104	Subpart 1
5	Manitowoc Co, WI	90	110	Subpart 1
9	Mariposa and Tuolumne Cos, CA (S. Mtn Cos)	91	113	Subpart 1

EPA Region	Area Name	Design Value ppb (2001-2003 data) 8-Hr	1-Hr	Category/Classification
5	Mason Co, MI	89	114	Subpart 1
4,6	Memphis, TN-AR	92	126	Subpart 2 Moderate
5	Milwaukee-Racine, WI	101	134	Subpart 2 Moderate
5	Muncie, IN	88	104	Subpart 1
4	Murray Co (Chattahoochee Nat Forest), GA	85	103	Subpart 1
5	Muskegon, MI	95	121	Subpart 2 Moderate
4	Nashville, TN	86	107	EAC Subpart 1
9	Nevada Co, CA (Western Portion)	98	116	Subpart 1
2,1	New York-N. N -Long Island,NY-NJ-CT	102	146	Subpart 2 Moderate
3	Norfolk-Virginia Beach-Newport News,VA	90	121	Subpart 2 Marginal
3,5	Parkersburg-Marietta, WV-OH	87	113	Subpart 1
3,2	Philadelphia-Wilmin-Atl.City,PA-NJ-MD-DE	106	133	Subpart 2 Moderate
9	Phoenix-Mesa, AZ	87	111	Subpart 1
3	Pittsburgh-Beaver Valley, PA	94	120	Subpart 1
1	Portland, ME	91	126	Subpart 2 Marginal
2	Poughkeepsie, NY	94	126	Subpart 2 Moderate
1	Providence (All RI), RI	95	130	Subpart 2 Moderate
4	Raleigh-Durham-Chapel Hill, NC	94	118	Subpart 1
3	Reading, PA	91	116	Subpart 1
3	Richmond-Petersburg, VA	94	131	Subpart 2 Moderate
9	Riverside Co, (Coachella Valley), CA	108	133	Subpart 2 Serious
3	Roanoke, VA	85	107	EAC Subpart 1
2	Rochester, NY	88	110	Subpart 1
4	Rocky Mount, NC	89	106	Subpart 1
9	Sacramento Metro, CA	107	143	Subpart 2 Serious
6	San Antonio, TX	89	119	EAC Subpart 1
9	San Diego, CA	93	118	Subpart 1
9	San Francisco Bay Area, CA	86	123	Subpart 2 Marginal
9	San Joaquin Valley, CA	115	151	Subpart 2 Serious
3	Scranton-Wilkes-Barre, PA	86	108	Subpart 1
5	Sheboygan, WI	100	124	Subpart 2 Moderate
5	South Bend-Elkhart, IN	93	116	Subpart 1
1	Springfield (Western MA), MA	94	132	Subpart 2 Moderate
7,5	St Louis, MO-IL	92	122	Subpart 2 Moderate
3	State College, PA	88	109	Subpart 1
5,3	Steubenville-Weirton, OH-WV	86	113	Subpart 1
9	Sutter Co, CA (Sutter Buttes)	88	113	Subpart 1
5	Terre Haute, IN	87	108	Subpart 1
3	Tioga Co, PA	86	102	Subpart 1
5	Toledo, OH	93	112	Subpart 1
9	Ventura Co, CA	95	124	Subpart 2 Moderate

EPA Region	Area Name	Design Value ppb (2001-2003 data) 8-Hr	1-Hr	Category/Classification
3	Washington Co (Hagerstown), MD	86	109	EAC Subpart 1
3	Washington, DC-MD-VA	99	140	Subpart 2 Moderate
3,5	Wheeling, WV-OH	87	111	Subpart 1
3	York, PA	89	114	Subpart 1
5,3	Youngstown-Warren-Sharon, OH-PA	95	118	Subpart 1

Boston-Manchester-Portsmouth(SE),NH has the same classification as Boston-Lawrence-Worcester (E. MA), MA. Fredericksburg, VA has the same classification as Washington, DC-MD-VA.

The level of the 8-hour ozone (O_3) National Ambient Air Quality Standards (NAAQS) is 0.08 parts per million (ppm). The air quality design value for the 8-hour O_3 NAAQS is the 3-year average of the annual 4th highest daily maximum 8-hour average O_3 concentration. The 8-hour O_3 NAAQS is not met when the 8-hour ozone design value is greater than 0.08 ppm (85 parts per billion [ppb] rounds up). Therefore, an area with a design value of 85 ppb does not meet the NAAQS.

An area with a 1-hour design value of 120 ppb or lower is in a Subpart 1 category and must attain the standard by up to 5 years after designation and they may apply for an extension of up to 5 years.

Areas classified under Subpart 2 must attain the standards by the following attainment dates:

- Marginal up to 3 years,
- Moderate up to 6 years,
- Serious up to 9 years,
- Severe up to 15 or 17 years,
- Extreme up to 20 years.

2.3.2.2.2 Risk of Future 8-Hour Ozone Violations

Our air quality modeling shows that there will continue to be a need for reductions in ozone concentrations in the future without additional controls. In this section we describe the air quality modeling including the non-emission inventory inputs. (See Chapter 3.6 summarizes the emission inventory inputs.) We then discuss the results of the modeling for baseline conditions absent additional control of nonroad diesel engines.

We have also used our air quality modeling to estimate the change in future ozone levels that would result from reductions in emissions from nonroad diesel engines. For this propose rule we modeled a preliminary control scenario that illustrates the likely emission reductions. Because of the substantial lead time to prepare the complex air quality modeling analyses, it was necessary to develop a control options early in the proposal process based on our best judgment at that time. Based on public comment and as additional data regarding technical feasibility and other factors became available, our judgment about the controls that are feasible has evolved. Thus, the preliminary control option differs from what we are finalizing, as summarized in Section 3.6 below.[N] It is important to note that these changes would not affect our estimates of the baseline conditions without additional controls from nonroad diesel engines. This final rule would produce nationwide air quality improvements in ozone levels, and we present the modeled improvements in this section. Those interested in greater detail should review the AQ Modeling TSD, which is available in the docket to this rule.

2.3.2.2.3 Ozone Modeling Methodology, Domains and Simulation Periods

In conjunction with this rulemaking, we performed a series of ozone air quality modeling simulations for the Eastern and Western United States using Comprehensive Air Quality Model with Extension (CAMx). The model simulations were performed for five emission scenarios: a 1996 baseline projection, a 2020 baseline projection and a 2020 projection with nonroad controls, a 2030 baseline projection and a 2030 projection with nonroad controls.

The model outputs from the 1996, 2020 and 2030 baselines, combined with current air quality data, were used to identify areas expected to exceed the ozone NAAQS in 2020 and 2030. These areas became candidates for being determined to be residual exceedance areas that will require additional emission reductions to attain and maintain the ozone NAAQS. The impacts of the new emission standards were determined by comparing the model results in the future year control runs against the baseline simulations of the same year. This modeling supports the conclusion that there is a broad set of areas with predicted ozone concentrations at or above 0.085 ppm between 1996 and 2030 in the baseline scenarios without additional emission reductions.

[N]Because of the complexities and non-linear relationships in the air quality modeling, we are not attempting to make any adjustments to the results. Instead, we are presenting the results for the preliminary control option with information about how the emission changes relate to what was modeled.

The air quality modeling performed for this rule was based upon the same modeling system as was used in the EPA's air quality assessment of the Clear Skies legislation with the addition of updated inventory estimates for 1996, 2020 and 2030. Further discussion of this modeling, including evaluations of model performance relative to predicted future air quality, is provided in the AQ Modeling TSD.

CAMx was utilized to estimate base and future-year ozone concentrations over the Eastern and Western United States for the various emission scenarios. CAMx simulates the numerous physical and chemical processes involved in the formation, transport, and destruction of ozone. CAMx is a photochemical grid model that numerically simulates the effects of emissions, advection, diffusion, chemistry, and surface removal processes on pollutant concentrations within a three-dimensional grid. This model is commonly used for purposes of determining attainment/nonattainment as well as estimating the ozone reductions expected to occur from a reduction in emitted pollutants. The following sections provide an overview of the ozone modeling completed as part of this rulemaking. More detailed information is included in the AQ Modeling TSD, which is located in the docket for this rule.

The regional ozone analyses used the modeling domains used previously for OTAG and the highway passenger vehicle Tier 2 rulemaking. The Eastern modeling domain encompasses the area from the East coast to mid-Texas and consists of two grids with differing resolutions. The model resolution was 36 km over the outer portions of the domain and 12 km in the inner portion of the grids. The vertical height of the eastern modeling domain is 4,000 meters above ground level with 9 vertical layers. The western modeling domain encompasses the area west of the 99th degree longitude (which runs through North and South Dakota, Nebraska, Kansas, Oklahoma, and Texas) and also consists of two grids with differing resolutions. The vertical height of the western modeling domains is 4,800 meters above ground level with 11 vertical layers. As for the Eastern United States, the model resolution was 36 km over the outer portions of the domain and 12 km in the inner portion of the grids.

The simulation periods modeled by CAMx included several multi-day periods when ambient measurements were representative of ozone episodes over the Eastern and Western United States. A simulation period, or episode, consists of meteorological data characterized over a block of days that are used as inputs to the air quality model. Three multi-day meteorological scenarios during the summer of 1995 were used in the model simulations over the Eastern United States: June 12-24, July 5-15, and August 7-21. Two multi-day meteorological scenarios during the summer of 1996 were used in the model simulations over the Western United States: July 5-15 and July 18-31. In general, these episodes do not represent extreme ozone events but, instead, are generally representative of ozone levels near local design values. Each of the five emission scenarios (1996 base year, 2020 base, 2020 control, 2030 baseline, 2030 control) were simulated for the selected episodes.

The meteorological data required for input into CAMx (wind, temperature, vertical mixing, etc.) were developed by separate meteorological models. For the Eastern United States, the gridded meteorological data for the three historical 1995 episodes were developed using the Regional Atmospheric Modeling System (RAMS), version 3b. This model provided needed data at every grid cell on an hourly basis. For the Western United States, the gridded meteorological data for the two historical 1996 episodes were developed using the Fifth-Generation National Center for Atmospheric Research (NCAR) / Penn State Mesoscale Model (MM5). These meteorological modeling results were evaluated against observed weather conditions before being input into CAMx and it was concluded that the model fields were adequate representations of the historical meteorology. A more detailed description of the settings and assorted input files employed in these applications is provided in the AQ Modeling TSD, which is located in the docket for this rule.

The modeling assumed background pollutant levels at the top and along the periphery of the domain as in Tier 2. Additionally, initial conditions were assumed to be relatively clean as well. Given the ramp-up days and the expansive domains, it is expected that these assumptions will not affect the modeling results, except in areas near the boundary (e.g., Dallas-Fort Worth TX). The other non-emission CAMx inputs (land use, photolysis rates, etc.) were developed using procedures employed in the highway light duty Tier 2/OTAG regional modeling. The development of model inputs is discussed in greater detail in the AQ Modeling TSD, which is available in the docket for this rule.

2.3.2.2.4 Model Performance Evaluation

The purpose of the base year photochemical ozone modeling was to reproduce the atmospheric processes resulting in the observed ozone concentrations over these domains and episodes. One of the fundamental assumptions in air quality modeling is that a model that adequately replicates observed pollutant concentrations in the base year can be used to assess the effects of future-year emission controls.

A series of performance statistics was calculated for both model domains, the four quadrants of the eastern domain, and multiple subregions in the eastern and western domains. Table 2.3-2 summarizes the performance statistics. The model performance evaluation consisted solely of comparisons against ambient surface ozone data. There was insufficient data available in terms of ozone precursors or ozone aloft to allow for a more complete assessment of model performance. Three primary statistical metrics were used to assess the overall accuracy of the base year modeling simulations.

- Mean normalized bias is defined as the average difference between the hourly model predictions and observations (paired in space and time) at each monitoring location, normalized by the magnitude of the observations.

- Mean normalized gross error is defined as the average absolute difference between the hourly model predictions and observations (paired in space and time) at each monitoring location, normalized by the magnitude of the observations.

- Average accuracy of the peak is defined as the average difference between peak daily model predictions and observations at each monitoring location, normalized by the magnitude of the observations.

In general, the model tends to underestimate observed ozone, especially in the modeling over the Western United States, as shown in Table 2.3-3. When all hourly observed ozone values greater than a 60 ppb threshold are compared with their model counterparts for the 30 episode modeling days in the eastern domain, the mean normalized bias is -1.1 percent and the mean normalized gross error is 20.5 percent. When the same statistics are calculated for the 19 episode days in the western domain, the bias is -21.4 percent and the error is 26.1 percent.

Table 2.3-3
Model Performance Statistics for the CAMx Ozone Predictions: Base Case

Region	Episode	Average Accuracy of the Peak	Mean Normalized Bias	Mean Normalized Gross Error
Eastern U.S.	June 1995	-7.3	-8.8	19.6
	July 1995	-3.3	-5.0	19.1
	August 1995	9.6	8.6	623.3
Western U.S.	July 1996	-20.5	-21.4	26.1

At present, there are no guidance criteria by which one can determine if a regional ozone modeling exercise is exhibiting adequate model performance. These base case simulations were determined to be acceptable based on comparisons to previously completed model rulemaking analyses (e.g., Ozone Transport Assessment Group (OTAG), the light-duty passenger vehicle Tier-2 standards, and on highway Heavy-Duty Diesel Engine 2007 standards). The modeling completed for this rule exhibits less bias and error than any past regional ozone modeling application done by EPA. Thus, the model is considered appropriate for use in projecting changes in future year ozone concentrations and the resultant health and economic benefits due to the anticipated emission reductions.

2.3.2.2.5 Results of Photochemical Ozone Modeling: Areas at Risk of Future 8-Hour Violations

This section summarizes the results of our modeling of ozone air quality impact in the future of reductions in nonroad diesel emissions. Specifically, it provides information on our calculations of the number of people estimated to live in counties in which ozone monitors are predicted to exceed design values or to be within 10 percent of the design value in the future. We also provide specific information about the number of people who would repeatedly experience levels of ozone of potential concern over prolonged periods, i.e., over 0.085 ppm ozone 8-hour concentrations over a number of days.

The determination that an area is at risk of exceeding the ozone standard in the future was made for all areas with current design values greater than or equal to 0.085 ppm (or within a 10 percent margin) and with modeling evidence that concentrations at and above this level will persist into the future. The following sections provide background on methods for analysis of attainment and maintenance. Those interested in greater detail should review the AQ TSD and AQ Modeling TSD, both of which are available in the docket to this rule.

The relative reduction factor method was used for interpreting the future-year modeling results to determine where nonattainment is expected to occur in the 2020 and 2030 control cases. The CAMx simulations were completed for base cases in 1996, 2020, and 2030 considering growth and expected emission controls that will affect future air quality. The effects of the nonroad engine reductions (control cases) were modeled for the two future years. As a means of assessing the future levels of air quality with regard to the ozone NAAQS, future-year estimates of ozone design values were calculated based on relative reduction factors (RRF) between the various baselines and 1999-2001 ozone design values. The procedures for determining the RRFs are similar to those in EPA's draft guidance for modeling for an 8-hour ozone standard.[320] Hourly model predictions were processed to determine daily maximum 8-hour concentrations for each grid cell for each non-ramp-up day modeled. The RRF for a monitoring site was determined by first calculating the multi-day mean of the 8-hour daily maximum predictions in the nine grid cells surrounding the site using only those predictions greater than or equal to 70 ppb, as recommended in the guidance.[O, 321] This calculation was performed for the base year scenario and each of the future-year baselines. The RRF for a site is the ratio of the mean prediction in the future-year scenario to the mean prediction in the base year scenario. RRFs were calculated on a site-by-site basis. The future-year design value projections were then calculated by county, based on the highest resultant design values for a site within that county from the RRF application.

Based upon our air quality modeling for this rule, we anticipate that without emission reductions beyond those already required under promulgated regulation and approved SIPs, ozone nonattainment will likely persist into the future. With reductions from programs already in place (but excluding the emission reductions from this rule), the number of counties violating the ozone 8-hour standard is expected to decrease in 2020 to 30 counties where 43 million people are projected to live.[322] Thereafter, exposure to unhealthy levels of ozone is expected to increase again. In 2030 the number of counties violating the ozone 8-hour NAAQS, without considering the emission reductions from this rule, is projected to increase to 32 counties where 47 million people are projected to live.

EPA is still developing the implementation process for bringing the nation's air into attainment with the ozone 8-hour NAAQS (see proposal, 68 FR 32702, June 2, 2003, that was recently finalized www.epa.gov/ozonedesignations) as described above. Since the VOC and NOx emission reductions expected from this final rule will go into effect during the period when areas will need to attain the 8-hour ozone NAAQS, the projected reductions in nonroad diesel emissions are expected to assist States and local agencies in their effort to meet and maintain that standard. Many states mentioned this need in their public comments. The following are sample comments from states and state associations on the proposed rule, which corroborate that this rule is a critical element in States' NAAQS attainment efforts. Fuller information can be found in the Summary and Analysis of Comments.

[O]For the one-hour NAAQS we used a cut-off of 80 ppb. Please see the Highway Passenger Vehicle Tier 2 Air Quality Modeling TSD for more details (EPA 1999b).

- "Unless emissions from nonroad diesels are sharply reduced, it is very likely that many areas of the country will be unable to attain and maintain health-based NAAQS for ozone and PM." (STAPPA/ALAPCO)
- "Adoption of the proposed regulation ... is necessary for the protection of public health in California and to comply with air quality standards." (California Air Resources Board)
- "Attainment of the NAAQS for ozone and $PM_{2.5}$ is of immediate concern to the states in the northeast region....Thus, programs ... such as the proposed rule for nonroad diesel engines are essential." (NESCAUM)

Furthermore, the inventories that underlie the ozone modeling conducted for this rulemaking included emission reductions from all current or committed federal, State, and local controls and, for the control case, including this rulemaking. There was no attempt to examine the prospects of areas attaining or maintaining the ozone standard with possible future controls (i.e., controls beyond current or committed federal, State, and local controls). Tables 2.2-4 and 2.2-5 below should therefore be interpreted as indicating what counties are at risk of ozone violations in 2020 or 2030 without additional federal or State measures that may be adopted and implemented after this rulemaking is finalized. We expect many of the areas listed in Table 2.2-4 to adopt additional emission reduction programs, but we are unable to quantify or rely upon future reductions from additional State programs since they have not yet been adopted.

Since the emission reductions expected from this final rule begin in the same time period in which areas will need reductions to attain by their attainment dates, the projected reductions in nonroad emissions will be extremely important to States in meeting the new NAAQS. In public comment, many States and local agencies commented that they will be relying on such nonroad reductions to help them attain and maintain the 8-hour NAAQS. Furthermore, since the nonroad emission reductions will continue to grow in the years beyond 2014, they will also be important for maintenance of the NAAQS for areas with attainment dates of 2014 and earlier.

On a population-weighted basis, the average change in future year design values would be a decrease of 1.8 ppb in 2020, and 2.5 ppb in 2030. Within nonattainment areas, the population-weighted average decrease would be somewhat higher: 1.9 ppb in 2020 and 3 ppb in 2030.[P] In terms of modeling accuracy, the count of modeled nonattaining counties is much less certain than the average changes in air quality. For example, actions by states to meet their SIP obligations would not be expected to significantly change the overall concentration changes induced by this final rule, but they could substantially change the number of counties in or out of attainment. If state actions resulted in an increase in the number of areas that are very close to, but still above, the NAAQS, then this rule might bring many of those counties down sufficiently to change their attainment status. On the other hand, if state actions brought several counties we project to be very close to the standard in the future down sufficiently to reach attainment status, then the air quality improvements from this rule might change the actual attainment status of very few counties. Bearing this limitation in mind, our modeling indicates that the nonroad diesel emission reductions will decrease the net number of nonattainment counties by 2 in 2020 and by 4 in 2030, without consideration of new state or local programs.

[P] This is in spite of the fact that NOx reductions can at certain times in some areas cause ozone levels to increase. Such "disbenefits" are observed in our modeling, but these results make clear that the overall effect of this final rule is positive.

This air quality modeling suggests that without emission reductions beyond those already required under promulgated regulations and approved SIPs, ozone nonattainment will likely persist into the future. With reductions from programs already in place, the number of counties violating the ozone 8-hour standard is expected to decrease from today's levels to 30 counties in 2020 where 43 million people are projected to live.[323] Thereafter, exposure to unhealthy levels of ozone is expected to begin to increase again. In 2030 the number of counties violating the ozone 8-hour NAAQS is projected to increase to 32 counties where 47 million people are projected to live. In addition, in 2030, 82 counties where 44 million people are projected to live will be within 10 percent of violating the ozone 8-hour NAAQS. Specifically, counties presented in Table 2.3-3 and 2.3-4 have monitored 1999-2001 air quality data[Q] and our modeling predicts violations of the 8-hour ozone NAAQS, or predicts concentrations within 10 percent of the standard, in 2020 or 2030. The base case indicates conditions predicted without the reductions from this rule, and the control case represents a preliminary control option similar to the final rule, as described in section 3.6 of the RIA.

In Table 2.3-4 we list the counties with 2020 and 2030 projected 8-hour ozone design values (4^{th} maximum concentration) that violate the 8-hour standard. Counties are marked with an "V" in the table if their projected design values are greater than or equal to 85 ppb. The 1999-2001 average design values of these counties are also listed. Recall that we project future design values only for counties that have 1999-2001 design values, so this list is limited to those counties with ambient monitoring data sufficient to calculate these design values.

[Q] Since the air quality modeling and analyses performed at proposal used the 1999-2001 monitored data set, we present these data rather than the 2000-2002 data for consistency.

Table 2.3-4: Counties with 2020 and 2030 Projected Ozone Design Values in Violation of the 8-Hour Ozone Standard.[a]

State	County	1999 - 2001 Design Value (ppb)	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
CA	Fresno	108	V	V	V	V	799,407
CA	Kern	109	V	V	V	V	661,645
CA	Los Angeles	105	V	V	V	V	9,519,338
CA	Orange	77	V	V	V	V	2,846,289
CA	Riverside	111	V	V	V	V	1,545,387
CA	San Bernardino	129	V	V	V	V	1,709,434
CA	Ventura	101	V	V	V	V	753,197
CT	Fairfield	97	V	V	V	V	882,567
CT	Middlesex	99	V	V	V	V	155,071
CT	New Haven	97	V	V	V	V	824,008
GA	Bibb	98	V		V		153,887
GA	Fulton	107	V	V	V		816,006
GA	Henry	107	V		V		119,341
IL	Cook	88	V	V	V	V	5,376,741
IN	Lake	90			V		484,564
MD	Harford	104	V		V		218,590
MI	Macomb	88			V	V	788,149
MI	Wayne	88	V	V	V	V	2,061,162
NJ	Camden	103	V	V	V	V	508,932
NJ	Gloucester	101	V	V	V	V	254,673
NJ	Hudson	93	V	V	V	V	608,975
NJ	Hunterdon	100	V	V	V	V	121,989
NJ	Mercer	105	V	V	V	V	350,761
NJ	Middlesex	103	V	V	V	V	750,162
NJ	Ocean	109	V	V	V	V	510,916
NY	Bronx	83		V		V	1,332,650
NY	Richmond	98	V	V	V	V	443,728
NY	Westchester	92	V	V	V	V	923,459
PA	Bucks	105	V	V	V	V	597,635
PA	Montgomery	100	V	V	V	V	750,097
TX	Galveston	98	V	V	V	V	250,158
TX	Harris	110	V	V	V	V	3,400,578
WI	Kenosha	95	V	V	V	V	149,577
Number of Violating Counties			30	28	32	28	
Population of Violating Counties[b]			42,930,060	43,532,490	46,998,413	46,038,489	

[a] The projected emission reductions differ based on updated information (see Chapter 3.6); however, the base results presented here would not change, but we anticipate the control case improvements would generally be smaller.

[b] Populations are based on 2020 and 2030 estimates from the U.S. Census.

In Table 2.3-5 we present the counties with 1999-2001 design values and 2020 and 2030 projected 8-hour ozone design values that are within 10 percent of it in either base or control scenarios. Counties are marked with an "X" in the table if their projected design values are greater than or equal to 77 ppb, but less than 85 ppb. Counties are marked with a "V" in the table if their projected design values are greater than or equal to 85 ppb. This list is limited to those counties with ambient monitoring data sufficient to calculate these design values, and the 1999-2001 average design values of these counties are also presented. Most of these are counties are not projected to violate the standard, but their future values are project to be close to the standard. Thus, the final rule will help ensure that these counties continue to meet the standard.

Table 2.3-5
Counties with 2020 and 2030 Projected Ozone Design Values
within Ten Percent of the 8-Hour Ozone Standard.[a]

State	County	1999 - 2001 Design Value (ppb)	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
AR	Crittenden	92	X	X	X	X	50,866
AZ	Maricopa	85	X	X	X	X	3,072,149
CA	Kings	98	X	X	X	X	129,461
CA	Merced	101	X	X	X	X	210,554
CA	Tulare	104	X	X	X	X	368,021
CO	Jefferson	81	X	X	X	X	527,056
CT	New London	90	X		X		259,088
DC	Washington	94	X	X	X	X	572,059
DE	New Castle	97	X	X	X	X	500,265
GA	Bibb	98	V	X	V	X	153,887
GA	Coweta	96	X	X	X	X	89,215
GA	De Kalb	102	X	X	X	X	665,865
GA	Douglas	98	X		X		92,174
GA	Fayette	99	X		X		91,263
GA	Fulton	107	V	V	V	X	816,006
GA	Henry	107	V	X	V	X	119,341
GA	Rockdale	104	X	X	X	X	70,111
IL	McHenry	83	X		X		260,077
IN	Lake	90	X	X	V	X	484,564
IN	Porter	90	X	X	X	X	146,798
LA	Ascension	86	X	X	X	X	76,627
LA	Bossier	90	X	X	X	X	98,310
LA	Calcasieu	86	X	X	X	X	183,577
LA	East Baton Rouge	91	X	X	X	X	412,852
LA	Iberville	86	X		X		33,320
LA	Jefferson	89	X	X	X	X	455,466

State	County	1999 - 2001 Design Value (ppb)	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
LA	Livingston	88	X	X	X	X	91,814
LA	St Charles	86	X	X	X	X	48,072
LA	St James	83			X		21,216
LA	St John The Ba	86	X	X	X	X	43,044
LA	West Baton Rou	88	X	X	X	X	21,601
MA	Barnstable	96	X		X		222,230
MA	Bristol	93	X		X		534,678
MD	Anne Arundel	103	X	X	X	X	489,656
MD	Baltimore	93	X	X	X	X	754,292
MD	Cecil	106	X	X	X	X	85,951
MD	Harford	104	V	X	V	X	218,590
MD	Kent	100	X		X		19,197
MD	Prince Georges	97	X	X	X		801,515
MI	Benzie	89	X		X		15,998
MI	Macomb	88	X	X	V	V	788,149
MI	Mason	91	X		X		28,274
MI	Muskegon	92	X	X	X		170,200
MI	Oakland	84	X	X	X	X	1,194,156
MI	St Clair	85			X		164,235
MO	St Charles	90			X		283,883
MO	St Louis	88			X		1,016,315
MS	Hancock	87	X		X		42,967
MS	Harrison	89	X	X	X	X	189,601
MS	Jackson	87	X	X	X	X	131,420
NJ	Cumberland	97	X		X		146,438
NJ	Monmouth	94	X	X	X	X	615,301
NJ	Morris	97	X	X	X	X	470,212
NJ	Passaic	89	X	X	X	X	489,049
NY	Bronx	83	X	V	X	V	1,332,650
NY	Erie	92	X	X	X	X	950,265
NY	Niagara	87	X		X		219,846
NY	Putnam	89	X		X		95,745
NY	Suffolk	91	X	X	X	X	1,419,369
OH	Geauga	93	X		X		90,895
OH	Lake	91	X		X		227,511
PA	Allegheny	92	X		X		1,281,666
PA	Delaware	94	X	X	X	X	550,864
PA	Lancaster	96	X		X		470,658
PA	Lehigh	96	X	X	X	X	312,090
PA	Northampton	97	X	X	X	X	267,066

State	County	1999 - 2001 Design Value (ppb)	2020		2030		Population in 2000
			Base	Control[a]	Base	Control[a]	
PA	Philadelphia	88	X	X	X	X	1,517,550
RI	Kent	94	X	X	X		167,090
RI	Washington	92	X		X		123,546
TN	Shelby	93	X	X	X	X	897,472
TX	Brazoria	91	X	X	X	X	241,767
TX	Collin	99	X	X	X	X	491,675
TX	Dallas	93	X	X	X	X	2,218,899
TX	Denton	101	X	X	X	X	432,976
TX	Jefferson	85	X	X	X	X	252,051
TX	Montgomery	91	X		X	X	293,768
TX	Tarrant	97	X	X	X	X	1,446,219
VA	Alexandria City	88			X		128,283
VA	Arlington	92	X	X	X	X	189,453
VA	Fairfax	95	X	X	X	X	969,749
WI	Door	93	X	X	X	X	27,961
WI	Kewaunee	89	X		X		20,187
WI	Manitowoc	92	X	X	X		82,887
WI	Milwaukee	89	X	X	X	X	940,164
WI	Ozaukee	95	X	X	X	X	82,317
WI	Racine	87	X		X		188,831
WI	Sheboygan	95	X	X	X	X	112,646
WI	Waukesha	86	X		X		360,767
Number of Counties within 10%			79	58	82	54	
Population of Counties within 10%[b]			40,465,492	33,888,031	44,013,587	35,631,215	

[a] The projected emission reductions differ based on updated information (see Section 3.6); however, the base results presented here would not change, but we anticipate the control case improvements would generally be smaller.
[b] Populations are based on 2020 and 2030 estimates from the U.S. Census.

Based on our modeling, we are also able to provide a quantitative prediction of the number of people anticipated to reside in counties in which ozone concentrations are predicted to for 8-hour periods in the range of 85 to 120 ppb and higher on multiple days. Our analysis relies on projected county-level population from the U.S. Department of Census for the period representing each year analyzed.[324]

For each of the counties analyzed, we determined the number of days for periods on which the highest model-adjusted 8-hour concentration at any monitor in the county was predicted, for example, to be equal to or above 85 ppb. We then grouped the counties that had days with ozone in this range according to the number of days this was predicted to happen and summed their projected populations.

In the base case (i.e., before the application of emission reductions resulting from this rule), we estimated in 2020 that 53 million people are predicted to live in counties with at least 2 days with 8-hour average concentrations of 85 ppb or higher. This baseline will increase in 2030 to 56 million people are predicted to live in counties with at least 2 days with 8-hour average concentrations of 85 ppb or higher. About 30 million people live in counties with at least 7 days of 8-hour ozone concentrations at or above 85 ppb in 2020 and 2030 without additional controls. Approximately 15 million people are predicted to live in counties with at least 20 days of 8-hour ozone concentrations at or above 85 ppb in 2020 and 2030 without additional controls.[325] Thus, reductions in ozone precursors from nonroad diesel engines are needed to assist States in meeting the ozone NAAQS and to reduce ozone exposures.

2.3.2.3 Potentially Counterproductive Impacts on Ozone Concentrations from NOx Emission Reductions

While this final rule will reduce ozone levels generally and provide significant ozone-related health benefits, this is not always the case at the local level. Due to the complex photochemistry of ozone production, NOx emissions lead to both the formation and destruction of ozone, depending on the relative quantities of NOx, VOC, and ozone catalysts such as the OH and HO_2 radicals. In areas dominated by fresh emissions of NOx, ozone catalysts are removed via the production of nitric acid, which slows the ozone formation rate. Because NOx is generally depleted more rapidly than VOC, this effect is usually short-lived and the emitted NOx can lead to ozone formation later and further downwind. The terms “NOx disbenefits” or “ozone disbenefits” refer to the ozone increases that can result from NOx emission reductions in these localized areas. According to the NARSTO Ozone Assessment, these disbenefits are generally limited to small regions within specific urban cores and are surrounded by larger regions in which NOx control is beneficial.[326]

In the context of ozone disbenefits, some have postulated that present-day weekend conditions serve as a demonstration of the effects of future NOx reduction strategies because NOx emissions decrease more than VOC emissions on weekends, due to a disproportionate decrease in the activity of heavy-duty diesel trucks and other diesel equipment. Recent research indicates that ambient ozone levels are higher in some metropolitan areas on weekends than weekdays.[327, 328] There are other hypotheses for the cause of the “weekend effect.”[329] For instance, the role of ozone and ozone precursor carryover from previous days is difficult to evaluate because of limited ambient data, especially aloft. The role of the changed timing of emissions is difficult to evaluate because of limited ambient and emission inventory information. It is also important to note that in many areas with “weekend effects” (e.g., Los Angeles and San Francisco) significant ozone reductions have been observed over the past 20 years for all days of the week, during a period in which both NOx and VOC emissions have been greatly reduced.

We received some public comments that in some cities, decreased motor vehicle traffic (particularly diesels) results in a higher VOC/NOx ratio which, in airsheds that are VOC-limited, can result in higher ozone concentrations. EPA’s air quality modeling predicts NOx disbenefits in the areas identified by some studies as “VOC-limited” (e.g., Los Angeles). However, these areas represent a small minority of the area in the United States. While some empirical studies to date point to a weekend ozone effect related to NOx reduction, modeling conducted for this rule predicts that this rule will result in net gains in benefits as a result of reduced ozone and $PM_{2.5}$ related to NOx.

EPA maintains that the best available approach for determining the value of a particular emission reduction strategy is the net air quality change projected to result from the rule, evaluated on a nationwide basis and for all pollutants that are health and/or welfare concerns. The primary tool for assessing the net impacts of this rule are the air quality simulation models.[330] Model scenarios of 2020 and 2030 with and without the emission controls from this rulemaking are compared to determine the expected changes in future pollutant levels resulting from the rule. There are several factors related to the air quality modeling and inputs that should be considered regarding the disbenefit issue. First, our future year modeling does not contain any local governmental actions beyond the controls in this rule. It is possible that significant local controls of VOC and/or NOx could modify the conclusions regarding ozone changes in some areas. Second, the modeled NOx reductions are greater than those actually included in the analysis to quantify the emission reductions resulting from the final rule (see Section 3.6 for more detail). This could lead to an exaggeration of the benefits and disbenefits expected to result from the rule. Also, recent work by California ARB has indicated that model limitations and uncertainties may lead to overestimates of ozone disbenefits attributed to NOx emission reductions. While EPA maintains that the air quality simulations conducted for the rule represent state-of-the-science analyses, any changes to the underlying chemical mechanisms, grid resolution, and emissions/meteorological inputs could result in revised conclusions regarding the strength and frequency of ozone disbenefits.

A wide variety of ozone metrics were considered in assessing the emission reductions. Three of the most important assessments are: 1) the effect of the rule on projected future-year ozone violations, 2) the effect of the rule in assisting local areas in attainment and maintenance of the NAAQS, and 3) an economic assessment of the rule benefits based on existing health studies. Additional metrics for assessing the air quality effects are discussed in the TSD for the modeling.

Based only on the reductions from this rule, our modeling predicts that periodic ozone disbenefits will occur most frequently in New York City, Los Angeles, and Chicago. Smaller and less frequent disbenefits also occur in Boston, Detroit, and San Francisco. As described below, despite these localized increases, the net ozone impact of the rule nationally is positive for the majority of the analysis metrics. Even within the few metropolitan areas that experience periodic ozone increases, these disbenefits are infrequent relative to the benefits accrued at ozone levels above the NAAQS. Furthermore, and most importantly, the overall air quality impact of this final rule is projected to be strongly positive due to the expected reductions in fine PM.

The projected net impact of the rule on 8-hour ozone violations in 2020 is that three counties will no longer violate the NAAQS.[331] Conversely, one county in the NewYork City CMSA (Bronx County), which is currently not in violation of the NAAQS, is projected to violate the standard in 2020 as a result of the rule. The net effect is a projected 1.4 percent increase in the population living in violating counties. It is important to note that ozone nonattainment designations are historically based on larger geographical areas than counties (e.g., see public comments from New York Department of Environmental Conservation requesting that EPA use metropolitan areas instead of counties for its analyses for this reason). Bronx County, NY is the only county within the New York City CMSA in which increases are detected in 8-hour violations in 2020. Considering a larger area, the modeling indicates that projected violations over the entire New York City CMSA will be reduced by 6.8 percent. Upon full turnover of the fleet in 2030, the net impact of the rule on projected 8-hour ozone violations is a 2.0 percent decrease in the population living in violating counties as two additional counties are no longer projected to violate the NAAQS. The net impact of the rule on projected 1-hour ozone violations is to eradicate projected violations from four counties (in both 2020 and 2030), resulting in a 10.5 percent decrease in the population living in violating counties.

Another way to assess the air quality impact of the rule is to calculate its effect on all projected future year design values concentrations, as opposed to just those that cross the threshold of the NAAQS. This metric helps assess the degree to which the rule will assist local areas in attaining and/or maintaining the NAAQS. Future year design values were calculated for every location for which complete ambient monitoring data existed for the period 1999-2001. These present-day design values were then projected by using the modeling projections (future base vs. future control) in a relative sense. For the 1999-2001 monitoring period, there were sites in 522 counties for which 8-hour design values could be calculated and sites in 510 counties for which 1-hour design values could be calculated.

Table 2.3.2-1 shows the average change in future year eight-hour and one-hour ozone design values. Average changes are shown 1) for all counties with design values in 2001, 2) for counties with design values that did not meet the standard in 1999-2001 (“violating” counties), and 3) for counties that met the standard, but were within 10 percent of it in 1999-2001. This last category is intended to reflect counties that meet the standard, but will likely benefit from help in maintaining that status in the face of growth. The average and population-weighted average over all counties in Table 2.3.2-1 demonstrates a broad improvement in ozone air quality. The average across violating counties shows that the rule will help bring these counties into attainment. The average over counties within ten percent of the standard shows that the rule will also help those counties to maintain the standard. All of these metrics show a decrease in 2020 and a larger decrease in 2030 (due to fleet turnover), indicating in four different ways the overall improvement in ozone air quality as measured by attainment of the NAAQS.

Table 2.3.2-1
Average Change in Projected Future-Year Ozone Design Value[f]

Design Value	Average[a]	Number of Counties	2020 Control[f] minus Base (ppb)	2030 Control[f] minus Base (ppb)
8-Hour	All	522	-1.8	-2.8
	All, population-weighted	522	-1.6	-2.6
	Violating counties[b]	289	-1.9	-3
	Counties within 10 percent of the standard[c]	130	-1.7	-2.6
1-Hour	All	510	-2.4	-3.8
	All, population-weighted	510	-2.3	-3.6
	Violating counties[d]	73	-2.9	-4.5
	Counties within 10 percent of the standard[e]	130	-2.4	-3.8

[a] Averages are over counties with 2001 design values.
[b] Counties whose present-day design values exceeded the 8-hour standard (≥ 85 ppb).
[c] Counties whose present-day design values were less than but within 10 percent of the 8-hour standard (77≤DV<85 ppb).
[d] Counties whose present-day design values exceeded the 1-hour standard (≥ 125 ppb).
[e] Counties whose present-day design values were less than but within 10 percent of the 1-hour standard (112≤DV<125 ppb) in 2001.
[f] The analysis in Chapter 3 differs based on updated information; however, we believe that the net results would approximate future emissions, although we anticipate the design value improvements would generally be slightly smaller.

Table 2.3.2-2 presents counts of the same set of counties (those with 1999-2001 design values) examined by the size and direction of their change in design value in 2020 and 2030. For the 8-hour design value, 96 percent of counties show a decrease in 2020, 97 percent in 2030. For the 1-hour design value, 97 percent of counties show a decrease in 2020, 98 percent in 2030.

Table 2.3.2-2
Numbers of Counties Projected to Be in
Different Design-Value Change Bins in 2020 and 2030 as a Result of the Rule[a]

Design value change	2020		2030	
	8-Hour	1-Hour	8-Hour	1-Hour
≥ 2ppb increase	1	1	1	1
1 ppb increase	1	5	3	2
No change	21	10	10	5
1 ppb decrease	140	69	42	22
2-3 ppb decrease	357	356	333	193
4 ppb decrease	2	69	133	287
Total	522	510	522	510

[a] The analysis in Chapter 3 differs based on updated information; however, we believe that the net results would approximate future emissions, although we anticipate the design value improvements would generally be slightly smaller.

A third way to assess the impacts of the rule is an economic consideration of the economic benefits. Benefits related to changes in ambient ozone are expected to be positive for the nation as a whole. However, for certain health endpoints associated with longer ozone-averaging times, such as minor restricted activity days related to 24-hour average ozone, the national impact may be small or even negative. This is due to the forecasted increases in ozone for certain hours of the day in some urban areas. Many of the increases occur during hours when baseline ozone levels are low, but the benefits estimates rely on the changes in ozone along the full distribution of baseline ozone levels, rather than changes occurring only above a particular threshold. As such, the benefits estimates are more sensitive to increases in ozone occurring due to the "NOx disbenefits" effect described above. For more details on the economic effects of the rule, please see Chapter 9: Public Health and Welfare Benefits.

Historically, NOx reductions have been very successful at reducing regional and national ozone levels. Consistent with that fact, the photochemical modeling completed for this rule indicates that the projected emission reductions will significantly assist in the attainment and maintenance of the ozone NAAQS at the national level. Furthermore, NOx reductions also result in reductions in PM and its associated health and welfare effects. This rule is one aspect of overall emission reductions that States, local governments, and Tribes need to reach their clean air goals. It is expected that future state, local and national controls that decrease VOC, CO, and regional ozone will mitigate any localized disbenefits. EPA will continue to rely on local attainment measures to ensure that the NAAQS are not violated in the future. Many organizations with an interest in improved air quality have supported the rule because they believe the resulting NOx reductions will reduce both ozone and PM.[332] EPA believes that a balanced air quality management approach that includes NOx emission reductions from nonroad engines is needed as part of the nation's progress toward clean air.

2.3.3 Welfare Effects Associated with Ozone and its Precursors

There are a number of significant welfare effects associated with the presence of ozone and NO_X in the ambient air.[333] Because this rule will reduce ground-level ozone and nitrogen deposition, benefits are expected to accrue to the welfare effects categories described in the following paragraphs.

2.3.3.1 Ozone-related welfare effects.

The Ozone Criteria Document notes that "ozone affects vegetation throughout the United States, impairing crops, native vegetation, and ecosystems more than any other air pollutant."[334] Like carbon dioxide (CO_2) and other gaseous substances, ozone enters plant tissues primarily through apertures (stomata) in leaves in a process called "uptake". To a lesser extent, ozone can also diffuse directly through surface layers to the plant's interior.[335] Once ozone, a highly reactive substance, reaches the interior of plant cells, it inhibits or damages essential cellular components and functions, including enzyme activities, lipids, and cellular membranes, disrupting the plant's osmotic (i.e., water) balance and energy utilization patterns.[336, 337] This damage is commonly manifested as visible foliar injury such as chlorotic or necrotic spots, increased leaf senescence (accelerated leaf aging) and/or as reduced photosynthesis. All these effects reduce a plant's capacity to form carbohydrates, which are the primary form of energy used by plants.[338] With fewer resources available, the plant reallocates existing resources away from root growth and storage, above ground growth or yield, and reproductive processes, toward leaf repair and maintenance. Studies have shown that plants stressed in these ways may exhibit a general loss of vigor, which can lead to secondary impacts that modify plants' responses to other environmental factors. Specifically, plants may become more sensitive to other air pollutants, more susceptible to disease, insect attack, harsh weather (e.g., drought, frost) and other environmental stresses (e.g., increasing CO_2 concentrations). Furthermore, there is considerable evidence that ozone can interfere with the formation of mycorrhiza, essential symbiotic fungi associated with the roots of most terrestrial plants, by reducing the amount of carbon available for transfer from the host to the symbiont.[339]

Not all plants, however, are equally sensitive to ozone. Much of the variation in sensitivity between individual plants or whole species is related to the plant's ability to regulate the extent of gas exchange via leaf stomata (e.g., avoidance of O_3 uptake through closure of stomata).[340, 341, 342] Other resistance mechanisms may involve the intercellular production of detoxifying substances. Several biochemical substances capable of detoxifying ozone have been reported to occur in plants including the antioxidants ascorbate and glutathione. After injuries have occurred, plants may be capable of repairing the damage to a limited extent.[343] Because of the differing sensitivities among plants to ozone, ozone pollution can also exert a selective pressure that leads to changes in plant community composition. Given the range of plant sensitivities and the fact that numerous other environmental factors modify plant uptake and response to ozone, it is not possible to identify threshold values above which ozone is toxic for all plants. However, in general, the science suggests that ozone concentrations of 0.10 ppm or greater can be phytotoxic to a large number of plant species, and can produce acute foliar injury responses, crop yield loss and reduced biomass production. Ozone concentrations below 0.10 ppm (0.05 to 0.09 ppm) can produce these effects in more sensitive plant species, and have the potential over a longer duration of creating chronic stress on vegetation that can lead to effects of concern associated with reduced carbohydrate production and decreased plant vigor.

The economic value of some welfare losses due to ozone can be calculated, such as crop yield loss from both reduced seed production (e.g., soybean) and visible injury to some leaf crops (e.g., lettuce, spinach, tobacco) and visible injury to ornamental plants (i.e., grass, flowers, shrubs), while other types of welfare loss may not be fully quantifiable in economic terms (e.g., reduced aesthetic value of trees growing in Class I areas).

Forests and Ecosystems. Ozone also has been shown conclusively to cause discernible injury to forest trees.[344, 345] In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts.[346] Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function.[347, 348, 349]

Because plants are at the center of the food web in many ecosystems, changes to the plant community can affect associated organisms and ecosystems (including the suitability of habitats that support threatened or endangered species and below ground organisms living in the root zone). Ozone damages at the community and ecosystem-level vary widely depending upon numerous factors, including concentration and temporal variation of tropospheric ozone, species composition, soil properties and climatic factors.[350] In most instances, responses to chronic or recurrent exposure are subtle and not observable for many years. These injuries can cause stand-level forest decline in sensitive ecosystems.[351, 352, 353] It is not yet possible to predict ecosystem responses to ozone with much certainty; however, considerable knowledge of potential ecosystem responses has been acquired through long-term observations in highly damaged forests in the United States.

Given the scientific information establishing that ambient ozone levels cause visible injury to foliage of some sensitive forest species,[354] there is a corresponding loss of public welfare from reduced aesthetic properties of forests.[355] However, present analytic tools and resources preclude EPA from quantifying the benefits of improved forest aesthetics.

Agriculture. Laboratory and field experiments have shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN) examined 15 species and numerous cultivars. The NCLAN results show that "several economically important crop species are sensitive to ozone levels typical of those found in the Unites States."[356] In addition, economic studies have shown a relationship between observed ozone levels and crop yields.[357 358 359]

Urban Ornamentals. Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels and likely to impact large economic sectors. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative analysis has been conducted. It is estimated that more than $20 billion (1990 dollars) are spent annually on landscaping using ornamentals, both by private property owners/tenants and by governmental units responsible for public areas.[360] This is therefore a potentially important environmental effect. However, methods are not available to allow for plausible estimates of the percentage of these expenditures that may be related to impacts associated with ozone exposure.

2.3.3.2 Nitrogen (NO_X)-related welfare effects.

Agriculture. By reducing NO_X emissions, this final rule will also reduce nitrogen deposition on agricultural land and forests. There is some evidence that nitrogen deposition may have positive effects on agricultural output through passive fertilization. Holding all other factors constant, farmers' and commercial tree growers use of purchased fertilizers or manure may increase as deposited nitrogen is reduced. Estimates of the potential value of this possible increase in the use of purchased fertilizers are not available, but it is likely that the overall value is very small relative to other health and welfare effects. The share of nitrogen requirements provided by this deposition is small, and the marginal cost of providing this nitrogen from alternative sources is quite low. In some areas, agricultural lands suffer from nitrogen over-saturation due to an abundance of on-farm nitrogen production, primarily from animal manure. In these areas, reductions in atmospheric deposition of nitrogen represent additional agricultural benefits.

Forests and Ecosystems. Information on the effects of changes in passive nitrogen deposition on forests and other terrestrial ecosystems is very limited. The multiplicity of factors affecting forests, including other potential stressors such as ozone, and limiting factors such as moisture and other nutrients, confound assessments of marginal changes in any one stressor or nutrient in forest ecosystems. However, reductions in nitrogen deposition can have negative effects on forest and vegetation growth in ecosystems where nitrogen is a limiting factor.[361]

On the other hand, there is evidence that forest ecosystems in some areas of the United States are already or are becoming nitrogen saturated.[362] Once saturation is reached, adverse effects of additional nitrogen begin to occur, such as soil acidification, which can lead to leaching of nutrients needed for plant growth and mobilization of harmful elements such as aluminum, leading to reductions in tree growth or forest decline. Increased soil acidification is also linked to higher amounts of acidic runoff to streams and lakes and leaching of harmful elements into aquatic ecosystems, harming fish and other aquatic life.[363]

The reductions in ground-level ozone and nitrogen deposition that will result from this rule are expected to reduce the adverse impacts described above. In particular, it is expected that economic impacts, such as those related to reduced crop yields and forest productivity, will be reduced.

2.4 Carbon Monoxide

This final rule will reduce levels of other pollutants for which NAAQS have been established: carbon monoxide (CO), nitrogen dioxide (NO_2), and sulfur dioxide (SO_2). Currently every area in the United States has been designated to be in attainment with the NO_2 NAAQS. As of August 27, 2003, there were 24 areas designated as nonattainment with the SO2 standard, and 11 designated CO nonattainment areas. The rest of this section describes issues related to CO.

2.4.1 General Background

Unlike many gases, CO is odorless, colorless, tasteless, and nonirritating. Carbon monoxide results from incomplete combustion of fuel and is emitted directly from vehicle tailpipes. Incomplete combustion is most likely to occur at low air-to-fuel ratios in the engine. These conditions are common during vehicle starting when air supply is restricted ("choked"), when vehicles are not tuned properly, and at high altitude, where "thin" air effectively reduces the amount of oxygen available for combustion (except in engines that are designed or adjusted to compensate for altitude). High concentrations of CO generally occur in areas with elevated mobile-source emissions. Carbon monoxide emissions increase dramatically in cold weather. This is because engines need more fuel to start at cold temperatures and because some emission control devices (such as oxygen sensors and catalytic converters) operate less efficiently when they are cold. Also, nighttime inversion conditions are more frequent in the colder months of the year. This is due to the enhanced stability in the atmospheric boundary layer, which inhibits vertical mixing of emissions from the surface.

As described in Chapter 3, nonroad diesel engines currently account for about one percent of the national mobile source CO inventory. EPA previously determined that the category of nonroad diesel engines cause or contribute to ambient CO and ozone in more than one nonattainment area (65 FR 76790, December 7, 2000). In that action, EPA found that engines subject to this final rule contribute to CO nonattainment in areas such as Los Angeles, Phoenix, Spokane, Anchorage, and Las Vegas. Nonroad land-based diesel engines emitted 1,004,600 tons of CO in 1996 (1 percent of mobile source CO). Thus, nonroad diesel engines contribute to CO nonattainment in more than one of these areas.

Although nonroad diesel engines have relatively low per-engine CO emissions, they can be a significant source of ambient CO levels in CO nonattainment areas. Thus, the emission benefits from this final rule will help areas to attain and maintain the CO NAAQS.

2.4.2 Health Effects of CO

Carbon monoxide enters the bloodstream through the lungs and forms carboxyhemoglobin (COHb), a compound that inhibits the blood's capacity to carry oxygen to organs and tissues.[364, 365] Carbon monoxide has long been known to have substantial adverse effects on human health, including toxic effects on blood and tissues, and effects on organ functions. Although there are effective compensatory increases in blood flow to the brain, at some concentrations of COHb, somewhere above 20 percent, these compensations fail to maintain sufficient oxygen delivery, and metabolism declines.[366] The subsequent hypoxia in brain tissue then produces behavioral effects, including decrements in continuous performance and reaction time.[367]

Carbon monoxide has been linked to increased risk for people with heart disease, reduced visual perception, cognitive functions and aerobic capacity, and possible fetal effects.[368] Persons with heart disease are especially sensitive to carbon monoxide poisoning and may experience chest pain if they breathe the gas while exercising.[369] Infants, elderly persons, and individuals with respiratory diseases are also particularly sensitive. Carbon monoxide can affect healthy individuals, impairing exercise capacity, visual perception, manual dexterity, learning functions, and ability to perform complex tasks.[370]

Several recent epidemiological studies have shown a link between CO and premature morbidity (including angina, congestive heart failure, and other cardiovascular diseases. Several studies in the United States and Canada have also reported an association of ambient CO exposures with frequency of cardiovascular hospital admissions, especially for congestive heart failure (CHF). An association of ambient CO exposure with mortality has also been reported in epidemiological studies, though not as consistently or specifically as with CHF admissions. EPA reviewed these studies as part of the Criteria Document review process.[371]

2.4.3 CO Nonattainment

The current primary NAAQS for CO are 35 parts per million for the one-hour average and 9 parts per million for the eight-hour average. These values are not to be exceeded more than once per year. Air quality carbon monoxide value is estimated using EPA guidance for calculating design values. Over 19 million people currently live in the 11 nonattainment areas for the CO NAAQS.

Nationally, significant progress has been made over the last decade to reduce CO emissions and ambient CO concentrations. Total CO emissions from all sources have decreased 16 percent from 1989 to 1998, and ambient CO concentrations decreased by 39 percent. During that time, while the mobile source CO contribution of the inventory remained steady at about 77 percent, the highway portion decreased from 62 percent of total CO emissions to 56 percent while the nonroad portion increased from 17 percent to 22 percent.[372] Over the next decade, we expect there to be a minor decreasing trend from the highway segment due primarily to the more stringent standards for certain light-duty trucks and gasoline nonroad engines.[373] CO standards for passenger cars and other light-duty trucks and heavy-duty vehicles did not change as a result of other recent rulemakings.

As noted above, CO has been linked to numerous health effects; however, we are unable to quantify the CO-related health or environmental effects of the Nonroad Diesel Engine rule at this time. However, nonroad diesel engines do contribute to nonattainment in some areas. Thus, the emission benefits from this rule will help areas to attain and maintain the CO NAAQS.

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373. Ref for Tier 2 and Large SI rules

CHAPTER 3: Emission Inventory

CHAPTER 3: Emission Inventory

This chapter presents our analysis of the emission impact of the final rule for the four categories of nonroad diesel engines affected: land-based diesel engines, commercial marine diesel vessels, locomotives, and recreational marine diesel engines. New engine controls are being adopted for the land-based diesel engine category. For the other three nonroad diesel categories, the final rule includes no new engine controls; however, the diesel fuel sulfur requirements will decrease emissions of particulate matter smaller than 2.5 microns ($PM_{2.5}$) and sulfur dioxide (SO_2) for these categories.

Section 3.1 presents an overview of the methodology used to generate the baseline inventories. The baseline inventories represent current and future emissions with only the existing standards. Sections 3.2 and 3.3 then describe the contribution of nonroad diesel engines to national and selected local baseline inventories, respectively. Section 3.4 describes the development of the controlled inventories, specifically the changes made to the baseline inputs to incorporate the new standards and fuel sulfur requirements. Section 3.5 follows with the projected emission reductions resulting from the final rule. Section 3.6 concludes the chapter by describing the changes in the inputs and resulting emission inventories between the preliminary baseline and control scenarios used for the air quality modeling and the updated baseline and control scenarios in this final rule.

The controlled inventory estimates do not include the potential uses of the averaging, banking, and trading (ABT) program or the transition provisions for engine manufacturers, since these are flexibilities that would be difficult to predict and model. More information regarding these provisions can be found in Section III of the preamble.

The estimates of baseline emissions and emission reductions for nonroad land-based, recreational marine, locomotive, and commercial marine vessel diesel engines are reported for both 48-state and 50-state inventories. The 48-state inventories are used for the air quality modeling that EPA uses to analyze regional ozone and PM air quality, of which Alaska and Hawaii are not a part. In addition, 50-state emission estimates for other sources (such as stationary and area sources) are not available. As a result, in cases where nonroad diesel sources are compared with other emission sources, the 48-state emission inventory estimates are used.

Inventories are presented for the following pollutants: $PM_{2.5}$, PM_{10}, oxides of nitrogen (NO_x), SO_2, volatile organic compounds (VOC), carbon monoxide (CO), and air toxics. The specific air toxics are benzene, formaldeyde, acetaldehyde, 1,3-butadiene, and acrolein. The PM inventories include directly emitted PM only, although secondary sulfates are taken into account in the air quality modeling.

3.1 Nonroad Diesel Baseline Emission Inventory Development

This section describes how the baseline emission inventories were developed for the four categories of nonroad diesel engines affected by this final rule: land-based diesel engines, commercial marine diesel vessels, locomotives, and recreational marine diesel engines. For land-based diesel engines, there is a section that discusses inventory development for $PM_{2.5}$, NO_x, SO_2, VOC, and CO, followed by a section for air toxics.

3.1.1 Land-Based Nonroad Diesel Engines—$PM_{2.5}$, NO_x, SO_2, VOC, and CO Emissions

The baseline emission inventories for land-based diesel engines were generated using the draft NONROAD2004 model. The baseline inventories account for the effect of existing federal emission standards that establish three tiers of emission standards (Tier 1 through Tier 3). Section 3.1.1.1 provides an overview of the draft NONROAD2004 model and a description of the methodology used in the model to estimate emissions. Details of the baseline modeling inputs (e.g., populations, activity, and emission factors) for land-based diesel engines can be found in the technical reports documenting the model. The single scenario option variable that affects diesel emissions is the in-use fuel sulfur level. The in-use diesel fuel sulfur level inputs used for the baseline scenarios are given in Section 3.1.1.2.3.

For the proposed rule, the draft NONROAD2002 model was used. Section 3.1.1.8 describes the changes made to the model for the final rule.

3.1.1.1 Overview

The draft NONROAD2004 model estimates emission inventories of important air emissions from diverse nonroad equipment. The model's scope includes all nonroad sources with the exception of locomotives, aircraft and commercial marine vessels. Users can construct inventories for criteria pollutants including carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_2), and particulate matter (PM), as well as other emissions including total hydrocarbon (THC) and carbon dioxide (CO_2). As a related feature, the model estimates fuel consumption. The model can distinguish emissions on the basis of equipment type, size and technology group. A central feature of the model is projection of future or past emissions between 1970 and 2050.

The draft NONROAD2004 model contains three major components: (1) the core model, a FORTRAN program that performs model calculations, (2) the reporting utility, a Microsoft Access application that compiles and presents results, and (3) the graphic user interface (GUI), a Visual-Basic application that allows users to easily construct scenarios for submission to the core model. The following discussion will describe processes performed by the core model in the calculation of emission inventories.

This section describes how the draft NONROAD2004 model estimates emissions particularly relevant to this analysis, including particulate matter (PM), oxides of nitrogen (NO_x), oxides of sulfur (SO_2), carbon monoxide (CO) and volatile organic compounds (VOC). As appropriate, we will focus on estimation of emissions of these pollutants by diesel engines. The model estimates emissions from approximately 80 types of diesel equipment. As with other engine classes, the model defines engine or equipment "size" in terms of the rated power (horsepower) of the engine. For diesel engines, the regulations also classify engines on the basis of rated power.

The first four chemical species are exhaust emissions, i.e., pollutants emitted directly as exhaust from combustion of diesel fuel in the engine. However, the last emission, VOC, includes both exhaust and evaporative components. The exhaust component represents hydrocarbons emitted as products of combustion; the evaporative component includes compounds emitted from unburned fuel during operation, i.e., "crankcase emissions." For VOC, we will first describe estimation of total hydrocarbon exhaust emissions, in conjunction with the description for the other exhaust emissions. We discuss subsequent estimation of associated VOC emissions in Section 3.1.1.4.

3.1.1.2 NONROAD's Major Inputs

The draft NONROAD2004 model uses three major sets of inputs in estimation of exhaust emission inventories: (1) emission calculation variables, (2) projection variables, and (3) scenario option variables.

3.1.1.2.1 Emission Calculation Variables

The draft NONROAD2004 model estimates exhaust emissions using the equation

$$I_{\text{exh}} = E_{\text{exh}} \cdot A \cdot L \cdot P \cdot N$$

where each term is defined as follows:

I_{exh} = the exhaust emission inventory (gram/year, gram/day),
E_{exh} = exhaust emission factor (gram/hp-hr),
A = equipment activity (operating hours/year),
L = Load factor (average proportion of rated power used during operation (percent)),
P = average rated power (hp)
N = Equipment population (units).

Emissions are then converted and reported as tons/year or tons/day.

For diesel engines, each of the inputs applies to sub-populations of equipment, as classified by type (dozer, tractor, backhoe, etc.), rated power class (50-100 hp, 100-300 hp, etc.) and regulatory tier (tier 1, tier 2, etc.).

Exhaust Emission Factor. The emission factor in a given simulation year consists of three components, a "zero-hour" emission level (ZHL) , a transient adjustment factor (TAF) and a deterioration factor (DF). The ZHL represents the emission rate for recently manufactured engines, i.e., engines with few operating hours, and is typically derived directly from laboratory measurements on new or nearly new engines on several commonly used duty cycles, hence the term "zero-hour."

Because most emission data have been collected under steady-state conditions (constant engine speed and load), and because most real-world operation involves transient conditions (variable speed and load), we attempt to adjust for the difference between laboratory measurements and real-world operation through the use of transient adjustment factors (TAFs). The TAF is a ratio representing the difference in the emission rate between transient and steady-state operation. The TAFs are estimated by collecting emission measurements on specific engines using both transient and steady-state cycles, and calculating the ratio

$$\mathrm{TAF} = \frac{\mathrm{EF}_{\mathrm{transient}}}{\mathrm{EF}_{\mathrm{steady-state}}}$$

where $\mathrm{EF}_{\mathrm{transient}}$ is the measurement for a given engine on a specific transient cycle, and $\mathrm{EF}_{\mathrm{steady\text{-}state}}$ is the corresponding measurement for the same engine on a selected steady-state cycle. Data from seven transient cycles were used to develop seven TAFs for each of the four pollutants. The seven cycle TAFs were then binned into two categories, based on the cycle load factors. TAFs were then assigned to each equipment type represented in the model on the basis of engineering judgment. If steady-state operation was typical of an equipment type, no adjustment was made (i.e., TAF = 1.0).

Emission factors in the model input file represent the product (ZHL·TAF) for each combination of equipment type, size class and regulatory tier represented by the model. We refer to this product as the "baseline emission factor." For more detail on the derivation and application of EFs and TAFs, refer to the model documentation on diesel emission factors.[1]

During a model run, the model applies emission deterioration to the baseline emission factor, based on the age distribution of the equipment type in the year simulated. Deterioration expresses an assumption that emissions increase with equipment age and is expressed as a multiplicative deterioration factor (DF). Thus, the final emission factor applied in the simulation year is the product ZHL·TAF·DF. Deterioration factors vary from year to year; we describe their calculation in more detail in Section 3.1.1.2.2 below.

The model estimates fuel consumption by substituting brake-specific fuel consumption (BSFC, lb/hp-hr) for the emission factor in the equation above. We apply a TAF to the BSFC but assume that BSFC does not deteriorate with equipment age.

In estimation of PM emissions, we apply an additional adjustment to the emission factor to account for the in-use sulfur level of diesel fuel.[1] Based on user-specified diesel sulfur levels for a given scenario, NONROAD adjusts the PM emission factor by the margin S_{PMadj} (g/hp-hr) calculated as

$$S_{PMadj} = BSFC \cdot m_{SO4,S} \cdot m_{PM,S} \cdot 0.01 \cdot (S_{base} - S_{in-use})$$

where: BSFC = brake-specific fuel consumption (g fuel/hp-hr),

$m_{SO4,S}$ = a constant, representing the sulfate fraction of total particulate sulfur, equal to 7.0 g PM SO_4/g PM S,

$m_{PM,S}$ = a constant, representing the fraction of fuel sulfur converted to particulate sulfur, equal to 0.02247 g PM S/g fuel S,

0.01 = conversion factor from wt% to wt fraction

S_{base} = base sulfur level in NONROAD (0.33 wt%, 3300 ppm for pre-control and Tier 1 engines; 0.20 wt%, 2000 ppm for Tier 2-3 engines),

S_{in-use} = in-use diesel sulfur level as specified by user (wt%).

Equipment Activity. Activity represents the usage of equipment, expressed in operating hours per year. Activity estimates are specific to equipment types and remain constant in any given simulation year. Activity estimates for diesel equipment have been adopted from the *Partslink* model, a commercial source developed and maintained by Power Systems Research/Compass International, Inc. For discussion of activity estimates for specific equipment types, refer to the technical documentation for the model.[2]

Load Factor. This parameter represents the average fraction of rated power that equipment uses during operation. Load factors are assigned by equipment type, and remain constant in any simulation year. For use in draft NONROAD2004, we derived load factors from the results of a project designed to develop transient engine test cycles. During the course of the project, seven cycles were developed, designed to represent the operation of specific common equipment types.

Specific load factors for the cycles fell into two broad groups, which we designated as “high” and “low.” We calculated an average for each group, with the high group containing four cycles and the low group three; resulting load factors were 0.59 for the high group and 0.21 for the low group. Then, we assigned one of these two factors to each equipment type for which we believed engineering judgment was sufficient to make an assignment. For remaining equipment types, for which we considered engineering judgment insufficient to make an assignment, we assigned a ‘steady-state’ load factor, calculated as the average of load factors for all seven transient cycles (0.43). Of NONROAD’s 90 diesel applications, half were assigned ‘high’ or ‘low’ load factors, with the remainder assigned ‘steady-state’ load factors. For more detail on the derivation of load factors and assignment to specific equipment types, refer to the appropriate technical report[2].

Rated Power. This parameter represents the average rated power for equipment, as assigned to each combination of equipment type and rated-power class represented by the model. Values assigned to a given type/power combination represents the sales-weighted average of engines for that equipment type in that rated-power class.[3] Rated-power assignments remain constant in any given simulation year. For use in draft NONROAD2004, we obtained estimates from the *Partslink* database, maintained by Power Systems Research/Compass International, Inc. The product of load factor and rated power (*LP*) represents actual power output during equipment operation.

Equipment Population. As the name implies, this model input represents populations of equipment pieces. For diesel engines, the model generates separate sub-populations for individual combinations of equipment type and rated-power class. However, unlike activity and load factor, populations do not remain constant from year to year. Projection of future or past populations is the means through which the draft NONROAD2004 model projects future or past emissions. As a reference point, the input file contains populations in the model's base year 2000 (updated from 1998 in draft NONROAD2002). We generated populations in the base year using a simple attrition model that calculated base-year populations as a function of equipment sales, scrappage, activity and load factor. Equipment sales by model year were obtained from the commercially available *Partslink* database, developed and maintained by Power Systems Research/Compass International, Inc. (PSR). This database contains sales estimates for nonroad equipment for model years 1973 through 2000. Base-year population development is discussed in the technical documentation.[3]

3.1.1.2.2 Projection Variables

The model uses three variables to project emissions over time: the annual population growth rate, the equipment median life, and the relative deterioration rate. Collectively, these variables represent population growth, changes in the equipment age distribution, and emission deterioration.

Annual Population Growth Rate (percent/year). The population growth rate represents the percentage increase in the equipment population for a given equipment type over successive years. The growth rate is linear for diesel equipment, and is applied to the entire population, including all rated-power classes and tiers.[4] Diesel growth rates vary by sector (e.g., agricultural, construction).

Equipment Median Life (hours @ full load). This variable represents the period of time over which 50 percent of the engines in a given "model-year cohort" are scrapped. A "model-year cohort" represents a sub-population of engines represented as entering the population in a given year. The input value assumes that (1) engines are run at full load until failure, and (2) equipment scrappage follows the model's scrappage curve. During a simulation, the model uses the "annualized median life," which represents the actual service life of equipment in years, depending on how much and how hard the equipment is used. Annualized median life is calculated as median life in hours (l_h), divided by the product of activity and load factor ($l_y = l_h/AL$). Engines persist in the equipment population over two median lives ($2l_y$); during the first median life, 50 percent of the engines are scrapped, and over the second, the remaining 50 percent are scrapped. For a more detailed description of median life, see the model documentation.[2]

Relative Deterioration Rate (percent increase in emission factor/percent median life expended). This variable plays a key role in calculation of the deterioration factor. Values of the relative deterioration rate are assigned based on pollutant, rated-power class, and tier. Using the relative deterioration rate (d), the annualized median life (l_y) and the equipment age, draft NONROAD2004 calculates the deterioration factor as

$$\mathrm{DF}_{\text{pollutant,tier,year}} = 1 + d_{\text{pollutant,tier}} \left(\frac{\mathrm{age}_{\text{year}}}{l_y} \right)$$

where:

$\mathrm{DF}_{\text{pollutant,year}}$ = the deterioration factor for a given pollutant for a model-year cohort in the simulation year
d = the relative deterioration rate for a given pollutant (percent increase in emission factor /percent useful life expended) and regulatory tier
age = the age of a specific model-year group of engines in the simulation year
l_y = the annualized median life of the given model-year cohort (years)

The deterioration factor adjusts the exhaust emission factor for engines in a given model-year cohort in relation to the proportion of median life expended. The model calculates the deterioration linearly over one median life for a given model-year cohort (represented as a fraction of the entire population). Following the first median life, the deteriorated emission factor is held constant over the remaining life for engines in the cohort. The model's deterioration calculations are discussed in greater detail in the technical documentation.[1]

3.1.1.2.3 Scenario Option Variables

These inputs apply to entire model runs or scenarios, rather than to equipment. Scenario options describe fuel characteristics and ambient weather conditions. The option that applies to inventories for diesel equipment is the in-use diesel sulfur level (wt%).

The in-use diesel fuel sulfur level inputs used for land-based diesel engines for the baseline scenarios are provided in Table 3.1-1. The fuel sulfur levels account for spillover use of highway fuel and are discussed in more detail in Chapter 7. The in-use sulfur levels in Table 3.1-1 used for modeling differ slightly from those presented in Chapter 7, since minor revisions were made subsequent to the modeling.

Table 3.1-1
Modeled Baseline In-Use Diesel Fuel Sulfur Content
for Land-Based Nonroad Diesel Engines

Calendar Year	48-State Fuel Sulfur (ppm)	50-State Fuel Sulfur (ppm)
through 2005	2283	2284
2006	2249	2242
2007-2009	2224	2212
2010	2167	2155
2011+	2126	2114

3.1.1.3 Emission Estimation Process

To project emissions in a given year, the draft NONROAD2004 model performs a series of steps (not necessarily in the order described).

Equipment Population. The model projects the equipment population for the user-specified simulation year. The current year's population (N_{year}) is projected as a function of the base-year population (N_{base}) as

$$N_{\text{year}} = N_{\text{base}}(1 + ng)$$

where g is the annual growth rate and n is the number of years between the simulation year and the base year. For diesel equipment, population projection follows a linear trend as in the equation above. Diesel growth rates in the model vary only by sector (e.g., agricultural, construction). The sector-specific growth rates are applied to all equipment types and hp categories within each sector.

Equipment Age Distribution. The model assigns an age distribution for each sub-population calculated in the previous step. This calculation divides the total population into a series of model-year cohorts of decreasing size, with the number of cohorts equal to twice the annualized median life for the rated-power class under consideration ($2l_y$). Each model-year cohort is estimated as a fraction of the total population, using fractions derived from NONROAD's scrappage curve, scaled to the useful life of the given rated-power class, also equal to $2l_y$.[5]

Emission and Deterioration Factors. Because the previous steps were performed for engines of a given rated-power class, the model assigns emission factors to different model year cohorts simply by relating equipment age to regulatory tier. Similarly, the model calculates deterioration factors for each cohort. The algorithm identifies the appropriate relative deterioration rate in relation to tier and rated-power class, calculates the age of the cohort, and supplies these inputs to the deterioration factor equation.

Activity and Load Factor. The model obtains the appropriate activity, load factor and rated power estimates. Activity and load factor are defined on the basis of equipment type alone; they are constant for all model-year cohorts, and rated power is determined on the basis of equipment type and rated power class.

Emission Calculation. For a given pollutant, the calculations described above are performed and the resulting inputs multiplied in the exhaust emission equation. The steps are repeated for each rated-power class within an equipment type to obtain total emissions for that type. The resulting subtotals for equipment types are then summed to obtain total emissions from all equipment types included in the simulation. These processes are repeated for each pollutant requested for the simulation. Using summation notation, the process may be summarized as

$$I_{\text{exh,poll}} = \overbrace{\sum \overbrace{\left[\sum \overbrace{\left(\sum \left(E_{\text{exh,poll}} \cdot A \cdot L \cdot P \cdot N \right) \right)}^{\substack{\text{sum over all model-year cohorts} \\ \text{within a rated-power class}}} \right]}^{\substack{\text{sum over all rated-power classes} \\ \text{within an equipment type}}}}^{\text{sum over all equipment types}}$$

3.1.1.4 Estimation of VOC Emissions

Volatile organic compounds are a class of hydrocarbons considered to be of regulatory interest. For purposes of inventory modeling, we define VOC as total hydrocarbon (THC) plus reactive oxygenated species, represented by aldehydes (RCHO) and alcohols (RCOH), less nonreactive species represented by methane and ethane (CH_4 and CH_3CH_3), as follows:

$$\text{VOC} = \text{THC} + (\text{RCHO} + \text{RCOH}) - (\text{CH}_4 + \text{CH}_3\text{CH}_3)$$

The NONROAD model estimates VOC in relation to THC, where THC is defined as those hydrocarbons measured by a flame ionization detector (FID) calibrated to propane. Total hydrocarbon has exhaust and evaporative components, where the evaporative THC represents 'crankcase emissions.' Crankcase emissions are hydrocarbons that escape from the cylinder through the piston rings into the crankcase. The draft NONROAD2004 model assumes that all diesel engines have open crankcases, allowing that gases in the crankcase to escape to the atmosphere.

For diesel engines, the emission factor for crankcase emissions (EF_{crank}) is estimated as a fraction of the exhaust emission factor (EF_{exh}), as

$$\text{EF}_{\text{crank,HC,year}} = 0.02 \cdot \text{EF}_{\text{exh,HC,year}}$$

Note that the model adjusts crankcase emissions for deterioration. In a given simulation year, the crankcase emission factor is calculated from the deteriorated exhaust emission factor for that year, i.e., $EF_{exh,year} = ZHL \cdot TAF \cdot DF_{year}$.

The model estimates exhaust and crankcase VOC as a fraction of exhaust and crankcase THC, respectively.

$$VOC_{exh} = 1.053 \cdot THC_{exh}, \quad VOC_{crank} = 1.053 \cdot THC_{crank}$$

Note the fraction is greater than one, reflecting the addition of oxygenated species to THC. For additional discussion of the model's estimation of crankcase and VOC emissions, refer to the model documentation.[1, 6]

3.1.1.5 Estimation of SO_2 Emissions

To estimate SO_2 emissions, the draft NONROAD2004 model does not use an explicit emission factor. Rather, the model estimates a SO_2 emission factor EF_{SO2} on the basis of brake-specific fuel consumption, the user-defined diesel sulfur level, and the emission factor for THC.

$$EF_{SO_2} = \left[BSFC \cdot (1 - m_{PM,S}) - EF_{THC}\right] \cdot S_{in-use} \cdot m_{SO_2,S}$$

where:

BSFC = brake-specific fuel consumption (g/hp-hr),
$m_{PM,S}$ = a constant, representing the fraction of fuel sulfur converted to particulate sulfur, equal to 0.02247 g PM S/g fuel S,
EF_{THC} = the in-use adjusted THC emission factor (g/hp-hr),
$S_{in\text{-}use}$ = the user-specified scenario-specific sulfur content of diesel fuel (weight fraction), and
$m_{SO2,S}$ = a constant, representing fraction of fuel sulfur converted to SO_2, equal to 2.0 g SO_2/g S.

This equation includes corrections for the fraction of sulfur that is converted to PM ($m_{PM,S}$) and for the sulfur remaining in the unburned fuel (EF_{THC}). The correction for unburned fuel, as indicated by THC emissions, is more significant for gasoline emissions, but insubstantial for diesel emissions.

Having estimated EF_{SO2}, the model estimates SO_2 emissions as it does other exhaust emissions.

3.1.1.6 Estimation of $PM_{2.5}$ Emissions

The model estimates emissions of diesel $PM_{2.5}$ as a multiple of PM_{10} emissions. $PM_{2.5}$ is estimated to compose 97 percent of PM_{10} emissions. This is an updated estimate, based on an analysis of size distribution data for diesel engines.[7]

3.1.1.7 Estimation of Fuel Consumption

The draft NONROAD2004 model estimates fuel consumption using the equation

$$F = \frac{BSFC \cdot A \cdot L \cdot P \cdot N}{D}$$

where:

F = fuel consumption (gallons/year)
BSFC = brake-specific fuel consumption (lb/hp-hr)
A = equipment activity (operating hours/year)
L = load factor (average proportion of rated power used during operation (percent))
P = average rated power (hp)
N = equipment population (units)
D = fuel density (lb/gal); diesel fuel density = 7.1 lb/gal

The fuel consumption estimates for land-based diesel and recreational marine diesel engines are given in Section 3.1.5.

3.1.1.8 Changes from Draft NONROAD2002 to Draft NONROAD2004

For the final rule, we have updated the model to incorporate the following changes:

1) Draft NONROAD2004 contains more horsepower bins in order to model the final standards. Specifically, the 50-100 hp bin was split into 50-75 hp and 75-100 hp bins. Also, the 1000-1500 hp bin was split into 1000-1200 hp and 1200-1500 hp bins.

2) Draft NONROAD2004 eliminates the Tier 3 NOx and PM transient adjustment factors (TAFs) for steady-state applications, which were mistakenly included in draft NONROAD2002.

3) The base year populations in draft NONROAD2004 were updated from 1998 to 2000, based on newer sales data.

4) The $PM_{2.5}$ fraction of PM_{10} was revised from 0.92 to 0.97, based on an updated analysis of size distribution data for diesel engines.

5) The recreational marine populations, median life, and deterioration factors for HC and NO_x were revised to match what was used in the 2002 final rulemaking that covers large spark ignition engines (>25 hp), recreational equipment, and recreational marine diesel engines (>50 hp).[8] The exhaust emission factors for these three categories were also revised in draft NONROAD2004 to reflect the final standards.

6) The output label was changed from 'SO_x' to 'SO_2' to avoid confusion, since SO_2 emissions are calculated by the model.

For land-based diesel nonroad engines, the net effect of these changes is generally within 3 percent, with the direction and variation of the change dependent on the calendar year and pollutant of interest.

3.1.1.9 Baseline Inventory

Tables 3.1-2a and 3.1-2b present the PM_{10}, $PM_{2.5}$, NO_x, SO_2, VOC, and CO baseline emissions for land-based nonroad engines in 1996 and 2000-2040, for the 48-state and 50-state inventories, respectively.

Table 3.1-2a
Baseline (48-State) Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	192,275	186,507	1,564,904	143,572	220,971	1,004,586
2000	176,056	170,774	1,550,355	161,977	199,887	916,507
2001	170,451	165,338	1,537,890	166,644	191,472	880,129
2002	165,017	160,067	1,526,119	171,309	183,525	845,435
2003	159,268	154,490	1,505,435	175,971	176,383	813,886
2004	153,932	149,314	1,486,335	180,630	169,873	787,559
2005	148,720	144,259	1,467,547	185,287	163,663	763,062
2006	143,840	139,525	1,435,181	187,085	156,952	741,436
2007	139,990	135,791	1,399,787	189,511	150,357	724,449
2008	137,366	133,245	1,359,661	194,019	143,306	710,202
2009	135,097	131,044	1,317,995	198,526	136,426	697,893
2010	132,712	128,730	1,278,038	197,829	129,711	687,234
2011	130,964	127,035	1,242,159	198,415	123,573	678,980
2012	130,091	126,189	1,211,982	202,740	118,363	674,285
2013	129,779	125,885	1,188,162	207,062	114,022	672,732
2014	129,700	125,809	1,168,310	211,382	110,284	672,819
2015	129,831	125,936	1,152,199	215,699	107,084	674,296
2016	130,128	126,224	1,139,969	219,971	104,426	677,095
2017	130,606	126,688	1,130,663	224,241	102,252	681,156
2018	131,211	127,275	1,124,057	228,510	100,383	685,866
2019	131,993	128,034	1,120,529	232,777	98,766	691,194
2020	133,049	129,058	1,119,481	237,044	97,513	697,630
2021	134,251	130,223	1,120,802	241,309	96,566	704,932
2022	135,491	131,426	1,124,159	245,573	95,837	712,591
2023	136,799	132,695	1,129,090	249,836	95,344	720,565
2024	138,136	133,992	1,135,338	254,099	95,061	729,001
2025	139,555	135,369	1,142,889	258,360	94,975	737,967
2026	141,007	136,777	1,151,480	262,591	95,043	747,219
2027	142,429	138,156	1,160,868	266,822	95,234	756,611
2028	143,901	139,584	1,170,868	271,052	95,529	766,274
2029	145,385	141,023	1,181,457	275,282	95,906	776,141
2030	146,891	142,484	1,192,833	279,511	96,374	786,181
2031	148,452	143,999	1,205,007	283,740	96,942	796,408
2032	150,035	145,534	1,217,535	287,969	97,568	806,761
2033	151,640	147,091	1,230,337	292,198	98,241	817,199
2034	153,253	148,655	1,243,467	296,426	98,967	827,712
2035	154,851	150,205	1,256,924	300,654	99,747	838,224
2036	156,499	151,804	1,270,722	304,882	100,591	848,884
2037	158,171	153,426	1,284,718	309,110	101,473	859,588
2038	160,204	155,398	1,299,415	313,337	102,472	870,258
2039	162,240	157,373	1,314,296	317,564	103,495	880,968
2040	164,275	159,346	1,329,330	321,792	104,543	891,684

Table 3.1-2b
Baseline (50-State) Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	193,166	187,371	1,573,083	144,409	222,084	1,009,804
2000	176,881	171,575	1,558,392	162,920	200,903	921,226
2001	171,256	166,118	1,545,852	167,615	192,447	884,645
2002	165,801	160,827	1,534,007	172,307	184,462	849,756
2003	160,030	155,229	1,513,203	176,996	177,287	818,037
2004	154,670	150,030	1,493,989	181,683	170,744	791,568
2005	149,434	144,951	1,475,092	186,368	164,505	766,944
2006	144,479	140,145	1,442,534	187,508	157,762	745,216
2007	140,579	136,362	1,406,936	189,505	151,134	728,159
2008	137,945	133,807	1,366,584	194,013	144,049	713,862
2009	135,668	131,598	1,324,685	198,521	137,135	701,516
2010	133,274	129,276	1,284,510	197,795	130,388	690,829
2011	131,521	127,576	1,248,440	198,360	124,220	682,563
2012	130,648	126,729	1,218,098	202,685	118,984	677,865
2013	130,337	126,426	1,194,153	207,006	114,621	676,320
2014	130,260	126,352	1,174,204	211,325	110,863	676,420
2015	130,394	126,482	1,158,023	215,641	107,647	677,918
2016	130,695	126,774	1,145,751	219,912	104,977	680,746
2017	131,178	127,243	1,136,425	224,181	102,793	684,843
2018	131,788	127,835	1,129,817	228,449	100,917	689,593
2019	132,575	128,598	1,126,301	232,716	99,294	694,964
2020	133,637	129,628	1,125,276	236,982	98,037	701,445
2021	134,844	130,799	1,126,633	241,246	97,086	708,795
2022	136,091	132,008	1,130,034	245,509	96,355	716,502
2023	137,406	133,284	1,135,015	249,772	95,860	724,528
2024	138,750	134,587	1,141,319	254,033	95,575	733,017
2025	140,177	135,972	1,148,929	258,294	95,490	742,039
2026	141,637	137,388	1,157,584	262,525	95,558	751,348
2027	143,067	138,775	1,167,040	266,754	95,752	760,798
2028	144,547	140,211	1,177,111	270,984	96,049	770,520
2029	146,038	141,657	1,187,773	275,213	96,429	780,446
2030	147,552	143,126	1,199,225	279,442	96,900	790,547
2031	149,123	144,649	1,211,478	283,670	97,472	800,835
2032	150,715	146,193	1,224,086	287,898	98,102	811,250
2033	152,329	147,759	1,236,969	292,126	98,779	821,751
2034	153,950	149,332	1,250,181	296,354	99,511	832,326
2035	155,557	150,891	1,263,722	300,581	100,296	842,901
2036	157,214	152,498	1,277,605	304,808	101,146	853,624
2037	158,896	154,129	1,291,688	309,035	102,033	864,392
2038	160,938	156,110	1,306,473	313,262	103,038	875,126
2039	162,984	158,095	1,321,443	317,489	104,068	885,901
2040	165,028	160,077	1,336,566	321,715	105,122	896,682

3.1.2 Land-Based Nonroad Diesel Engines—Air Toxics Emissions

EPA focused on five major air toxics pollutants for this rule: benzene, formaldehyde, acetaldehyde, 1,3-butadiene, and acrolein. These pollutants are VOCs and are included in the total land-based nonroad diesel VOC emission estimate. EPA developed the baseline inventory estimates for these pollutants by multiplying the baseline VOC emissions from the draft NONROAD2004 model for a given year by the constant fractional amount that each air toxic pollutant contributes to VOC emissions. Table 3.1-3 shows the fractions that EPA used for each air toxics pollutant. EPA developed these nonroad air toxics pollutant fractions for the National Emission Inventory.[9]

Table 3.1-3
Air Toxics Fractions of VOC

Benzene	Formaldehyde	Acetaldehyde	1,3-Butadiene	Acrolein
0.020	0.118	0.053	0.002	0.003

Tables 3.1-4a and 3.1-4b show our 48-state and 50-state estimates of national baseline emissions for five selected major air toxic pollutants (benzene, formaldehyde, acetaldehyde, 1,3-butadiene, and acrolein) for 1996, as well as for selected years from 2005 to 2030, modeled with the existing Tier 1-3 standards. Toxics emissions decrease over time until 2025 as engines meeting the Tier 1-3 standards are introduced into the fleet. Beyond 2025, the growth in population overtakes the effect of the existing emission standards. Chapter 2 discusses the health effects of these pollutants.

Table 3.1-4a
Baseline (48-State) Air Toxics Emissions
for Land-Based Nonroad Diesel Engines (short tons)

Year	Benzene	Formaldehyde	Acetaldehyde	1,3-Butadiene	Acrolein
1996	4,419	26,075	11,711	442	663
2000	3,998	23,587	10,594	400	600
2005	3,273	19,312	8,674	327	491
2007	3,007	17,742	7,969	301	451
2010	2,594	15,306	6,875	259	389
2015	2,142	12,636	5,675	214	321
2020	1,950	11,507	5,168	195	293
2025	1,900	11,207	5,034	190	285
2030	1,927	11,372	5,108	193	289

Table 3.1-4b
Baseline (50-State) Air Toxics Emissions
for Land-Based Nonroad Diesel Engines (short tons)

Year	Benzene	Formaldehyde	Acetaldehyde	1,3-Butadiene	Acrolein
1996	4,442	26,206	11,770	444	666
2000	4,018	23,707	10,648	402	603
2005	3,290	19,412	8,719	329	494
2007	3,023	17,834	8,010	302	453
2010	2,608	15,386	6,911	261	391
2015	2,153	12,702	5,705	215	323
2020	1,961	11,568	5,196	196	294
2025	1,910	11,268	5,061	191	286
2030	1,938	11,434	5,136	194	291

3.1.3 Commercial Marine Vessels and Locomotives

Though no new engine controls are being proposed for diesel commercial marine and locomotive engines, these engines use diesel fuel and the effects of the fuel changes in the final rule need to be modeled. This section addresses the modeling of the baseline case for these engines, which includes effects of certain other rules such as (a) the April 1998 final rule for locomotives, (b) the December 1999 final rule for Category 1 and 2 commercial marine diesel engines, (c) the January 2003 final rule for Category 3 commercial marine residual engines, and (c) the January 2001 heavy duty highway diesel fuel rule that takes effect in June 2006.

Since the draft NONROAD2004 model does not generate emission estimates for these applications, the emission inventories were calculated using the following methodology. VOC, CO, and NO_x emissions for 1996, 2020, and 2030 (the years chosen for air quality modeling) for commercial marine diesel engines were taken from the rulemaking documentation. For locomotives, the fuel-specific emission factors from the rulemaking documentation were multiplied by the updated fuel consumption annual estimates described in Chapter 7 to obtain the emission estimates. The VOC, CO, and NOx emission estimates for commercial marine diesel engines and locomotives are presented in Table 3.1-5. VOC emissions were calculated by multiplying THC emissions by a factor of 1.053, which is also the factor used for land-based diesel engines.

Table 3.1-5
Baseline (48-State) NO_x, VOC, and CO Emissions
for Locomotives and Commercial Marine Diesel Vessels (short tons)

Year	NO_x		VOC		CO	
	Locomotives	CMV	Locomotives	CMV	Locomotives	CMV
1996	934,070	639,630	38,035	21,540	92,496	93,638
2020	508,084	587,115	30,125	24,005	99,227	114,397
2030	481,077	602,967	28,580	26,169	107,780	123,436

Tables 3.1-6a and 3.1-6b provide the 48-state and 50-state baseline fuel volumes, fuel sulfur levels, PM sulfate, $PM_{2.5}$, and SO_2 emissions. The fuel sulfur levels account for "spillover" of low-sulfur highway diesel fuel into use by nonroad applications. The slight decrease in average sulfur level in 2006 is due to the introduction of highway diesel fuel meeting the 2007 15 ppm standard, and the "spillover" of this highway fuel into the nonroad fuel pool. The derivation of the fuel volumes and sulfur levels is discussed in more detail in Chapter 7. The marine fuel volumes reported in Chapter 7 include both commercial and recreational marine usage. The fuel consumption specific to commercial marine in Tables 3.1-6a and 3.1-6b was calculated by subtracting the recreational marine fuel consumption as generated by the draft NONROAD2004 model.

Table 3.1-6a
Baseline (48-State) Fuel Sulfur Levels, SO_2, Sulfate PM, and $PM_{2.5}$ Emissions for Locomotives and Commercial Marine Diesel Vessels

Year	Locomotive Usage (10^9 gal/yr)	Commercial Marine Usage (10^9 gal/yr)	Base Sulfur Level (ppm)	Base					
				SO_2		Sulfate PM		Total $PM_{2.5}$	
				Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)
1996	3.065	1.644	2641	56,193	30,136	4,521	2,424	22,266	17,782
2000	2.687	1.556	2641	49,268	28,523	3,964	2,295	19,522	18,542
2001	2.772	1.533	2637	50,737	28,065	4,082	2,258	20,137	18,723
2002	2.692	1.493	2638	49,291	27,339	3,966	2,199	19,554	18,905
2003	2.722	1.507	2638	49,843	27,598	4,010	2,220	19,772	19,090
2004	2.741	1.518	2639	50,205	27,793	4,039	2,236	19,913	19,019
2005	2.762	1.522	2639	50,583	27,867	4,070	2,242	19,474	18,915
2006	2.818	1.556	2616	51,170	28,252	4,117	2,273	19,270	18,808
2007	2.868	1.575	2599	51,736	28,416	4,162	2,286	18,998	18,671
2008	2.900	1.594	2599	52,317	28,749	4,209	2,313	18,588	18,533
2009	2.939	1.609	2599	53,021	29,019	4,266	2,335	18,526	18,394
2010	2.986	1.625	2444	50,658	27,565	4,076	2,218	18,183	18,259
2011	3.043	1.646	2334	49,278	26,655	3,965	2,144	18,527	18,125
2012	3.073	1.663	2334	49,779	26,947	4,005	2,168	18,384	17,996
2013	3.097	1.674	2334	50,176	27,118	4,037	2,182	18,198	17,871
2014	3.121	1.691	2335	50,581	27,395	4,069	2,204	18,007	17,752
2015	3.148	1.706	2335	51,011	27,645	4,104	2,224	17,821	17,640
2016	3.181	1.718	2335	51,551	27,837	4,147	2,240	17,671	17,575
2017	3.210	1.733	2335	52,028	28,093	4,186	2,260	17,490	17,541
2018	3.234	1.757	2336	52,437	28,495	4,219	2,292	17,619	17,538
2019	3.266	1.786	2337	52,973	28,972	4,262	2,331	17,444	17,588
2020	3.288	1.804	2338	53,352	29,268	4,292	2,355	17,213	17,665
2021	3.305	1.823	2339	53,646	29,593	4,316	2,381	16,947	17,765
2022	3.335	1.852	2340	54,148	30,072	4,356	2,419	16,743	17,890
2023	3.364	1.870	2340	54,635	30,364	4,396	2,443	16,891	18,032
2024	3.393	1.893	2341	55,123	30,745	4,435	2,473	16,675	18,188
2025	3.426	1.912	2341	55,659	31,062	4,478	2,499	16,469	18,356
2026	3.455	1.935	2341	56,140	31,440	4,517	2,529	16,238	18,533
2027	3.483	1.958	2342	56,624	31,825	4,556	2,560	16,374	18,720
2028	3.513	1.981	2343	57,113	32,216	4,595	2,592	16,136	18,906
2029	3.542	2.005	2343	57,606	32,615	4,635	2,624	15,892	19,098
2030	3.572	2.030	2344	58,103	33,020	4,675	2,657	16,025	19,294
2031	3.602	2.055	2345	58,605	33,433	4,715	2,690	15,775	19,497
2032	3.632	2.080	2345	59,111	33,852	4,756	2,723	15,519	19,701
2033	3.662	2.106	2346	59,621	34,279	4,797	2,758	15,649	19,903
2034	3.693	2.132	2346	60,136	34,713	4,838	2,793	15,385	20,108
2035	3.724	2.158	2347	60,655	35,154	4,880	2,828	15,514	20,315
2036	3.755	2.185	2348	61,179	35,603	4,922	2,864	15,644	20,523
2037	3.786	2.213	2348	61,707	36,059	4,964	2,901	15,370	20,733
2038	3.818	2.240	2349	62,240	36,523	5,007	2,938	15,499	20,945
2039	3.850	2.269	2349	62,777	36,995	5,051	2,976	15,218	21,158
2040	3.882	2.298	2350	63,319	37,475	5,094	3,015	15,345	21,372

Table 3.1-6b
Baseline (50-State) Fuel Sulfur Levels, SO_2, Sulfate PM, and $PM_{2.5}$ Emissions for Locomotives and Commercial Marine Diesel Vessels

Year	Locomotive Usage (10^9 gal/yr)	Commercial Marine Usage (10^9 gal/yr)	Base Sulfur Level (ppm)	Base					
				SO_2		Sulfate PM		Total $PM_{2.5}$	
				Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)
1996	3.072	1.724	2640	56,287	31,587	4,528	2,541	22,319	18,717
2000	2.691	1.634	2640	49,305	29,926	3,967	2,408	19,551	19,518
2001	2.776	1.610	2635	50,778	29,454	4,085	2,370	20,167	19,708
2002	2.696	1.569	2637	49,330	28,702	3,969	2,309	19,583	19,900
2003	2.726	1.584	2637	49,882	28,978	4,013	2,331	19,801	20,095
2004	2.745	1.595	2637	50,244	29,186	4,042	2,348	19,943	20,020
2005	2.766	1.599	2637	50,622	29,269	4,073	2,355	19,502	19,911
2006	2.823	1.636	2588	50,693	29,374	4,078	2,363	19,298	19,798
2007	2.873	1.656	2552	50,877	29,330	4,093	2,360	19,026	19,653
2008	2.904	1.675	2552	51,447	29,676	4,139	2,388	18,616	19,508
2009	2.944	1.691	2552	52,140	29,958	4,195	2,410	18,553	19,363
2010	2.990	1.708	2400	49,822	28,464	4,008	2,290	18,210	19,220
2011	3.047	1.731	2292	48,471	27,529	3,900	2,215	18,554	19,079
2012	3.077	1.749	2292	48,962	27,832	3,939	2,239	18,411	18,943
2013	3.102	1.761	2292	49,351	28,012	3,970	2,254	18,225	18,811
2014	3.126	1.778	2293	49,748	28,299	4,002	2,277	18,034	18,686
2015	3.152	1.794	2293	50,169	28,559	4,036	2,298	17,847	18,568
2016	3.186	1.807	2293	50,701	28,761	4,079	2,314	17,697	18,500
2017	3.215	1.824	2293	51,170	29,028	4,117	2,335	17,516	18,464
2018	3.239	1.849	2294	51,567	29,442	4,149	2,369	17,645	18,461
2019	3.271	1.879	2295	52,091	29,934	4,191	2,408	17,469	18,514
2020	3.293	1.898	2295	52,462	30,240	4,221	2,433	17,238	18,595
2021	3.310	1.919	2296	52,747	30,576	4,244	2,460	16,972	18,700
2022	3.339	1.949	2297	53,236	31,069	4,283	2,500	16,767	18,831
2023	3.369	1.968	2297	53,714	31,372	4,321	2,524	16,916	18,981
2024	3.398	1.992	2298	54,191	31,766	4,360	2,556	16,699	19,146
2025	3.431	2.012	2298	54,717	32,095	4,402	2,582	16,493	19,322
2026	3.460	2.037	2298	55,187	32,486	4,440	2,614	16,262	19,509
2027	3.489	2.061	2299	55,661	32,884	4,478	2,646	16,398	19,705
2028	3.518	2.086	2299	56,139	33,288	4,517	2,678	16,159	19,901
2029	3.547	2.111	2300	56,621	33,699	4,555	2,711	15,916	20,104
2030	3.577	2.137	2300	57,107	34,118	4,594	2,745	16,049	20,309
2031	3.607	2.163	2301	57,597	34,543	4,634	2,779	15,798	20,523
2032	3.637	2.190	2301	58,092	34,976	4,674	2,814	15,542	20,738
2033	3.668	2.217	2302	58,591	35,416	4,714	2,849	15,672	20,951
2034	3.698	2.244	2302	59,094	35,864	4,754	2,885	15,408	21,166
2035	3.729	2.272	2303	59,601	36,319	4,795	2,922	15,537	21,384
2036	3.760	2.301	2303	60,113	36,782	4,836	2,959	15,667	21,603
2037	3.792	2.330	2304	60,629	37,252	4,878	2,997	15,393	21,825
2038	3.824	2.359	2304	61,150	37,731	4,920	3,036	15,522	22,047
2039	3.856	2.389	2305	61,675	38,217	4,962	3,075	15,240	22,271
2040	3.888	2.420	2305	62,205	38,711	5,005	3,114	15,368	22,497

Annual SO_2 emission estimates for locomotives and commercial marine vessels were calculated by multiplying the gallons of fuel use by the fuel density, the fuel sulfur content, and the molecular weight ratio of SO_2 to sulfur. This is then reduced by the fraction of fuel sulfur that is converted to sulfate PM (2.247 percent on average for engines without aftertreatment).[1] Following is an example of the calculation for the case when fuel sulfur content is 2300 ppm.

SO_2 tons = gallons × 7.1 lb/gallon × 0.0023 S wt. Fraction × (1-0.02247 S fraction converted to SO_2) × 64/32 SO_2 to S M.W. ratio / 2000 lb/ton

Unlike the equation used in the draft NONROAD2004 model for land-based diesel and recreational marine diesel engines (described in Section 3.1.1.5), this equation does not include a correction for the sulfur remaining in the unburned fuel. The correction for unburned fuel, as indicated by THC emissions is insubstantial for diesel emissions.

Annual sulfate PM emission estimates for locomotives and commercial marine vessels were calculated by multiplying the gallons of fuel use by the fuel density, the fuel sulfur content, the molecular weight ratio of hydrated sulfate to sulfur, and the fraction of fuel sulfur converted to sulfate on average. Following is an example of the calculation for the case when fuel sulfur content is 2300 ppm.

Sulfate tons = gallons × 7.1 lb/gallon × 0.0023 S wt. Fraction × 0.02247 fraction of S converted to sulfate × 224/32 sulfate to S M.W. ratio / 2000 lb/ton

The baseline sulfate PM estimates are not used to generate baseline PM_{10} emission estimates, but are needed in order to calculate the PM benefits of reductions in fuel sulfur levels with the final rule.

Annual total PM_{10} emission estimates for locomotives were calculated by multiplying the gallons of fuel use by the gram per gallon PM emission factor from the 1998 locomotive final rule Regulatory Support Document. Following is an example calculation:

PM_{10} tons = gallons × g/gal EF / 454g/lb / 2000 lbs/ton

Annual PM_{10} emission estimates for commercial marine vessels were derived from the rulemaking documentation.

PM_{10} is assumed to be equivalent to total PM, and $PM_{2.5}$ is estimated by multiplying PM_{10} emissions by a factor of 0.97. This is the factor used for all nonroad diesel engines; the basis is described in Section 3.1.1.6.

3.1.4 Recreational Marine Engines

Diesel recreational marine engines consist mainly of inboard engines used in larger power boats and sailboats, but there are also a small number of outboard diesel engines in use. Emission estimates for this category were generated using the draft NONROAD2004 model. Details of the modeling inputs (e.g., populations, activity, and emission factors) for these engines can be found in the technical reports documenting the draft NONROAD2004 model. The emission inventory numbers presented here assume that recreational marine applications will use diesel fuel with the same sulfur content and sulfur-to-sulfate conversion rate as locomotives and commercial marine vessels.

It should be noted that, unlike the previous version of the NONROAD model, these inventory values generated with the draft NONROAD2004 model now account for the newest standards promulgated in September 2002, which take effect in 2006-2009, for diesel recreational marine engines greater than 37 kw (50 hp). Although those standards provide substantial benefits for the affected engines (e.g., 25 to 37 percent reductions of PM, NO_x, and HC in 2030), the impact of this on the total nonroad diesel inventory is quite small, representing less than 1 percent of the baseline nonroad diesel inventory (without locomotives or commercial marine) for PM, NO_x, and HC in 2030.

Tables 3.1-7a and 3.1-7b present the PM_{10}, $PM_{2.5}$, NO_x, SO_2, VOC, and CO emissions for recreational marine engines in 1996 and 2000-2040 for the 48-state and 50-state inventories, respectively.

Table 3.1-7a
Baseline (48-State) Emissions for Recreational Marine Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	951	923	33,679	4,286	1,297	5,424
2000	1,070	1,038	37,943	4,831	1,455	6,098
2001	1,099	1,066	39,071	4,968	1,494	6,271
2002	1,130	1,096	40,198	5,114	1,533	6,444
2003	1,160	1,125	41,325	5,259	1,571	6,615
2004	1,190	1,154	42,452	5,406	1,609	6,787
2005	1,220	1,183	43,578	5,551	1,647	6,958
2006	1,233	1,196	44,105	5,647	1,657	7,128
2007	1,247	1,210	44,602	5,754	1,664	7,298
2008	1,262	1,225	45,066	5,897	1,670	7,467
2009	1,275	1,237	45,415	6,041	1,670	7,636
2010	1,257	1,219	45,729	5,816	1,668	7,804
2011	1,245	1,208	46,022	5,682	1,665	7,971
2012	1,254	1,216	46,282	5,811	1,660	8,137
2013	1,261	1,223	46,528	5,939	1,655	8,303
2014	1,269	1,230	46,765	6,070	1,649	8,469
2015	1,275	1,236	46,969	6,198	1,642	8,635
2016	1,280	1,242	47,168	6,327	1,634	8,802
2017	1,285	1,247	47,362	6,455	1,627	8,969
2018	1,290	1,251	47,525	6,587	1,618	9,137
2019	1,295	1,256	47,687	6,718	1,611	9,308
2020	1,300	1,261	47,847	6,850	1,604	9,482
2021	1,304	1,265	48,003	6,982	1,597	9,655
2022	1,309	1,270	48,182	7,114	1,592	9,829
2023	1,314	1,275	48,363	7,243	1,586	10,004
2024	1,320	1,281	48,593	7,375	1,583	10,178
2025	1,330	1,290	48,961	7,504	1,587	10,354
2026	1,344	1,303	49,501	7,633	1,599	10,529
2027	1,359	1,319	50,092	7,765	1,614	10,704
2028	1,376	1,335	50,716	7,897	1,630	10,880
2029	1,394	1,352	51,392	8,026	1,649	11,056
2030	1,413	1,371	52,085	8,158	1,669	11,232
2031	1,432	1,389	52,790	8,290	1,689	11,409
2032	1,451	1,408	53,510	8,419	1,710	11,585
2033	1,471	1,427	54,228	8,552	1,731	11,762
2034	1,491	1,446	54,959	8,681	1,753	11,938
2035	1,511	1,466	55,702	8,814	1,775	12,115
2036	1,531	1,485	56,444	8,946	1,798	12,292
2037	1,552	1,505	57,197	9,075	1,820	12,469
2038	1,573	1,526	57,963	9,208	1,844	12,646
2039	1,593	1,546	58,729	9,338	1,868	12,823
2040	1,615	1,566	59,506	9,471	1,892	13,001

Table 3.1-7b
Baseline (50-State) Emissions for Recreational Marine Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	957	929	33,891	4,312	1,305	5,458
2000	1,076	1,044	38,182	4,859	1,464	6,137
2001	1,106	1,073	39,317	4,995	1,503	6,311
2002	1,137	1,103	40,452	5,145	1,542	6,484
2003	1,167	1,132	41,586	5,290	1,581	6,657
2004	1,197	1,161	42,719	5,436	1,619	6,829
2005	1,227	1,190	43,852	5,582	1,658	7,001
2006	1,236	1,199	44,383	5,622	1,667	7,173
2007	1,246	1,209	44,883	5,685	1,674	7,344
2008	1,262	1,224	45,350	5,827	1,680	7,514
2009	1,274	1,236	45,701	5,969	1,680	7,684
2010	1,256	1,219	46,018	5,747	1,678	7,853
2011	1,245	1,208	46,312	5,615	1,675	8,021
2012	1,253	1,215	46,573	5,742	1,671	8,189
2013	1,261	1,223	46,821	5,869	1,665	8,356
2014	1,268	1,230	47,060	5,998	1,660	8,523
2015	1,273	1,235	47,265	6,125	1,652	8,690
2016	1,279	1,241	47,465	6,252	1,645	8,857
2017	1,284	1,245	47,660	6,379	1,637	9,025
2018	1,288	1,250	47,825	6,509	1,629	9,195
2019	1,293	1,254	47,987	6,639	1,621	9,367
2020	1,298	1,259	48,148	6,766	1,614	9,541
2021	1,302	1,263	48,305	6,897	1,607	9,716
2022	1,307	1,268	48,485	7,027	1,602	9,891
2023	1,312	1,272	48,667	7,155	1,596	10,067
2024	1,317	1,278	48,899	7,285	1,593	10,243
2025	1,327	1,287	49,269	7,412	1,597	10,419
2026	1,341	1,301	49,813	7,540	1,609	10,595
2027	1,357	1,316	50,408	7,670	1,624	10,772
2028	1,373	1,332	51,036	7,797	1,640	10,949
2029	1,391	1,349	51,716	7,928	1,659	11,126
2030	1,410	1,367	52,413	8,055	1,679	11,303
2031	1,429	1,386	53,123	8,186	1,700	11,481
2032	1,448	1,404	53,847	8,313	1,721	11,658
2033	1,467	1,423	54,570	8,444	1,742	11,836
2034	1,487	1,442	55,305	8,572	1,764	12,013
2035	1,507	1,462	56,053	8,703	1,786	12,191
2036	1,527	1,481	56,799	8,830	1,809	12,369
2037	1,548	1,501	57,558	8,961	1,832	12,547
2038	1,568	1,521	58,329	9,089	1,856	12,726
2039	1,589	1,542	59,099	9,220	1,879	12,904
2040	1,610	1,562	59,881	9,348	1,904	13,082

3.1.5 Fuel Consumption for Nonroad Diesel Engines

Table 3.1-8 presents the fuel consumption estimates for the land-based, recreational marine, locomotive, and commercial marine nonroad diesel categories. Fuel consumption estimates are provided for 1996 and 2000-2040 for the 48-state and 50-state inventories.

The fuel consumption estimates for land-based diesel and recreational marine diesel engines were obtained using the draft NONROAD2004 model. The methodology is described in Section 3.1.1.7. The derivation of the fuel consumption estimates for locomotives and commercial marine vessels is described in Section 3.1.3.

For the final rule, the draft NONROAD2004 estimates for fuel consumption are the basis for both inventory generation and for the cost analyses. The land-based diesel fuel estimates in Chapter 7 differ from those presented in Table 3.1-8 by less than 1 percent, due to simple rounding error.

Although the locomotive diesel demand volumes in this chapter are identical to those described in Chapter 7, the marine diesel volumes are slightly different. In Chapter 7, the marine end-use category is a combination of both commercial and recreational marine end uses. In this chapter, recreational marine demand is estimated separately with the draft NONROAD2004 model for each calendar year, and subtracted from the respective combined marine end use volume to produce the commercial marine estimate.

Table 3.1-8
Fuel Consumption for Nonroad Diesel Engines

Year	Fuel Consumption (10^6 gal/year)							
	Land-Based Diesel		Recreational Marine		Locomotives		Commercial Marine	
	48-State	50-State	48-State	50-State	48-State	50-State	48-State	50-State
1996	9,120	9,169	234	236	3,065	3,072	1,644	1,724
2000	10,276	10,331	264	266	2,687	2,691	1,556	1,634
2001	10,568	10,625	272	274	2,772	2,776	1,533	1,610
2002	10,861	10,919	280	282	2,692	2,696	1,493	1,569
2003	11,153	11,213	288	289	2,722	2,726	1,507	1,584
2004	11,445	11,507	296	297	2,741	2,745	1,518	1,595
2005	11,737	11,801	303	305	2,762	2,766	1,522	1,599
2006	12,028	12,092	311	313	2,818	2,823	1,556	1,636
2007	12,318	12,384	319	321	2,868	2,873	1,575	1,656
2008	12,608	12,676	327	329	2,900	2,904	1,594	1,675
2009	12,898	12,968	335	337	2,939	2,944	1,609	1,691
2010	13,188	13,259	343	345	2,986	2,990	1,625	1,708
2011	13,480	13,553	351	353	3,043	3,047	1,646	1,731
2012	13,772	13,846	359	361	3,073	3,077	1,663	1,749
2013	14,063	14,139	367	369	3,097	3,102	1,674	1,761
2014	14,355	14,433	375	377	3,121	3,126	1,691	1,778
2015	14,647	14,726	383	385	3,148	3,152	1,706	1,794
2016	14,936	15,016	391	393	3,181	3,186	1,718	1,807
2017	15,224	15,307	399	401	3,210	3,215	1,733	1,824
2018	15,513	15,597	407	409	3,234	3,239	1,757	1,849
2019	15,802	15,887	415	417	3,266	3,271	1,786	1,879
2020	16,091	16,178	423	425	3,288	3,293	1,804	1,898
2021	16,380	16,468	431	433	3,305	3,310	1,823	1,919
2022	16,668	16,759	438	441	3,335	3,339	1,852	1,949
2023	16,957	17,049	446	449	3,364	3,369	1,870	1,968
2024	17,246	17,339	454	457	3,393	3,398	1,893	1,992
2025	17,535	17,630	462	465	3,426	3,431	1,912	2,012
2026	17,821	17,918	470	473	3,455	3,460	1,935	2,037
2027	18,108	18,206	478	481	3,483	3,489	1,958	2,061
2028	18,395	18,495	486	489	3,513	3,518	1,981	2,086
2029	18,682	18,783	494	497	3,542	3,547	2,005	2,111
2030	18,968	19,071	502	505	3,572	3,577	2,030	2,137
2031	19,255	19,360	510	513	3,602	3,607	2,055	2,163
2032	19,542	19,648	518	521	3,632	3,637	2,080	2,190
2033	19,829	19,936	526	529	3,662	3,668	2,106	2,217
2034	20,116	20,225	534	537	3,693	3,698	2,132	2,244
2035	20,402	20,513	542	545	3,724	3,729	2,158	2,272
2036	20,689	20,801	549	553	3,755	3,760	2,185	2,301
2037	20,976	21,090	557	561	3,786	3,792	2,213	2,330
2038	21,263	21,378	565	569	3,818	3,824	2,240	2,359
2039	21,549	21,666	573	577	3,850	3,856	2,269	2,389
2040	21,836	21,955	581	585	3,882	3,888	2,298	2,420

3.2 Contribution of Nonroad Diesel Engines to National Emission Inventories

This section provides the contribution of nonroad diesel engines to national baseline emission inventories in 1996, 2020, and 2030. The emission inventories are based on 48-state inventories that exclude Alaska and Hawaii to be consistent with the air quality modeling region. The baseline cases represent current and future emissions only with the existing standards. For the final rule, these baseline inventories now incorporate recent standards that cover large spark-ignition engines (>25 hp), recreational equipment, and recreational marine diesel engines (>50 hp).[10]

The calendar years correspond to those chosen for the air quality modeling. Pollutants discussed include $PM_{2.5}$, NO_x, SO_2, VOC, and CO. VOC includes both exhaust and evaporative emissions.

Of interest are the contributions of emissions from nonroad diesel sources affected by the final rule. For $PM_{2.5}$ and SO_2, this includes emissions from all nonroad diesel sources. For NO_x, VOC, and CO, this includes emissions from land-based nonroad diesel engines. Contributions to both total mobile source emissions and total emissions from all sources are presented. For $PM_{2.5}$, contributions of nonroad diesel engines to both total diesel $PM_{2.5}$ and total manmade $PM_{2.5}$ are also presented.

The development of the 1996, 2020, and 2030 baseline emission inventories for the nonroad sector and for the sectors not affected by this rule are briefly described, followed by discussions for each pollutant of the contribution of nonroad diesel engines to national baseline inventories.

3.2.1 Baseline Emission Inventory Development

For 1996, 2020, and 2030, county-level emission estimates were developed by Pechan under contract to EPA. These were used as input for the air quality modeling. These inventories account for county-level differences in parameters such as fuel characteristics and temperature. The draft NONROAD2002 model was used to generate the county-level emission estimates for all nonroad sources, with the exception of commercial marine engines, locomotives, and aircraft. The methodology has been documented elsewhere.[11]

The highway estimates are based on the MOBILE5b model, but with some further adjustments to reflect MOBILE6 emission factors. The highway inventories are similar to those prepared for HD2007 rulemaking, with the exception of adjustments to NO_x and VOC for California counties, based on county-level estimates from the California Air Resources Board.[12]

The stationary point and area source estimates are also based on the HD2007 rulemaking, with the exception of adjustments to NO_x and VOC for California counties, based on county-level estimates from the California Air Resources Board. There were also some stack parameter corrections made to the point source estimates.

The inventories developed by Pechan were used in this section for the following categories: recreational marine spark-ignition engines, commercial marine vessels fueled with gasoline and coal, aircraft, and stationary point and area sources. For the remaining categories, updated national estimates were substituted that reflect recent rulemakings and/or updated model inputs, fuel parameters and usage. The basis for the updated estimates for the remaining categories is described below.

The model inputs for the nonroad diesel sources have been described in detail in Section 3.1. The emission estimates for the land-based diesel and recreational marine diesel categories were based on national level runs with the draft NONROAD2004 model. This was done for two reasons. First, the baseline inventories for 2020 and 2030 were revised since the county-level estimates were developed (specifically, $PM_{2.5}$ and SO_2 emissions were changed to reflect revised diesel fuel sulfur inputs, standards affecting recreational marine diesel engines were promulgated, and model inputs such as base year populations were updated). It was not possible to develop revised county-level estimates for these categories due to resource and time constraints. Second, county-level estimates were developed only for 2020 and 2030. Estimates for interim years are also needed to fully evaluate the anticipated emission benefits of the final rule. Interim year estimates are generated using national level model runs. To be consistent with other sections of the Final RIA in which interim year estimates from 1996 to 2030 are presented, the inventory estimates presented here for the land-based diesel and recreational marine diesel categories are based on national level model runs. Model results for national level runs are similar to those based on an aggregation of county-level runs.

For nonroad spark-ignition engines, the emission estimates were based on national level runs with the draft NONROAD2004 model, in order to account for the recent rulemaking that affects large spark-ignition engines. The draft NONROAD2004 model accounts for the exhaust provisions of the rule. Additional adjustments were made to the VOC model output to account for the evaporative provisions of the rule, since the draft NONROAD2004 model does not yet incorporate the evaporative provisions of the rulemaking.

The commercial marine category has been divided into three subcategories: commercial marine diesel, commercial marine residual, and commercial marine other. The commercial marine diesel category includes compression-ignition engines using diesel fuel (generally includes Category 1 and 2 engines). The commercial marine residual category includes compression-ignition engines using residual fuel (includes Category 3 engines). The commercial marine other category includes commercial marine engines using gasoline or coal. The emission estimates for the commercial marine diesel and residual categories were updated to reflect the 1999 and 2003 rulemakings affecting commercial marine compression-ignition engines. In addition, the SO2 estimates for commercial marine diesel vessels are based on the updated fuel sulfur levels and fuel consumption estimates provided in Section 3.1.

Emission estimates for the locomotive category were revised to reflect the updated fuel sulfur levels and fuel consumption estimates provided in Section 3.1. Finally, the motorcycle portions of the highway estimates were revised to incorporate updated estimates contained in the recent rulemaking affecting motorcycles.

3.2.2 $PM_{2.5}$ Emissions

Table 3.2-1 provides the contribution of land-based diesel engines and other source categories to total diesel $PM_{2.5}$ emissions.

$PM_{2.5}$ emissions from land-based nonroad diesel engines are 46 percent of the total diesel $PM_{2.5}$ emissions in 1996, and this percentage increases to 72 percent by 2030. Emissions from land-based nonroad diesel engines actually decrease from 186,507 tons in 1996 to 129,058 tons in 2020 due to the existing emission standards. From 2020 to 2030, however, emissions increase to 142,484 tons, as growth in this sector offsets the effect of the existing emission standards.

$PM_{2.5}$ emissions from recreational marine diesel engines, commercial marine diesel engines, and locomotives will also be affected by this rule due to the fuel sulfur requirements. For all nonroad diesel sources affected by this rule, the contribution to total diesel $PM_{2.5}$ emissions increases from 56 percent in 1996 to 91 percent in 2030.

Table 3.2-2 provides the contribution of land-based diesel engines and other source categories to total manmade $PM_{2.5}$ emissions. $PM_{2.5}$ emissions from land-based nonroad diesel engines are 8 percent of the total manmade $PM_{2.5}$ emissions in 1996, and this percentage drops slightly to 6 percent in 2020 and 2030. The contribution of land-based diesel engines to total mobile source $PM_{2.5}$ emissions is 33 percent in 1996, rising slightly to 35 percent by 2030. For all nonroad diesel sources, the contribution to total manmade $PM_{2.5}$ emissions is 10 percent in 1996, and this percentage drops slightly to 8 percent in 2020 and 2030.

3.2.3 NO_x Emissions

Table 3.2-3 provides the contribution of land-based diesel engines and other source categories to total NO_x emissions.

NO_x emissions from land-based nonroad diesel engines are 6 percent of the total emissions in 1996, and this percentage increases to 8 percent by 2030. The contribution of land-based diesel engines to total mobile source NO_x emissions is 12 percent in 1996, rising to 24 percent by 2030. Emissions from land-based nonroad diesel engines actually decrease from 1,564,904 tons in 1996 to 1,119,481 tons in 2020 due to the existing emission standards. From 2020 to 2030, however, emissions increase to 1,192,833 tons, as growth in this sector offsets the effect of the existing emission standards.

NO_x emissions from recreational marine diesel engines, commercial marine diesel engines, and locomotives will not be affected by this rule. For these categories combined, the contribution to total NO_x emissions remains stable at 7-8 percent from 1996 to 2030.

3.2.4 SO_2 Emissions

Table 3.2-4 provides the contribution of land-based diesel engines and other source categories to total SO_2 emissions.

SO_2 emissions from land-based nonroad diesel engines are 1 percent of the total emissions in 1996, and this percentage increases to 2 percent by 2030. The contribution of land-based diesel engines to total mobile source SO_2 emissions is 20 percent in 1996, rising to 33 percent by 2030, due to continued growth in this sector.

SO_2 emissions from recreational marine diesel engines, commercial marine diesel engines, and locomotives will also be affected by this rule due to the fuel sulfur requirements. For all nonroad diesel sources affected by this rule, the contribution to total SO_2 emissions remains relatively stable at 1 percent.

3.2.5 VOC Emissions

Table 3.2-5 provides the contribution of land-based diesel engines and other source categories to total VOC emissions. VOC includes both exhaust and evaporative emissions. VOC is an ozone precursor; therefore, VOC inventories are required for air quality modeling.

VOC emissions from land-based nonroad diesel engines are 1 percent of the total emissions in 1996, and this percentage increases to 2 percent by 2030. The contribution of land-based diesel engines to total mobile source VOC emissions is 3 percent in 1996, decreasing slightly to 2 percent by 2030. Emissions from land-based nonroad diesel engines actually decrease from 220,971 tons in 1996 to 97,513 tons in 2020 due to the existing emission standards. From 2020 to 2030, however, emissions increase to 96,374 tons, as growth in this sector offsets the effect of the existing emission standards.

VOC emissions from recreational marine diesel engines, commercial marine diesel engines, and locomotives will not be affected by this rule. For these categories combined, the contribution to total VOC emissions is less than 1 percent.

3.2.6 CO Emissions

Table 3.2-6 provides the contribution of land-based diesel engines and other source categories to total CO emissions.

CO emissions from land-based nonroad diesel engines are 1 percent of the total emissions in 1996, and this percentage remains stable at 1 percent by 2030. The contribution of land-based diesel engines to total mobile source CO emissions is also 1 percent in 1996, remaining at 1 percent by 2030. Emissions from land-based nonroad diesel engines actually decrease from 1,004,586 tons in 1996 to 697,630 tons in 2020 due to the existing emission standards. From 2020 to 2030, however, emissions increase to 786,181 tons, as growth in this sector offsets the effect of the existing emission standards.

CO emissions from recreational marine diesel engines, commercial marine diesel engines, and locomotives will not be affected by this rule. For these categories combined, the contribution to total CO emissions is less than 1 percent in 1996 and 2030.

Table 3.2-1
Annual Diesel $PM_{2.5}$ Baseline Emission Levels for Mobile and Other Source Categories[a]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	186,507	47.2%	45.8%	129,058	70.3%	68.8%	142,484	73.8%	72.2%
Recreational Marine Diesel ≤50 hp	56	0.0%	0.0%	46	0.0%	0.0%	50	0.0%	0.0%
Recreational Marine Diesel >50 hp	867	0.2%	0.2%	1,214	0.7%	0.6%	1,321	0.7%	0.7%
Commercial Marine Diesel [b]	17,782	4.5%	4.4%	17,665	9.6%	9.4%	19,294	10.0%	9.8%
Locomotive	22,266	5.6%	5.5%	17,213	9.4%	9.2%	16,025	8.3%	8.1%
Total Nonroad Diesel	227,478	58%	56%	165,196	90%	88%	179,173	93%	91%
Total Highway Diesel	167,384	42%	41%	18,426	10%	10%	13,948	7%	7%
Total Mobile Source Diesel	394,862	100%	97%	183,622	100%	98%	193,121	100%	98%
Stationary Point and Area Source Diesel [c]	12,199	—	3%	4,010	—	2%	4,231	—	2%
Total Man-Made Diesel Sources	407,061	—		187,632	—		197,352	—	
Mobile Source Percent of Total	97%	—		98%	—		98%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.
[b] This category includes compression-ignition (CI) vessels using diesel fuel. It does not include CI vessels using residual fuel.
[c] This category includes point sources burning either diesel, distillate oil (diesel), or diesel/kerosene fuel.

Table 3.2-2
Annual $PM_{2.5}$ Baseline Emission Levels for Mobile and Other Source Categories [a,b]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	186,507	32.6%	8.4%	129,058	34.7%	6.2%	142,484	34.6%	6.4%
Recreational Marine Diesel ≤50 hp	56	0.0%	0.0%	46	0.0%	0.0%	50	0.0%	0.0%
Recreational Marine Diesel >50 hp	867	0.2%	0.0%	1,214	0.3%	0.1%	1,321	0.3%	0.1%
Recreational Marine SI	35,147	6.1%	1.6%	26,110	7.0%	1.3%	27,223	6.6%	1.2%
Nonroad SI ≤25 hp	24,309	4.2%	1.1%	30,151	8.1%	1.4%	34,598	8.4%	1.5%
Nonroad SI >25hp	1,374	0.2%	0.1%	2,302	0.6%	0.1%	2,692	0.7%	0.1%
Recreational SI	7,968	1.4%	0.4%	9,963	2.7%	0.5%	9,460	2.3%	0.4%
Commercial Marine Diesel [c]	17,782	3.1%	0.8%	17,665	4.7%	0.8%	19,294	4.7%	0.9%
Commercial Marine Residual [c]	16,126	2.8%	0.7%	34,532	9.3%	1.7%	51,026	12.4%	2.3%
Commercial Marine Other [c]	1,370	0.2%	0.1%	1,326	0.4%	0.1%	1,427	0.3%	0.1%
Locomotive	22,266	3.9%	1.0%	17,213	4.6%	0.8%	16,025	3.9%	0.7%
Aircraft	27,891	4.9%	1.3%	30,024	8.1%	1.4%	30,606	7.4%	1.4%
Total Nonroad	341,663	60%	15%	299,603	81%	14%	336,206	82%	15%
Total Highway	230,684	40%	10%	72,377	19%	4%	75,825	18%	3%
Total Mobile Sources	572,346	100%	26%	371,980	100%	18%	412,030	100%	18%
Stationary Point and Area Sources	1,653,392	—	74%	1,712,004	—	82%	1,824,609	—	82%
Total Man-Made Sources	2,225,738	—		2,083,984	—		2,236,639	—	
Mobile Source Percent of Total	26%	—		18%	—		18%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.
[b] Excludes natural and miscellaneous sources.

[c] Commercial marine diesel includes Category 1 and 2 compression-ignition (CI) engines using diesel fuel. The residual category includes Category 3 CI engines using residual fuel. The other category includes engines using gasoline and steamships fueled with coal.

Table 3.2-3
Annual NO_x Baseline Emission Levels for Mobile and Other Source Categories [a]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	1,564,904	12.1%	6.4%	1,119,481	22.2%	7.4%	1,192,833	24.3%	7.8%
Recreational Marine Diesel ≤50 hp	438	0.0%	0.0%	491	0.0%	0.0%	554	0.0%	0.0%
Recreational Marine Diesel >50 hp	33,241	0.3%	0.1%	47,356	0.9%	0.3%	51,531	1.0%	0.3%
Recreational Marine SI	33,304	0.3%	0.1%	61,749	1.2%	0.4%	67,893	1.4%	0.4%
Nonroad SI ≤25 hp	63,120	0.5%	0.3%	98,584	2.0%	0.7%	114,447	2.3%	0.8%
Nonroad SI >25hp	273,082	2.1%	1.1%	43,315	0.9%	0.3%	43,527	0.9%	0.3%
Recreational SI	4,297	0.0%	0.0%	17,129	0.3%	0.1%	19,389	0.4%	0.1%
Commercial Marine Diesel [b]	639,630	4.9%	2.6%	587,115	11.6%	3.9%	602,967	12.3%	4.0%
Commercial Marine Residual [b]	184,275	1.4%	0.8%	356,445	7.1%	2.4%	514,881	10.5%	3.4%
Commercial Marine Other [b]	5,979	0.0%	0.0%	4,207	0.1%	0.0%	4,020	0.1%	0.0%
Locomotive	934,070	7.2%	3.8%	508,084	10.1%	3.4%	481,077	9.8%	3.2%
Aircraft	165,018	1.3%	0.7%	228,851	4.5%	1.5%	258,102	5.2%	1.7%
Total Nonroad	3,901,357	30%	16%	3,072,808	61%	20%	3,351,220	68%	22%
Total Highway	9,060,923	70%	37%	1,975,312	39%	13%	1,566,902	32%	10%
Total Mobile Sources	12,962,279	100%	53%	5,048,120	100%	33%	4,918,123	100%	32%
Stationary Point and Area Sources [c]	11,449,752	—	47%	10,050,213	—	67%	10,320,361	—	68%
Total Man-Made Sources	24,412,031	—		15,098,333	—		15,238,484	—	
Mobile Source Percent of Total	53%	—		33%	—		32%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.

[b] Commercial marine diesel includes Category 1 and 2 compression-ignition (CI) engines using diesel fuel. The residual category includes Category 3 CI engines using residual fuel. The other category includes engines using gasoline and steamships fueled with coal.
[c] Does not include effects of the proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule). 69 FR 4566 (January 30, 2004). See http://www.epa.gov/interstateairquality/rule.html.

Table 3.2-4
Annual SO_2 Baseline Emission Levels for Mobile and Other Source Categories [a]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	143,572	19.9%	0.8%	237,044	35.7%	1.6%	279,511	32.8%	1.8%
Recreational Marine Diesel ≤50 hp	53	0.0%	0.0%	85	0.0%	0.0%	101	0.0%	0.0%
Recreational Marine Diesel >50 hp	4,234	0.6%	0.0%	6,766	1.0%	0.0%	8,057	0.9%	0.1%
Recreational Marine SI	2,170	0.3%	0.0%	2,522	0.4%	0.0%	2,698	0.3%	0.0%
Nonroad SI ≤25 hp	6,803	0.9%	0.0%	8,623	1.3%	0.1%	10,007	1.2%	0.1%
Nonroad SI >25hp	890	0.1%	0.0%	879	0.1%	0.0%	998	0.1%	0.0%
Recreational SI	949	0.1%	0.0%	2,561	0.4%	0.0%	2,691	0.3%	0.0%
Commercial Marine Diesel [b]	30,136	4.2%	0.2%	29,268	4.4%	0.2%	33,020	3.9%	0.2%
Commercial Marine Residual [b]	151,559	21.0%	0.8%	263,076	39.6%	1.7%	387,754	45.6%	2.5%
Commercial Marine Other [b]	9,266	1.3%	0.1%	9,677	1.5%	0.1%	10,366	1.2%	0.1%
Locomotive	56,193	7.8%	0.3%	53,352	8.0%	0.4%	58,103	6.8%	0.4%
Aircraft	11,305	1.6%	0.1%	15,267	2.3%	0.1%	16,813	2.0%	0.1%
Total Nonroad	417,128	58%	2%	629,118	95%	4%	810,119	95%	5%
Total Highway	302,938	42%	2%	35,311	5%	0%	40,788	5%	0%
Total Mobile Sources	720,066	100%	4%	664,429	100%	4%	850,907	100%	5%
Stationary Point and Area Sources [c]	17,636,602	—	96%	14,510,426	—	96%	14,782,220	—	95%
Total Man-Made Sources	18,356,668	—		15,174,855	—		15,633,127	—	
Mobile Source Percent of Total	4%	—		4%	—		5%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.

[b] Commercial marine diesel includes Category 1 and 2 compression-ignition (CI) engines using diesel fuel. The residual category includes Category 3 CI engines using residual fuel. The other category includes engines using gasoline and steamships fueled with coal.

[c] Does not include effects of the proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule). 69 FR 4566 (January 30, 2004). See http://www.epa.gov/interstateairquality/rule.html.

Table 3.2-5
Annual VOC Baseline Emission Levels for Mobile and Other Source Categories [a]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	220,971	2.7%	1.2%	97,513	2.5%	0.7%	96,374	2.3%	0.6%
Recreational Marine Diesel ≤50 hp	106	0.0%	0.0%	52	0.0%	0.0%	50	0.0%	0.0%
Recreational Marine Diesel >50 hp	1,191	0.0%	0.0%	1,552	0.0%	0.0%	1,619	0.0%	0.0%
Recreational Marine SI	804,488	9.7%	4.3%	380,891	9.8%	2.8%	372,970	8.8%	2.5%
Nonroad SI ≤25 hp	1,332,392	16.0%	7.2%	656,845	16.9%	4.9%	758,512	17.9%	5.1%
Nonroad SI >25hp	88,526	1.1%	0.5%	10,629	0.3%	0.1%	9,664	0.2%	0.1%
Recreational SI	322,766	3.9%	1.7%	345,649	8.9%	2.6%	327,403	7.7%	2.2%
Commercial Marine Diesel [b]	21,540	0.3%	0.1%	24,005	0.6%	0.2%	26,169	0.6%	0.2%
Commercial Marine Residual [b]	7,446	0.1%	0.0%	17,584	0.5%	0.1%	26,711	0.6%	0.2%
Commercial Marine Other [b]	892	0.0%	0.0%	925	0.0%	0.0%	1,001	0.0%	0.0%
Locomotive	38,035	0.5%	0.2%	30,125	0.8%	0.2%	28,580	0.7%	0.2%
Aircraft	176,394	2.1%	1.0%	239,654	6.2%	1.8%	265,561	6.3%	1.8%
Total Nonroad	3,014,747	36%	16%	1,805,424	47%	13%	1,914,614	45%	13%
Total Highway	5,291,388	64%	29%	2,071,456	53%	15%	2,312,561	55%	15%
Total Mobile Sources	8,306,135	100%	45%	3,876,880	100%	29%	4,227,175	100%	28%
Stationary Point and Area Sources	10,249,136	—	55%	9,648,376	—	71%	10,751,134	—	72%
Total Man-Made Sources	18,555,271	—		13,525,256	—		14,978,309	—	
Mobile Source Percent of Total	45%	—		29%	—		28%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.

[b] Commercial marine diesel includes Category 1 and 2 compression-ignition (CI) engines using diesel fuel. The residual category includes Category 3 CI engines using residual fuel. The other category includes engines using gasoline and steamships fueled with coal.

Table 3.2-6
Annual CO Baseline Emission Levels for Mobile and Other Source Categories [a]

Category	1996			2020			2030		
	short tons	% of mobile source	% of total	short tons	% of mobile sources	% of total	short tons	% of mobile source	% of total
Land-Based Nonroad Diesel	1,004,586	1.3%	1.1%	697,630	0.9%	0.7%	786,181	0.8%	0.7%
Recreational Marine Diesel $\leq$50 hp	304	0.0%	0.0%	243	0.0%	0.0%	259	0.0%	0.0%
Recreational Marine Diesel >50 hp	5,120	0.0%	0.0%	9,239	0.0%	0.0%	10,973	0.0%	0.0%
Recreational Marine SI	1,995,907	2.5%	2.1%	1,977,403	2.4%	2.0%	2,075,666	2.2%	1.9%
Nonroad SI $\leq$25 hp	18,013,533	23.0%	19.0%	26,372,980	32.4%	27.2%	30,611,599	32.8%	27.9%
Nonroad SI >25hp	1,614,394	2.1%	1.7%	275,647	0.3%	0.3%	264,047	0.3%	0.2%
Recreational SI	921,345	1.2%	1.0%	1,820,865	2.2%	1.9%	1,836,350	2.0%	1.7%
Commercial Marine Diesel [b]	93,638	0.1%	0.1%	114,397	0.1%	0.1%	123,436	0.1%	0.1%
Commercial Marine Residual [b]	15,245	0.0%	0.0%	36,165	0.0%	0.0%	54,924	0.1%	0.1%
Commercial Marine Other [b]	5,869	0.0%	0.0%	6,542	0.0%	0.0%	7,058	0.0%	0.0%
Locomotive	92,496	0.1%	0.1%	99,227	0.1%	0.1%	107,780	0.1%	0.1%
Aircraft	949,313	1.2%	1.0%	1,387,178	1.7%	1.4%	1,502,265	1.6%	1.4%
Total Nonroad	24,711,750	32%	26%	32,797,515	40%	34%	37,380,538	40%	34%
Total Highway	53,685,026	68%	57%	48,529,203	60%	50%	55,847,203	60%	51%
Total Mobile Sources	78,396,776	100%	83%	81,326,718	100%	84%	93,227,742	100%	85%
Stationary Point and Area Sources	16,318,451	—	17%	15,648,555	—	16%	16,325,306	—	15%
Total Man-Made Sources	94,715,227	—		96,975,273	—		109,553,048	—	
Mobile Source Percent of Total	83%	—		84%	—		85%	—	

[a] These are 48-state inventories. They do not include Alaska and Hawaii.

[b] Commercial marine diesel includes Category 1 and 2 compression-ignition (CI) engines using diesel fuel. The residual category includes Category 3 CI engines using residual fuel. The other category includes engines using gasoline and steamships fueled with coal.

3.3 Contribution of Nonroad Diesel Engines to Selected Local Emission Inventories

The contribution of land-based nonroad compression-ignition (CI) engines to $PM_{2.5}$ and NO_x emission inventories in many U.S. cities can be significantly greater than that reflected by national average values.[A] This is not surprising given the high density of these engines one would expect to be operating in urban areas. EPA selected a collection of typical cities spread across the United States to compare projected urban inventories with national average ones for 1996, 2020, and 2030. The results of this analysis are shown below.

3.3.1 $PM_{2.5}$ Emissions

As illustrated in Tables 3.3-1, 3.3-2, and 3.3-3, EPA's city-specific analysis of selected metropolitan areas for 1996, 2020, and 2030 show that land-based nonroad diesel engine engines are a significant contributor to total $PM_{2.5}$ emissions from all man-made sources.

[A] Construction, industrial, and commercial nonroad diesel equipment comprise most of the land-based nonroad emission inventory. These types of equipment are more concentrated in urban areas where construction projects, manufacturing, and commercial operations are prevalent.

Table 3.3-1
Land-Based Nonroad Percent Contribution
to $PM_{2.5}$ Inventories in Selected Urban Areas in 1996[a,b]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	1,650	7,308	22,190	7%	23%
Boston, MA	4,265	9,539	23,254	18%	45%
Chicago, IL	3,374	10,106	40,339	8%	33%
Dallas-Fort Worth, TX	1,826	5,606	13,667	13%	33%
Indianapolis, IN	1,040	3,126	7,083	15%	33%
Minneapolis, MN	1,484	4,238	15,499	10%	35%
New York, NY	2,991	6,757	23,380	13%	44%
Orlando, FL	764	2,559	5,436	14%	30%
Sacramento, CA	529	2,140	7,103	7%	25%
San Diego, CA	879	3,715	9,631	9%	24%
Denver, CO	1,125	3,199	10,107	11%	35%
El Paso, TX	252	822	1,637	15%	31%
Las Vegas, NV-AZ	1,155	2,700	7,511	15%	43%
Phoenix-Mesa, AZ	1,549	4,994	10,100	15%	31%
Seattle, WA	1,119	4,259	15,187	7%	26%

[a] Includes only direct exhaust emissions; see Chapter 2 for a discussion of secondary fine PM levels.
[b] Based on inventories developed for the proposed rule.

Table 3.3-2
Annual Land-Based Nonroad Diesel Contributions
to $PM_{2.5}$ Inventories in Selected Urban Areas in 2020[a,b]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	1,429	4,506	22,846	6%	32%
Boston, MA	3,580	6,720	20,365	18%	53%
Chicago, IL	2,824	6,984	42,211	7%	40%
Dallas-Fort Worth, TX	1,499	3,544	15,202	10%	42%
Indianapolis, IN	794	1,779	6,238	13%	45%
Minneapolis, MN	1,188	2,509	15,096	8%	47%
New York, NY	2,573	4,549	21,566	12%	57%
Orlando, FL	652	1,743	5,627	12%	37%
Sacramento, CA	391	1,301	5,505	7%	30%
San Diego, CA	678	2,478	9,135	7%	27%
Denver, CO	923	2,149	10,954	8%	43%
El Paso, TX	212	478	1,140	19%	44%
Las Vegas, NV-AZ	961	2,080	7,804	12%	46%
Phoenix-Mesa, AZ	1,299	3,512	10,768	12%	37%
Seattle, WA	946	3,043	13,094	7%	31%

[a] Includes only direct exhaust emissions; see Chapter 2 for a discussion of secondary fine PM levels.
[b] Based on inventories developed for the proposed rule.

Table 3.3-3
Land-Based Nonroad Percent Contribution
to $PM_{2.5}$ Inventories in Selected Urban Areas in 2030[a,b]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	1,647	4,937	24,880	7%	33%
Boston, MA	4,132	7,529	21,846	19%	55%
Chicago, IL	3,236	7,735	45,975	7%	42%
Dallas-Fort Worth, TX	1,721	3,919	16,622	10%	44%
Indianapolis, IN	902	1,934	6,753	13%	47%
Minneapolis, MN	1,354	2,769	16,586	8%	49%
New York, NY	2,953	5,064	22,891	13%	58%
Orlando, FL	752	1,957	6,084	12%	38%
Sacramento, CA	447	1,445	5,890	8%	31%
San Diego, CA	777	2,770	10,096	8%	28%
Denver, CO	1,060	2,379	12,117	9%	45%
El Paso, TX	244	524	1,243	20%	47%
Las Vegas, NV-AZ	1,113	2,307	8,512	13%	48%
Phoenix-Mesa, AZ	1,499	3,870	11,989	13%	39%
Seattle, WA	1,084	3,357	14,148	8%	32%

[a] Includes only direct exhaust emissions; see Chapter 2 for a discussion of secondary fine PM levels.
[b] Based on inventories developed for the proposed rule.

3.3.2 NO_x Emissions

As presented in Tables 3.3-4, 3.3-5, and 3.3-6, EPA's city-specific analysis of selected metropolitan areas for 1996, 2020, and 2030 show that land-based nonroad diesel engine engines are a significant contributor to total NO_x emissions from all man-made sources.

Table 3.3-4
Land-Based Nonroad Percent Contribution
to NO_x Inventories in Selected Urban Areas in 1996[a]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	16,238	205,465	298,361	5%	8%
Boston, MA	43,362	232,444	311,045	14%	19%
Chicago, IL	32,276	296,710	509,853	6%	11%
Dallas-Fort Worth, TX	17,852	152,878	186.824	10%	12%
Indianapolis, IN	9,487	89,291	113,300	8%	11%
Minneapolis, MN	13,843	124,437	224,817	6%	11%
New York, NY	29,543	184,384	262,021	11%	16%
Orlando, FL	7,493	61,667	75,714	10%	12%
Sacramento, CA	5,666	55,144	58,757	10%	10%
San Diego, CA	9,460	99,325	107,024	9%	10%
Denver, CO	11,080	86,329	146,807	8%	13%
El Paso, TX	2,498	24,382	30,160	8%	10%
Las Vegas, NV-AZ	11,788	50,724	108,875	11%	23%
Phoenix-Mesa, AZ	15,145	115,544	161,606	9%	13%
Seattle, WA	11,227	115,264	133,840	8%	10%

[a] Based on inventories developed for the proposed rule.

Table 3.3-5
Annual Land-Based Nonroad Diesel Contributions
to NO_x Inventories in Selected Urban Areas in 2020[a]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	12,650	69,816	193,456	7%	18%
Boston, MA	31,282	93,308	167,572	19%	34%
Chicago, IL	24,732	123,823	333,945	7%	20%
Dallas-Fort Worth, TX	13,334	60,745	101,453	13%	22%
Indianapolis, IN	6,982	36,283	60,059	12%	19%
Minneapolis, MN	10,376	47,375	165,775	6%	22%
New York, NY	22,456	67,083	112,960	20%	33%
Orlando, FL	5,837	28,653	45,362	13%	20%
Sacramento, CA	4,297	18,870	23,111	19%	23%
San Diego, CA	7,464	46,005	51,909	14%	16%
Denver, CO	8,251	38,435	103,533	8%	21%
El Paso, TX	1,847	10,105	12,452	15%	18%
Las Vegas, NV-AZ	8,501	26,840	72,829	12%	32%
Phoenix-Mesa, AZ	11,560	48,348	105,185	11%	24%
Seattle, WA	8,283	51,252	76,161	11%	16%

[a] Based on inventories developed for the proposed rule.

Table 3.3-6
Land-Based Nonroad Percent Contribution
to NO_x Inventories in Selected Urban Areas in 2030[a]

MSA, CMSA / State	Land-Based Diesel (short tons)	Mobile Sources (short tons)	Total Man-Made Sources (short tons)	Land-Based Diesel as % of Total	Land-Based Diesel as % of Mobile Sources
Atlanta, GA	14,190	65,746	191,932	7%	22%
Boston, MA	35,039	92,537	168,422	21%	38%
Chicago, IL	27,525	120,694	334,334	8%	23%
Dallas-Fort Worth, TX	14,839	56,907	100,721	15%	26%
Indianapolis, IN	7,641	34,442	58,793	13%	22%
Minneapolis, MN	11,444	45,326	167,154	7%	25%
New York, NY	25,064	67,163	108,215	23%	37%
Orlando, FL	6,551	28,365	45,267	14%	23%
Sacramento, CA	4,806	17,498	21,952	22%	27%
San Diego, CA	8,401	43,930	50,296	17%	19%
Denver, CO	9,185	37,105	104,217	9%	25%
El Paso, TX	2,062	9,422	11,905	17%	22%
Las Vegas, NV-AZ	9,544	26,349	72,926	13%	36%
Phoenix-Mesa, AZ	12,952	46,280	106,061	12%	28%
Seattle, WA	9,247	49,258	77,133	12%	19%

[a] Based on inventories developed for the proposed rule.

3.4 Nonroad Diesel Controlled Emission Inventory Development

This section describes how the controlled emission inventories were developed for the four categories of nonroad diesel engines affected by this rule: land-based diesel engines, commercial marine diesel vessels, locomotives, and recreational marine diesel engines. For land-based diesel engines, there are separate sections for criteria (i.e., $PM_{2.5}$, NO_x, SO_2, VOC, and CO) and air toxics emission development.

3.4.1 Land-Based Diesel Engines—$PM_{2.5}$, NO_x, SO_2, VOC, and CO Emissions

The emission inventory estimates used in this rule were generated using the draft NONROAD2004 model with certain input modifications to account for the in-use diesel fuel sulfur reductions and the engine controls associated with the new emission standards. This section will describe only these modifications to the model inputs, since the other aspects of the model, including inputs for earlier engines, are covered in detail in the technical reports that document the draft NONROAD2004 model.

3.4.1.1 Standards and Zero-Hour Emission Factors

The new emission standards are summarized in Table 3.4-1. The modeled emission factors corresponding to the new emission standards are shown in Table 3.4-2. These emission factors are derived from the standards by applying an assumed 8 percent compliance margin to the standard. This compliance margin was derived from data for highway diesel vehicles and used in the HD2007 rulemaking.

Besides exhaust emissions, the final rule includes changes in crankcase hydrocarbon emissions. Crankcase losses before Tier 4 have been modeled as 2.0 percent of exhaust HC, and any crankcase emissions of other pollutants have been considered negligible. For all Tier 4 engines, including those using transitional controls without particulate traps, our modeling now assumes zero crankcase emissions.

3.4.1.2 Transient Adjustment Factors

The supplemental nonroad transient test will apply to a nonroad diesel engine when that engine must first show compliance with the Tier 4 PM and NO_x+NMHC emissions standards which are based on the performance of the advanced post-combustion emissions control systems (e.g., catalyzed-diesel particulate filters and NO_x adsorbers). This is 2011 for engines at or above 175 hp, 2012 for 75-175 hp engines, and 2013 for engines under 75 hp. Details regarding the transient testing requirements and manufacturer options are provided in Section III of the preamble. More broadly though, transient emissions control is expected to be an integral part of all Tier 4 engine design considerations, including engines under 75 hp meeting either the 0.22 g/hp-hr or 0.30 g/hp-hr Tier 4 PM standards in 2008. Thus, there was no Transient Adjustment Factor (TAF) applied to the emission factors for Tier 4 engines (i.e., the model applies a TAF of 1.0); the zero-hour emission factor was modeled simply as the value of the standard minus an assumed 8 percent compliance margin.

Table 3.4-1
Tier 4 Emission Standards Modeled

Engine Power	Emission Standard (g/hp-hr)					Model Year(s)
	transitional or final	PM	NO_x [a]	NMHC [a]	CO [d]	
kW < 19 (hp <25)	final	0.30	5.6 [b,c]		6.0/4.9 [c]	2008
19 ≤ kW < 56 (25 ≤ hp < 75)	transitional	0.22	5.6/3.5 [b,c]		4.1/3.7 [c]	2008-2012
	final	0.02	3.5 [b]		4.1/3.7 [c]	2013
56 ≤ kW < 130 (75 ≤ hp < 175)	transitional	0.01	0.30 (50%)	0.14 (50%)	3.7 [c]	2012-2013
	final	0.01	0.30	0.14	3.7 [c]	2014
130 ≤ kW < 560 (175 ≤ hp < 750)	transitional	0.01	0.30 (50%)	0.14 (50%)	2.6 [c]	2011-2013
	final	0.01	0.30	0.14	2.6 [c]	2014
kW ≥ 560 (hp ≥ 750) except Generator sets	transitional	0.075	2.6	0.30	2.6 [c]	2011-2014
	final	0.03	2.6	0.14	2.6 [c]	2015
Generator sets 560 ≤ kW ≤ 895 (750 ≤ hp ≤ 1200)	transitional	0.075	2.6	0.30	2.6 [c]	2011-2014
	final	0.02	0.50	0.14	2.6 [c]	2015
Generator sets kW > 895 (hp > 1200)	transitional	0.075	0.50	0.30	2.6 [c]	2011-2014
	final	0.02	0.50	0.14	2.6 [c]	2015

[a] Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required. For a complete description of manufacturer options and alternative standards, refer to Section II of the preamble.

[b] This is a combined NMHC + NO_x standard.

[c] This emission standard level is unchanged from the level that applies in the previous model year. For 25-75 hp engines, the transitional NMHC + NO_x standard is 5.6 g/hp-hr for engines below 50 hp and 3.5 g/hp-hr for engines at or above 50 hp. For engines under 75 hp, the CO standard is 6.0 g/hp-hr for engines below 11 hp, 4.9 g/hp-hr for engines 11 to under 25 hp, 4.1 g/hp-hr for engines 25 to below 50 hp and 3.7 g/hp-hr for engines at or above 50 hp.

[d] There are no Tier 4 CO standards. The CO emission standard level is unchanged from the level that applies in the previous model year.

Table 3.4-2
NONROAD Model EF Inputs for Tier 4 Engines

Engine Power	Emission Factor Modeling Inputs, g/hp-hr [a]						Model Year(s)
	Type of standard	PM	NO_x [b,c]		THC [c,d]	CO [e]	
hp ≤ 11	final	0.28	4.30		0.55	4.11	2008
11 < hp ≤ 25	final	0.28	4.44		0.44	2.16	2008
25 < hp ≤ 50	transitional	0.20	4.73		0.28	1.53	2008
	final	0.018	3.0		0.13	0.15	2013
50 < hp ≤ 75	transitional	0.20	3.0		0.18	2.4	2008
	final	0.018	3.0		0.13	0.24	2013
75 < hp ≤ 100	transitional	0.01	3.0 (50%)	0.28 (50%)	0.13	0.24	2012-2013
	final	0.01	0.28		0.13	0.24	2014
100 < hp ≤ 175	transitional	0.01	2.5 (75%)	0.28 (25%)	0.13	0.087	2012-2014
	final	0.01	0.28		0.13	0.087	2015
175 < hp ≤ 300	transitional	0.01	2.5 (50%)	0.28 (50%)	0.13	0.075	2011-2013
	final	0.01	0.28		0.13	0.075	2014
300 < hp ≤ 600	transitional	0.01	2.5 (50%)	0.28 (50%)	0.13	0.084	2011-2013
	final	0.01	0.28		0.13	0.084	2014
600 < hp ≤ 750	transitional	0.01	2.5 (50%)	0.28 (50%)	0.13	0.13	2011-2013
	final	0.01	0.28		0.13	0.13	2014
hp > 750 except Generator sets	transitional	0.069	2.39		0.28	0.076	2011-2014
	final	0.028	2.39		0.13	0.076	2015
Generator sets 750 ≤ hp ≤ 1200	transitional	0.069	2.39		0.28	0.076	2011-2014
	final	0.018	0.46		0.13	0.076	2015
Generator sets hp > 1200	transitional	0.069	0.46		0.28	0.076	2011-2014
	final	0.018	0.46		0.13	0.076	2015

[a] Transient emission control is assumed for Tier 4 engines, so Transient Adjustment Factors are not applied to the emission factors shown here.
[b] Percentages are model-year sales fractions required to comply with the indicated standard.
[c] NMHC + NO_x is a combined standard, so for modeling purposes the NO_x and HC are separated using a NO_x/HC ratio that approximates the results found in prior test programs, as described in technical report NR-009b.
[d] HC Standards are in terms of NMHC, but the model expects inputs as THC, so a conversion factor of 1.02 is applied to the NMHC value to get the THC model input.

[e] CO emissions from Tier 4 engines are assumed to decrease by 90% from its prior levels in any cases where particulate traps are expected for PM control.

3.4.1.3 Deterioration Rates

The deterioration rates (*d*) used for the modeling of Tier 4 engines are the same as used for Tier 3 engines for all affected pollutants (PM, NO_x, HC, and CO). These are listed in Table 3.4-3 below and are fully documented in technical report NR-009b.[1]

Table 3.4-3
Deterioration Rates for Nonroad Diesel Engines

Pollutant	Relative Deterioration Rate (percent increase per percent useful life expended)[a]				
	Base/Tier 0	Tier 1	Tier 2	Tier 3	Tier 4
HC	0.047	0.036	0.034	0.027	0.027
CO	0.185	0.101	0.101	0.151	0.151
NO_x	0.024	0.024	0.009	0.008	0.008
PM	0.473	0.473	0.473	0.473	0.473

[a] At the median life point, the Deterioration Factor = 1 + relative deterioration rate.

3.4.1.4 In-Use Sulfur Levels, Certification Sulfur Levels, and Sulfur Conversion Factors

Tables 3.4-4 and 3.4-5 show the certification and in-use fuel sulfur levels by calendar year and engine power range that were assumed for modeling the engines regulated under this rule. The certification sulfur levels are the default fuel sulfur levels used to calculate the zero mile PM and SO_2 emission factors in the model (referred to as S_{base} in Section 3.1.1.2.1). The in-use fuel sulfur level is the episodic fuel sulfur level (referred to as $S_{in\text{-}use}$ in Section 3.1.1.2.1). Adjustments to PM and SO_2 for in-use fuel sulfur levels are made relative to the certification sulfur levels in the model. As described above for the baseline inventory development, the in-use fuel sulfur content, fuel consumption, sulfate conversion factor, and exhaust HC emission factor (unburned fuel) determine the SO_2 emissions, and a fraction of the fuel sulfur is also converted to sulfate PM. The changes for modeling of the control case are (a) lower sulfur content for in-use and certification fuel per this rule, and (b) the use of a higher sulfur-to-sulfate conversion factor for engines that are expected to use a particulate trap/filter to achieve the PM standards of 0.01 or 0.02 g/hp-hr (30 percent conversion instead of 2.247 percent that is used for all earlier nontrap-equipped engines).

The in-use sulfur levels account for the 500 ppm standard beginning in 2007, the 15 ppm standard for land-based engines beginning in 2010, and the 15 ppm standard for marine engines and locomotives beginning in 2012. The derivation of the annual fuel sulfur levels is described in detail in Chapter 7. The in-use sulfur levels in Table 3.4-5 used for modeling differ slightly from those presented in Chapter 7, since minor revisions were made subsequent to the modeling.

Table 3.4-4
Modeled Certification Diesel Fuel Sulfur Content

Engine Power	Standards	Modeled Certification Fuel Sulfur Content, PPM	Model Year(s)
kW < 56 (hp <75)	Tier 2	2000	through 2007
	transitional	500	2008-2012
	final	15	2013
56 ≤ kW < 75 (75 ≤ hp < 100)	Tier 3 transitional [a]	500	2008-2011
	final	15	2012
75 ≤ kW < 130 (100 ≤ hp < 175)	Tier 3	2000	2007-2011
	final	15	2012
130 ≤ kW < 560 (175 ≤ hp < 750)	Tier 3	2000	2006-2010
	final	15	2011
kW ≥ 560 (hp ≥ 750)	Tier 2	2000	2006-2010
	final	15	2011

[a] The emission standard here is still Tier 3 as in the Baseline case, but since the Tier 3 standard begins in 2008 for 50-100 hp engines it is assumed that this new technology introduction will allow manufacturers to take advantage of the availability of 500 ppm fuel that year.

Table 3.4-5
Modeled 48-State & 50-State In-Use Diesel Fuel Sulfur Content for Controlled Inventories

Applications	Calendar Year(s)	Modeled In-Use Fuel Sulfur Content, ppm	
		48-State	50-State
Land-based, all power ranges	through 2005	2283	2284
	2006	2249	2242
	2007	1140	1139
	2008-2009	348	351
	2010	163	165
	2011-2013	31	32
	2014	19	20
	2015+	11	11
Recreational Marine, Commercial Marine, and Locomotives	through 2000	2641	2640
	2001	2637	2635
	2002-2003	2638	2637
	2004-2005	2639	2637
	2006	2616	2588
	2007	1328	1332
	2008-2009	408	435
	2010	307	319
	2011	234	236
	2012	123	124
	2013	43	44
	2014	51	52
	2015-2017	56	56
	2018-2038	56	55
	2039-2040	55	55

3.4.1.5 Controlled Inventory

Tables 3.4-6a and 3.4-6b present the PM_{10}, $PM_{2.5}$, NO_x, SO_2, VOC, and CO controlled emissions for land-based nonroad diesel engines in 1996 and 2000-2040, for the 48-state and 50-state inventories, respectively.

Table 3.4-6a
Controlled (48-State) Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	192,275	186,507	1,564,904	143,572	220,971	1,004,586
2000	176,056	170,774	1,550,355	161,977	199,887	916,507
2001	170,451	165,338	1,537,890	166,644	191,472	880,129
2002	165,017	160,067	1,526,119	171,309	183,525	845,435
2003	159,268	154,490	1,505,435	175,971	176,383	813,886
2004	153,932	149,314	1,486,335	180,630	169,873	787,559
2005	148,720	144,259	1,467,547	185,287	163,663	763,062
2006	143,840	139,525	1,435,181	187,085	156,952	741,436
2007	132,534	128,558	1,399,787	97,142	150,357	724,449
2008	123,646	119,936	1,359,631	30,359	143,138	707,098
2009	120,512	116,896	1,317,925	31,064	136,085	691,627
2010	116,263	112,775	1,277,888	14,881	129,186	677,599
2011	110,940	107,612	1,224,329	2,853	122,434	650,276
2012	104,319	101,189	1,165,155	2,850	115,877	609,685
2013	97,187	94,271	1,108,560	2,832	109,726	563,695
2014	89,522	86,837	1,031,680	1,724	104,160	518,729
2015	81,780	79,326	958,769	992	98,766	475,349
2016	74,718	72,476	890,935	987	93,976	435,137
2017	68,079	66,036	828,178	984	89,760	398,578
2018	61,986	60,127	772,291	983	85,896	365,813
2019	56,496	54,801	722,094	984	82,398	336,094
2020	51,613	50,065	677,420	986	79,372	309,593
2021	47,285	45,866	639,156	991	76,813	286,679
2022	43,376	42,074	606,068	996	74,680	266,071
2023	39,837	38,642	576,872	1,003	72,854	247,738
2024	36,548	35,452	551,570	1,011	71,291	231,324
2025	33,508	32,503	529,260	1,019	69,973	216,510
2026	30,735	29,813	510,126	1,028	68,878	203,435
2027	28,234	27,387	493,869	1,039	68,008	192,100
2028	26,125	25,341	479,930	1,050	67,319	182,716
2029	24,177	23,452	467,852	1,062	66,761	174,448
2030	22,369	21,698	458,649	1,074	66,344	167,014
2031	20,873	20,247	451,478	1,087	66,118	161,116
2032	19,492	18,907	445,218	1,100	65,979	155,882
2033	18,188	17,643	439,984	1,113	65,904	151,053
2034	16,970	16,461	435,620	1,126	65,909	146,747
2035	15,877	15,401	432,306	1,140	66,004	143,229
2036	14,930	14,482	429,867	1,155	66,186	140,378
2037	14,053	13,631	428,058	1,169	66,418	137,840
2038	13,577	13,169	427,438	1,183	66,781	135,517
2039	13,194	12,798	427,591	1,198	67,195	133,748
2040	12,852	12,467	428,084	1,213	67,645	132,256

Table 3.4-6b
Controlled (50-State) Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	193,166	187,371	1,573,083	144,409	222,084	1,009,804
2000	176,881	171,575	1,558,392	162,920	200,903	921,226
2001	171,256	166,118	1,545,852	167,615	192,447	884,645
2002	165,801	160,827	1,534,007	172,307	184,462	849,756
2003	160,030	155,229	1,513,203	176,996	177,287	818,037
2004	154,670	150,030	1,493,989	181,683	170,744	791,568
2005	149,434	144,951	1,475,092	186,368	164,505	766,944
2006	144,479	140,145	1,442,534	187,508	157,762	745,216
2007	133,159	129,165	1,406,936	97,580	151,134	728,159
2008	124,257	120,529	1,366,553	30,786	143,880	710,743
2009	121,113	117,479	1,324,613	31,501	136,792	695,221
2010	116,841	113,336	1,284,357	15,145	129,859	681,150
2011	111,492	108,147	1,230,489	2,961	123,074	653,692
2012	104,846	101,700	1,170,969	2,957	116,483	612,882
2013	97,687	94,757	1,114,051	2,939	110,299	566,639
2014	89,993	87,293	1,036,731	1,825	104,704	521,423
2015	82,171	79,706	963,408	997	99,281	477,800
2016	75,070	72,818	895,198	992	94,464	437,357
2017	68,395	66,343	832,101	989	90,227	400,587
2018	62,269	60,401	775,920	988	86,343	367,637
2019	56,750	55,047	725,464	989	82,828	337,757
2020	51,840	50,285	680,563	991	79,786	311,112
2021	47,489	46,064	642,114	996	77,214	288,075
2022	43,560	42,254	608,874	1,001	75,070	267,360
2023	40,006	38,806	579,551	1,008	73,234	248,939
2024	36,703	35,602	554,147	1,016	71,662	232,449
2025	33,651	32,641	531,753	1,024	70,338	217,569
2026	30,866	29,940	512,553	1,034	69,237	204,437
2027	28,355	27,504	496,243	1,044	68,363	193,052
2028	26,237	25,450	482,261	1,056	67,671	183,622
2029	24,280	23,552	470,147	1,068	67,110	175,312
2030	22,464	21,790	460,918	1,080	66,690	167,841
2031	20,963	20,334	453,730	1,093	66,464	161,916
2032	19,577	18,990	447,458	1,106	66,324	156,659
2033	18,269	17,721	442,218	1,119	66,250	151,810
2034	17,047	16,536	437,851	1,133	66,256	147,486
2035	15,951	15,472	434,539	1,147	66,352	143,953
2036	15,000	14,550	432,104	1,161	66,535	141,089
2037	14,120	13,696	430,302	1,175	66,769	138,541
2038	13,642	13,233	429,692	1,190	67,135	136,210
2039	13,257	12,859	429,857	1,204	67,551	134,435
2040	12,915	12,527	430,365	1,219	68,004	132,940

3.4.2 Land-Based Diesel Engines—Air Toxics Emissions

Since air toxics emissions are part of the VOC emission inventory, NMHC standards in this rule will also affect air toxics emissions. Tables 3.4-7a and 3.4-7b show 48-state and 50-state estimated emissions for five major air toxics, benzene, formaldehyde, acetaldehyde, 1,3-butadiene, and acrolein, resulting from the final rule. EPA uses the same fractions used to calculate the base air toxic emissions without the final rule (see Section 3.1.2), along with the estimated VOC emissions resulting from the final rule, to calculate the air toxics emissions resulting from the final rule.

Table 3.4-7a
Controlled (48-State) Air Toxic Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	3,998	23,587	10,594	400	600
2005	3,273	19,312	8,674	327	491
2007	3,007	17,742	7,969	301	451
2010	2,584	15,244	6,847	258	388
2015	1,975	11,654	5,235	198	296
2020	1,587	9,366	4,207	159	238
2025	1,399	8,257	3,709	140	210
2030	1,327	7,829	3,516	133	199

Table 3.4-7b
Controlled (50-State) Air Toxic Emissions for Land-Based Nonroad Diesel Engines (short tons)

Year	Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	4,018	23,707	10,648	402	603
2005	3,290	19,412	8,719	329	494
2007	3,023	17,834	8,010	302	453
2010	2,597	15,323	6,883	260	390
2015	1,986	11,715	5,262	199	298
2020	1,596	9,415	4,229	160	239
2025	1,407	8,300	3,728	141	211
2030	1,334	7,869	3,535	133	200

3.4.3 Commercial Marine Vessels and Locomotives

The control case locomotive and commercial marine inventories for VOC, CO, and NO_x are identical to the base case inventories, since no new controls apply for these engines. However, due to the new requirements to reduce sulfur levels in diesel fuel, decreases are expected in PM and SO_2 inventories for these engines.

The method used for estimating PM and SO_2 emissions in the control case is nearly almost identical to that described in Section 3.1.3 for the base case, but the fuel sulfur levels in the equations are changed to reflect the control case sulfur. The control case PM and SO_2 emission inventory estimates presented here assume that locomotive and commercial marine applications will use diesel fuel meeting a 500 ppm sulfur standard beginning in June 2007 and a 15 ppm sulfur standard beginning in June 2012. Additional sulfur adjustments were made to account for the "spillover" of low-sulfur highway fuel meeting a 15 ppm standard in the applicable years before the start of the 15 ppm nonroad fuel standard.

As in the base case, the same sulfur-to-sulfate conversion rate was used as for land-based diesel applications before they started using aftertreatment technologies (2.247 percent). The slight decrease in average sulfur level in 2006 is due to the introduction of highway diesel fuel meeting the 2007 15 ppm standard, and the "spillover" of this highway fuel into the nonroad fuel pool. Note that there are transition years in which the control sulfur level begins in June, in which case the annual average sulfur level shown reflects an interpolation of five months at the higher sulfur level of the prior year plus seven months at the new lower sulfur level. The derivation of these sulfur levels are described in more detail in Chapter 7.

The control case locomotive and commercial marine PM inventories were calculated by subtracting the sulfate PM benefits (from decreased fuel sulfur content) described above from the base case locomotive and commercial marine PM inventories. The 48-state and 50-state control case locomotive and commercial marine $PM_{2.5}$ and SO_2 inventories are given in Tables 3.4-8a and 3.4-8b, respectively.

Table 3.4-8a
Controlled (48-State) Fuel Sulfur Levels, SO_2,
Sulfate PM, and $PM_{2.5}$ Emissions for Locomotives and Commercial Marine Vessels

Year	Control Sulfur Level (ppm)	Control					
		SO_2		Sulfate PM		Total $PM_{2.5}$	
		Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)
2007	1,328	26,430	14,517	2,126	1,168	17,023	17,586
2008	408	8,210	4,512	661	363	15,146	16,641
2009	408	8,321	4,554	669	366	15,038	16,485
2010	307	6,352	3,457	511	278	14,725	16,377
2011	234	4,944	2,675	398	215	15,067	16,254
2012	123	2,614	1,415	210	114	14,703	16,003
2013	43	921	498	74	40	14,354	15,793
2014	51	1,099	595	88	48	14,146	15,660
2015	56	1,231	667	99	54	13,936	15,534
2016	56	1,244	672	100	54	13,745	15,455
2017	56	1,255	678	101	55	13,527	15,402
2018	56	1,263	687	102	55	13,626	15,367
2019	56	1,274	697	103	56	13,409	15,382
2020	56	1,282	703	103	57	13,149	15,436
2021	56	1,288	710	104	57	12,861	15,511
2022	56	1,298	721	104	58	12,618	15,599
2023	56	1,309	727	105	59	12,729	15,719
2024	56	1,319	736	106	59	12,476	15,846
2025	56	1,332	743	107	60	12,229	15,990
2026	56	1,342	751	108	60	11,962	16,138
2027	56	1,352	760	109	61	12,060	16,295
2028	56	1,363	769	110	62	11,785	16,452
2029	56	1,373	777	110	63	11,504	16,614
2030	56	1,384	786	111	63	11,599	16,778
2031	56	1,394	795	112	64	11,310	16,950
2032	56	1,405	805	113	65	11,016	17,122
2033	56	1,416	814	114	65	11,107	17,292
2034	56	1,427	824	115	66	10,804	17,463
2035	56	1,438	833	116	67	10,893	17,636
2036	56	1,449	843	117	68	10,983	17,811
2037	56	1,460	853	117	69	10,669	17,986
2038	56	1,471	863	118	69	10,757	18,162
2039	55	1,482	874	119	70	10,434	18,339
2040	55	1,494	884	120	71	10,520	18,517

Table 3.4-8b
Controlled (50-State) Fuel Sulfur Levels, SO_2,
Sulfate PM, and $PM_{2.5}$ Emissions for Locomotives and Commercial Marine Vessels

Year	Control Sulfur Level (ppm)	Control					
		SO_2		Sulfate PM		Total $PM_{2.5}$	
		Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)	Loco (tons/yr)	CMV (tons/yr)
2007	1,332	26,548	15,305	2,136	1,231	17,127	18,559
2008	435	8,764	5,055	705	407	15,285	17,587
2009	435	8,881	5,103	715	411	15,177	17,423
2010	319	6,615	3,779	532	304	14,838	17,293
2011	236	4,990	2,834	401	228	15,161	17,152
2012	124	2,646	1,504	213	121	14,796	16,888
2013	44	943	535	76	43	14,447	16,667
2014	52	1,133	645	91	52	14,240	16,528
2015	56	1,215	692	98	56	14,027	16,393
2016	56	1,228	697	99	56	13,836	16,310
2017	56	1,239	703	100	57	13,619	16,254
2018	55	1,247	712	100	57	13,719	16,219
2019	55	1,258	723	101	58	13,502	16,234
2020	55	1,266	729	102	59	13,243	16,292
2021	55	1,271	737	102	59	12,955	16,372
2022	55	1,281	747	103	60	12,713	16,465
2023	55	1,291	754	104	61	12,825	16,591
2024	55	1,302	763	105	61	12,572	16,726
2025	55	1,314	771	106	62	12,326	16,878
2026	55	1,324	779	107	63	12,058	17,034
2027	55	1,334	788	107	63	12,158	17,200
2028	55	1,344	797	108	64	11,883	17,366
2029	55	1,355	806	109	65	11,603	17,537
2030	55	1,365	815	110	66	11,699	17,710
2031	55	1,375	825	111	66	11,411	17,892
2032	55	1,386	834	112	67	11,116	18,073
2033	55	1,397	844	112	68	11,208	18,253
2034	55	1,407	854	113	69	10,906	18,434
2035	55	1,418	864	114	70	10,996	18,617
2036	55	1,429	874	115	70	11,087	18,801
2037	55	1,440	885	116	71	10,774	18,987
2038	55	1,451	895	117	72	10,863	19,173
2039	55	1,462	906	118	73	10,541	19,359
2040	55	1,473	917	119	74	10,628	19,548

3.4.4 Recreational Marine Engines

Even though this final rule does not include any emission standards for marine engines, there are PM and SO_2 benefits associated with these engines due to the fuel sulfur standards. The emission inventory estimates presented in Tables 3.4-9a and 3.4-9b assume that recreational marine applications will use diesel fuel meeting the same standards as locomotive and commercial marine diesel fuel, as shown in Table 3.4-5.

Table 3.4-9a
Controlled (48-State) Emissions for Recreational Marine Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	951	923	33,679	4,286	1,297	5,424
2000	1,070	1,038	37,943	4,831	1,455	6,098
2001	1,099	1,066	39,071	4,968	1,494	6,271
2002	1,130	1,096	40,198	5,114	1,533	6,444
2003	1,160	1,125	41,325	5,259	1,571	6,615
2004	1,190	1,154	42,452	5,406	1,609	6,787
2005	1,220	1,183	43,578	5,551	1,647	6,958
2006	1,233	1,196	44,105	5,647	1,657	7,128
2007	1,020	990	44,602	2,940	1,664	7,298
2008	862	836	45,066	926	1,670	7,467
2009	865	839	45,415	948	1,670	7,636
2010	847	822	45,729	731	1,668	7,804
2011	833	808	46,022	570	1,665	7,971
2012	810	786	46,282	306	1,660	8,137
2013	792	768	46,528	109	1,655	8,303
2014	790	767	46,765	133	1,649	8,469
2015	787	764	46,969	149	1,642	8,635
2016	783	759	47,168	152	1,634	8,802
2017	778	755	47,362	155	1,627	8,969
2018	772	749	47,525	158	1,618	9,137
2019	767	744	47,687	161	1,611	9,308
2020	761	738	47,847	164	1,604	9,482
2021	756	733	48,003	167	1,597	9,655
2022	750	728	48,182	170	1,592	9,829
2023	745	722	48,363	173	1,586	10,004
2024	740	718	48,593	176	1,583	10,178
2025	740	717	48,961	180	1,587	10,354
2026	744	721	49,501	183	1,599	10,529
2027	749	727	50,092	186	1,614	10,704
2028	756	733	50,716	189	1,630	10,880
2029	763	741	51,392	192	1,649	11,056
2030	772	749	52,085	195	1,669	11,232
2031	781	757	52,790	198	1,689	11,409
2032	790	766	53,510	201	1,710	11,585
2033	799	775	54,228	204	1,731	11,762
2034	808	784	54,959	207	1,753	11,938
2035	818	794	55,702	210	1,775	12,115
2036	828	803	56,444	213	1,798	12,292
2037	838	813	57,197	216	1,820	12,469
2038	849	823	57,963	220	1,844	12,646
2039	859	833	58,729	219	1,868	12,823
2040	870	844	59,506	222	1,892	13,001

Table 3.4-9b
Controlled (50-State) Emissions for Recreational Marine Diesel Engines (short tons)

Year	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO
1996	957	929	33,891	4,312	1,305	5,458
2000	1,076	1,044	38,182	4,859	1,464	6,137
2001	1,106	1,073	39,317	4,995	1,503	6,311
2002	1,137	1,103	40,452	5,145	1,542	6,484
2003	1,167	1,132	41,586	5,290	1,581	6,657
2004	1,197	1,161	42,719	5,436	1,619	6,829
2005	1,227	1,190	43,852	5,582	1,658	7,001
2006	1,236	1,199	44,383	5,622	1,667	7,173
2007	1,027	997	44,883	2,967	1,674	7,344
2008	872	846	45,350	993	1,680	7,514
2009	875	849	45,701	1,017	1,680	7,684
2010	855	829	46,018	764	1,678	7,853
2011	839	814	46,312	578	1,675	8,021
2012	816	791	46,573	311	1,671	8,189
2013	797	773	46,821	113	1,665	8,356
2014	795	772	47,060	136	1,660	8,523
2015	792	768	47,265	150	1,652	8,690
2016	788	764	47,465	153	1,645	8,857
2017	783	759	47,660	156	1,637	9,025
2018	777	753	47,825	156	1,629	9,195
2019	771	748	47,987	159	1,621	9,367
2020	766	743	48,148	162	1,614	9,541
2021	760	737	48,305	165	1,607	9,716
2022	755	732	48,485	168	1,602	9,891
2023	749	727	48,667	171	1,596	10,067
2024	745	722	48,899	174	1,593	10,243
2025	744	722	49,269	177	1,597	10,419
2026	748	726	49,813	180	1,609	10,595
2027	754	731	50,408	183	1,624	10,772
2028	760	737	51,036	187	1,640	10,949
2029	768	745	51,716	190	1,659	11,126
2030	776	753	52,413	193	1,679	11,303
2031	785	762	53,123	196	1,700	11,481
2032	794	771	53,847	199	1,721	11,658
2033	804	779	54,570	202	1,742	11,836
2034	813	789	55,305	205	1,764	12,013
2035	823	798	56,053	208	1,786	12,191
2036	833	808	56,799	211	1,809	12,369
2037	843	818	57,558	214	1,832	12,547
2038	854	828	58,329	217	1,856	12,726
2039	865	839	59,099	220	1,879	12,904
2040	876	849	59,881	223	1,904	13,082

3.5 Projected Emission Reductions from the Final Rule

Emissions from nonroad diesel engines will continue to be a significant part of the emission inventory in the coming years. In the absence of new emission standards, we expect overall emissions from nonroad diesel engines to generally decline across the nation for the next 10 to 15 years, depending on the pollutant. Although nonroad diesel engine emissions decline during this period, this trend will not be enough to adequately reduce the large amount of emissions that these engines contribute. In addition, after the 2010 to 2015 time period we project that this trend reverses and emissions rise into the future in the absence of additional regulation of these engines. The initial downward trend occurs as the nonroad fleet becomes increasingly dominated over time by engines that comply with existing emission regulations. The upturn in emissions beginning around 2015 results as growth in the nonroad sector overtakes the effect of the existing emission standards.

The engine and fuel standards in this rule will affect fine particulate matter ($PM_{2.5}$), oxides of nitrogen (NO_x), sulfur oxides (SO_2), volatile organic hydrocarbons (VOC), air toxics, and carbon monoxide (CO). For engines used in locomotives, commercial marine vessels, and recreational marine vessels, the requirements for low-sulfur fuel will affect $PM_{2.5}$ and SO_2.

This section discusses the projected emission reductions associated with this final rule. The baseline case represents future emissions with current standards. The controlled case estimates the future emissions of these engines based on the new emission standards and fuel requirements. Both 48-state and 50-state results are presented. Tables 3.5-1a and 3.5-1b present a summary of the total 48-state and 50-state emission reductions for each pollutant.

3.5.1 $PM_{2.5}$ Reductions

48-State and 50-state emissions of $PM_{2.5}$ from land-based nonroad diesel engines are shown in Tables 3.5-2a and 3.5-2b, respectively, along with estimates of the reductions from this final rule. $PM_{2.5}$ will be reduced as a result of the new PM emission standards and changes in the sulfur level in nonroad diesel fuel. The exhaust emission standards begin in 2008 for engines less than 75 hp, and are completely phased in for all hp categories by 2015. Nonroad diesel fuel sulfur is reduced to a 500 ppm standard in June of 2007, and further reduced to a 15 ppm standard (11 ppm in-use) in June of 2010. The 15 ppm standard is fully phased in starting in 2011.

Tables 3.5-2a and 3.5-2b present results for five-year increments from 2000 to 2030. Individual years from 2007 to 2011 are also included, since fuel sulfur levels are changing during this period. Emissions are projected to 2030 to reflect close to complete turnover of the fleet to engines meeting the new emission standards. For comparison purposes, emission reductions are also shown from reducing the diesel fuel sulfur level to 500 ppm in 2007 and to 15 ppm in 2010, without any new emission standards.

Table 3.5-1a
Total Emission Reductions (48-State) from the Final Rule

Year	$PM_{2.5}$	NO_x	SO_2	VOC	CO	Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0
2007	10,511	0	134,388	0	0	0	0	0	0	0
2008	19,031	30	236,976	168	3,104	3	20	9	0	1
2009	19,943	70	241,719	341	6,266	7	40	18	1	1
2010	21,692	149	256,447	525	9,634	11	62	28	1	2
2011	25,154	17,830	268,989	1,139	28,704	23	134	60	2	3
2012	31,103	46,827	278,092	2,486	64,599	50	293	132	5	7
2015	53,072	193,431	297,513	8,318	198,947	166	981	441	17	25
2020	85,808	442,061	323,378	18,141	388,037	363	2,141	961	36	54
2025	110,043	613,629	349,312	25,002	521,457	500	2,950	1,325	50	75
2030	128,350	734,184	375,354	30,030	619,167	601	3,544	1,592	60	90

Table 3.5-1b
Total Emission Reductions (50-State) from the Final Rule

Year	$PM_{2.5}$	NO_x	SO_2	VOC	CO	Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0
2007	10,403	0	132,998	0	0	0	0	0	0	0
2008	18,908	31	235,366	169	3,119	3	20	9	0	1
2009	19,821	72	240,084	343	6,296	7	41	18	1	1
2010	21,627	153	255,525	529	9,680	11	62	28	1	2
2011	25,142	17,951	268,613	1,146	28,871	23	135	61	2	3
2012	31,122	47,129	277,804	2,501	64,983	50	295	133	5	8
2015	53,238	194,615	297,440	8,367	200,118	167	987	443	17	25
2020	86,157	444,714	323,302	18,251	390,333	365	2,154	967	37	55
2025	110,508	617,176	349,233	25,152	524,471	503	2,968	1,333	50	75
2030	128,899	738,307	375,269	30,210	622,706	604	3,565	1,601	60	91

Table 3.5-2a
Estimated National (48-State) $PM_{2.5}$
Emissions and Reductions From Nonroad Land-Based Diesel Engines[a]

Year	$PM_{2.5}$ Emissions [short tons]				$PM_{2.5}$ Reductions [short tons]		
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010; No Tier 4 standards	With Rule (Fuel sulfur reduced to 15 ppm in 2010; Tier 4 standards)	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010; No Tier 4 standards	With Rule
2000	170,774	170,774	170,774	170,774	0	0	0
2005	144,259	144,259	144,259	144,259	0	0	0
2007	135,791	128,558	128,558	128,558	7,232	7,232	7,232
2008	133,245	120,434	120,434	119,936	12,811	12,811	13,309
2009	131,044	117,938	117,938	116,896	13,106	13,106	14,148
2010	128,730	115,273	114,416	112,775	13,458	14,315	15,955
2011	127,035	113,243	111,739	107,612	13,792	15,296	19,423
2015	125,936	110,950	109,157	79,326	14,986	16,779	46,610
2020	129,058	112,595	110,625	50,065	16,463	18,433	78,993
2025	135,369	117,428	115,281	32,503	17,941	20,087	102,866
2030	142,484	123,076	120,754	21,698	19,408	21,730	120,786

[a] $PM_{2.5}$ represents 97 percent of PM10 emissions.

Table 3.5-2b
Estimated National (50-State) $PM_{2.5}$
Emissions and Reductions From Nonroad Land-Based Diesel Engines[a]

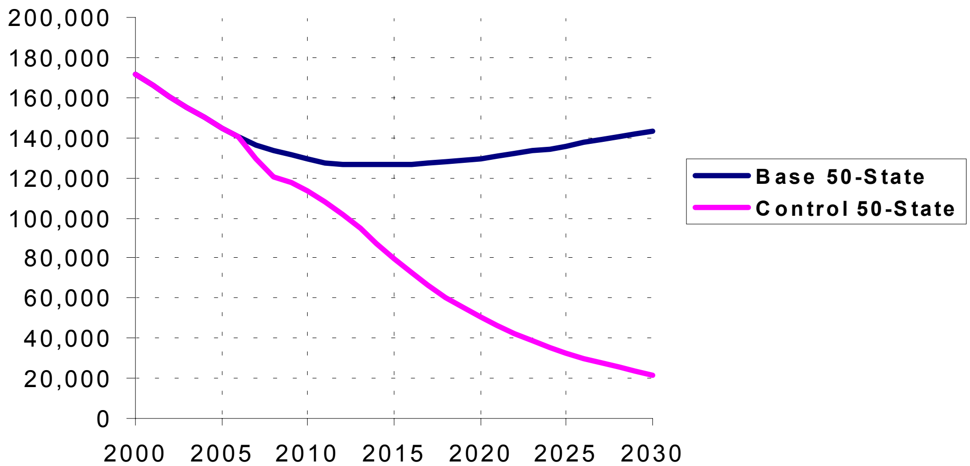
Year	$PM_{2.5}$ Emissions [short tons]				$PM_{2.5}$ Reductions [short tons]		
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010; No Tier 4 standards	With Rule (Fuel sulfur reduced to 15 ppm in 2010; Tier 4 standards)	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010; No Tier 4 standards	With Rule
2000	171,575	171,575	171,575	171,575	0	0	0
2005	144,951	144,951	144,951	144,951	0	0	0
2007	136,362	129,165	129,165	129,165	7,197	7,197	7,197
2008	133,807	121,030	121,030	120,529	12,777	12,777	13,277
2009	131,598	118,526	118,526	117,479	13,071	13,071	14,118
2010	129,276	115,846	114,984	113,336	13,430	14,292	15,940
2011	127,576	113,797	112,292	108,147	13,778	15,283	19,428
2015	126,482	111,511	109,708	79,706	14,971	16,774	46,777
2020	129,628	113,181	111,200	50,285	16,447	18,428	79,343
2025	135,972	118,049	115,891	32,641	17,923	20,081	103,331
2030	143,126	123,737	121,402	21,790	19,389	21,724	121,336

[a] $PM_{2.5}$ represents 97 percent of PM10 emissions.

The benefits in the early years of the program (i.e., pre-2010) are primarily from reducing the diesel fuel sulfur level to 500 ppm. As the standards phase in and fleet turnover occurs, $PM_{2.5}$ emissions are impacted more significantly from the requirements of the final rule. $PM_{2.5}$ emissions from land-based diesel engines are projected to decrease by roughly 120,000 tons by 2030 as a result of this rule.

Figure 3.5-1 shows EPA's estimate of 50-state $PM_{2.5}$ emissions from land-based diesel engines for 2000 to 2030 with and without the new PM emission standards. We estimate that $PM_{2.5}$ emissions from this source would decrease by 85 percent in 2030.

Figure 3.5-1: Estimated Reductions in $PM_{2.5}$ Emissions From Land-Based Nonroad Engines (tons/year)



Nonroad diesel engines used in locomotives, commercial marine vessels, and recreational marine vessels are not affected by the emission standards in this rule. $PM_{2.5}$ emissions from these engines will be reduced as a result of the lower fuel sulfur levels from a current in-use average of about 2640 ppm to about 55 ppm by 2015. The estimated 48-state and 50-state reductions in $PM_{2.5}$ emissions from these engines based on the diesel fuel-sulfur requirements are given in Tables 3.5-3a and 3.5-3b, respectively. Total $PM_{2.5}$ reductions reach roughly 7,500 tons in 2030 for these engine categories.

Tables 3.5-4a and 3.5-4b present the $PM_{2.5}$ emissions and reductions for all nonroad diesel categories combined. The 50-state results are also presented graphically in Figure 3.5-2. For all nonroad diesel categories combined, the estimated reductions in $PM_{2.5}$ emissions are 86,000 tons in 2020, increasing to 128,000 tons in 2030. Simply reducing the fuel sulfur level to 500 ppm in 2007 will lead to projected $PM_{2.5}$ reductions of 23,000 tons in 2020 and 26,000 tons in 2030. Reducing the fuel sulfur level further to 15 ppm (in 2010 for land-based diesel engines and in 2012 for marine engines and locomotives) in the absence of Tier 4 standards (i.e., a fuel only program) will lead to projected $PM_{2.5}$ reductions of 25,000 tons in 2020 and 29,000 tons in 2030.

Table 3.5-3a
Estimated National (48-State) $PM_{2.5}$ Reductions
From Locomotives, Commercial Marine, and Recreational Marine Diesel Engines

Year	$PM_{2.5}$ Reductions with Rule [short tons]			
	Locomotives	Commerical Marine Diesel	Recreational Marine Diesel	Total $PM_{2.5}$ Reductions
2000	0	0	0	0
2005	0	0	0	0
2007	1,975	1,085	220	3,279
2008	3,442	1,891	389	5,722
2009	3,488	1,909	398	5,796
2010	3,458	1,882	397	5,737
2011	3,460	1,871	400	5,731
2015	3,885	2,105	473	6,463
2020	4,063	2,229	522	6,815
2025	4,240	2,366	572	7,178
2030	4,426	2,516	622	7,564

Table 3.5-3b
Estimated National (50-State) $PM_{2.5}$ Reductions
From Locomotives, Commercial Marine, and Recreational Marine Diesel Engines

Year	$PM_{2.5}$ Reductions with Rule [short tons]			
	Locomotives	Commerical Marine Diesel	Recreational Marine Diesel	Total $PM_{2.5}$ Reductions
2000	0	0	0	0
2005	0	0	0	0
2007	1,899	1,095	212	3,206
2008	3,331	1,921	378	5,630
2009	3,376	1,940	387	5,702
2010	3,372	1,927	390	5,689
2011	3,393	1,927	394	5,714
2015	3,820	2,175	467	6,462
2020	3,995	2,303	516	6,814
2025	4,168	2,445	565	7,177
2030	4,350	2,599	614	7,563

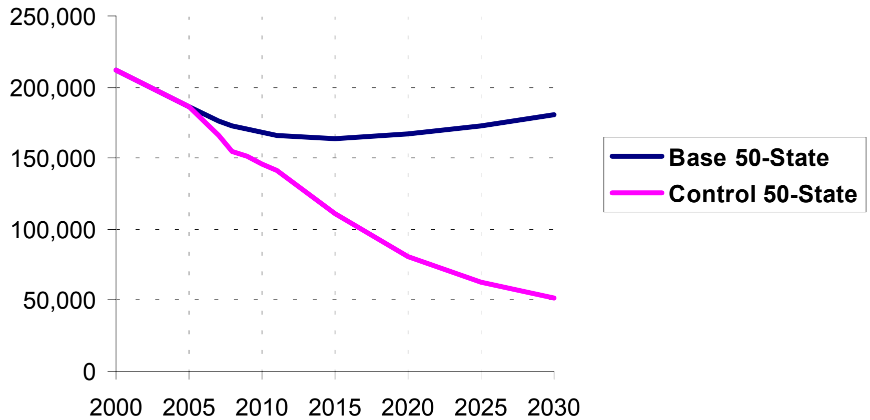
Table 3.5-4a
Estimated National (48-State) $PM_{2.5}$ Emissions and Reductions from
Land-Based Nonroad, Locomotive, Commercial Marine, and Recreational Marine Vessels

Year	$PM_{2.5}$ Emissions [short tons]				$PM_{2.5}$ Reductions [short tons]		
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010/2012; No Tier 4 standards	With Rule (Fuel sulfur further reduced to 15 ppm in 2010/2012; Tier 4 standards)	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010/2012; No Tier 4 standards	With Rule (Fuel sulfur further reduced to 15 ppm in 2010/2012; Tier 4 standards)
2000	209,876	209,876	209,876	209,876	0	0	0
2005	183,831	183,831	183,831	183,831	0	0	0
2007	174,668	164,157	164,157	164,157	10,511	10,511	10,511
2008	171,591	153,058	153,058	152,560	18,533	18,533	19,031
2009	169,201	150,300	150,300	149,258	18,901	18,901	19,943
2010	166,391	147,235	146,340	144,699	19,156	20,051	21,692
2011	164,894	145,438	143,868	139,741	19,457	21,027	25,154
2012	163,784	143,965	142,054	132,681	19,819	21,730	31,103
2015	162,633	141,757	139,391	109,560	20,876	23,241	53,072
2020	165,196	142,522	139,948	79,388	22,674	25,248	85,808
2025	171,484	147,002	144,219	61,440	24,482	27,265	110,043
2030	179,173	152,873	149,880	50,824	26,300	29,293	128,350

Table 3.5-4b
Estimated National (50-State) $PM_{2.5}$ Emissions and Reductions from
Land-Based Nonroad, Locomotive, Commercial Marine, and Recreational Marine Vessels

Year	$PM_{2.5}$ Emissions [short tons]				$PM_{2.5}$ Reductions [short tons]		
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010/2012; No Tier 4 standards	With Rule (Fuel sulfur further reduced to 15 ppm in 2010/2012; Tier 4 standards)	With fuel sulfur reduced to 500 ppm in 2007; No Tier 4 standards	With fuel sulfur further reduced to 15 ppm in 2010/2012; No Tier 4 standards	With Rule (Fuel sulfur further reduced to 15 ppm in 2010/2012; Tier 4 standards)
2000	211,688	211,688	211,688	211,688	0	0	0
2005	185,555	185,555	185,555	185,555	0	0	0
2007	176,250	165,847	165,847	165,847	10,403	10,403	10,403
2008	173,154	154,747	154,747	154,247	18,407	18,407	18,908
2009	170,750	151,976	151,976	150,929	18,774	18,774	19,821
2010	167,923	148,844	147,944	146,296	19,079	19,979	21,627
2011	166,416	146,990	145,419	141,274	19,426	20,997	25,142
2012	165,298	145,510	143,591	134,176	19,788	21,707	31,122
2015	164,133	143,289	140,897	110,894	20,843	23,236	53,238
2020	166,719	144,080	141,477	80,562	22,639	25,242	86,157
2025	173,075	148,630	145,816	62,567	24,445	27,259	110,508
2030	180,851	154,591	151,565	51,953	26,260	29,287	128,899

Figure 3.5-2: Estimated Reductions in $PM_{2.5}$ Emissions From Land-Based Nonroad Engines, CMVs, RMVs, and Locomotives (tons/year)



3.5.2 NO_x Reductions

Tables 3.5-5a and 3.5-5b show the estimated 48-state and 50-state NO_x emissions in five-year increments from 2000 to 2030 with and without this rule. The 50-state results are shown graphically in Figure 3.5-3. We estimate that NO_x emissions from these engines will be reduced by 62 percent in 2030.

We note that the magnitude of NOx reductions determined in the final rule analysis is somewhat less than what was reported in the proposal's draft RIA, especially in the later years when the fleet has mostly turned over to Tier 4 designs. The greater part of this is due to the fact that we have deferred setting a long-term NOx standard for mobile machinery over 750 hp to a later action. When this future action is completed, we would expect roughly equivalent reductions between the proposal and the overall final program, though there are some other effects reflected in the differing NOx reductions as well, due to updated modeling assumptions and the adjusted NOx standards levels for engines over 750 hp. Preamble Section II.A.4 contains a detailed discussion of the NOx standards we are adopting for engines over 750 hp, and the basis for those standards.

NO_x emissions from locomotives, commercial marine diesel vessels, and recreational marine diesel vessels are not affected by this rule.

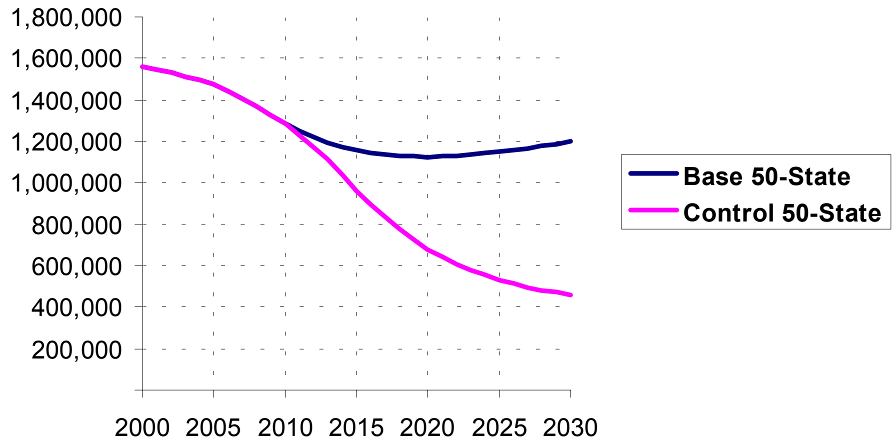
Table 3.5-5a
Estimated National (48-State) NO_x Emissions
and Reductions From Nonroad Land-Based Diesel Engines

Year	NO_x Emissions Without Rule [short tons]	NO_x Emissions With Rule	NO_x Reductions With Rule
2000	1,550,355	1,550,355	0
2005	1,467,547	1,467,547	0
2010	1,278,038	1,277,888	149
2015	1,152,199	958,769	193,431
2020	1,119,481	677,420	442,061
2030	1,192,833	458,649	734,184

Table 3.5-5b
Estimated National (50-State) NO_x Emissions
and Reductions From Nonroad Land-Based Diesel Engines

Year	NO_x Emissions Without Rule [short tons]	NO_x Emissions With Rule	NO_x Reductions With Rule
2000	1,558,392	1,558,392	0
2005	1,475,092	1,475,092	0
2010	1,284,510	1,284,357	153
2015	1,158,023	963,408	194,615
2020	1,125,276	680,563	444,714
2030	1,199,225	460,918	738,307

Figure 3.5-3: Estimated Reductions in NOx Emissions From Land-Based Nonroad Engines (tons/year)



3.5.3 SO_2 Reductions

As part of this final rule, sulfur levels in fuel will be significantly reduced, leading to large reductions in nonroad diesel SO_2 emissions. By 2007, the sulfur in diesel fuel used by all nonroad diesel engines will be reduced to 500 ppm. By 2010, the sulfur in diesel fuel used by nonroad land-based engines will be further reduced to 15 ppm. By 2012, the sulfur in diesel fuel used by marine engines and locomotives will also be reduced to 15 ppm.

48-State and 50-state emissions of SO_2 from land-based nonroad diesel engines are shown in Tables 3.5-6a and 3.5-6b, respectively, along with estimates of the emission reductions resulting from this final rule. Results are presented for five-year increments from 2000 to 2030. Individual years from 2007 to 2011 are also included, since fuel sulfur levels are changing during this period. SO_2 will be reduced due to the changes in the sulfur level in nonroad diesel fuel. For comparison purposes, emission reductions are also shown from reducing the diesel fuel sulfur level to 500 ppm beginning in June of 2007, without any new emission standards or any additional sulfur level reductions.

Table 3.5-6a
Estimated National (48-State) SO_2
Emissions and Reductions From Nonroad Land-Based Diesel Engines

Year	SO_2 Emissions [short tons]			SO_2 Reductions [short tons]	
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007	With Rule (Fuel sulfur reduced to 15 ppm in 2010)	With fuel sulfur reduced to 500 ppm in 2007	With Rule
2000	161,977	161,977	161,977	0	0
2005	185,287	185,287	185,287	0	0
2007	189,511	97,142	97,142	92,370	92,370
2008	194,019	30,359	30,359	163,660	163,660
2009	198,526	31,064	31,064	167,462	167,461
2010	197,829	25,835	14,881	171,993	182,948
2011	198,415	22,119	2,853	176,296	195,562
2015	215,699	24,045	992	191,654	214,707
2020	237,044	26,425	986	210,619	236,057
2025	258,360	28,801	1,019	229,559	257,341
2030	279,511	31,159	1,074	248,352	278,437

Table 3.5-6b
Estimated National (50-State) SO_2
Emissions and Reductions From Nonroad Land-Based Diesel Engines

Year	SO_2 Emissions [short tons]			SO_2 Reductions [short tons]	
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007	With Rule (Fuel sulfur reduced to 15 ppm in 2010)	With fuel sulfur reduced to 500 ppm in 2007	With Rule
2000	162,920	162,920	162,920	0	0
2005	186,368	186,368	186,368	0	0
2007	189,505	97,580	97,580	91,926	91,926
2008	194,013	30,786	30,786	163,227	163,227
2009	198,521	31,501	31,501	167,019	167,019
2010	197,795	26,159	15,145	171,637	182,651
2011	198,360	22,238	2,961	176,122	195,400
2015	215,641	24,175	997	191,466	214,644
2020	236,982	26,568	991	210,414	235,990
2025	258,294	28,957	1,024	229,337	257,270
2030	279,442	31,328	1,080	248,114	278,362

The benefits in the early years of the program (i.e., pre-2010) are from reducing the diesel fuel sulfur level to 500 ppm. Reducing the diesel fuel sulfur level to 15 ppm in June of 2010 proportionately reduces SO_2 further. Total 50-state SO_2 emissions are projected to decrease by 278,000 tons in 2030 as a result of this final rule. Note that SO_2 emissions continue to increase over time due to the growth in the nonroad sector.

Nonroad diesel engines used in locomotives, commercial marine vessels, and recreational marine vessels are also affected by the new fuel sulfur requirements. The estimated 48-state and 50-state reductions in SO_2 emissions from these engines based on the new requirements for diesel fuel are given in Tables 3.5-7a and 3.5-7b, respectively. Total 50-state SO_2 reductions reach 96,000 tons in 2030 for these nonroad diesel engine categories.

Tables 3.5-8a and 3.5-8b present the SO_2 emissions and reductions for all nonroad diesel categories combined. The 50-state results are also presented graphically in Figure 3.5-4. For all nonroad diesel categories combined, the estimated 50-state reductions in SO_2 emissions resulting from the final rule are 323,000 tons in 2020, increasing to 375,000 tons in 2030. Simply reducing the fuel sulfur level to 500 ppm in 2007 will result in SO_2 reductions of 289,000 tons in 2020 and 336,000 tons in 2030.

Table 3.5-7a
Estimated National (48-State) SO_2 Reductions
From Locomotives, Commercial Marine, and Recreational Marine Diesel Engines

Year	SO_2 Reductions with Rule [short tons]			
	Locomotives	Commerical Marine Diesel Vessels	Recreational Marine Diesel Vessels	Total SO_2 Reductions
2000	0	0	0	0
2005	0	0	0	0
2007	25,305	13,899	2,814	42,018
2008	44,107	24,238	4,972	73,316
2009	44,700	24,465	5,093	74,257
2010	44,306	24,108	5,085	73,499
2011	44,334	23,980	5,112	73,426
2015	49,779	26,977	6,049	82,806
2020	52,070	28,564	6,686	87,320
2025	54,328	30,319	7,324	91,971
2030	56,720	32,234	7,963	96,917

Table 3.5-7b
Estimated National (50-State) SO_2 Reductions
From Locomotives, Commercial Marine, and Recreational Marine Diesel Engines

Year	SO_2 Reductions with Rule [short tons]			
	Locomotives	Commerical Marine Diesel Vessels	Recreational Marine Diesel Vessels	Total SO_2 Reductions
2000	0	0	0	0
2005	0	0	0	0
2007	24,329	14,025	2,718	41,072
2008	42,683	24,621	4,834	72,139
2009	43,258	24,855	4,952	73,065
2010	43,207	24,685	4,983	72,875
2011	43,481	24,695	5,037	73,213
2015	48,954	27,867	5,975	82,797
2020	51,196	29,511	6,604	87,311
2025	53,404	31,325	7,235	91,963
2030	55,742	33,302	7,863	96,907

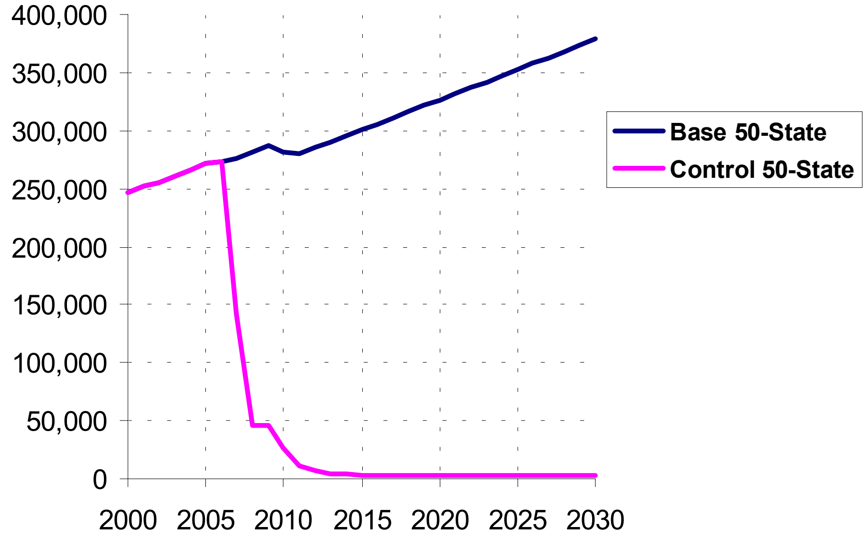
Table 3.5-8a
Estimated National (48-State) SO_2 Emissions and Reductions from
Land-Based Nonroad, Locomotive, Commercial Marine, and Recreational Marine Vessels

Year	SO_2 Emissions [short tons]			SO_2 Reductions [short tons]	
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007	With fuel sulfur further reduced to 15 ppm in 2010/2012	With fuel sulfur reduced to 500 ppm in 2007	With fuel sulfur further reduced to 15 ppm in 2010/2012
2000	244,599	244,599	244,599	0	0
2005	269,288	269,288	269,288	0	0
2007	275,416	141,029	141,029	134,388	134,388
2008	280,983	44,007	44,007	236,976	236,976
2009	286,606	44,887	44,888	241,719	241,719
2010	281,867	36,860	25,420	245,007	256,447
2011	280,031	31,152	11,041	248,879	268,989
2012	285,277	31,735	7,185	253,542	278,092
2015	300,552	33,434	3,039	267,118	297,513
2020	326,514	36,322	3,136	290,192	323,378
2025	352,585	39,218	3,273	313,367	349,312
2030	378,793	42,128	3,439	336,665	375,354

Table 3.5-8b
Estimated National (50-State) SO_2 Emissions and Reductions from
Land-Based Nonroad, Locomotive, Commercial Marine, and Recreational Marine Vessels

Year	SO_2 Emissions [short tons]			SO_2 Reductions [short tons]	
	Without Rule	With fuel sulfur reduced to 500 ppm in 2007	With fuel sulfur further reduced to 15 ppm in 2010/2012	With fuel sulfur reduced to 500 ppm in 2007	With fuel sulfur further reduced to 15 ppm in 2010/2012
2000	247,010	247,010	247,010	0	0
2005	271,841	271,841	271,841	0	0
2007	275,397	142,399	142,399	132,998	132,998
2008	280,964	45,598	45,598	235,366	235,366
2009	286,588	46,503	46,503	240,085	240,084
2010	281,828	37,802	26,303	244,026	255,525
2011	279,976	31,486	11,363	248,490	268,613
2012	285,221	32,075	7,418	253,147	277,804
2015	300,494	33,788	3,054	266,706	297,440
2020	326,450	36,701	3,149	289,749	323,302
2025	352,519	39,625	3,286	312,894	349,233
2030	378,722	42,565	3,453	336,157	375,269

Figure 3.5-4: Estimated Reductions in SO_2 Benefits From Reducing Fuel Sulfur for Land-Based Nonroad Engines, CMVs, RMVs, and Locomotives (tons/year)



3.5.4 VOC and Air Toxics Reductions

Tables 3.5-9a and 3.5-9b show our projection of the 48-state and 50-state reductions in VOC emissions expected from implementing the new NMHC emission standards.

Although this final rule does not include specific standards for air toxics, these pollutants decrease as manufacturers take steps to meet the NMHC emission standards. Tables 3.5-10a and 3.5-10b show our estimate of reduced emissions of benzene, formaldehyde, acetaldehyde, 1,3-butadiene, and acrolein. We base these numbers on the assumption that air toxic emissions are a constant fraction of hydrocarbon exhaust emissions.

Table 3.5-9a
VOC Reductions (48-State) from Land-Based Nonroad Diesel Engines

Calendar Year	VOC Without Rule [short tons]	VOC With Rule [short tons]	VOC Reductions With Rule [short tons]
2000	199,887	199,887	0
2005	163,663	163,663	0
2010	129,711	129,186	525
2015	107,084	98,766	8,318
2020	97,513	79,372	18,141
2025	94,975	69,973	25,002
2030	96,374	66,344	30,030

Table 3.5-9b
VOC Reductions (50-State) from Land-Based Nonroad Diesel Engines

Calendar Year	VOC Without Rule [short tons]	VOC With Rule [short tons]	VOC Reductions With Rule [short tons]
2000	200,903	200,903	0
2005	164,505	164,505	0
2010	130,388	129,859	529
2015	107,647	99,281	8,367
2020	98,037	79,786	18,251
2025	95,490	70,338	25,152
2030	96,900	66,690	30,210

Table 3.5-10a
Air Toxic Reductions (48-State) (tons/year)

Year		Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	Base	3,998	23,587	10,594	400	600
	Control	3,998	23,587	10,594	400	600
	Reduction	0	0	0	0	0
2005	Base	3,273	19,312	8,674	327	491
	Control	3,273	19,312	8,674	327	491
	Reduction	0	0	0	0	0
2007	Base	3,007	17,742	7,969	301	451
	Control	3,007	17,742	7,969	301	451
	Reduction	0	0	0	0	0
2010	Base	2,594	15,306	6,875	259	389
	Control	2,584	15,244	6,847	258	388
	Reduction	11	62	28	1	2
2015	Base	2,142	12,636	5,675	214	321
	Control	1,975	11,654	5,235	198	296
	Reduction	166	981	441	17	25
2020	Base	1,950	11,507	5,168	195	293
	Control	1,587	9,366	4,207	159	238
	Reduction	363	2,141	961	36	54
2025	Base	1,900	11,207	5,034	190	285
	Control	1,399	8,257	3,709	140	210
	Reduction	500	2,950	1,325	50	75
2030	Base	1,927	11,372	5,108	193	289
	Control	1,327	7,829	3,516	133	199
	Reduction	601	3,544	1,592	60	90

Table 3.5-10b
Air Toxic Reductions (50-State) (tons/year)

Year		Benzene	Formaldehyde	Acetaldehyde	1,3-butadiene	Acrolein
2000	Base	4,018	23,707	10,648	402	603
	Control	4,018	23,707	10,648	402	603
	Reduction	0	0	0	0	0
2005	Base	3,290	19,412	8,719	329	494
	Control	3,290	19,412	8,719	329	494
	Reduction	0	0	0	0	0
2007	Base	3,023	17,834	8,010	302	453
	Control	3,023	17,834	8,010	302	453
	Reduction	0	0	0	0	0
2010	Base	2,608	15,386	6,911	261	391
	Control	2,597	15,323	6,883	260	390
	Reduction	11	62	28	1	2
2015	Base	2,153	12,702	5,705	215	323
	Control	1,986	11,715	5,262	199	298
	Reduction	167	987	443	17	25
2020	Base	1,961	11,568	5,196	196	294
	Control	1,596	9,415	4,229	160	239
	Reduction	365	2,154	967	37	55
2025	Base	1,910	11,268	5,061	191	286
	Control	1,407	8,300	3,728	141	211
	Reduction	503	2,968	1,333	50	75
2030	Base	1,938	11,434	5,136	194	291
	Control	1,334	7,869	3,535	133	200
	Reduction	604	3,565	1,601	60	91

3.5.5 CO Reductions

Tables 3.5-11a and 3.5-11b show the estimated 48-state and 50-state emissions of CO from land-based diesel engines in five-year increments from 2000 to 2030 with and without the final rule. Although there are no Tier 4 CO standards, CO is estimated to decrease by 90 percent with the advent of trap-equipped engines (corresponding to the start of 0.02 or 0.01 g/hp-hr PM standards). We estimate that 50-state CO emissions from these engines will decrease by 623,000 tons in 2030.

CO emissions from locomotives, commercial marine diesel vessels, and recreational marine diesel vessels are not affected by this rule.

Table 3.5-11a
Estimated National (48-State) CO
Emissions and Reductions From Nonroad Land-Based Diesel Engines

Year	CO Emissions Without Rule [short tons]	CO Emissions With Rule [short tons]	CO Reductions With Rule [short tons]
2000	916,507	916,507	0
2005	763,062	763,062	0
2010	687,234	677,599	9,634
2015	674,296	475,349	198,947
2020	697,630	309,593	388,037
2030	786,181	167,014	619,167

Table 3.5-11b
Estimated National (50-State) CO
Emissions and Reductions From Nonroad Land-Based Diesel Engines

Year	CO Emissions Without Rule [short tons]	CO Emissions With Rule [short tons]	CO Reductions With Rule [short tons]
2000	921,226	921,226	0
2005	766,944	766,944	0
2010	690,829	681,150	9,680
2015	677,918	477,800	200,118
2020	701,445	311,112	390,333
2030	790,547	167,841	622,706

3.5.6 $PM_{2.5}$ and SO_2 Reductions from the 15 ppm Locomotive and Marine (LM) Fuel Program

Tables 3.5-12a and 3.5-12b provide the 48-state and 50-state $PM_{2.5}$ and SO_2 emissions and reductions from reducing locomotive and marine fuel sulfur from 500 ppm to 15 ppm in 2012. This is referred to as the 15 ppm LM fuel program. The reductions are shown relative to the full engine and fuel program for land-based diesel engines, and locomotive and marine fuel sulfur control to 500 ppm starting in 2007. To model the reductions for this program, the in-use fuel sulfur levels in Chapter 7 were used. The 15 ppm LM fuel program provides additional $PM_{2.5}$ reductions of approximately 400 tons by 2030, and additional SO_2 reductions of approximately 5,300 tons by 2030.

Table 3.5-12a
Estimated National (48-State) $PM_{2.5}$ and SO_2 Emissions and Reductions from a 15 ppm Locomotive and Marine (LM) Fuel Program

Year	Emissions (short tons)				Reductions (short tons)	
	Land-based full engine and fuel program; LM fuel sulfur reduced to 500 ppm in 2007		Land-based full engine and fuel program; LM fuel sulfur further reduced to 15 ppm in 2012		LM fuel sulfur reduced from 500 ppm to 15 ppm in 2012	
	$PM_{2.5}$	SO_2	$PM_{2.5}$	SO_2	$PM_{2.5}$	SO_2
2000	209,876	244,599	209,876	244,599	0	0
2005	183,831	269,288	183,831	269,288	0	0
2010	144,667	24,864	144,667	24,864	0	0
2012	133,144	11,639	132,755	7,269	389	4,370
2015	110,027	8,285	109,613	2,977	414	5,308
2020	79,870	8,517	79,450	3,139	420	5,378
2030	51,296	8,925	50,882	3,621	414	5,304

Table 3.5-12b
Estimated National (50-State) $PM_{2.5}$ and SO_2 Emissions and Reductions from a 15 ppm Locomotive and Marine (LM) Fuel Program

Year	Emissions (short tons)				Reductions (short tons)	
	Land-based full engine and fuel program; LM fuel sulfur reduced to 500 ppm in 2007		Land-based full engine and fuel program; LM fuel sulfur further reduced to 15 ppm in 2012		LM fuel sulfur reduced from 500 ppm to 15 ppm in 2012	
	$PM_{2.5}$	SO_2	$PM_{2.5}$	SO_2	$PM_{2.5}$	SO_2
2000	211,688	247,010	211,688	247,010	0	0
2005	185,555	271,841	185,555	271,841	0	0
2010	146,152	25,793	146,152	25,793	0	0
2012	134,509	11,871	134,137	7,567	372	4,305
2015	111,240	8,308	110,825	2,989	415	5,319
2020	80,915	8,537	80,495	3,153	420	5,385
2030	52,279	8,935	51,866	3,640	413	5,294

3.5.7 SO_2 and Sulfate PM Reductions from Other Nonhighway Fuel

The fuel sulfur requirements in this rule are also expected to indirectly affect diesel fuel for other nonhighway end uses. This includes any application other than land-based nonroad engines, locomotives, or marine vessels. Tables 3.5-13a and 3.5-13b provide the 48-state and 50-state estimates of fuel volumes, fuel sulfur levels, and SO_2 emissions and reductions for diesel fuel for other nonhighway end uses. Tables 3.5-14a and 3.5-14b provide similar information for sulfate PM emissions and reductions. Details regarding the estimated volumes and fuel sulfur levels can be found in Chapter 7.

The tables show the incremental reductions from controlling fuel sulfur: 1) to 500 ppm in 2007 for land-based, locomotive, and marine use (the 500 ppm NRLM fuel program), 2) further control to 15 ppm in 2010 for land-based use only, and 3) further control to 15 ppm in 2010 for locomotive and marine use (the 15 ppm LM fuel program).

SO_2 emissions are calculated similarly to the commercial marine and locomotive categories, as described in Section 3.1.3. We estimate that 99 percent of the sulfur in other nonhighway fuel is emitted in the form of SO_2 and 1 percent in the form of sulfate PM.[13]

For the incremental step of reducing LM fuel sulfur from 500 ppm to 15 ppm, heating oil related benefits dominate those related to the LM fuel itself. This occurs because the final rule prohibits the use of downgraded distillate in NRLM fuel starting in mid-2010 in the Northeast/Mid-Atlantic area, while this fuel would be able to be used in LM fuel in this area under a 500 ppm cap. When this downgraded distillate cannot be used in LM fuel, it will shift to the heating oil market. The downgrade contains between 31 (highway-based) and 435 ppm (jet-based) sulfur, well below that of heating oil. Thus, the sulfur content of heating oil decreases significantly in the Northeast/Mid-Atlantic area with a 15 ppm cap on LM fuel.

Chapter 8 provides details regarding the estimated number of gallons of downgrade shifted to the heating oil market and the corresponding sulfur content of this downgrade. The resulting SO_2 and sulfate PM emission reductions for the 15 ppm LM program given in Chapter 8 are reproduced here. The 48-state and 50-state reductions for the 15 ppm LM program are the same, since the benefits only occur in the Northeast/Mid-Atlantic area, which does not include Alaska or Hawaii.

Total SO_2 reductions in 2030 for other nonhighway uses are estimated to be 19,000 tons with the full fuel program. Of that, approximately 6,300 tons are due to the 500 ppm NRLM fuel program and 12,000 tons are due to the 15 ppm LM fuel program. Total sulfate PM reductions in 2030 are estimated to be 670 tons with the full fuel program. Of that, approximately 220 tons are due to the 500 ppm NRLM fuel program and 420 tons are due to the 15 ppm LM fuel program. These reductions are not included in Tables 3.5-1a and 3.5-1b.

Table 3.5-13a
Estimated National (48-State) SO_2 Emissions and Reductions from Other Nonhighway Fuel [a]

		Sulfur (ppm)				SO_2 Emissions (tons/year)				Incremental SO_2 Reductions (tons/year)			
Year	Volume (10^6 gals)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	500 ppm NRLM Fuel Program	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	15 ppm LM Fuel Program (LM to15 ppm in 2012)	Full Fuel Program
2000	10,471	2,871	2,871	2,871	2,871	211,286	211,286	211,286	211,286	0	0	0	0
2005	10,174	2,871	2,871	2,871	2,871	205,291	205,291	205,291	205,291	0	0	0	0
2007	10,058	2,858	2,671	2,671	2,671	202,026	188,820	188,820	188,820	13,206	0	0	13,206
2008	10,000	2,858	2,534	2,534	2,534	200,866	178,086	178,086	178,086	22,780	0	0	22,780
2009	9,943	2,858	2,534	2,534	2,534	199,713	177,064	177,064	177,064	22,649	0	0	22,649
2010	9,886	2,724	2,530	2,530	2,530	189,258	175,775	175,773	175,773	13,483	2	0	13,486
2011	9,829	2,628	2,527	2,527	2,527	181,561	174,572	174,568	174,568	6,989	4	0	6,993
2012	9,772	2,628	2,527	2,527	--	180,519	173,570	173,566	168,683	6,949	4	4,884	11,837
2015	9,605	2,628	2,527	2,515	--	177,429	170,599	169,830	160,886	6,830	768	8,944	16,542
2020	9,333	2,628	2,527	2,515	--	172,394	165,758	165,012	155,190	6,636	747	9,822	17,204
2025	9,068	2,628	2,527	2,515	--	167,503	161,055	160,330	149,494	6,448	725	10,836	18,009
2030	8,811	2,628	2,527	2,515	--	162,751	156,486	155,781	143,852	6,265	705	11,929	18,899

[a] NRLM refers to land-based diesel engines, locomotives, and recreational and commercial marine vessels.
NR refers to land-based diesel nonroad engines.
LM refers to locomotives, recreational and commercial marine vessels.

Table 3.5-13b
Estimated National (50-State) SO_2 Emissions and Reductions from Other Nonhighway Fuel [a]

		Sulfur (ppm)				SO_2 Emissions (tons/year)				Incremental SO_2 Reductions (tons/year)			
Year	Volume (10^6 gals)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	500 ppm NRLM Fuel Program	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	15 ppm LM Fuel Program (LM to15 ppm in 2012)	Full Fuel Program
2000	10,819	2,859	2,859	2,859	2,859	217,431	217,431	217,431	217,431	0	0	0	0
2005	10,512	2,859	2,859	2,859	2,859	211,262	211,262	211,262	211,262	0	0	0	0
2007	10,392	2,846	2,666	2,666	2,666	207,911	194,712	194,712	194,712	13,199	0	0	13,199
2008	10,332	2,846	2,533	2,533	2,533	206,717	183,944	183,944	183,944	22,773	0	0	22,773
2009	10,273	2,846	2,533	2,533	2,533	205,531	182,889	182,889	182,889	22,642	0	0	22,642
2010	10,214	2,717	2,529	2,529	2,529	195,041	181,561	181,559	181,559	13,481	2	0	13,483
2011	10,155	2,624	2,526	2,526	2,526	187,310	180,321	180,317	180,317	6,989	4	0	6,993
2012	10,097	2,624	2,526	2,526	--	186,235	179,286	179,282	174,399	6,949	4	4,884	11,837
2015	9,924	2,624	2,526	2,515	--	183,047	176,217	175,448	166,504	6,830	768	8,944	16,542
2020	9,643	2,624	2,526	2,515	--	177,853	171,217	170,471	160,649	6,636	747	9,822	17,204
2025	9,369	2,624	2,526	2,515	--	172,807	166,359	165,634	154,798	6,448	725	10,836	18,009
2030	9,103	2,624	2,526	2,515	--	167,904	161,639	160,934	149,006	6,265	705	11,929	18,899

[a] NRLM refers to land-based diesel engines, locomotives, and recreational and commercial marine vessels.
NR refers to land-based diesel nonroad engines.
LM refers to locomotives, recreational and commercial marine vessels.

Table 3.5-14a
Estimated National (48-State) Sulfate Emissions and Reductions from Other Nonhighway Fuel [a]

		Sulfur (ppm)				Sulfate Emissions (tons/year)				Incremental Sulfate Reductions (tons/year)			
Year	Volume (10^6 gals)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	500 ppm NRLM Fuel Program	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	15 ppm LM Fuel Program (LM to15 ppm in 2012)	Full Fuel Program
2000	10,471	2,871	2,871	2,871	2,871	7,470	7,470	7,470	7,470	0	0	0	0
2005	10,174	2,871	2,871	2,871	2,871	7,258	7,258	7,258	7,258	0	0	0	0
2007	10,058	2,858	2,671	2,671	2,671	7,142	6,675	6,675	6,675	467	0	0	467
2008	10,000	2,858	2,534	2,534	2,534	7,101	6,296	6,296	6,296	805	0	0	805
2009	9,943	2,858	2,534	2,534	2,534	7,061	6,260	6,260	6,260	801	0	0	801
2010	9,886	2,724	2,530	2,530	2,530	6,691	6,214	6,214	6,214	477	0	0	477
2011	9,829	2,628	2,527	2,527	2,527	6,419	6,172	6,172	6,172	247	0	0	247
2012	9,772	2,628	2,527	2,527	--	6,382	6,136	6,136	5,964	246	0	173	418
2015	9,605	2,628	2,527	2,515	--	6,273	6,031	6,004	5,688	241	27	316	585
2020	9,333	2,628	2,527	2,515	--	6,095	5,860	5,834	5,487	235	26	347	608
2025	9,068	2,628	2,527	2,515	--	5,922	5,694	5,668	5,285	228	26	383	637
2030	8,811	2,628	2,527	2,515	--	5,754	5,532	5,507	5,086	221	25	422	668

[a] NRLM refers to land-based diesel engines, locomotives, and recreational and commercial marine vessels.
NR refers to land-based diesel nonroad engines.
LM refers to locomotives, recreational and commercial marine vessels.

Table 3.5-14b
Estimated National (50-State) Sulfate Emissions and Reductions from Other Nonhighway Fuel [a]

Year	Volume (10^6 gals)	Sulfur (ppm)				Sulfate Emissions (tons/year)				Incremental Sulfate Reductions (tons/year)			
		Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	Base	500 ppm NRLM Fuel Program (Control to 500 ppm in 2007)	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	Full Fuel Program (NR Control to 15 ppm in 2010; LM in 2012)	500 ppm NRLM Fuel Program	500 ppm NRLM Fuel Program and NR only to 15 ppm in 2010	15 ppm LM Fuel Program (LM to15 ppm in 2012)	Full Fuel Program
2000	10,819	2,859	2,859	2,859	2,859	7,687	7,687	7,687	7,687	0	0	0	0
2005	10,512	2,859	2,859	2,859	2,859	7,469	7,469	7,469	7,469	0	0	0	0
2007	10,392	2,846	2,666	2,666	2,666	7,350	6,884	6,884	6,884	467	0	0	467
2008	10,332	2,846	2,533	2,533	2,533	7,308	6,503	6,503	6,503	805	0	0	805
2009	10,273	2,846	2,533	2,533	2,533	7,266	6,466	6,466	6,466	800	0	0	800
2010	10,214	2,717	2,529	2,529	2,529	6,895	6,419	6,419	6,419	477	0	0	477
2011	10,155	2,624	2,526	2,526	2,526	6,622	6,375	6,375	6,375	247	0	0	247
2012	10,097	2,624	2,526	2,526	--	6,584	6,338	6,338	6,166	246	0	173	418
2015	9,924	2,624	2,526	2,515	--	6,471	6,230	6,203	5,887	241	27	316	585
2020	9,643	2,624	2,526	2,515	--	6,288	6,053	6,027	5,680	235	26	347	608
2025	9,369	2,624	2,526	2,515	--	6,109	5,881	5,856	5,473	228	26	383	637
2030	9,103	2,624	2,526	2,515	--	5,936	5,715	5,690	5,268	221	25	422	668

[a] NRLM refers to land-based diesel engines, locomotives, and recreational and commercial marine vessels.
NR refers to land-based diesel nonroad engines.
LM refers to locomotives, recreational and commercial marine vessels.

3.6 Emission Inventories Used for Air Quality Modeling

The emission inputs for the air quality modeling are required early in the analytical process to conduct the air quality modeling and present the results. The air quality modeling was based on a preliminary control scenario. Since the preliminary control scenario was developed, we have gathered more information regarding the technical feasibility of the standards (see Section III of the preamble for the final rule and Chapter 4 of the Final RIA). As a result, we have revised the Tier 4 emission standards for land-based diesel engines. We have also made changes to the fuel provisions of the rule for locomotives and diesel marine vessels. This section describes the changes in the inputs and resulting emission inventories between the preliminary baseline and control scenarios used for the air quality modeling and the updated baseline and control scenarios in this final rule. This section will focus on the four nonroad diesel categories that are affected by the new emission standards and/or the fuel sulfur requirements: land-based diesel engines, recreational marine diesel engines, commercial marine diesel engines, and locomotives.

The methodology used to develop the emission inventories for the air quality modeling is first briefly described, followed by comparisons of the preliminary and final baseline and control inventories.

3.6.1 Methodology for Emission Inventory Preparation

Air quality modeling was performed for calendar years 1996, 2020, and 2030. For these years, county-level emission estimates were developed by Pechan under contract to EPA. These inventories account for county-level differences in fuel characteristics and temperature. The NONROAD model was used to generate the county-level emission estimates for all nonroad sources, with the exception of commercial marine engines, locomotives, and aircraft. The methodology has been documented in detail.[10]

For the nonroad diesel categories affected by the final rule, the only fuel characteristic that affects emissions is the fuel sulfur level. The specific pollutants affected by fuel sulfur level are PM and SO_2. To develop the county-level emission estimates for each baseline and control inventory, one diesel fuel sulfur level was used to characterize all counties outside California. A separate diesel fuel sulfur level was used to characterize all counties within California. Diesel emissions as modeled are not affected by ambient temperature.

3.6.2 Baseline Inventories

Table 3.6-1 presents the preliminary 48-state baseline inventories used for the air quality modeling. These are an aggregation of the county-level results. Results expressed as short tons are presented for 1996, 2020, and 2030 for the land-based diesel, recreational marine diesel, commercial marine diesel, and locomotive categories. The pollutants include $PM_{2.5}$, NO_x, SO_2, VOC, and CO. VOC includes both exhaust and crankcase emissions.

Table 3.6-1
Modeled 48-State Baseline Emissions
Preliminary Baseline Used for Air Quality Modeling

Applications	Year	NO_x [short tons]	$PM_{2.5}$ [short tons]	SO_2 [short tons]	VOC [short tons]	CO [short tons]
Land-Based Diesel Engines	1996	1,583,641	178,500	172,175	221,398	1,010,501
	2020	1,144,686	127,755	308,075	97,113	702,145
	2030	1,231,981	143,185	360,933	97,345	793,899
Recreational Marine Diesel Engines	1996	19,438	511	2,535	803	3,215
	2020	34,814	876	4,562	1,327	5,537
	2030	41,246	1,021	5,418	1,528	6,464
Commercial Marine Diesel Engines [a]	1996	960,153	37,203	37,252	31,613	126,523
	2020	819,544	42,054	43,028	37,362	160,061
	2030	815,162	46,185	48,308	41,433	176,708
Locomotives	1996	921,556	22,396	57,979	48,381	112,171
	2020	612,722	17,683	62,843	36,546	119,302
	2030	534,520	16,988	70,436	31,644	119,302

[a] Includes emissions from vessels using both diesel and residual fuel, with the exception of SO_2. For the pollutants other than SO_2, it was not possible to separate emissions from diesel-fueled and residual-fueled vessels.

For the final baseline inventories, we have made minor changes to the diesel fuel sulfur levels. The diesel fuel sulfur inputs used for the preliminary and final baseline inventories are provided in Table 3.6-2. The diesel fuel sulfur level for land-based diesel engines is now reduced from 2500ppm to roughly 2200ppm, beginning in 2006. Both the preliminary and final sulfur levels account for spillover of highway fuel, but the preliminary sulfur levels did not properly account for the 15ppm highway fuel sulfur content control phase-in beginning in 2006. The diesel fuel sulfur levels for marine engines and locomotives are now higher prior to 2009 and lower beginning in 2010.

Table 3.6-2
Modeled Baseline In-Use Diesel Fuel Sulfur Content
Final Baseline vs. Preliminary Baseline Used for Air Quality Modeling

Applications	Final Baseline		Preliminary Baseline	
	Fuel Sulfur ppm	Calendar Year	Fuel Sulfur ppm	Calendar Year
Land-Based Diesel Engines	2283	through 2005	2500[a]	all years
	2249	2006		
	2224	2007-2009		
	2167	2010		
	2126	2011+		
Commercial and Recreational Marine Engines and Locomotives	2637-2641	through 2005	2500[a]	all years
	2616	2006		
	2599	2007-2009		
	2444	2010		
	2334-2350	2011		

[a] 2500ppm is the 48-state average diesel fuel sulfur level, based on 2700ppm in 47 states and 120ppm in California.

For the nonroad land-based diesel category, the preliminary inventories were generated with the draft NONROAD2002 model. For the final inventory, the draft NONROAD2004 model was used. The changes from draft NONROAD2002 to draft NONROAD2004 are described in Section 3.1.1.8. The net difference in land-based diesel emissions with the two model versions is generally within 3 percent, with the direction and variation of the change dependent on the calendar year and pollutant of interest. Apart from the model changes, the lower fuel sulfur levels will serve to reduce the PM and SO_2 baseline inventories in 2020 and 2030. Table 3.6-3 compares the preliminary and final 48-state baseline scenario inventories for land-based diesel engines, as well as recreational marine diesel engines, commercial marine diesel engines, and locomotives.

For recreational marine diesel engines, the preliminary inventories were generated with the draft NONROAD2002 model. For the final inventory, the draft NONROAD2004 model was used. The changes from draft NONROAD2002 to draft NONROAD2004 are more substantial for this category. The recreational marine populations, median life, and deterioration factors for HC and NO_x were revised to match what was used in the 2002 final rulemaking that covers large spark ignition engines (>25 hp), recreational equipment, and recreational marine diesel engines (>50 hp). The exhaust emission factors for HC, NO_x, and PM were also revised in draft NONROAD2004 to reflect the final standards.

For locomotives, there have been reductions to the fuel volume estimates used to calculate emissions for this category. For the preliminary inventory development, railroad distillate values were taken from the EIA Fuel and Kerosene Supply 2000 report. Fuel consumption specific to locomotives was calculated by subtracting the rail maintenance fuel consumption as generated by the draft NONROAD2002 model from the EIA railroad distillate estimates.

For the final inventory, the EIA railroad distillate estimates were taken from the EIA Fuel and Kerosene Supply 2001 report. The estimates were first adjusted to estimate the fraction of distillate that is diesel fuel. The diesel fraction used was 0.95 for railroad distillate. Fuel consumption estimates from rail maintenance were then subtracted. The estimate of rail maintenance fuel consumption was also revised by assuming these engines consume one percent of the total railroad diesel fuel estimate, rather than using the estimate derived from draft NONROAD2002. The revised estimate of rail maintenance fuel consumption is roughly half of the NONROAD-derived estimate; however, the rail maintenance portion of the total railroad diesel fuel consumption is small, so this change alone does not significantly affect the resulting locomotive estimate. The derivation of diesel fractions and the revised estimate of rail maintenance fuel consumption is documented in Chapter 7.

There have also been reductions to the fuel volumes assigned to commercial marine vessels. For the preliminary inventory development, vessel bunkering distillate values were taken from the EIA Fuel and Kerosene Supply 2000 report. Fuel consumption specific to commercial marine vessels was calculated by subtracting the recreational marine fuel consumption as generated by the draft NONROAD2002 model from the EIA vessel bunkering estimates.

For the final inventory, the EIA vessel bunkering distillate estimates were taken from the EIA Fuel and Kerosene Supply 2001 report. The vessel bunkering distillate estimates were first adjusted to estimate the fraction of distillate that is diesel fuel. The diesel fraction used was 0.90 for vessel bunkering distillate. Fuel consumption estimates from recreational marine engines were then subtracted. The estimate of recreational marine fuel consumption was that generated by the draft NONROAD2004 model. These revised fuel volumes were used to generate SO_2 and sulfate PM estimates for commercial marine diesel engines in the final inventory. Emission estimates for other pollutants emitted by commercial marine vessels were also revised in the final inventory to reflect the January 2003 final rule for Category 3 commercial marine residual engines.

As a result, differences in total emissions between the final and preliminary baseline scenarios are generally within 10 percent. Exceptions include $PM_{2.5}$ and SO_2. Total $PM_{2.5}$ emissions are higher with the final baseline scenario, in part due to the upward revision of the $PM_{2.5}$ fraction of total PM.from 92 to 97 percent. Total SO_2 emissions are lower, due to reductions in fuel volumes for some categories and reductions in fuel sulfur levels.

Table 3.6-3
Modeled 48-State Emission Impact Due to Changes in Baseline

Applications	Year	NO_x [short tons]			VOC Emissions [short tons]			CO [short tons]		
		Final	Preliminary	Difference	Final	Preliminary	Difference	Final	Preliminary	Difference
Land-Based Diesel Engines	1996	1,564,904	1,583,641	-18,737 (-1.2%)	220,971	221,398	-427 (0.0%)	1,004,586	1,010,501	-5,915 (-0.6%)
	2020	1,119,481	1,144,686	-25,205 (-2.2%)	97,513	97,113	400 (0.4%)	697,630	702,145	-4,515 (-0.6%)
	2030	1,192,833	1,231,981	-39,148 (-3.2%)	96,374	97,345	-971 (1.0%)	786,181	793,899	-7,718 (-1.0%)
Recreational Marine Diesel Engines	1996	33,679	19,438	14,241 (73.3%)	1,297	803	494 (61.5%)	5,424	3,215	2,209 (68.7%)
	2020	47,847	34,814	13,033 (37.4%)	1,604	1,327	277 (20.9%)	9,482	5,537	3,945 (71.2%)
	2030	52,085	41,246	10,839 (26.3%)	1,669	1,528	141 (9.2%)	11,232	6,464	4,768 (73.8%)
Commercial Marine Diesel Engines[a]	1996	823,905	960,153	-136,248 (-14.2%)	28,986	31,613	-2,627 (-9.1%)	108,883	126,523	-17,640 (-13.9%)
	2020	943,560	819,544	124,016 (15.1%)	41,588	37,362	4,226 (11.3%)	150,562	160,061	-9,499 (-5.9%)
	2030	1,117,848	815,162	302,686 (37.1%)	52,880	41,433	11,447 (27.6%)	178,360	176,708	1,652 (0.9%)
Locomotives	1996	934,070	921,556	12,514 (1.4%)	38,035	48,381	-10,346 (-21.4%)	92,496	112,171	-19,675 (-17.5%)
	2020	508,084	612,722	-104,638 (-17.1%)	30,125	36,546	-6,421 (-17.6%)	99,227	119,302	-20,075 (-16.8%)
	2030	481,077	534,520	-53,443 (-10.0%)	28,580	31,644	-3,064 (-9.7%)	107,780	119,302	-11,522 (-9.7%)
Total	1996	3,356,558	3,484,788	-128,230 (-3.7%)	289,289	302,195	-12,906 (-4.3%)	1,211,389	1,252,410	-41,021 (-3.3%)
	2020	2,618,972	2,611,766	7,206 (0.3%)	170,830	172,348	-1,518 (0.9%)	956,901	987,045	-30,144 (-3.1%)
	2030	2,843,843	2,622,909	220,934 (8.4%)	179,503	171,950	7,553 (4.4%)	1,083,553	1,096,373	-12,820 (-1.2%)

a To provide direct comparisons, for pollutants other than SO_2, emissions include vessels using both diesel and residual fuels.

Table 3.6-3 (cont.)
Modeled 48-State Emission Impact Due to Changes in Baseline

Applications	Year	$PM_{2.5}$ Emissions [short tons]			SO_2 [short tons]		
		Final	Preliminary	Difference	Final	Preliminary	Difference
Land-Based Diesel Engines	1996	186,507	178,500	8,007 (4.5%)	143,572	172,175	-28,603 (-16.6%)
	2020	129,058	127,755	1,303 (1.0%)	237,044	308,075	-71,031 (-23.1%)
	2030	142,484	143,185	-701 (-0.5%)	279,511	360,933	-81,422 (-22.6%)
Recreational Marine Diesel Engines	1996	923	511	412 (80.6%)	4,286	2,535	1,751 (69.1%)
	2020	1,261	876	385 (43.9%)	6,850	4,562	2,288 (50.2%)
	2030	1,371	1,021	350 (34.3%)	8,158	5,418	2,740 (50.6%)
Commercial Marine Diesel Engines [a]	1996	33,908	37,203	-3,295 (-8.9%)	30,136	37,252	-7,116 (-19.1%)
	2020	52,197	42,054	10,143 (24.1%)	29,268	43,028	-13,760 (-32.0%)
	2030	70,319	46,185	24,134 (52.3%)	33,020	48,308	-15,288 (-31.6%)
Locomotives	1996	22,266	22,396	-130 (-0.6%)	56,193	57,979	-1,786 (-3.1%)
	2020	17,213	17,683	-470 (-2.7%)	53,352	62,843	-9,491 (-15.1%)
	2030	16,025	16,988	-963 (-5.7%)	58,103	70,436	-12,333 (-17.5%)
Total	1996	243,604	238,610	4,994 (2.1%)	234,187	269,941	-35,754 (-13.2%)
	2020	199,729	188,368	11,361 (6.0%)	326,514	418,508	-91,994 (-22.0%)
	2030	230,199	207,379	22,820 (11.0%)	378,792	485,095	-106,303 (-21.9%)

[a] To provide direct comparisons, for pollutants other than SO_2, emissions include vessels using both diesel and residual fuels.

3.6.3 Control Inventories

Table 3.6-4 presents the preliminary 48-state control inventories used for the air quality modeling. These are an aggregation of the county-level results. Results expressed as short tons are presented for 2020 and 2030 for the land-based diesel, recreational marine diesel, commercial marine diesel, and locomotive categories. Results are not presented for 1996, since controls will affect only future-year emission estimates.

Table 3.6-4
Modeled 48-State Controlled Emissions
Preliminary Control Scenario Used for Air Quality Modeling

Applications	Year	NO_x [short tons]	$PM_{2.5}$ [short tons]	SO_2 [short tons]	VOC [short tons]	CO [short tons]
Land-Based Diesel Engines	2020	481,068	36,477	1,040	73,941	249,734
	2030	222,237	14,112	1,159	63,285	133,604
Recreational Marine Diesel Engines	2020	34,814	552	20	1,327	5,537
	2030	41,246	636	24	1,528	6,464
Commercial Marine Diesel Engines	2020	819,544	38,882	184	37,362	160,061
	2030	815,162	42,625	206	41,433	176,708
Locomotives	2020	612,722	13,051	272	36,546	119,302
	2030	534,520	11,798	305	31,644	119,302

The certification standards used for the preliminary and final control scenarios are provided in Tables 3.6-5 and 3.6-6, respectively. In general, the preliminary control scenario is more stringent in terms of levels and effective model years for PM and NO_x than the final control scenario for all horsepower categories. The NMHC standard is 0.14 g/hp-hr with both scenarios for <750 hp engines, although the phase-in of this standard is later in the final control scenario. The final control scenario also has a transitional NMHC standard of 0.30 g/hp-hr for engines over 750 hp. There are no Tier 4 CO standards in both control scenarios, although CO is assumed to be reduced 90 percent in both scenarios with the advent of trap-equipped engines (corresponding to the start of 0.02 or 0.01 g/hp-hr PM standards). As a result, the final standards will increase the emissions of PM, NO_x, NMHC, and CO in 2020 and 2030 relative to the preliminary standards.

Table 3.6-5
Preliminary Tier 4 Emission Standards Used for Air Quality Modeling

Engine Power	Emission Standards g/hp-hr					Model Year
	transitional or final	PM	NO_x	NMHC	CO	
hp <25	transitional	0.01	5.6 [a,b]		6.0/4.9 [b]	2010
	final	0.01	0.30	0.14	6.0/4.9 [b]	2012
25 ≤ hp < 50	transitional	0.01	5.6 [a,b]		4.1 [b]	2010
	final	0.01	0.30	0.14	4.1 [b]	2012
50 ≤ hp < 100	transitional	0.01	3.5 [a,b]		3.7 [b]	2010
	final	0.01	0.30	0.14	3.7 [b]	2012
100 ≤ hp < 175	transitional	0.01	3.0 [a,b]		3.7 [b]	2010
	final	0.01	0.30	0.14	3.7 [b]	2012
175 ≤ hp < 750	transitional	0.01	3.0 [a,b]		2.6 [b]	2009
	final	0.01	0.30	0.14	2.6 [b]	2011
hp ≥ 750	transitional	0.01	4.8 [a,b]		2.6 [b]	2009
	final	0.01	0.30	0.14	2.6 [b]	2011

[a] This is a combined NMHC + NO_x standard.
[b] This emission standard is unchanged from the level that applies in the previous model year. For engines below 25 hp, the CO standard is 6.0 g/hp-hr for engines below 11 hp and 4.9 g/hp-hr for engines at or above 11 hp. There are no Tier 4 CO standards.

Table 3.6-6
Tier 4 Emission Standards

Engine Power	Emission Standard (g/hp-hr)					Model Year(s)
	transitional or final	PM	NO_x [a]	NMHC [a]	CO [d]	
hp <25	final	0.30	5.6 [b,c]		6.0/4.9 [c]	2008
25 ≤ hp < 75	transitional	0.22	5.6/3.5 [b,c]		4.1/3.7 [c]	2008-2012
	final	0.02	3.5 [b]		4.1/3.7 [c]	2013
75 ≤ hp < 175	transitional	0.01	0.30 (50%)	0.14 (50%)	3.7 [c]	2012-2013
	final	0.01	0.30	0.14	3.7 [c]	2014
175 ≤ hp < 750	transitional	0.01	0.30 (50%)	0.14 (50%)	2.6 [c]	2011-2013
	final	0.01	0.30	0.14	2.6 [c]	2014
hp ≥ 750 except Generator sets	transitional	0.075	2.6	0.30	2.6 [c]	2011-2014
	final	0.03	2.6	0.14	2.6 [c]	2015
Generator sets 750 ≤ hp ≤ 1200	transitional	0.075	2.6	0.30	2.6 [c]	2011-2014
	final	0.02	0.50	0.14	2.6 [c]	2015
Generator sets hp > 1200	transitional	0.075	0.50	0.30	2.6 [c]	2011-2014
	final	0.02	0.50	0.14	2.6 [c]	2015

[a] Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required. For a complete description of manufacturer options and alternative standards, refer to Section II of the preamble.
[b] This is a combined NMHC + NO_x standard.
[c] This emission standard level is unchanged from the level that applies in the previous model year. For 25-75 hp engines, the transitional NMHC + NO_x standard is 5.6 g/hp-hr for engines below 50 hp and 3.5 g/hp-hr for engines at or above 50 hp. For engines under 75 hp, the CO standard is 6.0 g/hp-hr for engines below 11 hp, 4.9 g/hp-hr for engines 11 to under 25 hp, 4.1 g/hp-hr for engines 25 to below 50 hp and 3.7 g/hp-hr for engines at or above 50 hp.
[d] There are no Tier 4 CO standards. The CO emission standard level is unchanged from the level that applies in the previous model year.

The diesel fuel sulfur inputs used for the preliminary and final control scenarios are provided in Tables 3.6-7 and 3.6-8, respectively. For land-based diesel engines, the modeled in-use diesel fuel sulfur content is 11 ppm in 2020 and 2030 for both scenarios. For recreational marine engines, commercial marine engines and locomotives, the modeled in-use diesel fuel sulfur content is 11 ppm in 2020 and 2030 for the preliminary control scenario, but 55 ppm in 2020 and 2030 for the final control scenario. As a result, the fuel sulfur levels required by the final rule will serve to increase the PM and SO_2 control inventories for the recreational marine, commercial marine, and locomotive categories in 2020 and 2030. This will be offset slightly by the reduced fuel volumes assigned to the commercial marine and locomotive categories.

Table 3.6-7
Modeled 48-State In-Use Diesel Fuel Sulfur Content Used for Air Quality Modeling

Applications	Standards	Modeled In-Use Fuel Sulfur Content, ppm	Calendar Year
All Diesel Categories	Baseline + hwy 500 ppm "spillover"	2500	through 2005
	Baseline + hwy 15 ppm "spillover"	2400	2006-2007
	June intro of 15 ppm	1006	2008
	Final 15 ppm standard	11	2009

Table 3.6-8
Modeled 48-State In-Use Diesel Fuel Sulfur Content

Applications	Calendar Year(s)	Modeled In-Use Fuel Sulfur Content, ppm
Land-based, all power ranges	through 2005	2283
	2006	2249
	2007	1140
	2008-2009	348
	2010	163
	2011-2013	31
	2014	19
	2015+	11
Recreational and Commercial Marine Diesel Engines and Locomotives	through 2000	2641
	2001	2637
	2002-2003	2638
	2004-2005	2639
	2006	2616
	2007	1328
	2008-2009	408
	2010	307
	2011	234
	2012	123
	2013	43
	2014	51
	2015-2017	56
	2018-2038	56
	2039-2040	55

To adjust PM emissions for these in-use fuel sulfur levels, the adjustment is made relative to the certification diesel fuel sulfur levels in the model. The modeled certification diesel fuel sulfur inputs used for the preliminary and final control scenarios are provided in Tables 3.6-9 and 3.6-

10, respectively. For 2020 and 2030, the certification diesel fuel sulfur levels are the same for both the preliminary and final control scenarios.

Table 3.6-11 compares the preliminary and final 48-state control scenario inventories for land-based diesel engines, recreational marine diesel engines, commercial marine diesel engines, and locomotives. Results are presented for $PM_{2.5}$, NO_x, SO_2, VOC, and CO emissions.

For land-based diesel engines, emissions of $PM_{2.5}$, NO_x, VOC, and CO emissions are higher for the final control scenario. This is due to the less stringent emission standards. There were no differences in either the in-use or certification diesel fuel sulfur levels in 2020 and 2030 for this category. The minor difference in SO_2 emissions between the preliminary and final scenarios is attributed to differences in the version of the NONROAD model used and aggregation of county-level runs for the preliminary scenario compared with using one national level run for the final control scenario.

The recreational marine, commercial marine, and locomotive categories are controlled in both scenarios; however, the in-use fuel sulfur level is 11 ppm for the preliminary control scenario and 56 ppm for the final control scenario. This directly affects the SO_2 emissions. Accordingly, the SO_2 emissions for these categories are higher for the final control scenario.

For the recreational marine category, differences are also attributed to the version of the NONROAD model used. For the commercial marine category, the final control scenario now accounts for the latest rulemaking inventories, as well as updated fuel volumes. For locomotives, the final control scenario incorporates updated fuel volume estimates.

Table 3.6-9
Modeled Certification Diesel Fuel Sulfur Content Used for Air Quality Modeling

Engine Power	Standards	Modeled Certification Fuel Sulfur Content, PPM	Model Year
hp <50	Tier 2	2000	through 2009
	Tier 4[a]	15	2010
50 ≤ hp < 175	Tier 3	2000	through 2009
	Tier 4[a]	15	2010
175 ≤ hp < 750	Tier 3	2000	through 2008
	Tier 4[a]	15	2009
hp ≥ 750	Tier 2	2000	through 2008
	Tier 4[a]	15	2009

[a] Tier 4 refers to both transitional and final standards.

Table 3.6-10
Modeled Certification Diesel Fuel Sulfur Content

Engine Power	Standards	Modeled Certification Fuel Sulfur Content, PPM	Model Year
hp <75	Tier 2	2000	through 2007
	transitional	500	2008
	final	15	2013
$75 \leq hp < 100$	Tier 3 transitional[a]	500	2008-2011
	final	15	2012
$100 \leq hp < 175$	Tier 3	2000	2007-2011
	final	15	2012
$175 \leq hp < 750$	Tier 3	2000	2006-2010
	final	15	2011
$hp \geq 750$	Tier 2	2000	2006-2010
	final	15	2011

[a] The emission standard here is still Tier 3 as in the Baseline case, but since the Tier 3 standard begins in 2008 for 50-100 hp engines it is assumed that this new technology introduction will allow manufacturers to take advantage of the availability of 500 ppm fuel that year.

Table 3.6-11
Modeled 48-State Emission Impact Due to Changes in Control Scenario

Applications	Year	NO_x [short tons]			$PM_{2.5}$ [short tons]			SO_2 [short tons]		
		Final	Preliminary	Difference	Final	Preliminary	Difference	Final	Preliminary	Difference
Land-Based Diesel Engines	2020	677,420	481,068	196,352 (40.8%)	50,065	36,477	13,588 (37.3%)	986	1,040	-54 (-5.2%)
	2030	458,649	222,237	236,412 (106%)	21,698	14,112	7,586 (53.8%)	1,074	1,159	-85 (-7.3%)
Recreational Marine Diesel Engines	2020	47,847	34,814	13,033 (37.4%)	738	552	186 (33.7%)	164	20	144 (720%)
	2030	52,085	41,246	10,839 (26.3%)	749	636	113 (17.8%)	195	24	171 (713%)
Commercial Marine Diesel Engines [a]	2020	943,560	819,544	124,016 (15.1%)	49,968	38,882	11,086 (28.5%)	703	184	519 (282%)
	2030	1,117,848	815,162	302686 (37.1%)	67,804	42,625	25,179 (59.1%)	786	206	580 (282%)
Locomotives	2020	508,084	612,722	-104,638 (-17.1%)	13,149	13,051	98 (0.8%)	1,282	272	1,010 (371%)
	2030	481,077	534,520	-53,443 (-10.0%)	11,599	11,798	-199 (-1.7%)	1,384	305	1,079 (354%)

[a] To provide direct comparisons, for pollutants other than SO_2, emissions include vessels using both diesel and residual fuels.

Table 3.6-11, continued

Applications	Year	VOC [short tons]			CO [short tons]		
		Final	Preliminary	Difference	Final	Preliminary	Difference
Land-Based Diesel Engines	2020	79,372	73,941	5,431 (7.3%)	309,593	249,734	59,859 (24.0%)
	2030	66,344	63,285	3,059 (4.8%)	167,014	133,604	33,410 (25.0%)
Recreational Marine Diesel Engines	2020	1,604	1,327	277 (20.9%)	9,482	5,537	3,945 (71.2%)
	2030	1,669	1,528	141 (9.2%)	11,232	6,464	4,768 (73.8%)
Commercial Marine Diesel Engines [a]	2020	41,589	37,362	4,227 (11.3%)	150,562	160,061	-9,499 (-5.9%)
	2030	52,880	41,433	11,447 (27.6%)	178,360	176,708	1,652 (0.9%)
Locomotives	2020	30,125	36,546	-6,421 (-17.6%)	99,227	119,302	-20,075 (-16.8%)
	2030	28,580	31,644	-3,064 (-9.7%)	107,780	119,312	-11,532 (-9.7%)

[a] To provide direct comparisons, for pollutants other than SO_2, emissions include vessels using both diesel and residual fuels.

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CHAPTER 4: Technologies and Test Procedures for Low-Emission Engines

CHAPTER 4: Technologies and Test Procedures for Low-Emission Engines

The new emission standards will require both new engine technologies and new measurement procedures. Section 4.1 documents the technical analysis supporting the feasibility of meeting the Tier 4 emission standards for nonroad diesel engines, including the not-to-exceed standards. Section 4.2 describes the development and characteristics of the new transient duty cycles and Section 4.3 describes issues related to steady-state duty cycles, including the development of new ramped-modal duty cycles and new cycles for transportation refrigeration units.

4.1 Feasibility of Emission Standards

A description of the new emission standards and our reasons for setting those standards can be found in Section II of the preamble to the final rule. This chapter documents the analysis we completed to inform the decisions described in the preamble regarding new emission standards for nonroad diesel engines. This analysis incorporates recent Agency analyses of emission-control technologies for highway diesel engines and expands those analyses with more recent data and additional analysis specific to the application of technology to nonroad diesel engines.[1,2,3]

This section is organized into subsections describing diesel emission-control technologies, issues specific to the application of these technologies to new nonroad engines, specific analyses for engines within distinct power categories (<25 hp and 25-75 hp) and an analysis of the need for low-sulfur diesel fuel (15 ppm sulfur) to enable these emission-control technologies.

For the past 30 or more years, emission-control development for gasoline vehicles and engines has concentrated most aggressively on exhaust emission-control devices. These devices currently provide as much as or more than 95 percent of the emission control on a gasoline vehicle. In contrast, the emission-control development work for highway and nonroad diesel engines has concentrated on improvements to the engine itself to limit the emissions leaving the combustion chamber.

During the past 15 years, however, more development effort has been put into catalytic exhaust emission-control devices for diesel engines, particularly in the area of particulate matter (PM) control. Those developments, and recent developments in diesel NOx exhaust emission-control devices, make the widespread commercial use of diesel exhaust emission controls feasible. EPA has recently set new emission standards for diesel engines installed in highway vehicles based on the emission-reduction potential of these devices. We believe these devices will make possible a level of emission control for nonroad diesel engines that is similar to that attained by gasoline three-way-catalyst applications. However, without low-sulfur diesel fuel, these technologies cannot be implemented.

Although the primary focus of the Tier 4 emissions program and the majority of the analysis contained in this RIA is directed at the application of catalytic emission control technologies enabled by 15 ppm sulfur diesel fuel, there are also important elements of the program based upon continuing improvements in engine-out emission controls. Like the advanced catalytic based technologies, these engine-out emission solutions for nonroad diesel engines rely upon technologies already applied to on-highway diesel engines. Additionally, these technologies form the basis for the Tier 3 emission standards for some nonroad diesel engines in other size categories. Extensive analysis and discussion of these engine-out emission control technologies can be found in the RIAs associated with the On-Highway Heavy-Duty 2004 emission standards and the Nonroad Tier 2 and Tier 3 emission standards.[4,5,6,7] Those detailed analyses are not repeated here but are a fundamental underpinning of EPA's understanding of engine-out emission controls for diesel engines and the feasibility of applying those controls to nonroad diesel engines in the Tier 4 timeframe.

4.1.1 PM Control Technologies

Particulate matter from diesel engines is made of four components;
- solid carbon soot,
- volatile and semi-volatile organic matter
- inorganic solids (ash) , and
- sulfate.

The formation of the solid carbon soot portion of PM is inherent in diesel engines due to the heterogenous distribution of fuel and air in a diesel combustion system. Diesel combustion is designed to allow for overall lean (excess oxygen) combustion giving good efficiencies and low CO and HC emissions with a small region of rich (excess fuel) combustion within the fuel-injection plume. It is within this excess fuel region of the combustion that PM is formed when high temperatures and a lack of oxygen cause the fuel to pyrolize, forming soot. Much of the soot formed in the engine is burned during the combustion process as the soot is mixed with oxygen in the cylinder at high temperatures. Any soot that is not fully burned before the exhaust valve is opened will be emitted from the engine as diesel PM.

The volatile and semi-volatile organic material in diesel PM is often simply referred to as the soluble organic fraction (SOF) in reference to a test method used to measure its level. SOF is primarily composed of engine oil that passes through the engine with no oxidation or only partial oxidation and condenses in the atmosphere to form PM. The SOF portion of diesel PM can be reduced through reductions in engine oil consumption and through oxidation of the SOF catalytically in the exhaust.

The inorganic solids (ash) in diesel PM comes primarily from metals found in engine oil and to certain extent from engine wear. Ash makes up a very small portion of total PM such that it is often not listed as a PM component and has no impact on compliance with PM emission standards. However, it does impact maintenance of PM filter technologies, as discussed later, because in aggregate over a very long period of time ash accumulation in the PM filter can reach a level such that it must be cleaned from the filter (see section 4.1.1.3.4 below).

The sulfate portion of diesel PM is formed from sulfur present in diesel fuel and engine lubricating oil that oxidizes to form sulfuric acid (H_2SO_4) and then condenses in the atmosphere to form sulfate PM. Approximately two percent of the sulfur that enters a diesel engine from the fuel is emitted directly from the engine as sulfate PM.[8] The balance of the sulfur content is emitted from the engine as SO_2. Oxidation catalyst technologies applied to control the SOF and soot portions of diesel PM can inadvertently oxidize SO_2 in the exhaust to form sulfate PM. The oxidation of SO_2 by oxidation catalysts to form sulfate PM is often called sulfate make. Without low-sulfur diesel fuel, oxidation catalyst technology to control diesel PM is limited by the formation of sulfate PM in the exhaust as discussed in more detail in the discussion below of the need for low-sulfur fuel.

4.1.1.1 In-Cylinder PM Control

The soot portion of PM emissions can be reduced by increasing the availability of oxygen within the cylinder for soot oxidation during combustion. Oxygen can be made more available by either increasing the oxygen content in-cylinder or by increasing the mixing of the fuel and oxygen in-cylinder. Several current technologies can influence oxygen content and in-cylinder mixing, including improved fuel-injection systems, air management systems, and combustion system designs. Many of these PM-reducing technologies offer better control of combustion in general, and better utilization of fuel allowing for improvements in fuel efficiency concurrent with reductions in PM emissions. Improvements in combustion technologies and refinements of these systems is an ongoing effort for highway engines and for some nonroad engines where emission standards or high fuel use encourage their introduction. The application of better combustion system technologies across the broad range of nonroad engines for meeting the new emission standards offers an opportunity for significant reductions in engine-out PM emissions and possibly for reductions in fuel consumption.

In general, the application of these in-cylinder emission control solutions for PM are more successful (reduce PM to a lower level) as engine size increases. This occurs for three reasons: 1) larger engines have a higher volume to surface area within the cylinder reducing the proportion of the in-cylinder volume near a cooler cylinder wall and thus decreasing PM formation in these cool regions; 2) larger engines operate over a narrow engine speed range allowing for better matching of turbomachinery to the engine (i.e., higher boost and more oxygen); and 3) larger engines operate at lower engine speeds reducing oil consumption which contributes to SOF and providing longer residence time for combustion to complete (i.e., at slower speeds the combustion event measured in time is longer). In the Tier 4 program, we are setting an emission standard of 0.075 g/bhp-hr for some nonroad diesel engines >750 hp beginning in 2011. This emission level is approximately 25 percent lower than the level for most current on-highway diesel engines (using 500 ppm sulfur fuel).[A] We are projecting that in-cylinder PM emission control technologies along with 15 ppm sulfur diesel fuel will allow these very large nonroad diesel engines to meet this emission standard. Given the inherent PM control advantage that these larger diesel engines enjoy when compared to the smaller on-highway counterparts and the use of lower sulfur diesel fuel which lowers sulfate PM, we can conclude that the 0.075 g/bhp-hr emission standard is clearly feasible for these engines in 2011.

Another means to reduce the soot portion of engine-out PM emissions from diesel (compression-ignited) engines is to operate the engine with a homogenous method of operation, rather than the typical heterogeneous operation. In homogenous diesel combustion, also called premixed diesel combustion, the fuel is dispersed evenly with the air throughout the combustion system. This means there are no fuel-rich/oxygen-deprived regions of the system where fuel can be pyrolized rather than burned. Rather, combustion occurs globally initiating at an indeterminate number of locations. Because there are no fuel-rich/oxygen deprived regions in homogenous combustion, the carbon (soot) PM emissions are eliminated. The resulting PM emissions are very low, consisting primarily of SOF and sulfate.

Homogenous diesel combustion has been under development for more than twenty years, yet it is still unable to overcome a number of developmental issues.[9,10] Fundamental among these issues is the ability to control the start of combustion.[11] Conventional diesel engines control the start of combustion by controlling the start of fuel injection: injection-timing control. Homogenous diesel combustion systems cannot readily use fuel-injection timing to control the start of combustion because it is difficult to inject fuel into the engine without initiating combustion. If combustion is initiated while the fuel is being injected, the engine will operate under heterogenous combustion resulting in high PM emissions. Techniques used to delay the start of combustion such as decreasing intake air temperatures or reducing the engines compression ratio can lead to misfire, a failure to ignited the fuel at all. Engine misfire results in no engine power and high hydrocarbon (raw fuel) emissions. Conversely, techniques to advance the start of combustion such as increasing intake air temperatures or increasing the engine compression ratio can lead to premature uncontrolled combustion called engine knock. Engine knock causes exceedingly high in-cylinder pressure spikes that can irreversibly damage a diesel engine at all but low-load conditions.

Controlled homogenous combustion is possible with a diesel engine under certain circumstances, and is used in limited portions of engine operation by some engine manufacturers. Nissan, a passenger car manufacturer, has developed a modified version of premixed combustion that they call modulated-kinetics, or MK, combustion.[12,13] When operated under MK combustion the PM and NOx emissions of the engine are dramatically decreased. Unfortunately, the range of engine operation for which the MK combustion process can function is limited to low-load conditions. At higher engine loads the combustion process is not stable and the engine reverts to operation with conventional diesel combustion. This dual mode operation allows the engine to benefit from the homogenous combustion approach when

[A] On-highway diesel engines used in urban buses must meet an even lower PM standard of 0.05 g/bhp-hr.

possible, while still providing the full range of engine operation. Other approaches that are similarly limited to low-load engine operation have been proposed to produce a dual combustion mode engine.[14, 15, 16]

4.1.1.2 Diesel Oxidation Catalyst (DOC)

Diesel oxidation catalyst (DOCs) are the most common form of diesel aftertreatment technology today and have been used for compliance with the PM standards for some highway engines since the early 1990s. DOCs reduce diesel PM by oxidizing a small fraction of the soot emissions and a significant portion of the SOF emissions. Total DOC effectiveness to reduce PM emissions is normally limited to approximately 30 percent because the SOF portion of diesel PM for modern diesel engines is typically less than 30 percent and because the DOC increases sulfate emissions, reducing the overall effectiveness of the catalyst. Limiting fuel sulfur levels to 15ppm allows DOCs to be designed for maximum effectiveness (nearly 100% control of SOF with highly active catalyst technologies) since their control effectiveness is not reduced by sulfate make (i.e., their sulfate make rate is high but because the sulfur level in the fuel is low the resulting PM emissions are well controlled).

DOC effectiveness to control HC and CO emissions are directly related to the “activity” of the catalyst material used in DOC washcoating. Highly active (hence effective) DOCs can reduce HC emissions by 97 percent while low activity catalysts realize approximately 50 percent HC control.[17] Today, highly active DOC formulations cannot be used for NMHC and CO control because the sulfur in current diesel fuel leads to unacceptable sulfate PM emissions, as discussed later in this section. However, with the low sulfur diesel fuel that will be available under this program, DOCs will be able to provide substantial control of these pollutants. We have projected the use of DOCs as part of an overall compliance strategy for engines meeting the interim PM standards in 2008. For those engines, DOC would also provide significant reductions in CO and HC including over the various emission test cycles for these engines. Oxidation catalyst technologies generally (i.e., DOCs and CDPFs) will be an effective tool to ensuring compliance over the NTE provisions of the Tier 4 program and to ensuring compliance with the CO standards under the new test cycles.

Data presented by one engine manufacturer regarding the existing Tier 2 PM standard show that while a DOC can be used to reduce PM emissions when tested on 2,000 ppm sulfur fuel, lowering the fuel sulfur level to 380 ppm enabled the DOC to reduce PM by 50 percent from the 2,000 ppm sulfur fuel.[18] Without the availability of 500 ppm sulfur fuel in 2008, DOCs would be of limited use for nonroad engine manufacturers and would not provide the emission-control necessary for most engine manufacturers to meet the 2008 interim Tier 4 standards. With the availability of 500 ppm sulfur fuel, DOCs can be designed to provide PM reductions on the order of 20 to 50%, while suppressing particulate sulfate reduction.[19] These levels of reductions have been seen on transient duty cycles as well as on highway and nonroad steady-state duty cycles.

DOCs are also very effective at reducing the air toxic emissions from diesel engines. Test data show that emissions of toxics such as polycyclic aromatic hydrocarbons (PAHs) can be reduced by more than 80 percent with a DOC.[20]

DOCs are less effective at controlling the solid carbon soot portion of PM. The solid (soot) typically constitutes 60 to 90 percent of the total diesel PM. Even with 15 ppm sulfur fuel, DOCs would therefore not be able to achieve the level of PM control needed to meet the PM filter based PM emission standards (i.e., PM standards at or below 0.03 g/bhp-hr). As noted above however, DOCs can be effective tools to accomplish emission reductions on the order of 20 to 50 percent even when operated on 500 ppm sulfur diesel fuel and thus may be used by some manufacturers as a means to reduce emissions in order to comply with the 2008 interim Tier 4 standards for engines <75 hp.

4.1.1.3 Catalyzed Diesel Particulate Filter (CDPF)

4.1.1.3.1 CDPF PM and HC Control Effectiveness

Emission levels from a catalyzed diesel particulate filter (CDPF) are determined by several factors. Filtering efficiencies for solid particle emissions like soot are determined by the characteristics of the PM filter, including wall thickness and pore size. Some of these characteristics represent a tradeoff between mechanical strength, weight, size and filtering efficiency. Filtering efficiencies for ceramic based diesel soot filters can be as high as 99 percent with the appropriate filter design.[21] Given an appropriate PM filter design, the contribution of the soot portion of PM to the total PM emissions can be negligible (less than 0.001 g/hp-hr). For some wire mesh or ceramic fiber filter technologies the filtering efficiency is lower, around 70 percent, but the mechanical strength (resistance to thermal and mechanical stress) especially for very large filter sizes is improved.[B,22,23] The level of soot emission control is much less dependent on engine test cycle or operating conditions due to the mechanical filtration characteristics of the particulate filter.

Control of the SOF portion of diesel soot is accomplished on a CDPF through catalytic oxidation. At the elevated temperature of diesel exhaust, the SOF portion of diesel PM consists primarily of gas-phase hydrocarbons which later form particulate matter in the environment when the SOF condenses. Catalytic materials applied to CDPFs can oxidize a substantial fraction of the SOF in diesel PM just as the SOF portion is oxidized by a DOC. However, we believe that for engines with very high SOF emissions the emission rate may be higher than can be handled by a conventionally sized catalyst resulting in higher than zero SOF emissions. If a manufacturer’s base engine technology has high oil consumption rates, and therefore high engine-out SOF emissions (i.e., higher than 0.04 g/hp-hr), compliance with the 0.01 g/hp-hr

[B] There are a number of different ways to measure mechanical strength and toughness. One metric for comparison is tensile strength. Comparing the tensile strength of fiber based filter technologies (approximately 1,000 MPa) to a ceramic filter technology such as Silicon Nitride (5.1 MPa) is illustrative of the higher strength of the fiber based technology.

emission standard may require additional technology beyond the application of a CDPF system alone.[C]

Modern highway diesel engines have controlled SOF emission rates to comply with the existing 0.1 g/hp-hr emission standards. Typically the SOF portion of PM from a modern highway diesel engine contributes less than 0.02 g/hp-hr to the total PM emissions. This level of SOF control is accomplished by controlling oil consumption through the use of engine modifications (e.g., piston ring design, the use of 4-valve heads, the use of valve stem seals, etc.).[24] Nonroad diesel engines may similarly need to control engine-out SOF emissions to comply with the new emission standards. The means to control engine-out SOF emissions are well known and have additional benefits, as they decrease oil consumption reducing operating costs. With good control of engine-out SOF emissions (i.e., engine-out SOF < 0.02 g/hp-hr) and the application of catalytic material to the DPF, SOF emissions from CDPF equipped nonroad engines will contribute only a very small fraction of the total tailpipe PM emissions (less than 0.004 g/hp-hr). Alternatively, it may be less expensive or more practical for some applications to ensure that the SOF control realized by the CDPF is in excess of 90 percent, thereby allowing for higher engine-out SOF emission levels.

The catalytic materials used on a CDPF to promote soot regeneration and to control SOF emissions are also effective to control NMHC emissions including toxic hydrocarbon emissions. CDPFs designed for operation on low-sulfur diesel fuel (i.e., with highly active catalyst technologies) can reduce total hydrocarbon emissions by more than 90 percent.[25] Toxic hydrocarbon emissions are typically reduced in proportion to total hydrocarbon emissions. Table 4.1-1 shows hydrocarbon compound reduction data for two different CDPF technologies.[26]

[C] SOF oxidation efficiency is typically better than 80 percent and can be better than 90 percent. Given a base engine SOF rate of 0.04 g/hp-hr and an 80 percent SOF reduction a tailpipe emission of 0.008 can be estimated from SOF alone. This level may be too high to comply with a 0.01 g/hp-hr standard once the other constituents of diesel PM (soot and sulfate) are added. In this case, engine-out SOF emissions will need to be reduced or the CDPF will need to reduce SOF emissions by more than 90 percent.

Table 4.1-1 Polyaromatic Hydrocarbon Reductions with a CDPF

Polyaromatic Hydrocarbon Reductions with Catalyzed Diesel Particulate Filters					
Compound	**Baseline**	**DPF-A**	**DPF-B**	**%Red DPF-A**	**%Red DPF-B**
Napthalene	295	50	0	83%	100%
2-Methylnapthalene	635	108	68	83%	89%
Acenapthalene	40	0.8	1	98%	98%
Acenapthene	46	6.7	11	85%	76%
Fluorene	72	29	12	60%	83%
Phenanthrene	169	33	26	81%	85%
Anthracene	10	1	1	90%	90%
Fluoranthene	7.7	0	2	100%	74%
Pyrene	14	0	2	100%	86%
Benzo(a)anthracene	0.22	0	0.01	100%	95%
Chrysene	0.51	0	0	100%	100%
Benzo(b)fluoranthene	0.26	0	0	100%	100%
Benzo(k)fluoranthene	0.15	0	0	100%	100%
Benzo(e)pyrene	0.26	0	0	100%	100%
Perylene	0.01	0	0	100%	100%
Indeno(123-cd)pyrene	0.13	0	0	100%	100%
Dibenz(ah)anthracene	0.01	0	0	100%	100%
Benzo(ghi)perylene	0.32	0	0	100%	100%

The best means to reduce sulfate emissions from diesel engines is by reducing the sulfur content of diesel fuel and lubricating oils. This is one of the reasons that we are limiting sulfur levels in nonroad diesel fuel to 15ppm or less. The catalytic material on the CDPF is crucial to ensuring robust regeneration and high SOF oxidation; however, it can also oxidize the sulfate in the exhaust with high efficiency. The result is that the predominant form of PM emissions from CDPF equipped diesel engines is sulfate PM. Even with 15ppm sulfur diesel fuel a CDPF equipped diesel engine can have total PM emissions including sulfate emissions as high as 0.009 g/hp-hr over some representative operating cycles using conventional diesel engine oils. This level of emissions will meet the new PM emission standard of 0.01 g/hp-hr for engines between 75 hp and 750 hp. We further believe there is room for reductions from this level to provide engine manufacturers with additional compliance margin. Our recently released Highway Diesel Progress Review Report 2 documents progress by a consortium of engine manufacturers, oil companies and other stakeholders to develop a new engine oil formulation with reduced Sulfur, Ash, and Phosphorous (SAP) content for diesel engines. The new engine oil formulation is expected to be ready in 2006. Any reduction in the sulfur level of engine lubricating oils will be beneficial. Similarly, as discussed above, we expect engine manufacturers to reduce engine oil consumption to reduce SOF emissions and secondarily to reduce sulfate PM emissions. While we believe sulfate PM emissions will be the single largest source of the total PM from diesel engines, we believe that with the combination of technology, and the appropriate control of engine-out PM emissions, sulfate and total PM emissions will be low enough to allow compliance with a 0.01 g/hp-hr standard, except in the case of small engines with higher fuel consumption rates, as described later in this section.[D]

CDPFs have been shown to be very effective at reducing PM mass by reducing dramatically the soot and SOF portions of diesel PM. In addition, recent data show that they are also very effective at reducing the overall number of emitted particles when operated on low-sulfur fuel. Hawker, et al, found that a CDPF reduced particle count by over 95 percent, including some of the smallest measurable particles (< 50 nm), at most of the tested conditions. The lowest observed efficiency in reducing particle number was 86 percent. No generation of particles by the CDPF was observed under any tested conditions.[27] Kittelson, et al, confirmed that ultrafine particles can be reduced by a factor of ten by oxidizing volatile organics, and by an additional factor of ten by reducing sulfur in the fuel. Catalyzed PM traps efficiently oxidize nearly all of the volatile organic PM precursors (SOF), and the reduction of diesel fuel sulfur levels to 15ppm or less will substantially reduce the number of ultrafine PM emitted from diesel engines. The combination of CDPFs with low-sulfur fuel is expected to result in very large reductions in both PM mass and the number of ultrafine particles.

Engine operating conditions have little impact on the particulate trapping efficiency of carbon particles by CDPFs, so the greater than 90 percent efficiency for elemental carbon particulate matter will apply to engine operation within the NTE zone and over the regulated transient cycles, as well as to the test modes that comprise the steady-state test procedures such as the ISO C1. However, engine operation will affect the CDPF regeneration and oxidation of SO_2 to sulfate PM (i.e., “sulfate-make”). Sulfate-make will reduce the measured PM removal efficiency at some NTE operating conditions and some steady-state modes, even at the 15 ppm fuel sulfur cap. This increased sensitivity to fuel sulfur is caused by the higher temperatures that are found at some of the steady-state modes. High exhaust temperatures promote the oxidation of SO_2 to SO_3 (which then combines with water in the exhaust, forming a hydrated sulfate) across the precious metals found in CDPFs. The sulfate emissions condense in the atmosphere (as well as in the CFR mandated dilution tunnel used for PM testing) forming PM.

Under contract from the California Air Resources Board, two nonroad diesel engines were recently tested for control of PM emissions with the application of a CDPF over several transient and steady-state test cycles.[28] The first engine was a 1999 Caterpillar 3408 (480 hp, 18 liter displacement) nonroad diesel engine certified to the Tier 1 standards. The engine was tested with and without a CDPF on 12 ppm sulfur diesel fuel. The transient emission results for this engine are summarized in Table 4.1-2. The steady-state emission results are summarized in Table 4.1-3. The test results confirm the excellent PM control performance realized by a CDPF with low-sulfur diesel fuel across a wide range of nonroad operating cycles in spite of the relatively high engine-out PM emissions from this Tier 1 engine. We expect engine-out PM emissions to be lower for production engines meeting Tier 3 standards, which will form the

[D] We have also set slightly higher PM standards for >750 hp engines predicated on the use of alternative PM filter technologies. These higher levels (standards of 0.02 g/bhp-hr for gensets, and 0.03 g/bhp-hr for mobile machines) are not based on higher sulfate emission rates, as for the <75 hp engines, but instead on slightly less effective PM filtration efficiencies and differing engine out emission rates.

technology baseline for the Tier 4 engines. The engine demonstrated PM emissions of 0.009 g/hp-hr on the Nonroad Transient Cycle (NRTC) from an engine-out emission level of 0.256 g/hp-hr, a reduction of 0.247 g/hp-hr (a greater than 96% reduction). The engine also demonstrated excellent PM performance on the existing steady-state ISO C1 cycle with PM emissions of 0.010 g/hp-hr from an engine-out emission level of 0.127, a reduction of 0.107 g/hp-hr. Thus, this engine would meet the new emission standards for 75-750 hp variable-speed nonroad engines.

Table 4.1-2 Transient PM Emissions for a Tier 1 NR Diesel Engine with a CDPF

1999 (Tier 1) Caterpillar 3408 (480hp, 18l)

Test Cycle	PM [g/bhp-hr]		Reduction
	Engine Out	w/ CDPF	%
Proposed Nonroad TransientCycle (NRTC)	0.256	0.009	96%
Proposed Constant Speed Variable Load Cycle (CSVL)	0.407	0.016	96%
On-Highway U.S. FTP Transient Cycle (FTP)	0.239	0.019	92%
Agricultural Tractor Cycle (AGT)	0.181	0.009	95%
Backhoe Loader Cycle (BHL)	0.372	0.022	94%
Crawler Tractor Dozer Cycle (CRT)	0.160	0.014	91%
Composite Excavator Duty Cycle (CEX)	0.079	0.009	88%
Skid Steer Loader Typical No. 1 (SST)	0.307	0.016	95%
Skid Steer Loader Typical No. 2 (SS2)	0.242	0.013	95%
Skid Steer Loader Highly Transient Speed (SSS)	0.242	0.008	97%
Skid Steer Loader Highly Transient Torque (SSQ)	0.351	0.004	99%
Arc Welder Typical No.1 (AWT)	0.510	0.018	96%
Arc Welder Typical No.2 (AW2)	0.589	0.031	95%
Arc Welder Highly Transient Speed (AWS)	0.424	0.019	96%
Rubber-Tired Loader Typical No.1 (RTL)	0.233	0.010	96%
Rubber-Tired Loader Typical No.2 (RT2)	0.236	0.011	96%
Rubber-Tired Loader Highly Transient Speed (RTS)	0.255	0.008	97%
Rubber-Tired Loader Highly Transient Torque (RTQ)	0.294	0.009	97%

Table 4.1-2 also shows results over a large number of additional test cycles developed from real-world in-use test data to represent typical operating cycles for different nonroad equipment applications (see Section 4.2 for information on these test cycles). The results show that the CDPF technology is highly effective to control in-use PM emissions over any number of disparate operating conditions. Remembering that the base Tier 1 engine was not designed to meet a transient PM standard, the CDPF emissions demonstrated here show that very low emission levels are possible even when engine-out emissions are exceedingly high (e.g., a reduction of 0.558 g/hp-hr is demonstrated on the AW2 cycle).

The results summarized in the two tables support the feasibility of the NTE provisions in this rulemaking. In spite of the Tier 1 baseline of this engine, there are only three test results with emissions higher than the permissible limit for the NTE standards. The first, in Table 4.1-2, shows PM emissions of 0.031 over the AW2 cycle, but from a very high baseline level of nearly 0.6 g/hp-hr. We believe that simple improvements to the engine-out PM emissions as needed to comply with the Tier 2 emission standard would reduce these emission below the 0.02 level required by the NTE standard. There are two other test points in Table 4.1-3 that are above the

NTE standard, both at 10 percent engine load. However, both test points are outside the NTE zone, which excludes emissions for engine loads below 30 percent. It is important to note that, although the engine would not be constrained to meet NTE standards under these conditions, the resulting reductions at both points are still substantially greater than 96 percent.

Table 4.1-3 Steady-State PM Emissions from a Tier 1 NR Diesel Engine w/ CDPF

1999 (Tier 1) Caterpillar 3408 (480hp, 18l)				
Engine Speed	Engine Load	PM ([g/bhp-hr]		Reduction
%	%	Engine Out	w/ CDPF	%
100	100	0.059	0.010	83%
100	75	0.103	0.009	91%
100	50	0.247	0.012	95%
100	25	0.247	0.000	100%
100	10	0.925	0.031	97%
60	100	0.028	0.011	61%
60	75	0.138	0.009	93%
60	50	0.180	0.010	95%
60	25	0.370	0.007	98%
60	10	0.801	0.018	98%
91	82	0.091	0.006	93%
80	63	0.195	0.008	96%
63	40	0.240	0.008	97%
0	0	--	--	--
	ISO C1 Composite	0.127	0.011	91%

The second engine tested was a prototype engine developed at Southwest Research Institute (SwRI) under contract to EPA.[29] The engine, dubbed Deere Development Engine 4045 (DDE-4045) because the prototype engine was based on a John Deere 4045 production engine, was also tested with a CDPF from a different manufacturer on the same 12 ppm diesel fuel. The engine is very much a prototype and experienced a number of part failures during testing, including to the turbocharger actuator. Nevertheless, the transient emission results summarized in Table 4.1-4 and the steady-state results summarized in Table 4.1-5 show that substantial PM reductions are realized on this engine as well. The emission levels on the NRTC and the ISO C1 duty cycles would meet the PM standard of 0.01 g/hp-hr once the appropriate rounding convention is applied.[E] Note also that measured emissions over the transient highway FTP cycle are higher than for either of the new nonroad transient duty cycles. This suggests that developing PM-compliant engines on the new nonroad transient cycles may not be substantially different from developing compliant technologies for highway engines.

[E] The rounding procedures in ASTM E29-90 are applied to the emission standard. The emission results are therefore rounded to the same number of significant digits as the specified standard, i.e., 0.014 g/hp-hr is rounded to 0.01 g/hp-hr, while 0.015 g/hp-hr would be rounded to 0.02 g/hp-hr.

Table 4.1-4 Transient PM Emissions for a Prototype NR Diesel Engine with a CDPF

EPA Prototype Tier 3 DDE-4045 (108hp, 4.5l)			
	PM [g/bhp-hr]		Reduction
Test Cycle	Engine Out	w/ CDPF	%
Proposed Nonroad TransientCycle (NRTC)	0.143	0.013	91%
Proposed Constant Speed Variable Load Cycle (CSVL)	0.218	0.018	92%
On-Highway U.S. FTP Transient Cycle (FTP)	0.185	0.023	88%
Agricultural Tractor Cycle (AGT)	0.134	0.008	94%
Backhoe Loader Cycle (BHL)	0.396	0.021	95%
Crawler Tractor Dozer Cycle (CRT)	0.314	0.008	97%
Composite Excavator Duty Cycle (CEX)	0.176	0.009	95%
Skid Steer Loader Typical No. 1 (SST)	0.288	0.012	96%
Skid Steer Loader Typical No. 2 (SS2)	0.641	0.013	98%
Skid Steer Loader Highly Transient Speed (SSS)	0.298	0.011	96%
Skid Steer Loader Highly Transient Torque (SSQ)	0.536	0.014	97%
Arc Welder Typical No.1 (AWT)	0.290	0.018	94%
Arc Welder Typical No.2 (AW2)	0.349	0.019	95%
Arc Welder Highly Transient Speed (AWS)	0.274	0.019	93%
Rubber-Tired Loader Typical No.1 (RTL)	0.761	0.014	98%
Rubber-Tired Loader Typical No.2 (RT2)	0.603	0.012	98%
Rubber-Tired Loader Highly Transient Speed (RTS)	0.721	0.010	99%
Rubber-Tired Loader Highly Transient Torque (RTQ)	0.725	0.009	99%

As with the results from the Caterpillar engine, the two low-load (10 percent load) steady-state emission points (see Table 4.1-5) have some of the highest brake specific emission rates. However, these rates are not high enough to preclude compliance with the steady-state emission cycle. The test points are also not within the NTE zone and still show substantial levels of PM reduction.

Table 4.1-5 Steady-State PM Emissions for a Prototype NR Diesel Engine w/CDPF

EPA Prototype Tier 3 DDE-4045 (108hp, 4.5l)				
Engine Speed	Engine Load	PM [g/bhp-hr]		Reduction
%	%	Engine Out	w/ CDPF	%
100	100	0.178	0.012	93%
100	75	0.116	0.006	95%
100	50	0.126	0.006	96%
100	25	0.218	0.013	94%
100	10	0.470	0.029	94%
60	100	0.045	0.007	84%
60	75	0.062	0.014	78%
60	50	0.090	0.009	90%
60	25	0.146	0.019	87%
60	10	0.258	0.046	82%
91	82	0.094	0.004	95%
80	63	0.099	0.006	94%
63	40	0.136	0.011	92%
0	0	--	--	--
	ISO C1 Composite	0.129	0.010	92%

The new NTE requirement, unlike the nonroad transient cycle (NRTC) or the existing ISO C1 cycle, is not a composite test. In fact, several of the individual modes within the C1 cycle test fall within the NTE zone. As discussed above, CDPFs are very efficient at capturing elemental carbon PM (up to 99 percent), but sulfate-make under certain operating conditions may exceed the standard of 0.01 g/hp-hr over the NRTC or C1 duty cycles, which is part of the reason the NTE standard for PM is greater than the PM standards that apply for testing over the NRTC and C1 duty cycles.

In this rulemaking, we are making changes to the test procedures for nonroad CI engines. The switch to the test procedures specified in part 1065 and part 86 (from those specified in part 89) will generally improve the repeatability of emission measurements. These changes do not change our analysis of the feasibility to comply with the Tier 4 standards as they are designed to improve accuracy and repeatability and as such do not adversely impact stringency. Also, as described in section III.G.3 of the preamble, we are considering in a separate proceeding additional changes to the part 1065 regulations to further improve the test procedures. Like the changes finalized in this rulemaking, these planned changes will not impact stringency only accuracy and repeatability, and thus, will not impact feasibility.

The new NTE requirements apply not only during standard laboratory conditions, but also during the expanded ambient temperature, humidity, and altitude limits defined in the regulations. We believe the new NTE PM standard is technologically feasible across this range of ambient conditions. As discussed above, CDPFs are mechanical filtration devices, and ambient temperature changes will have minimal effect on CDPF performance. Ambient altitude will also have minimal, if any, effects on CDPF filtration efficiencies, and ambient humidity should have no effect on CDPF performance. As discussed above, particulate sulfate make is sensitive to high exhaust gas temperatures; however, at sea-level conditions, the NTE requirements apply up to ambient temperatures that are only 14˚F greater than standard test cell conditions (100˚F under the NTE standards, versus 86˚F for C1 laboratory conditions). At an altitude of 5,500 feet above sea level, the NTE standards apply only up to an ambient temperature within the range of standard laboratory conditions (i.e., 86˚F). These small or non-existent differences in ambient temperature should have little effect on the sulfate make of CDPFs, and as can be seen in Tables 4.1-3 and 4.1-5 above, even when tested at an engine operating test mode representative of the highest particulate sulfate generating conditions (peak-torque operation) with 12 ppm sulfur diesel fuel, the results show the engine would easily meet the NTE PM standard. Based on the available test data and the expected impact of the expanded, but constrained, ambient conditions under which engines must comply with the NTE standards, we conclude that the NTE PM standard for engines > 75 hp is technologically feasible (including engines >750 hp), provided low-sulfur diesel fuel (15 ppm or lower) is available. Although we do not have data available specific to the application of wire or fiber mesh filter technologies on diesel engines >750 hp, the same filtration principles and control mechanisms apply to this technology as to the ceramic technology described here. A discussion of the technical feasibility for engines with rated power lower than 75 hp is given in Sections 4.1.4 and 4.1.5.

4.1.1.3.2 CDPF Regeneration

Diesel particulate filters (DPFs) control diesel PM by capturing the soot portion of PM in a filter media, typically a ceramic wall flow substrate, and then by oxidizing (burning) it in the oxygen-rich atmosphere of diesel exhaust. The SOF portion of diesel PM can be controlled through the addition of catalytic materials to the DPF to form a catalyzed diesel particulate filter (CDPF).[F] The catalytic material is also very effective to promote soot burning. This burning off of collected PM is referred to as "regeneration." In aggregate over an extended period of operation, the PM must be regenerated at a rate equal to or greater that its accumulation rate, or the DPF will clog.

For a non-catalyzed DPF the soot can regenerate only at very high temperatures, in excess of 600˚C, a temperature range that occurs infrequently in normal diesel engine operation (exhaust temperatures for many engines might never reach 600˚C). With the addition of a catalytic coating to make a CDPF, the temperature necessary to ensure regeneration is decreased significantly to approximately 250˚C, a temperature within the normal operating range for most diesel engines.[30]

The catalytic materials that most effectively promote soot and SOF oxidation, however, are significantly impacted by sulfur in diesel fuel. Sulfur both degrades catalyst oxidation efficiency (i.e., poisons the catalyst) and forms sulfate PM. Both catalyst poisoning by sulfur and increases in PM emissions due to sulfate make influence our decision to limit the sulfur level of diesel fuel to 15 ppm as discussed in greater detail in the discussion below of the need for low-sulfur diesel fuel.

Filter regeneration is affected by catalytic materials used to promote oxidation, sulfur in diesel fuel, engine-out soot rates, and exhaust temperatures. At higher exhaust temperatures, soot oxidation occurs at a higher rate. Catalytic materials accelerate soot oxidation at a single exhaust temperature compared with non-catalyst DPFs, but even with catalytic materials increasing the exhaust temperature further accelerates soot oxidation.

Having applied 15 ppm sulfur diesel fuel and the best catalyst technology to promote low-temperature oxidation (regeneration), the regeneration balance of soot oxidation equal to or greater than soot accumulation over aggregate operation simplifies to the following question: are the exhaust temperatures high enough on aggregate to oxidize the engine-out PM emission rate?[G] The answer is yes, for most highway applications and many nonroad applications, as demonstrated by the widespread success of retrofit CDPF systems for nonroad equipment and the use of both retrofit and original equipment CDPF systems for highway vehicles.[31,32,33]

[F] With regard to gaseous emissions such as NMHCs and CO, the CDPF works in the same manner with similar effectiveness as the DOC (i.e., NMHC and CO emissions are reduced by more than 80 percent).

[G] If the question was asked, "without 15 ppm sulfur fuel and the best catalyst technology, are the exhaust temperatures high enough on aggregate to oxidize the engine-out PM emission rate?" the answer would be no, for all but a very few highway or nonroad diesel engines.

However, it is possible that for some nonroad applications the engine-out PM emission rate may exceed the soot oxidation rate even with low-sulfur diesel fuel and the best catalyst technologies. Should this occur, successful regeneration requires that either engine-out PM emission rates be decreased or exhaust temperatures be increased, both feasible strategies. In fact, we expect both to occur as highway-based technologies are transferred to nonroad engines. As discussed earlier, engine technologies to lower PM emissions while improving fuel consumption are continuously being developed and refined. As these technologies are applied to nonroad engines driven by both new emission standards and market pressures for better products, engine-out PM emissions will decrease. Similarly, techniques to raise exhaust temperatures periodically for initiating soot oxidation in a PM filter have been developed for highway diesel vehicles as typified by the PSA system used on more than 400,000 vehicles in Europe.[34]

During our 2002 Highway Diesel Progress Review, we investigated the plans of highway engine manufacturers to use CDPF systems to comply with the HD2007 emission standards for PM. We learned that all diesel engine manufacturers intend to comply through the application of CDPF system technology. We also learned that the manufacturers are developing means to raise the exhaust temperature, if necessary, to ensure that CDPF regeneration occurs.[35] These technologies include modifications to fuel-injection strategies, modifications to EGR strategies, and modifications to turbocharger control strategies. These systems are based upon the technologies used by the engine manufacturers to comply with the 2004 highway emission standards. In general, the systems anticipated to be used by highway manufacturers to meet the 2004 emission standards are the same technologies that engine manufacturers have indicated to EPA that they will use to comply with the Tier 3 nonroad regulations (e.g., electronic fuel systems).[36] In a manner similar to highway engine manufacturers, we expect nonroad engine manufacturers to adapt their Tier 3 emission-control technologies to provide back-up regeneration systems for CDPF technologies to comply with the new emission standards. We have estimated costs for such systems in our cost analysis.

4.1.1.3.3 Current Status of CDPF Technology

More than one emission control manufacturer is developing CDPFs. In field trials, they have demonstrated highly efficient PM control and promising durability. A recent publication documents results from a sample of these field test engines after years of use in real-world applications.[37] The sampled CDPFs had on average four years of use covering more than 225,000 miles in applications ranging from city buses to garbage trucks to intercity trains, with some units accumulating more than 360,000 miles. When tested on the highway FTP cycle, they continued to demonstrate PM reductions in excess of 90 percent.

Another program evaluating CDPFs in the field is the ARCO Emission Control Diesel (EC-D) program.[H] In that program, a technology validation is being run to evaluate EC-D and CDPFs using diesel vehicles operating in southern California. The fuel's performance, impact

[H] EC-D is a diesel fuel developed recently by ARCO (Atlantic Richfield Company) from typical crude oil using a conventional refining process and having a fuel sulfur content less than 15 ppm.

on engine durability and vehicle performance, and emission characteristics are being evaluated in several fleets in various applications. The program is still ongoing, but interim results have been made available.[38] These interim results have shown that vehicles retrofitted with CDPFs and fueled with EC-D (7.4 ppm sulfur) emitted 91 percent to 99 percent less PM compared with the vehicles fueled with California diesel fuel (121 ppm sulfur) having no exhaust filter equipment. Further, the test vehicles equipped with the CDPFs and fueled with EC-D have operated reliably during the program start-up period and no significant maintenance issues have been reported for the school bus, tanker truck and grocery truck fleets that have been operating for over six months (approximately 50,000 miles).[39] These results from on-highway diesel engines are significant because in form and function the engines are virtually the same as those used for nonroad diesel applications. In fact, in many cases on-highway diesel engines have directed nonroad counterparts that are virtually identical. Further, even for nonroad engines which may differ in physical size or horsepower range, the underlying chemistry and filtration efficiency of CDPFs is the same.

Even with the relatively mature state of the CDPF technology, progress is still being made to improve catalytic-based soot regeneration technologies and to develop system solutions to ensure that even under the most extreme conditions soot regeneration can be ensured. Improvements in catalytic soot oxidation are important because more active soot oxidation can help to improve fuel economy and to ensure robust soot regeneration. A PM filter with a more effective soot oxidation catalyst would be expected to have a lower average soot loading and therefore would be less restrictive to exhaust flow, thus decreasing the pressure drop across the PM filter and leading to better fuel economy. Improved effectiveness in oxidizing soot will also further ensure that excessive soot loading that might lead to PM filter failure will not occur.

A paper presented at a recent conference of the Society of Automotive Engineers (SAE) documented design improvements in catalyzed diesel particulate filters with improved soot oxidation effectiveness. The paper showed that changes in where catalytic materials were coated within a PM filter system (on an upfront flow-through catalyst, on the surface of the PM filter or a combination of both) influenced the effectiveness of the catalyst material to promote soot oxidation.[40] This kind of system analysis suggests that there remain opportunities to further improve how diesel particulate filters are designed to promote soot oxidation and that different solutions may be chosen dependent upon expected nonroad equipment operation (expected exhaust temperature history), packaging constraints and cost.

Alhough highly effective catalytic soot oxidation, enabled by clean diesel fuel (15 ppm S), suggests that PM filters will regenerate passively for most vehicle and many nonroad equipment applications, there remains the possibility that for some conditions active regeneration systems (backup systems) may be desirable.[I] For this reason, some vehicle manufacturers have

[I] We are defining backup regeneration to include any number of methods for raising exhaust temperatures in order to promote PM filter regeneration. These could include changes to engine management to change engine operation and raise exhaust temperature, any external mechanism to add heat into the exhaust, or a combination of engine management to increase hydrocarbon (fuel) emissions from the engine in order to oxidize those emissions across a diesel oxidation catalyst (DOC) and thus raise exhaust temperatures.

developed systems to help ensure that PM soot regeneration can occur under all conditions. One example of this is a current production product sold in Europe by PSA/Peugeot. On diesel powered Peugeot 607 passenger cars (a Ford Taurus-sized passenger car) a PM filter system is installed that includes mechanisms for engine-promoted soot oxidation. The vehicle estimates soot loading from several parameters, including exhaust backpressure and can periodically promote more rapid soot oxidation by injecting additional fuel late in the combustion cycle. This fuel is injected so late in the cycle that it does not contribute to engine power but instead is combusted (oxidized) across an oxidation catalyst in front of the PM filter. The combustion of the fuel across the catalyst increases the exhaust temperature substantially, encouraging rapid soot oxidation. Peugeot has sold more than 400,000 passenger cars with this technology and expects to expand the use of the system across all of its diesel vehicle lines.[41] Other European vehicle manufacturers indicated to EPA during our progress review, that they intend to introduce similar technologies in the near future. They noted that this was not driven by regulation but by customer demand for clean diesel technologies. The fact that manufacturers are introducing PM filter technologies in advance of mandatory regulations suggests that the technology is well developed and mature.

The potential for synergistic benefits to the application of both PM filters and NOx adsorbers was highlighted in the HD2007 Regulatory Impact Analysis, but at that time little was known as to the extent of these synergistic benefits.[42] Toyota has developed a combined diesel particulate filter and NOx adsorber technology dubbed DPNR (Diesel Particulate NOx Reduction). The mechanism for synergistic PM soot regeneration with programmed NOx regeneration was recently documented by Toyota in a SAE publication. The paper showed that active oxygen molecules created both under lean conditions as part of the NOx storage function and under rich conditions created by the NOx regeneration function were effective at promoting soot oxidation at low temperatures.[43] This suggests that the combination of a NOx adsorber catalyst function with a diesel particulate filter can provide a more robust soot regeneration system than a PM filter-only technology.

4.1.1.3.4 CDPF Maintenance

Inorganic solid particles present in diesel exhaust can be captured by diesel particulate filters. Typically these inorganic materials are metals derived from engine oil, diesel fuel or even engine wear. Without a PM filter these materials are normally exhausted from the engine as diesel PM. While the PM filter is effective at capturing inorganic materials it is not typically effective at removing them, since they do not tend to be oxidized into a gaseous state (carbon soot is oxidized to CO_2 which can easily pass through the PM filter walls). Because these inorganic materials are not typically combusted and remain after the bulk of the PM is oxidized from the filter they are typically referred to as ash. While filtering metallic ash from the exhaust is an environmental benefit of the PM filter technology it also creates a maintenance need for the PM filter to remove the ash from the filter periodically.

The maintenance function for the removal of ash is relatively straightforward, and itself does not present a technical challenge for the industry. We have estimated cost for ash removal as one of the costs of this rule (see RIA Chapter 6). However, both the industry and EPA would like to see ash-related PM filter maintenance reduced as much as possible. EPA has specific guidelines for acceptable maintenance intervals for nonroad diesel engines with CDPFs intended to ensure robust emission-control technologies (3,000hrs for engines <175 hp and 4,500hrs for engines ≥175hp). Nonroad engine manufacturers are similarly motivated to improve reliability to minimize end-user maintenance costs. The issue of ash accumulation was raised consistently during our progress review visits with the industry. The industry is investigating several ways to address this issue including means to improve ash tolerance and to reduce the amount of ash present in diesel exhaust.

For most current PM filter designs ash accumulates at the end of the inlet passages of the PM filter. As more ash is accumulated, the effective filter size is reduced because the ash fills the end of the passage shortening the effective filter length. Increasing PM filter size to tolerate higher levels of ash accumulation is one simple approach to address ash. This approach, though effective, is undesirable due to the added cost and size of the resulting PM filter. Several companies are investigating means to develop PM filter mechanisms that are more ash-tolerant. These approaches include concepts to increase storage area within the filter itself and concepts that promote self-cleaning of the filter, perhaps driven by engine and vehicle vibrations during normal vehicle operation. Our recent Highway Diesel Progress Review Report 2 described two such systems recently introduced for on-highway applications. For light-duty vehicle applications the technologies are described as fit for life, meaning that ash cleaning maintenance will not be necessary over the life of a light-duty diesel vehicle. For heavy-duty diesel engines (and for nonroad diesel engines >250 hp) the technologies are expected to increase the interval between ash cleaning by 50 percent.

In addition to concepts to improve ash handling, possibilities exist to decrease the amount of ash present in diesel exhaust. The predominant source of ash in diesel exhaust is inorganic materials contained in engine oil (oil ash). A significant fraction of the ash in engine oil is from additives necessary to control acidification of engine oil due in part to sulfuric acid derived from sulfur in diesel fuel. As the sulfur content of diesel fuel is decreased, the need for additives to neutralize the acids in engine oil should also decrease. The concept of an engine oil with less ash content is often referred to as "low-ash oil." Several technical programs are ongoing to determine the impact of changes in oil ash content and other characteristics of engine oil on exhaust emission-control technologies and engine wear and performance. Historically, as engine technologies have changed (often due to changes in emission regulations) engine oil formulations have also changed. These changes have been accomplished through industry consensus on oil specifications based on defined test protocols. This process of consensus definition has begun to develop engine oils specifications for highway diesel engines for the 2007 model year. This engine oil will also be appropriate for application to nonroad diesel engine designed with the same technologies (i.e., an engine oil specification designed for highway HD2007 engines would also be appropriate for use with Tier 4 engines).

It may also be possible to reduce the ash level in diesel exhaust by reducing oil consumption from diesel engines. Diesel engine manufacturers over the years have reduced engine oil consumption to reduce PM emissions and to reduce operating costs for engine owners. Further improvements in oil consumption may be possible to reduce ash accumulation rates in PM filters. If oil accumulation rates could be halved and engine oil ash content similarly decreased, the PM filter maintenance interval would be increased four-fold. Current retrofit PM filter ash maintenance intervals can range from 50k miles to more than 200k miles.[44]

4.1.2 NOx Control Technologies

Oxides of nitrogen (NO and NO_2, collectively called NOx) are formed at high temperatures during the diesel combustion process from nitrogen and oxygen present in the intake air. The NOx formation rate is exponentially related to peak cylinder temperatures and is also strongly related to nitrogen and oxygen content (partial pressures). NOx control technologies for diesel engines have focused on reducing emissions by lowering the peak cylinder temperatures and by decreasing the oxygen content of the intake air.

4.1.2.1 In-Cylinder NOx Control Technologies

Several technologies have been developed to accomplish these objectives, including fuel-injection timing retard, fuel-injection rate control, charge air cooling, exhaust gas recirculation (EGR) and cooled EGR. The use of these technologies can result in significant reductions in NOx emissions, but are limited due to practical and physical constraints of heterogeneous diesel combustion.[45]

Our recent Highway Diesel Progress Review Report 2, investigated the extent to which in-cylinder NOx control technologies had advanced. The report noted that a number of diesel engine manufacturers introduced cooled EGR systems on their heavy-duty diesel engines in 2002 compliant with the 2004 emission standards for NOx and NMHC of 2.5 g/bhp-hr. The engines circulate a portion of the exhaust gases through a heat exchanger cooling the exhaust before reintroducing the gases into the engine intake manifold. The systems control NOx emissions by providing a diluent (spent exhaust gases) reducing the oxygen content of the intake air and recirculated exhaust mixture. Engine manufacturers have now demonstrated that these systems can be further refined to allow NOx emissions compliant with the 2007 NOx averaging level of approximately 1.2 g/bhp-hr. To reduce NOx emissions below 1.2 g/bhp-hr engine manufacturers will likely need to increase EGR rates (use higher levels of EGR), thus we are referring to such refinements for on-highway 2007 diesel engines as high flow EGR. Although there are nonroad specific challenges to applying similar technologies to nonroad diesel engines (most notably the lack of ram-air for cooling), the fundamental NOx control technologies are applicable to all diesel engines. We are confident based on the continuing development of on-highway technologies for in-cylinder NOx control using cooled EGR or ACERT™ that nonroad diesel engines between 25 and 75 hp and mobile machine nonroad engines >750 hp will be able to comply with their respective Tier 4 standards (i.e., 3.5 g/bhp-hr NOx+NMHC for 25-50 hp engines, the same standard certified using the NRTC and NTE for 50-75 hp engines, and 2.6 g/bhp-hr NOx for >750 hp engines), including the NRTC (with cold-start) and the NTE standards all of which are similar in difficulty to the heavy-duty FTP (with cold-start) and the NTE standards for on-highway engines. For additional discussion of these emission control technologies and the impact of the NTE and cold-start, see the RIA for the on-highway HD 2004 emission standards and the RIA for the Tier 2/3 emission standards.[46,47]

A new form of diesel engine combustion, commonly referred to as homogenous diesel combustion or premixed diesel combustion, can give very low NOx emissions over a limited range of diesel engine operation. In the regions of diesel engine operation over which this combustion technology is feasible (light-load conditions), NOx emissions can be reduced enough to comply with the 0.3 g/hp-hr NOx emission standard.[48] Some engine manufacturers are already producing engines that utilize this technology over a narrow range of engine operation.[49] Unfortunately, it is not possible today to apply this technology over the full range of diesel engine operation. We believe that more engine manufacturers will utilize this alternative combustion approach in the limited range over which it is effective, but will have to rely on conventional heterogenous diesel combustion for the bulk of engine operation. See Section 4.1.1.1 for additional discussion of homogenous diesel combustion and PM emission control.

4.1.2.2 Lean-NOx Catalyst Technology

Lean-NOx catalysts have been under development for some time, and two methods have been developed for using a lean NOx catalyst depending on the level of NOx reduction desired though neither method can produce more than a 30 percent NOx reduction. The "active" lean-NOx catalyst injects a reductant that serves to reduce NOx to N_2 and O_2 (typically diesel fuel is used as the reductant). The reductant is introduced upstream of, or into, the catalyst. The presence of the reductant provides locally oxygen-poor conditions that allow the NOx emissions to be reduced by the catalyst.

The lean-NOx catalyst washcoat incorporates a zeolite catalyst that acts to adsorb hydrocarbons from the exhaust stream. Once adsorbed on the zeolite, the hydrocarbons will oxidize and create a locally oxygen-poor region that is more conducive to reducing NOx. To promote hydrocarbon oxidation at lower temperatures, the washcoat can incorporate platinum or other precious metals. The platinum also helps to eliminate the emission of unburned hydrocarbons that can occur if too much reductant is injected, referred to as "hydrocarbon slip." With platinum, the NOx conversion can take place at the low exhaust temperatures that are typical of diesel engines. However, the presence of the precious metals can lead to production of sulfate PM, as already discussed for PM control technologies.

Active lean-NOx catalysts have been shown to provide up to 30 percent NOx reduction under limited steady-state conditions. However, this NOx control is achieved with a fuel economy penalty upwards of 7 percent due to the need to inject fuel into the exhaust stream.[50] NOx reductions over the transient highway FTP cycle are only on the order of 12 percent due to excursions outside the optimum NOx reduction efficiency temperature range for these devices.[51] Consequently, the active lean-NOx catalyst does not appear to be capable of enabling the significantly lower NOx emissions required by the Tier 4 NOx standards.

The "passive" lean-NOx catalyst uses no reductant injection. The passive lean-NOx catalyst is therefore even more limited in its ability to reduce NOx because the exhaust gases normally contain very few hydrocarbons. For that reason, today's passive lean-NOx catalyst is capable of best steady-state NOx reductions of less than 10 percent. Neither approach to lean-

NOx catalysis listed here can provide the significant NOx reductions necessary to meet the Tier 4 standards.

4.1.2.3 NOx Adsorber Technology

NOx emissions from gasoline-powered vehicles are controlled to extremely low levels through the use of the three-way catalyst technology first introduced in the 1970s. Three-way-catalyst technology is very efficient in the stochiometric conditions found in the exhaust of properly controlled gasoline-powered vehicles. Today, an advancement upon this well-developed three-way catalyst technology, the NOx adsorber, has shown that it too can make possible extremely low NOx emissions from lean-burn engines such as diesel engines.[J] The potential of the NOx adsorber catalyst is limited only by its need for careful integration with the engine and engine control system (as was done for three-way catalyst equipped passenger cars in the 1980s and 1990s) and by poisoning of the catalyst from sulfur in the fuel. The Agency set stringent new NOx standards for highway diesel engines beginning in 2007 predicated upon the use of the NOx adsorber catalyst enabled by significant reductions in fuel sulfur levels (15 ppm sulfur or less). The final rule includes similarly stringent NOx emission standards for nonroad engines from 75-750 hp and for certain engines >750 hp, again based on using technology enabled by a reduction in fuel sulfur levels.

NOx adsorbers work to control NOx emissions by storing NOx on the surface of the catalyst during the lean engine operation typical of diesel engines. The adsorber then undergoes subsequent brief rich regeneration events where the NOx is released and reduced across precious-metal catalysts. The NOx storage period can be as short as 15 seconds and as along as 10 minutes depending upon engine-out NOx emission rates and exhaust temperature. Several methods have been developed to accomplish the necessary brief rich exhaust conditions necessary to regenerate the NOx adsorber technology including late-cycle fuel injection, also called post injection, in exhaust fuel injection, and dual bed technologies with off-line regeneration.[52,53,54] This method for NOx control has been shown to be highly effective when applied to diesel engines but has some technical challenges associated with it. Primary among these is sulfur poisoning of the catalyst, as described in Section 4.1.2.3.4.2 below.

4.1.2.3.1 How do NOx Adsorbers Work?

As noted, the NOx adsorber catalyst is a further development of the three-way catalyst technology developed for gasoline powered vehicles more than twenty years ago. The NOx adsorber enhances the three-way catalyst function through the addition of storage materials on the catalyst surface that can adsorb NOx under oxygen-rich conditions. This enhancement means that a NOx adsorber can allow for control of NOx emissions under lean-burn (oxygen-rich) operating conditions typical of diesel engines.

[J] NOx adsorber catalysts are also called, NOx storage catalysts (NSCs), NOx storage and reduction catalysts (NSRs), and NOx traps.

Three-way catalysts reduce NOx emissions as well as HC and CO emissions (hence the name three-way) by promoting oxidation of HC and CO to water and CO_2 using the oxidation potential of the NOx pollutant, and, in the process, reducing the NOx emissions to atomic nitrogen, N_2. Said another way, three-way catalysts work with exhaust conditions where the net oxidizing and reducing chemistry of the exhaust is approximately equal, allowing the catalyst to promote complete oxidation/reduction reactions to the desired exhaust components, carbon dioxide (CO_2), water (H_2O) and nitrogen (N_2). The oxidizing potential in the exhaust comes from NOx emissions and from oxygen (O_2) that is not consumed during combustion. The reducing potential in the exhaust comes from HC and CO emissions, which are products of incomplete combustion. Operation of the engine to ensure that the oxidizing and reducing potential of the combustion and exhaust conditions is precisely balanced is referred to as stoichiometric engine operation.

If the exhaust chemistry varies from stoichiometric conditions emission control is decreased. If the exhaust chemistry is net "fuel-rich," meaning there is an excess of HC and CO emissions in comparison to the oxidation potential of the NOx and O_2 present in the exhaust, the excess HC and CO pollutants are emitted from the engine. Conversely, if the exhaust chemistry is net "oxygen-rich" (lean-burn), meaning there is an excess of NOx and O_2 in comparison to the reducing potential of the HC and CO present in the exhaust, the excess NOx pollutants are emitted from the engine. It is this oxygen-rich operating condition that typifies diesel engine operation. Because of this, diesel engines equipped with three-way catalysts (or simpler oxidation catalysts) have very low HC and CO emissions while NOx (and O_2) emissions remain almost unchanged from the high engine-out emission levels. For this reason, when diesel engines are equipped with catalysts (diesel oxidation catalysts (DOCs)) they have HC and CO emissions that are typically lower, but have NOx emissions that are an order of magnitude higher, than for gasoline engines equipped with three-way catalysts.

The NOx adsorber catalyst works to overcome this situation by storing NOx emissions when the exhaust conditions are oxygen-rich. Unfortunately the storage capacity of the NOx adsorber is limited, requiring that the stored NOx be periodically purged from the storage component. If the exhaust chemistry is controlled such that when the stored NOx emissions are released the net exhaust chemistry is at stoichiometric or net fuel-rich conditions, then the three-way catalyst portion of the catalyst can reduce the NOx emissions in the same way as for a gasoline three-way catalyst equipped engine. Simply put, the NOx adsorber works to control NOx emissions by storing NOx on the catalyst surface under lean-burn conditions typical of diesel engines and then by reducing the NOx emissions with a three-way catalyst function by periodically operating under stoichiometric or fuel-rich conditions.

The NOx storage process can be further broken down into two steps. First the NO in the exhaust is oxidized to NO_2 across an oxidation promoting catalyst, typically platinum. Then the NO_2 is further oxidized and stored on the surface of the catalyst as a metallic nitrate (MNO_3). The storage components are typically alkali or alkaline earth metals that can form stable metallic nitrates. The most common storage component is barium carbonate ($BaCO_3$), which can store NO_2 as barium nitrate ($Ba(NO_3)_2$) while releasing CO_2. For the NOx storage function to work, the NOx must be oxidized to NO_2 prior to storage and a storage site must be available (the device cannot be "full"). During this oxygen-rich portion of operation, NOx is stored while HC and CO emissions are oxidized across the three-way catalyst components by oxygen in the exhaust. This can result in near zero emissions of NOx, HCs, and CO under the net oxygen-rich operating conditions typical of diesel engines.

The NOx adsorber releases and reduces NOx emissions under fuel-rich operating conditions through a similar two step process, referred to here as NOx adsorber regeneration. The metallic nitrate becomes unstable under net fuel-rich operating conditions, decomposing and releasing the stored NOx. Then the NOx is reduced by reducing agents in the exhaust (CO and HCs) across a three-way catalyst system, typically containing platinum and rhodium. Typically, this NOx regeneration step occurs at a significantly faster rate than the period of lean-NOx storage such that the fuel-rich operation constitutes only a small fraction of the total operating time. Since this release and reduction step, NOx adsorber regeneration, occurs under net fuel-rich operating conditions, NOx emissions can be almost completely eliminated. But for some of the HC and CO emissions, "slip"(failure to remove all of the HC and CO) may occur during this process. The HC and CO slip can be controlled with a downstream "clean-up" catalyst that promotes their oxidation or potentially by controlling the exhaust constituents such that the excess amount of the HC and CO pollutants at the fuel-rich operating condition is as low as possible, that is, as close to stoichiometric conditions as possible.

The difference between stoichiometric three-way catalyst function and the newly developed NOx adsorber technology can be summarized as follows. Stoichiometric three-way catalysts work to reduce NOx, HCs and CO by maintaining a careful balance between oxidizing (NOx and O_2) and reducing (HCs and CO) constituents and then promoting their mutual destruction across the catalyst on a continuous basis. The newly developed NOx adsorber technology works to reduce the pollutants by balancing the oxidation and reduction chemistry on a discontinuous basis, alternating between net oxygen-rich and net fuel-rich operation to control the pollutants. This approach allows lean-burn engines (oxygen-rich operating), like diesel engines, to operate under their normal operating mode most of the time, provided that they can periodically switch and operate such that the exhaust conditions are net fuel-rich for brief periods. If the engine/emission-control system can be made to operate in this manner, NOx adsorbers offer the potential to employ the highly effective three-way catalyst chemistry to lean-burn engines.

4.1.2.3.2 NOx Adsorber Regeneration Mechanisms

NOx adsorbers work to control NOx emissions by storing the NOx pollutants on the catalyst surface during oxygen-rich engine operation (lean-burn engine operation) and then by periodically releasing and reducing the NOx emissions under fuel-rich exhaust conditions. This approach to controlling NOx emissions can work for a diesel engine provided that the engine and emission-control system can be designed to work in concert, with relatively long periods of oxygen-rich operation (typical diesel engine operation) followed by brief periods of fuel-rich exhaust operation. The ability to control the NOx emissions in this manner is the production basis for lean-burn NOx emission control in stationary power systems and for lean-burn gasoline engines. As outlined below, we believe there are several approaches to accomplish the required periodic operation on a diesel engine.

The most frequently mentioned approach for controlling the exhaust chemistry of a diesel engine is through in-cylinder changes to the combustion process. This approach roughly mimics the way in which lean-burn gasoline engines function with NOx adsorbers. That is, the engine itself changes in operation periodically between “normal” lean-burn (oxygen-rich) combustion and stoichiometric or even fuel-rich combustion to promote NOx control with the NOx adsorber catalyst. For diesel engines this approach typically requires the use of common rail fuel systems, which allow for multiple fuel-injection events, along with an air handling system that includes exhaust gas recirculation (EGR).

The normal lean-burn engine operation can last from as little time as 15 seconds to more than three minutes as the exhaust NOx emissions are stored on the surface of the NOx adsorber catalyst. The period of fuel-lean, oxygen-rich, operation is determined by the NOx emission rate from the engine and the storage capacity of the NOx adsorber. Once the NOx adsorber catalyst is full (once an unacceptable amount of NOx is slipping through the catalyst without storage) the engine must switch to fuel-rich operation to regenerate the NOx adsorber.

The engine typically changes to fuel-rich operation by increasing the EGR rate, by throttling the fresh air intake, and by introducing an additional fuel-injection event late in the combustion cycle. The increased EGR rate works to decrease the oxygen content of the intake air by displacing fresh air that has a high oxygen content with exhaust gases that have a much lower oxygen content. Intake air throttling further decreases the amount of fresh air in the intake gases again lowering the amount of oxygen entering the combustion chamber. The combination of these first two steps serves to lower the oxygen concentration in the combustion chamber, decreasing the amount of fuel required to reach a fuel-rich condition. The fuel is metered then into the combustion chamber in two steps under this mode of operation. The first, or primary, injection event meters a precise amount of fuel to deliver the amount of torque (energy) required by the operator demand (accelerator pedal input). The second injection event is designed to meter the amount of fuel necessary to achieve a net fuel-rich operating condition. That is, the primary plus secondary injection events introduce an excess of fuel when compared with the amount of oxygen in the combustion chamber. The secondary injection event occurs very late in the combustion cycle, so it does not generate additional torque. This is necessary so the switching between the normal lean-burn operation and this periodic fuel-rich operation is transparent to the user.

Additional ECM capability will be necessary to monitor the NOx adsorber and determine when the NOx regeneration events are necessary. This can be done in a variety of ways, though they fall into two general categories: predictive and reactive. First, the predictive method estimates or measures the NOx flow into the adsorber in conjunction with the predicted adsorber performance to determine when the adsorber is near capacity. Then, upon entering optimal engine operating conditions, the system performs a NOx regeneration. This particular step is similar to an on-board diagnostic (OBD) algorithm waiting for proper conditions to perform a functionality check. During the NOx regeneration, sensors determine how accurately the predictive algorithm performed, and adjust it accordingly. Second, the reactive method is envisioned to monitor NOx downstream of the NOx adsorber and detection of NOx slippage triggers a regeneration event. This method is dependent on good NOx-sensor technology. This method also depends on the ability to regenerate under any given engine operating condition, since the algorithm reacts to indications that the adsorber had reached its NOx storage capacity. In either case, we believe these algorithms are not far removed from the systems that will be used by nonroad manufacturers to meet Tier 3 emission standards and will be virtually identical to the systems used by highway engine manufacturers to comply with the HD2007 emission regulations. When used in combination with the sophisticated control systems that will be available, we expect that NOx regeneration events can be seamlessly integrated into engine operation such that the operator may not be aware that the events are taking place.

Using this approach of periodic switching between normal lean-burn operation and brief periods of fuel-rich operation all accomplished within the combustion chamber of a diesel engine is one way in which an emission-control system for a diesel engine can be optimized to work with the NOx adsorber catalyst. This approach requires no new engine hardware beyond the air handling and advanced common rail fuel systems that many advanced diesel engines will have already applied to meet the Tier 3 NOx standard. For this reason an in-cylinder approach is likely to appeal to engine manufacturers for product lines where initial purchase cost or package size is the most important factor in determining engine purchases.

Another approach to accomplish the NOx adsorber regeneration is through the use of a so-called “dual-bed” or “multiple-bed” NOx adsorber catalyst system. Such a system is designed so the exhaust flow can be partitioned and routed through two or more catalyst “beds” operating in parallel. Multiple-bed NOx adsorber catalysts restrict exhaust flow to part of the catalyst during its regeneration. By doing so, only a portion of the exhaust flow need be made rich, reducing dramatically the amount of oxygen needing to be depleted and thus the fuel required to be injected to generate a rich exhaust stream. One simple example of a multiple bed NOx adsorber is the dual-bed system in Figure 4.1-1. In this example, the top half of the adsorption catalyst system is regenerating under a low exhaust flow condition (exhaust control valve nearly closed), while the remainder of the exhaust flow is bypassed to a lower half of the system. A system of this type has the following characteristics:

- Half of the system operates with a major flow in an “adsorption mode,” where most of the exhaust is well lean of stoichiometric ($\lambda > 1$ or $>>1$, typical diesel exhaust), NO is converted to NO_2 over a Pt-catalyst, and stored as a metallic nitrate within the NOx adsorbent material.[K]

- The other half of the system has its exhaust flow restricted to just a small fraction (~5 percent) of the total flow and operates in a regeneration mode.
  - While the flow is restricted for regeneration, a small quantity of fuel is sprayed into the regenerating exhaust flow at the beginning of the regeneration event.
  - The fuel is oxidized by the oxygen in the exhaust until sufficient oxygen is depleted for the stored NOx to be released. This occurs at exhaust conditions of $\lambda \leq 1$.

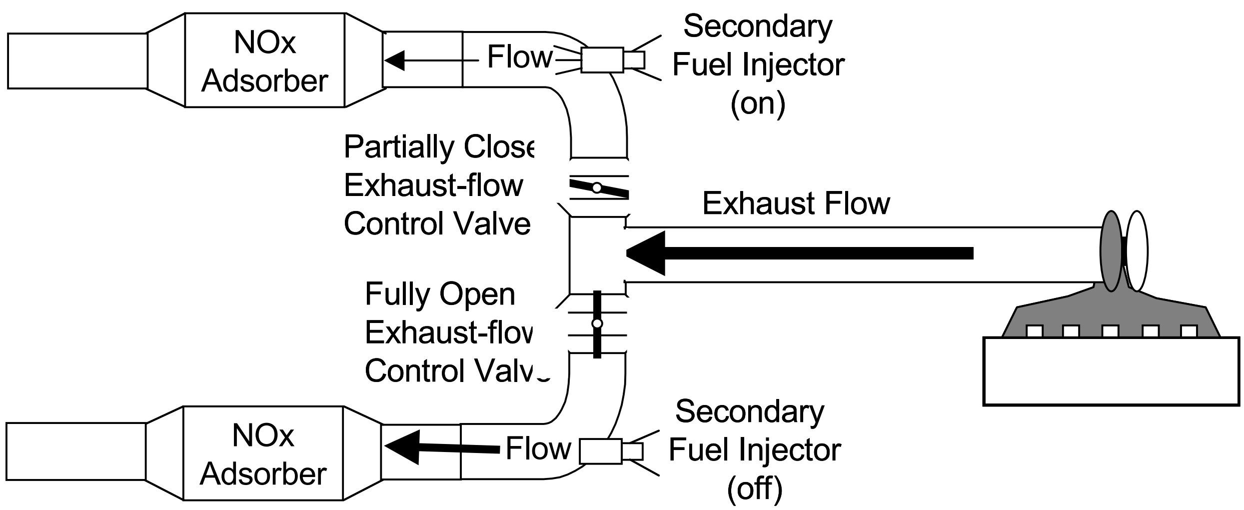
[K] A condition of $\lambda = 1$ means that there are precisely the needed quantity of reactants for complete reaction at equilibrium. $\lambda < 1$ means that there is insufficient oxygen, $\lambda > 1$ means that there is excess oxygen.

- At these conditions, NOx can also be very efficiently reduced to N_2 and O_2 over a precious-metal catalyst.

- At the completion of regeneration, the majority of the flow can then be reintroduced into the regenerated half of the system by opening the flow control valve.

- Simultaneously, flow is restricted to the other half of the system to allow it to regenerate.

Figure 4.1-1
Schematic Representation of the Operation of a Dual-Bed NOx Adsorption Catalyst



Although the schematic shows two separate systems, the diversion of exhaust flow can occur within a single catalyst housing, and with a single catalyst monolith. There may also be advantages to using more than one partition for the NOx adsorber system such as the use of multiple beds allows desulfation of one bed while normal NOx adsorption and regeneration events occur in other beds.

The NOx adsorber performance can be enhanced by incorporating a catalyzed diesel particulate filter (CDPF) into the system. A number of synergies exist between NOx adsorber systems and CDPFs. Both systems rely on conversion of NO to NO_2 over a Pt catalyst for part of their functioning. Partial oxidation reforming of diesel fuel to hydrogen and CO over a Pt-catalyst has been demonstrated for fuel-cell applications. A similar reaction to reform the fuel upstream of the NOx adsorber during regeneration provides a more reactive reductant for desorption and reduction of NOx. Heavier fuel hydrocarbons are known to inhibit NOx reduction on the NOx adsorption catalyst since competitive adsorption by hydrocarbons on the precious-metal sites inhibits NOx reduction during adsorber regeneration.[55] Partial oxidation of the secondary fuel injected into the exhaust during regeneration could lead to sooting of the fuel. Using a CDPF upstream of the NOx adsorber, but downstream of the secondary fuel injection, allows partial oxidation of the fuel hydrocarbons to occur over the Pt catalyst on the surface of the CDPF. The wall-flow design of the CDPF efficiently captures any soot formed during partial oxidation of the fuel injected into the exhaust, preventing any increase in soot emissions. The partial oxidation reaction over the CDPF is exothermic, which can be used increase the rate of temperature rise for the NOx adsorber catalyst after cold starts, similar to the use of light-off catalysts with cascade three-way catalyst systems.[56]

4.1.2.3.3 How Efficient are Diesel NOx Adsorbers?

Research into applying the NOx adsorber catalyst to diesel exhaust is only a few years old but benefits from the larger body of experience with stationary power sources and with lean-burn gasoline systems. In simplest terms the question is how well does the NOx adsorber store NOx under normal lean-burn diesel engine operation, and then how well does the control system perform the NOx regeneration function. Both of these functions are affected by the temperature of the exhaust and of the catalyst surface. For this reason efficiency is often discussed as a function of exhaust temperature under steady-state conditions. This is the approach used in this section and is extended in Section 4.1.3.1.2 below to predict the effectiveness of the NOx adsorber technology when engines operate over the new transient duty cycles. The potential for both NOx storage and reduction to operate at very high efficiencies can be realized through careful emission-control system design, as described below.

The NOx storage function consists of oxidation of NO to NO_2 and then storage of the NOx as a metallic nitrate on the catalyst surface. The effectiveness of the catalyst at accomplishing these tasks is dependent upon exhaust temperature, catalyst temperature, precious-metal dispersion, NO storage volume, and transport time (mass flow rates through the catalyst). Taken as a whole, these factors determine how effectively a NOx adsorber-based control system can store NOx under lean-burn diesel engine operation.

Catalyst and exhaust temperature are important because the rate at which the desirable chemical reactions occur is a function of the local temperature where the reaction occurs. The reaction rate for NO to NO_2 oxidation and for NOx storage increases with increasing temperature. Beginning at temperatures as low as 100˚C NO oxidation to NO_2 can be promoted across a platinum catalyst at a rate high enough to allow for NOx storage to occur. Below 100˚C the reaction can still occur (as it does in the atmosphere); however, the reaction rate is so slow as to make NOx storage ineffective below this temperature in a mobile source application. At higher exhaust temperatures, above 400˚C, two additional mechanisms affect the ability of the NOx adsorber to store NOx. First the NO to NO_2 reaction products are determined by an equilibrium reaction that favors NO rather than NO_2. That is across the oxidation catalyst, NO is oxidizing to form NO_2 and NO_2 is decaying to form NO at a rate that favors a larger fraction of the gas being NO rather than NO_2. As this is an equilibrium reaction when the NO_2 is removed from the gas stream by storage on the catalyst surface, the NOx gases quickly "re-equilibrate" forming more NO_2. This removal of NO_2 from the gas stream and the rapid oxidation of NO to NO_2 means that in spite of the NO_2 fraction of the NOx gases in the catalyst being low at elevated conditions (30 percent at 400˚C) the storage of NOx can continue to occur with high efficiencies, near 100 percent.

Unfortunately, the other limitation of high-temperature operation is not so easily overcome. The metallic nitrates that are formed on the catalyst surface and that serve to store the NOx emissions under fuel-lean operating conditions can become unstable at elevated temperatures. That is, the metallic nitrates thermally decompose releasing the stored NOx under lean operating conditions allowing the NOx to exit the exhaust system "untreated." The temperature at which the storage metals begin to thermally release the stored NOx emissions varies dependent upon the storage metal or metals used, the relative ratio of the storage metals, and the washcoat design. Changes to catalyst formulations can change the upper temperature threshold for thermal NOx desorption by as much as 100˚C.[57] Thermal stability is the primary factor determining the NOx control efficiency of the NOx adsorber at temperatures higher than 400-500˚C. NOx adsorber catalyst developers are continuing to work to improve this aspect of NOx adsorber performance, and as documented in EPA's 2002 Highway Progress Review improving temperature performance is being realized.

The NOx adsorber catalyst releases stored NOx emissions under fuel-rich operating conditions and then reduces the NOx over a three-way catalyst function. While the NOx storage function determines the NOx control efficiency during lean operation, it is the NOx release and reduction function that determines the NOx control efficiency during NOx regeneration. Since NOx storage can approach near 100 percent effectiveness for much of the temperature range of the diesel engine, the NOx reduction function often determines the overall NOx control efficiency.

NOx release can occur under relatively cool exhaust temperatures even below 200˚C for current NOx adsorber formulations. Unfortunately, the three-way NOx reduction function is not operative at such cool exhaust temperatures. The lowest temperature at which a chemical reaction is promoted at a defined efficiency (often 50 percent) is referred to as the "light-off" temperature. The 80 percent light-off temperature for the three-way catalytic NOx reduction function of current NOx adsorbers is between 200˚C and 250˚C. Even though NOx storage and release can occur at cooler temperatures, NOx control is therefore limited under steady-state conditions to temperatures greater than this light-off temperature.

Under transient operation, however, NOx control can be accomplished at temperatures below this NOx reduction light-off temperature provided that the period of operation at the lower temperature is preceded by operation at higher temperatures and provided that the low-temperature operation does not continue for an extended period. This NOx control is possible due to two characteristics of the system specific to transient operation. First, NOx control can be continued below the light-off temperature because storage can continue below that temperature. If the exhaust temperature again rises above the NOx reduction light-off temperature before the NOx adsorber storage function is full, the NOx reduction can then precede at high efficiency. Said another way, if the excursions to very low temperatures are brief enough, NOx storage can proceed under this mode of operation, followed by NOx reduction when the exhaust temperatures are above the light-off temperature. Although this sounds like a limited benefit because NOx storage volume is limited, in fact it can be significant, because the NOx emission rate from the engine is low at low temperatures. While the NOx storage rate may be limited such that at high-load conditions the lean-NOx storage period is as short as 30 seconds, at the very low NOx rates typical of low-temperature operation (operation below the NOx reduction light-off temperature) this storage period can increase dramatically. This is due to the NOx mass flow rate from the engine changing dramatically between idle conditions and full load conditions. The period of lean-NOx storage is expected to increase in inverse proportion to the NOx emission rate from the engine. The period of NOx storage under light load conditions therefore can likewise be expected to increase dramatically.

Transient operation can further allow for NOx control below the NOx reduction light-off temperature due to the thermal inertia of the emission-control system itself. The thermal inertia of the emission-control system can work to warm the exhaust gases to a local temperature high enough to promote the NOx reduction reaction even though the inlet exhaust temperatures are below the light-off temperature for the catalyst.

The combination of these two effects was observed during testing of NOx adsorbers at the National Vehicle and Fuel Emissions Laboratory (NVFEL), especially regarding NOx control under idle conditions. It was observed that when idle conditions followed loaded operation, for example when cooling the engine down after a completing an emission test, that the NOx emissions were effectively zero (below background levels) for extended periods of idle operation (for more than 10 minutes). It was also discovered that the stored NOx can be released and reduced in this operating mode, even though the exhaust temperatures were well below 250˚C, provided that the regeneration event was triggered within the first 10 minutes of idle operation (before the catalyst temperature decreased significantly). However, if the idle mode was continued for extended periods (longer than 15 minutes) NOx control eventually diminished. The loss of NOx control at extended idle conditions appeared to be due to the inability to reduce the stored NOx leading to high NOx emissions during NOx regeneration cycles.

NOx control efficiency with the NOx adsorber technology under steady-state operating conditions can be seen to be limited by the light-off temperature threshold of the three-way catalyst NOx reduction function. Further, a mechanism for extending control below this temperature is described for transient operation and is observed in testing of NOx adsorber-based catalyst systems. In addition, as described later in this section, new combustion strategies such as Toyota’s low-temperature combustion technology can raise exhaust temperatures at low loads to promote improved NOx performance with a NOx adsorber catalyst.

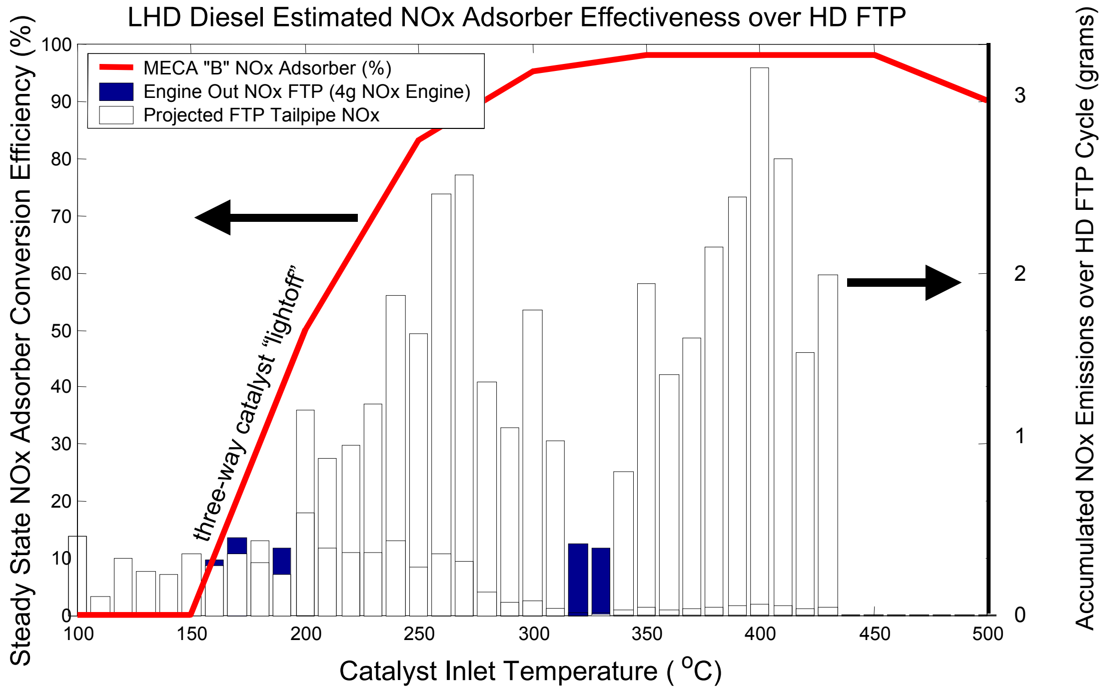
Overall, NOx adsorber efficiency reflects the composite effectiveness of the NOx adsorber in storing, releasing and reducing NOx over repeated lean/rich cycles. As detailed above, exhaust temperatures play a critical role in determining the relative effectiveness of each of these catalyst functions. These limits on the individual catalyst functions can explain the observed overall NOx control efficiency of the NOx adsorber, and can be used to guide future research to improve overall NOx adsorber efficiency and the design of an integrated NOx emission-control system.

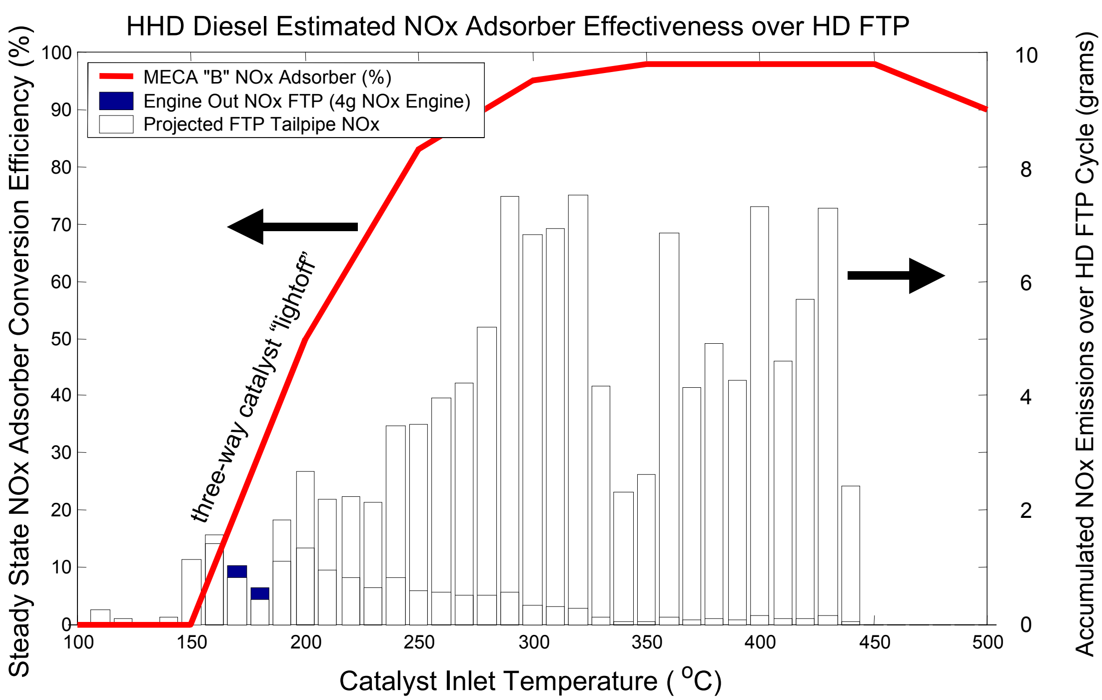
At low exhaust temperatures overall NOx control is limited by the light-off temperature threshold of the three-way NOx reduction function in the range from 200˚C to 250˚C. At high temperatures (above 400˚ to 500˚C) overall NOx control is limited by the thermal stability of the

NOx storage function. For exhaust temperatures between these two extremes NOx control can occur at virtually 100 percent effectiveness.

The ability of the complete system, including the engine and the emission-control system, to control NOx emissions consistently (well in excess of 90 percent) is therefore dependent upon the careful management of temperatures within the system. Figure 4.1-2 provides a pictoral representation of these constraints and indicates how well a diesel engine can match the capabilities of a NOx adsorber-based NOx control system. The figure shows accumulated NOx emissions (grams) over the highway FTP cycle for both a light heavy-duty and a heavy heavy-duty engine. The engine-out NOx emissions are shown as the dark bars on the graphs. The accumulated NOx emissions shown here, divided by the integrated work over the test cycle gives a NOx emission rate of 4 g/hp-hr (the 1998 emission standard for highway heavy-duty diesel engines) for each of these engines. Also shown on the graph as a solid line is the steady-state NOx conversion efficiency for a NOx adsorber, MECA "B", used in testing at NVFEL (see Section 4.1.2.3.5.2 below for more details on testing at NVFEL). The line has been annotated to show the constraint under low-temperature operation (three-way catalyst light-off). The white bars on the graph represent an estimate of the tailpipe NOx emissions that can be realized from the application of the NOx adsorber based upon the steady-state efficiency curve for adsorber MECA "B". These estimated tailpipe emissions are highest in the temperature range below 250˚C even though the engine-out NOx emissions are the lowest in this region. This is due to the light-off temperature threshold for the NOx three-way reduction function.

Figure 4.1-2
NOx Adsorber Efficiency Characteristics versus Exhaust Temperature





Since the conversion efficiencies are based upon steady-state operation, it is likely that the low-temperature performance can be better than estimated here due to a catalyst's ability to store the NOx emissions at these low temperatures and then to reduce them when transient operation raises the exhaust temperatures above the three-way light-off temperature. This assertion provides one explanation for differences noted between this approximation of the NOx efficiency over the highway FTP cycle for the light heavy-duty engine shown in Figure 4.1-2 and actual NOx adsorber efficiency demonstrated with this engine in the NVFEL test program. Based upon the figure above (using the steady-state conversion estimate) the NOx adsorber catalyst should have provided less than an 84 percent reduction in NOx emissions over the highway FTP cycle. However, testing at NVFEL (detailed in Section 4.1.2.3.5) has demonstrated a greater than 90 percent reduction in NOx emissions with this same engine and catalyst pair without significant optimization of the system. Clearly then, steady-state NOx adsorber performance estimates can underestimate the real NOx reductions realized in transient vehicle operation. Nevertheless, we have used this approach as a screening analysis to predict performance for nonroad engines equipped with NOx adsorber catalysts in Section 4.1.3.1.2 below.

The tailpipe NOx emissions are the lowest in the range from 250˚C to 450˚C, even though this is where the majority of the engine-out NOx emissions are created, because of the high overall NOx reduction efficiency of the NOx adsorber system under these conditions. At temperatures above 500˚C the NOx conversion efficiency of the NOx adsorber can be seen to decrease.

Figure 4.1-2 shows that the temperature window of a current technology NOx adsorber catalyst is well matched to the exhaust temperature profiles of a light heavy-duty and a heavy heavy-duty diesel engine operated over the highway FTP cycle. The discussion in Section 4.1.3.1.2 below shows similarly that the nonroad transient cycle (NRTC) is also well matched to the performance of the NOx adsorber catalyst. Testing at NVFEL on the same engine operated over a wide range of steady-state points, shows that even for extended high-load operation, as typified by the 100 percent load test points in the test, NOx conversion efficiencies remained near or above 90 percent (see discussion of the NVFEL test program in Section 4.1.2.3.5 below).

The discussion above makes it clear that when the engine and NOx adsorber-based emission-control system are well matched, NOx reductions can be far in excess of 90 percent. Conversely, it can be inferred that if exhaust temperatures are well in excess of 500˚C or well below 200˚C for significant periods of engine operation then NOx control efficiency may be reduced. Researchers are developing and testing new NOx adsorber formulations designed to increase the high temperature stability of the NOx adsorber and to therefore widen this window of operation.[58]

How effective are NOx adsorbers for cold-start emissions?

In addition to broadening the catalyst temperature window, the exhaust temperature from the diesel engine can be managed to align with the temperature window of the catalyst.

The steady-state analysis discussed above is based on steady-state emission results (i.e., after exhaust temperatures have stabilized), but the NRTC also includes a cold-start test where the catalyst initial temperature will be at ambient conditions (see Section 4.2). The NRTC emission level for the engine is determined by weighting the cold-start emissions by 1/20 (5 percent), and weighting the hot-start emission results by 19/20 (95 percent). Historically, for highway heavy-duty diesel engines that are similar to current technology nonroad diesel engines not equipped with an exhaust emission-control device, the cold-start and hot-start emissions have been nearly identical. However, with the application of emission-control devices which have optimal temperature operating windows, such as a NOx adsorber, the cold-start test will become a design challenge for highway diesel engine manufacturers and for nonroad diesel engine manufacturers, just as it has been a design challenge for light-duty gasoline vehicle manufacturers for more than 20 years.

Manufacturers have several available tools to overcome this challenge:

- The volume, shape, and substrate material have a significant effect on the warm-up time of a NOx adsorber (just as they do for light-duty three-way catalysts). Manufactures will optimize the make-up of the adsorber for best light-off characteristics, such as the thin-walled ceramic monolith catalysts typical of modern low-emission light-duty gasoline applications.

- The packaging of the exhaust emission-control devices, including the use of insulating material and air-gap exhaust systems, will also decrease light-off time, and we expect manufacturers to explore those opportunities.

- The location of the adsorber, with respect to it's proximity to the exhaust manifold, will have a significant impact on the light-off characteristics.

- As discussed above, NOx adsorbers have the ability to store NOx at temperatures much less than the three-way catalyst function temperature operating window, on the order of 100˚C. This is unlike the performance of catalysts for light-duty gasoline engines, and it allows the NOx adsorber to store NOx for some period of time before the light-off time of the three-way function of its catalyst, resulting in an overall lower effective temperature for the device.

These first four tools available to manufacturers all deal with system design opportunities to improve the cold-start performance of the NOx adsorber system. In addition, manufacturers have several active tools that can be used to enhance the cold-start performance of the system, all based on technologies that may be used to comply with the Tier 3 emission standards (i.e., technologies that will form the baseline for most engines meeting the Tier 4 standards). These include the use of engine start-up routines that have a primary purpose of adding heat to the exhaust to enhance NOx adsorber light-off. For example:

- retarded injection timing;

- intake air throttling;

- post-injection addition of fuel; or

- or increasing back-pressure with an exhaust brake or a VGT system.

We anticipate manufacturers will explore all these tools to choose the best combination necessary to minimize light-off time and improve the cold-start NRTC performance. Highway manufacturers must overcome this same challenge to comply with the HD2007 emission standards some number of years before these nonroad emission standards go into effect. Additionally, highway manufacturers must do this with a higher cold-start weighting of 1/7, rather than 1/20 we are adopting for nonroad diesel engines. This means that highway engine manufacturers must have lower cold-start emissions relative to their hot-start emissions than will nonroad engine manufacturers meeting the Tier 4 standards. We therefore believe that manufacturers of nonroad diesel engines will be able to use the technologies described above to comply with the Tier 4 standards over the NRTC, including the cold-start test.

One light-duty passenger car manufacturer, Toyota, has already demonstrated such an approach to comply with light-duty cold-start requirements. Toyota has shown with its low-temperature combustion technology one mechanism for raising exhaust temperatures even at extremely low-load conditions. The approach, called Low Temperature Combustion (LTC), increases exhaust temperatures at low-load conditions by more than 50˚C while decreasing engine-out NOx emissions.[59] As a result, exhaust temperature are increased into the region for effective NOx adsorber operation even at light loads. The technologies that Toyota uses to accomplish LTC, cooled EGR and advanced common rail fuel systems, are similar to the systems that we expect many nonroad engine manufacturers will use to comply with the Tier 3 standards.

Another example of system integration approaches for diesel engines designed to allow compliance with transient emission control standards including hot and cold emissions can be seen in recent work by the Department of Energy and contractors under the Advanced Petroleum Based Fuels Program - Diesel Emission Control (APBF-DEC). This work documented in a recent SAE paper and in EPA's Highway Diesel Progress Review Report 2, shows that NOx emission can be reduced adequately on a combined hot and cold start FTP test procedure to demonstrate emissions below 0.3 g/bhp-hr.[60,61] The work illustrates both the ability to control NOx emissions under cold-start conditions using rapid warm-up procedures and the ability to reduce NOx emissions below the regulated standards under hot-start conditions to compensate for the slightly elevated emissions levels experienced under cold-start conditions.

How effective are NOx adsorbers over the NTE zone?

We are adopting an NTE standard for nonroad Tier 4 engines that replicates the provisions for highway diesel trucks. A complete discussion of the NTE provisions can be found in Section III.J of the preamble to the final rule. In short, we are setting an NTE emission limit, over a broad range of engine operating conditions, that is 1.5 times the limit that applies for testing over the NRTC and over the steady-state tests. As discussed below, a 90 percent NOx reduction is technologically feasible across the range of engine operating conditions and ambient conditions subject to the NTE standards. Also, as discussed below, some modifications to the NTE provisions to address technical issues that result from the application of advanced NOx catalyst systems were included in the HD2007 standards and are carried over into this final rule.

Section 4.1.2.3.5.2 contains a description of the ongoing NOx adsorber evaluation test program run by our EPA laboratory. Included in that section are test data on four different NOx adsorbers for which extensive steady-state mapping was performed to calculate various steady-state emission levels (See Figures 4.1-10 through 4.1-13). Several of the test modes presented in these figure are not within the NTE zone for NOx, and so would not be subject to the NTE standard. The following modes listed in these four figures are within the NTE zone for NOx: EPA modes 6 - 13, 15, 17, 19, 20. For all of the adsorbers, efficiencies of 90 percent or greater were achieved across the majority of the NTE zone. The region of the NTE zone for which efficiencies less than 90 percent were achieved were concentrated on or near the torque curve (EPA modes 8, 9, 15 and 17), with the exception of Adsorber D, for which EPA modes 6 and 7 achieved 87 percent and 89 percent NOx reduction, respectively. However, Adsorber D was able to achieve NOx reductions greater than 90 percent along the torque curve. The test modes along the torque curve represent the highest exhaust gas temperature conditions for this test engine, on the order of 500˚C. Exhaust temperatures of 500˚C are near the current upper temperature limit of the peak NOx reduction efficiency range for NOx adsorbers. It is therefore not unexpected that the NOx reductions along the torque curve for the test engine are not as high as in other regions of the NTE zone. We expect manufacturers to choose a NOx adsorber formulation that matches the operating range of exhaust gas temperatures for the engine. In addition, the steady-state mode data in Figures 4.1-10 through 4.1-13 were collected under stabilized conditions. In reality, actual in-use operation of a heavy-duty diesel vehicle likely does not experience periods of sustained operation along the torque curve, which diminishes the likelihood that the NOx adsorber bed itself will achieve temperatures in excess of 500˚C. Regardless, as observed in our ongoing diesel progress review and documented in the 2002 diesel progress report, catalyst developers are realizing incremental improvements in the high-temperature NOx reduction capabilities of NOx adsorbers through improvements in NOx adsorber formulations.[62,63,64] As discussed above, only small improvements in the current characteristics are necessary to achieve 90 percent NOx reductions or greater across the NTE zone.

As discussed above, the use of advanced NOx adsorber-based catalyst systems will present cold-start challenges for highway heavy-duty diesel engines, and for nonroad diesel engines, under our Tier 4 program, similar to what light-duty gasoline manufacturers have faced in the past, due to the light-off characteristics of the NOx adsorber. We have previously discussed the tools available to engine manufacturers to overcome these challenges to achieve the NOx standard. The majority of engine operation within the NTE zone will occur at exhaust gas temperatures well above the light-off requirement of the NOx adsorbers. Figures 4.1-10 through 4.1-13 below show that all test modes within the NTE zone have exhaust gas temperatures greater than 300˚C, which is well within the peak NOx reduction efficiency range of current generation NOx adsorbers. However, although NTE testing does not include engine start-up conditions, a diesel engine that has not been warmed up could conceivably be started and very quickly be operated under conditions that are subject to NTE testing; for example, within a minute or less of vehicle operation after the vehicle has left an idle state. The final rule specifies a minimum emission sampling period of 30 seconds for NTE testing. Conceivably, vehicle emissions could be measured against the NTE standards during that first minute of operation, and in all likelihood it would not meet the NTE NOx standard. Given that the NRTC standards will require control of cold-start emissions, manufacturers will be required to pay close attention to cold start to comply with the NRTC. As discussed above, engine operation during NTE testing will be at exhaust gas temperatures within the optimum NOx reduction operating window of the NOx adsorbers. In addition, the NOx adsorber is capable of adsorbing NOx at temperatures on the order of 100˚C. Figures 4.1-10 through 4.1-13 all show NOx emission reductions on the order of 70 - 80 percent are achieved at temperatures as low as 250˚C. We are therefore setting a threshold for exhaust gas temperatures of 250˚C, below which the specified NTE requirements do not apply; we also adopted this provision for the same reason for highway engines in our HD2007 program.

The NTE requirements apply not only during laboratory conditions applicable to the transient test, but also under the wider range of ambient conditions for altitude, temperature and humidity specified in the regulations. These expanded conditions will have minimal impact on the emission-control systems expected to be used to meet the NTE NOx standard. In general, it can be said that the performance of the NOx adsorbers are only affected by the exhaust gas stream to which the adsorbers are exposed. The impact of ambient humidity, temperature, and altitude will therefore affect the performance of the adsorber only to the extent these ambient conditions change the exhaust gas conditions (i.e., exhaust gas temperature and gas constituents). The ambient humidity conditions subject to the NTE requirement will have minimal, if any, impact on the performance of the NOx adsorbers. The exhaust gas itself, independent of the ambient humidity, contains a very high concentration of water vapor, and the impact of the ambient humidity on top of the products of dry air and fuel combustion are minimal. The effect of altitude on NOx adsorber performance should also be minimal or negligible. NTE testing is limited to altitudes below 5,500 feet above sea level. The decrease in atmospheric pressure at 5,500 feet should have minimal impact on the NOx adsorber performance. Increasing altitude can decrease the air-fuel ratio for diesel engines, which can in turn increase exhaust gas temperatures. However, as discussed in the final rule for the highway 2004 standards (Phase 1), highway engines with Phase 1 technology (and thus the similar Tier 3 nonroad diesel engines) can be designed to target air-fuel ratios at altitude that will maintain appropriate exhaust gas temperatures within the ambient conditions specified by the highway NTE test procedure and thus the similar NTE procedure for Tier 4 engines. This approach also allows manufacturers to maintain engine-out PM emission levels near the 0.1 g/hp-hr level. Finally, the NTE regulations specify ambient temperatures that are broader than the NRTC temperature range of 68-86˚F. The NTE test procedure specifies no lower ambient temperature bounds. However, as discussed above, we limit NTE requirements on NOx (and NMHC) for engines equipped with NOx (and/or NMHC) catalysts to include only engine operation with exhaust gas temperatures greater than 250˚C. Low ambient temperatures will therefore not present any difficulties for NTE NOx compliance. NTE standards also apply under ambient temperatures that are higher than the laboratory conditions. The NTE standards apply up to a temperature of 100˚F at sea level, and up to 86˚F at 5,500 feet above sea level. At altitudes in between, the upper NTE ambient temperature requirement is a linear fit between these two conditions. At 5,500 feet, the NTE ambient temperature requirement is the same as the upper end of the temperature range (86˚F) for testing with prescribed duty cycles, and will therefore have no impact on the performance of the NOx adsorbers, considering that majority of the test data described throughout this chapter were collected under laboratory conditions. The NTE upper temperature limits at sea level is 100˚F, which is 14˚F (7.7˚C) greater than the NRTC range. This increase is relatively minor, and while it will increase the exhaust gas temperature; in practice the increase should be passed through the engine to the exhaust gas, and the exhaust gas would be on the order of 8˚C higher. Within the exhaust gas temperature range for a diesel engine during NTE operation, an 8˚C increase is very small. As discussed above, we expect manufacturers to choose an adsorber formulation matched to a particular engine design and we expect the small increase in exhaust gas temperature that can occur from the expanded ambient temperature requirements for the NTE to be taken into account by manufacturers when designing the complete emission-control system.

To summarize, based on the information presented in this chapter, and the analysis and discussion presented in this section, we conclude the NTE NOx requirement (1.5 × NRTC/C1 standard) contained in this final rule will be feasible.

Further discussion of feasibility of the NOx requirement under transient testing conditions can be found in Section 4.1.3.1.2.

4.1.2.3.4 Are Diesel NOx Adsorbers Durable?

The considerable success in demonstrating NOx adsorbers makes us confident that the technology is capable of providing the level of conversion efficiency needed to meet the Tier 4 NOx standard. However, there are several engineering challenges that will need to be addressed in going from this level of demonstration to implementation of durable and effective emission-control systems on nonroad equipment. In addition to the generic need to optimize engine operation to match the NOx adsorber performance, engine and catalyst manufacturers will further need to address issues of system and catalyst durability. The nature of these issues are well understood. The hurdles that must be overcome have direct analogues in technology issues that have been addressed previously in automotive applications and are expected to be overcome with many of the same solutions. With the transfer of highway technologies to nonroad engines anticipated in this rulemaking, we believe we have already addressed the issues highlighted in this section for highway engines well before the start of this nonroad program.

In this section, we will describe the major technical hurdles that must be addressed to ensure that the significant emission reductions from NOx adsorbers occur throughout the life of nonroad diesel engines. This section is organized into separate durability discussions for the system components (hardware) and various near-term and long-term durability issues for the NOx adsorber catalyst itself.

4.1.2.3.4.1 NOx Adsorber Regeneration Hardware Durability

The system we have described in Figure 4.1-1 represents but one possible approach for generating the necessary exhaust conditions to allow for NOx adsorber regeneration and desulfation. The system consists of three catalyst substrates (for a CDPF/Low Temperature NOx Adsorber, a High Temperature NOx Adsorber and an Oxidation Catalyst), a support can that partitions the exhaust flow through the first two catalyst elements, three fuel injectors, and a means to divert exhaust flow through one or more of the catalyst partitions. Though not shown in the figure, a NOx /O_2 sensor is also likely to be needed for control feedback and on-board diagnostics (OBD). All of these elements have already been applied in one form or another to either diesel or gasoline engines in high volume long life applications.

The NOx adsorber system we described earlier borrows several components from the gasoline three-way catalyst systems and benefits from the years of development on three way catalysts. The catalyst substrates (the ceramic support elements on which a catalyst coating is applied) have developed through the years to address concerns with cracking due to thermal cycling and abrasive damage from vehicle vibration. The substrates applied for diesel NOx adsorbers will be virtually identical to the ones used for today's passenger cars in every way but size. They are expected to be equally durable when applied to diesel applications as has already been shown in the successful application of diesel oxidation catalysts (DOCs) on some diesel engines over the last 15 years. Retrofit catalyst-based systems have similarly been applied to nonroad diesel engines with good durability, as described in Section 4.1.3.2 below.

The NOx/O_2 sensor needed for regeneration control and OBD is another component originally designed and developed for gasoline powered vehicles (in this case lean-burn gasoline vehicles) that are already well developed and can be applied with confidence in long life for NOx adsorber-based diesel emission control. The NOx/O_2 sensor is an evolutionary technology based largely on the current Oxygen (O_2) sensor technology developed for gasoline three-way catalyst-based systems. Oxygen sensors have proven to be extremely reliable and long lived in passenger car applications, which see significantly higher temperatures than are normally encountered on a diesel engine.[65,66] Diesel engines do have one characteristic that makes the application of NOx/O_2 sensors more difficult. Soot in diesel exhaust can cause fouling of the NOx/O_2 sensor damaging its performance. However this issue can be addressed through the application of a catalyzed diesel particulate filter (CDPF) in front of the sensor. (See Section 4.1.2.3.2 above, noting synergies that can result from use in tandem of NOx adsorbers and CDPFs.) The CDPF then provides a protection for the sensor from PM while not hindering its operation. Since the NOx adsorber will likely be located downstream of a CDPF in each of the potential technology scenarios we have considered this solution to the issue of PM sooting is readily addressed.

Fuel is metered into a modern gasoline engine with relatively low pressure pulse-width-modulated fuel-injection valves. These valves are designed to cycle well over a million times over the life of a vehicle while continuing to accurately meter fuel. Applying this technology to provide diesel fuel as a reductant for a NOx adsorber system is a relatively straightforward extension of the technology. A NOx adsorber system cycles far fewer times over its life when compared with the current long life of gasoline injectors. However, these gasoline fuel injectors designed to meter fuel into the relatively cool intake of a car cannot be directly applied to the exhaust of a diesel engine. In the testing done at NVFEL, a similar valve design was used that had been modified in material properties to allow application in the exhaust of an engine. While benefitting from the extensive experience with gasoline-based injectors a designer can therefore, in a relatively straightforward manner, improve the characteristics of the injector to allow application for exhaust reductant regeneration. Toyota has shown with its Avensis DPNR diesel passenger car how to use a gasoline direct injection (GDI)-based fuel injector to inject diesel fuel in the exhaust manifold of a diesel engine to allow for NOx adsorber regeneration and desulfation.[67]

The NOx adsorber system we describe in Figure 4.1-1 requires a means to partition the exhaust during regeneration and to control the relative amounts of exhaust flow between two or more regions of the exhaust system. Modern diesel engines already employ a valve designed to carry out this very task. Most modern turbochargers employ a wastegate valve that allows some amount of the exhaust flow to bypass the exhaust turbine to control maximum engine boost and limit turbocharger speed. These valves can be designed to be proportional, bypassing a specific fraction of the exhaust flow to track a specified boost pressure for the system. Turbocharger wastegate valves applied to heavy-duty diesel engines typically last the life of the engine in spite of the extremely harsh environment within the turbocharger. This same valve approach can be applied to accomplish the flow diversion required for diesel NOx adsorber regeneration and desulfation. Since temperatures will typically be cooler at the NOx adsorber compared with the inlet to the exhaust turbine on a turbocharger, the control valve should be equally reliable in this application.

4.1.2.3.4.2 NOx Adsorber Catalyst Durability

In many ways a NOx adsorber, like other engine catalysts, acts like a small chemical process plant. It has specific chemical processes that it promotes under specific conditions with different elements of the catalyst materials. There is often an important sequence to the needed reactions and a need to match process rates to keep this sequence of reactions going. Because of this need to promote specific reactions under the right conditions early catalysts were often easily damaged. This damage prevents or slows one or more the reactions causing a loss in emission control. For example, contaminants from engine oil, like phosphorous or zinc, can attach to catalysts sites partially blocking the site from the exhaust constituents and slowing reactions. Similarly, lead added to gasoline to increase octane levels bonds to the catalyst sites, causing poisoning as well. Likewise, sulfur, which occurs naturally in petroleum products like gasoline and diesel fuel, can poison many catalyst functions preventing or slowing the desired reactions. High exhaust temperatures experienced under some conditions can cause the catalyst materials to sinter (thermally degrade) decreasing the surface area available for reactions to decrease.

All of these problems have been addressed over time for the gasoline three-way catalysts, resulting in the high efficiency and long life durability now typical of modern vehicles. To accomplish this, changes were made to fuels and oils used in vehicles (e.g., lead additives banned from gasoline, sulfur levels reduced in gasoline distillates, specific oil formulations for aftertreatment equipped cars), and advances in catalysts designs were needed to promote sintering-resistant catalyst formulations with high precious-metal dispersion.

The wealth of experience gained and technological advancements made over the last 30 years of gasoline catalyst development can now be applied to the development of the NOx adsorber catalyst. The NOx adsorber is itself an incremental advancement from current three-way catalyst technology. It adds one important additional component not currently used on three-way catalysts, NOx storage catalyst sites. The NOx storage sites (normally alkali or alkaline earth metals) allow the catalyst to store NOx emissions with extremely high efficiency under the lean-burn conditions typical of the diesel exhaust. It also adds a new durability concern due to sulfur storage on the catalyst.

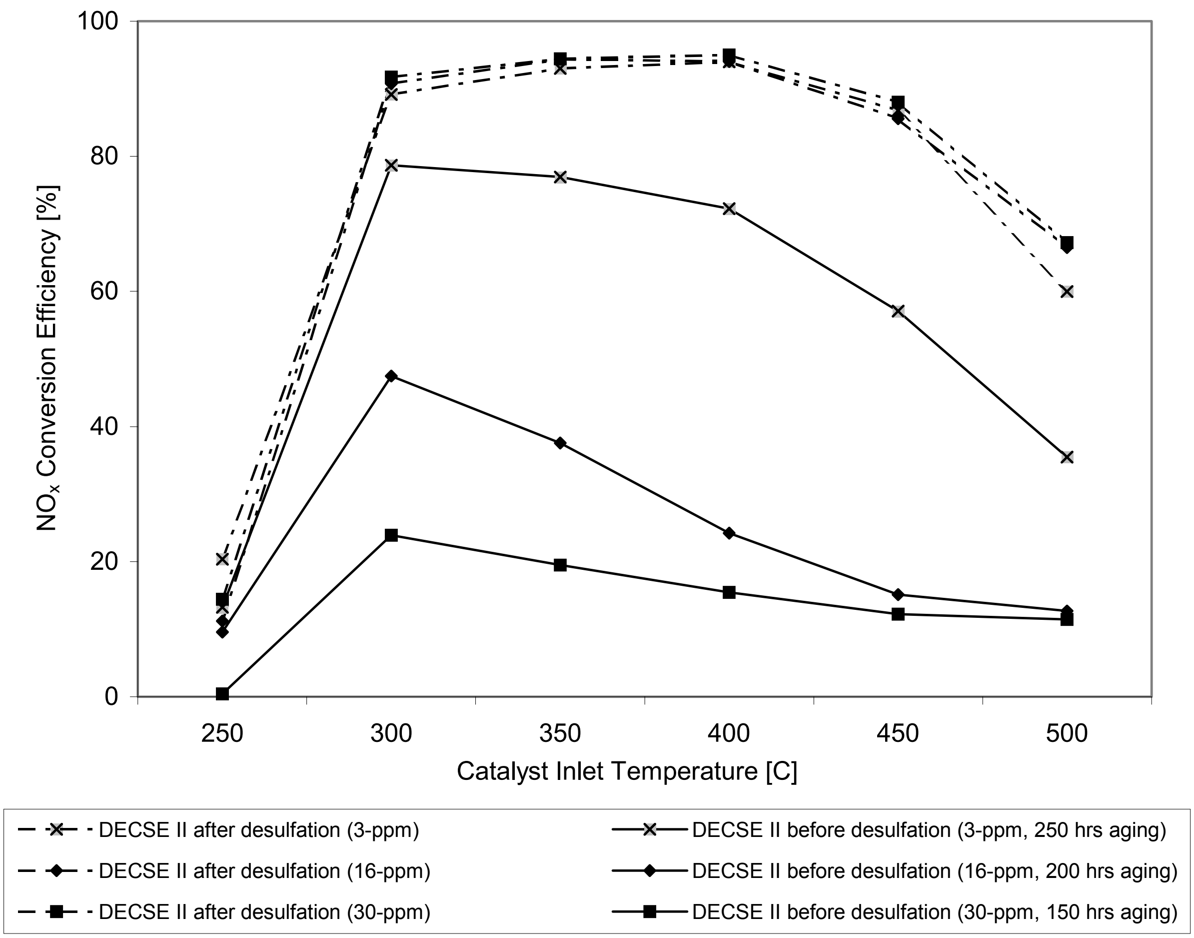
This section will explore the durability issues of the NOx adsorber catalyst applied to diesel engines. It describes the effect of sulfur in diesel fuel on catalyst performance, the methods to remove the sulfur from the catalyst through active control processes, and the implications for durability of these methods. It then discusses these durability issues relative to similar issues for existing gasoline three-way catalysts and the engineering paths to solve these issues. This discussion shows that the NOx adsorber is an incremental improvement upon the existing three-way catalyst, with many of the same solutions for the expected durability issues.

Sulfur Poisoning of the NOx Storage Sites

The NOx adsorber technology is extremely efficient at storing NOx as a nitrate on the surface of the catalyst, or adsorber (storage) bed, during lean operation. Because of the similarities in chemical properties of SOx and NOx, the SO_2 present in the exhaust is also stored on the catalyst surface as a sulfate. The sulfate compound that is formed is significantly more stable than the nitrate compound and is typically not released during the NOx release and reduction step (NOx regeneration step) (i.e., it is stored preferentially to NOx). Since the NOx adsorber is virtually 100 percent effective at capturing SO_2 in the adsorber bed, sulfate compounds quickly occupy the NOx storage sites on the catalyst thereby reducing and eventually rendering the catalyst ineffective for NOx reduction (poisoning the catalyst).

Figure 4.1-3 shows the effect of sulfur poisoning of a NOx adsorber catalyst as reported by the DOE DECSE program. The graph shows the NOx adsorber efficiency versus exhaust inlet temperature under steady-state conditions for a diesel engine-based system. The three dashed lines that overlap each other show the NOx conversion efficiency of the catalyst when sulfur has been removed from the catalyst. The three solid lines show the effect of sulfur poisoning on the catalyst at three different fuel sulfur levels over different periods of extended aging (up to 250 hours). From the figure, it can be seen that even with three ppm sulfur fuel a significant loss in NOx efficiency can occur in as little as 250 hours. Further, it can be seen that quite severe sulfur poisoning can occur with elevated fuel sulfur levels. Catalyst performance was degraded by more than 70 percent over only 150 hours of operation when 30 ppm sulfur fuel was used.[68]

Figure 4.1-3
Comparison of NOx Conversion Efficiency before and after Desulfation



The DECSE researchers drew three important conclusions from Figure 4.1-3:

- Fuel sulfur, even at very low levels like three ppm, can limit the performance of the NOx adsorber catalyst significantly.

- Higher fuel sulfur levels, like 30 ppm, dramatically increase the poisoning rate, further limiting NOx adsorber performance.

- Most importantly though, the figure shows that if the sulfur can be removed from the catalyst through a desulfation (or desulfurization) event, the NOx adsorber can provide high NOx control even after exposure to sulfur in diesel fuel. This is evidenced by the sequence of the data presented in the figure. The three high conversion efficiency lines show the NOx conversion efficiencies after a desulfation event that was preceded by the sulfur poisoning and degradation shown in the solid lines.

It is clear from this data that higher fuel sulfur levels dramatically reduce the efficiency of NOx adsorber catalysts. Sulfur accumulates in the NOx storage sites preventing their use for NOx storage. In other words, they decrease the storage volume of the catalyst. The rate at which sulfur fills NOx storage sites is expected to be directly proportional to the amount of sulfur that enters the catalyst. A doubling in fuel-sulfur levels should therefore correspond to a doubling in the SOx poisoning rate.

The design of a NOx adsorber will need to address accommodating an expected volume of sulfur before experiencing unacceptable penalties in either lost NOx control efficiency or increased fuel consumption due to more frequent NOx regenerations. The amount of operation allowed before that limit is realized for a specific adsorber design will be inversely proportional to fuel sulfur quantity. In the theoretical case of zero sulfur, the period of time before the sulfur poisoning degraded performance excessively would be infinite. For a more practical fuel sulfur level like the 10 ppm average expected with a 15 ppm fuel sulfur cap, the period of operation before unacceptable poisoning levels have been reached is expected to be less than 40 hours (with today's NOx adsorber formulations).[69]

Future improvements in the NOx adsorber technology are expected due to its relatively early state of development. Some of these improvements are likely to include improvements in the kinds of materials used in NOx adsorbers to increase the means and ease of removing stored sulfur from the catalyst bed. However, because the stored sulfate species are inherently more stable than the stored nitrate compounds (from stored NOx emissions), we expect that future NOx adsorbers will continue to be poisoned by sulfur in the exhaust. A separate sulfur release and reduction cycle (desulfation cycle) will therefore always be needed to remove the stored sulfur.

NOx Adsorber Desulfation

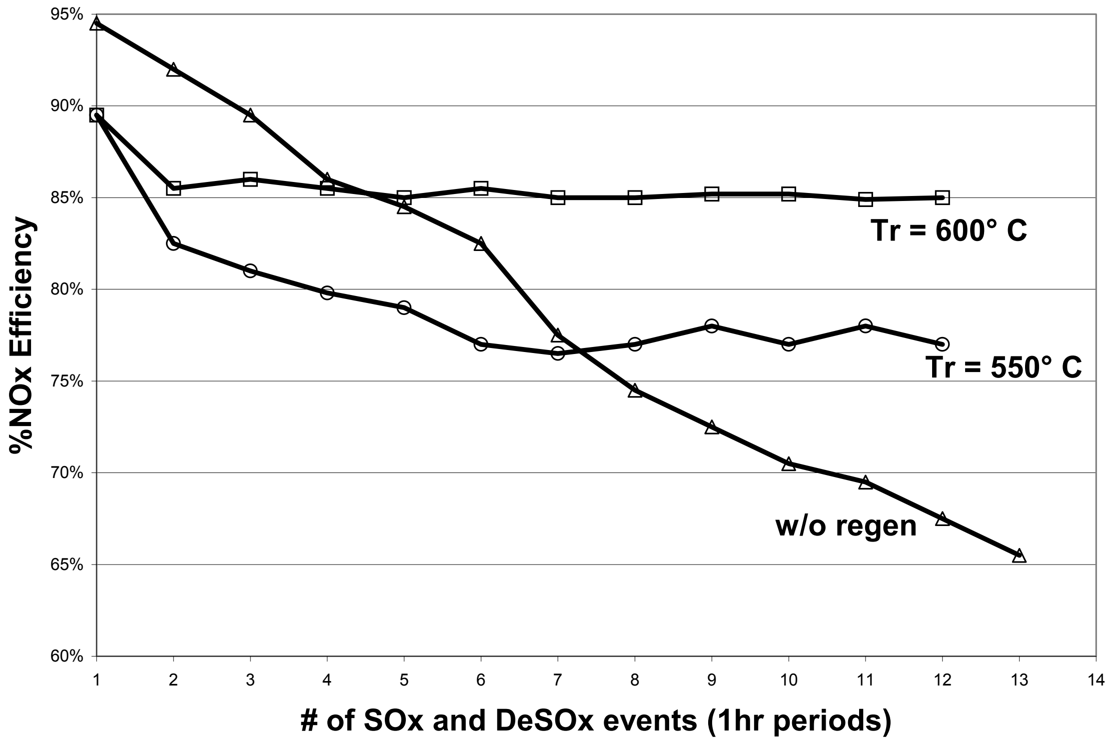
Numerous test programs have shown that sulfur can be removed from the catalyst surface through a sulfur regeneration step (desulfation step) not dissimilar from the NOx regeneration function.[70,71,72,73,74,75] The stored sulfur compounds are removed by exposing the catalyst to hot and rich (air-fuel ratio below the stoichiometric ratio of 14.5 to 1) conditions for a brief period. Under these conditions, the stored sulfate is released and reduced in the catalyst. This sulfur removal process, called desulfation or desulfurization in this document, can restore the performance of the NOx adsorber to near new operation.

Most of the information in the public domain on NOx adsorber desulfation is based upon research done either in controlled bench reactors using synthetic gas compositions or on advanced lean-burn gasoline engine vehicles. As outlined above, these programs have shown that desulfation of NOx adsorber catalysts can be accomplished under certain conditions but the work does not directly answer whether NOx adsorber desulfation is practical for diesel engine exhaust conditions. The DECSE Phase II program answers that question.

Phase II of the DECSE program developed and demonstrated a desulfurization (desulfation) process to restore NOx conversion efficiency lost to sulfur contamination. The engine used in the testing was a high-speed direct-injection diesel selected to provide a representative source of diesel exhaust and various exhaust temperature profiles to challenge the emission-control devices. The desulfation process developed in the DECSE Phase II program controlled the air-fuel ratio and catalyst inlet temperatures to achieve the high temperatures required to release the sulfur from the device. Air-fuel ratio control was accomplished in the program with exhaust gas recirculation (EGR) and a post-injection of fuel to provide additional reductants. Using this approach the researchers showed that a desulfation procedure can be developed for a diesel engine with the potential to meet in-service engine operating conditions and acceptable levels of torque fluctuation. The NOx efficiency recovery accomplished in DECSE Phase II using this approach is shown in Figure 4.1-3, above.

The effectiveness of NOx adsorber desulfation appears to be closely related to the temperature of the exhaust gases during desulfation, the exhaust chemistry (relative air-fuel ratio), and to the NOx adsorber catalyst formulation.[76, 77] Lower air-fuel ratios (more available reductant) works to promote the release of sulfur from the surface, promoting faster and more effective desulfation. Figure 4.1-4 shows results from Ford testing on NOx adsorber conversion efficiency with periodic aging and desulfation events in a control flow reactor test.[78] The control flow reactor test uses controlled gas constituents that are meant to represent the potential exhaust gas constituents from a lean-burn engine. The solid line with the open triangles labeled “w/o regen” shows the loss of NOx control over thirteen hours of testing without a desulfation event and with eight ppm sulfur in the test gas (this is roughly equivalent to 240 ppm fuel sulfur, assuming an air-fuel ratio for diesel engines of 30:1).[79] From the figure it can be seen that without a desulfation event, sulfur rapidly degrades the performance of the NOx adsorber catalyst. The remaining two lines show the NOx adsorber performance with periodic sulfur regeneration events timed at one-hour intervals and lasting for 10 minutes (a one-hour increment on 240 ppm fuel sulfur is approximately equivalent to 34 hours of operation on 7 ppm fuel). The desulfation events were identical to the NOx regeneration events, except that the desulfation events occurred at elevated temperatures. The base NOx regeneration temperature for the testing was 350˚C. The sulfur regeneration, or desulfation, event was conducted at two different gas temperatures of 550˚C and 600˚C to show the effect of exhaust gas temperature on desulfation effectiveness, and thus NOx adsorber efficiency. From Figure 4.1-4 it can be seen that, for this NOx adsorber formulation, the NOx recovery after desulfation is higher for the desulfation event at 600˚C than at 550˚C.

Figure 4.1-4
Flow Reactor Testing of a NOx Adsorber with Periodic Desulfations



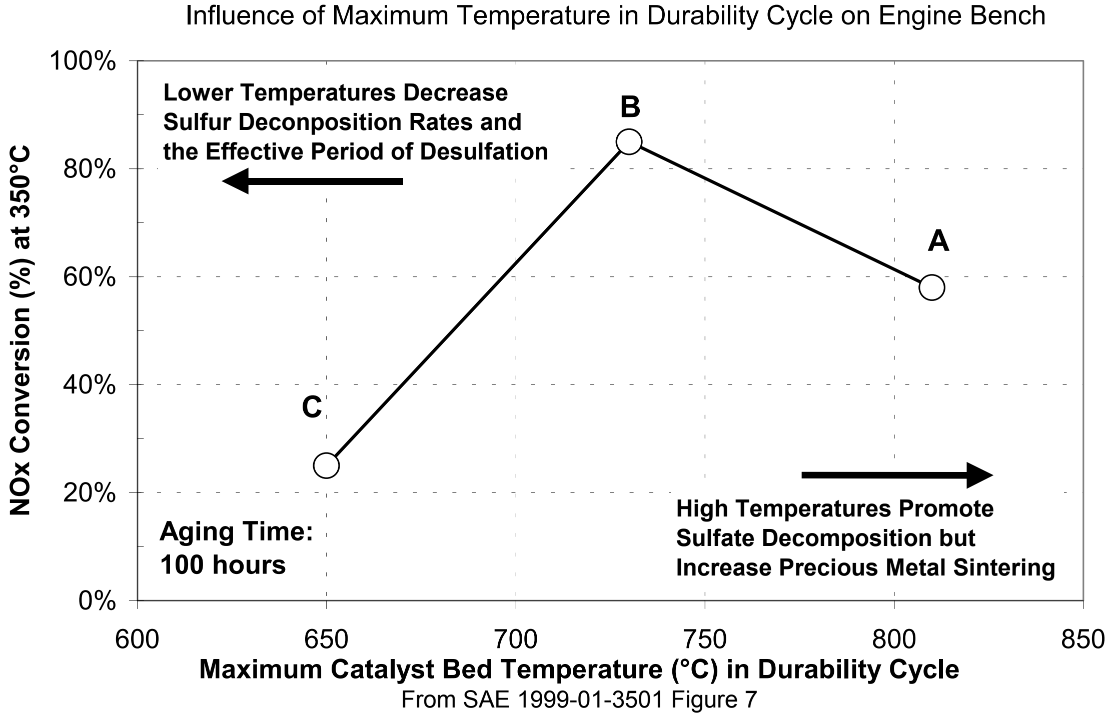
As suggested by Figure 4.1-4, it is well known that the rate of sulfur release (also called sulfur decomposition) in a NOx adsorber increases with temperature.[80,81] However, while elevated temperatures directionally promote more rapid sulfur release, they also can directionally promote sintering of the precious metals in the NOx adsorber washcoat. The loss of conversion efficiency due to exposure of the catalyst to elevated temperatures is referred to as thermal degradation in this document.

Thermal Degradation

The catalytic metals that make up most exhaust emission-control technologies, including NOx adsorbers, are designed to be dispersed throughout the catalyst into as many small catalyst "sites" as possible. By spreading the catalytic metals into many small catalyst sites, rather than into a fewer number large sites, catalyst efficiency is improved. This is because smaller catalyst sites have more surface area per mass, or volume, of catalyst when compared with larger catalyst sites. Since most of the reactions being promoted by the catalyst occur on the surface, increasing surface area increases catalyst availability and thus conversion efficiency. While high dispersion (many small catalyst sites) is in general good for most catalysts, it is even more beneficial to the NOx adsorber catalyst because of the need for the catalytic metal sites to perform multiple tasks. NOx adsorber catalysts typically rely on platinum to oxidize NO to NO_2 prior to adsorption of the NO_2 on an adjacent NOx storage site. Under rich operating conditions, the NOx is released from the adsorption site, and the adjacent platinum (or platinum + rhodium) catalyst site can serve to reduce the NOx emissions into N_2 and O_2. High dispersion, combined with NO oxidation, NOx storage and NOx reduction catalyst sites being located in close proximity, provide the ideal catalyst design for a NOx adsorber catalyst. But high temperatures, especially under oxidizing conditions, can promote sintering of the platinum and other PGM catalyst sites, permanently decreasing NOx adsorber performance.

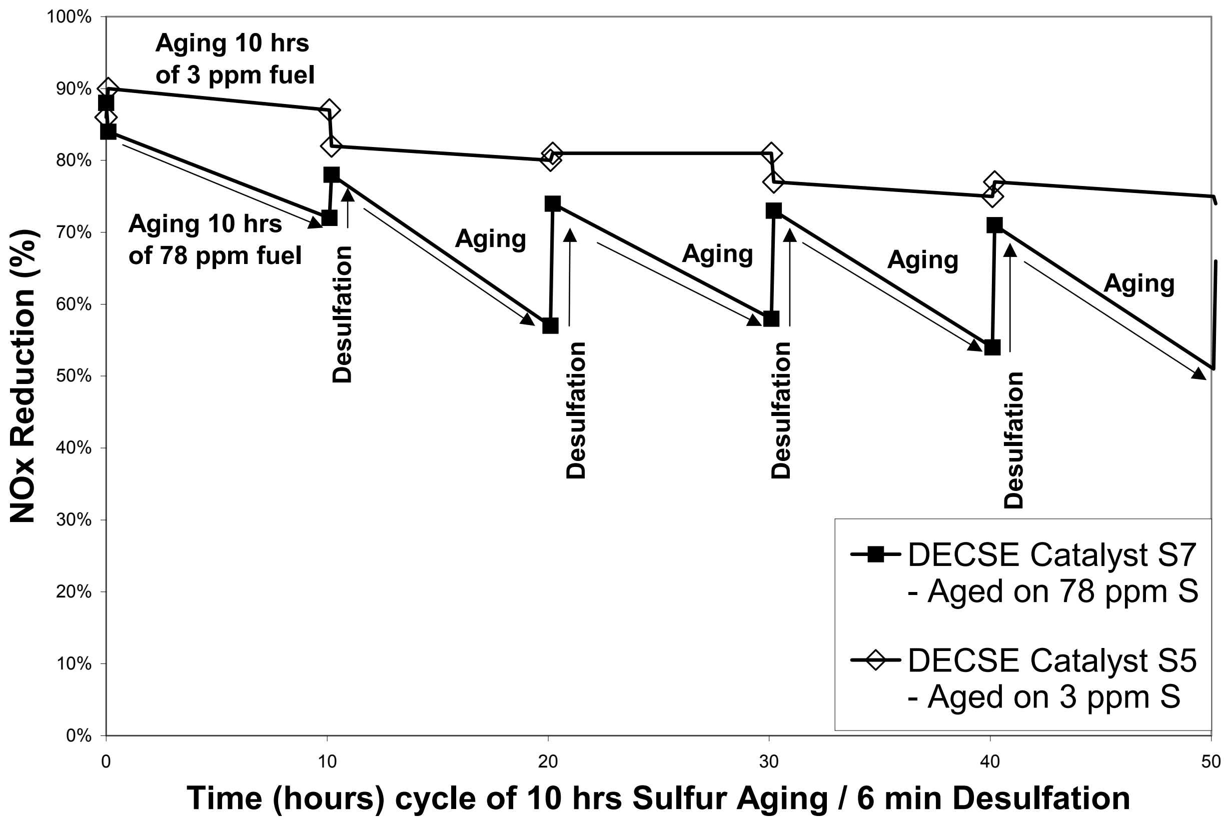
Catalyst sintering is a process by which adjacent catalyst sites can “melt” and regrow into a single larger catalyst site (crystal growth). The single larger catalyst site has less surface area available to promote catalytic activity than the original two or more catalyst sites that were sintered to form it. This loss in surface area decreases the efficiency of the catalyst.[82] High temperatures, promote sintering of platinum catalysts especially under oxidizing conditions.[83] It is therefore important to limit the exposure of platinum-based catalysts to high exhaust temperatures especially during periods of lean operation. Consequently, the desire to promote rapid desulfation of the NOx adsorber catalyst technology by maximizing the desulfation temperature and the need to limit the exposure of the catalyst to the high temperatures that promote catalyst sintering must be carefully balanced. An example of this tradeoff can be seen in Figure 4.1-5, which shows the NOx conversion efficiency of three NOx adsorber catalysts evaluated after extended periods of sulfur poisoning followed by sulfur regeneration periods.[84] The three catalysts (labeled A, B, and C) are identical in formulation and size but were located at three different positions in the exhaust system of the gasoline direct injection engine used for this testing. Catalyst A was located 1.2 meters from the exhaust manifold, catalyst B 1.8 meters from the exhaust manifold and catalyst C was located 2.5 meters from the exhaust manifold. Locating the catalysts further from the engine lowered the maximum exhaust temperature and thus catalyst bed temperature experienced during the programmed sulfur regeneration cycle. Catalyst A experienced the highest catalyst bed temperature of 800˚C, while catalyst C experienced the lowest catalyst bed temperature of 650˚C. Catalyst B experienced a maximum catalyst bed temperature of 730˚C. Figure 4.1-5 shows that there is an optimum desulfation temperature that balances the tradeoffs between rapid sulfur regeneration and thermal degradation (thermal sintering) at high temperatures.

Figure 4.1-5
Influence of Maximum Catalyst Bed Temperature During Desulfation



The DECSE Phase II program, in addition to investigating the ability of a diesel engine / NOx adsorber-based emission-control system to desulfate, provides a preliminary assessment of catalyst durability when exposed to repeated aging and desulfurization cycles. Two sets of tests were completed using two different fuel sulfur levels (three ppm and 78 ppm) to investigate these durability aspects. The first involved a series of aging, performance mapping, desulfurization and performance mapping cycles. An example of this testing is shown in Figure 4.1-6. The graph shows a characteristic "sawtooth" pattern of gradual sulfur poisoning followed by an abrupt improvement in performance after desulfation. The results shown in Figure 4.1-6 are for two identical catalysts one operated on 3 ppm sulfur fuel (catalyst S5) and the other operated on 78 ppm sulfur fuel (catalyst S7). For the catalyst operated on 3 ppm sulfur fuel the loss in performance over the ten hours of poisoning is noted to be very gradual. There appears to be little need to desulfate that catalyst at the ten-hour interval set in the experiment. In fact it can be seen that in several cases the performance after desulfation is worse than prior to desulfation. This suggests, as discussed above, that the desulfation cycle can itself be damaging to the catalyst. In actual use, we would expect an engine operating on 3 ppm sulfur fuel not to desulfate until well beyond a ten-hour interval and be engineered to better withstand the damage caused by desulfation, as discussed later in this section. For the catalyst operated on 78 ppm sulfur fuel the loss in performance over the ten-hour poisoning period is dramatic. To ensure continued high performance when operating on 78 ppm sulfur fuel, the catalyst requires frequent desulfations. From the figure it can be inferred that the desulfation events need to be spaced at intervals as short as one to two hours to maintain acceptable performance.

Figure 4.1-6
Integrated NOx Conversion Efficiency following Aging and Desulfation



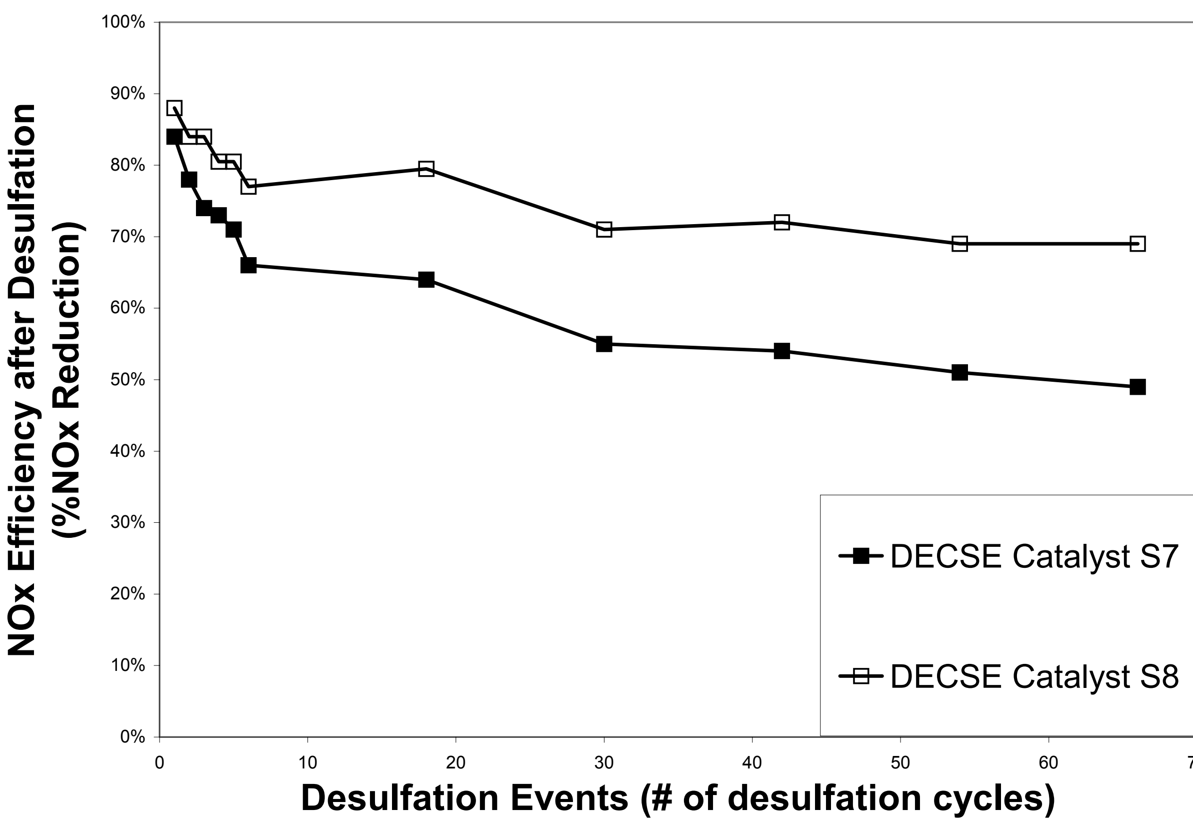
As a follow on to the work shown in Figure 4.1-6, the desulfation events were repeated an additional 60 times without sulfur aging between desulfation events. This was done to investigate the possibility of deleterious affects from the desulfation event itself even without additional sulfur poisoning. As can be seen in Figure 4.1-7, the investigation did reveal that repeated desulfation events even without additional sulfur aging can cause catalyst deterioration. As described previously, high temperatures can lead to a loss in catalyst efficiency due to thermal degradation (sintering of the catalytic metals). This appears to be the most likely explanation for the loss in catalyst efficiency shown here. For this testing, the catalyst inlet temperature was controlled to approximately 700˚C; however, the catalyst bed temperatures may have been higher.[85]

Based on the work in DECSE Phase II, the researchers concluded that:
• The desulfurization procedure developed has the potential to meet in-service engine operating conditions and to provide acceptable driveability conditions.

• Although aging with 78 ppm sulfur fuel reduced NOx conversion efficiency more than aging with three ppm sulfur fuel as a result of sulfur contamination, the desulfurization events restored the conversion efficiency to nearly the same level of performance. However, repeatedly exposing the catalyst to the desulfurization procedure developed in the program caused a continued decline in the catalyst's desulfated performance.

• The rate of sulfur contamination during aging with 78 ppm sulfur fuel increased with repeated aging / desulfurization cycles (from 10 percent per ten hours to 18 percent per ten hours). This was not observed with the three ppm sulfur fuel, where the rate of decline during aging was fairly constant at approximately two percent per ten hours.

Figure 4.1-7
Integrated NOx Conversion Efficiency after Repeated Desulfation



Currently available data on NOx adsorber formulations show clearly that sulfur can be removed from the surface of the NOx adsorber catalyst. The initial high performance after a desulfation event is then degraded over time by the presence of sulfur until the next desulfation event. The resulting characteristic NOx adsorber performance level over time exhibits a saw-tooth pattern with declining performance followed by rapid recovery of performance following desulfation. The rate of this decline increases substantially with higher fuel sulfur levels. Tto ensure a gradual and controllable decline in performance, fuel sulfur levels must be minimized.

However, even given very low fuel sulfur levels, gradual decline in performance must be periodically overcome. The development experience so far shows that diesel engines can accomplish the required desulfation event. The circumstances that effectively promote rapid desulfation also promote thermal degradation. It will therefore be important to limit thermal degradation.

Limiting Thermal Degradation

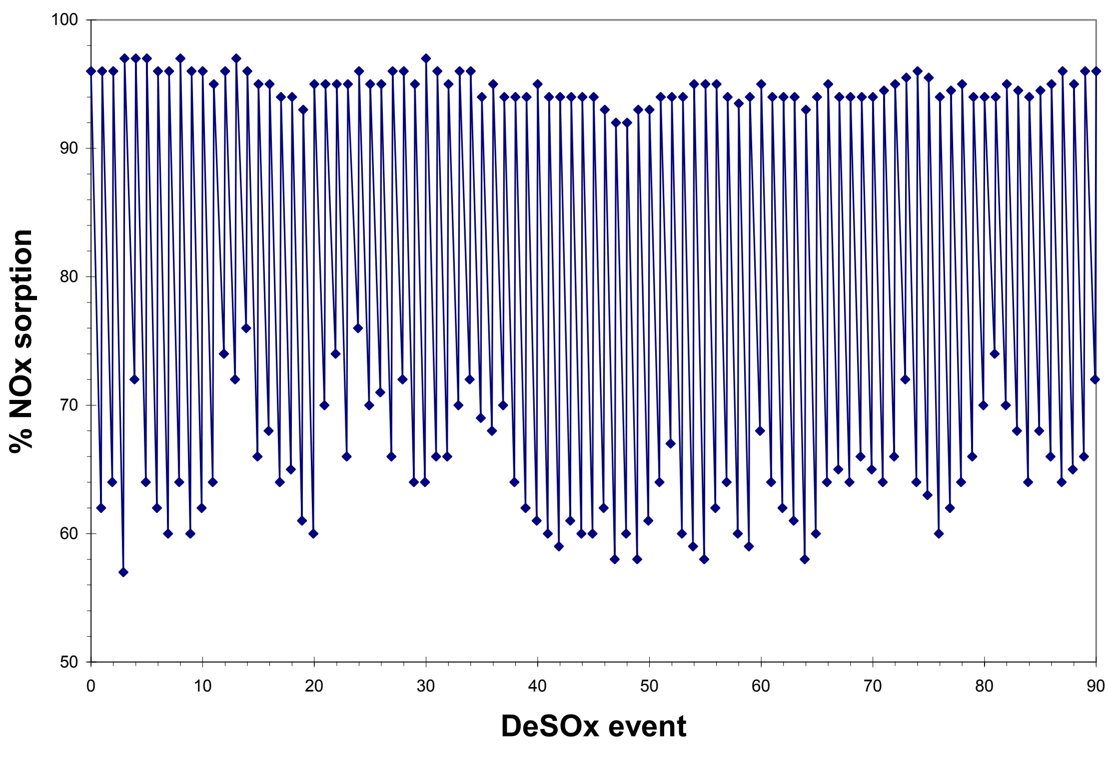
The issue of thermal degradation of NOx adsorber catalyst components is similar to the thermal sintering issues faced by light-duty three-way catalysts for vehicles developed to meet current California LEV and future Federal Tier 2 standards using platinum+rhodium (Pt+Rh) catalysts. Initial designs were marked by unacceptable levels of platinum sintering that limited the effectiveness of Pt+Rh catalysts. This problem has been overcome through modifications to the catalyst supports and surface structures that stabilize the precious metals at high temperatures (>900 ˚C). Stabilization of ceria components using Zirconium (Zr) has pushed the upper temperature limits of ceria migration to well over 1000 ˚C.[86, 87] Stabilization components can function in different ways. Some are used to "fill" structural vacancies, for example "open" locations within a crystalline lattice, thus strengthening the lattice structure. Such strengthening of crystalline lattice structures is particularly important at high temperatures. Other types of stabilizing components can act as obstructions within a matrix to prevent migration of components, or can enhance the mobility of other molecules or atoms, such as oxygen. An approach stabilizing NOx adsorber catalyst components similar to the approaches taken with LEV three-way catalyst designs should help to minimize thermal sintering of components during desulfation.

In many ways, limiting the thermal degradation of the NOx adsorber catalyst should be easier than for the gasoline three-way catalyst. Typical exhaust gas temperatures for a heavy light-duty gasoline truck (e.g., a Ford Expedition) commonly range from 450˚C to more than 800˚C during normal operation.[88] A heavy-duty diesel engine in contrast rarely has exhaust gas temperatures in excess of 500˚C. Further, even during the desulfation event, exhaust temperatures are expected to be controlled below 700˚C. The NOx adsorber applied to diesel engines is therefore expected to see both lower average temperatures and lower peak temperatures when compared with an equivalent gasoline engine. Once thermal degradation improvements are made to NOx adsorber catalysts, thermal degradation will reasonably be expected to be less than the level predicted for future Tier 2 gasoline applications.

In addition to the means to improve the thermal stability of the NOx adsorber by applying many of the same techniques being perfected for the Tier 2 gasoline three-way catalyst applications, an additional possibility exists that the desulfation process itself can be improved to give both high sulfur removal and to limit thermal degradation. The means to do this might include careful control of the maximum temperature during desulfation to limit the exposure to high temperatures. Also, improvements in how the regeneration process occurs may provide avenues for improvement. Low air-fuel ratios (high levels of reductant) are known to improve the desulfation process. The high level of reductant may also help to suppress oxygen content in the exhaust to further limit thermal degradation.

Researchers at Ford Scientific Research Labs have investigated NOx adsorber catalyst desulfation (called DeSOx in their work) to answer the question: "if a regeneration process (sulfur regeneration) is required periodically, will the high temperatures required for the regeneration have deleterious, irreversible effects on NOx efficiency?" To explore the issue of NOx adsorber durability after repeated desulfation events, Ford conducted repeated sequential sulfur poisoning and desulfation cycles with a NOx adsorber catalyst. The results of their experiment are shown in Figure 4.1-8.[89] As shown in Figure 4.1-8, the NOx adsorber sample underwent more than 90 poisoning and desulfation cycles with 12 hours occurring between the end of one desulfation to the end of the next desulfation without a measurable loss in post-desulfation performance. This testing was done using a laboratory tool called a pulsator, used to study ceramic monolith catalyst samples. The ceramic test samples were heated to between 700˚C and 750˚C. These results indicate that for some combinations of temperatures and reductant chemistries the NOx adsorber can be repeatedly desulfated without a significant loss in NOx reduction efficiency. This work indicates that it is possible to optimize the desulfation process to allow for adequate sulfur removal without a significant decrease in NOx reduction efficiency.

Figure 4.1-8
Repeated Sulfur Poisoning and Desulfation on a Bench Pulsator



These results indicate that, with further improvements to the NOx adsorber catalyst design incorporating the experience gained on gasoline three-way catalysts and continuing improvements in the control of the desulfation, degradation of the NOx adsorber catalyst with each desulfation event can be limited. However, the expectation remains that there will be some level of deterioration with desulfation that must be managed to ensure long-term high efficiency of the NOx adsorber. This means that the number and frequency of desulfation events must be kept to a minimum. The key to this is to limit the amount of sulfur to which the catalyst is exposed over its life. In this way, the deterioration in performance between desulfation events is controlled at a gradual rate and the period between desulfations can be maximized to limit thermal degradation.

Overall System Durability

NOx emission control with a NOx adsorber catalyst-based systems is an extension of the very successful three-way catalyst technology. NOx adsorber technology is most accurately described as incremental and evolutionary with system components that are straightforward extensions of existing technologies. The technology therefore benefits substantially from the considerable experience gained over the past 30 years with the today's highly reliable and durable three-way catalyst systems.

The following observations can be made from the data provided in the preceding sections on NOx adsorber durability:

- NOx adsorber catalysts are poisoned by sulfur in diesel fuel, even at fuel sulfur levels as low as three ppm.

- A sulfur regeneration event (desulfation) can restore NOx adsorber performance.

- A diesel engine can produce exhaust conditions that are conducive to desulfation.

- Desulfation events, which require high catalyst temperatures, can cause sintering of the catalytic metals in the NOx adsorber, thereby reducing NOx-control efficiency.

- The means exist from the development of gasoline three-way catalysts to improve the NOx adsorber's thermal durability.

- In carefully controlled experiments, NOx adsorbers can be desulfated repeatedly without an unacceptable loss in performance.

- The number and frequency of desulfation events must be limited to ensure any gradual thermal degradation over time does not excessively deteriorate the catalyst.

Based on these observations, we are confident that NOx adsorber technology for HD2007 and later engines will be durable over the life of heavy-duty diesel vehicles, provided that the engines use fuel with a 15 ppm sulfur cap and that the technology will prove to be similarly durable when applied some years later to nonroad diesel engines to comply with the Tier 4 emission standards. Without the use of this low-sulfur fuel, we can no longer be confident that the increased number of desulfation cycles that will be required to address the impact of sulfur on efficiency can be accomplished without unrecoverable thermal degradation and thus loss of

NOx adsorber efficiency. Limiting the number and frequency of these deleterious desulfation events through the use of diesel fuel with sulfur content less than 15 ppm allows us to conclude with confidence that NOx adsorber catalysts will be developed that are durable throughout the life of a nonroad diesel engine.

4.1.2.3.5 Current Status of NOx Adsorber Development

NOx adsorber catalysts were first introduced in the power generation market less than five years ago. Since then, NOx adsorber systems in stationary source applications have enjoyed considerable success. In 1997, the South Coast Air Quality Management District of California determined that a NOx adsorber system provided the “Best Available Control Technology” NOx limit for gas turbine power systems.[90] Average NOx control for these power generation facilities is in excess of 92 percent.[91] A NOx adsorber catalyst applied to a natural gas fired powerplant has demonstrated better than 99 percent reliability for more than 21,000 hours of operation while controlling NOx by more than 90 percent.[92] The experience with NOx adsorbers in these stationary power applications shows that NOx adsorbers can be highly effective for controlling NOx emissions for extended periods of operation with high reliability.

4.1.2.3.5.1 Lean-Burn Gasoline Engines

The NOx adsorber’s ability to control NOx under oxygen-rich (fuel-lean) operating conditions has led industry to begin applying NOx adsorber technology to lean-burn engines in mobile source applications. NOx adsorber catalysts have been developed and are now in production for lean-burn gasoline vehicles in Japan, including several vehicle models sold by Toyota Motor Corporation.[L] The 2000 model year saw the first application of this technology in the United States with the introduction of the Honda Insight, certified to the California LEV-I ULEV category standard. Table 4.1-6 lists some of the 2002 European lean-burn direct-injection gasoline vehicles that use NOx adsorber catalyst technology.[93] These lean-burn gasoline applications are of particular interest because they are similar to diesel vehicle applications in terms of lean-NOx storage and the need for periodic NOx regeneration under transient driving conditions. The fact that they have been successfully applied to these mobile source applications shows clearly that NOx adsorbers can work under transient conditions provided that engineering solutions can be found to periodically cause normally lean-burn exhaust conditions to operate in a rich regeneration mode.

[L] Toyota requires that their lean-burn gasoline engines equipped with NOx adsorbers are fueled on premium gasoline in Japan, which has an average sulfur content of six ppm.

Table 4.1-6 2002 European Lean-Burn Gasoline Direct-Injection Engines

Model	Displacement(liter)	Power(KW/PS)
Audi A2 FSI	1.6	81/110
Audi A4 FSI	2	110/150
BMW 760 iL	6	ca. 300/408
Citroen C5 HPI	2	103/140
Mercedes CLK 200 CGI	1.8	125/170
Mercedes C 200 CGI	1.8	125/170
Mitsubishi Carisma GDI	1.8	90/122
Mitsubishi Space Star GDI	1.8	90/122
Mitsubishi Space Wagon 2.4 GDI	2.4	108/147
Mitsubishi Space Runner 2.4 GDI	2.4	110/150
Mitsubishi Galant 2.4 GDI	2.4	106/144
Mitsubishi Pajero Pinin 2.0 GDI	2	90/122
Mitsubishi Pajero 3.2 V6 GDI	3.5	149/202
Peugeot 406 HPI	2	103/140
VW Lupo FSI	1.4	77/105
VW Polo FSI	1.4	63/85
VW Golf FSI	1.6	81/110
VW Bora FSI	1.6	81/110
Volvo S40 1.8	1.6	90/122

4.1.2.3.5.2 EPA National Vehicle and Fuel Emissions Laboratory

As part of an ongoing effort to evaluate the rapidly developing state of this technology, the Manufacturers of Emission Control Association (MECA) have provided numerous NOx adsorber catalyst formulations to EPA for evaluation. Testing of some of these catalysts at NVFEL revealed that formulations were capable of reducing NOx emissions by more than 90 percent over the broad range of operation in the highway steady-state SET procedure (sometimes called the EURO 4 test). At operating conditions representative of “road-load” operation for a highway trucks, the catalysts showed NOx reductions as high as 99 percent resulting in NOx emissions well below 0.1 g/hp-hr from an engine-out level of nearly 5 g/hp-hr. Figure 4.1-9 shows an engine torque vs. speed map with the various steady-state test modes used in this testing as well as the 8 modes of the ISO-C1 cycle used for nonroad certification. Though not included in the test results shown in Figures 4.1-10 through 4.1-12, the ISO-C1 modes are closely approximated by some other test modes, as can be seen in Figure 4.1-9. We therefore expect similarly good performance on the ISO-C1 test modes. Testing on the highway transient test procedure has shown similarly good results, with hot-start NOx emissions over the highway FTP cycle reduced by more than 90 percent. These results demonstrate that significant NOx reductions are possible over a broad range of operating conditions with current NOx adsorber technology, as typified by the highway FTP cycle and the SET procedure.

The test program at NVFEL can be divided into phases. The first phase began with an adsorber screening process using a single leg of the planned dual-leg system. The goals of this screening process, a description of the test approach, and the results are described below. The next phase of the test program consisted of testing the dual-leg system on a more advanced Tier 3 like diesel engine (i.e., with common rail fuel system and cooled EGR) using a NOx adsorber chosen during the first phase in each of two legs. The current ongoing phase is working on improved systems approaches including a demonstration of an improved package four “leg” system.

Testing Goals—Single-Leg NOx Adsorber System

The goal of the NOx adsorber screening process was to evaluate available NOx adsorber formulations from different manufacturers with the objective of choosing an adsorber with 90 percent or better NOx reduction for continued evaluation. To this end, four different adsorber formulations were provided from three different suppliers. Since this was a screening process and since a large number of each adsorber formulation would be required for a full dual-leg system, it was decided to run half of a dual-leg system (a single-leg system) and mathematically correct the emissions and fuel economy impact to reflect a full dual-leg system. The trade-off was that the single-leg system would be able to run only steady-state modes, as the emissions could not be corrected over a transient cycle. The configuration used for this test was similar to that shown in Figure 4.1-1, but with a catalyst installed only on one side of the system.

Test Approach—Single-Leg NOx Adsorber System

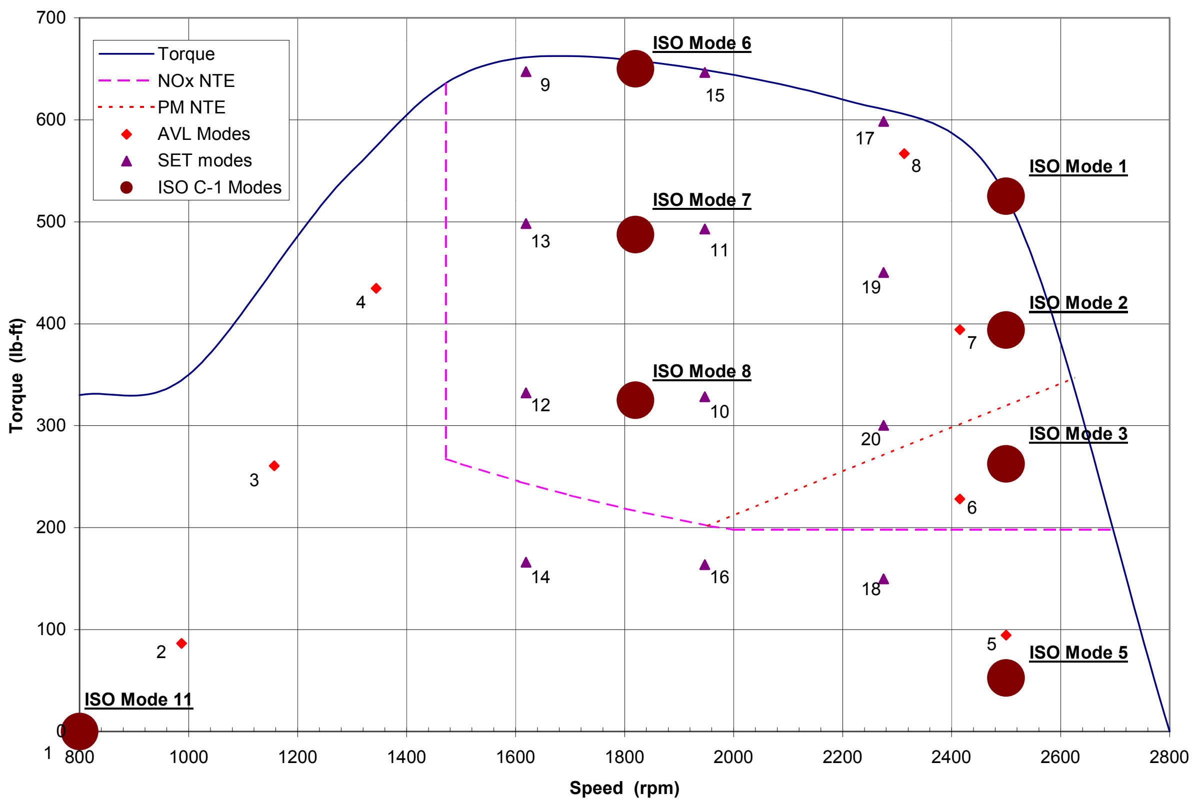
The single-leg system consisted of an exhaust brake, a fuel injector, CDPF, and a NOx adsorber in one test leg. The other leg, the “bypass leg,” consisted of an exhaust brake that opened when the test-leg brake was closed; this vented the remainder of the exhaust out of the test cell. Under this setup, the test leg, i.e., the leg with the adsorber, was directed into the dilution tunnel where the emissions were measured and then compensated to account for emissions from the bypass leg. The restriction in the bypass leg was set to duplicate the backpressure of the test leg so that, while bypassing the test leg to conduct a NOx regeneration, the backpressure of the bypass leg simulated the presence of a NOx adsorber system. A clean-up diesel oxidation catalyst (DOC) downstream of the NOx adsorber was not used for this testing.

The measured emissions had to be adjusted to account for the lack of any NOx adsorber in the bypass leg. For this correction, it was assumed that the bypass leg’s missing (virtual) adsorber would adsorb only while the actual leg was regenerating. It was also assumed the virtual adsorber would have regeneration fuel requirements in proportion to its adsorbing time. The emission-control performance of the virtual adsorber was assumed to be the same as the performance of the actual adsorber. With these assumptions, the gaseous emissions could be adjusted.[94]

Test Results—Single-Leg NOx Adsorber System

Two sets of steady-state modes were run with each adsorber formulation. These modes consisted of the SET modes and the AVL 8 mode composite FTP prediction.[M] The modes are illustrated in Figure 4.1-9 and are numbered sequentially one through 20 to include both the eight AVL modes and the 13 SET modes (the idle mode is repeated in both tests). The mode numbers shown in the figure are denoted as "EPA" modes in the subsequent tables to differentiate between the AVL and SET modes that have duplicate mode numbers. The highway NTE zone (which is the same as the nonroad NTE zone) is also shown in Figure 4.1-9 to show that these two sets of modes give comprehensive coverage of the NTE zone. The ISO C1 steady-state modes used for nonroad engines are closely represented by the test modes shown here. The only C1 mode not well represented is the 10 percent load point (ISO Mode 5), which is outside of the nonroad NTE zone. The modes were run with varying levels of automation, with the general strategy being to inject sufficient fuel during regeneration to obtain a lambda at or slightly fuel-rich of stoichiometric ($\lambda \leq 1$). The NOx regenerations were then timed to achieve the desired NOx reduction performance. The adsorber formulations were identified as A, B, D, and E. Prior to testing, each set of adsorbers were aged at 2500 rpm, 150 lb-ft for 40 minutes, then 2500 rpm full load for 20 minutes, repeated for a total of 10 hours.

Figure 4.1-9 Steady-State Test Modes from NVFEL Testing and ISO C-1 Modes



[M] The AVL 8 mode test procedure is a steady-state test procedure developed by Anstalt für Verbrennungskraftmaschinen, Prof. Dr. Hans List (or Institute for Internal Combustion Engines) to approximate emission levels that would occur while operating the engine over the transient highway FTP cycle.

The SET and AVL Composite emission results, along with the NOx reduction performance vs. adsorber inlet temperature, are shown in Figures 4.1-10 through 4.1-13 for each of the tested NOx adsorber formulations. The SET composites for all four adsorber formulations had NOx reductions in excess of 90 percent with under a three percent impact on fuel economy. The HC emissions varied most widely, most likely due to differences in regeneration strategies, and to some extent, adsorber formulation. The HC emissions with the exception of adsorber "A" were very good, less than 0.1 g/hp-hr over the SET and less than 0.2 g/hp-hr over the AVL composite. Note that no DOC was used to clean up the HC emissions.

Another point to note is that the EPA mode 1 (ISO-C1 Mode 11) data for each composite is the same. This is because EPA mode 1, low idle, is too cold for effective steady-state regeneration, but efficient NOx adsorption can occur for extended periods of time. (Note that the exhaust temperature at idle is well below the NTE threshold of 250˚C discussed earlier.) For either of these composite tests, a regeneration would not be needed under such conditions. EPA mode 1 has very little impact on either composite in any case because of the low power and emission rate. EPA mode 2 also had very low steady-state temperatures, and the difficulty regenerating at this mode can be seen in the impacts on HC emissions and on fuel economy. But, like EPA mode 1, the engine would adsorb during EPA mode 2 for extended periods without needing regeneration. None of the ISO-C1 modes, other than the idle mode, are similar to EPA mode 2. Further, no attempt was made to apply new combustion approaches such as the Toyota low-temperature combustion technology to raise exhaust temperatures at these operating modes.

The AVL composite showed greater differences between the adsorber formulations than the SET. Three of the adsorbers achieved greater than 90 percent NOx reduction over the AVL composites with the other adsorber at 84 percent NOx reduction. The greater spread in NOx reduction performance was, in part, due to this composite's emphasis on EPA mode 8, which was at the upper end of the NOx reduction efficiency temperature window. Adsorber E had an EPA mode 8 NOx reduction of 66 percent, and the NOx reduction efficiency vs. inlet temperature graph clearly shows that this formulation's performance falls off quickly above 450˚C. In contrast, the other formulations do not show such an early, steep loss in performance. The fuel economy impacts vary more widely also, partly due to the test engineers' regeneration strategies, particularly with the low-temperature modes, and to the general inability to regenerate at very low-temperature modes at steady-state. Note also that none of the regeneration strategies here can be considered fully optimized, as they reflect the product of trial and error experimentation by the test engineers. With further testing and understanding of the technology a more systematic means for optimization should be possible. In spite of the trial and error approach the results shown here are quite promising.

The AVL composite was developed as a steady-state test that would predict engine-out emission levels over the transient highway FTP cycle. As discussed in 4.1.3.1.2 below, NOx adsorber control effectiveness is projected to be more effective over the NRTC than over the highway FTP cycle. The AVL cycle loses some accuracy when testing engines with NOx adsorbers, since regeneration does not occur at the low-temperature modes (EPA modes 1, 2, 5). In real-world conditions, diesel engines do not come to steady-state temperatures at any of these modes, and the adsorber temperatures will be higher at EPA modes 1, 2, and 5 than the stabilized steady-state values used for this modal testing. Consequently, the actual performance over a transient duty cycle should be much better than the composites would suggest (see the discussion of transient testing below).

Based on the composite data and the temperature performance charts, amongst other factors, adsorber formulation B was chosen for further dual-leg performance work. Both composites for this formulation were well above 90 percent. The NOx vs. temperature graph, Figure 4.1-11, also shows that this formulation was a very good match for this engine.

					Base	Adsorber				
EPA Mode	SET Mode	SET Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	15%	Idle	0	13.0	144	0.16	100%	0.00	0.0%
9	2	8%	1619	630	4.6	461	0.11	98%	0.92	2.4%
10	3	10%	1947	328	4.7	357	0.07	98%	1.02	2.0%
11	4	10%	1947	493	5.0	411	0.06	99%	1.35	2.6%
12	5	5%	1619	332	5.0	384	0.13	97%	0.11	1.3%
13	6	5%	1619	498	5.0	427	0.24	95%	0.81	1.6%
14	7	5%	1619	166	5.5	287	0.25	95%	1.39	3.3%
15	8	9%	1947	630	4.0	498	0.89	78%	0.36	1.9%
16	9	10%	1947	164	5.0	293	0.14	97%	1.88	4.1%
17	10	8%	2275	599	4.0	515	0.48	88%	1.12	3.8%
18	11	5%	2275	150	4.8	282	0.42	91%	0.68	3.5%
19	12	5%	2275	450	5.0	404	0.08	98%	0.62	3.0%
20	13	5%	2275	300	4.8	357	0.14	97%	0.70	2.8%
Composite Results					4.6		0.31	93%	0.91 *	2.6% *

					Base	Adsorber				
EPA Mode	AVL Mode	AVL Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	42%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
2	2	8%	987	86	8.80	172	0.83	91%	0.75	7.7%
3	3	3%	1157	261	8.40	346	0.36	96%	1.10	3.1%
4	4	4%	1344	435	5.90	430	0.20	97%	2.16	3.0%
5	5	10%	2500	94	5.50	286	0.37	93%	4.93	3.6%
6	6	12%	2415	228	4.60	325	0.08	98%	2.30	3.6%
7	7	12%	2415	394	4.90	386	0.10	98%	2.38	3.1%
8	8	9%	2313	567	4.10	505	1.06	74%	0.03	1.9%
Composite Results					4.9		0.44	91%	1.69 *	2.9% *

* HC results & FE Impacts do not reflect future potential as they are derived using a 5 g NOx engine which requires more frequent NOx regens than would result using a 2.5 g engine and the tested system was not a fully optimized engine & emission control system.

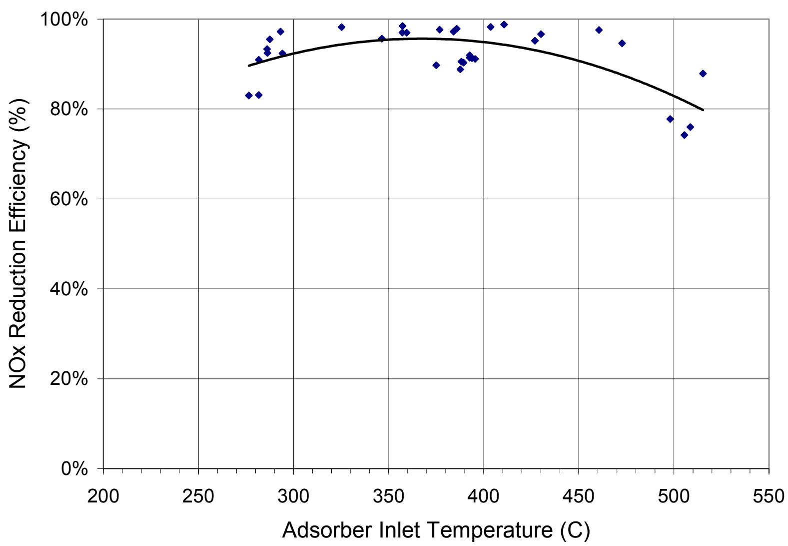


Figure 4.1-10. SET & AVL Composites, and Temperature vs. NOx Chart for Adsorber A

					Base	Adsorber				
EPA	SET	SET	Speed	Torque	BSNOx	Inlet T	BSNOx	NOx Red	HC *	FE Impact
Mode	Mode	Weighting	(rpm)	(lb-ft)	(g/hp-hr)	(C)	(g/hp-hr)		(g/hp-hr)	*
1	1	15%	Idle	0	13.0	144	0.16	100%	0.00	0.0%
9	2	8%	1619	630	4.6	498	0.18	96%	0.01	1.2%
10	3	10%	1947	328	4.7	366	0.07	98%	0.04	0.5%
11	4	10%	1947	493	5.0	446	0.14	97%	0.01	1.5%
12	5	5%	1619	332	5.0	375	0.06	99%	0.08	0.7%
13	6	5%	1619	498	5.0	420	0.07	98%	0.10	2.3%
14	7	5%	1619	166	5.5	296	0.18	97%	0.10	0.3%
15	8	9%	1947	630	4.0	524	0.46	89%	0.01	3.2%
16	9	10%	1947	164	5.0	293	0.36	93%	0.05	0.4%
17	10	8%	2275	599	4.0	537	0.56	86%	0.04	4.3%
18	11	5%	2275	150	4.8	280	0.29	94%	0.03	0.4%
19	12	5%	2275	450	5.0	426	0.24	95%	0.04	4.3%
20	13	5%	2275	300	4.8	357	0.11	98%	0.02	0.9%
Composite Results					4.6		0.27	94%	0.03 *	2.2% *

					Base	Adsorber				
EPA	AVL	AVL	Speed	Torque	BSNOx	Inlet T	BSNOx	NOx Red	HC *	FE Impact
Mode	Mode	Weighting	(rpm)	(lb-ft)	(g/hp-hr)	(C)	(g/hp-hr)		(g/hp-hr)	*
1	1	42%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
2	2	8%	987	86	8.80	162	0.56	94%	2.11	1.8%
3	3	3%	1157	261	8.40	355	0.30	96%	0.16	0.3%
4	4	4%	1344	435	5.90	446	0.09	98%	0.23	0.9%
5	5	10%	2500	94	5.50	263	0.66	88%	0.25	1.6%
6	6	12%	2415	228	4.60	346	0.11	98%	0.03	0.4%
7	7	12%	2415	394	4.90	403	0.05	99%	0.02	1.4%
8	8	9%	2313	567	4.10	544	0.73	82%	0.35	4.0%
Composite Results					4.9		0.33	93%	0.19 *	2% *

* HC results & FE Impacts do not reflect future potential as they are derived using a 5 g NOx engine which requires more frequent NOx regens than would result using a 2.5 g engine and the tested system was not a fully optimized engine & emission control system.

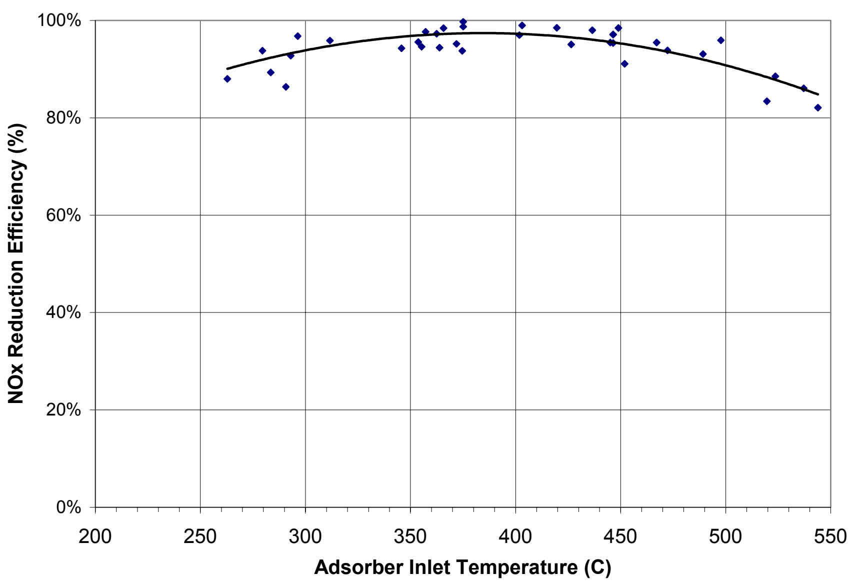


Figure 4.1-11. SET & AVL Composites, and Temperature vs. NOx Chart for Adsorber B

					Base	Adsorber				
EPA Mode	SET Mode	SET Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	15%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
9	2	8%	1619	630	4.60	451	0.18	96%	0.07	1.3%
10	3	10%	1947	328	4.70	356	0.14	97%	0.15	1.7%
11	4	10%	1947	493	5.00	400	0.09	98%	0.05	1.6%
12	5	5%	1619	332	5.00	377	0.07	99%	0.01	1.2%
13	6	5%	1619	498	5.00	431	0.11	98%	0.02	1.6%
14	7	5%	1619	166	5.50	305	0.23	96%	0.14	2.3%
15	8	9%	1947	630	4.00	501	0.16	96%	0.04	2.1%
16	9	10%	1947	164	5.00	303	0.15	97%	0.14	3.1%
17	10	8%	2275	599	4.00	489	0.93	93%	0.09	1.7%
18	11	5%	2275	150	4.80	278	0.57	88%	0.18	3.5%
19	12	5%	2275	450	5.00	391	0.12	98%	0.10	1.8%
20	13	5%	2275	300	4.80	330	0.21	96%	0.09	2.9%
Composite Results					4.6		0.28	94%	0.08 *	1.9% *

					Base	Adsorber				
EPA Mode	AVL Mode	AVL Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	42%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
2	2	8%	987	86	8.80	162	0.56	94%	2.11	1.8%
3	3	3%	1157	261	8.40	359	0.08	99%	0.30	3.1%
4	4	4%	1344	435	5.90	427	0.14	98%	0.19	1.7%
5	5	10%	2500	94	5.50	273	1.25	77%	0.26	6.4%
6	6	12%	2415	228	4.60	301	0.52	89%	0.13	1.9%
7	7	12%	2415	394	4.90	363	0.66	87%	0.04	1.4%
8	8	9%	2313	567	4.10	493	0.31	92%	0.08	1.6%
Composite Results					4.9		0.51	90%	0.14 *	1.9% *

* HC results & FE Impacts do not reflect future potential as they are derived using a 5 g NOx engine which requires more frequent NOx regens than would result using a 2.5 g engine and the tested system was not a fully optimized engine & emission control system.

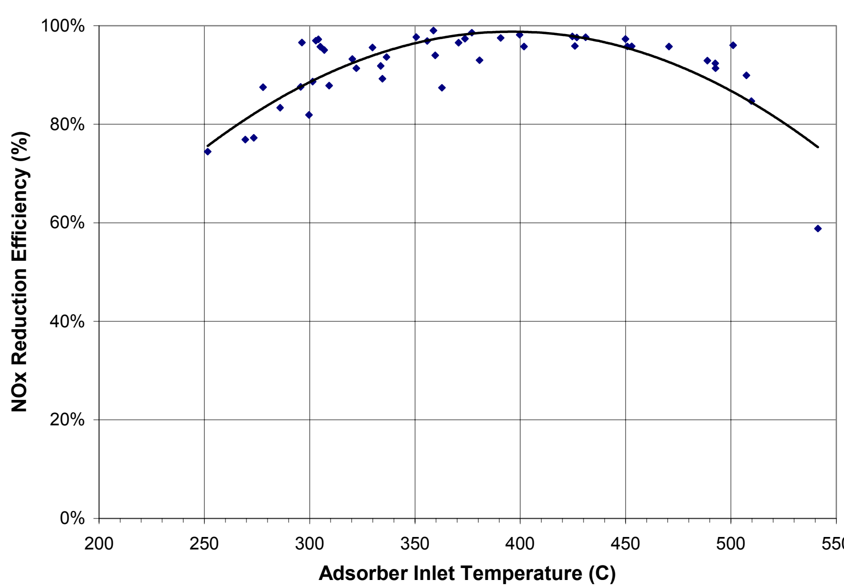


Figure 4.1-12. SET & AVL Composites, and Temperature vs. NOx Chart for Adsorber D

					Base	Adsorber				
EPA Mode	SET Mode	SET Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	15%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
9	2	8%	1619	630	4.60	455	0.47	89%	0.02	2.1%
10	3	10%	1947	328	4.70	343	0.07	98%	0.05	0.9%
11	4	10%	1947	493	5.00	442	0.36	93%	0.07	9.0%
12	5	5%	1619	332	5.00	377	0.08	98%	0.01	1.5%
13	6	5%	1619	498	5.00	419	0.29	94%	0.03	1.6%
14	7	5%	1619	166	5.50	412	0.14	98%	0.05	1.7%
15	8	9%	1947	630	4.00	392	0.05	99%	0.02	2.1%
16	9	10%	1947	164	5.00	294	0.09	98%	0.26	4.4%
17	10	8%	2275	599	4.00	492	0.95	76%	0.03	2.0%
18	11	5%	2275	150	4.80	388	0.11	98%	0.03	2.4%
19	12	5%	2275	450	5.00	391	0.12	98%	0.10	1.8%**
20	13	5%	2275	300	4.80	327	0.22	95%	0.02	1.4%
						** Md 19 data from Adsorber D				
		Composite Results			4.6		0.33	93%	0.05 *	2.9% *

					Base	Adsorber				
EPA Mode	AVL Mode	AVL Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	Inlet T (C)	BSNOx (g/hp-hr)	NOx Red	HC * (g/hp-hr)	FE Impact *
1	1	42%	Idle	0	13.00	144	0.16	100%	0.00	0.0%
2	2	8%	987	86	8.80	166	7.39	16%	1.02	71.9%
3	3	3%	1157	261	8.40	339	0.09	99%	0.05	2.3%
4	4	4%	1344	435	5.90	449	0.65	89%	0.01	2.1%
5	5	10%	2500	94	5.50	256	1.36	75%	0.91	15.8%
6	6	12%	2415	228	4.60	313	0.35	92%	0.21	5.6%
7	7	12%	2415	394	4.90	372	0.12	97%	0.10	2.6%
8	8	9%	2313	567	4.10	508	1.39	66%	0.04	3.3%
		Composite Results			4.9		0.80	84%	0.16 *	5.4% *

* HC results & FE Impacts do not reflect future potential as they are derived using a 5 g NOx engine which requires more frequent NOx regens than would result using a 2.5 g engine and the tested system was not a fully optimized engine & emission control system.

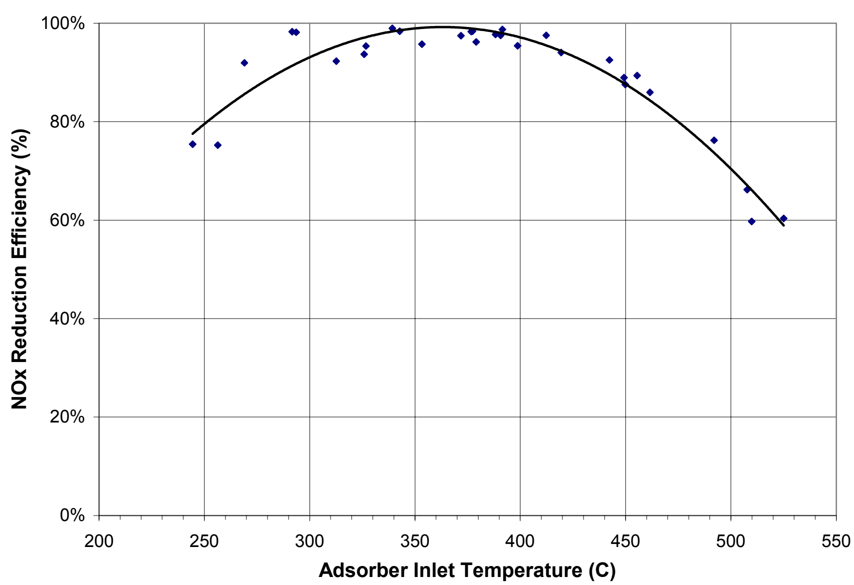


Figure 4.1-13. SET & AVL Composites, and Temperature vs. NOx Chart for Adsorber E

Testing Goals—Dual-Leg NOx Adsorber System

After completing the screening process and selecting NOx adsorber "B," the dual-leg system was developed. The dual-leg system was first tested on the same ISB engine as was used for the single-leg testing. The results from that portion of the testing were similar to the single-leg results (i.e., >90 percent NOx reductions for most test modes) and were reported in the HD2007 Regulatory Impact Analysis.[95] Subsequent testing of the NOx adsorber system was made at NVFEL but with a new ISB engine that had been upgraded to include nonroad Tier 3 type technologies, such as common rail fuel injection and cooled EGR. The change in engine technology led to significantly lower engine-out emissions (similar to the levels expected for 2004 highway engines Tier 3 nonroad engines) and to different exhaust gas temperature characteristics. As a result of the engine changes, the overall system performance was improved on both the steady-state test points and on the transient highway FTP cycle.[96] As discussed further in Section 4.1.3.1.2 below, performance over the NRTC is projected to be better than for the highway FTP cycle. Also, as can be seen in Figure 4.1-9 above, the SET steady-state test points are not significantly different from the ISO C1 test points (to which nonroad engines would be subject). Emission reductions are therefore expected to be similar.

Testing Approach—Dual-Leg NOx Adsorber System

The steady-state SET testing was conducted in a manner similar to that used in the screening process described above. The modes were run with varying levels of automation, with the general strategy being to inject sufficient fuel during regeneration to obtain a lambda at or slightly fuel-rich of stoichiometric ($\lambda \leq 1$). The NOx regenerations were then timed to achieve the targeted 90 percent NOx reduction. The regeneration control and optimization strategies are described in more detail in an SAE paper included in the docket for this rule.[97]

Transient regeneration control over the highway FTP cycle was accomplished using a time-based regeneration schedule. This control regenerated on a prescribed schedule of time and fuel quantities, so regenerations occurred at predetermined engine conditions during the transient cycle.

The emission results presented here are only for hot-start portions of the highway FTP cycle. The adsorber system was not optimized for cold-start performance and does not provide a meaningful assessment of adsorber warmup performance. To better simulate the "cold-soak-hot" procedure called for in highway FTP cycle, a preconditioning mode was chosen to provide adsorber temperatures at the start of the "hot" cycle similar to those found following the "cold-soak" portion of the test. The mode chosen was EPA mode 10 (1947 rpm, 328 lb-ft), which resulted in adsorber inlet temperatures (i.e., at the outlet of the CDPF) at the start of the hot cycle of about 280°C. Another purpose for the preconditioning was to ensure the adsorbers were in the same condition at the start of each test. Given that our regeneration control system did not automatically take into account the starting condition of the NOx adsorbers, this preconditioning was necessary to provide repeatable transient test results.

Test Results—Dual-Leg NOx Adsorber System

The highway SET is made up of the 13 Euro III modes. Several modes were run twice by different engineers, and the best calibration was chosen for the SET composite. Table 4.1-7 shows the SET composite test results. These data show that 90 percent NOx reductions were possible over the SET composite, with a modal NOx reduction range from 89 percent to nearly 100 percent. The adsorber NOx and HC reduction performance varied primarily as a function of exhaust temperature.

Table 4.1-7 SET Results for Dual-Leg System at NVFEL

Modal and composite SET NOx and HC emissions results for the Modified Cummins ISB engine.

Modified Cummins ISB (HPCR, cooled EGR)						Modified Cummins ISB (Baseline + CDPF and NOx adsorber catalysts)				
SET Mode	SET Weighting	Speed (rpm)	Torque (lb-ft)	BSNOx (g/hp-hr)	BSHC (g/hp-hr)	Outlet T (°C)	BSNOx (g/hp-hr)	NOx (%-Reduction)	BSHC (g/hp-hr)	Reductant FE Impact (%)*
1	15%	Idle	0	6.95	6.77	144	0.16	100%	0.00	0.0%
2	8%	1649	633	3.10	0.08	529	0.33	89%	0.03	1.6%
3	10%	1951	324	1.79	0.21	403	0.06	96%	0.01	1.0%
4	10%	1953	490	1.98	0.12	486	0.07	96%	0.02	1.3%
5	5%	1631	328	1.90	0.22	403	0.10	95%	0.01	0.9%
6	5%	1626	496	2.35	0.09	504	0.07	97%	0.02	1.6%
7	5%	1623	161	2.05	0.56	313	0.02	99%	0.03	0.9%
8	9%	1979	609	2.09	0.08	524	0.19	91%	0.03	1.7%
9	10%	1951	159	1.68	0.49	323	0.01	100%	0.02	0.8%
10	8%	2348	560	1.95	0.11	524	0.10	95%	0.04	2.3%
11	5%	2279	145	1.66	0.57	306	0.01	99%	0.02	0.7%
12	5%	2275	447	1.84	0.14	465	0.10	95%	0.01	0.9%
13	5%	2274	296	1.76	0.25	400	0.03	98%	0.01	0.9%
SET Weighted Composite Results:				2.10	0.17		0.12	94%	0.03	1.4%**

Notes:
* Fuel economy impact of fuel-reductant addition for NOx adsorber regeneration.
** Increased exhaust restriction from the wall-flow and flow through monoliths results in a further FE impact of approximately 1-2% over the SET composite.

The fuel economy impact was defined as the percent increase in fuel consumption caused by the adsorber regeneration fuel, or the mass of fuel used for regeneration, divided by the mass of fuel consumed by the engine during one regeneration and adsorption cycle. The fuel economy impact varied from virtually zero to 2.3 percent depending on the mode with a composite fuel economy impact of 1.4 percent. We anticipate significant improvements in regeneration strategies are possible with different system configurations. Also, changes in engine operation designed to increase exhaust temperatures, not attempted in this work, can provide substantial improvements in catalyst performance and potentially a lower fuel economy impact.

Test Results over the Highway FTP Cycle

As with the steady-state test results, the test results over the hot-start portion of the highway FTP cycle showed NOx and PM emission reductions greater than 90 percent. The baseline (without the catalyst system) NOx emissions of 2.7 g/hp-hr were reduced to 0.1 g/hp-hr with the addition of the catalyst system, a better than 95 percent reduction in NOx emissions. Similarly, the PM emissions were reduced to below 0.003 g/hp-hr from a baseline level of approximately 0.1 g/hp-hr, a reduction of more than 95 percent. The fuel economy impact associated with regeneration of the NOx adsorber system was measured as 1.5 percent over the highway FTP cycle. The fuel economy impact associated with increased exhaust restriction from the CDPF was less than the measurement variability for the test cycle (i.e., less than 0.5 percent).[98]

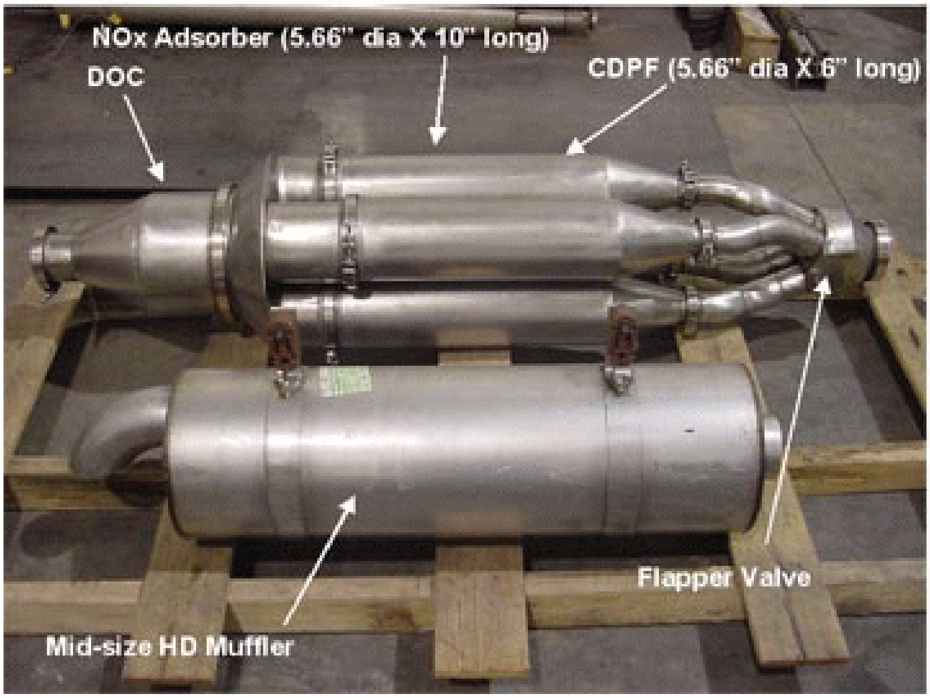
Durability Baseline NOx Adsorber Catalyst Testing

Additional testing was conducted at NVFEL to provide baseline performance data to gauge improvements in NOx adsorber durability performance in support of the HD2007 technology reviews. The data provide a look at the state of adsorber technology in 2001, with a glimpse of improvements that will be made in the future and is documented in a SAE paper.[99] It is clear from the analysis that there were vast differences in the durability performance of the formulations over these short tests. Adsorber suppliers were early on in their development and rapid improvements were being made. Two adsorbers representing one company's progress over two years showed significantly better aging performance (i.e., less degradation over time). This performance was evidenced by its NO_x adsorbing and regeneration performance after 100 hours.[100] In support of the U.S. EPA's continuing effort to monitor NO_x adsorber progress, new formulations are continuing to be evaluated.

Development of a Four "Leg" System Design

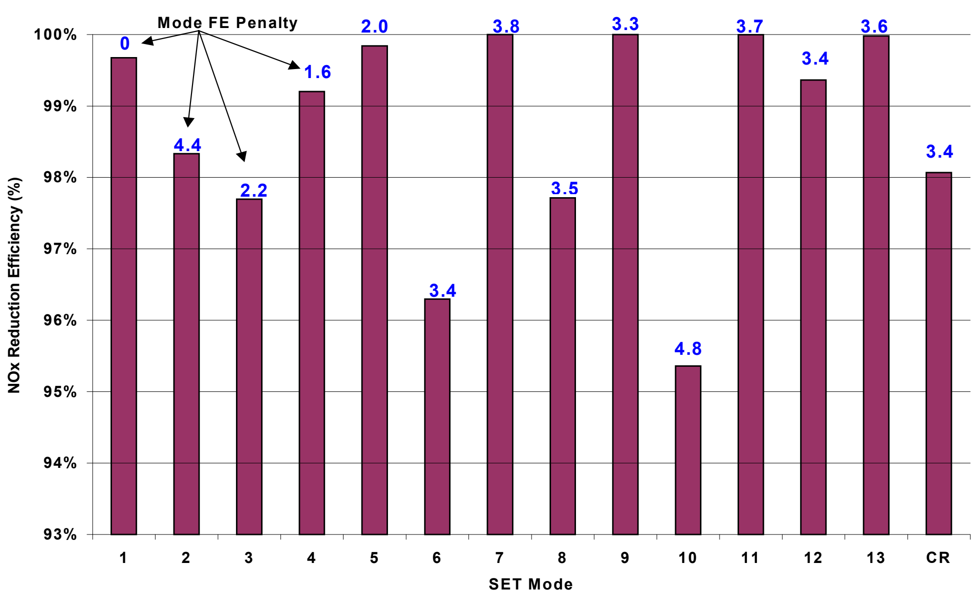
At NVFEL, developments have continued on methods and system designs for NOx adsorber catalyst technologies. A novel four-leg NOx adsorber/PM trap system was developed as an evolution of the proof-of-concept two-leg system that was used for previous testing at NVFEL (the system used in the test results reported here). The four-leg system has a catalyst volume that is less than half of the volume of the two-leg system. This allows the four-leg system to be packaged in a volume not much larger than a muffler for a medium heavy duty truck application as can be seen in Figure 4.1-14. Efforts have also been made to reduce the cost of the system by using simpler injectors and valve actuators.

Figure 4.1 -14 Prototype 4-leg System Compared with a Truck Muffler



Initial testing indicates that the four-leg system at least matches the previous two-leg systems NOx reduction efficiency with similar fuel consumption as can be seen in Figure 4.1-15. Note that the results shown in the figure are based upon the NOx sensor data used in the control system. Work is underway to confirm these steady-state results and to demonstrate the performance over transient cycles.

Figure 4.1-15 Preliminary Results for Prototype Four-Leg System



4.1.2.3.5.3 Department of Energy (DOE) Test Programs

The U.S. Department of Energy (DOE) has funded several test programs at national laboratories and in partnership with industry to investigate the NOx adsorber technology. Most of these test programs are part of the Advanced Petroleum Based Fuel (APBF) program of DOE's Office of Transportation Technology (OTT). The initial phases of the programs are often referred to as the Diesel Emission Control Sulfur Effects (DECSE) program, which are part of the APBF programs. Five reports documenting the DECSE program are available from the DOE OTT website (www.ott.doe.gov/decse) and were used extensively throughout our analysis.[101,102,103 104,105]

In the DECSE program, an advanced diesel engine equipped with common rail fuel injection and exhaust gas recirculation (EGR) was combined with a NOx adsorber catalyst to control NOx emissions. The system used an in-cylinder control approach. Rich regeneration conditions are created for the NOx adsorber catalyst regeneration through increased EGR rates and a secondary injection event designed to occur late enough in the engine cycle so as not to change engine torque output. Using this approach, the DECSE program has shown NOx conversion efficiencies exceeding 90 percent over a catalyst inlet operating temperature window of 300˚C to 450˚C. This performance level was achieved while staying within the four percent fuel economy penalty target defined for regeneration calibration.[106]

Subsequent work organized under the APBF program is commonly referred to as the APBF-Diesel Emission Control program, or APBF-DEC. The ongoing APBF-DEC work includes additional phases to develop prototype CDPF/NOx adsorber systems for a heavy-duty truck, a large sport utility vehicle and a passenger car. The program is looking at all important issues related to the technology including, packaging systems, effective regeneration, emission performance and durability.[107]

4.1.2.3.5.4 Heavy-Duty Engine Manufacturers

Heavy-duty diesel engine manufacturers (highway manufacturers) are currently developing systems to comply with the HD2007 emission standards including the NOx adsorber technology. As noted in EPA's Highway Diesel Progress Review Report 2, which documents in more detail progress by the highway diesel engine industry to develop CDPF and NOx adsorber technology, the progress to develop these emission-control systems is progressing rapidly. Although much of the work being done is protected as confidential business information, a recent public presentation by Daimler Chrysler Powersystems is illustrative some of the work that has been done prior to 2003.[108] The presentation reviews three possible system configurations for a combined CDPF / NOx adsorber system and compares the trade-offs among the approaches. Similar to the results shown in Section 4.1.2.3.5.3 by EPA, a dual-leg system demonstrated 90 percent or higher NOx emission control over a wide range of operation.

Two Japanese truck manufacturers, Toyota and Hino have recently introduced light heavy-duty diesel trucks in Japan using the Toyota developed Diesel Particulate NOx Reduction

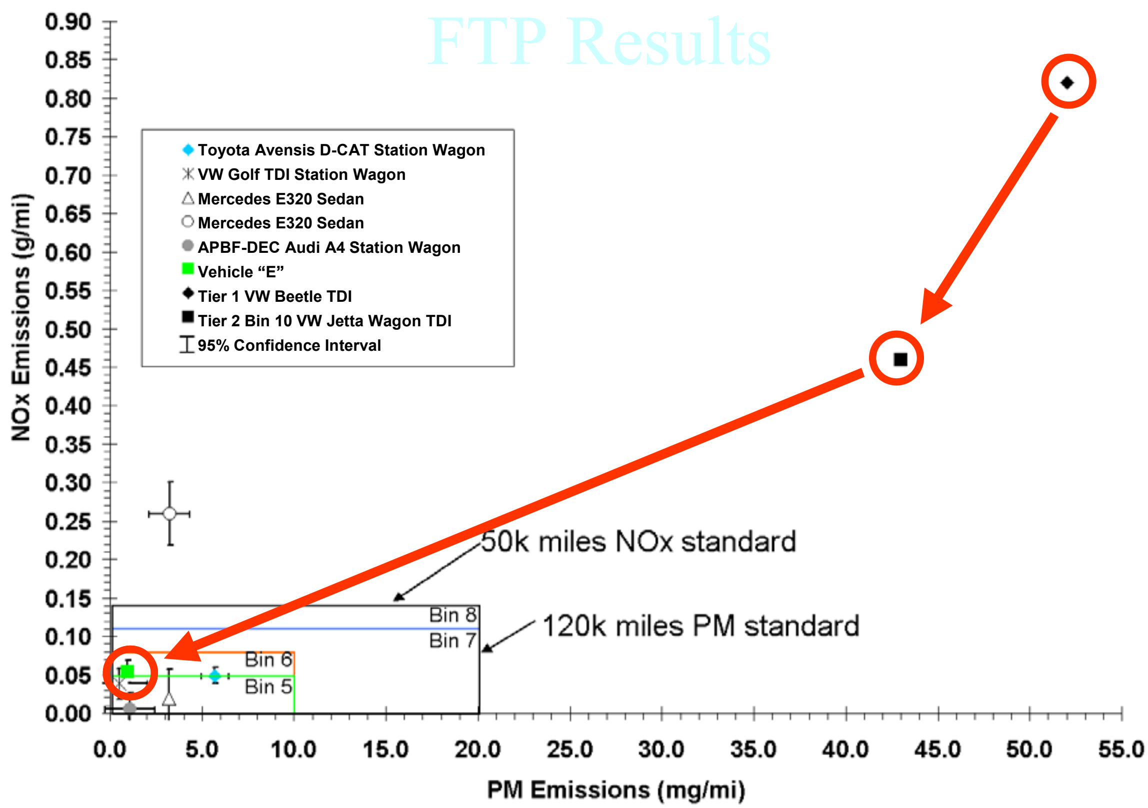
(DPNR) catalyst system. The DPNR system described in a light-duty application in our 2002 Highway Diesel Progress Review, consists of a diesel particulate filter with NOx storage catalyst coated onto the PM filter substrate. In some applications, the system can be further enhanced with the addition of an oxidation catalyst and an additional NOx adsorber catalyst applied to a conventional flow through catalyst substrate. The new trucks introduced in Japan, the Toyota Dyna and the Hino Dutro are commonly used as urban delivery vehicles and as refuse hauling vehicles.

In July 2003, EPA engineers visited Toyota's Higashifuji Technical Center in Japan to participate in testing of the engine and DPNR catalyst system being introduced later in the year as the Toyota Dyna product. EPA participated in several days of testing and reviewed detailed technical information regarding the emission control system and its potential for further development. The information shared with EPA in that test program was designated as confidential business information by Toyota. However, Toyota has published a relatively detailed SAE paper in Japan describing the system and its performance.[109] The paper summarizes the demonstrated emission reduction of the vehicle as aged to an estimated 250,000 kilometers with NOx emissions controlled below 0.5 g/bhp-hr and PM emissions controlled below 0.01 g/bhp-hr.

4.1.2.3.5.5 Light-Duty Diesel Vehicle Manufacturers

Diesel passenger car manufacturers are developing emission-control systems using NOx adsorbers and PM filters in a combined control strategy to meet upcoming Euro IV emission standards for larger passenger cars and sedans in Europe and the light-duty Tier 2 emission standards in the United States. EPA has tested five prototype diesel passenger cars with these technologies over the last year and a half. The results shown in Figure 4.1-16 demonstrate the potential for substantial reductions with NOx adsorber and PM filter technologies when tested with low-sulfur diesel fuel. All five vehicles demonstrated substantial reductions in NOx and PM emissions when compared with a current relatively clean (compared with only a few years ago) diesel passenger cars as represented by the solid black diamond and solid black square in Figure 4.1-16.[110]

Figure 4.1-16 Tier 2 Passenger Car Prototypes Tested at NVFEL on the FTP75 Cycle



One vehicle in the test program, the Mercedes E320, was tested with both new catalyst hardware and aged catalyst hardware. The aged catalyst had experienced the equivalent of the 100,000 km of aging. The aged test results show that the aged catalyst system has lost some amount of NOx storage volume, causing the NOx emissions to breakthrough as the catalyst fills with NOx prior to the periodic NOx regenerations. In this testing, the NOx regeneration period was fixed for the new and aged catalyst at the same interval. It appears from the data that the regeneration interval for the fresh catalyst was too infrequent for the aged catalyst, which had a reduced NOx-storage volume. At the very low NOx emission levels shown in the figure, it takes only a very small breakthrough in NOx emissions to significantly increase the emissions over the lowest control levels. Manufacturers are currently working to keep the number of regeneration episodes to the minimum number to minimize stress on catalyst materials (i.e., limit thermal degradation as discussed in Section 4.2 above). We believe manufacturers are continuing to develop more heat-resistant materials that will reduce overall aging of the catalyst. If such materials had been available at this time, we believe the NOx results for the aged vehicle would have been better. Note however, that the PM emissions show no deterioration for the aged system compared with the new system.

The most recently tested vehicle, vehicle "E" was tested after aging of the catalyst system to the equivalent of 50,000 miles of vehicle operation. The emissions results even after this extended aging where very good demonstrating NOx emission levels below 0.07 g/mile and PM emissions below 0.01 g/mile. Relative to vehicle "D" this demonstrates substantial progress by manufacturers to improve the overall durability of NOx adsorber catalysts.

4.1.2.4 Selective Catalytic Reduction (SCR) Technology

Another NOx catalyst-based emission-control technology is selective catalytic reduction (SCR). SCR catalysts require a reductant, ammonia, to reduce NOx emissions. Because of the significant safety concerns with handling and storing ammonia, most SCR systems make ammonia within the catalyst system from urea. Such systems are commonly called urea SCR systems. Throughout this document, the term SCR and urea SCR may be used interchangeably and should be considered as referring to the same urea-based catalyst system. With the appropriate control system to meter urea in proportion to engine-out NOx emissions, urea SCR catalysts can reduce NOx emissions by over 90 percent for a significant fraction of the diesel engine operating range.[111] Although EPA has not done an extensive analysis to evaluate its effectiveness, we believe it may be possible to reduce NOx emissions with a urea SCR catalyst to levels consistent with compliance with Tier 4 NOx standards.

We have significant concerns regarding a technology that requires extensive user intervention to function properly and the lack of the urea delivery infrastructure necessary to support this technology. Urea SCR systems consume urea in proportion to the engine-out NOx rate. The urea consumption rate can be on the order of five percent of the engine fuel consumption rate. Unless the urea tank is prohibitively large, the urea must therefore be replenished frequently. Most urea systems are designed to be replenished every time fuel is added or at most every few times that fuel is added. There is not a system in place today to deliver or dispense automotive-grade urea to diesel fueling stations. One study conducted for the National Renewable Energy Laboratory (NREL), estimated that if urea were to be distributed to every diesel fuel station in the United States, the cost would be more than $30 per gallon.[112]

We are not aware of a proven mechanism that ensures that the user will replenish the urea supply as necessary to maintain emission-control performance. Further, we believe that, given the additional cost for urea, there will be significant disincentives for the end-user to replenish the urea because the cost of urea can be avoided without equipment performance loss. See *NRDC v. EPA*, 655 F. 2d 318, 332 (D.C. Cir. 1981) (referring to "behavioral barriers to periodic restoration of a filter by a [vehicle] owner" as a valid basis for EPA considering a technology unavailable). Due to the lack of an infrastructure to deliver the needed urea, and the lack of a track record of successful ways to ensure urea use, we have concluded that the urea SCR technology is not likely to be available for general use in the time frame of the Tier 4 standards. We have therefore not based the feasibility or cost analysis of this emission-control program on the use or availability of the urea SCR technology. However, we do not preclude its use for compliance with the emission standards, provided that a manufacturer can demonstrate satisfactorily that the engine will use urea under all conditions. We believe that consistent use of urea can only be ensured only for a few unique installations and therefore believe it is inappropriate to base a national emission-control program on a technology that can effectively serve only in a few niche applications.

This section has described several technologies that can reduce emissions from diesel engines. The following section describes the challenges to applying these diesel engine technologies to engines and equipment designed for nonroad applications.

4.1.3 Can These Technologies Be Applied to Nonroad Engines and Equipment?

The emission standards and the introduction dates for those standards, as described earlier in Section III of the preamble, are premised on the transfer of diesel engine technologies being, or already developed, to meet light-duty and heavy-duty vehicle standards that begin in 2007. The Tier 4 aftertreatment based standards for engines from 75-750 hp will begin to go into effect four years later. This time lag between equivalent highway and nonroad diesel engine standards is necessary to allow time for engine and equipment manufacturers to further develop these highway engine technologies for nonroad engines and to align this program with nonroad Tier 3 emission standards that begin to go into effect in 2006.

The test procedures and regulations for the HD2007 highway engines include a transient test procedure, a broad steady-state procedure and NTE provisions that require compliant engines to emit at or below 1.5 times the regulated emission levels under virtually all conditions. An engine designed to comply with the HD2007 emission standards will meet the Tier 4 standards if it is tested over the transient and steady-state duty cycles specified in the final rule, which cover the same regions and types of engine operation. Said in another way, a highway diesel engine produced in 2007 may be certified in compliance with the transient and steady-state standards in this final rule for nonroad diesel engines several years in advance of the date when these standards are scheduled to go into effect. However, that engine, while compliant with certain of the nonroad emission standards, would not necessarily be designed to address the various durability and performance requirements of many nonroad equipment manufacturers. We expect that the engine manufacturers will need additional time to further develop the necessary emission-control systems to address some of the nonroad issues described below as well as to develop the appropriate calibrations for engine rated speed and torque characteristics required by the diverse range of nonroad equipment. Furthermore, not all nonroad engine manufacturers produce highway diesel engines or produce nonroad engines that are developed from highway products. There is therefore a need for lead time between the Tier 3 emission standards, which go into effect in 2006-2008, and the Tier 4 emission standards. We believe the technologies developed to comply with the Tier 3 emission standards such as improved air handling systems and electronic fuel systems will form an essential technology baseline that manufacturers will need to initiate and control the various regeneration functions required of the catalyst-based technologies for Tier 4. The Agency has given consideration to all these issues in setting the levels and timing of the Tier 4 emission standards.

This section presents some of the challenges of applying advanced emission-control technologies to nonroad engines and equipment and describes why we believe technologies developed for highway diesel engines can be further refined to address these issues in a timely manner for nonroad engines consistent with the Tier 4 emission standards.

4.1.3.1 Nonroad Operating Conditions and Exhaust Temperatures

Nonroad equipment is highly diverse in design, application, and typical operating conditions. This variety of operating conditions affects emission-control systems through the resulting variation in the torque and speed demands (i.e., power demands). This wide range in what constitutes typical nonroad operation makes the design and implementation of advanced emission-control technologies more difficult. The primary concern for catalyst-based emission-control technologies is exhaust temperature. In general, exhaust temperature increases with engine power and can vary dramatically as engine power demands vary.

For most catalytic emission-control technologies there is a minimum temperature below which the chemical reactions necessary for emission control do not occur. The temperature above which substantial catalytic activities is realized is often called the light-off temperature. For gasoline engines, the light-off temperature is typically important only in determining cold-start emissions. Once gasoline vehicle exhaust temperatures exceed the light-off temperature, the catalyst is "lit-off" and remains fully functional under all operating conditions. Diesel exhaust is significantly cooler than gasoline exhaust due to the diesel engine's higher thermal efficiency and its operation under predominantly lean conditions. Absent control action taken by an electronic engine control system, diesel exhaust may fall below the light-off temperature of catalyst technology even when the engine is fully warmed up.

The relationship between the exhaust temperature of a nonroad diesel engine and light-off temperature is an important factor for both CDPF and NOx adsorber technologies. For the CDPF technology, exhaust temperature determines the rate of filter regeneration and if too low causes a need for supplemental means to ensure proper filter regeneration. In the case of the CDPF, it is the aggregate soot regeneration rate that is important, not the regeneration rate at any particular moment in time. A CDPF controls PM emissions under all conditions and can function properly (i.e., not plug) even when exhaust temperatures are low for an extended time and the regeneration rate is lower than the soot accumulation rate, provided that occasionally exhaust temperatures and thus the soot regeneration rate are increased enough to regenerate the CDPF. A CDPF can passively (without supplemental heat addition) regenerate if exhaust temperatures remain above 250°C for more than 40 percent of engine operation.[113] Similarly (and as discussed in more detail earlier), there is a minimum temperature (e.g., 200°C) for NOx adsorbers below which NOx regeneration is not readily possible and a maximum temperature (e.g., 500°C) above which NOx adsorbers are unable to effectively store NOx. These minimum and maximum temperatures define a characteristic temperature window of the NOx adsorber catalyst. When the exhaust temperature is within the temperature window (above the minimum and below the maximum) the catalyst is highly effective. When exhaust temperatures fall outside this window of operation, NOx adsorber effectiveness is diminished. There is therefore a need to match diesel exhaust temperatures to conditions for effective catalyst operation under the various operating conditions of nonroad engines.

Although the range of products for highway vehicles is not as diverse as for nonroad equipment, the need to match exhaust temperatures to catalyst characteristics is still present. This is a significant concern for highway engine manufacturers and has been a focus of our ongoing diesel engine progress review. There we have learned that substantial progress is being made to broaden the operating temperature window of catalyst technologies, while at the same time, engine systems are being designed to better control exhaust temperatures. Highway diesel engine manufacturers are working to address this need through modifications to engine design, modifications to engine control strategies and modifications to exhaust system designs. Engine design changes including the ability for multiple late fuel injections and the ability to control total air flow into the engine give controls engineers additional flexibility to change exhaust temperature characteristics. Modifications to the exhaust system, including the use of insulated exhaust manifolds and exhaust tubing, can help to preserve the temperature of the exhaust gases. New engine control strategies designed to take advantage of engine and exhaust system modifications can then be used to manage exhaust temperatures across a broad range of engine operation. The technology solutions being developed for highway engines to better manage exhaust temperature are built upon the same emission-control technologies (i.e., advanced air handling systems and electronic fuel-injection systems) that we expect nonroad engine manufacturers to use for meeting the Tier 3 emission standards.

4.1.3.1.1 CDPFS and Nonroad Operating Temperatures

EPA has conducted a screening analysis to better understand the effect of engine operating cycles and engine power density on exhaust temperatures, specifically to see if passive CDPF regeneration can be expected under all conditions for nonroad engine applications. Our approach for assessing the likelihood of passive regeneration by a CDPF is based on what we learned from the literature as well as information submitted by various catalyst manufacturers for product verification to our voluntary diesel retrofit program.

For this analysis three representative nonroad engines were tested. The engines are described in Table 4.1-8. In the case of the Cummins engine, the testing was done at three different engine ratings (250hp, 169hp, and 124hp) to evaluate the effect of engine power density on expected exhaust temperatures and therefore the likelihood of passive PM filter regeneration.

Table 4.1-8
Engines Tested to Evaluate PM Filter Regeneration

Engine Model	Model Year	Displacement (L)	Cylinder Number	Rated Power (hp)	Air Induction	Engine Type
Lombardini LDW1003-FOCS	2001	1.0	3	26	naturally aspirated	IDI
Kubota V2203-E	1999	2.2	4	50	naturally aspirated	IDI
Cummins ISB	2000	5.9	6	260	turbocharged intercooled	DI

As described in 4.1.1.3 above, passive filter regeneration occurs when the exhaust temperatures are high enough that on aggregate the PM accumulation rate on the filter is less than the PM oxidation rate on the filter over an extended time period. During that time period there can be periods of low-temperature operation where the PM accumulation rate is higher than the oxidation rates, provided that there are other periods of higher temperature operation where the PM oxidation rate is significantly higher than the accumulation rate. CDPF manufacturers provide guidelines for CDPF applications where passive regeneration is necessary (i.e., no provision for occasional active regeneration is provided). These guidelines are based on the cumulative amount of typical engine operation above and below a particular exhaust temperature. One CDPF manufacturer has stated that passive regeneration will occur if temperatures exceed 250ºC for more than 30 percent of engine operation.[114] Another CDPF manufacturer has stated that catalyzed diesel particulate filters will work properly in the field if the engine exhaust temperature is at least 250-275ºC for about 40-50 percent of the duty cycle.[115]

EPA used the more restrictive of these guidelines to evaluate the likelihood that passive regeneration will during typical nonroad operating cycles. To do this, the exhaust temperatures collected from testing each engine on various nonroad transient duty cycles were sorted in an ascending order. Upon sorting, we identified the 50th and 60th percentile mark of the temperature obtained for a transient cycle run, which lasted anywhere between 8 to 20 minutes for an entire cycle duration. The temperatures associated with the 50th and 60th percentile mark correspond to the minimum temperatures for 50 and 40 percent of the duty cycle, respectively. In addition, we also calculated the average temperature obtained throughout a given cycle.

Tables 4.1-9, 4.1-10, and 4.1-11 show the 50th and 60th percentile temperatures representing the minimum temperatures for 50% and 40% of the duty cycle, respectively. The tables show that the 60th percentile temperature exceeded 250˚C for most of the engine tests on all three engines. The runs that did not result in at least 250˚C for 40% of the duty cycle were from the highway FTP cycle for the two small engines, and from the backhoe cycle for the lowest power rating, i.e., 124 hp, on the Cummins ISB engine.

Table 4.1-9
Engine-out Exhaust Gas Temperature Data - 124, 163, 260 hp Cummins ISB

Cycle		Average T (ºC)	50th %tile T (ºC)	60th %tile T (ºC)	Operation at T m 275ºC
Agricultural Tractor	260 hp (test #1454)	418	444	452	92%
	124 hp (test #1518)	319	336	339	89%
Wheel Loader	260 hp (test #1449)	295	323	295	57%
	169 hp (test #1530)	264	277	311	50%
	124 hp (test #1526)	221	222	258	29%
Backhoe	260 hp (test #1455)	261	280	303	52%
	169 hp (test #1528)	236	238	254	24%
	124 hp (test #1523)	185	194	201	0%
JRC Composite	260 hp (test #1660)	311	323	337	75%
	260 hp (test #1661)	317	326	339	78%
	169 hp (test #1529)	289	290	304	61%
	124 hp (test #1525)	252	243	265	37%

Table 4.1-10
Engine-out Exhaust Gas Temperature Data - 50 hp Kubota V2203E

Cycle	Average T (ºC)	50th %tile T (ºC)	60th %tile T (ºC)	Operation at T m 275ºC
Agricultural Tractor	518	544	561	96%
Nonroad Composite	289	286	310	56%
Skid Steer Loader	259	257	268	34%
Federal Test Procedure	232	210	238	30%

Table 4.1-11
Engine-out Exhaust Gas Temperature Data - 26 hp Lombardini LDW1003

Cycle	Average T (ºC)	50th %tile T (ºC)	60th %tile T (ºC)	Operation at T m 275ºC
Arc Welder	262	257	263	26%
Nonroad Composite	274	271	290	48%
Skid Steer Loader	243	239	252	24%
Federal Test Procedure	177	148	175	15%
Agricultural Tractor	516	548	554	97%

The results shown here lead us to conclude that, for a significant fraction of nonroad diesel engine operation, exhaust temperatures are likely to be high enough to ensure passive regeneration of CDPFs. However, the results also indicate that for some operating conditions it may be that passive filter regeneration is not realized. In the case of those operating conditions, we believe that active backup regeneration systems (systems designed to increase exhaust temperature periodically to initiate filter regeneration) can be used to ensure CDPF regeneration. Additional data regarding in-use temperature operation are contained in a recent report from the Engine Manufacturers Association (EMA) and the European Association of Internal Combustion Engine Manufacturers (Euromot).[116] This report contains data from a range of applications and power categories. Similar to the data presented above, the EMA/Euromot data indicate that, while several nonroad applications generate temperatures high enough to passively regenerate a filter, there are also some applications that require active regeneration.

We have assumed in our cost analysis that all nonroad engines complying with a PM standard of 0.03 g/hp-hr or lower (those engines that we are projecting will use a CDPF) will have an active means to control temperature (i.e., we have costed a backup active regeneration system, though some applications may not need one). We have made this assumption believing that manufacturers will not be able to predict, accurately, in-use conditions for every piece of equipment and will thus choose to provide the technologies on a back-up basis. As explained earlier, the technologies necessary to accomplish this temperature management are enhancements of the Tier 3 emission-control technologies that will form the baseline for Tier 4 engines, and the control strategies being developed for highway diesel engines. We believe there are no nonroad engine applications above 25 hp for which these highway engine approaches will not work. However, given the diversity in nonroad equipment design and application, we believe that additional time will be needed to match the engine performance characteristics to the full range of nonroad equipment.

Matching the operating temperature window of the broad range of nonroad equipment may be somewhat more challenging for nonroad engines than for many highway diesel engines simply because of the diversity in equipment design and equipment use. Nonetheless, the problem has been successfully solved in highway applications facing low-temperature performance situations as difficult to address as any encountered faced by nonroad applications. The most challenging temperature regime for highway engines are encountered at very light-loads as typified by congested urban driving. Under congested urban driving conditions exhaust temperatures may be too low for effective NOx reduction with a NOx adsorber catalyst. Similarly, exhaust temperatures may be too low to ensure passive CDPF regeneration. To address these concerns, light-duty diesel engine manufacturers have developed active temperature management strategies that provide effective emissioncontrol even under these difficult light-load conditions. Toyota has shown with their prototype DPNR vehicles that changes to EGR and fuel-injection strategies can realize an increase in exhaust temperatures of more than 50˚C under even very light-load conditions allowing the NOx adsorber catalyst to function under these normally cold exhaust conditions.[117] Similarly, PSA has demonstrated effective CDPF regeneration under demanding light-load taxi cab conditions with current production technologies.[118] Both of these are examples of technology paths available to nonroad engine manufacturers to increase temperatures under light-load conditions.

We are not aware of any in-use operating cycles for nonroad equipment that are more demanding of low-temperature performance than highway urban driving. Both the Toyota and

PSA systems are designed to function even with extended-idle operation typical of a taxi waiting to pick up a fare.[N] By actively managing exhaust temperatures engine manufacturers can ensure highly effective catalyst-based emission-control performance (i.e., compliance with the emission standards) and reliable filter regeneration (failsafe operation) across a wide range of engine operation typical of the broad range of nonroad engine operation in use and the new nonroad transient duty cycle.

The systems described here from Toyota and PSA are examples of highly integrated engine and exhaust emission-control systems based upon active engine management designed to facilitate catalyst function. Because these systems are based upon the same engine control technologies likely to be used to comply with the Tier 3 standards and because they allow great flexibility to trade-off engine control and catalyst control approaches depending on operating mode and need, we believe most nonroad engine manufacturers will use similar approaches to comply with the Tier 4 emission standards. However, there are other technologies available that are designed to be added to existing engines without the need for extensive integration and engine management strategies. One example of such a system is an active DPF system developed by Deutz for use on a wide range on nonroad equipment. The Deutz system has been sold as an OEM retrofit technology that does not require changes to the base engine technology. The system is electronically controlled and uses supplemental in-exhaust fuel injection to raise exhaust temperatures periodically to regenerate the DPF. Deutz has sold over 2,000 of these units and reports that the systems have been reliable and effective. Some manufacturers may choose to use this approach for compliance with the Tier 4 PM standard, especially in the case of engines that may be able to meet the NOx standards with engine-out emission-control technologies (i.e., engines rated between 25 and 75 hp and mobile machines >750 hp).

We believe that, given the timing of the Tier 4 emission standards and the availability and continuing development of technologies to address temperature management for highway engines (whose technologies are transferrable to all nonroad engines with greater than 25 hp power rating), nonroad engines can be designed to meet the emission standards adopted in this final rule in a timely manner.

[N] There is one important distinction between the current PSA system and the kind of system that we project industry will use to comply with the Tier 4 standards: the PSA system incorporates a cerium fuel additive to help promote soot oxidation. The additive serves a similar function to a catalyst to promote soot oxidation at lower temperatures. Even with the use of the fuel additive, passive regeneration is not realized on the PSA system and an active regeneration is conducted periodically involving late cycle fuel injection and oxidation of the fuel on an up-front diesel oxidation catalyst to raise exhaust temperatures. This form of supplemental heating to ensure infrequent but periodic PM filter regeneration has proven to be robust and reliable for more than 500,000 PSA vehicles. Our 2002 progress review found that other manufacturers will be introducing similar systems in the next few years without the use of a fuel additive. One vehicle manufacturer, Renault has recently announced that they will introduce this year a CDPF system on a diesel passenger car that does not rely on an additive to help ensure that regeneration occurs.

4.1.3.1.2 NOx Adsorbers and Nonroad Operating Temperatures

Section 4.1.2.3.3 above describes a method to directionally evaluate the match between the operating temperature characteristics of a diesel engine in typical use and the range of temperatures over which a NOx adsorber catalyst is highly effective, the operating window of the NOx adsorber catalyst technology. The analysis is not effective to accurately predict exact emission results as it does not account for the thermal inertia of the catalyst technologies nor the ability of the NOx adsorber to store NOx at lower temperatures as discussed in more fully in Section 4.1.2.3.3. Nevertheless, this analysis approach can be used to compare predicted performance of an engine with a NOx adsorber catalyst on various test cycles and with various engine configurations.

In this case, we have used this analysis approach to better understand the characteristics of the NRTC and the C1 composite cycle relative to the highway FTP cycle. We have extensive experience testing NOx adsorber catalyst systems on the highway FTP cycle (see discussion above in Section 4.2) showing that NOx reductions in excess of 90% can be expected. Here, we are trying to understand if the NOx performance on the NRTC and the C1 composite cycle should be expected to be better or worse than the highway FTP cycle. To accomplish that, we tested a Cummins ISB (see Table 4.1-8) engine at three different power ratings representative of the range of engine power density currently seen for nonroad diesel engines (250hp, 169hp, and 124hp). Following the technique described in Section 4.1.2.3.3, we estimated a notional NOx adsorber efficiency for the various test cycles and engine power ratings described here. Further, we performed this analysis for several different NOx adsorber mounting locations (i.e., we measured exhaust temperatures at several locations in the exhaust system, a catalyst is not actually installed for this testing). By measuring temperature at several locations, we could further understand the impact of heat loss in the exhaust system on NOx adsorber performance. The results of this testing and analysis are presented in Tables 4.1-12, 4.1-13 and 4.1-14.

Table 4.1-12
Estimated NOx Adsorber Efficiency on Cummins ISB ISO-C1 Composite[a]

Engine Power (hp)	6" from turbo outlet (%)	25" from turbo outlet (%)	4' from turbo outlet (%)	6' 7" from turbo outlet (%)
124	90.5	90.7	90.6	89.8
169	86.2	87.1	88.7	90.8
250	79.5	84.2	85.2	87.9

[a] The estimates are based on the absorber B curve shown in Figure 4.1-11.

Table 4.1-13
Estimated NOx Adsorber Efficiency on Cummins ISB - NRTC Cycle[a]

Engine Power (hp)	6" from turbo outlet (%)	25" from turbo outlet (%)	4' from turbo outlet (%)	6' 7" from turbo outlet (%)
124	85.6	83.9	81.7	77.4
169	93.0	92.2	91.1	88.6
250	91.6	92.9	93.6	93.5

[a] The estimates are based on the absorber B curve shown in Figure 4.1-11.

Table 4.1-14
Estimated NOx Adsorber Efficiency on Cummins ISB - Highway FTP Cycle[a]

Engine Power (hp)	6" from turbo outlet (%)
124	60.3
169	72.4
250	83.0

[a] The estimates are based on the absorber B curve shown in Figure 4.1-11.

Results of the analysis show that for many nonroad engines, the expected exhaust temperatures are well matched for NOx adsorber control giving high NOx conversion efficiencies with today's NOx adsorber technology. The NOx-reduction potential by these devices was higher over nonroad cycles when compared with that achieved from the highway FTP cycle. This higher efficiency obtained from the engine testing results was due to comparatively higher engine-out exhaust temperatures obtained from running on various nonroad transient cycles compared with the highway FTP cycle, thus indicating that the transfer of highway engine technologies developed for the HD2007 emission standards will be able to provide similar or better control for nonroad diesel engines designed to comply with the Tier 4 standards.

4.1.3.1.3 Power Density Trends in Nonroad

An analysis of power density trends in nonroad diesel engines was undertaken to understand what levels of power density to expect in the future for nonroad diesel engines. This analysis included consideration of data from the Power Systems Research 2002 database (PSR). The PSR data includes estimates of nonroad diesel engine model specifications and sales going back at least 20 years. This data set represents the most comprehensive nonroad engine database of this nature available.

This analysis specifically examined trends in power density within various power categories from 1985 to 2000. The PSR database reports both rated power and engine displacement, from which power was calculated.[O] The data were divided into 5 power categories: 70-100 hp; 100 - 175hp; 175 - 300hp, 300 - 600hp, and >600hp. For each power category, a sales-weighted average of power density was calculated for each year. Table 4.1-15 shows the resulting data, as well as the percent change from 1985 to 2000. Figure 4.1-17 is a graphical representation of the data in Table 4.1-15.

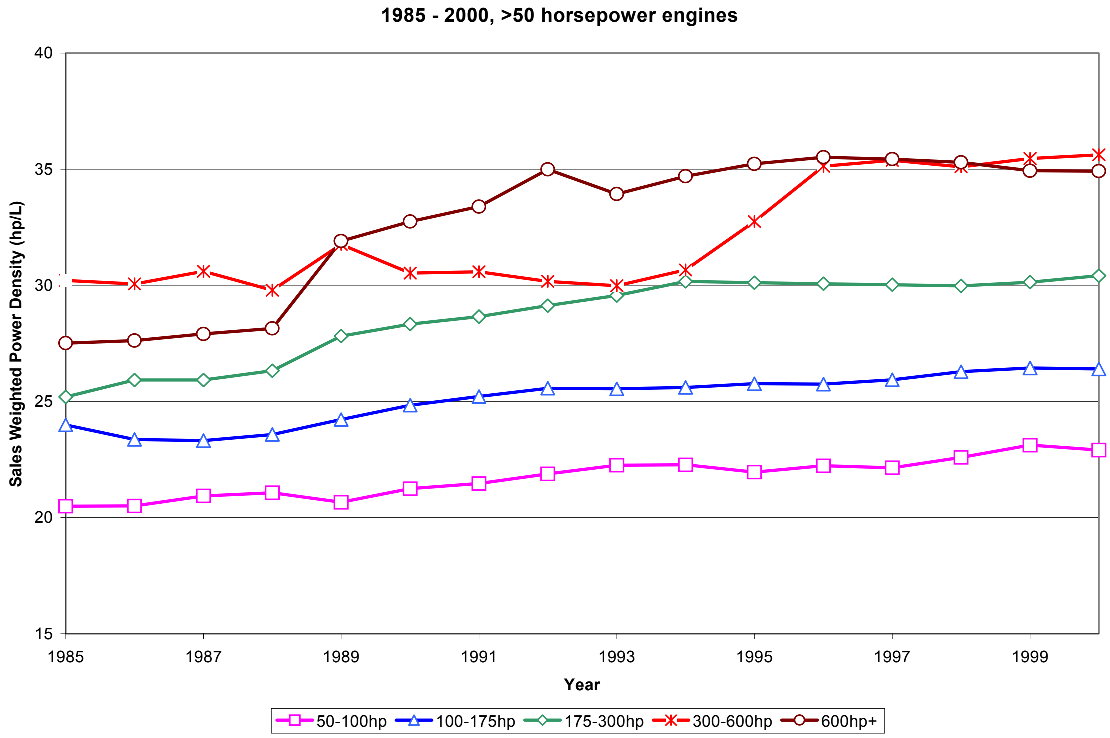
Table 4.1-15
Sales-Weighted Power Density by Power Category (hp/liter), 1985 - 2000

Year	50-100hp	100-175hp	175-300hp	300-600hp	600hp+
1985	20.5	24.0	25.2	30.2	27.5
1986	20.5	23.4	25.9	30.1	27.6
1987	20.9	23.3	25.9	30.6	27.9
1988	21.1	23.6	26.3	29.8	28.1
1989	20.7	24.2	27.8	31.8	31.9
1990	21.2	24.8	28.3	30.5	32.7
1991	21.5	25.2	28.7	30.6	33.4
1992	21.9	25.6	29.1	30.2	35.0
1993	22.3	25.5	29.6	30.0	33.9
1994	22.3	25.6	30.2	30.7	34.7
1995	22.0	25.8	30.1	32.7	35.2
1996	22.2	25.7	30.1	35.1	35.5
1997	22.1	25.9	30.0	35.4	35.4
1998	22.6	26.3	30.0	35.1	35.3
1999	23.1	26.4	30.1	35.5	34.9
2000	22.9	26.4	30.4	35.6	34.9
% Change 1985 - 2000	11%	9%	17%	15%	21%

Figure 4.1-7 shows reasonably steady increase in power density for engines all power categories from 1985 until approximately 1994/1995, though the rate of increase varies between the power categories. From 1994/95 until 2000 most power categories saw either no change or a slight increase in power density, with the exception of the >600hp category, which saw a small decrease. Power density increases by engine rated power, with the 70-100hp category showing the lowest values, with year 2000 being 22.9 hp/liter, and the 300-600hp and 600+hp categories have sales-weighted power densities on the order of 35 hp/liter.

[O] Power density is equal to the engine's rated power divided by the engines total displacement. The data in this memorandum is presented in terms of horsepower per liter.

Figure 4.1-17 Power Density Trends for Nonroad Diesel Engines



4.1.3.2 Durability and Design

Nonroad equipment is designed to be used in a wide range of tasks in some of the harshest operating environments imaginable, from mining equipment to crop cultivation and harvesting to excavation and loading. In the normal course of equipment operation the engine and its associated hardware will experience levels of vibration, impacts, and dust that may exceed conditions typical of highway diesel vehicles. Failing to consider differences in operating conditions in engine and equipment design would be expected to lead to eventual failure of the equipment.

Specific efforts to design for the nonroad operating conditions will be required to ensure that the benefits of these new emission-control technologies are realized for the life of nonroad equipment. Much of the engineering knowledge and experience to address these issues already exists with the nonroad equipment manufacturers. Vibration and impact issues are fundamentally mechanical durability concerns (rather than issues of technical feasibility of achieving emission reductions) for any component mounted on a piece of equipment (e.g., an engine coolant overflow tank). Equipment manufacturers must design mounting hardware such as flanges, brackets, and bolts to support the new component without failure. Further, the catalyst substrate material itself must be able to withstand the conditions encountered on nonroad equipment without itself cracking or failing. There is a large body of real-world testing with retrofit emission-control technologies that demonstrates the durability of the catalyst components themselves even in the harshest of nonroad equipment applications.

Deutz, a nonroad engine manufacturer, sold approximately 2,000 diesel particulate filter systems for nonroad equipment in the period from 1994 through 2000. The very largest of these systems were limited to engine sizes below 850 hp. The majority of these systems were sold into significantly smaller applications. Many of these systems were sold for use in mining equipment. No other applications are likely to be more demanding than this. Mining equipment is exposed to extraordinarily high levels of vibration, experiences impacts with the mine walls and face, and high levels of dust. Yet in meetings with the Agency, Deutz shared their experience that no system had failed due to mechanical failure of the catalyst or catalyst housing.[119] The Deutz system utilized a conventional cordierite PM filter substrate as is commonly used for heavy-duty highway truck CDPF systems. The canning and mounting of the system was a Deutz design. Deutz was able to design the catalyst housing and mounting in such a way as to protect the catalyst from the harsh environment as evidenced by its excellent record of reliable function.

Other nonroad equipment manufacturers have also offered OEM diesel particulate filter systems to comply with requirements of some mining and tunneling worksite standards. Liebherr, a nonroad engine and equipment manufacturer, offers diesel particulater filter systems as an OEM option on 340 different nonroad equipment models.[120] We believe this experience shows that appropriate design considerations, as are necessary with any component on a piece of nonroad equipment, will be adequate to address concerns with the vibration and impact conditions that can occur in some nonroad applications. This experience applies equally well to the NOx adsorber catalyst technologies, as the mechanical properties of DOCs, CDPFs, and NOx adsorbers are all similar. We believe that no new or fundamentally different solutions are needed to address the vibration and impact constraints for nonroad equipment below 750 hp. Engines above 750 hp are fundamentally similar to smaller engines with the most obvious difference being their larger size. Their larger size does create some additional issues regarding the size and physical strength of emission control technologies. While we believe that it may be possible to address these concerns using the same technologies as for engines <750 hp, we recognize that today we have limited evidence to draw that conclusion definitively. As described in Preamble Section II, we have therefore made some revisions to the proposed emission standards for engines >750 hp reflecting technologies (e.g., wire or fiber mesh PM filters) that we can say with confidence will be appropriate and available in the timeframe of this rulemaking.

Certain nonroad applications, including some forms of harvesting equipment and mining equipment, may have specific limits on maximum surface temperature for equipment components to ensure that the components do not serve as ignition sources for flammable dust particles (e.g. coal dust or fine crop dust). Some have suggested that these design constraints might limit the equipment manufacturers ability to install advanced diesel catalyst technologies such as NOx adsorbers and CDPFs. This concern seems to be largely based upon anecdotal experience with gasoline catalyst technologies where, under certain circumstances, catalyst temperatures can exceed 1,000˚C and, without appropriate design considerations, could conceivably serve as an ignition source. We do not believe these concerns are justified in the case of either the NOx adsorber catalyst or the CDPF technology. Catalyst temperatures for NOx adsorbers and CDPFs should not exceed the maximum exhaust manifold temperatures already commonly experienced by diesel engines (i.e., catalyst temperatures are expected to be below 800˚C).[P] CDPF temperatures are not expected to exceed approximately 700˚C in normal use and are expected to reach the 650˚C temperature only during periods of active regeneration. Similarly, NOx adsorber catalyst temperatures are not expected to exceed 700˚C and again only during periods of active sulfur regeneration, as described in Section 4.1.7 below. Under conditions where diesel exhaust temperatures are naturally as high as 650˚C, no supplemental heat addition from the emission-control system will be necessary and therefore exhaust temperatures will not exceed their natural level. When natural exhaust temperatures are too low for effective functioning of the emission-control system, then supplemental heating (as described earlier) may be necessary, but this is not expected to produce temperatures higher than the maximum levels normally encountered in diesel exhaust. Furthermore, even if it were necessary to raise exhaust temperatures to a higher level to promote effective emission control, there are technologies available to isolate the higher exhaust temperatures from flammable materials such as dust. One approach is the use of air-gapped exhaust systems (i.e., an exhaust pipe inside another concentric exhaust pipe separated by an air-gap) that serve to insulate the inner high-temperature surface from the outer surface, which could come into contact with the dust. The use of such a system may be additionally desirable to maintain higher exhaust temperatures inside the catalyst to promote better catalyst function. Another technology to control surface temperature already used by some nonroad equipment manufacturers is water cooled exhaust systems.[121] This approach is similar to the air-gapped system but uses engine coolant water to actively cool the exhaust system. Flammable dust concerns should not prevent the use of either a NOx adsorber or a CDPF, because catalyst temperatures are not expected to be unacceptably high and because remediation technologies exist to address these concerns. In fact, exhaust emission-control technologies (i.e., aftertreatment) have already been applied on both an OEM basis and for retrofit to nonroad equipment for use in potentially explosive environments. Many of these applications must undergo Underwriters Laboratory (UL) approval before they can be used.[122]

We agree that nonroad equipment must be designed to address durable performance for a wide range of operating conditions and applications that are not commonly experienced by highway vehicles. We believe further, as demonstrated by retrofit experiences around the world, that there are technical solutions that allow catalyst-based emission-control technologies to be applied to nonroad equipment.

4.1.4 Are the Standards for Engines >25 hp and <75 hp Feasible?

As discussed in Section II of the preamble, the emission standards for engines between 25 and 75 hp consist of a 2008 transitional standard and long-term 2013 standards. The transitional standard is a 0.22 g/hp-hr PM standard. The 2013 standards consist of a 0.02 g/hp-hr PM

[P] The hottest surface on a diesel engine is typically the exhaust manifold, which connects the engines exhaust ports to the inlet of the turbocharger. The hot exhaust gases leave the engine at a very high temperature (800˚C at high power conditions) and then pass through the turbo where the gases expand driving the turbocharger providing work and are cooled in the process. The exhaust leaving the turbocharger and entering the catalyst and the remaining pieces of the exhaust system is normally at least 100˚C cooler than in the exhaust manifold.

standard and a 3.5 g/hp-hr NMHC+NOx standard. The transitional standard is optional for 50-75 hp engines, as the 2008 implementation date is the same as the effective date of the Tier 3 standards. Manufactures may decide, at their option, not to undertake the 2008 transitional PM standard, in which case their implementation date for the 0.02 g/hp-hr PM standard begins in 2012.

The remainder of this section discusses (1) what makes the 25-75 hp category unique, (2) which engine technology is used currently, (3) which engine technology will be used for applicable Tier 2 and Tier 3 standards, and (4) why the Tier 4 standards are technologically feasible.

4.1.4.1 What makes the 25 - 75 hp category unique?

Many of the nonroad diesel engines $\geq$75 hp are either a direct derivative of highway heavy-duty diesel engines, or share some common traits with highway diesel engines. These include similarities in displacement, aspiration, fuel systems, and electronic controls. At the time of the proposal, we summarized some of the key engine parameter using data from the 2001 engines certified for sale in the United States. For this final rule, we have also added to this data set by including the 2004 engines certified for sale in the U.S. A comparison of these two data sets show a number of important trends, as discussed below.

Table 4.1-16 contains a summary of some key engine parameters from the 2001 engines certified for sale in the United States, and Table 4.1-17 is a summary of the 2004 engines.[Q]

Table 4.1-16
Summary of Model Year 2001 Key Engine Parameters by Power Category

Engine Parameter	Percent of 2001 U.S. Production[a]			
	0-25 hp	25-75 hp	75-100 hp	>100 hp
IDI Fuel System	83%	47%	4%	<0.1%
DI Fuel System	17%	53%	96%	>99%
Turbocharged	0%	7%	62%	91%
1 or 2 Cylinder Engines	47%	3%	0%	0%
Electronic fuel systems	0%	0%	0%	14%

[a] Based on sales weighting of 2001 engine certification data.

[Q] Data in Table 4.1-16 are derived from a combination of the publically available certification data for model year 2001 engines, as well as the manufacturers reported estimates of 2001 production targets, which is not public information.

Table 4.1-17
Summary of Model Year 2004 Key Engine Parameters by Power Category

Engine Parameter	Percent of 2004 U.S. Production[a]			
	0-25 hp	25-75 hp	75-100 hp	>100 hp
IDI Fuel System	85%	54%	6%	0.0%
DI Fuel System	15%	46%	94%	100.0%
Turbocharged	0%	22%	78%	99.9%
1 or 2 Cylinder Engines	18%	<1%	0%	0%
Electronic fuel systems	0%	0%	18%	61%

[a] Based on sales weighting of 2004 engine certification data.

As can be seen in Table 4.1-16 & 4.1-17, the engines in the 25-75 hp category have some important technology differences from the larger engines. These include a higher percentage of indirect-injection fuel systems, and a lower fraction of turbocharged engines. (The distinction in the <25 hp category is even more different, with no turbocharged engines, a large number of the engines have two cylinders or less, and a significant majority of the engines have indirect-injection fuel systems.)

The distinction is particularly marked with respect to electronically controlled fuel systems. These are commonly available in the ≥ 75 hp power categories (see Table 4.1.17 above showing that the technology is already migrating in significant amounts even into the 75-100 hp power band), but, based on the available certification data as well as our discussions with engine manufacturers, we believe there are very limited, if any in the 25-75 hp category (and no electronic fuel systems in the less than 25 hp category) at this time. The research and development work currently being performed for the heavy-duty highway market is targeted at turbocharged and electronically controlled, direct-injection engines with at least four cylinders and per-cylinder displacements greater than 0.5 liters. As discussed in more detail below (and in the preamble), as well as in Section 4.1.5.1 (regarding the <25 hp category), these engine distinctions are important from a technology perspective and warrant a different set of standards and implementation time-frame for the 25-75 hp category (as well as for the <25 hp category).

At the same time, the data in Tables 4.1-16 and 4.1-17 shows that engine technology is steadily progressing in the nonroad diesel engine market, and the penetration of that technology has increased in the past few years, i.e., from 2001 to 2004. In 2001, only engines in the 300-600hp range were required to comply with Tier 2. Today, in 2004, all engines in the 25-750hp range must comply with the Tier 2 emission standards. As a result of the inherent benefits of electronically controlled fuel systems and turbocharging, and as a response to the Tier 2 emission standards, the penetration of these engine technologies in the past few years has been dramatic. Nearly all engines >100 hp are turbocharged and have direct injection fuel systems. In addition, more than 60 percent of the engines > 100 hp now have electronically controlled fuel systems (up from 14% in 2001). In the 75-100hp range, turbocharging has increased from 62 to

78 percent, and electronically controlled fuel systems have increased from 0 percent in 2001 to 18 percent in 2004. The certification data shows that these electronically controlled fuel systems are available across the full 75-100 hp range, with some engines which use these fuel systems having a rated power of 75 hp and others having a rated power of 99 hp. The data also indicate that the engines in the 75-100 hp range with electronically controlled fuel systems are designed for use in nonroad equipment such as agricultural tractors, mobile cranes, dozers, loaders, fork lifts, and a range of other nonroad equipment. Even in the 25-75 hp range, turbocharging has increased by a factor of 3, from 7 to 21 percent. We expect all of these trends to continue as Tier 2 is fully implemented by 2006, and as the Tier 3 standards are phased-in from 2006 to 2008. Another reason we expect that the trend will continue is because of the inherent benefits for the end-user which result from the use of electronically controlled fuel systems and turbocharging.

4.1.4.2 What engine technology is used currently, and will be used for Tier 2 and Tier 3, in the 25-75hp range?

In the 1998 nonroad diesel rulemaking, we established Tier 1 and Tier 2 standards for engines in the 25-50 hp category. Tier 1 standards were implemented in 1999, and the Tier 2 standards take effect in 2004. The 1998 rule also established Tier 2 and Tier 3 standards for engines between 50 and 75 hp. The Tier 2 standards take effect in 2004, and the Tier 3 standards take effect in 2008. The Tier 1 standards for engines between 50 and 75 hp took effect in 1998. All engines in the 25-75 hp range were first required to meet Tier 2 standards in the 2004 model year, and the MY 2004 data presented in Table 4.1-17 represent Tier 2 technology for this power range.

Engines in the 25-75 hp category use either indirect injection (IDI) or direct injection (DI) fuel systems. The IDI system injects fuel into a pre-chamber rather than directly into the combustion chamber as in the DI system.[123] This difference in fuel systems results in substantially different emission characteristics, as well as several important operating parameters. In general, the IDI engine has lower engine-out PM and NOx emissions, while the DI engine has better fuel efficiency and lower heat rejection.[124]

We expect a significant shift in the engine technology that will be used in this power category as a result of the upcoming Tier 2 and Tier 3 standards, in particular for the 50-75 hp engines. In the 50-75 hp category, the 2008 Tier 3 standards will likely result in the significant use of turbocharging and electronic fuel systems, as well as the introduction of both cooled and uncooled exhaust gas recirculation by some engine manufacturers and possibly the use of charge-air-cooling.[125] To some extent this has already begun to occur as a result of the Tier 2 standards, as discussed above in relation to Tables 4.1-16 and 4.1-17. In addition, we have heard from some engine manufacturers that the engine technology used to meet Tier 3 for engines in the 50-75 hp range will also be made available on those engines in the 25-50 hp range that are built on the same engine platform. For the Tier 2 standards for the 25-50 hp products, a large number of engines already meet these standards; we therefore expect to see more moderate changes in these engines, including an increased penetration of turbocharging.[126]

4.1.4.3 Are the standards for 25 -75 hp engines technologically feasible?

This section discusses the feasibility of both the interim 2008 PM standard and the long-term 2013 standards.

4.1.4.3.1 2008 PM Standards

As just discussed in Section 4.1.4.2, engines in the 25-50 hp category must already meet Tier 1 NMHC+NOx and PM standards. We have examined the model year 2002 engine certification data for engines in the 25-50 hp category.[127] We have also examined the model year 2004 certification data for engines in the 25-50hp category. For the model year 2002 data, there is no Tier 1 PM standard for engines in the 50-75 hp range, and engine manufacturers are therefore not required to report PM emission levels until Tier 2 starts in 2004, so there is no 2002 data to summarize for the 50-75hp range.

Summary of 2002 Model Year Certification Data for 25-50 hp

A summary of the 2002 model year certification data for the 25-50 hp engines is presented in Table 4.1-18, and Figure 4.1-18 is a graph of the HC+NOx and PM results from these same engines. These data indicate that over 10 percent of the engine families already meet the 2008 0.22 g/hp-hr PM standard and 5.6 g/hp-hr NMHC+NOx standard (unchanged from Tier 2 in 2008). These include a variety of engine families using a mix of engine technologies (IDI and DI, turbocharged and naturally aspirated) tested on a variety of certification test cycles.[R] Five engine families are more than 20 percent below the 0.22 g/hp-hr PM standard; an additional 24 engine families that already meet the 2008 NMHC+NOx standards will require no more than a 30 percent PM reduction to meet the 2008 PM standards. Unfortunately, similar data do not exist for engines between 50 and 75 hp for the 2002 model year.

[R] The Tier 1 standards for this power category must be demonstrated on one of a variety of different engine test cycles. The appropriate test cycle is selected by the engine manufacturer based on the intended in-use application of the engine.

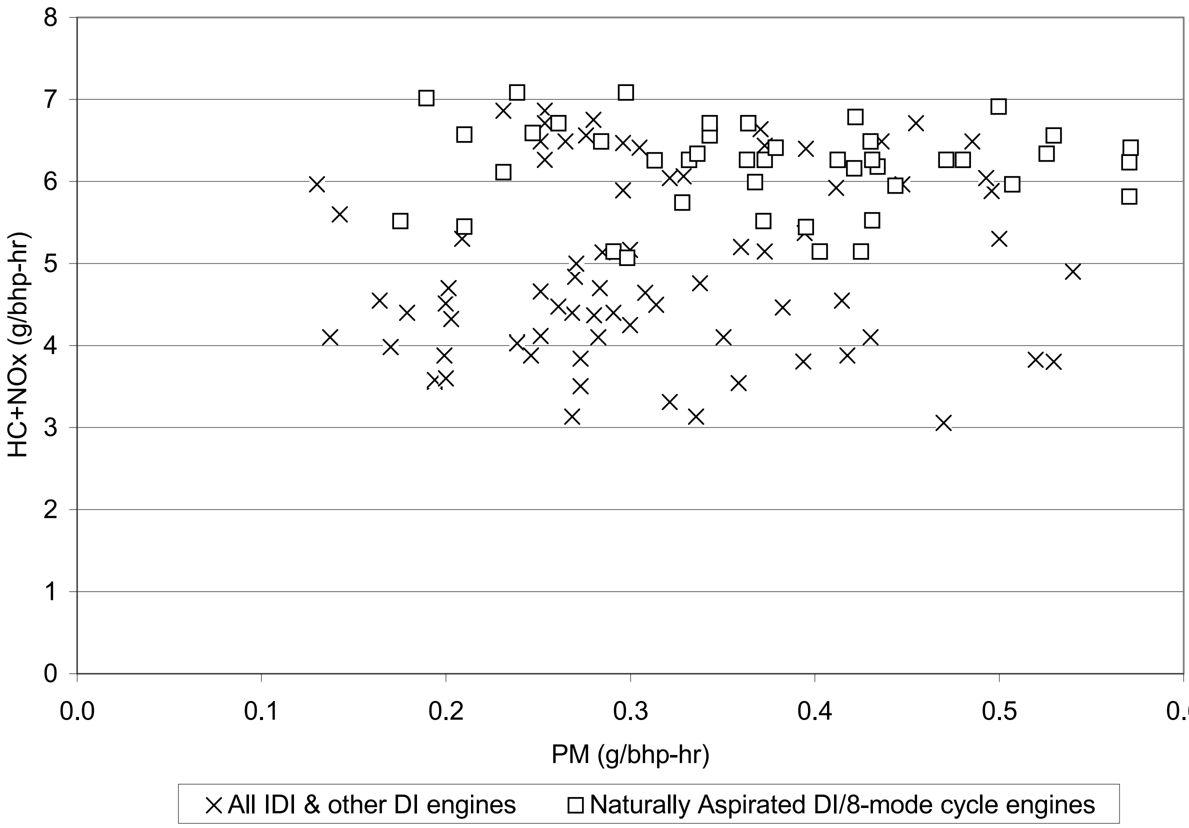
Table 4.1-18
2002 Model Year Certification Data for 25-50 hp Nonroad Diesel Engines

PM Emissions Relative to the 0.22 g/hp-hr Standard	IDI Engines				DI Engines			Totals
	5-mode/ NA	8-mode/ NA	5-mode/ TC	8-mode/ TC	5-mode/ NA	8-mode/ NA	8-mode/ TC	
0 - 5 % below T4[a]	0	0	0	0	0	1	0	1
5 - 20 % below T4[a]	1	5	1	2	0	0	0	9
>20 % below T4[a]	2	1	0	1	0	1	0	5
require ≤30% PM reduction to meet T4[a]	3	15	0	4	0	2	0	24
requires >30%PM reduction and/or	2	17	1	3	8	40	8	79
Total # of Engine Families	8	38	2	10	8	44	8	118

[a] Engine also meets 2008 NMHC+NOx

The model year 2002 engines in this power range use well known engine-out emission-control technologies, such as optimized combustion chamber design and fuel-injection timing control strategies, to comply with the existing standards. These data have a two-fold significance. First, they indicate that some engines in this power range can already achieve the 2008 standard for PM using only engine-out technology, and that other engines should be able to achieve the standard making improvements just to engine-out performance.

Figure 4.1-18 Emission Certification Data for 25-50 HP Model Year 2002 Engines



Summary of 2004 Model Year Certification Data for 25-75 hp

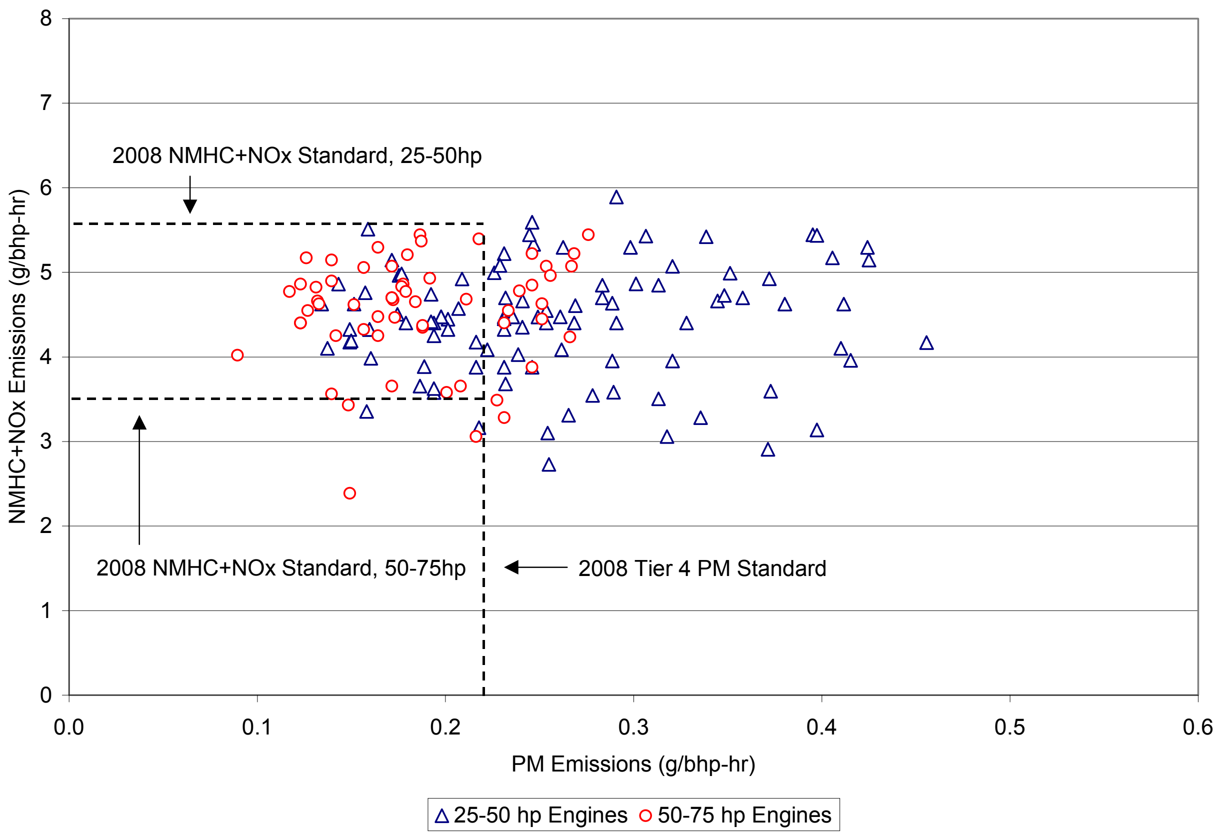
Table 4.1-19 contains a summary of the model year 2004 certification data for PM and NMHC+NOx as it relates to the 2008 Tier 4 emission standards for engines in the 25-75hp range. The data represented in Table 4.1-19 is also shown graphically in Figure 4.1-19. As can be seen, the 2004 data shows 35 percent of the engine families in the 25-50hp range already meet the 2008 0.22 g/hp-hr PM standard and a 5.6 g/hp-hr NMHC+NOx standard (which standard is unchanged from Tier 2 in 2008). In the 50-75 hp range, the data shows 7 percent of the families can meet the 2008 Tier 4 standards (0.22 g/bhp-hr PM and 3.5 g/bhp-hr NMHC+NOx). The relatively low percentage of engines in the 50-75 hp category which meet the Tier 4 standards today is largely a result of the stringency of the Tier 3 NMHC+NOx emission standards, which are required for this power category in 2008. As discussed in our Tier 3 Staff Technical Paper which reviewed the feasibility of the Tier 3 standards, we believe in-cylinder technologies such as cooled EGR will be necessary to comply with the Tier 3 emission standards (and we included the cost of such systems in our assessment of costs for the Tier 3 rule). Technologies such as cooled EGR and advanced fuel systems have been shown to be capable of reducing NOx emissions by 50 percent or more without increasing PM emissions. As can be seen by the data in Figure 4.1-19, more than 70 percent of the engines in the 50-75 hp range are below the 0.22 g/bhp-hr PM level, and a NOx reduction of 50 percent would easily bring these engines into compliance with the Tier 3 NMHC+NOx standards. Finally, when considered as a whole, nearly one-quarter of the model year 2004 engine families in the 25-75 hp range could comply with the Tier 4 2008 PM and NMHC+NOx requirements today.

Table 4.1-19
2004 Model Year Certification Data for 25-75hp Nonroad Diesel Engines

Power Catergory	PM Emissions < 0.22 g/bhp-hr and 2008 NMHC+NOx standards?	Naturally Aspirated			Turbocharged			Grand Total
		DI	IDI	NA	DI	IDI	TC	
25-50 hp, # of Engine Families	No	23	35	58	6	4	10	68
	Yes	12	17	29	2	5	7	36
	Total	35	52	87	8	9	17	104
50-75 hp, # of Engine Families	No	22	11	33	15	9	24	57
	Yes	0	4	4	0	0	0	4
	Total	22	15	37	15	9	24	61

Power Catergory	PM Emissions < 0.22 g/bhp-hr and 2008 NMHC+NOx standards?	Naturally Aspirated			Turbocharged			Grand Total
		DI	IDI	NA Total	DI	IDI	TC Total	
25-50 hp, % of Engine Families	No	66%	67%	67%	75%	44%	59%	65%
	Yes	34%	33%	33%	25%	56%	41%	35%
50-75 hp, % of Engine Families	No	100%	73%	89%	100%	100%	100%	93%
	Yes	0%	27%	11%	0%	0%	0%	72%
25-75hp, % of Engine Families	No	79%	69%	73%	91%	72%	83%	76%
	Yes	21%	31%	27%	9%	28%	17%	24%

Figure 4.1-19 Emissions Certification Data for 25-75 HP Model Year 2004 Engines



Discussion of Certification Data and 2008 Feasibility

Despite the fact that the certification data from recent model years indicates that engine-out techniques are capable of meeting the Tier 4 2008 PM standards for some engines, we are not basing the feasibility of the 2008 PM standard on engine-out techniques alone, as discussed below.

As can be seen from the 2002 model year data in Figure 4.1-18, while the engines are all certified to the same emission standard (Tier 1) with similar engine technology, the emission levels from these engines vary widely. The same can be seen for the 2004 model year data shown in Figure 4.1-19, in particular for the 25-50hp engines. Figure 4.1-18 highlights a specific example of this wide range: engines using naturally aspirated DI technology and tested on the 8-mode test cycle. Even for this subset of DI engines achieving approximately the same HC+NOx level of ~6.5 g/hp-hr, the PM rates vary from approximately 0.2 to more than 0.5 g/hp-hr. There is limited information available to indicate why for these small diesel engines with similar technology operating at approximately the same HC+NOx level the PM emission rates cover such a broad range. We are therefore not predicating the 2008 PM standard on the lowest engine-out emissions being achieved today, because it is uncertain whether or not additional engine-out improvements will lower all engines to the 2008 PM standard. Instead, we believe there are two likely means by which companies can comply with the 2008 PM standard. First, some engine manufacturers can comply with this standard using known engine-out techniques (e.g., optimizing combustion chamber designs, fuel-injection strategies). However, based on the available data as shown in Figure 4.1-18 and 4.1-19, it is unclear whether engine-out techniques will work in all cases. We therefore believe some engine companies will choose to use a combination of engine-out techniques and diesel oxidation catalysts, as discussed below.

Emission Reductions from Engine-out Techniques

For some of the engines not already meeting the 2008 Tier 4 PM standard, engine-out techniques may bring the engines into compliance with the 2008 standards. In our recent Staff Technical Paper on the feasibility of the Tier 2 and Tier 3 standards, we projected that engines greater than 50 hp will rely on some combination of technologies—including electronic fuel systems such as electronic rotary pumps or common-rail fuel systems—to comply with the Tier 3 NMHC+NOx standards.[128] In addition to enabling the Tier 3 NMHC+NOx standards, electronic fuel systems with high injection pressure and the capability to perform pilot-injection and rate-shaping, have the potential to substantially reduce PM emissions.[129] Even for mechanical fuel systems, increased injection pressures can reduce PM emissions substantially.[130] As discussed above, we are projecting that the Tier 3 engine technologies used in engines between 50 and 75 hp, such as turbocharging and electronic fuel systems, will make their way into engines in the 25-50 hp range. However, we do not believe this technology will be required to achieve the Tier 4 2008 PM standard. As demonstrated by the 2002 and 2004 certification data, engine-out techniques such as optimized combustion chamber design, fuel-injection pressure increases and fuel-injection timing can be used to achieve the 2008 Tier 4 standards for many of the engines in the 25-75 hp category without the need to add turbocharging or electronic fuel systems.

Emission Reductions from Diesel Oxidation Catalysts

For those engines not able to achieve the Tier 4 standards with known engine-out techniques, we project that these engines can meet the standards with diesel oxidation catalysts. DOCs are passive flow-through emission-control devices that are typically coated with a precious metal or a base-metal washcoat. DOCs have been proven to be durable in use on both light-duty and heavy-duty diesel applications. In addition, DOCs have already been used to control PM or carbon monoxide on some nonroad applications.[131]

Certain DOC formulations can be sensitive to diesel fuel sulfur levels, and depending on the level of emission reduction necessary, sulfur in diesel fuel can be an impediment to PM reductions. Precious-metal oxidation catalysts can oxidize the sulfur in the fuel and form particulate sulfates. However, even with current high-sulfur nonroad fuel, some manufacturers have demonstrated that a properly formulated DOC can be used in combination with other technologies to achieve the existing Tier 2 PM standards for larger engines (i.e., the 0.15 g/hp-hr standard).[132] However, given the high level of sulfur in current nonroad fuel, the use of DOCs as a PM-reduction technology is severely limited. Data presented by one engine manufacturer regarding the existing Tier 2 PM standard show that, while a DOC can be used to meet the current standard even when tested on 2,000 ppm sulfur fuel, lowering the fuel sulfur level to 380 ppm enabled the DOC to reduce PM by 50 percent from the 2,000 ppm sulfur fuel.[133] Without the availability of 500 ppm sulfur fuel in 2008, DOCs would be of limited use for nonroad engine manufacturers and would not provide the emission-control necessary for most manufacturers to meet the Tier 4 standards. With the availability of 500 ppm sulfur fuel, DOCs can be designed to provide PM reductions on the order of 20 to 50%, while suppressing particulate sulfate reduction.[134] These levels of reductions have been seen on transient duty cycles as well as highway and nonroad steady-state duty cycles. As discussed above, 24 engine families in the 25-50 hp range are within 30 percent of the 2008 PM standard and are at or below the 2008 NMHC+NOx standard for this power range, indicating that use of DOCs should achieve the incremental improvement necessary to meet the 2008 PM standard. However, we also do not believe that an emission level lower than 0.22 g/bhp-hr will be generally feasible in 2008 due to the diesel fuel sulfur level of 500 ppm and consequent potential for sulfate PM formation.

4.1.4.3.2 2013 Standards

For engines in the 25-50 range, we are adopting standards starting in 2013 of 3.5 g/hp-hr for NMHC+NOx and 0.02 g/hp-hr for PM. Additionally, compliance with the existing CO emission standards will need to be demonstrated over new test cycles including the NRTC with cold-start, and NTE. For the 50-75 hp engines, we are adopting a 0.02 g/hp-hr PM standard that will be implemented in 2013, and for those manufacturers who choose to pull-ahead the standard one-year, 2012 (manufacturers who choose to pull-ahead the 2013 standard for engine in the 50-75 range do not need to comply with the transitional 2008 PM standard).

4.1.4.3.2.1 PM Standard

Sections 4.1.1 through 4.1.3 have already discussed catalyzed diesel particulate filters, including explanations of how CDPFs reduce PM emissions, and how to apply CDPFs to nonroad engines. We concluded there that CDPFs can be used to achieve the Tier 4 PM standard for engines ≥75 hp. Specifically we discussed the ability of ceramic based filter technologies to meet the 0.01 g/bhp-hr standard for engines from 75-750 hp and the ability of alternate depth filter technologies to meet a slightly less stringent standard of 0.02 g/bhp-hr standard (0.03 for mobile machines) for engines > 750 hp. As also discussed in Section 4.1.3, PM filters may require active back-up regeneration systems for many nonroad applications. Secondary technologies will likely be needed in addition to enable proper regeneration, possibly including electronic fuel systems such as common rail, which makes possible multiple post-injections for raising exhaust gas temperatures to aid in filter regeneration.

Particulate filter technology, with the requisite trap regeneration technology, can also be applied to engines in the 25 to 75 hp range. The fundamentals of how a filter is able to reduce PM emissions, as described in Section 4.1.1, are not a function of engine power, and CDPFs are just as effective at capturing soot emissions and oxidizing SOF on smaller engines as on larger engines. As discussed in more detail below, particulate sulfate generation rates are slightly higher for the smaller engines; however, we have addressed this issue in the final rule. The PM filter regeneration systems described in Sections 4.1.1 and 4.1.3 are also applicable to engines in this size range and are therefore likewise feasible. Engine manufacturers may prefer some specific trap-regeneration technologies over others in the 25-75 hp category. Specifically, an electronically controlled secondary fuel-injection system (i.e., a system that injects fuel into the exhaust upstream of a PM filter). Such a system has been commercially used successfully by at least one nonroad engine manufacturer, and other systems have been tested by technology companies.[135]

We are, however, adopting a slightly higher PM standard (0.02 g/hp-hr rather than 0.01) for these engines. As discussed in Section 4.1.1, with the use of a CDPF, the PM emissions emitted by the filter are primarily derived from the fuel sulfur. The smaller power category engines tend to have higher fuel consumption than larger engines. This occurs for a number of reasons. First, the lower power categories include a high fraction of IDI engines, which by their nature consume approximately 15 percent more fuel than a DI engine. Second, as engine displacements get smaller, the engine's combustion chamber surface-to-volume ratio increases. This leads to higher heat-transfer losses and therefor lower efficiency and higher fuel consumption. In addition, frictional losses are a higher percentage of total power for the smaller displacement engines, which also contributes to higher fuel consumption. Because of the higher fuel consumption rate, we expect a higher particulate sulfate level, and are therefore adopting a 0.02 g/hp-hr standard.

Test data confirm that this standard, as well as the NTE of 1.5 times the standard, is achievable. In 2001, EPA completed a test program on two small nonroad diesel engines (a 25 hp IDI engine and a 50 hp IDI engine) that demonstrated the 0.02 g/hp-hr standard can be achieved with the use of a CDPF.[136] This test program included testing on the existing 8-mode steady-state duty cycle as well as the new nonroad transient cycle. The 0.02g/hp-hr level was achieved on each engine over both test cycles. In addition, the 0.02 g/hp-hr level was achieved on a variety of nonroad test cycles that are intended to represent several specific applications, such as skid-steer loaders, arc-welders, and agricultural tractors. We believe these data indicate the robust emission-reduction capability of particulate filters and demonstrate that the NTE standard of 1.5 × 0.02 g/hp-hr standard (0.03 g/hp-hr) can be achieved under the NTE test requirements, because the data was generated over a number of test cycles which are intended to represent real in-use operation, such as we would expect the NTE to represent. This test program also demonstrates why we have adopted a slightly higher PM standard for the 25 - 75 hp category (0.02 g/hp-hr vs. 0.01). The data from the test program described above showed fuel consumption rates over the 8-mode test procedure between 0.4 and 0.5 lbs/bhp-hr, while typical values for a modern turbocharged DI engine with 4-valves per cylinder in the ≥75 hp categories are on the order of 0.3 to 0.35 lbs/hp-hr.

The CDPF technology applied to meet the PM standard will also serve to ensure compliance with the existing CO emission standards over the new test procedures. CDPFs can reduce CO emissions by more than 80 percent, a level of control that will more than offset any increase in CO emission due to the new test cycles.

4.1.4.3.2.2 NMHC+NOx Standard

We are adopting a 3.5 g/hp-hr NMHC+NOx standard for engines in the 25 - 50 hp range starting in 2013. This will align the NMHC+NOx standard for engines in this power range with the Tier 3 standard for engines in the 50 - 75 hp range, which starts in 2008. EPA's recent Staff Technical paper, which reviewed the technological feasibility of the Tier 3 standards, contains a detailed discussion of a variety of technologies capable of achieving a 3.5 g/hp-hr standard. These include cooled EGR, uncooled EGR, as well as advanced in-cylinder technologies relying on electronic fuel systems and turbocharging.[137] These technologies are capable of reducing NOx emission by more than 50 percent including when measured over transient test cycles including cold-start.[138] Given the Tier 2 NMHC+NOx standard of 5.6 g/hp-hr, a 50 percent reduction will allow a Tier 2 engine to comply with the 3.5 g/hp-hr NMHC+NOx standard. In addition, because this NMHC+NOx standard is concurrent with the 0.02 g/hp-hr PM standards, which we project will be achievable with particulate filters, engine designers will have significant additional flexibility in reducing NOx because the PM filter will eliminate the traditional concerns with the engine-out NOx vs. PM trade-off. Further, the CDPF technology will substantially reduce NMHC emissions (by more than 80 percent) providing additional control effective to help meet the NOx+NMHC emission standards.

4.1.5 Are the Standards for Engines <25 hp Feasible?

As discussed in Section III of the preamble, there is a new PM standard of 0.30 g/hp-hr for engines less than 25 hp beginning in 2008. As discussed below, the NMHC+NOx and CO levels for this power category is unchanged from Tier 2 levels although compliance will need to be demonstrated over additional test cycles beginning in 2013. This section describes (1) what makes the <25 hp category unique, (2) which engine technologies are currently used in the <25 hp category, and (3) data showing that the new emission standards are technologically feasible.

4.1.5.1 What makes the < 25 hp category unique?

Nonroad engines less than 25 hp are the least sophisticated nonroad diesel engines from a technological perspective. All of the engines currently sold in this power category lack electronic fuel systems and turbochargers (see Table 4.1-17). Nearly 20 percent of the products have two-cylinders or less, and 14 percent of the engines sold in this category are single-cylinder products, several of these have no batteries and are crank-start machines, much like a simple walk-behind lawnmower. In addition, given the available data and taking into account the Tier 2 standards that have not yet been implemented, we are not projecting any significant penetration of advanced engine technology, such as electronically controlled fuel systems, into this category in the next five to ten years.

4.1.5.2 What engine technology is currently used in the <25 hp category?

In the 1998 nonroad diesel rulemaking we established Tier 1 and Tier 2 standards for these products. Tier 1 was implemented in model year 2000, and Tier 2 will be implemented in model year 2005. As discussed in EPA's recent Staff Technical Paper, we project the Tier 2 standards will be met by basic engine-out emission-optimization strategies.[139] We are not predicting that Tier 2 will require electronic fuel systems, EGR, or turbocharging. As discussed in Section 4.1.5.3 of this RIA and in the Staff Technical Paper, a large number of engines in this power category already meet the Tier 2 standards by a wide margin.[140]

Two basic types of engine fuel-injection technologies are currently present in the less than 25 hp category, mechanical indirect injection (IDI) and mechanical direct injection (DI). The IDI system injects fuel into a pre-chamber rather than directly into the combustion chamber as in the DI system. This difference in fuel systems results in substantially different emission characteristics, as well as several important operating parameters. In general, as noted earlier, the IDI engine has lower engine-out PM and NOx emissions, while the DI engine has better fuel efficiency and lower heat rejection.

4.1.5.3 What data support the feasibility of the new standards?

We project that the Tier 4 PM standard can be met by 2008 based on:
—the existence of a large number of engine families already meeting the standards,
—the use of engine-out reduction techniques and
—the use of diesel oxidation catalysts.

We have examined model year 2002 and 2004 engine certification data for nonroad diesel engines less than 25 hp category.[141] Tier 2 does not begin for these engines until model year 2005, and thus all of the data we examined are certified to the Tier 1 emission standards. As described below, there is little difference between these data sets, and it is likely that many of the 2004 model year engine families are carry overs from the model year 2002.

<u>Summary of 2002 Model Year Certification Data for Engines <25 hp</u>

A summary of the model year 2002 certification data for engines <25hp is presented in Table 4.1-20. The data is also shown in graphical form in Figure 4.1-20. These data indicate that some engine families already meet the Tier 4 PM standard (and the 2008 NMHC+NOx standard, unchanged from Tier 2). The current data indicate that approximately 28% of the engine families are already at or below the Tier 4 PM standard, while meeting the 2008 NMHC+NOx standard. These data reflect a range of certification test cycles, and include both IDI and DI engines.[S] Many of the engine families are certified well below the Tier 4 standard while meeting the 2008 NMHC+NOx level. Specifically, 15 percent of the engine families are more than 20 percent below the Tier 4 PM standard. An additional 15 percent of the engine families already meeting 2008 NMHC+NOx standards will require no more than a 30 percent PM reduction to meet the 2008 PM standards. The public certification data indicate that these engines do not use turbocharging, electronic fuel systems, exhaust gas recirculation, or aftertreatment technologies.

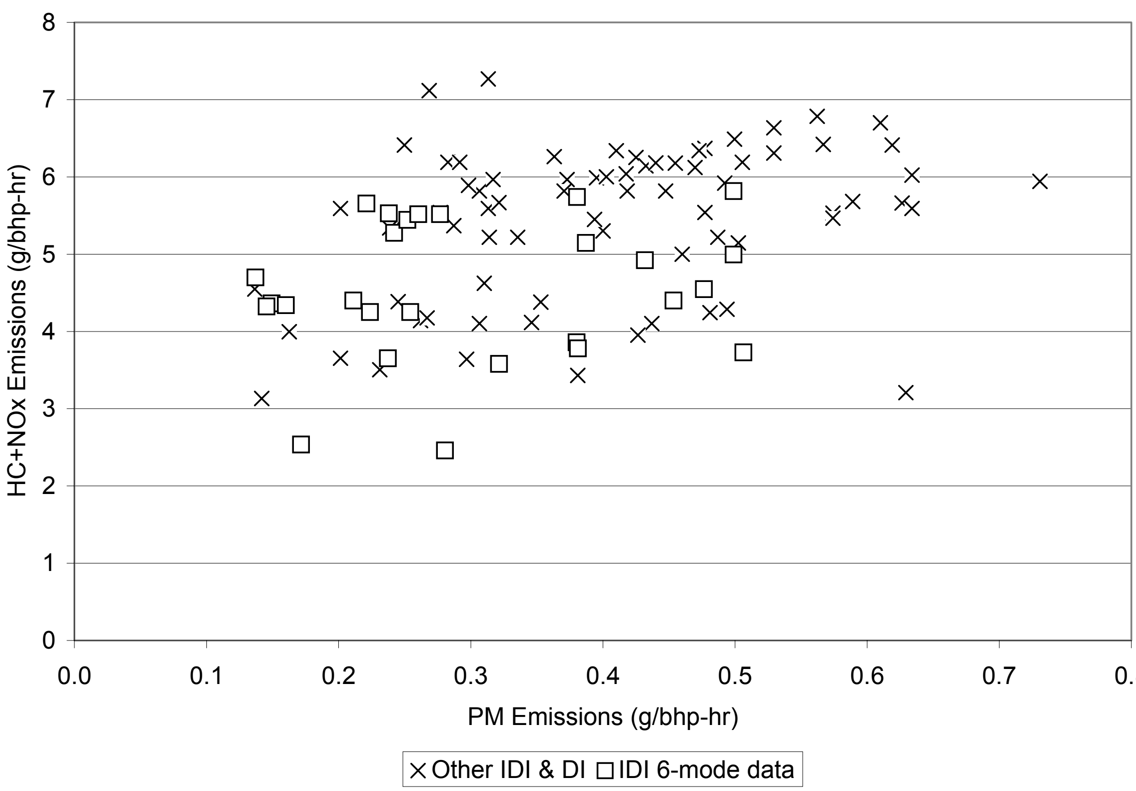
[S] The Tier 1 and Tier 2 standards for this power category must be demonstrated on one of a variety of different engine test cycles. The appropriate test cycle is selected by the engine manufacturer based on the intended in-use applications(s) of the engine.

Table 4.1-20
2002 Model Year Certification Data for <25 hp Nonroad Diesel Engines

PM Emissions Relative to the 0.30 g/hp-hr Standard	IDI Engines			DI Engines			Totals
	5-mode	6-mode	8-mode	5-mode	6-mode	8-mode	
0-5% below T4[a]	1	0	1	0	0	0	2
5-20% below T4[a]	4	6	1	0	0	0	11
>20% below T4[a]	1	9	5	0	1	0	16
require ≤30% PM reduction to meet T4[a]	5	4	4	0	2	0	15
requires >30%PM reduction and/or > 2008 NMHC+NOx std.	7	8	4	18	18	3	58
Total # of Engine Families	18	27	15	18	21	3	102

[a] Engine also meets the 2008 NMHC+NOx standard.

Figure 4.1-20 Emission Certification Data for <25 HP Model Year 2002 Engines



Summary of 2004 Model Year Certification Data for 25-50 hp

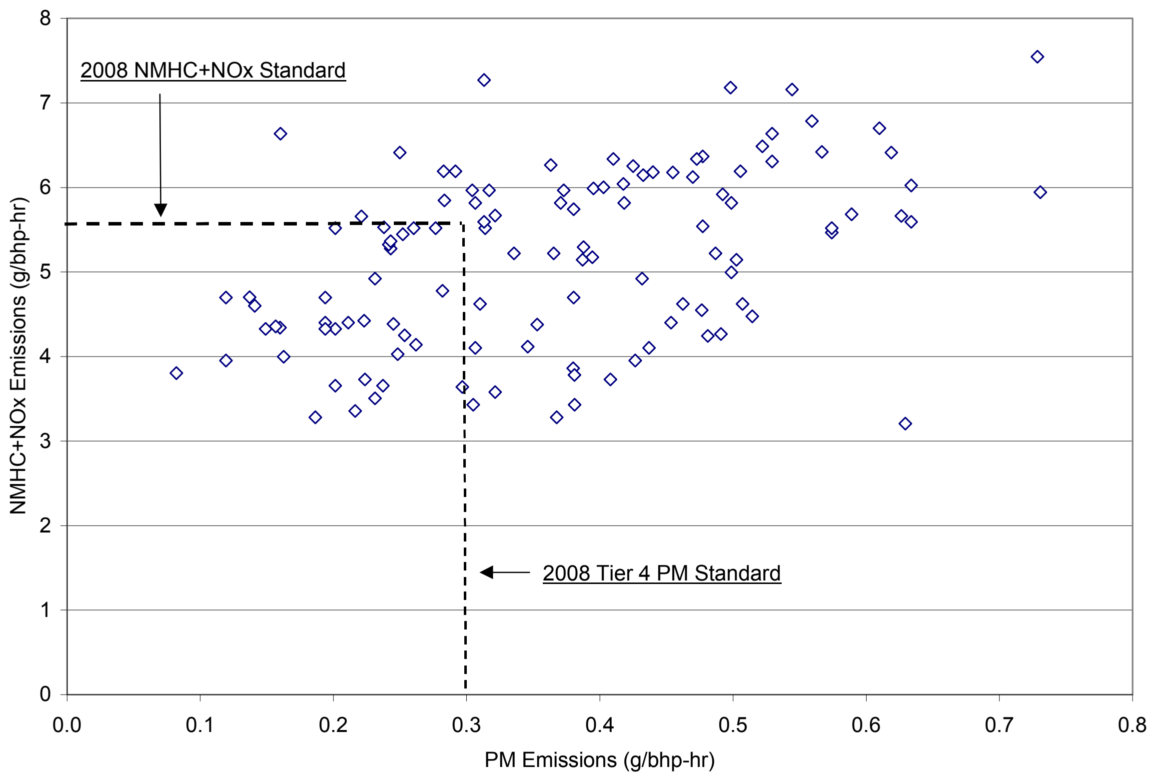
The certification data for model year 2004 engines is summarized in Table 4.1.-21. In general, this data is similar to the 2002 data shown in Table 4.1-20. The data shows that 31% of the certified engines are below the 2008 Tier 4 standards, as compared to 28% in the 2002 data. However, one of the differences is a higher number of 2004 direct-injection engines are below the Tier 4 levels in 2004 (5 out of 48) as compared to 2002 (1 out of 42). This data is also shown in Figure 4.1-21.

Table 4.1-21
2004 Model Year Certification Data for <25hp Nonroad Diesel Engines

	PM Emissions Below 0.30 g/bhp-hr?	Direct Injection Fuel System	Indirect Injection Fuel System	Totals
Engine Family Count	No	43	38	81
	Yes[a]	5	32	37
	Total	48	70	118
% of Engine Families	No	90%	54%	69%
	Yes[a]	10%	46%	31%

[a] Engine also meets the 2008 NMHC+NOx standard.

Figure 4.1-21 Emissions Certification Data for <25 HP Model Year 2004 Engines



Discussion of Certification Data and 2008 Feasibility

These model year 2002 and 2004 engines use well known engine-out emission-control technologies, such as combustion chamber design and fuel-injection timing control strategies, to comply with the existing standards (Tier 1 in both cases). As with 25-75 hp engines, these data have a two-fold significance. First, they indicate that some engines in this power category can already achieve the 2008 PM standard using only engine-out technology, and that other engines should be able to achieve the standard making improvements just to engine-out performance. However, the data does not indicate that all engines could comply with the 2008 PM standard using engine-out techniques alone. Despite being certified to the same emission standards with similar engine technology, the emission levels from these engines vary widely. As can be seen in the Figure 4.1-20, the emission levels cover a wide range. Figure 4.1-20 highlights a specific example of this wide range: engines using naturally aspirated IDI technology and tested on the 6-mode test cycle. Even for this subset of IDI engines achieving approximately the same HC+NOx level of~4.5 g/hp-hr, the PM rates vary from approximately 0.15 to 0.5 g/hp-hr. There is limited information available to indicate why for these small diesel engines with similar technology operating at approximately the same HC+NOx level the PM emission rates cover such a broad range. The model year 2004 data in Figure 4.1-21 shows a similarly large spread in PM emissions. We are therefore not predicating the 2008 PM standard on the combination of diesel oxidation catalysts and the lowest engine-out emissions in the final rule, because it is uncertain whether or not additional engine-out improvements would lower all engines to the 2008 PM standard. Instead, we believe there are two likely means by which companies can comply with the 2008 PM standard. First, some engine manufacturers can comply with this standard using known engine-out techniques (e.g., optimizing combustion chamber designs, fuel-injection strategies). However, based on the available data, it is unclear whether engine-out techniques will work in all cases. We therefore believe some engine companies will choose to use a combination of engine-out techniques and diesel oxidation catalysts, as discussed below.

Emission Reductions from Engine-out Techniques

PM emissions can be reduced through in-cylinder techniques for small nonroad diesel engines using similar techniques as used in larger nonroad and highway engines. As discussed in Section 4.1.1 there several technologies that can influence oxygen content and in-cylinder mixing (and thus lower PM emissions) including improved fuel-injection systems and combustion system designs. For example, increased injection pressure can reduce PM emissions substantially.[142] The wide-range of emission characteristics present in the existing engine certification data likely result from differences in fuel systems and combustion chamber designs. For many of the engines with higher emission levels, further optimization of the fuel system and combustion chamber can provide additional PM reductions.

Emission Reductions from Diesel Oxidation Catalysts

Diesel oxidation catalysts (DOCs) also offer the opportunity to reduce PM emissions from the engines in this power category. As explained earlier, DOCs are passive flow-through emission-control devices that are typically coated with a precious metal or a base-metal wash-coat. DOCs have been proven to be durable in-use on both light-duty and heavy-duty diesel applications. In addition, DOCs have already been used to control either PM or in some cases carbon monoxide on some nonroad applications.[143] However, as discussed in Section 4.1.1, certain DOC formulations can be sensitive to diesel fuel sulfur level. Specifically, precious-metal oxidation catalysts (which have the greatest potential for reducing PM) can oxidize the sulfur in the fuel and form particulate sulfates. Given the high level of sulfur in current nonroad fuel, the use of DOCs as a PM reduction technology is severely limited. Data presented by one engine manufacturer regarding the existing Tier 2 PM standard show that while a DOC can be used to meet the current standard when tested on 2,000 ppm sulfur fuel, lowering the fuel sulfur level to 380 ppm enabled the DOC to reduce PM by 50 percent from the 2,000 ppm sulfur fuel.[144] Without the availability of 500 ppm sulfur fuel in 2008, DOCs would be of limited use for nonroad engine manufacturers and would not provide the emission-control necessary for most engine manufacturers to meet the Tier 4 standards. With the availability of 500 ppm sulfur fuel, DOCs can be designed to provide PM reductions on the order of 20 to 50%, while suppressing particulate sulfate reduction.[145] These levels of reductions have been seen on transient duty cycles as well as on highway and nonroad steady-state duty cycles.

DOCs are also effective to control HC and CO emissions. The application of DOC as a means to comply with the PM standard in 2008 will also provide an effective means to meet the existing standards for NOx+NMHC and CO over the new test cycles in 2013. The increase in NOx emissions over transient test conditions with typical in-cylinder controls are very small as indicated by the transient adjustment factors estimated in the NONROAD model. HC emissions may increase during transient testing conditions, however the ability of a DOC to reduce HC emissions in excess of 80 percent would more than offset any increase in NOx+NMHC emissions observed over the new test cycles. Similarly for CO, the additional CO control allowed by the use of the DOC will more than offset any increase in CO emissions as measured over the new test cycles. For purposes of our cost analysis contained in Chapter 6, we have assumed that all engines certifying to the 2008 interim PM standards will use DOCs for compliance.

4.1.6 Meeting the Crankcase Emission Requirements

The most common way to eliminate crankcase emissions has been to vent the blow-by gases into the engine air intake system, so the gases can be recombusted. Prior to the HD2007 rulemaking, we have required that crankcase emissions be controlled only on naturally aspirated diesel engines. We had made an exception for turbocharged diesel engines (both highway and nonroad) because of concerns in the past about fouling that could occur by routing the diesel particulates (including engine oil) into the turbocharger and aftercooler. However, this is an environmentally significant exception since most nonroad equipment over 75hp use turbocharged engines, and a single engine can emit over 100 pounds of NOx, NMHC, and PM from the crankcase over its lifetime.

Given the available means to control crankcase emissions, we are eliminating this exception for nonroad diesel engines, as we did for highway engines in 2007. We anticipate that the diesel engine manufacturers will be able to control crankcase emissions through the use of closed crankcase filtration systems or by routing unfiltered blow-by gases directly into the exhaust system upstream of the emission-control equipment. However, the crankcase provision has been written such that if adequate control can be had without "closing" the crankcase, then the crankcase vent to the atmosphere. Manufacturers show that they meet this requirement by adding the emissions from the crankcase ventilation system to the emissions from the engine's exhaust system, either by measuring them separately and adding together mathematically or by routing crankcase emissions into the exhaust stream before sampling for emission measurement.

We expect that manufacturers will have to utilize closed crankcase approaches, as described here to meet the stringent tailpipe emission standards in this final rule. Closed crankcase filtration systems work by separating oil and particulate matter from the blow-by gases through single or dual stage filtration approaches, routing the blow-by gases into the engine's intake manifold and returning the filtered oil to the oil sump. Oil separation efficiencies in excess of 90 percent have been demonstrated with production ready prototypes of two stage filtration systems.[146] By eliminating 90 percent of the oil that would otherwise be vented to the atmosphere, the system works to reduce oil consumption and to eliminate concerns over fouling of the intake system when the gases are routed through the turbocharger. Hatz, a nonroad engine manufacturer, currently has closed crankcase systems on many of its turbocharged engines.

4.1.7 Why Do We Need 15 ppm Sulfur Diesel Fuel?

As stated earlier, we strongly believe that fuel sulfur control is critical to ensuring the success of NOx and PM aftertreatment technologies. To evaluate the effect of sulfur on diesel exhaust control technologies, we used three key factors for categorizing the impact of sulfur in fuel on emission-control function. These factors were efficiency, reliability, and fuel economy. Taken together, these three factors support the position that the Tier 4 standards are feasible only with diesel fuel sulfur levels of 15 ppm or lower. Brief summaries of these factors are provided below.

The **efficiency** of emission-control technologies to reduce harmful pollutants is directly affected by sulfur in diesel fuel. Initial and long-term conversion efficiencies for NOx, NMHC, CO and diesel PM emissions are significantly reduced by catalyst poisoning and catalyst inhibition due to sulfur. NOx conversion efficiencies with the NOx adsorber technology in particular are dramatically reduced in a very short time due to sulfur poisoning of the NOx storage bed. In addition, total PM control efficiency is negatively impacted by the formation of sulfate PM. As explained in the following sections, the CDPF, NOx adsorber, and urea SCR catalyst technologies described here have the potential to make significant amounts of sulfate PM under operating conditions typical of many nonroad engines. We believe that the formation of sulfate PM will be in excess of the total PM standard, unless diesel fuel sulfur levels are at or below 15 ppm. Based on the strong negative impact of sulfur on emission-control efficiencies for all of the technologies evaluated, we believe that 15 ppm represents an upper threshold of acceptable diesel fuel sulfur levels.

Reliability refers to the expectation that emission-control technologies must continue to function as required under all operating conditions for the life of the engine. As discussed in the following sections, sulfur in diesel fuel can prevent proper operation of both NOx and PM control technologies. This can lead to permanent loss in emission-control effectiveness and even catastrophic failure of the systems. Sulfur in diesel fuel impacts reliability by decreasing catalyst efficiency (poisoning of the catalyst), increasing diesel particulate filter loading, and negatively impacting system regeneration functions. Among the most serious reliability concerns with sulfur levels greater than 15 ppm are those associated with failure to properly regenerate. In the case of the NOx adsorber, failure to regenerate the stored sulfur (desulfate) will lead to rapid loss of NOx emission control as a result of sulfur poisoning of the NOx adsorber bed. In the case of the diesel particulate filter, sulfur in the fuel reduces the reliability of the regeneration function. If regeneration does not occur, catastrophic failure of the filter could occur. It is only by the availability of low-sulfur diesel fuels that these technologies become feasible.

Fuel economy impacts due to sulfur in diesel fuel affect both NOx and PM control technologies. The NOx adsorber sulfur regeneration cycle (desulfation cycle) can consume significant amounts of fuel unless fuel sulfur levels are very low. The larger the amount of sulfur in diesel fuel, the greater the adverse effect on fuel economy. As sulfur levels increase above 15 ppm, the adverse effect on fuel economy becomes more significant, increasing above one percent and doubling with each doubling of fuel sulfur level. Likewise, PM trap regeneration is inhibited by sulfur in diesel fuel. This leads to increased PM loading in the diesel particulate filter and increased work to pump exhaust across this restriction. With low-sulfur diesel fuel, diesel particulate filter regeneration can be optimized to give a lower (on average) exhaust backpressure and thus better fuel economy. As a result, for both NOx and PM technologies, reducing the fuel sulfur level decreases the operating costs of the vehicle.

4.1.7.1 Catalyzed Diesel Particulate Filters and the Need for Low-Sulfur Fuel

CDPFs function to control diesel PM through mechanical filtration of the solid PM (soot) from the diesel exhaust stream and then oxidation of the stored soot (trap regeneration) and oxidation of the SOF. Through oxidation in the catalyzed diesel particulate filter the stored PM is converted to CO_2 and released into the atmosphere. Failure to oxidize the stored PM leads to accumulation in the trap, eventually causing the trap to become so full that it severely restricts exhaust flow through the device, leading to trap or vehicle failure.

Uncatalyzed diesel particulate filters require exhaust temperatures in excess of 650˚C in order for the collected PM to be oxidized by the oxygen available in diesel exhaust. That temperature threshold for oxidation of PM by exhaust oxygen can be decreased to 450˚C through the use of base metal catalytic technologies. For a broad range of operating conditions typical of in-use diesel engine operation, diesel exhaust can be significantly cooler than 400˚C. If oxidation of the trapped PM would occur only at exhaust temperatures lower than 300˚C, then diesel particulate filters would be more robust for most applications and operating regimes. Oxidation of PM (regeneration of the trap) at such low exhaust temperatures can occur by using oxidants that are more readily reduced than oxygen. One such oxidant is NO_2.

NO_2 can be produced in diesel exhaust through the oxidation of the nitrogen monoxide (NO), created in the engine combustion process, across a catalyst. The resulting NO_2-rich exhaust is highly oxidizing in nature and can oxidize trapped diesel PM at temperatures as cool as 250˚C.[147] Some platinum group metals are known to be good catalysts to promote the oxidation of NO to NO_2. To promote more effective passive regeneration of the diesel particulate filters, significant amounts of platinum group metals (primarily platinum) are therefore being used in the wash-coat formulations of advanced CDPFs. The use of platinum to promote the oxidation of NO to NO_2 introduces several system vulnerabilities affecting both the durability and the effectiveness of the CDPF when sulfur is present in diesel exhaust. (In essence, diesel engine exhaust temperatures are in a range necessitating use of precious-metal catalysts to adequately regenerate the PM filter, but precious-metal catalysts are in turn highly sensitive to sulfur in diesel fuel.) The two primary mechanisms by which sulfur in diesel fuel limits the robustness and effectiveness of CDPFs are inhibition of trap regeneration, through inhibition of the oxidation of NO to NO_2, and a dramatic loss in total PM control effectiveness due to the formation of sulfate PM. Unfortunately, these two mechanisms trade-off against one another in the design of CDPFs. Changes to improve the reliability of regeneration by increasing catalyst loadings lead to increased sulfate emissions and, thus, loss of PM control effectiveness. Conversely, changes to improve PM control by reducing the use of platinum group metals and, therefore, limiting "sulfate make" leads to less reliable regeneration. We believe the best means of achieving good PM emission control and reliable operation is to reduce sulfur in diesel fuel, as shown in the following subsections.

4.1.7.1.1 Inhibition of Trap Regeneration Due to Sulfur

The CDPF technology relies on the generation of a very strong oxidant, NO_2, to ensure that the carbon captured by the PM trap's filtering media is oxidized under the exhaust temperature range of normal operating conditions. This prevents plugging and failure of the PM trap. NO_2 is produced through the oxidation of NO in the exhaust across a platinum catalyst. This oxidation is inhibited by sulfur poisoning of the catalyst surface.[148] This inhibition limits the total amount of NO_2 available for oxidation of the trapped diesel PM, thereby raising the minimum exhaust temperature required to ensure trap regeneration. Without sufficient NO_2, the amount of PM trapped in the diesel particulate filter will continue to increase and can lead to excessive exhaust back pressure and low engine power.

The failure mechanisms experienced by diesel particulate filters due to low NO_2 availability vary significantly in severity and long-term consequences. In the most fundamental sense, the failure is defined as an inability to oxidize the stored particulate at a rate fast enough to prevent net particulate accumulation over time. The excessive accumulation of PM over time blocks the passages through the filtering media, making it more restrictive to exhaust flow. To continue to force the exhaust through the now more restrictive filter, the exhaust pressure upstream of the filter must increase. This increase in exhaust pressure is commonly referred to as increasing "exhaust backpressure" on the engine.

The increase in exhaust backpressure represents increased work being done by the engine to force the exhaust gas through the increasingly restrictive particulate filter. Unless the filter is frequently cleansed of the trapped PM, this increased work can lead to reductions in engine performance and increases in fuel consumption. This loss in performance may be noted by the equipment operator in terms of sluggish engine response.

Full field test evaluations and retrofit applications of these catalytic trap technologies are occurring in parts of the United States and Europe where low-sulfur diesel fuel is already available.[T] The experience gained in these field tests helps to clarify the need for low-sulfur diesel fuel. In Sweden and some European city centers where 10 ppm diesel fuel sulfur is readily available, more than 3,000 catalyzed diesel particulate filters have been introduced into retrofit applications without a single failure. Given the large number of vehicles participating in these test programs, the diversity of the vehicle applications, and the extended time periods of operation, there is a strong indication of the robustness of this technology on 10 ppm low-sulfur diesel fuel.[149] Vehicle applications included intercity trains, airport buses, mail trucks, city buses and garbage trucks. Some vehicles have been operating with traps for more than 5 years and in excess of 300,000 miles. The field experience in areas where sulfur is capped at 50 ppm has been less definitive. In regions without extended periods of cold ambient conditions, such as the United Kingdom, field tests on 50 ppm cap low-sulfur fuel have also been positive, matching the durability at 10 ppm, though sulfate PM emissions are much higher. However, field tests on 50 ppm fuel in Finland, where colder winter conditions are sometimes encountered (similar to many parts of the United States), showed a significant number of failures (~10 percent) due to trap plugging. This 10 percent failure rate has been attributed to insufficient trap regeneration due to fuel sulfur in combination with low ambient temperatures.[150] Other possible reasons for the high failure rate in Finland when contrasted with the Swedish experience appear to be unlikely. The Finnish and Swedish fleets were substantially similar, with both fleets consisting of transit buses powered by Volvo and Scania engines in the 10 to 11 liter range. Further, the buses were operated in city areas and none of the vehicles were operated in northern extremes such as north of the Arctic Circle.[151] Given that the fleets in Sweden and Finland were substantially similar,

[T] Through tax incentives 50 ppm cap sulfur fuel is widely available in the United Kingdom and 10 ppm sulfur fuel is available in Sweden and in certain European city centers.

and given that ambient conditions in Sweden are expected to be similar to those in Finland, we believe that the increased failure rates noted here are due to the higher fuel sulfur level in a 50 ppm cap fuel versus a 10 ppm cap fuel.[U]

Testing on an even higher fuel sulfur level of 200 ppm was conducted in Denmark on a fleet of 9 vehicles. In less than six months all of the vehicles in the Danish fleet had failed due to trap plugging.[152] The failure of some fraction of the traps to regenerate when operated on fuel with sulfur caps of 50 ppm and 200 ppm is believed to be primarily due to inhibition of the NO to NO_2 conversion, as described here. Similarly the increasing frequency of failure with higher fuel sulfur levels is believed to be due to the further suppression of NO_2 formation when higher sulfur level diesel fuel is used. Since this loss in regeneration effectiveness is due to sulfur poisoning of the catalyst this real-world experience is expected to apply equally well to nonroad engines (i.e., operation on lower-sulfur diesel fuel, 15 ppm versus 50 ppm, will increase regeneration robustness).

As shown above, sulfur in diesel fuel inhibits NO oxidation leading to increased exhaust backpressure and reduced fuel economy. We therefore believe that sulfur levels in nonroad diesel fuel must be at or below 15 ppm to ensure reliable and economical operation over the wide range of expected operating conditions.

4.1.7.1.2 Loss of PM Control Effectiveness

In addition to inhibiting the oxidation of NO to NO_2, the sulfur dioxide (SO_2) in the exhaust stream is itself oxidized to sulfur trioxide (SO_3) at very high conversion efficiencies by the precious metals in the catalyzed particulate filters. The SO_3 serves as a precursor to the formation of hydrated sulfuric acid (H_2SO_4+H_2O), or sulfate PM, as the exhaust leaves the vehicle tailpipe. Virtually all of the SO_3 is converted to sulfate under dilute exhaust conditions in the atmosphere as well in the dilution tunnel used in heavy-duty engine testing. Since virtually all sulfur present in diesel fuel is converted to SO_2, the precursor to SO_3, as part of the combustion process, the total sulfate PM is directly proportional to the amount of sulfur present in diesel fuel. Therefore, even though diesel particulate filters are very effective at trapping the carbon and the SOF portions of the total PM, the overall PM reduction efficiency of catalyzed diesel particulate filters drops off rapidly with increasing sulfur levels due to the formation of sulfate PM downstream of the CDPF.

SO_2 oxidation is promoted across a catalyst in a manner very similar to the oxidation of NO, except it is converted at higher rates, with peak conversion rates in excess of 50 percent. The SO_2 oxidation rate for a platinum-based oxidation catalyst typical of the type that might be used

[U] The average temperature in Helsinki, Finland, for the month of January is 21˚F. The average temperature in Stockholm, Sweden, for the month of January is 26˚F. The average temperature at the University of Michigan in Ann Arbor, Michigan, for the month of January is 24˚F. The temperatures reported here are from www.worldclimate.com based upon the Global Historical Climatology Network (GHCN) produced jointly by the National Climatic Data Center and Carbon Dioxide Information Analysis Center at Oak Ridge National Laboratory (ORNL).

in conjunction with, or as a washcoat on, a CDPF can vary significantly with exhaust temperature. At the low temperatures the oxidation rate is relatively low, perhaps no higher than ten percent. However at the higher temperatures that might be more typical of agricultural tractor use pulling a plow and the highway Supplemental Emission Test (also called the EURO 4 or 13 mode test), the oxidation rate may increase to 50 percent or more. These high levels of sulfate make across the catalyst are in contrast to the very low SO_2 oxidation rate typical of diesel exhaust (typically less than 2 percent). This variation in expected diesel exhaust temperatures means that there will be a corresponding range of sulfate production expected across a CDPF.

The U.S. Department of Energy in cooperation with industry conducted a study entitled DECSE to provide insight into the relationship between advanced emission-control technologies and diesel fuel sulfur levels. Interim report number four of this program gives the total particulate matter emissions from a heavy-duty diesel engine operated with a diesel particulate filter on several different fuel sulfur levels. A straight line fit through this data is presented in Table 4.1-19 showing the expected total direct PM emissions from a diesel engine on the supplemental emission test cycle.[V] The SET test cycle, a 13 mode steady-state cycle that these data were developed on, is similar to the C1 eight mode steady-state nonroad test cycle. Both cycles include operation at full and intermediate load points at approximately rated-speed conditions and torque peak-speed conditions. As a result, the sulfate make rate for the C1 cycle and the SET cycle are expected to be similar. The data can be used to estimate the PM emissions from diesel engines operated on fuels with average fuel sulfur levels in this range.

Table 4.1-19
Estimated PM Emissions from a Diesel Engine at the Indicated Fuel Sulfur Levels

Fuel Sulfur [ppm]	Steady-State Emission-Control Performance[a]	
	Tailpipe PM[b] [g/hp-hr]	PM Increase Relative to 3 ppm Sulfur
3	0.003	--
7[a]	0.006	100%
15[a]	0.009	200%
30	0.017	470%
150	0.071	2300%

[a] The PM emissions at these sulfur levels are based on a straight-line fit to the DECSE data; PM emissions at other sulfur levels are actual DECSE data. (Diesel Emission Control Sulfur Effects (DECSE) Program - Phase II Interim Data Report No. 4, Diesel Particulate Filters-Final Report, January 2000. Table C1.) Although DECSE tested diesel particulate filters at these fuel sulfur levels, they do not conclude that the technology is feasible at all levels, but they do note that testing at 150 ppm is a moot point as the emission levels exceed the engine's baseline emission level.
[b] Total exhaust PM (soot, SOF, sulfate).

[V] Note that direct emissions are those pollutants emitted directly from the engine or from the tailpipe depending on the context in which the term is used, and indirect emissions are those pollutants formed in the atmosphere through chemical reactions between direct emissions and other atmospheric constituents.

Table 4.1-19 makes it clear that there are significant PM emission reductions possible with the application of catalyzed diesel particulate filters and low-sulfur diesel fuel. At the observed sulfate PM conversion rates, the DECSE program results show that the 0.01 g/hp-hr total PM standard is feasible for CDPF equipped engines operated on fuel with a sulfur level at or below 15 ppm. The results also show that diesel particulate filter control effectiveness is rapidly degraded at higher diesel fuel sulfur levels due to the high sulfate PM make observed with this technology. It is clear that PM reduction efficiencies are limited by sulfur in diesel fuel and that, to realize the PM emission benefits sought in this rule, diesel fuel sulfur levels must be at or below 15 ppm.

4.1.7.1.3 Increased Maintenance Cost for Diesel Particulate Filters Due to Sulfur

In addition to the direct performance and durability concerns caused by sulfur in diesel fuel, it is also known that sulfur can lead to increased maintenance costs, shortened maintenance intervals, and poorer fuel economy for CDPFs. CDPFs are highly effective at capturing the inorganic ash produced from metallic additives in engine oil. This ash is accumulated in the filter and is not removed through oxidation, unlike the trapped soot PM. Periodically the ash must be removed by mechanical cleaning of the filter with compressed air or water. This maintenance step is anticipated to occur on intervals of well over 1,500 hours (depending on engine size). However, sulfur in diesel fuel increases this ash accumulation rate through the formation of metallic sulfates in the filter, which increases both the size and mass of the trapped ash. By increasing the ash accumulation rate, the sulfur shortens the time interval between the required maintenance of the filter and negatively impacts fuel economy.

4.1.7.2 Diesel NOx Catalysts and the Need for Low-Sulfur Fuel

NOx adsorbers are damaged by sulfur in diesel fuel because the adsorption function itself is poisoned by the presence of sulfur. The resulting need to remove the stored sulfur (desulfate) leads to a need for extended high temperature operation that can deteriorate the NOx adsorber. These limitations due to sulfur in the fuel affect the overall performance and feasibility of the NOx adsorber technology.

4.1.7.2.1 Sulfur Poisoning (Sulfate Storage) on NOx Adsorbers

The NOx adsorber technology relies on the ability of the catalyst to store NOx as a metallic nitrate (MNO_3) on the surface of the catalyst, or adsorber (storage) bed, during lean operation. Because of the similarities in chemical properties of SOx and NOx, the SO_2 present in the exhaust is also stored by the catalyst surface as a sulfate (MSO_4). The sulfate compound that is formed is significantly more stable than the nitrate compound and is not released and reduced during the NOx release and reduction step (NOx regeneration step). Since the NOx adsorber is essentially 100 percent effective at capturing SO_2 in the adsorber bed, the sulfur build up on the adsorber bed occurs rapidly. As a result, sulfate compounds quickly occupy all of the NOx storage sites on the catalyst thereby rendering the catalyst ineffective for NOx storage and subsequent NOx reduction (poisoning the catalyst).

The stored sulfur compounds can be removed by exposing the catalyst to hot (over 650˚C) and rich (air-fuel ratio below the stoichiometric ratio of 14.5 to 1) conditions for a brief period.[153] Under these conditions, the stored sulfate is released and reduced in the catalyst.[154] While research to date on this procedure has been very favorable regarding sulfur removal from the catalyst, it has revealed a related vulnerability of the NOx adsorber catalyst. Under the high temperatures used for desulfation, the metals that make up the storage bed can change in physical structure. This leads to lower precious-metal dispersion, or "metal sintering," (a less even distribution of the catalyst sites) reducing the effectiveness of the catalyst.[155] This degradation of catalyst efficiency due to high temperatures is often referred to as thermal degradation. Thermal degradation is known to be a cumulative effect. That is, with each excursion to high temperature operation, some additional degradation of the catalyst occurs.

One of the best ways to limit thermal degradation is by limiting the accumulated number of desulfation events over the life of the engine. Since the period of time between desulfation events will likely be determined by the amount of sulfur accumulated on the catalyst (the higher the sulfur accumulation rate, the shorter the period between desulfation events), the desulfation frequency should be proportional to the fuel sulfur level. In other words, for each doubling in the average fuel sulfur level, the frequency and accumulated number of desulfation events are expected to double. We concluded in the HD2007 rulemaking, that this thermal degradation would be unacceptable high for fuel sulfur levels greater than 15 ppm. Some commenters to the HD2007 rule suggested that the NOx adsorber technology can meet the HD2007 NOx standard using diesel fuel with a 30 ppm average sulfur level. This implies that NOx adsorbers can tolerate as much as a four-fold increase in desulfation frequency (when compared with an expected seven to 10 ppm average) without any increase in thermal degradation. That conclusion was inconsistent with our understanding of the technology at the time of the HD2007 rulemaking and remains inconsistent with our understanding of progress made by industry since that time. Diesel fuel sulfur levels must be at or below 15 ppm to limit the number and frequency of desulfation events. Limiting the number and frequency of desulfation events will limit thermal degradation and thus enable the NOx adsorber technology to meet the NOx standard.

This conclusion remains true for the highway NOx adsorber catalyst technology and will be equally true for nonroad engines applying the NOx adsorber technology to comply with the Tier 4 standards.

Nonroad and highway diesel engines are similarly durable, so they consume a similar amount of diesel fuel their lifetimes. This means that both nonroad and highway diesel engines will have the same exposure to sulfur in diesel fuel and will therefore require the same number of desulfation cycles over their lifetimes. This is true independent of the test cycle or in-use operation of the nonroad engine.

Sulfur in diesel fuel for NOx adsorber equipped engines will also have an adverse effect on fuel economy. The desulfation event requires controlled operation under hot and net fuel-rich exhaust conditions. These conditions, which are not part of a normal diesel engine operating cycle, can be created through the addition of excess fuel to the exhaust. This addition of excess fuel causes an increase in fuel consumption.

Future improvements in the NOx adsorber technology, as we have observed in our ongoing diesel progress reviews, are expected and needed to meet the Tier 4 NOx standards. Some of these improvements are likely to include improvements in the means and ease of removing stored sulfur from the catalyst bed. However because the stored sulfate species are inherently more stable than the stored nitrate compounds (from stored NOx emissions) and so will always be stored preferentially to NOx on the adsorber storage sites, we expect that a separate release and reduction cycle (desulfation cycle) will always be needed to remove the stored sulfur. We therefore believe that fuel with a sulfur level at or below 15 ppm sulfur will be necessary to control thermal degradation of the NOx adsorber catalyst and to limit the fuel economy impact of sulfur in diesel fuel.

4.1.7.2.2 Sulfate Particulate Production and Sulfur Impacts on Effectiveness of NOx Control Technologies

The NOx adsorber technology relies on a platinum-based oxidation function to ensure high NOx-control efficiencies. As discussed more fully in Section 4.F.1, platinum-based oxidation catalysts form sulfate PM from sulfur in the exhaust gases significantly increasing PM emissions when sulfur is present in the exhaust stream. The NOx adsorber technology relies on the oxidation function to convert NO to NO_2 over the catalyst bed. For the NOx adsorber this is a fundamental step prior to the storage of NO_2 in the catalyst bed as a nitrate. Without this oxidation function the catalyst will trap only that small portion of NOx emissions from a diesel engine that is NO_2. This would reduce the NOx adsorber effectiveness for NOx reduction from in excess of 90 percent to something well below 20 percent. The NOx adsorber relies on platinum to provide this oxidation function due to the need for high NO oxidation rates under the relatively cool exhaust temperatures typical of diesel engines. Because of this fundamental need for a precious-metal catalytic oxidation function, the NOx adsorber inherently forms sulfate PM when sulfur is present in diesel fuel, since sulfur in fuel invariably leads to sulfur in the exhaust stream.

The Compact-SCR technology, like the NOx adsorber technology, uses an oxidation catalyst to promote the oxidation of NO to NO_2 at the low temperatures typical of much of diesel engine operation. By converting a portion of the NOx emissions to NO_2 upstream of the ammonia SCR reduction catalyst, the overall NOx reductions are improved significantly at low temperatures. Without this oxidation function, low-temperature SCR NOx effectiveness is dramatically reduced, making compliance with the NOx standard impossible. Future Compact-SCR systems therefore need to rely on a platinum oxidation catalyst to provide the required control of NOx emissions. This use of an oxidation catalyst to enable good NOx control means that Compact-SCR systems will produce significant amounts of sulfate PM when operated on anything but the lowest fuel sulfur levels due to the oxidation of SO_2 to sulfate PM promoted by the oxidation catalyst.

Without conversion of NO to NO_2 promoted by oxidation catalysts, neither of these control technologies can meet the Tier 4 NOx standard. Each of these technologies will therefore require low-sulfur diesel fuel to control the sulfate PM emissions inherent in the use of highly active oxidation catalysts. The NOx adsorber technology may be able to limit its impact on sulfate PM emissions by releasing stored sulfur as SO_2 under rich operating conditions. The Compact-SCR technology, on the other hand, has no means to limit sulfate emissions other than through lower catalytic function or lowering sulfur in diesel fuel. The degree to which the NOx emission-control technologies increase the production of sulfate PM through oxidation of SO_2 to SO_3 varies somewhat from technology to technology, but it is expected to be similar in magnitude and environmental impact to that for the PM control technologies discussed previously, since both the NOx and the PM control catalysts rely on precious metals to achieve the required NO to NO_2 oxidation reaction.

At fuel sulfur levels below 15 ppm this sulfate PM concern is greatly diminished. Without this low-sulfur fuel, the NOx control technologies are expected to create PM emissions well in excess of the PM standard regardless of the engine-out PM levels. We therefore believe that diesel fuel sulfur levels will need to be at or below 15 ppm to apply the NOx control technology.

4.2 Transient Emission Testing

4.2.1 Background and Justification

In the 1998 Rulemaking for Nonroad Compression Ignition Engines, we acknowledged that effective in-use control of emissions from nonroad sources would be positively impacted by having a duty cycle that more accurately characterized the transient nature of nonroad activity. While no certification cycle may guarantee complete in-use emission control, a cycle that appropriately characterizes the activity of the subject equipment achieves a greater level of control. The basics of any nonroad transient duty cycle should fulfill the following goals:

- Represent nonroad activity broadly, with a basis in real-world activities through diverse data segments;
- Exercise the engine over its operating range; cycle not limited to a specific speed or load, but traverses the operating range over the engine's full power range;
- Measure particulate matter (PM) on a transient basis;
- Capture the basic characteristics of PM, as currently defined, including:
    - organic and inorganic carbon fractions
    - volatile fraction
    - sulfate fraction
    - ash, etc., and
- Ensure that measures developed to control emissions over the cycle encourage and afford greater assurance of adequate control of emissions in-use.

Since that rulemaking, we have embarked on a strategy for cataloging operational data, generating a duty cycle from those data sets, and compiling a transient composite duty cycle that represents a broad range of activity for nonroad diesel equipment. Working cooperatively with the Engine Manufacturers Association (EMA) and through contract with the Southwest Research Institute (SwRI), we created a set of duty cycles based on the following nonroad applications:

- Agricultural Tractor
- Backhoe Loader
- Crawler Tractor
- Arc Welder
- Skid Steer Loader
- Wheel Loader
- Excavator

These application duty cycles were created from actual speed and load data recorded in-use on each of these pieces of equipment. The strategy for generating the duty cycles and the base data sets differed slightly. However, combining these two strategies has ensured that the strengths of both approaches are integrated into the resultant composite duty cycle. Each of the pieces of equipment represented the top tier of nonroad equipment as defined by their contribution to nonroad diesel inventory as defined by the 1991 Nonroad Engine and Vehicles Emissions Study (NEVES). The pieces of equipment selected have retained their historical significance even today as they appear to match fairly well with EPA modeling data for the impacts of those applications.

The existing steady-state duty cycle affords good coverage of the range of activity seen by nonroad diesel applications; however, it is incomplete. The range of nonroad activity is much broader and much more varied than can be captured by a set of steady-state points (see Figure 4.2-1). No single transient cycle, of reasonable length, could capture the full body of nonroad diesel activity from the various equipment applications. However, it is possible to capture typical operation of nonroad equipment and to extrapolate the applicability of available data to the remainder of nonroad equipment for purposes of certification and modeling. This can't replace an in-use characterization, but it does drive development of engine design strategies to focus emission-control and performance parameters on a broader set of activity that is much more likely to be seen in use.

A much broader set of data from the nonroad duty cycle generation may be found in Memorandum from Cleophas Jackson to EPA Air Docket A-2001-28. This operational and cycle data demonstrate the amount of nonroad activity that can occur outside the modes of the ISO C1 duty cycle.

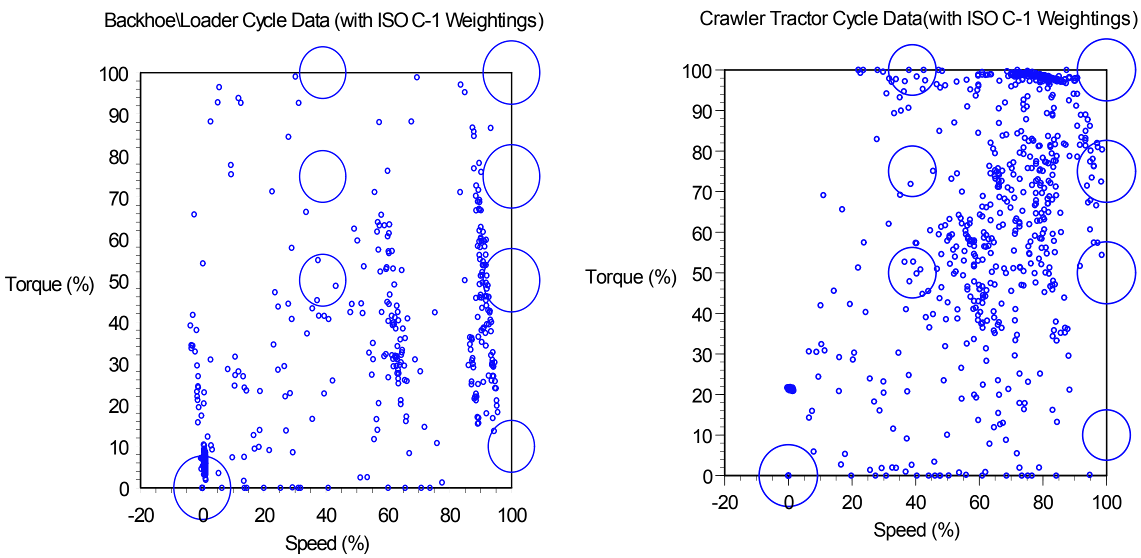
4.2.1.1 Microtrip-Based Duty Cycles

The microtrip-based cycles were created based on a range of activity the equipment is likely to see in use. The weighting of each microtrip impacted the duration of each segment within the resulting duty cycle. Each microtrip was extracted from a full set of data with the equipment being operated within the targeted implement application. The data from the extracted segment were compared with the full body of data for the targeted implement application based on a chi square analysis, with a 95% confidence level, of the nature of the operation. This included a characterization of the speeds, loads, velocities, and accelerations over the full operating map, for the given piece of equipment. Experienced operators conducting actual work operated each unit. The projects ranged from an actual farmer plowing to a backhoe digging a trench for a municipal works project to a wheel loader in a rock quarry loading a truck to a skid steer loader preparing plots in a subdivision under construction. The microtrip-based application duty cycles were the Agricultural Tractor cycle, the Backhoe Loader cycle and the Crawler/Dozer cycle.

4.2.1.2 "Day-in-the-Life"-Based Duty Cycles

In attempting to address real-world activity, another strategy was employed for the second set of nonroad duty cycles. This approach was termed the “day-in-the-life” strategy. It could be said that this approach yielded only a single or perhaps two microtrips per piece of equipment. This approach was employed to capture data for work that would have otherwise have been done regardless of EPA data collection needs. With these pieces, the data recorded was simply data generated as selected pieces of equipment were used by contractors or construction personnel during their normal operation versus being asked to do certain types of operation. The day-in-the-life duty cycles consisted of the Skidsteer Loader cycle, the Arc Welder cycle, the Rubber Tire Loader cycle, and the Excavator cycle. The Excavator Cycle is in fact a composite duty cycle assembled from three equal time segments of operating data from two different excavators.

Figure 4.2-1
Backhoe Loader and Crawler Tractor Cycle Data versus the ISO 8178-4 C1 Cycle



4.2.2 Data Collection and Cycle Generation

4.2.2.1 Test Site Descriptions

Operators were instructed to complete a job commensurate with the functionality of the vehicle and at their customary pace. Experienced operators conducted their normal work with a given piece of nonroad equipment. The work conducted by the equipment during the data collection was actual work and not artificial scenarios, which ensured the accuracy of the data.

4.2.2.1.1 Agricultural Tractor Cycle Operation

The John Deere agricultural tractor was operated by an experienced farmer on his farm. The farmer was asked to conduct the following activities as he normally would on any given work day. This activity formed the basis for the microtrips for the agricultural tractor duty cycle. The microtrip activity segments included: planter, tandem offset discing (35 foot), bedder, cultivator, ripper (10 row), folding chisel plow, and turnaround. The work was conducted during spring planting season in Hamlin, Texas, using an actual in-use field being prepared for cultivation. The tractor was used to make passes with each selected implement. The normal load operation retained for inclusion in the cycle generation was the “normal” operation with each implement. The data from the intentionally, highly loaded pass were not included in the eventual Agricultural Tractor cycle.

4.2.2.1.2 Backhoe Loader Cycle Operation

The Caterpillar backhoe loader was utilized on a site by the City of Houston, Utility Maintenance Division, Fleet Management Department to conduct the following activities: roading, trenching, loading and grade and level. The operation was conducted by a municipal employee experienced in the operation of the backhoe conducting that activity. Engine data were collected during the repair of a collapsed city sewage line in a residential neighborhood. The activity included demolishing the road over the sewage line, trenching to reach the pipe, craning to remove the old pipe and install the new pipe, backfilling, loading, spreading gravel, and finish-grading the site.

4.2.2.1.3 Crawler Tractor Cycle Operation

The Caterpillar D4 Tractor was used to conduct the following activity on the grounds of Southwest Research Institute by an experienced operator. The microtrips included road bed preparation, clearing activity, and pit activity. The operation was examined at three independent sites. Site 1 included clearing trees and brush for a construction site. At Site 2 the equipment dug and prepared a road bed. At Site 3 V-trench and pit operations were examined. This activity was similar to preparing a site for a small building foundation.

4.2.2.1.4 Wheel Loader Operation

The Caterpillar 988F Wheel Loader was operated at Redland Stone Products Company (quarry) in San Antonio, Texas. Data were collected between June 8 and June 10, 1998. The equipment was operated from morning until midnight, working to fill construction and mining trucks, open-topped trailers of Class-8 highway trucks, and rail cars.[156] The material being moved was typical for a quarry application, including aggregate of various densities, such as crushed stone, gravel, and sand. Twenty-six hours of data were gathered at the quarry for the wheel loader.

4.2.2.1.5 Skid Steer Loader Operation

The Daewoo skid steer loader was operated at a construction site for a new complex of townhouses in the San Antonio, Texas, area by a commercial site preparation company. The equipment was used to create drives for individual homes. Specifically, the skid steer loader was used to haul and position aggregate foundation material to prepare the driveway and sidewalk areas prior to laying asphalt. Over twelve hours of data were gathered over three work days for the skid steer loader. The implement used by the skid steer loader during this operation was its bucket.

4.2.2.1.6 Arc Welder Operation

The Lincoln Electric 250-amp arc welder was operated at Redland Stone Products Company (quarry) in San Antonio, Texas. Data were collected over a single work day. The equipment was used to perform repairs on a large, mobile steel crusher tower by a private contract firm, Holt. Eight hours of data were gathered at the quarry for the arc welder.

4.2.2.1.7 Excavator Operations

The Hitachi EX300LC excavator was operated at 3 different sites over 7 days in the greater San Antonio metropolitan area. Data were collected during Winter 1998 and Spring 1999. The equipment was used to level ground at a building site, to load aggregate materials into trucks at a quarry and to dig trenches and transport pipes for a sewer project. Almost thirty-nine hours of data were gathered for this excavator.

The Caterpillar 320BL excavator was operated at 4 different sites over 6 days in the greater San Antonio metropolitan area. Data were collected during Winter 1998 and Spring 1999. The equipment was used to perform digging, trenching, pipe transport and placement and backfilling associated with an on-going sewer project. More than thirty-eight hours of data were gathered for this excavator.

4.2.2.2 Engine and Equipment Description

In generating the microtrip-based and the day-in-the-life duty cycles, the equipment selected were based on the highest sales volume applications and the contribution of those applications to the ambient inventories for NOx and PM. Those cycles were created based on a John Deere 4960 Agricultural Tractor, Caterpillar 446B Backhoe Loader, and a Caterpillar D4H Crawler Tractor. The detailed description of the engines may be seen in Table 4.2-1 through Table 4.2-3.[157]

Table 4.2-1
Agricultural Tractor—John Deere 4960

Engine Characteristic	Value
Rated Speed (rpm)	2200
Peak Torque (Nm)	970
Peak Power (kW)	189.2
Low Idle Speed (rpm)	850
Operating Range (rpm)	850-2400
Other Engine Descriptors	7.6L displacement, electronic controls

Table 4.2-2
Backhoe Loader—Caterpillar 446B

Engine Characteristic	Value
Rated Speed (rpm)	2200
Peak Torque (Nm)	405
Peak Power (kW)	76.8
Low Idle Speed (rpm)	800
Operating Range (rpm)	800-2300
Other Engine Descriptors	CAT 3114-D17 engine

Table 4.2-3
Crawler Tractor—Caterpillar D4H

Engine Characteristic	Value
Rated Speed (rpm)	2200
Peak Torque (Nm)	442
Peak Power (kW)	85
Low Idle Speed (rpm)	800
Other Engine Descriptors	3204-D17 engine

The engines used for data generation for the day-in-the-life approach were from a skid steer loader, an arc welder, and a wheel loader. The engine parameters of the Caterpillar 988F Series II rubber tire loader, the Lincoln arc welder and the Daewoo skidsteer loader are listed in Table 4.2-4 through Table 4.2-6.

Table 4.2-4
Rubber Tired Loader—1997 Caterpillar 988F Series II

Engine Characteristic	Value
Rated Speed (rpm)	2080
Peak Torque (Nm)	2908
Peak Power (kW)	321
Low Idle Speed (rpm)	850
Operating Range (rpm)	850-2250
Other Engine Descriptors	CAT 3408E-TA engine, Caterpillar HEUI Fuel System, electronic

Table 4.2-5
Arc Welder—1997 Lincoln Electric Shield-Arc 250

Engine Characteristic	Value
Rated Speed (rpm)	1,725
Peak Torque (Nm)	162
Peak Power (kW)	28.3
Low Idle Speed (rpm)	1375
Operating Range (rpm)	800-1900
Other Engine Descriptors	Perkins D3.152 engine

Table 4.2-6
Skid Steer Loader—1997 Daewoo DSL-601

Engine Characteristic	Value
Rated Speed (rpm)	2,800
Peak Torque (Nm)	121 Nm
Peak Power (kW)	30.6 kW
Low Idle Speed (rpm)	800
Peak Torque Speed (rpm)	1,700
Other Engine Descriptors	Yanmar 4TNE84 engine, 2.0 L Displacement, in-line 4 cyl, naturally aspirated

Two pieces of equipment were selected for generating the excavator duty cycle based on estimates of equipment population and power distribution among excavators in the nonroad equipment inventory in the United States at that time.[158] With the highest excavator sales volumes being in the 60-130 kW and 130-225 kW ranges, the Agency created its excavator duty cycle based on both a Hitachi EX300LC excavator at 155 kW (208 hp) and a Mitsubishi/CAT 320 BL excavator at 95 kW (128 hp). The detailed description of the engines may be seen in Table 4.2-7 and Table 4.2-8.

Table 4.2-7
Excavator (higher power output)—1997 Hitachi EX300LC

Engine Characteristic	Value
Rated Speed (rpm)	2,200
Peak Torque (Nm)	Nm (636 lbs-ft)
Peak Power (kW)	155 kW
Low Idle Speed (rpm)	680
Peak Torque Speed (rpm)	1,500
Other Engine Descriptors	ISUZU A-6SD1TQA(AC/JI) engine, 9.8 L displacement, mechanical controls

Table 4.2-8
Excavator (lower power output)—1997 Mitsubishi/CAT 320 BL

Engine Characteristic	Value
Rated Speed (rpm)	1,800
Peak Torque (Nm)	Nm (473lbs-ft)
Peak Power (kW)	95 kW
Low Idle Speed (rpm)	800
Peak Torque Speed (rpm)	1,200
Other Engine Descriptors	Mitsubishi/CAT 3066T engine, 6.4 L displacement

4.2.2.3 Data Collection Process

The data collection process for both the microtrip-based and the day-in-the-life duty cycles was based on collecting engine operational data in the field by mechanical and electronic means. Engine speed data were measured by instrumenting the engine of each piece of equipment with a tachometer to measure engine speed in revolutions per minute (rpm). The torque was measured either mechanically by linear transducer or as transmitted across the engine's control area network as a fuel-based torque signal. The mechanical torque measurement utilized rack position to determine the load being demanded of the engine. To calibrate the voltage signal from the linear actuator the engine rack position versus actual fuel rate and engine-out torque were determined based on laboratory evaluation of the same model engine. Once a map of engine speed, load, actual torque, and fuel rate was compiled, the in-field load was determined based on rack position and engine speed, as measured by the tachometer.

Data loggers were used to record field data during operation and the data loggers were equipped with flash memory media. The data loggers recorded engine parameters only during operation, so data gathering did not occur while the engine was stopped. Data collection rates varied from cycle to cycle from a rate of 3.33 Hz to 5 Hz. Using cubic spline interpolation, the data were then reduced to 1 Hz format for the purpose of cycle generation.

4.2.2.4 Cycle Creation Process

The basic methodology of comparing extracted segments to the full body of data were used for both duty cycle types. The major difference is in how the activity was defined for each. The microtrip-based activity specified the type of work performed by various implements for a given piece of nonroad equipment in an effort to effectively incorporate the different types of operation through which the equipment could be exercised over its lifetime. The day-in-the-life approach was meant simply to characterize the nature of the full range of activity seen by the equipment during its typical operation over the period of evaluation. The body of data for neither approach was meant to be all encompassing to the extent that no other activity would be expected from that piece of equipment over its lifetime. The microtrip approach represents the broadest sweep in the compilation of nonroad operation. The resulting duty cycles in each case do represent the most representative set of data from the full body of data collected.

4.2.2.4.1 Microtrip Cycle Creation

The contractor that conducted the in field testing and data reduction was Southwest Research Institute (SwRI) with significant input from the Engine Manufacturers Association (EMA) and direction from the United States Environmental Protection Agency (EPA). The methodology used for creating the microtrip-based cycles involved extracting the actual data by comparing the running window of actual data to the full body of data that was collected for each type of activity. This involved a chi-square[W] analysis comparing observed to expected data. The observed data set was the data being evaluated for inclusion in the cycle for the specific active window. The expected data set was represented by the full body of data from the given activity. The chi-square comparison involved assessing the following for each window of operation:

- Rate of change in speed (dSpeed)
- Rate of change in torque (dTorque)

[W] $\sum(O_i - E_i)^2 / E_i$ where O_i is the Observed frequency in the ith interal and E_i is the Expected frequency in the ith interval based on the frequency distribution of the entire population for the given quantity.

- Power
- Rate of change in power (dPower)
- Speed and torque
- Torque and dSpeed
- Speed and dTorque
- Duration and magnitude of change in power

The specific steps involved in cycle generation were the following:

1. Separate the raw vehicle data into data files by vehicle activity.
2. Load first activity file.
3. Calculate power. Add to raw data file.
4. Normalize speed using the FTP process and manufacturer's specified rated speed. Normalize torque, and power using measured peak values and create a scalar-normalized data file.
5. Calculate the time derivative of normalized speed, torque, and power.
6. Calculate the duration and magnitude of all increases, decreases, and steady-state periods from the normalized power data.[X] Count occurrences of duration and magnitude of changes in power for selected ranges.
7. Count occurrences of power and rates of change of speed, torque, and power for selected ranges. Count occurrences of speed and torque, change in speed at selected torque levels, change in torque at selected speed levels, and duration and magnitude of changes in power for selected ranges. The relative frequencies of occurrence (RFO) were collected within the specified ranges of activity (e.g. normalized range of speed of 20 units).
8. Characteristic graphs of each activity was created for each piece of equipment. Several formats were used to characterize the various analysis of the equipment operation:
   - Scatter plots of normalized speed and load data
   - RFO data for delta[Y] speed versus normalized torque
   - RFO data for normalized speed versus delta normalized torque
   - RFO plots of magnitudes and duration of delta power
9. The analysis of steps 1-8 was conducted by SwRI for each activity for each duty cycle.
10. The scalar normalized speed data (based on manufacturer specified rated speed) and normalized torque (or load - based on the peak torque available at the given speed) was used to generate the final set of activity comparisons for extracting the "actual" data for the microtrip from the full body of activity data collected for the specific application.

Microtrip Weightings

The microtrips of the agricultural tractor cycle, backhoe loader cycle, and crawler cycle were weighted based on feedback from the engine manufacturers on the amount of time each

[X]Steady-state is defined as any instantaneous change in normalized speed or normalized torque with a magnitude less than 2%.

[Y]Delta is used to describe the instantaneous rate of change of the specified quantity.

application was expected to operate using a given implement performing a set function over the lifetime of that piece of equipment. The microtrip weighting for the Agricultural Tractor cycle may be seen in Figure 4.2-2 to Figure 4.2-4. The cycle creation was based on linking the microtrips with transition points between each activity segment.

Figure 4.2-2

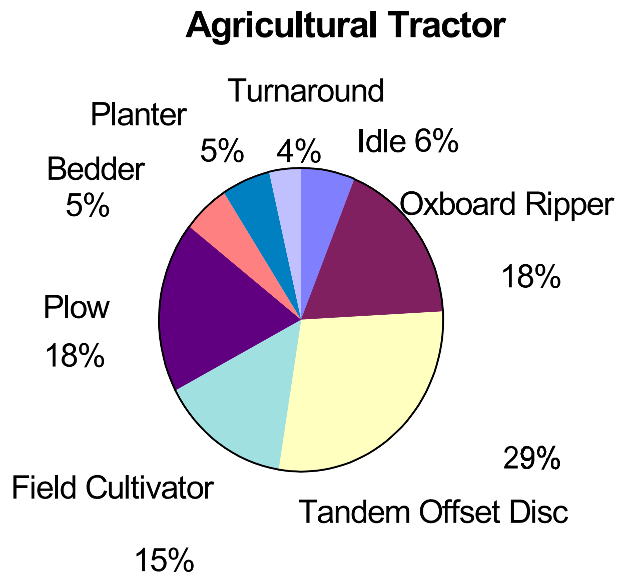


Figure 4.2-3

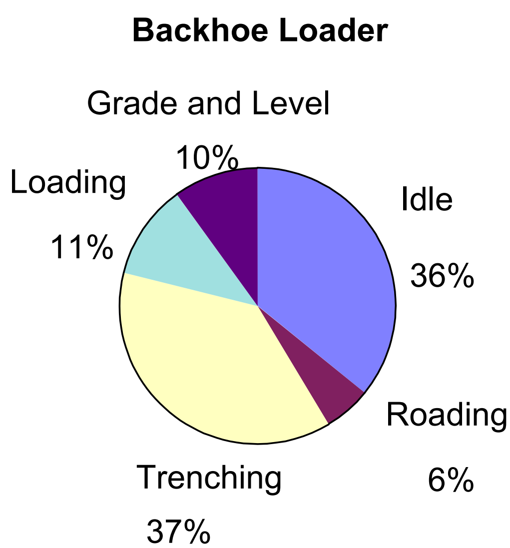
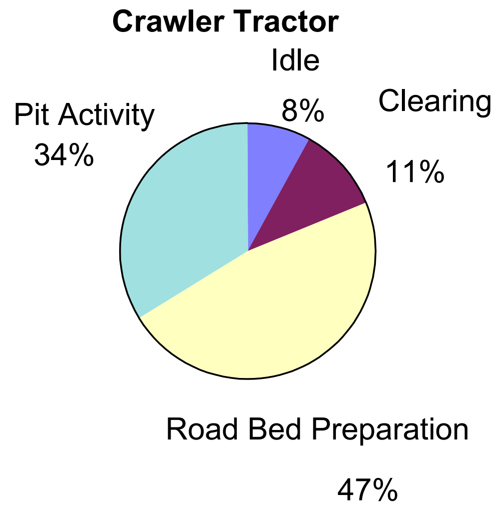


Figure 4.2-4



In generating the duty cycles and conducting the analyses, relative frequency of occurrence of various parameters as reported by the contractor were compared with the full set of real-world data. Figure 4.2-5 shows the difference in the full set of real-world data collected versus the microtrip, for one activity type. As can be seen in this figure, the difference in the total data set and the identified microtrip was relatively small, based on the relative frequency of occurrence.

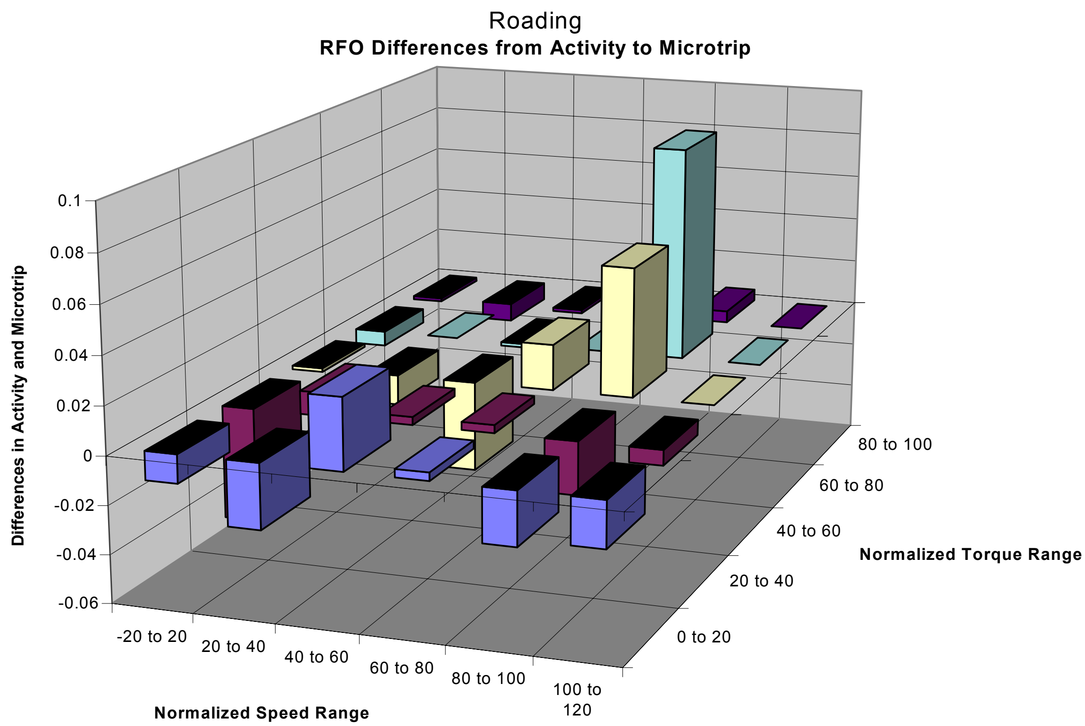


Figure 4.2-.5
Example of Microtrip vs. Data Set for Tractor Activity

Cycle Creation

Each of the microtrip-based duty cycles were created based on the statistical analysis previously described. The linked component microtrips were then reduced to 1 Hz data from the original 3.33 Hz signal using a cubic spline interpolation. The duty cycle was then speed and torque normalized, based on the maximum available power/torque mapping. These duty cycles were the first set of cycles that were used for creating the composite nonroad transient duty cycle.

4.2.2.4.2 Day-in-the-Life Duty Cycle Generation

In generating the day-in-the-life data, a similar chi-square analysis was used to compare RFO data from the running window of data with the full body of data. The distinction lies in that this was not done for multiple activity types for each piece of equipment. The analysis was conducted using a nineteen-minute window incremented at one-minute intervals. The approach used for data reduction, while similar, also varied in that the bin increments used for the day-in-the-life duty cycles was 100 rpm and 200 lb-ft for torque versus the normalized 20 percent windows from the microtrip approach. The steps taken by SwRI are as follows.

1. Define "bins" sized at 100 rpm for speed by 200 ft-lb for torque.
2. Sort entire data file (e.g. 376,768 observations ~ 26 hours) into bins.
3. Compute a frequency table to indicate the number of observations contained in each bin. Similar to the RFO bins from the microtrip analysis.
4. Increment within data file by 1 minute, and sort the next 19 minutes
5. Compute the chi-square statistic for comparison with frequency distribution of the population data file.
6. The approach to analyzing each nineteen-minute "window" of activity was repeated at one-minute increments for the entire body of data.
7. The window of activity that best represented the full body of data for that piece of equipment was selected as the most typical duty cycle.
8. Four iterations on the analysis was conducted to develop a typical 1 duty cycle, a typical 2 duty cycle, a high transient speed[Z] duty cycle, and a high transient torque duty cycle for each application.
9. For each window of activity, the data used were the actual, contiguous data from the body of data for that piece of equipment.

Given the nature of this data-generation process, the detailed analysis needed for weighting the microtrips and determining the time basis for inclusion into a composite cycle was not needed. The resulting duty cycles were simply the result of the extraction of data from the complete raw data set, which were subsequently normalized.

4.2.2.4.3 Excavator Cycle Generation

Data files for each piece of equipment were appended together in chronological order to form a data population for that excavator. Each data population contained columns for time of data acquisition (incremented at 5 Hz), engine speed, and rack position. Data for engine speed and rack position were used to compute a column for torque in units of pound-feet (lb-ft), based on the rack-to-torque algorithm using correlation information compiled earlier for the corresponding excavator engine. Tasks of choosing the representative segments to form a composite excavator cycle were then initiated based on these two different data populations.

The in-use data population of each excavator was sorted into two-dimensional intervals or "bins," and a histogram was compiled based on the frequency of occurrences for speed and torque pairs within the designated bins. The percent or relative frequency of occurrence (RFO) is considered a histogram that describes the data population. By choosing a segment that closely matched the characteristic RFO compilation, it is therefore rationalized that the chosen segment is indeed representative of the given data population. Using the same bin intervals as were applied to create a histogram (RFO) for each data population, a similar histogram was created for each 380-second candidate segment of data. Each candidate segment overlapped the previous segment by 320 seconds, as the process for excerpting candidate segments incremented through

[Z]High transient duty cycles (speed or torque) represent the single most transient speed or torque window of data (highest number and magnitude of instantaneous changes in speed or torque) from the full body of data.

the data population using a 60-second step size. Chi-square analyses tested each candidate segment to rank each segment by comparing its RFO histogram to the RFO histogram created for its associated data population. The following is the approach used for computing a chi-square statistic, relative frequency of occurrence distributions to that of the corresponding population for engine speed and torque values, for each candidate segment:

1. Define “bins” for speed expressed in rpm, and torque as lb-ft
2. Sort each data population (approximately 38 hours, at 5 Hz) into bins
3. Compute a relative frequency of occurrence table to indicate the percentage of observations contained in each bin
4. Increment through the data population by 60 seconds, sort the next 380-second segment into similar bins, and compute a relative frequency of occurrence table
5. Compute a chi-squarea statistic for comparing the frequency distribution of the segment to that of the population
6. Repeat Steps 4 and 5 for all such 380-second candidate segments, for an entire data population
7. Sort segments by increasing chi-square rank (low statistic means good correlation)

Note: The chi-square statistic is the summation of:

$$(O_i - E_i)^2 / E_i$$

where O_i is the observed frequency in the ith interval of the 380-second sample window, and E_i is the expected frequency of the ith interval based on the frequency distribution of the entire population.

The sliding 380-second "window" was used to determine the distribution of speed-torque combinations experienced by each type of equipment over the entire range of operating data collected on each unit. The "window" was advanced by one-minute increments through the data to determine a most typical segment for each excavator and a second most typical segment for the lower-powered unit.

Based on initial torque map information obtained with each engine on the steady-state test bench, a normalizing process was applied to each of the 5 Hz data segments (part of “data smoothing”). FTP normalizing methods outlined in the 40 CFR part 86, subpart N, were used for expressing observed engine speed and torque values for the three selected segments of 5 Hz data in terms of the percentage of an engine’s full load performance and idle speed. The 5 Hz data for segments chosen to represent the first- and second-most typical segments in the data population generated with the Caterpillar 320BL excavator were normalized using the rated speed and torque map information obtained with the Caterpillar 3066T engine mounted on the steady-state test bench. Similarly, the 5 Hz data for the segment best representing the typical operation of the higher powered Hitachi excavator were normalized using torque map information obtained for the Isuzu A-6SD1T engine on the steady-state test bench.

An averaging method was applied to the three selected segments to convert each segment from the original 5 Hz to 1 Hz data files. Each 5 Hz data pair was first normalized and then the percentage values were averaged. In general, the smoothing technique produced a value for speed and a value for torque for each one-second interval (1 Hz) by averaging the five values in the interval of interest.

After establishing in-use operating engine speed and torque data populations for excavators rated in both the low and high power ranges, three representative segments were appended together to form a 20-minute composite excavator cycle. The first two segments were the most representative data from the lower and higher powered excavators, respectively. The third segment represented the second-most typical data from the lower-powered excavator (i.e., ranked number two in chi-square analyses for that population). This resulted in a composite cycle that was apportioned with two-thirds data gathered from the Caterpillar 320BL excavator rated in the 100 to 175 hp range, and one-third from data gathered from the Hitachi EX300LC excavator rated in the 176 to 300 hp range. The three segments were then joined into a composite 20-minute excavator duty cycle by the addition of appropriate transition segments leading into and linking each segment of transient operation. A three-second transition joined Segment 1 and Segment 2, and similarly another three-second transition joined Segments 2 and 3. A no-load idle condition was appended for 27 seconds at the beginning and end of the cycle.

4.2.3 Composite Cycle Construction

Having all seven application cycles in hand, including the four cycle variations apiece for the arc welder, skidsteer loader and rubber-tire loader, we began construction of a transient composite nonroad duty cycle. The approach for addressing the weighting of contributions from each equipment type to the composite cycle was left at equally weighting each contribution. While consideration was given to population-weighted or inventory-based weighting factors for the composite cycle, in the interest of ensuring a universally applicable cycle, no unique weighting factors were assigned. The decision of which data segments to extract from the component duty cycles was based on uniqueness of operation (avoidance of replicate data in the composite cycle) and level of transient operation (steady-state operation was not included in the transient cycle).[AA] Extracted cycle segments were linked using three second transition periods, when needed, to ensure smooth transitions within the cycle and to avoid spurious data generation based on changes in speed and load that were unrealistic between segments. Transition periods were deemed necessary when the change in the magnitude of the torque or speed value was greater than twenty using the normalized data. The cycle was constructed using the denormalized segments for each component cycle based on the original engine map for the engines used to generate the component cycles. Once the raw data were available, the normalization based on the max speed map was conducted. This was necessary because each cycle was originally normalized using different procedures (e.g., FTP speed and torque

[AA]Steady State Operation is defined as an instantaneous speed or torque change less than 2% of the maximum magnitude.

normalization or GCS[BB] speed with FTP torque normalization). The MAP used for normalizing the raw data remained FTP-based (percent of maximum torque at the given speed) for torque. The Maximum Speed Determination was used for the speed normalization. Figure 4.2-6 identifies the location of the cycle segments as extracted from the component application duty cycles, the segment duration, and segment position in the composite duty cycle.

Figure 4.2-6

Supplemental NRTC (Nonroad Transient Composite) Cycle

Application Number	Nonroad Application	Application Duration (seconds)	Application in Cycle Position (#seconds)	Segments from Application Cycle (#seconds)	Segment Name	Segment Duration (seconds)	Cumulative Cycle Time (seconds)	Segment in Cycle Position (#seconds)
					Start/Transition	28	28	0-28
1	Backhoe Loader	206	29-234	52-86	Roading	35	63	29-63
				108-141	Trenching	34	97	64-97
				174-218	Loading	45	142	98-142
				351-442	Grade/Level	92	234	143-234
2	Rubber-Tire Loader	184	235-418	746-822	Typical Operation	77	311	235-311
				531-637	Hi-Spd Transient	107	418	312-418
3	Crawler-Dozer	209	419-627	85-206	Road Bed Prep	122	540	419-540
				376-462	Clearing	87	627	540-627
4	Agricultural Tractor	150	628-777	265-414	AgTractor	150	777	628-777
5	Excavator	35	778-812	319-338	LowerHp (128Hp)	20	797	778-797
				431-445	HigherHp (208Hp)	15	812	798-812
					Transition	3	815	813-815
6	Arc Welder	204	816-1019	1007-1103	Typical Operation	97	912	816-912
				544-650	Hi-Spd Transient	107	1019	913-1019
7	Skid Steer Loader	185	1020-1204	264-365	Typical Operation	102	1121	1020-1121
				150-232	Hi-Trq Transient	83	1204	1122-1204
					Idle/Transition/End	34	1238	1215-1238

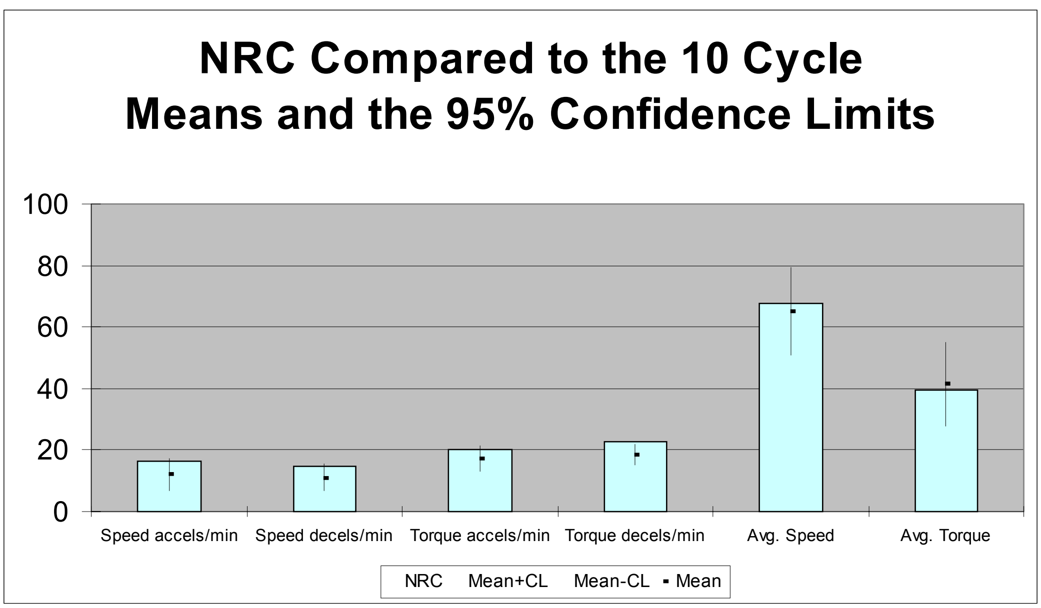
[BB]GCS Speed or Governed Central Speed is defined as the speed corresponding to the point along the engine's MAP (maximum allowable power) curve at which power is 50% of maximum measured rated power once the maximum measured power has been surpassed.

4.2.4 Cycle Characterization Statistics

The characterization of the operational data were also subsequently revisited for purposes of comparison in addressing composite cycle construction. The nature of the transient activity is characterized in a report to EPA by Dyntel.[159] The goal of the analysis was to provide an assessment of the transient nature of nonroad activity between different applications. These analyses (small bin, large bin, and general cycle) were used to address the comparability of the resulting composite nonroad diesel transient duty cycle to the component data set that was collected for each of the component cycles. The size of the bin was simply a reference to the scale used for the analysis (either coarse or fine). As may be seen in Figure 4.2-7, the composite nonroad transient duty cycle fit well within the average of all of the original nonroad duty cycles based on the operational data. The figure is a plot of the nonroad composite cycle characteristics with the statistics of the remainder of the nonroad diesel cycles plotted as a mean with the standard deviation between those statistics from the other cycles shown. The ten cycles represented include:

- Ag Tractor
- Crawler
- Skid Steer Typical 1
- Wheel Loader High Torque Transient
- Arc Welder High Torque Transient
- Backhoe
- Arc Welder Typical 2
- Wheel Loader Typical 1
- Excavator
- Skid Steer Loader High Torque Transient

Figure 4.2-7
Summary of Nonroad Cycles Comparison to NR Composite



4.2.5 Cycle Normalization/Denormalization Procedure

The actual values for speed and load in rpm and lbs-ft for each of the application cycles needed to be converted into normalized values before any application cycle could be used on an engine, other than the engine originally used to create the application cycle itself. This process of normalization entailed converting the actual in-use operating speed and load values of the “raw” duty cycle, as recorded from the engine used to create the cycle originally, into a percentage of that engine’s maximum achievable speed and load values. This yields a schedule of percentage-based speed and load values that can be converted to absolute values for speed (rpm) and load (lbs-ft). This conversion depends on applying the normalized percentage values for speed and load to the maximum achievable power (MAP) for the new test engine. Multiplying the percentage values of the normalized cycle by the measured speed and load maximums of the new engine’s MAP curve, in fact, denormalizes the cycle. This means that the denormalized speed and load values may be used as commanded values on a test cell dynamometer to exercise the new engine in exactly the same manner as the original engine was run for a particular application cycle. The load values in lbs-ft for each of the seven types of application cycles and all their cycle permutations, i,e., Typical, High Transient Speed , etc., were all converted to normalized values (and conversely, into denormalized values, at later times) using the FTP normalization procedure detailed in 40 CFR Part 86. The speed values in rpm for each type of application cycle were normalized initially in one of three different ways.

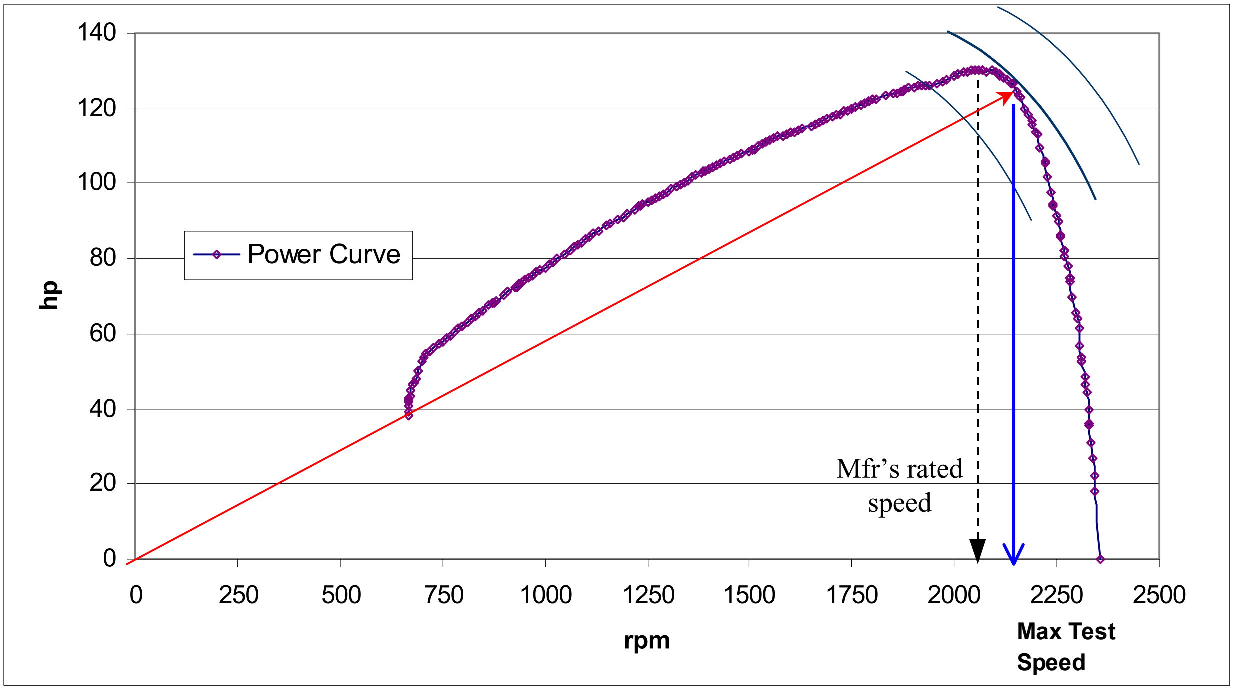
The speed values in each of the original microtrip cycles, the agricultural tractor, backhoe loader, and crawler-dozer, were all normalized using the FTP procedure. The speed values in each of the original day-in-the-life cycles, rubber tire loader, skidsteer loader and arc welder were all normalized using the governed central speed procedure (GCS).[CC] The speed values in the excavator cycle were normalized, and later denormalized, using the FTP normalization procedure detailed in 40 CFR Part 86. However, in time and for the construction of EPA’s composite nonroad cycle, all the application cycles were normalized using the Agency’s Maximum Speed determination procedure.

The Maximum Speed Determination procedure uses the measured speed and load values from an engine’s power curve to determine what is the maximum power that the engine can attain and at what speed that engine will achieve its maximum power. This value for speed at maximum power can then be used in lieu of a manufacturer’s rated speed number for a particular engine to conduct a normalization or denormalization of engine or cycle for purposes of running a duty cycle on a particular engine. The procedure is based on a spreadsheet calculation and is discussed in our analysis of comments associated with the final rule for marine diesel engines (64 FR 73300, December 29, 1999).[160, 161] As detailed in Figure 4.2-8, the maximum speed can be found below the point on the engine power curve that is the farthest distance from the point of

[CC] GCS is the speed value on the Maximum Achievable Power (MAP) curve of an engine at which the engine’s speed is 50% of the measured rated power for that engine, after measured rated power has been passed on the MAP curve.

origin of the graph of engine's measured speed and power values. That farthest point on the curve is described as the point of maximum power achievable by the engine under study.

Figure 4.2-8
Maximum Test Speed Determination



4.2.6 Cycle Performance Regression Statistics

In assessing the nonroad transient duty cycles, ten nonroad diesel engines were exercised over the nonregulatory[162] nonroad duty cycles to assess emission impacts of each duty cycle, as well as to determine the ability of typical nonroad diesel engines to pass the existing highway cycle performance regression statistics. That data may be seen in a report from SwRI with an accompanying EPA summary of the results in the Memorandum to EPA Air Docket 2001-28 from Cleophas Jackson entitled "Nonroad Duty Cycle Regression Statistics." Subsequent analysis on the composite nonroad transient cycle was based on test cell data collected from testing at the National Vehicle and Fuel Emissions Laboratory and Southwest Research Institute, as well as through the European Commission's Joint Research Center (EC-JRC), and various engine manufacturers from the United States, Europe, and Japan.

4.2.7 Constant-Speed, Variable-Load Equipment Considerations

Some nonroad diesel engines operate in equipment that calls for constant engine speeds. Some examples of engines in this category of nonroad diesel equipment include pumps, electrical power generator sets (gen sets), pavement saws and cement mixers. While the operating speed in many cases is not truly constant, it is generally true that the unit's speed will vary little during operation. These types of equipment are more tolerant of changes in operating load than other more closely governed constant-speed nonroad applications. Some pieces of constant-speed equipment will be governed to a nominal "zero" variation in rpm during operation for critical operations such as maintenance of electrical power and refrigeration loads. For those engines designed to operate under less restrictive, more "transient" conditions, the Agency had proposed an alternative constant-speed, variable-load (CSVL) transient duty test cycle over which an engine manufacturer might operate their engines. The CSVL duty cycle was meant to capture emissions from these infrequent modes of operation. However, after a review of comments and a broader look at the wide range of applications embraced by the constant-speed, variable-load segment of the nonroad diesel equipment population, the Agency has chosen not to adopt a CSVL transient test cycle at this time. Instead, EPA, with all of its stakeholders in this regard, will map out a process of engine testing and analysis to better characterize constant-speed equipment in-use to design the most appropriate test cycle for the largest number of constant-speed engines. Consideration will also be given to addressing the operation of gen set applications as a potentially unique subset of this category. EPA undertakes this process with an eye to initiating a rulemaking which would lead to promulgation of a transient cycle for constant-speed engines before the Agency's 2007 Nonroad Technical Review.

4.2.7.1. Background on Cycle Considered

The CSVL transient test cycle was derived from EPA's Arc Welder Highly-Transient Torque nonroad application duty cycle. That cycle was developed on a direct-injection, naturally-aspirated, 30kW (40 hp) diesel arc welder engine, a constant-speed application running at variable load. The Highly-Transient Torque cycle, one of four arc welder cycles, is comprised of a single twenty-minute segment of all the real-time operating data collected on that engine.

While designed to control nonroad engines in a broad range of constant-speed applications, commenters noted that EPA's proposed CSVL test cycle had an average speed which was lower than the speed which many manufacturers considered optimal for their constant-speed engines in-use. Further, EPA had received comments that many constant speed engines operated near or at their rated engine rpm during much of that engine's useful life, as with electrical generating sets in particular. EPA had proposed that these constant-speed engines, when tested in the laboratory with installed speed governors, be required to meet cycle statistics for engine load but not for engine speed. This relief was aimed at addressing the twin concerns that many engines operated at a significantly high percent of their rated speed much of the time in-use and had different degrees of engine speed variation during that operation.

Engine manufacturers raised additional design concerns for constant-speed engines required to meet emission standards over EPA's proposed cycle. Their concerns generally focused on the fact that the cycle had relatively light engine loads and was derived from an arc welder powered by a naturally-aspirated engine. Commenters questioned the representativeness of the CSVL cycle for generators, which they claimed was a more common application within the constant-speed engine population than was an arc welder. A second issue involved the average load that would be experienced by an engine running on the CSVL test cycle. The average load factor of the normalized application cycle was approximately 25% of engine capacity. Manufacturers of constant-speed engines with significantly higher load factors on their engines during operation, upwards of 90% of normalized engine load at constant speed, argued that their engines would not be able to pass cycle-regression statistics for certification without significant re-tuning of the engines to operate over the CSVL cycle. Several commenters noted that some nonroad constant-speed engines with high brake-mean effective pressures (BMEP), or high rated-power constant-speed engines, were narrowly focused on providing higher power capability at a single speed while meeting emission requirements. These engines used larger, less-responsive turbochargers to achieve their requisite higher BMEP. Manufacturers pointed out that the smaller BMEP engine on which the arc welder cycles were developed was more responsive to torque changes than their high BMEP engines were designed to encounter. As such, these manufacturers felt that their engines would be penalized by the number and magnitude of torque changes in the CSVL cycle.

At the same time, however, the Agency shared engine manufacturers' concerns for creating a duty cycle that achieved emission reductions while appropriately modeling in-use operation of their engines. EPA would have find it unproductive to require an approach that lead merely to improvements in the operation and emissions of the engine under laboratory conditions which, were in turn unrelated to the engine's in-use operation. Based on the comments the Agency has received regarding the constant-speed, variable-load duty cycle, we intend to continue to work with all interested parties to develop a new constant-speed, variable-load duty cycle. The Agency envisions that any new test cycle would result in comparable stringency for ensuring effective in-use control, as does the current duty cycle developed for fully transient test characterization - EPA's NRTC test cycle.

4.2.7.2. Follow-on Constant-Speed Engine Testing and Analysis

In consultation with the Engine Manufacturers Association (EMA) and other stakeholders, the Agency will embark on a process with the nonroad engine and equipment manufacturers that will result in collection of additional engine operation data that will appropriately characterize the operation of nonroad diesel engines used in equipment in constant-speed applications. To ensure that the data collected is robust and applicable to most, if not all, segments of the nonroad equipment market, and to facilitate global technical regulations and eventual cycle harmonization, the Agency, manufacturers and other interested parties, in consultation with non-domestic governmental entities will work together to develop a plan that incorporates the following elements:

Define operation of a non-generator, non-transient equipment class:

– Target Equipment/Application Types[DD]

[DD]- When the arc welder application was originally considered for inclusion in the cycle generation effort, EMA endorsed EPA's choice of the arc welder as a constant speed application.

•air/gas compressors, pressure washers, water/irrigation pumps, oil field equipment, hydro power units, leaf blower/vacuums, shredders, bore/drill rigs, mixing equipment, pavement saws, arc welding sets, chippers/shredders/grinders, light plants/sign boards, tampers, rammers, and plate compactors, concrete/industrial saws, crushers/material handling equipment and refrigeration/AC equipment;
– Engine Speed Range - anticipate EMA feedback
– Power range
  • 25 to 175 hp, 175-350 hp[EE], and 350 to 750 hp
– Market Sectors
  • construction, agriculture, maintenance/handling, pumps/welders

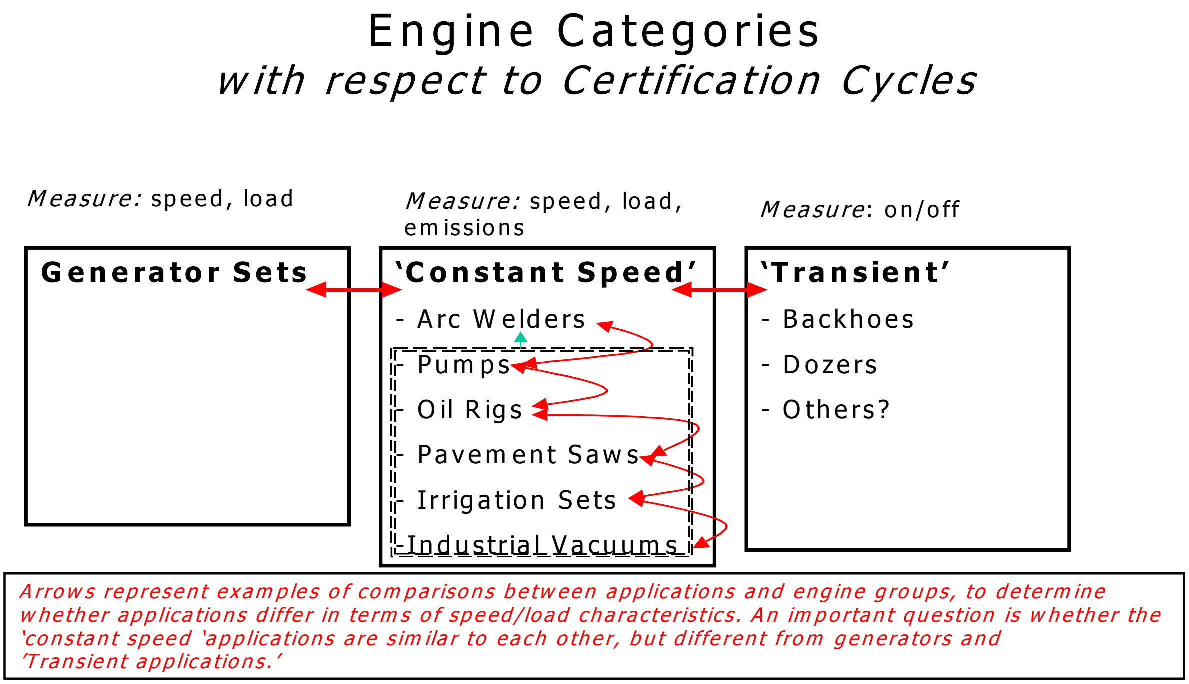
Define sample sizes, duration of "cycle" for application intercomparisons :
– Number of pieces of equipment in each category
  • Sufficient to discern significant differences in speed and load characteristics
– Number of hours of operation per application per site
  • Forty or more hours of operating data

Define data collection parameters:
– Speed
– Load
– Exhaust Temperature
– Engine Oil Temperature (1st 20 minutes of engine on after 4 hours of engine off)
– Engine Coolant Temperature (1st 20 minutes of engine on after 4 hours of engine off)

In addition to ensuring that the sampling plan addresses the issues outlined above, EPA will seek agreement among the stakeholders on the level of involvement of all parties in the data collection and generation, data reduction and analysis, and final cycle construction and assessment efforts. Initially, the logistical questions concerning program timing and duration of all parts of the data collection and eventual cycle development efforts would have to be charted and agreed upon by program participants. EPA expects that broad groupings of nonroad engines from various applications would then be compared between and among each other to determine whether particular applications differed in terms of speed and load operating characteristics (see Figure 4.2-9 below). One question which is particularly important is whether “constant speed” applications are similar to one another, but different than either transient or generator-type applications. As we move forward with the process of data collection and subsequent cycle generation, other interested parties, including the state of California, will also be invited to participate in these efforts. Future engine emission control technologies would need to be anticipated and considered for their impacts on nonroad equipment emissions.

[EE]The Agency's current data base for cold start operation includes construction equipment in the power range of 150 to 350 hp.

Figure 4.2-9



4.2.8 Cycle Harmonization

4.2.8.1 Technical Review

One concern raised by the engine manufacturers was that the mapping method used to generate the real-world torque data introduced an error by no appropriately accounting for the impact of transient activity of the actual torque signal from the engine. The basis of the issue was primarily a torque signal in the field, based on the rack position, that may not have actually occurred had an in-line torque meter been employed. Two aspects of this warrant review. The first aspect of actual torque versus inferred torque. The second aspect of this issue is whether or not rack position or the demanded load is an appropriate metric for developing duty cycles representing real-world operation. To address the second issue in the context of responsiveness of a nonroad engine, it should be clear that, although feedback torque from the engine provides a clear signal of what was accomplished by the engine, it is not a fair metric of the demanded load. Given the fact that a typical operator or driver tends to demand a desired torque the engine's response to that demand, though not distinct, is a separate issue. It is this reasoning through which command cycles are generated. The command cycle represents the speed and load demanded of the engine. The engine's responsiveness can be addressed through performance statistics.

Engine manufacturers sought to address the first concern through a playback analysis that addressed the Iα correction as an offset to the commanded load signal. The playback approach would involve rerunning one of the engines (identical engine model) in the test cell over the defined duty cycle with the calculated Iα offset to measure torque using an in-line torque meter. Manufacturers provided the inertia data for their engines either used for cycle development or anticipated to be included in the testing program. The data provided by members of the Engine Manufacturers Association (EMA) may be seen in Table 4.2-9 and Table 4.2-10.

Table 4.2-9
Nonroad Diesel Engines Used for Cycle Generation

No.	Engine Mfg	Engine Model	Machine Mfg	Machine Model	Application	Rated Power (Kw)	Peak Torque (N m)	Rated Speed (RPM)	Low Idle (RPM)
1	Caterpillar	3204-D17	Caterpillar	Cat D4H	Crawler Tractor	85 peak	442	2200	800
2	Caterpillar	3114-D17	Caterpillar	Cat 446B	Backhoe Loader	76.8 peak; 70.8 rated	405	2200	800
3	Caterpillar	3408E - TA	Caterpillar	988F-II	Wheel Loader (2)	321		2100	850
4	Isuzu	A-6SD1 TQA	Hitachi	EX-300LC	Excavator High Power	161	834	2000	850
5	John Deere	6081	John Deere	JD 4960	Ag Tractor	186	970	2200	850
6	Mitsubishi	3066T	Caterpillar	Cat 320 Excavator	Excavator Low Power	95	641	1800	860
7	Perkins	'97 D3.152	Lincoln	97 'Shield-Arc' 250, K1283	Arc Welder	28		1725	800 (1)
8	Yanmar	'97 4TNE84	Daewoo	DSL-601	Skid Steer Loader	31	121	2800	800

Table 4.2-10
Engine Inertia Data Used for Iα Correction Calculation

No.	Engine Mfg	Engine Model	Total Inertia (Kg-m2)	Total Inertia (N-m-s2)	Engine Inertia (N-m-s2 = kg-m2)	Flywheel Inertia (N-m/s2 = kg-m2)
1	Caterpillar	3204-D17	1.7899	1.7899	0.2249	1.5650
2	Caterpillar	3114-D17	0.9770	0.9770	0.5550	0.4220
3	Caterpillar	3408E - TA	2.8637	2.8637	1.3147	1.5490
4	Isuzu	A-6SD1 TQA	7.5303	7.5303	2.8263	4.7040
5	John Deere	6081	2.4400	2.4400	0.5000	1.9400
6	Mitsubishi	3066T	0.9160	0.9160	0.2160	0.7000
7	Perkins	'97 D3.152	0.1083	0.1083	0.1083	
8	Yanmar	'97 4TNE84	0.2317	2.3629		

The correction that was undertaken by EPA and Southwest Research Institute (SwRI) used the following methodology. The original 3 Hz data set was used to correct the torque data rather than interpolated 1 Hz data to ensure the raw data were corrected to avoid error propagation within the 1 Hz scalar data.

1. Apply the Iα correction to calculate the new torque command.
2. Apply original technique to create 1 Hz raw command cycles using the cubic spline interpolation for the those cycles that were originally collected at 3.33 Hz.
3. Each resultant correct raw data duty cycle was then normalized using the Maximum Speed determination method (See Section 4.2.3).

4. Cycle segments for the Composite Nonroad Transient duty cycle were then reassemble from the component duty cycles.

The result of the correction, as conducted by SwRI, was that there were very small modifications to the most severe torque excursions. The peaks and valleys were trimmed slightly. The overall change in the cycle resulted in less than 0.5% correction, typically.

4.2.8.2 Global Harmonization Strategy

4.2.8.2.1 The Need for Harmonization

Given the increasingly global marketplace in which nonroad engines are sold, alignment of standards and procedures helps facilitate introduction of cleaner technology at lower across in multiple markets. Given the nature of the nonroad diesel market with a large number of very diverse product offerings and in some cases, small niche market volumes, the ability to design once for different markets helps reduce the costs, especially of the lower volume equipment models. While alignment of limit values may be a key component of harmonized regulations, alignment of test procedures, measurement protocols, and other aspects of certification and testing procedures help reduce the testing burden manufacturers will face when selling and distributing their products in multiple markets. Much of the development of new procedures and test methods has originated in the United States, Europe, and Japan. While other markets tend to adopt emission limits and procedures as a part of a more global process on a different time frame. Given the nature of regulatory and technological development, allowing the leading markets for which new technology will need to be introduced to have comparable protocols simply reduces the costs those markets will be forced to absorb. In any effort to utilize procedures in multiple regulatory arenas, care should be taken to include an assessment of equivalence and appropriateness. In so doing, both Europe and the United States conducted an assessment of real-world operation of nonroad diesel equipment. The data-collection effort in the United States started in 1995. The subsequent data-collection effort in Europe confirmed that, as expected, nonroad diesel activity in Europe was comparable.

In moving forward with a single test cycle for both Europe and the United States, and potentially a global nonroad diesel cycle, the basic framework for the cycle was agreed upon. In addition to the work initiated by the Agency in compiling a nonroad transient duty cycle, it was important to ensure that concerns about global suitability be addressed. The context used for this assessment in Europe was the existing European Transient Cycle (ETC). While this duty cycle was developed for highway diesel applications, it was seen as an adequate basis for which European industry and government staff could assess EPA's proposed Nonroad Transient Duty Cycle. Representatives from Japan's government and industry have periodically participated in this process as well; however, no such framework for comparison was requested for the evaluation process from any representative from Japan. Throughout the development of the duty cycle, industry representatives from the United States, Europe, and Japan have provided detailed technical input. In Table 4.2-11 shows early results presented by Deutz exercising a nonroad diesel engine over the EPA-generated Nonroad Transient Duty Cycle indicating an ability to pass cycle performance criteria with only a slight problem with the Torque Intercept statistic.

Table 4.2-11
Initial Deutz Data Submission for
EPA Nonroad Diesel Transient Duty Cycle (Nov. 13, 2000)

			Speed	Torque	Power
Standard error of estimate (SE)	measured	NRTC	56,48 rpm	7,58%	7,15%
		ETC	24,29 rpm	6,59%	5,67%
	tolerance		max 100 rpm	max 13%	max 8 %
Slope of the regression line (m)	measured	NRTC	1,010	0,925	0,968
		ETC	0,990	0,963	0,976
	tolerance		0,95 to 1,03	0,83 to 1,03	0,89 to 1,03
Regression coefficient (r^2)	measured	NRTC	0,996	0,958	0,973
		ETC	0,993	0,980	0,981
	tolerance		min 0,9700	min 0,88	min 0,91
Y intercept of the regression line (b)	measured	NRTC	18,01 rpm	30,10 Nm	3,62 kW
		ETC	17,67 rpm	5,80 Nm	0,62 kW
	tolerance		+/- 50 rpm	+/- 20 Nm	+/- 4 kW

red:	out of tolerance
green:	near to tolerance limit

4.2.8.2.2 Harmonization Methodology

The composite Nonroad Transient (NRTC) duty cycle developed by the Agency was used as the reference cycle for conducting subsequent development and testing work. It was originally introduced to the global regulatory community and engine industry in Geneva in June 2000. After an on-going dialogue with industry in the United States and Europe, additional modifications were suggested by the European Commission based on manufacturer concerns with their ability to meet test cell performance statistics with this duty cycle. In September 2001, it was decided by a joint European, American, and Japanese government and industry workgroup that the Joint Research would use the then "candidate" cycle to conduct additional changes commensurate with the goal of not allowing the instantaneous transient speed and torque changes to be greater than those experienced within the European Transient Cycle (ETC). Using a Bessel filtering algorithm, the cycle was then modified by the EC-JRC to meet the ETC target of 23% of torque events faster than 4 seconds. The two cycles may be seen on a time basis in Figures 4.2-11 and 4.2-10. The average load and average speed of each cycle are shown in Table 4.2-12. The speed characteristics of the original cycle were similar to the speed characteristics of the ETC. This is not an indication that the speed trace was identical, but rather that the maximum instantaneous speed changes of the NRTC were similar to the maximum instantaneous speed changes of the ETC.[FF]

[FF]Memorandum to EPA Air Docket A-2001-28 from Cleophas Jackson, Report from the JRC entitled "Contribution to the NRTC Development Based on Test Data Supplied by Engine Manufacturers," February 26, 2001.

Figure 4.2-10
EPA Nonroad Transient Test Cycle as of March 2001

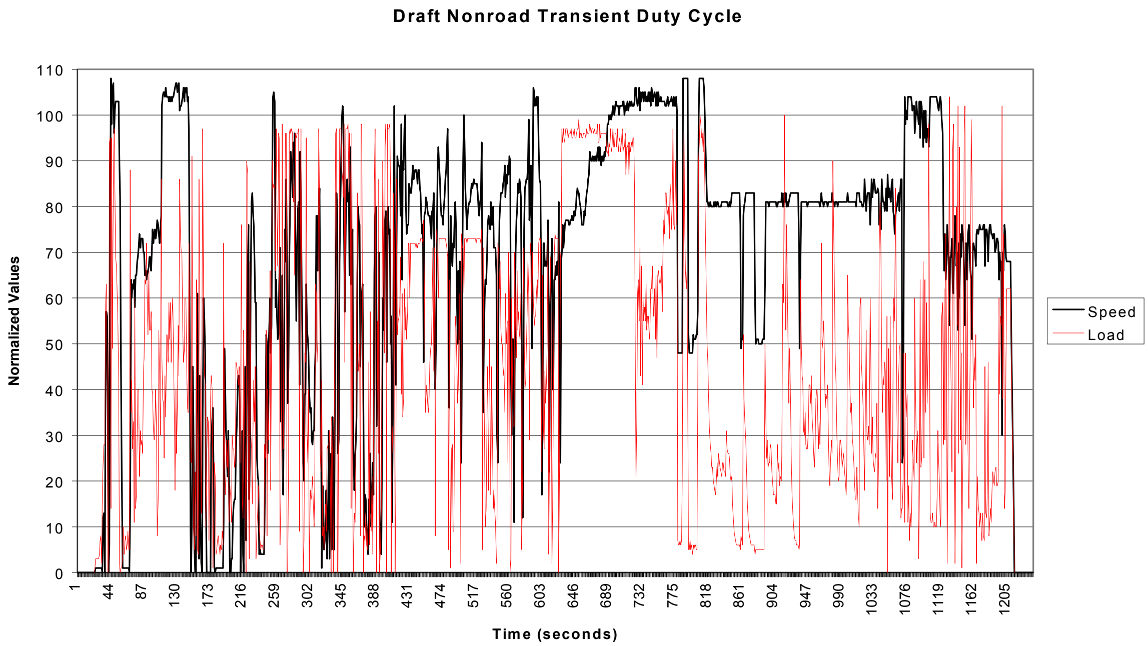


Table 4.2-12
Comparison of Cycle Averages

Duty Cycles	Average Normalized Speed	Average Normalized Torque
EPA NRTC	63%	47%
JRC Modified NRTC	68%	39%

The following figures 4.2-12 through 4.2-16 describe the JRC Modified NRTC with respect to speed and load and the transient nature of the cycle. This will be contrasted with the same characteristics of the EPA- generated NRTC. The JRC modified NRTC was also known as the San Antonio cycle or the JRC.

Figure 4.2-11
JRC Nonroad Transient Test Cycle after Bessel Filtering

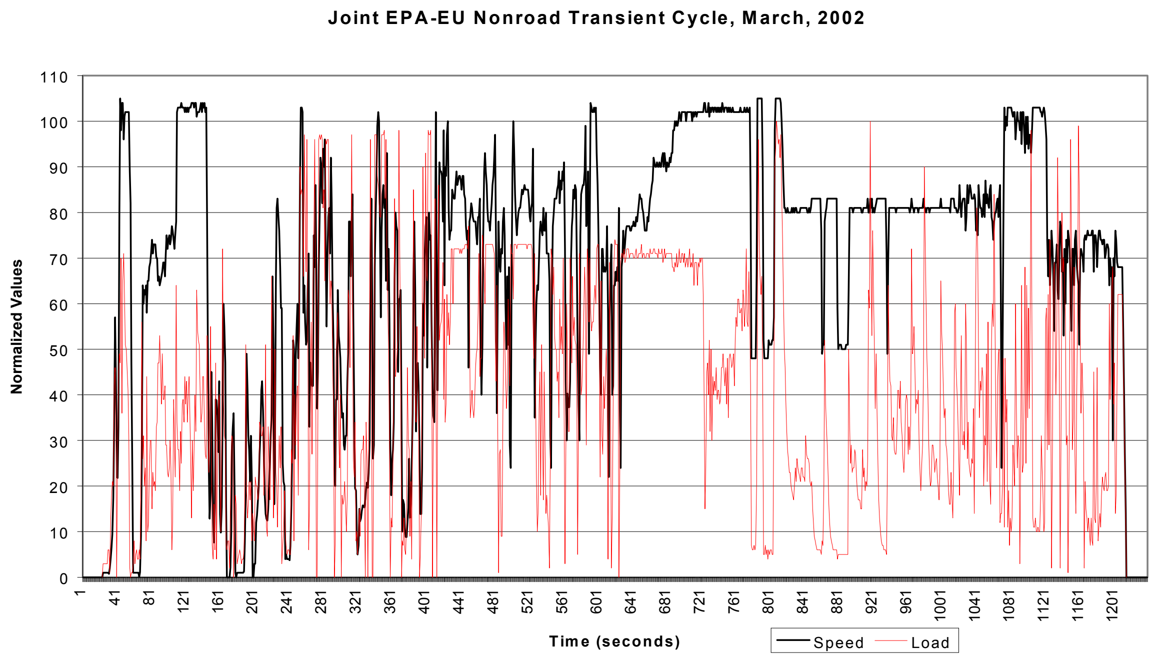


Figure 4.2-12

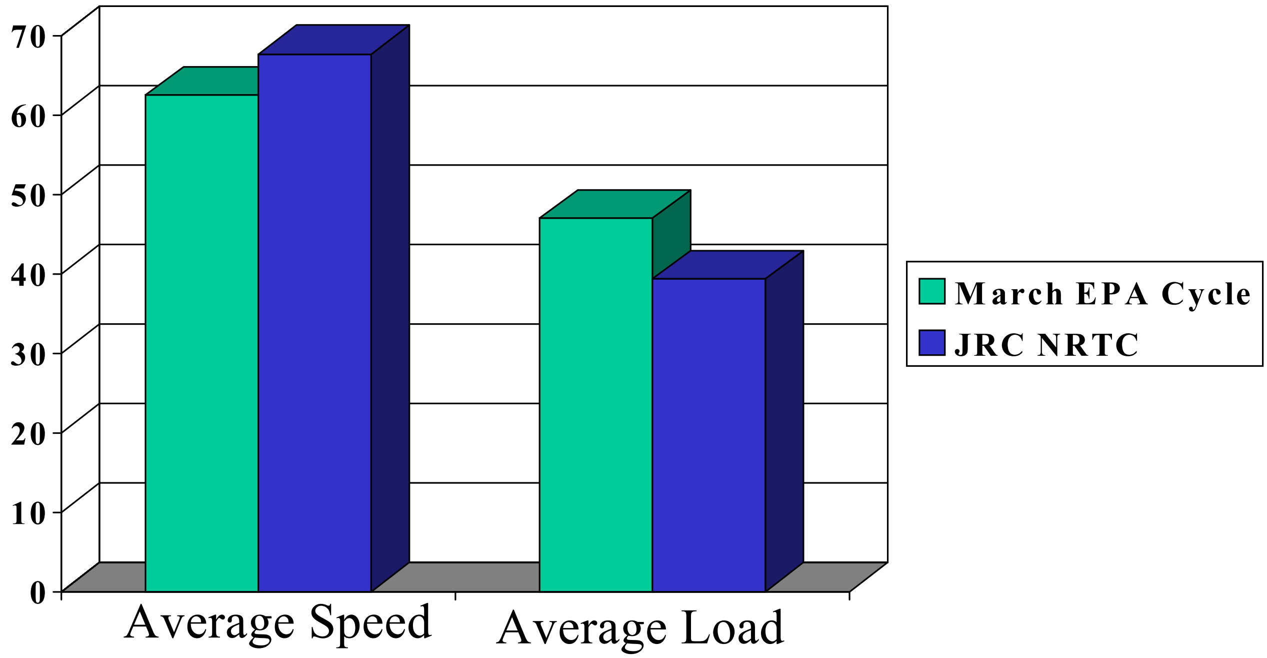


Figure 4.2-13
Average Speed Changes of the EPA NRTC

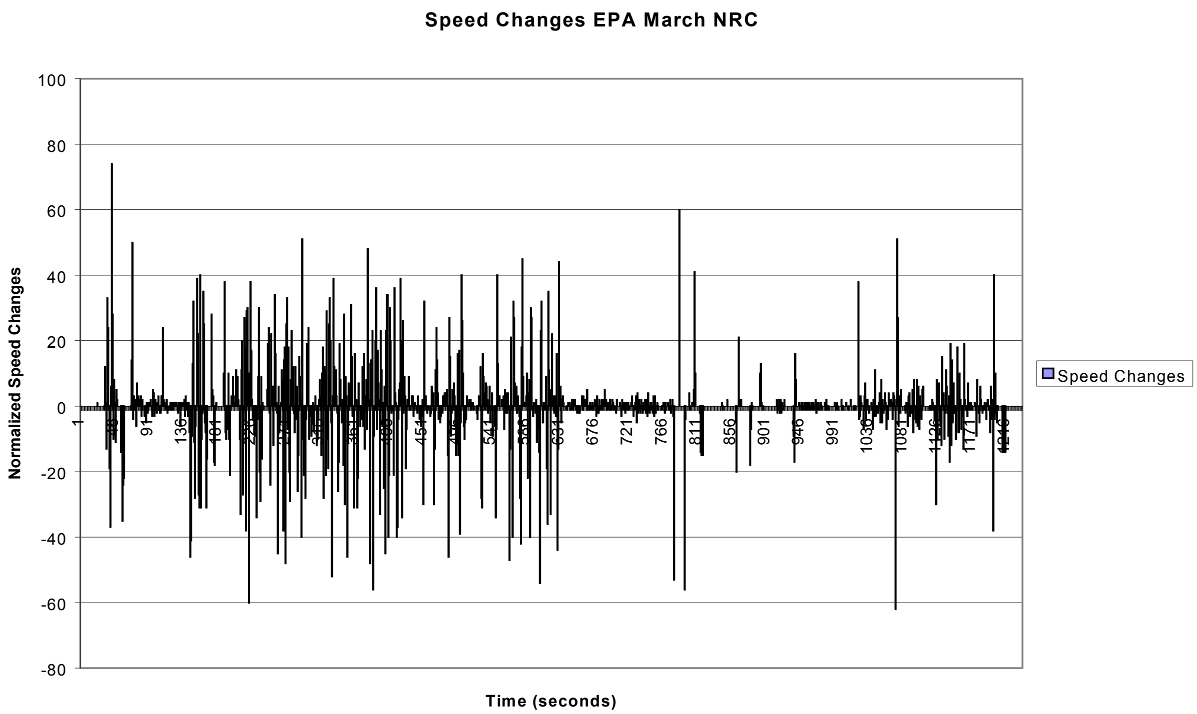


Figure 4.2-14
Average Speed Changes of JRC Modified NRTC

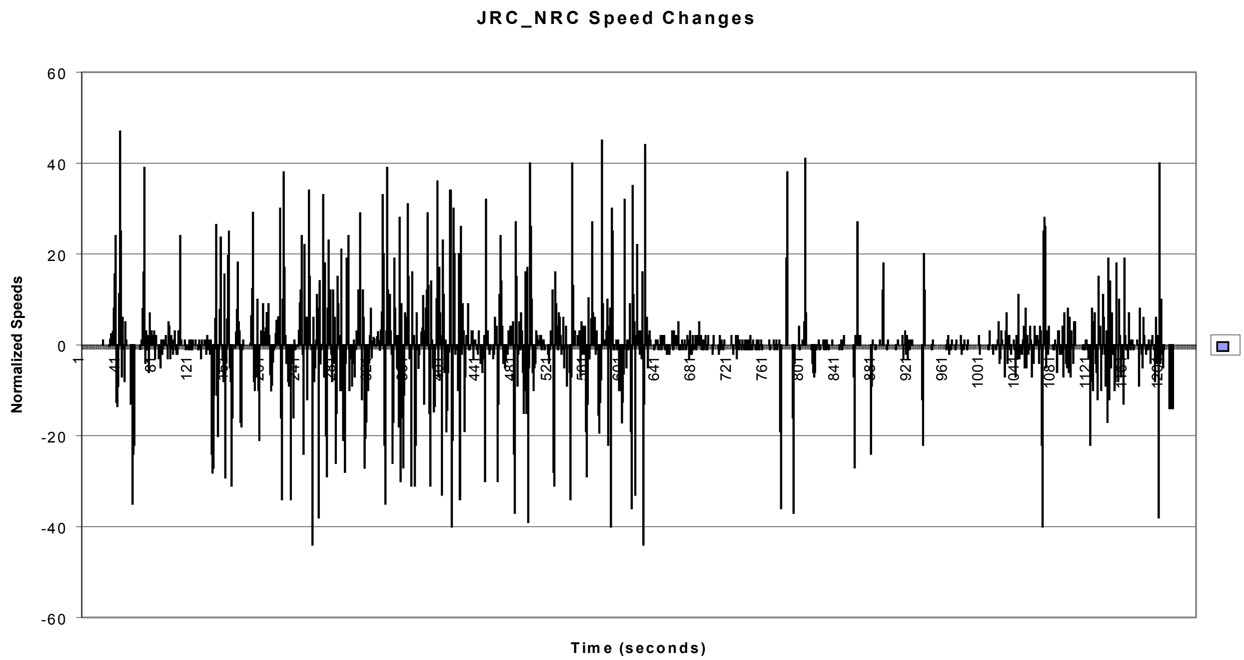


Figure 4.2-13
Average Speed Changes of the EPA NRTC

Figure 4.2-15
Average Load Changes of JRC Modified NRTC

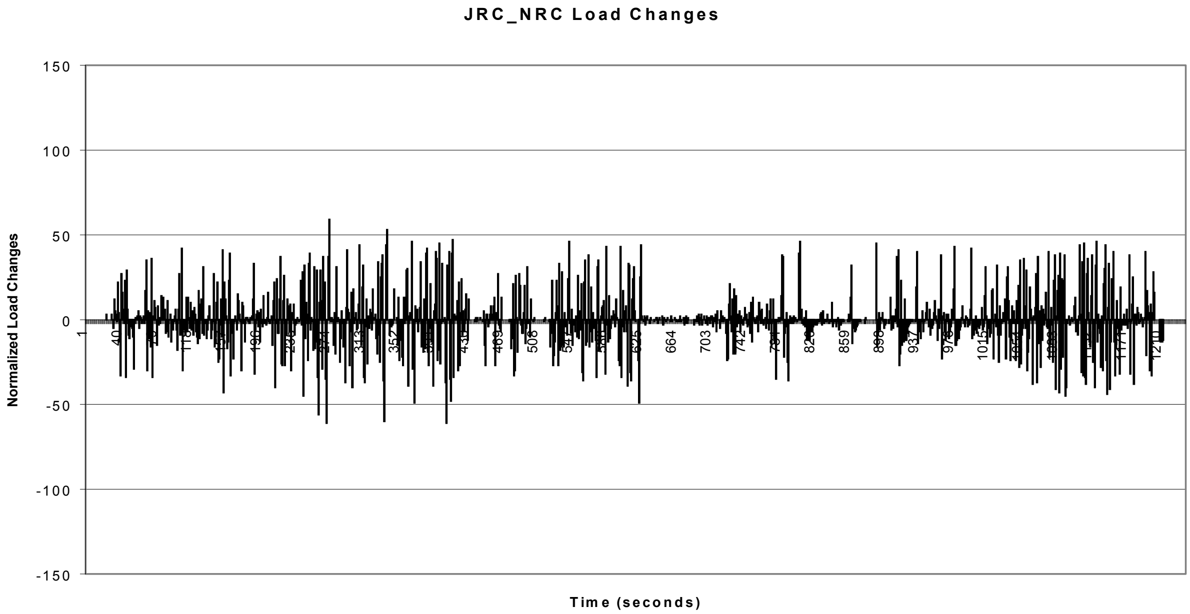
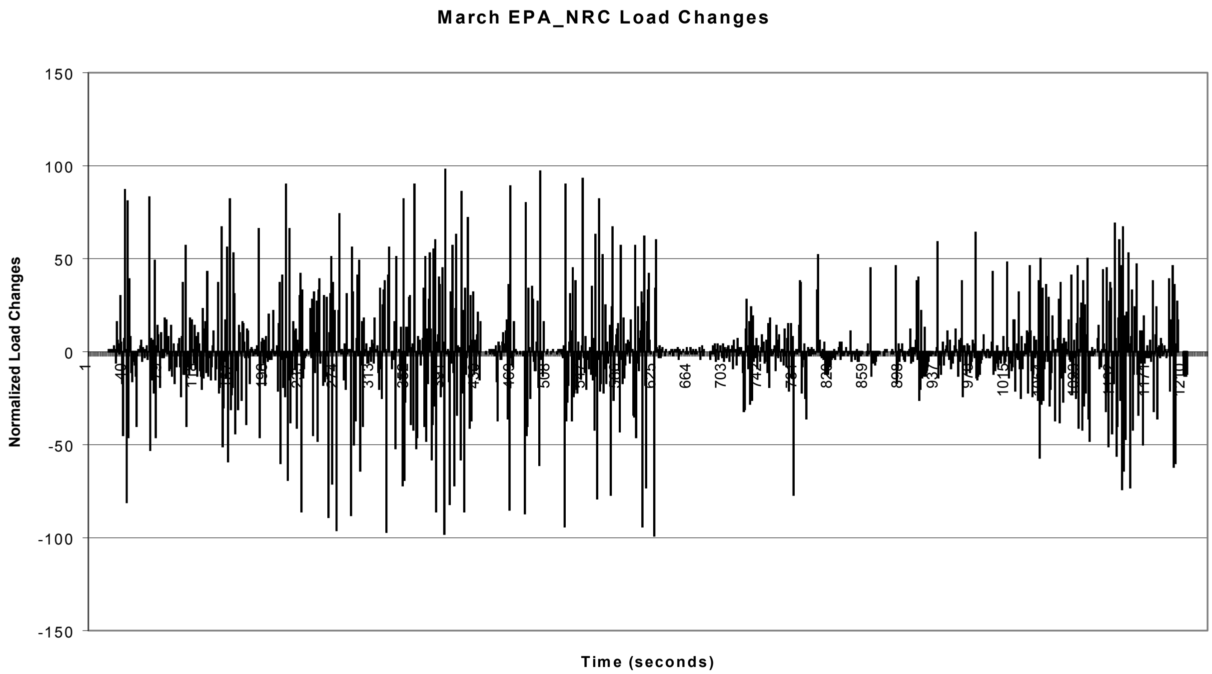


Figure 4.2-16
Average Load Changes of the EPA-Generated NRTC



Given the modifications in the duty cycle, it was critical to assess the impact on the emission signature of the cycle. Table 4.2-13 shows that the emission signature, based on tests at the National Vehicle and Fuel Emissions Laboratory and at Southwest Research Institute as of May 2001, were relatively unchanged.

Table 4.2-13
Emissions and Cycle-Regression Performance Summary as Presented to the Workgroup on June 1, 2001, at the Joint Research Center in Ispera, Italy

Caterpillar 3508	NOx		PM		Speed							
Heavy Duty	Mean	Standard Dev.	Mean	Standard Dev.	SE		M		R2		B	
850 hp					Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.
Sep-00	10.30	0.02	0.20	0.004	79	1.41	1.03	0	0.949	0.001	-35	2.83
Mar-01	10.14	0.03	0.20	0.002	90	2.12	1.01	0.01	0.939	0.002	-9	3.54
JRC	11.198	0.03	0.20	0.004	68	0.71	1.03	0.00	0.962	0.001	-33	1.41

Torque								Power							
SE		M		R2		B		SE		M		R2		B	
Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.
15	0	0.8	0	0.734	0.004	184	0	14	0	0.88	0	0.801	0.283	29.6	0.283
15	0	0.83	0.007	0.734	0.001	188.5	3.54	14	0	0.9	0	0.804	0.002	29.5	1.273
12	0	0.91	0.007	0.765	0.001	56	1.41	11	0	0.95	0	0.823	0	6.1	0.141

Cummins ISB	NOx		PM		Speed							
Medium Duty	Mean	Standard Dev.	Mean	Standard Dev.	SE		M		R2		B	
					Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.
Sep-00	3.76	0.01	0.08	0.001	54.7	24.62	0.987	0.011	0.987	0.010	30.0	3.11
Mar-01	3.79	0.03	0.08	0.003	68	18.67	0.98	0.01	0.982	0.008	32	14.48
JRC-Max Spd	4.06	0.03	0.08	0.002	66	6.22	0.98	0.00	0.978	0.005	34	5.23
JRC-ETC Pk Spd	4.09	0.01	0.08	0.009	50	8.15	0.98	0.00	0.991	0.003	37	6.68

Torque								Power							
SE		M		R2		B		SE		M		R2		B	
Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.	Mean	Std dev.
69.7	2.06	0.955	0.011	0.930	0.005	30.0	3.11	14.8	0.35	0.979	0.009	0.943	0.003	4.5	0.361
67.5	3.12	0.96	0.008	0.933	0.007	26.7	2.64	14.9	0.61	0.981	0.007	0.943	0.005	4.2	0.404
43.5	0.14	0.981	0.002	0.960	0.001	12.0	0.354	9.9	0.21	0.994	0.002	0.961	0.002	1.6	0.141
48.4	2.63	0.985	0.00306	0.946	0.005	11.6	1.386	10.0	0.68	0.999	0.002	0.958	0.005	1.6	0.265

As noted earlier, EPA modified the cycle between September 2000 and March 2001 to address concerns related to the Arc Welder duty cycle segment of the NRTC. The modified EPA version was provided to JRC in early 2001, for its subsequent analysis; however, not knowing the impact of the changes, all three cycles were tracked until the September 2000 version was eventually dropped.

In subsequent data submitted by engine manufacturers through December 5, 2001, the validity of the cycle from an emission signature and test cell feasibility perspective was evidenced. Data submitted by Yanmar, Daimler Chrysler, Deere, Caterpillar, and Cummins to the JRC summary and analysis effort gave clear indication that the duty cycle could be run across multiple power ranges with good cycle performance results and consistent emission signature.[GG] The cycle performance regression statistics would be defined based on nonroad engines, rather than adopting the highway performance statistics without review. The concern raised by Daimler Chrysler was that the cycle-regression statistics needed to be sufficiently

[GG]Memorandum from Cleophas Jackson to EPA Air Docket A-2001-28, # II-A-170 "JRC December 5, 2001, Report on Cycle Performance."

stringent to ensure an accurate and repeatable emission signature was achieved.[HH] With the conclusion of the international workgroup's efforts, EPA considered the cycle to be complete. In an effort to facilitate the use of the cycle as a global nonroad transient duty cycle, it has been introduced into GRPE as a candidate cycle for the global compendium. The ISO procedure 8178-11 is being drafted to address test cell procedures for exercising an engine over the duty cycle. New limit values for the cycle performance regression statistics were developed as a part of this process and may be seen in Table 4.2-14[II].

Table 4.2-14
NRTC Cycle-Regression Statistics[163]

	Speed [rpm]	Torque [N·m]	Power [kW]
Standard Error of Estimate of Y on X	100 rpm	13% of power map maximum engine torque	8% of power map maximum
Slope of the regression line, m	0.95 to 1.03	0.83-1.03 (hot) 0.77-1.03 (cold)*	0.89-1.03 (hot) 0.87 -1.03 (cold)[a]
Coefficient of determination, r^2	min 0.970	min 0.8800 (hot) min 0.8500 (cold)*	min 0.9100 (hot) min 0.8500 (cold)
Y intercept of the regression line, b	± 50 rpm	± 20 N·m or ± 2.0% of max engine torque, whichever is greater	± 4 kW or ± 2.0% of max power, whichever is greater

[a] Under consideration by ISO workgroup.

4.2.9 Cold-Start Transient Test Procedure

Nonroad diesel engines typically operate in the field by starting and warming to a point of stabilized hot operation at least once in a workday. Such "cold-start" conditions may also occur at other times over the course of the workday, such as after a lunch break. We have observed that certain test engines, which generally had emission-control technologies for meeting Tier 2 or Tier 3 standards, had elevated emission levels for about 10 minutes after starting from a cold condition. The extent and duration of increased cold-start emissions will likely be affected by changing technology for meeting Tier 4 standards, but there is no reason to believe that this effect will lessen. In fact, cold-start concerns are especially pronounced for engines with catalytic devices for controlling exhaust emissions, because many require heating to a "light-off"

[HH] Memorandum from Cleophas Jackson to EPA Air Docket A-2001-28, ######*Nonroad Transient Duty Cycle Development Report*, Cornetti, G., Hummel, R., and Jackson, C.

[II] The deletion point criteria for engine manufacturers to use in deriving these cycle performance statistics may be found in regulations at 40 CFR Part 1039, subpart F and Part 1065.530. See also cycle performance criteria discussions in Memorandum from Cleophas Jackson to EPA Air Docket A-2001-28, ###### *Nonroad Transient Duty Cycle Development Report*, Cornetti, G., Hummel, R., and Jackson, C. and Memorandum from Matthew Spears to EPA Air Docket A-2001-28, ##### "Test Point Omission Criteria for Determining Cycle Statistics".

or peak-efficiency temperature to begin working. EPA's highway engine and vehicle programs, which increasingly involve such catalytic devices, address this by specifying a test procedure that first measures emissions with a cold engine, then repeats the test after the engine is warmed up, weighting emission results from the two tests for a composite emission measurement.

In the proposal, we described an analytical approach that led to a weighting of 10 percent for the cold-start test and 90 percent for the hot-start test. Manufacturers pointed out that their analysis of the same data led to a weighting of about 4 percent for cold-start testing and that a high cold-start weighting would affect the feasibility of the proposed emission standards. Manufacturers also expressed a concern that there would be a big test burden associated with cold-start testing.

Unlike steady-state tests, which always start with hot-stabilized engine operation, transient tests come closer to simulating actual in-use operation, in which engines may start operating after only a short cool-down (hot-start) or after an extended soak (cold-start). The new transient test and manufacturers' expected use of catalytic devices to meet Tier 4 emission standards make it imperative to address cold-start emissions in the measurement procedure.[JJ] We are therefore adopting a test procedure that requires measurement of both cold-start and hot-start emissions over the transient duty cycle, much like for highway diesel engines. We acknowledge that limited data are available to establish an appropriate cold-start weighting. For this final rule, we are therefore opting to establish a cold-start weighting of 5 percent. This is based on a typical scenario of engine operation involving an overnight soak and a total of seven hours of operation over the course of a workday. Under this scenario, the 20-minute cold-start portion constitutes 5 percent of total engine operation for the day. Section 4.1.2.3.3 above addresses the feasibility of meeting the emission standards with cold-start testing. Regarding the test burden associated with cold-start testing, we believe that manufacturers will be able to take steps to minimize the burden by taking advantage of the provision that would allow for forced cooling to reduce total testing time.

We believe the 5-percent weighting is based on a reasonable assessment of typical in-use operation and it addresses the need to design engines to control emissions under cold-start operation. We believe cold-start testing with these weighting factors will be sufficient to require manufacturers to take steps to minimize emission increases under cold-start conditions. Once manufacturers apply technologies and strategies to minimize cold-start emissions, they will be achieving the greatest degree of emission reductions achievable for those conditions. A higher weighting factor for cold-start testing will likely not be more effective in achieving in-use emission control.

However, given our interest in controlling emissions under cold-start conditions and the relatively small amount of information available in this area, we intend to revisit the cold-start weighting factor for transient testing in the future as additional data become available.

[JJ]Note that the cold-start discussion applies only to engines that are subject to testing with transient test procedures. For example, this excludes constant-speed engines and all engines over 750 hp.

Additionally, as the composite transient test represents a combination of variable-speed and constant-speed operations, we would consider operating data from both of these types of engines in evaluating the cold-start weighting. We will apply the same cold-start weighting, as well, when we adopt a transient duty cycle specifically for engines certified only for constant-speed operation.

The planned data-collection effort will focus on characterizing cold-start operation for nonroad diesel equipment. The objective will be to reassess, and if necessary, develop a weighting factor that accounts for the degree of cold-start operation so that in-use engines effectively control emissions during these conditions. As we move forward with this investigation, other interested parties, including the State of California, will be invited to participate. We are interested in pursuing a joint effort, in consultation with other national government bodies, to ensure a robust and portable data set that will facilitate common global technical regulations. This effort will require consideration of at least the following factors:

- What types of equipment will we investigate?
- How many units of each equipment type will we instrument?
- How do we select individual models that will together provide an accurate cross-section of the type of equipment they represent?
- When will the program start and how long will it last?
- How should we define a cold-start event from the range of in-use operation?

We expect to complete our further evaluation of the cold-start weighting in the context of the 2007 Technology Review, if not sooner. In case changes to the regulation are necessary, this timing will allow enough time for manufacturers to adjust their designs as needed to meet the Tier 4 standards.

4.2.10 Applicability of Component Cycles to Nonroad Diesel Market

In the 1997-1998 time frame, we started to pursue application-specific operating duty cycles that could be normalized for laboratory testing of nonroad diesel engines. With a standardized set of operating duty cycles, we would have a basis upon which to compare the brake-specific emission rates of nonroad engines, both within and across power categories, or bands. These cycles became the component cycles of the NRTC cycle. The choice of the seven nonroad component application duty cycles was based on the frequency of finding engines of that particular mode of operation in the nonroad population and summing those with engines/equipment doing related work. Agricultural tractors were seen to have operations generally similar to combines and off-highway trucks in addition to tractors. Arc welders represented the broad group of constant-speed applications. The backhoe-loader group included most of the lawn/garden/commercial turf tractors, commercial lifts and sweepers. The crawler/dozer application matched with other dozer, grader and scraper applications. Rubber-tire loaders were found to be similar to industrial and rough terrain forklifts, aircraft support and forestry equipment. Skidsteer loaders were seen, at the time, as a unique application/category. Finally, excavators and cranes were grouped together as similar applications. In time, the seven base nonroad equipment applications, agricultural tractor, arc welder, backhoe loader, crawler-dozer, excavator, rubber-tire loader and skidsteer loader were characterized for their daily operations and engine duty cycles were constructed for each type of work.

4.2.10.1 Market Representation of Component Cycles

The determination of which cycles best represent the nonroad equipment population in the United States was aided by an analysis of the our nonroad equipment population database.[164] Our source of data placed the total 1995 nonroad equipment population figure at 7,100,113 units in the United States. The population broke out into at least 59 different equipment applications, or specific work categories. Agricultural tractors held the largest percentage by far at approximately 34% of units. Constant-speed applications like generating sets, A/C and refrigeration units comprised a further 14%. Of the remaining pieces of the nonroad equipment, another 11% of the total population were constant-speed engines like welders, air compressors and irrigation rigs. Commercial lawn and garden equipment made up an additional 7.5% of all units, with combines, backhoe and skidsteer loaders at 12%, each application adding a further 4% to the total population. In the approximately 20% of units remaining, rubber-tire loaders and crawler-dozers constituted 6% of all nonroad units, each contributing 3% to the nonroad population. Excavators and cranes comprised a little more than 2% of the total equipment population. The seven component application classesalone covered 51% of all nonroad equipment units. When "related" nonroad applications were grouped with the original seven applications, over 95% of the nonroad equipment population was represented by the component applications.

4.2.10.2 Inventory Impact of Equipment Component Cycles

When EPA created an emission distribution from its database according to a list of the seven nonroad applications used to create the NRTC duty cycle, those seven base applications accounted for 59 percent of regulated nonroad engine emissions (see Table 4.2-16).

Table 4.2-16
Emissions Attributable to Base Nonroad Applications

Application	Emission Distribution by Application
Ag tractor	34%
Welder	1%
Backhoe/loader	6%
Crawler	7%
Excavator	3%
R/T Loader	6%
Skid/steer	2%
Total	59%

4.2.10.3 Power and Sales Analysis

The nonroad equipment market is broad and varies in both range of power available and application, or intended use, of each piece of equipment. EPA's database was the source for the distribution of nonroad applications between the various engine power bands. Agricultural tractors, while accounting for fully a third of the nonroad equipment population, are built generally to smaller engine displacement specifications and so constituted only 20% of total nonroad power. With similar equipment applications included, the equipment equipped with engines that have power or displacement similar to that of agricultural tractors approaches 30 percent. Backhoe loaders, crawler dozers and rubber-tire loaders together accounted for 12 percent of the total power in the nonroad population and, with similar applications included, accounted for approximately 35 percent of total nonroad power. The last three cycle component applications—excavators, skidsteer loaders and arc welders, with arc welders and like equipment generally falling under 50 hp—constitute only 8 percent of total nonroad power. However, because small constant-speed engines exist in numerous applications, they also constitute a large number of discrete units in the nonroad population. This helps to explain their relatively large contribution (18%) as a group of similar applications to total nonroad power. Taking the sum of power represented by all applications similar to the seven component equipment applications found in the NRTC cycle, we have represented equipment operations and engine displacements and, by analogy, in-use operations of 91% of nonroad equipment units.

4.2.10.4 Broad Application Control

Aggregating all those equipment classifications whose operating characteristics were similar to the seven NRTC component cycles for their emission contributions, we found that the composite nonroad cycle covered emissions from almost 96% of the documented applications in the nonroad equipment population (see Table 4.2-17).

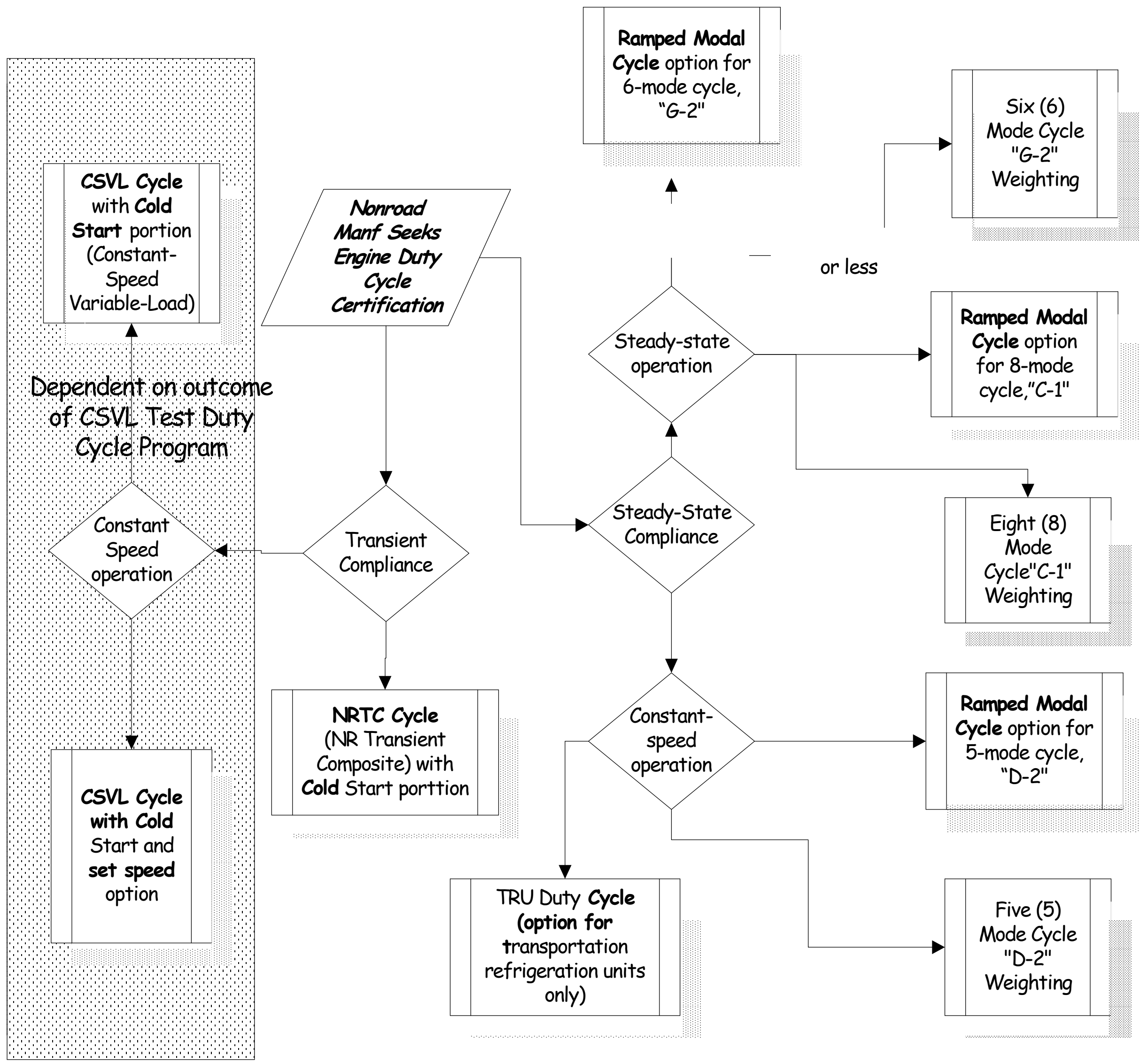
Table 4.2-17
Similarities Among Various Nonroad Equipment Applications

Application	Other Applications with Similar Operating Characteristics		Emission Distribution	Cycle characterization
Ag tractor	Combine Off-Hwy Tractor	Off-Hwy Truck	38.4%	Heavy-load operation along governor/lug curve
Welder	Air Compressors Gas Compressors Generators Pumps Bore/Drill Rigs Cement Mixers Chippers/Grinders Concrete/Ind. Saw Crush/Proc. Equip Hydr. Power Unit	Irrigation Sets Leaf Blow/Vacs Lt Plants/Signal Board Oil Fld Equip. Plate Compactors Pressure Washers Refrigeration/AC Shredder	25.2%	Transient loads at tightly governed rated speeds
Backhoe/loader	Aerial Lifts Comm. Turf Scrub/Sweeper Front Mowers	Lawn/Grdn. Tractor Rear Eng. Rider Specialty carts Terminal Tractor	13.5%	Widely varying loads and speeds, weighted toward lighter operation; most like highway operation
Crawler	Graders R/T Dozer	Scrapers Trenchers	5.7%	Widely varying loads and speeds, weighted toward heavier operation
Excavator	Cranes		2.4%	Transient loads at loosely governed rated speed
R/T Loader	Aircraft Support Forest Equip Forklifts	Rough Trn Fork.	6.7%	Stop and go driving with widely varying loads.
Skid/steer	—		3.6%	Widely varying loads at different nominally constant-speed points
Total			95.5%	

4.2.11 Final Certification Cycle Selection Process

Figure 4.2-18 outlines the process by which a manufacturer of a particular nonroad diesel engine might approach certification using the nonroad transient and steady-state test requirements (NTE certification requirements have been deliberately omitted from this discussion to simplify the presentation).

Figure 4.2-18
NR Diesel Engine Transient and Steady-State Testing Requirements



4.3 Steady-State Testing

Recognizing the variety of both power classes and work applications to be found within the nonroad vehicle and engine population, EPA will retain current Federal steady-state test procedures for nonroad engines. The steady-state duty cycle applicable in each of the following categories: 1) nonroad engines 25 hp and greater; 2) nonroad engines less than 25 hp; and 3) nonroad engines having constant-speed, variable-load applications, (e.g., generator sets) will remain, respectively, the 8-mode cycle, the 6-mode cycle, and the 5-mode cycle.[KK] Manufacturers are required to meet emission standards under steady-state conditions in addition to meeting any emission standards under transient test cycle requirements. Steady-state test cycles are needed so that testing for certification will reflect the broad range of operating conditions experienced by these engines. A steady-state test cycle represents an important type of modern engine operation, in power and speed ranges that are typical in-use. The mid-to-high speeds and loads represented by present steady-state testing requirements are the speeds and loads at which these engines are designed to operate for extended periods for maximum efficiency and durability. Manufacturers would perform each steady-state test following all applicable test procedures detailed in regulations at 40 CFR Part 1039, subpart F, e.g., procedures for engine warm-up and exhaust emissions measurement. The testing must be conducted with all emission-related engine control variables in the maximum NOx-producing condition which could be encountered for a 30 second or longer averaging period at a given test point. Details concerning the three steady-state procedures for nonroad engines and equipment can be found in regulations at 40 CFR 1039.505 and in Appendices I-III to Section 1039 which follow that section, one for each cycle.

4.3.1 Ramped Modal Cycle

4.3.1.1 Introduction and Background

In response to manufacturers' concerns for the potential of some PM trap-equipped diesel engines to exhibit highly variable emissions under current emission test cycles, EPA has developed ramped modal versions of its steady-state certification duty cycles. These ramped modal cycle emission tests will reliably and consistently report steady-state emissions from PM trap and other emission control hardware-equipped nonroad engines.

For all the laboratory- based steady-state testing currently specified in 40 CFR Part 89, EPA has determined that any certification steady-state test cycle may be run as a ramped modal cycle (RMC). A RMC consists of the same series of steady-state test modes, but they are connected to one another by gradual ramps in engine speed and/or torque. However, the mode order is rearranged so as to alternate between high- and low-torque modes. In a RMC, the steady-state modes are connected with linear speed and torque transitions. The difference is that these transitions are sampled as part of the test. In other words, emissions sampling would start at the beginning of a RMC and would not stop until the last mode of the cycle is completed.

Instead of using weighting factors for each steady-state mode, a RMC specifies different time durations for each mode. Time durations are proportioned to weight each mode and transition to reflect the exact original ISO steady-state test weighting factors upon which the certification

[KK] The three certification steady-state test cycles are similar to test cycles found in International Standard ISO 8178-4:1996 (E) and remain consistent with the existing 40 CFR Part 89 steady state duty cycles.

testing is based. The information and test cycle tables needed to run a certification steady-state test cycle as a RMC are given in 40 CFR Section 1039.505(a)(2). Refer to 40 CFR Part 1039, subpart F for the procedures required for transforming and running a particular test cycle on a specific engine.

Because a RMC weights individual modes by the amount of time spent at each mode, we considered the effect of a RMC's total test time on emissions. Based on the RMC data presented in this section, we concluded that if insufficient time was spent in an individual mode, the mode would not adequately represent the steady-state condition that was intended. This effect was exaggerated when engines with aftertreatment systems were tested. By inspecting data from individual modes, we determined that emissions differences between a RMC and its respective certification steady-state test cycle occurred primarily when exhaust temperatures between the two cycles differed greatly.

As mentioned earlier in this section, the modes in the RMC are intentionally arranged to alternate between high- and low-torque modes. This results in more moderate and repeatable aftertreatment temperatures overall. However, in some cases, more time in certain modes would have helped to achieve exhaust temperatures over a RMC that were more representative of exhaust temperatures for typical steady-state cycles.

The appropriate total time for the RMC was in part determined from testing of a diesel engine equipped with both a NO_x adsorption catalyst and PM trap exhaust emission controls, which will be described in this section. Based on the number of modes in a given steady-state cycle, we determined that twenty minutes is an appropriate total time for a RMC that has five or fewer steady-state modes. Twenty minutes is also an appropriate minimum time for collecting an adequate PM sample from an engine certified to a PM standard less than 0.05 g/kW-hr. For which has six to ten modes, thirty minutes is an appropriate total time. Thirty minutes ensures that the lightly weighted modes on the RMC have adequate time to approach the same exhaust temperatures achieved when the test is run as a steady-state test. For a RMC with ten to fourteen modes, forty minutes is an appropriate total test time. A forty-minute length ensures that a sufficient amount of the total test time was spent at steady-state rather than in transition from one mode to the next. For all of the RMCs, these times ensure that less than 10% of the total time is spent in transition from one steady-state mode to the next.

There are a number of advantages to running a steady-state test as a RMC. The current procedure for conducting a steady-state test allows emission sampling periods as short as the last minute of each mode.[165] Discrete aftertreatment regeneration events, NO_x and SO_x regeneration for NO_x adsorption catalysts, forced PM regeneration for PM traps, etc., typically cause short-duration sharp increases in NO_x, HC and PM emissions. Thus, it may be challenging to gather good, repeatable emissions from the current steady-state procedures since a regeneration event may or may not be sampled in a given mode. For sampling low concentrations of PM, this inconsistency is exaggerated because the short sample time per mode may not provide enough PM sample to weigh in a repeatable way. Furthermore, without specific start and stop times for sampling each mode, an anticipated regeneration event may be intentionally or unintentionally included or excluded. With a RMC, this variability is removed by requiring emissions sampling over the entire cycle.

There are other advantages to running a steady-state test as a RMC. The RMC reduces the number of sampling system starts and stops. This is significant at low emission standards when considering that a previous mode's emissions may be incorrectly included in the next mode due to an unavoidable dead volume in a sampling system. The longer sampling period of a RMC also increases the mass of the PM sampled. This is extremely significant because the PM standard already approaches the minimum detection limits for many current PM microbalances.

The RMC also enables the use of batch sampling systems, such as bag samplers. This is an advantage because batch sampling systems are generally capable of quantifying lower levels of pollutants with less uncertainty than continuous sampling systems at low emission concentrations. This may be due to:

1. Gas analyzer zero-drift over time can be a much larger percentage of the measured value for continuous measurements at continuous low average emission concentrations. This is much less of an issue with batch measurements at low concentrations, since they can conduct a zero and span operation immediately preceding the concentration measurement.

2. Zero-drift and transient response of the NO_x analyzer from engines using high-capacity NO_x-adsorption catalysts can be a significant challenge for continuous measurement systems. For some modes of operation, NO_x emissions are truly at, or very close to, zero during adsorption with a rapid spike in NO_x emissions during regeneration. Covering the full dynamic range requires:

    a. automatic range switching to allow measurement on a low-concentration analyzer range when NO_x is near zero during adsorption and switching to a higher range to catch the NO_x spike during regeneration, accepting the uncertainty introduced from loss of data during the short duration needed to accomplish range switching; or

    b. operating on a single higher concentration analyzer range and accepting the uncertainty and increased zero-drift introduced at low concentrations during adsorption; or

    c. operating on a single lower concentration analyzer range and accepting loss of data that is "clipped" when the analyzer signal saturates during regeneration.

    Batch-sampled NO_x can be measured using a single analyzer range appropriate for the measured concentration and the same sample can be measured repeatedly over more than one range using the same analyzer. Thus, repeat measurements may be utilized to ensure an accurate measurement at the lowest possible range.

3. During a continuous measurement, each instantaneous emission concentration measurement has a level of uncertainty associated with it that propagates from each collected data point to the final integrated concentration. By contrast, a batch-sampled emission measurement is

typically a stabilized average of repeated measurements of a near-constant concentration within the bag or other grab-sample container.

During EPA testing of the first pre-production prototype light-duty diesel vehicle (Toyota Avensis D-Cat) with a NO_x adsorption catalyst system, continuous and bag-sampled NO_x agreed to within 4% at very low integrated mass concentrations, but the coefficient of variance for the continuous NO_x measurement was approximately four times the coefficient of variance for the bag-sampled NO_x measurement, which was likely due to a combination of the above effects.

Use of a RMC can also significantly reduce the cost of steady-state testing. Not only is the per-test cost anticipated to be lower with the RMC, but the lower thermal-load on CVS and air-handling systems due to less sustained high-load operation during testing may reduce the cost for construction of test facilities. The RMC can typically be accomplished in much less time, further reducing total cost.

4.3.1.2 Comparison of Steady-State vs. RMC Testing

4.3.1.2.1 Manufacturer's testing

An engine manufacturer provided paired and unpaired emissions data to EPA comparing the 13-mode highway SET (supplemental emissions test) to a RMC developed from the highway SET. The paired data contain 34-39 test replicates representing 29 light-heavy, medium-heavy, and heavy-heavy-duty highway engine families in the range of 250 - 500 hp certified to the 2004 model year heavy-duty on-highway emission standards. The engines were not equipped with exhaust aftertreatment, but were equipped with high-pressure, electronically controlled fuel injection systems and cooled EGR systems. The unpaired data are for 10 engine families built from one basic engine platform for a heavy-heavy-duty engine of approximately 15 liters displacement. The paired data are summarized in Figures 4.3-1 and 4.3-2. The results of a F-test comparison of the unpaired SET data to the RMC data are presented in table 4.3-1. Emissions results did not differ significantly between the SET and the RMC. Further, when comparing the uncertainty of the RMC to the SET, it met the F-test criteria at a 90% confidence level using the test equivalency criteria as per an EPA letter to the Engine Manufacturers Association, dated December 12, 2002 regarding guidance on test procedures for heavy-duty on-highway and non-road engines (page 3, item 1).[166]

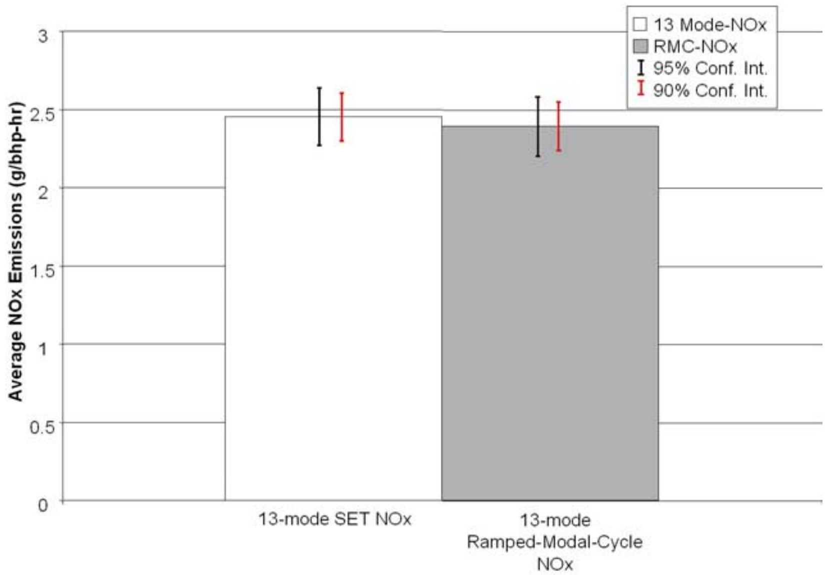


Figure 4.3-1: A comparison of SET and RMC NO_x emissions based on paired data from 29 engine families certified to a 2.5 g/bhp-hr NO_x and 0.1 g/bhp-hr PM standard.

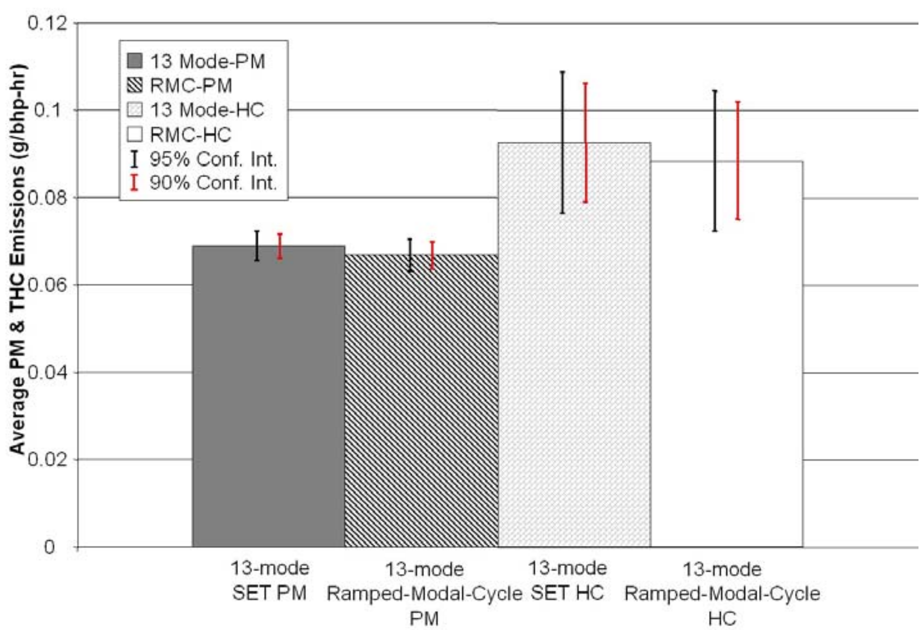


Figure 4.3-2: A comparison of SET and RMC PM and total HC emissions based on paired data from 29 engine families certified to a 2.5 g/bhp-hr NO_x and 0.1 g/bhp-hr PM standard.

Table 4.3-1: F-test comparison of the RMC to the SET steady-state test. NO_x and HC emissions were measured using continuous analyzers. Note that the ability to use batch-sampling for NO_x and HC would further reduce the standard-deviation for the RMC. The PM measurement for the SET also used a single, flow-weighted PM filter sample. Using one filter-sample per mode would likely have further increased the variability in the SET steady-state tests.

	NO_x	PM	HC	CO	CO_2
Mean Emissions (SET)	2.029	0.0754	0.072	0.329	507
σ_{SET}	0.056	0.0080	0.014	0.062	13
Mean Emissions (RMC)	1.931	0.078	0.072	0.372	510
σ_{RMC}	0.070	0.0057	0.013	0.091	17
			F-test		
$F_{90\%}$:	2.44	2.44	2.44	2.44	2.44
F_{RMC}:	1.56	0.516	0.776	2.18	1.69
Pass at 90% Confidence Interval?	*Pass*	*Pass*	*Pass*	*Pass*	*Pass*

4.3.1.2.2 EPA testing over the 8-mode C-1 cycle and its RMC derivative (with and without exhaust aftertreatment)

EPA has determined that its 8-mode C-1 test cycle (40 CFR Part 89) may be run as a RMC. The RMC version of this cycle consists of the same series of eight steady-state test modes but the modes are connected to one another by linear speed and torque transitions. That is, emissions sampling would start at the beginning of this RMC and would not stop until its last "mode" was completed. As well, the mode order from the 8-mode C-1 cycle is rearranged in this RMC to alternate between high-load and low-load modes. Instead of using weighting factors for each steady-state mode, the RMC specifies different time durations for each mode. Time durations are proportioned to weight each mode exactly as the original C-1 weighting factors. The information needed to run an 8-mode C-1 test cycle as a RMC is given in 40 CFR, §1039.505. The procedures required for transforming and running this test cycle with a specific engine are found on 40 CFR Part 1039 subpart F.

To compare the emission levels between a steady-state 8-mode C-1 test and the corresponding RMC test, four engines ranging from 42 to 400 brake-horsepower (bhp) were tested at Southwest Research Institute (SwRI) and at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). Table 4.3-2 below contains a summary of the specifications of these engines. The testing was performed with engines having various exhaust configurations. The Yanmar engine had no exhaust aftertreatment while the Kubota engine was tested both with and without a DOC. The DDC engine was tested with a continuously-regenerating trap (CRT) system that used a platinum-catalyzed DOC located upstream of a non-catalyzed PM trap.

Table 4.3-2: Engine properties

Engine	Model Year	Power (bhp)	Fuel Inj.	Displ. (L)	Air Induction	Configurations tested
Yanmar 4TNE84	2002	48	DI	1.99	Naturally Aspirated	No exhaust aftertreatment
Kubota V1903E	2001	42	IDI	1.9	Naturally Aspirated	With and without DOC
DDC Series 60	1998	400	DI	12.7	Turbocharged	With CRT (passive regeneration)
Cummins ISB	2000	180	DI	5.9	Turbocharged	With CDPF + NO_x adsorption catalyst system

The Cummins ISB engine was tested with a system which combined a catalyzed diesel particulate filter (CDPF) with a NOx adsorption catalyst.[167] The engine was also equipped with a high-pressure common-rail fuel injection system and cooled low-pressure-loop EGR.. The test configuration of the ISB engine was that of a 180 b-hp rated nonroad engine and EPA developed the engine's test calibration values.

Table 4.3-3, below, summarizes the engine operating conditions for the 8-mode C-1 cycle and for the RMC derived from that cycle. The RMC contains a "split idle mode" (the idle condition occurs twice versus once in the 8-mode C-1). Note also that it is possible to run the 8-mode C-1 cycle with different lengths of time-in-mode. A period of five-minutes duration per steady-state mode is allowable under current regulations in 40 CFR Part 89 and there is no limit on maximum time-in-mode. Different exhaust sampling periods are also allowed, having a minimum length of 60 seconds and no maximum length. Thus, for the 8-mode C-1 steady-state cycle, the minimum time-in-mode under current regulations would be a period of four minutes of stabilization with one minute of sampling per mode. The maximum time for stabilization and sampling are left undefined.

All of the engines were tested using a twenty minutes long RMC derived from the 8-mode C-1 cycle. The EPA-modified Cummins ISB was also tested using a thirty minutes long RMC cycle. The length of time spent in each mode for the 8-mode C-1 test cycles varied by engine. The Yanmar and Kubota engines were tested over the 8-mode C-1 test cycle at mode lengths of ten minutes each. Gaseous emissions and PM emissions were sampled for the last five minutes of each ten-minute mode. The DDC and the modified Cummins ISB engines were tested over the 8-mode C-1 cycle at mode lengths totaling ten minutes each. Their gaseous and PM emissions were sampled for the last three minutes of each ten-minute mode. The modified Cummins ISB engine was also tested using a five minutes long mode length over the 8-mode C-1 cycle. For those tests having a five minutes long mode length, the first four minutes were used for stabilization and the last minute was used for emissions sampling to model the minimum time specifications found in 40 CFR Part 89.

Table 4.3-3:
Engine operating conditions for the steady-state 8-Mode C-1 and RMC tests

8-Mode C-1	1	2	3	4	5	6	7	8	
Speed	Rated				Intermediate			Idle	
Torque	100	75	50	10	100	75	50	No load	
RMC	1	2	3	4	5	6	7	8	9
Speed	Idle	Intermediate			Rated				Idle
Torque	No load	100	50	75	100	10	75	50	No load

Figures 4.3-3 and 4.3-4 below summarize the emissions results obtained from emission testing on the DDC Series-60 engine. However, due to the use of a non-standard PM sampling medium and measurement inconsistencies associated with filter handling during emission testing, PM data are not available for these tests (PM mass loss was attributed to physical damage to the sample filters after installation into the sampling cassettes). As shown in these figures, NO_x emissions for both engine-out and CRT-out configurations of this engine over the RMC and 8-mode C-1 test cycles do not differ at the 95% confidence interval. Differences between HC and CO emission levels over the two cycles were either negligible or extremely low during all testing and well under the Tier 4 emission standards.

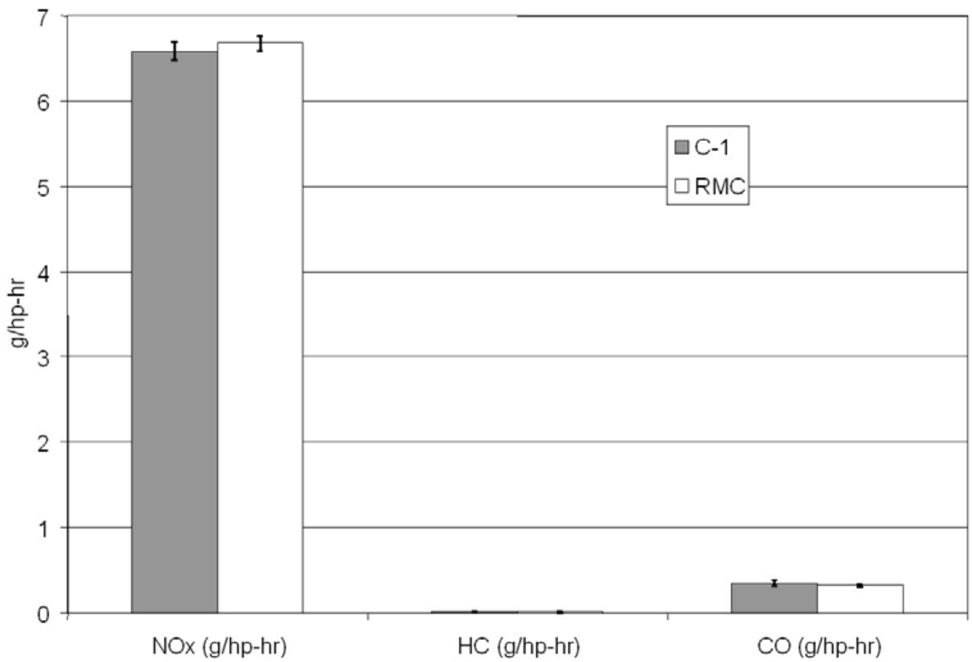


Figure 4.3-3: Emissions from the DDC Series-60 engine over the steady-state 8-mode C-1 test and the 20-minute RMC test with no exhaust aftertreatment.

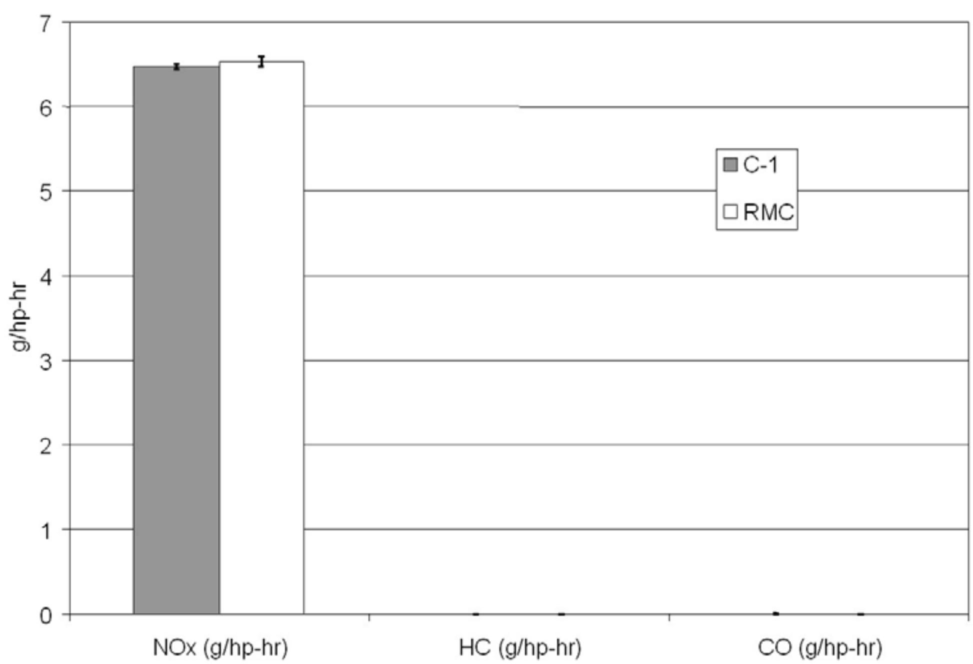


Figure 4.3-4: Emissions from the DDC Series-60 engine over the steady-state 8-mode C-1 test and the 20-minute RMC test with a CRT.

Figures 4.3-5 and 4.3-6 compare exhaust emissions from the Kubota V1903E engine over both the 8-mode C-1 and RMC cycles without and fitted with a DOC, respectively. PM emissions over both test cycles from both of the tested engine configurations did not differ at either the 95% or 90% confidence interval. There was however a general trend toward a reduced coefficient of variance for RMC versus 8-mode C-1 PM emissions and the number of replicates was insufficient for a rigorous F-test comparison of variance. Differences in mean NO_x emissions in the no exhaust aftertreatment configuration were small, and did not differ at a 95% confidence interval, but did differ at a 90% confidence interval. CO emissions were somewhat lower over the RMC, possibly due to increased CO oxidation caused by the somewhat higher exhaust temperatures of that cycle compared to the 8-mode C-1 cycle. In both cases, though, CO emissions were less than 50% of the Tier 4 standard.

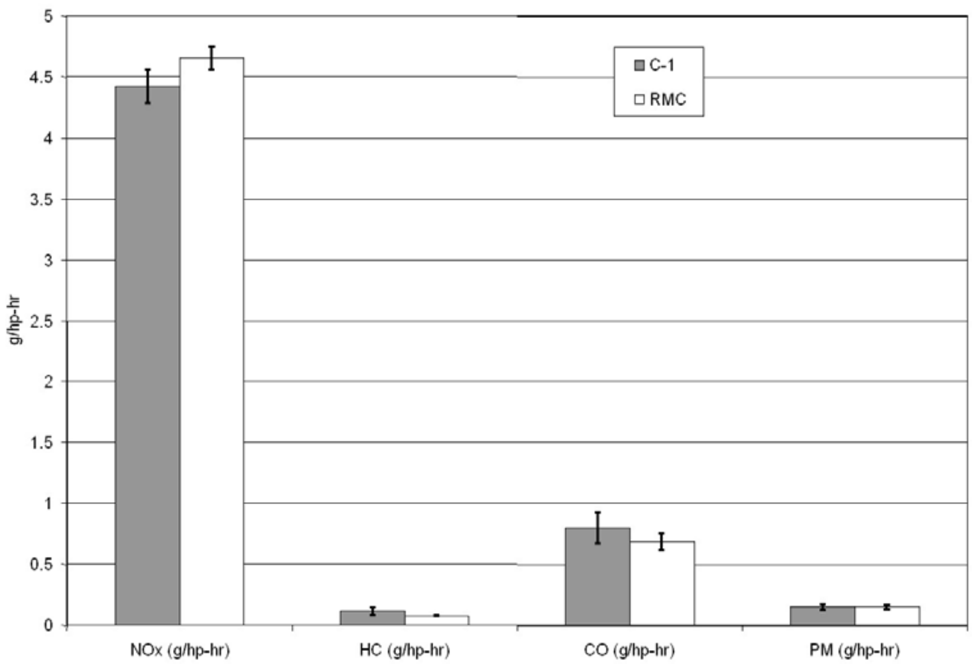


Figure 4.3-5: Emissions for the Kubota V1903E engine with no exhaust aftertreatment over the steady-state 8-mode C-1 test and the 20-minute RMC test.

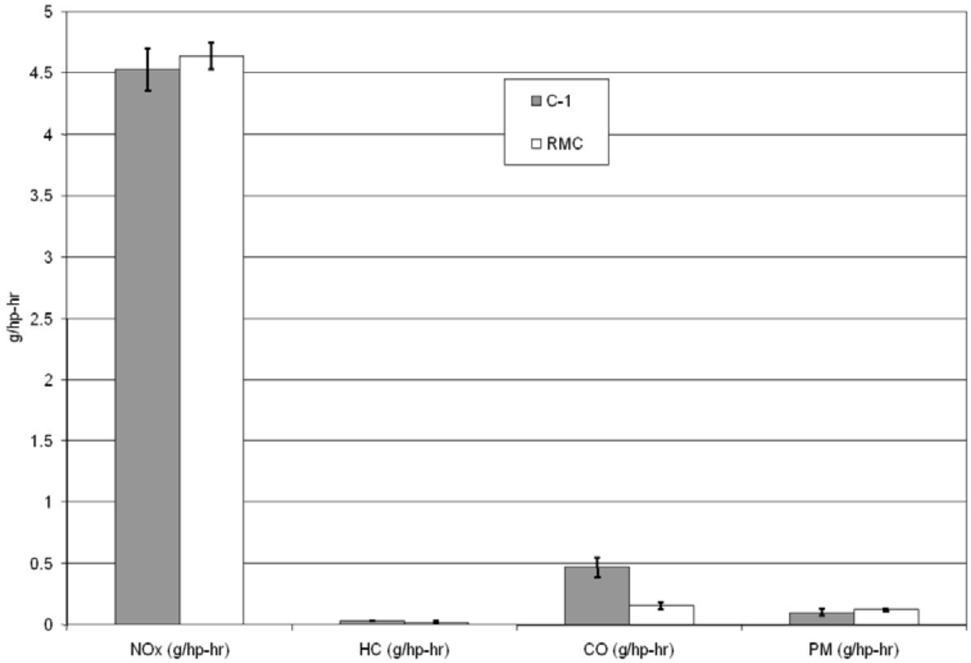


Figure 4.3-6: DOC-out emission levels obtained from the Kubota V1903E engine over the steady-state 8-mode C-1 test and the 20-minute RMC test.

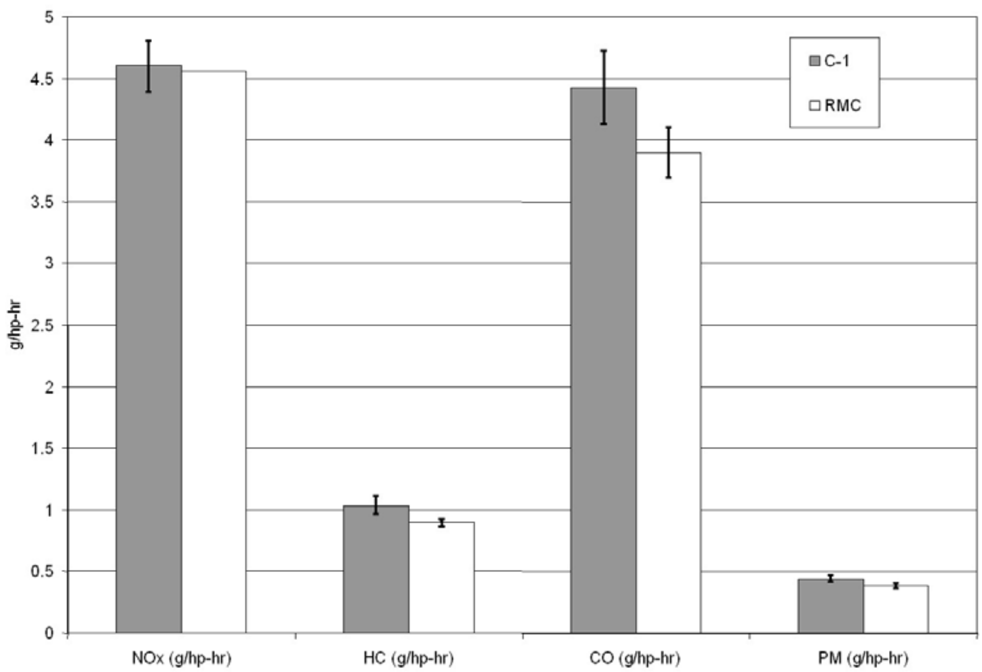


Figure 4.3-7: Engine-out emission levels obtained from the Yanmar 4TNE84 engine over the steady-state 8-mode C-1 test and the 20-minute RMC test.

Emissions from the Yanmar 4TNE84 engine operating without exhaust aftertreatment over both the 8-mode C-1 and 20 minutes long RMC test cycles are summarized above in Figure 4.3-7. As can be seen in this figure, the average engine-out NO_x emission over the RMC is within the 95% confidence interval of the NO_x data gathered over the steady-state 8-mode C-1 test, although the number of test replicates were insufficient to determine a confidence interval for the RMC for this particular data comparison. With regards to the HC and CO emissions, the data showed a slight, statistically significant difference for these emissions of 5% or less between the two cycles. CO emissions exceeded the Tier 1 standards over the 8-mode C-1 cycle and were unusually high for a diesel engine over both of these cycles. This may indicate that a mechanical problem exists with this particular test engine.

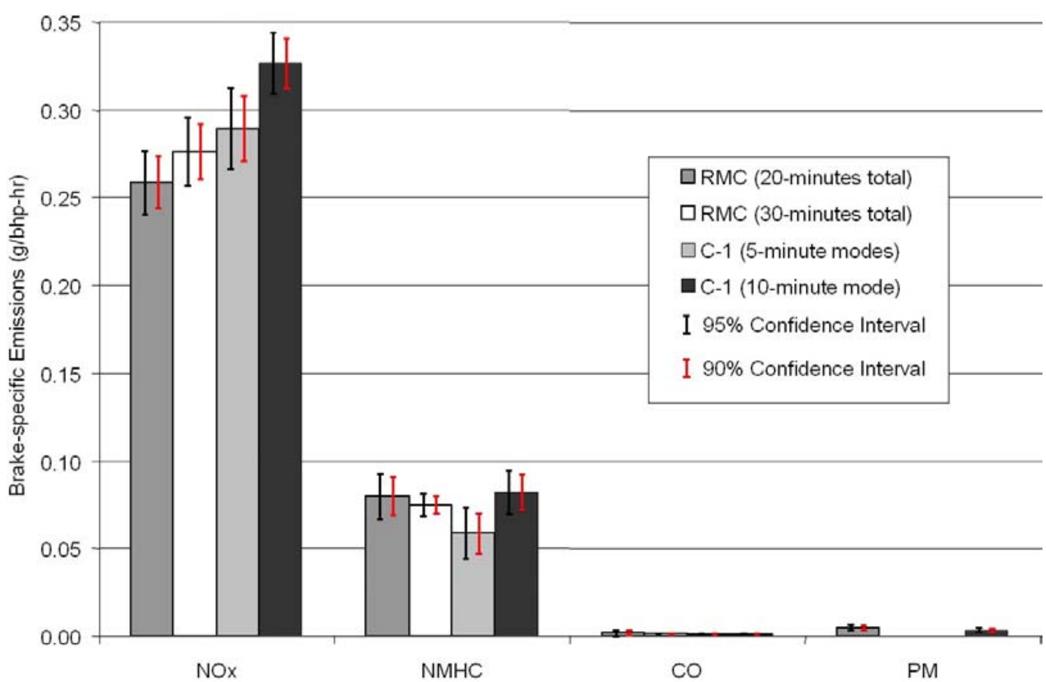


Figure 4.3-8: Emissions from the EPA-modified Cummins ISB engine over the steady-state 8-mode C-1 test cycle and the RMC test cycle. Note that the data represent the 2 different mode lengths specified for the 8-mode C-1 and two different total test times for the RMC. PM emissions were only available for the 10 minutes per mode 8-mode C-1 and the 20 minutes long RMC results. Results are shown for mean-emissions calculated for 7 test replicates. Confidence intervals were calculated using a 2-sided Student t-test.

Figure 4.3-8 above compares the emission levels obtained from testing the Cummins ISB engine on the 8-mode C-1 cycle at both five minutes per mode and ten minutes per mode, as described in 40 CFR Part 89, with the RMC version of that cycle at both twenty minutes and thirty minutes of total cycle time. The five minutes and ten minutes per mode represent mode lengths that are currently used in the 8-mode C-1 test cycle for emissions testing of nonroad diesel engines. PM emissions were measured only for the ten minutes per mode 8-mode C-1 and the twenty minutes total time RMC cycles, which among the cycles investigated represented the largest differences in exhaust temperature and gaseous emissions. PM emissions were extremely low due to the use of the CDPF and were approximately 50% of the Tier 4 standards. Mean PM emissions for these two cycles did not differ at either a 95% or a 90% confidence level. Some statistically significant differences in mean NO_x emissions were found between the various cycles used, including the two different mode length 8-mode C-1 cycles, due to differences in exhaust temperatures achieved over individual cycles. There were statistically significant differences in mean NO_x emissions between the ten minutes per mode and the five minutes per mode 8-mode C-1 cycles. Likewise, there were statistically significant differences in mean NO_x emissions between the ten minutes per mode 8-mode C-1 and both the twenty and thirty minutes total time RMCs. Differences in mean NO_x emissions between the thirty minutes total time RMC and the five minutes per mode 8-mode C-1 were not statistically significant at either a 95% or a 90% confidence level. All other emission levels were extremely low over both the RMC and the 8-mode C-1 tests. Mean HC, CO and PM emissions did not differ significantly at either a 95% or a 90% confidence level for either of these cycles.

4.3.1.2.3 Summary of engine test results

These data confirm that emissions from engines which do not use NO_x adsorption catalysts are relatively insensitive to the choice of the 8-mode C-1 test cycle or its RMC counterpart. Neither are these engine emissions sensitive to the impact of time spent at any steady-state speed-load set-point. However, the effect of test cycle length and time-in-mode on exhaust temperatures did have an impact on NO_x emissions when an engine was equipped with a NO_x adsorption catalyst system, due to the:

1. effect of catalyst temperature on the ability to oxidize NO-to-NO_2 for NO_x storage (kinetically-limited at low temperatures and equilibrium-limited at high temperatures);

2. effect of thermal-desorption of NO_x at high temperatures; and

3. difficulty in effectively vaporizing fuel reductant at very low exhaust temperatures.

Based on NO_x emissions and engine exhaust temperature data from EPA tests of the modified Cummins ISB engine, a thirty minutes total time 8-mode C-1-based RMC was selected as comparable to the five minutes per mode 8-mode C-1 test cycle for NO_x emission and engine exhaust temperature results. Furthermore, based on the results of both EPA and engine manufacturer testing, the Agency has determined that steady-state test procedures should be modified to include changes necessary to allow repeatable NO_x emission results for all steady-state testing conducted on engines having catalytic exhaust emission controls for NO_x emissions. Steady-state testing for certification will be conducted in the following manner:

1. The manufacturer may choose either the appropriate laboratory-based certification steady-state test cycle or its RMC derivative as found in regulations at 40 CFR, Section 1039.505. For RMC tests with five or fewer modes, the length of the RMC test cycle will be

twenty-minutes long. For RMC tests with six to nine modes, the length of that test cycle will be thirty-minutes long. For RMC tests with ten or more modes, the length of that test cycle will be forty-minutes long.

2. When testing an engine having an exhaust aftertreatment system which reduces NOx emissions, a manufacturer will operate that engine for four to six minutes, then sample emissions for one to three minutes in each mode. The sampling time for PM emissions may be extended to improve measurement accuracy, using good engineering judgment. If a longer sampling time is chosen for PM emissions, the manufacturer must calculate and validate cycle performance statistics for the gaseous and PM sampling periods separately.

3. When testing other engines, a manufacturer will operate those engines for at least five minutes, then sample emissions for at least one minute in each mode.

These changes in measurement procedures for nonroad engines have been incorporated into regulations at 40 CFR Section 1039.505.

4.3.2 Transportation Refrigeration Unit Test Cycle

Transportation refrigeration units (TRU), a specific application of steady-state engine operation, are refrigeration systems powered by diesel engines designed to refrigerate perishable products that are transported in various containers, including semi-trailers, truck vans, shipping containers, and rail cars. TRU engines are relatively small with most units ranging from 7 to 38 kW (10 to 50 horsepower)[LL].

Engines that are designated as TRU engines at the time of certification are expected to operate in the field primarily under steady-state conditions. These engines may from time to time be subject to minor setpoint performance perturbations; however those changes are not expected to last for a total duration at any one point of greater than 30 seconds and are not multiple, highly transient, repetitive changes in speed or load such as seen in the nonroad transient duty cycle. These parameters appropriately characterize TRU equipment operation independent of unit application, whether used for fresh product (chilled to 3°C) or for frozen goods at the standard maximum rating (-20°C). So, to that end, EPA has adopted a four-mode steady-state test cycle designed specifically for engines used in TRU applications.

The TRU certification test cycle consists of four steady-state modes of operation. Two modes are to be run at 50% of the manufacturer's declared peak torque value for that engine. The remaining two modes are to be run at 75% of that same declared peak torque value for that same engine. One of the modes at 50% load is to be run at the engine manufacturer's speed at peak, or rated, power, while the other mode at 50% load is to be run at the engine manufacturer's

[LL] Information on the proposed TRU cycle may be found on and downloaded from the CARB website at http://www.arb.ca.gov/diesel/dieselrrp.htm. In particular, see the Technical Bulletin to the Proposed TRU cycle determination.

"intermediate" test speed. Likewise, one of the modes at 75% load is to be run at the engine manufacturer's speed at rated horsepower and the remaining mode at 75% load is to be run at the manufacturer's "intermediate" test speed. All four modes would be weighted equally in determining a particular mode's contribution to the engine's total test cycle emissions. Early data submissions in response to California-ARB's call for TRU engine operating data showed that the majority of TRU engines operated in-use in at least three, if not all four of the test cycle's modes[168]. It was equally clear from comments to the rule that a TRU test cycle was more representative of refrigeration unit operation than the nonroad cycles currently available to manufacturers since TRUs generally did not operate at low idle, high idle, peak torque or rated power conditions.

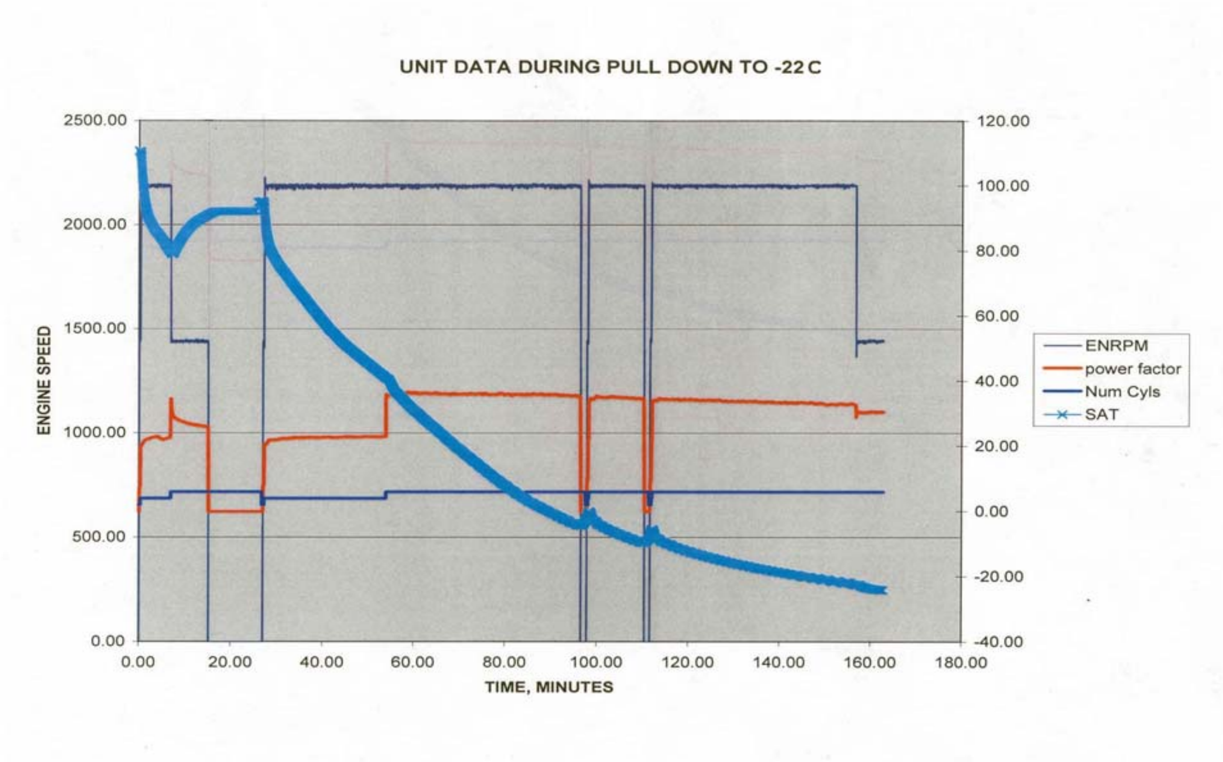
EPA will allow manufacturers to test their engines under a broad definition of intermediate test speed, similar to recommendations found in ISO-8178-4 steady-state test guidelines. The intermediate speed shall be the declared maximum torque speed if it occurs between 60% and 75% of rated speed / maximum test speed. If the declared maximum torque speed is less than 60% of rated speed, then the intermediate speed shall be 60% of the rated speed. If the declared maximum torque speed is greater than 75% of the rated speed then the intermediate speed shall be 75% of rated speed. This will enable an engine manufacturer to more closely match the TRU cycle at engine certification to the operation of their engines in-use.

The set point value for speed in a TRU engine is expected to remain consistent without repetitive transient changes on a 1 hertz basis. The magnitude of any changes in actual speed from the engine are expected to be under 2% which is consistent with the Agency's treatment of operation as steady state in the creation of the transient duty cycle. Additionally, the set point value demanded by the application remains within this 2% steady state definition. Should application demands differ from the steady state condition for speed, the engine shall not be considered an actual steady state TRU engine. The TRU engine is likewise not allowed to drop, or drift[MM], from a load set point by more than 15% of torque at the speed for a particular operating mode before changing its load setpoint.

As seen below in Figure 4.3-9[169], the operation of the typical piece of TRU equipment tested is relatively consistent, as evidenced by the power factor curve, a surrogate for engine response to load demand on the unit. Many factors may affect unit "drift" from a set point, but that set point of operation does not deteriorate significantly over longer periods of time, in minutes. TRU equipment is responsive to feedback from a broad number of engine operating parameters and user input options. Operating temperature, intake air temperature, i.e., ambient, and exhaust air temperature are some engine operating parameters to which the engine must be responsive. User or owner inputs include tolerances around set point temperatures, minimum time-on, and minimum time-off for the unit. Likewise the condition and age of the engine and container, especially the insulation, may influence ability to hold a desired temperature, or load[170],[171].

[MM]Drift is restricted to load deterioration not to exceed 15% over a sixty minute duration.

Figure 4.3-9
TRU Equipment Operation at Pull-Down



The expectation is that the engine is governed in such a way that this demand is not possible. If that engine is deemed a steady-state TRU engine at the time of certification, the application within which the engine is sold, must meet these standards of operation.

As an additional way of ensuring that TRU certification is limited to those engines for which it is warranted, we are adding a requirement that any TRU-certified engine must meet appropriate NTE standards for any in-use operation. Practically, this means that TRU engines are subject to NTE standards based on the normal operation that these engines would experience in the field. This is limited neither to later model years nor to any particular range of engine speeds and loads. If TRU engine operation is limited as much as manufacturers have described, the resulting "NTE zone" should be practically limited to a narrow range of speeds and loads very close to those points represented by the specified duty cycle.

4.4 Not-to-Exceed Testing

The Agency's examination of emissions data from heavy duty highway diesel engines , and the confidential discussions with several heavy duty diesel engine manufacturers, led EPA to the conclusion that the 1.25 emission cap associated with the not-to-exceed zone requirement is technologically feasible. This conclusion has not changed since the initiation of the not-to-exceed concept. The Agency believes the 1.25 factor proposed for the not-to-exceed standard provides sufficient room to allow for the uneven nature of the emission maps. For these reasons, EPA believes the primary technologies discussed earlier in this chapter will provide the necessary NMHC+NOx and PM control on the existing steady state, as well as on the transient cycle testing and not-to-exceed zone testing.

The goal of the Not-To-Exceed (NTE) limits on nonroad diesel engines remains consistent with the reasoning for highway heavy duty diesel engines . The NTE helps ensure that emission benefits are achieved in-use and provides a practical approach for a post-promulgation in-use testing program. The NTE established for the highway heavy duty diesel engines has been demonstrated to be not only feasible, but practical. The NTE approach provides an area under the maximum allowable torque curve of an engine for which an engine may not exceed a specified value for the regulated pollutants. The NTE zones, limits, and ambient conditions are described in detail below.

The advantages to adopting an NTE strategy originally adopted for highway diesel engines are numerous. These include:

- Proven design strategy can be utilized by manufacturers
- Development costs can be minimized as new test protocols will not need to be refined
- Assurance of comparable control effectiveness analogous to existing programs
- Demonstrated effectiveness in the heavy duty highway diesel market can be carried forward to the nonroad diesel market
- Allows for direct comparison of control effectiveness in-use

The Not-To-Exceed (NTE) provision was initially finalized for HDDEs certified to the 2004 FTP emission standards with implementation beginning in model year 2007. (See 65 FR 59896, October 6, 2000.) The NTE approach establishes an area (the "NTE control area") under the torque curve of an engine where emissions must not exceed a specified value for any of the regulated pollutants.[NN] The NTE requirements apply under engine operating conditions that could reasonably be expected to be seen in normal vehicle operation and use which occur during the conditions specified in the NTE test procedure. (See 40 CFR 86.1370.) This test procedure covers a specific range of engine operation and ambient operating conditions (i.e., temperature, altitude, and

[NN] Torque is a measure of rotational force. The torque curve for an engine is determined by an engine "mapping" procedure specified in the Code of Federal Regulations. The intent of the mapping procedure is to determine the maximum available torque at all engine speeds. The torque curve is merely a graphical representation of the maximum torque across all engine speeds.

humidity). The NTE control area, emissions standards, ambient conditions and test procedures for nonroad diesel engines are described in the 40 CFR 1039.515.

The NTE provisions for nonroad diesel engines mirror the highway diesel program and so a manufacturer will need to undertake the engine mapping procedure as defined in 40 CFR 1065; however, speed definitions will need to be determined based on 40 CFR 86.1360(c). Valid NTE compliance evaluation will be based on the following factors:

- Operating speeds greater than the speed determined by: $n_{lo} + 0.15 \times (n_{hi}-n_{lo})$
- Engine load points greater than or equal to 30% of the maximum torque value produced by the engine
- Brake Specific Fuel Consumption (BSFC) requirements as specified in 40 CFR 86.1370-2007 (b)(3)
- Exclusion areas for which the NTE requirement does not apply may be found in 40 CFR 86.1370-2007 (e.g. PM carve-out zones for engines certifying to a PM standard above 0.07 g / kW-hr)
- Control area limits as defined in 40 CFR86.1370-2007 (d) for averaging times that may or may not include discrete regeneration events
- Corrections for ambient conditions as defined in 40 CFR 86.1370-2007 (e)
- Cold temperature exclusions as adopted in 40 CFR 86.1370-2007 (f)
- Engines equipped with NOx and NMHC aftertreatment systems (both single and multi-bed systems) with warm-up provisions as defined in 40 CFR 86.1370-2007 (g)

The NTE requirements will not apply during engine start-up conditions 40 CFR 86.1370-2007 (g). In addition, with the application of advanced exhaust emission control devices, an exhaust emission control device warm-up provision is a necessary criterion for the NTE to address the impact of thermal inertia on aftertreatment efficiency for the catalytic reduction strategies. Until the exhaust gas temperature on the outlet side of the exhaust emission control device(s) achieves 250 degrees Celsius, the engine is not subject to the NTE as discussed in 40 CFR 86.1370-2007 (g). Control of cold-start emissions is expected to happen through the nonroad transient cycle cold-start provisions.

For a more detailed technical description of the application of the NTE Zone to diesel engines, please see the Regulatory Impact Analysis: Heavy -Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements EPA420-R-00-026.

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CHAPTER 5: Fuel Standard Feasibility

CHAPTER 5: Fuel Standard Feasibility

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

5.1 The Blendstocks and Properties of Non-Highway Diesel Fuel

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

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

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

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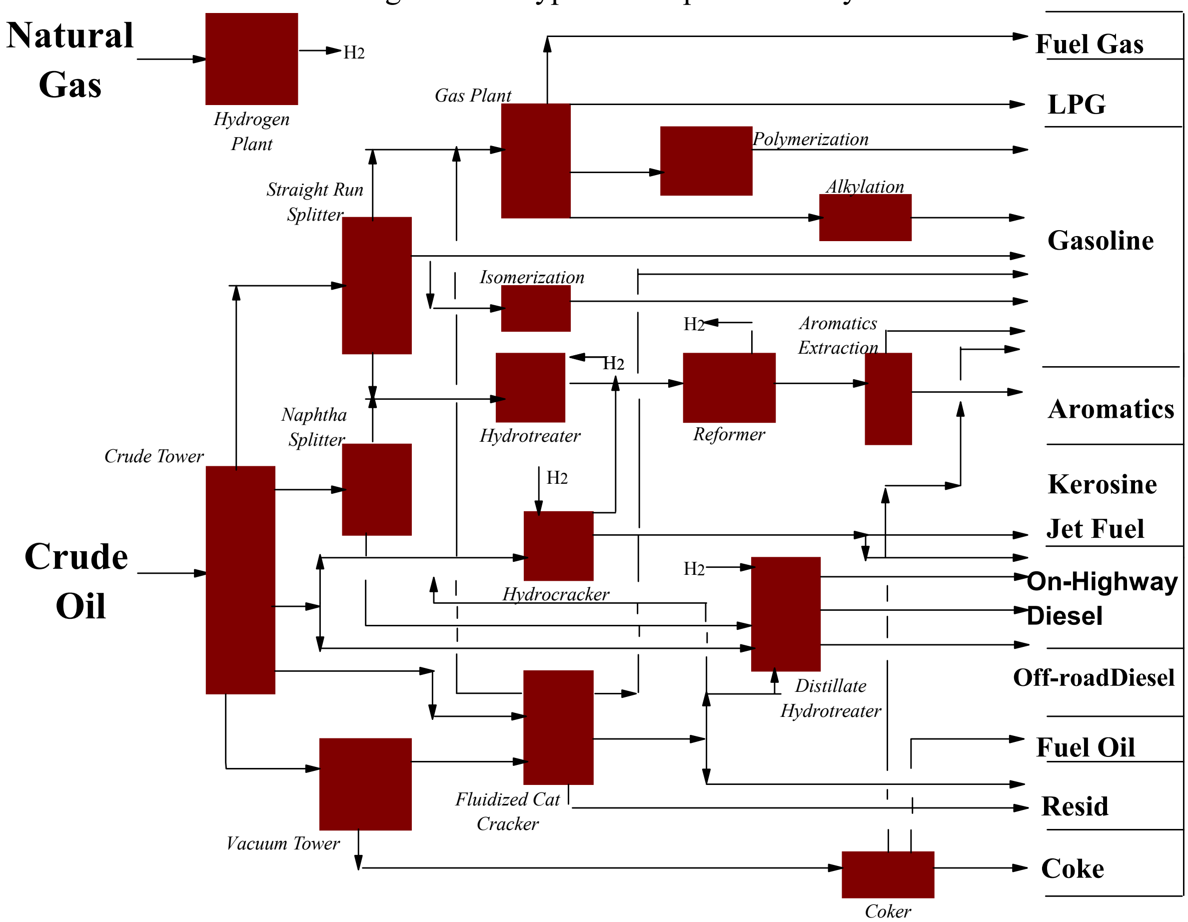
[A] Additives that contain sulfur are sometimes intentionally added to diesel fuel. For a discussion how the addition of these additives will be affected under this program, see Section IV.D.5.

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

Figure 5.1-1
Diagram of a Typical Complex Refinery



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2 Evaluation of Diesel Fuel Desulfurization Technology

5.2.1 Introduction to Diesel Fuel Sulfur Control

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

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

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

5.2.2 Conventional Hydrotreating

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

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

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

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

5.2.2.1 Fundamentals of Distillate Hydrotreating

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2.2.2 Meeting a 15 ppm Cap with Distillate Hydrotreating

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2.2.3 Low-Sulfur Performance of Distillate Hydrotreating

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

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

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

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

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

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

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

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

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

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

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

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

5.2.3 Process Dynamics Isotherming

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

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

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

Where:

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

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

Where:

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

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

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

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

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

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

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

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

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

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

5.2.4 Phillips S-Zorb Sulfur Adsorption

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

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

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

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

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

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

5.2.5 Chemical Oxidation and Extraction

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

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

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

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

5.2.6 FCC Feed Hydrotreating

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

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

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

5.3.1 Expected use of Desulfurization Technologies for 2007

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

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

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

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

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

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

5.3.2 Lead-time Evaluation

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

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

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

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

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

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

5.3.2.1 Tier 2 Gasoline Sulfur Program

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

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

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

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

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

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

5.3.2.2 15 ppm Highway Diesel Fuel Sulfur Cap

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.3.2.4 Comparison with the 500 ppm Highway Diesel Fuel Program

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

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

5.3.2.5 Small Refiners

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

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

5.4.1 Expected use of Desulfurization Technologies in 2010 and 2012

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

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

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

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

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

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

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

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

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

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

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

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

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

5.4.2 Lead-time Evaluation

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

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

5.5 Distribution Feasibility Issues

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

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

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

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

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

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

5.5.1.2 Potential for Additional Product Segregation Under the NRLM Sulfur Program

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[1] The term "terminal" is used as shorthand to refer to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.
[2] The 15 ppm highway diesel program and the 500 ppm NRLM early credit provisions are effective 2006.
[3] 500 ppm NRLM program effective 2007.
[4] 15 ppm NRLM early credit generating provisions effective 2009.
[5] 15 ppm NRLM program effective 2010. HS NRLM small-refiner and credit-use provisions expire. No 500 ppm NRLM may be sold except small-refiner, credit, and pipeline interface generated 500 ppm NRLM.
[6] 500 ppm NRLM small refiner, and credit use provisions expire 2014
[7] 500 ppm early credit generating NRLM.
[8] 15 ppm early credit generating NRLM.
[9] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors

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

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

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

[1] Terminal used as shorthand refers to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.
[2] The 15 ppm highway diesel and the 500 ppm NRLM early credit provisions are effective.
[3] 500 ppm NRLM program effective 2007 and no HS NRLM may be sold except small-refiner and credit HS NRLM. HS NRLM small-refiner and credit-use fuel may not be sold in the Northeast/Mid-Atlantic Area.
[4] 15 ppm NRLM early credit provisions effective 2009.
[5] 15 ppm NRLM program effective 2010. No 500 ppm NRLM small refiner, credit use, or pipeline interface generated fuels may be sold in the Northeast/Mid-Atlantic Area.
[6] 500 ppm NRLM credit fuel.
[7] 15 ppm NRLM credit fuel.
[8] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors transport. Earlier, when 500 ppm NRLM was available, such fuel could have been used for heating purposes.

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

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

[1] Terminal used as shorthand refers to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.
[2] The 15 ppm highway diesel and the 500 ppm NRLM early credit provisions are effective.
[3] 500 ppm NRLM program effective 2007. HS NRLM small-refiner provisions require segregation and tracking of HS NRLM.
[4] 15 ppm NRLM early credit provisions effective 2009.
[5] 15 ppm NRLM program effective 2010. HS NRLM small-refiner provisions expire in 2010. 500 ppm small-refiner NRLM provisions require segregation and tracking of 500 ppm NRLM.
[6] 500 ppm NRLM small-refiner provisions expire 2014.
[7] 500 ppm NRLM credit fuel.
[8] 15 ppm NRLM credit fuel.
[9] 500 ppm heating oil is not required, but is a fuel grade that some refiners may choose to produce and distributors transport. Earlier, when 500 ppm NRLM was available, such fuel could have been used for heating purposes.
[10] Segregated HS NRLM small-refiner fuel only.
[11] Segregated 500 ppm NRLM small-refiner fuel only.
[12] Segregated 500 ppm NR small-refiner fuel only.

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

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

[1] Refinery rack sales are covered under the "Post Terminal" segment.
[2] The term "terminal" is used as shorthand to refer to the point where taxes are paid on highway fuel, dye added to NRLM, or marker added to heating oil.
[3] 15 ppm highway diesel program and 500 ppm NRLM early credit generating provisions are effective 2006.
[4] 500 ppm NRLM program effective 2007.
[5] 15 ppm NRLM early credit generating provisions effective 2009.
[6] 15 ppm NRLM program effective 2010. HS NRLM small-refiner and credit-use provisions expire.
[7] 500 ppm NRLM small-refiner and credit-use provisions expire 2014.
[8] Refinery rack sales or sales at terminals of segregated interface.
[9] Sales at terminals of segregated interface and from transmix processors of fuel produced from transmix.
[10] 15 ppm early credit generating NRLM.

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

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

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

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

Refineries:

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

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

Pipelines:

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

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

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

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

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

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

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

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

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

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

Terminals:

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

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

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

Bulk Plants:

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

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

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

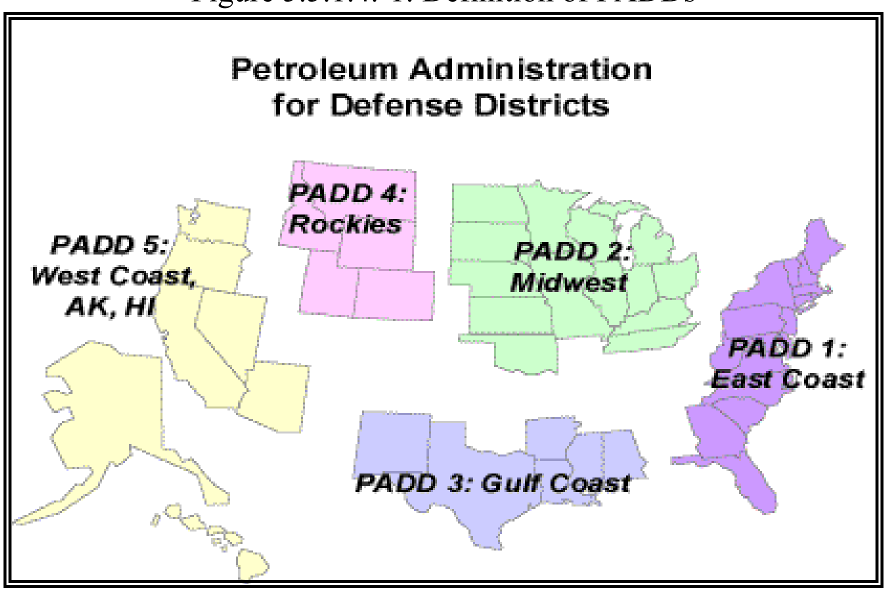
[P] In the Northeast/Mid-Atlantic Area heating oil would be dyed. Outside of the Northeast/Mid-Atlantic Area and Alaska, heating oil would be dyed and marked. In Alaska, heating oil will neither be dyed or marked.

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

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

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

Figure 5.5.1.4.-1: Definition of PADDs



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

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

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

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

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

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

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

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

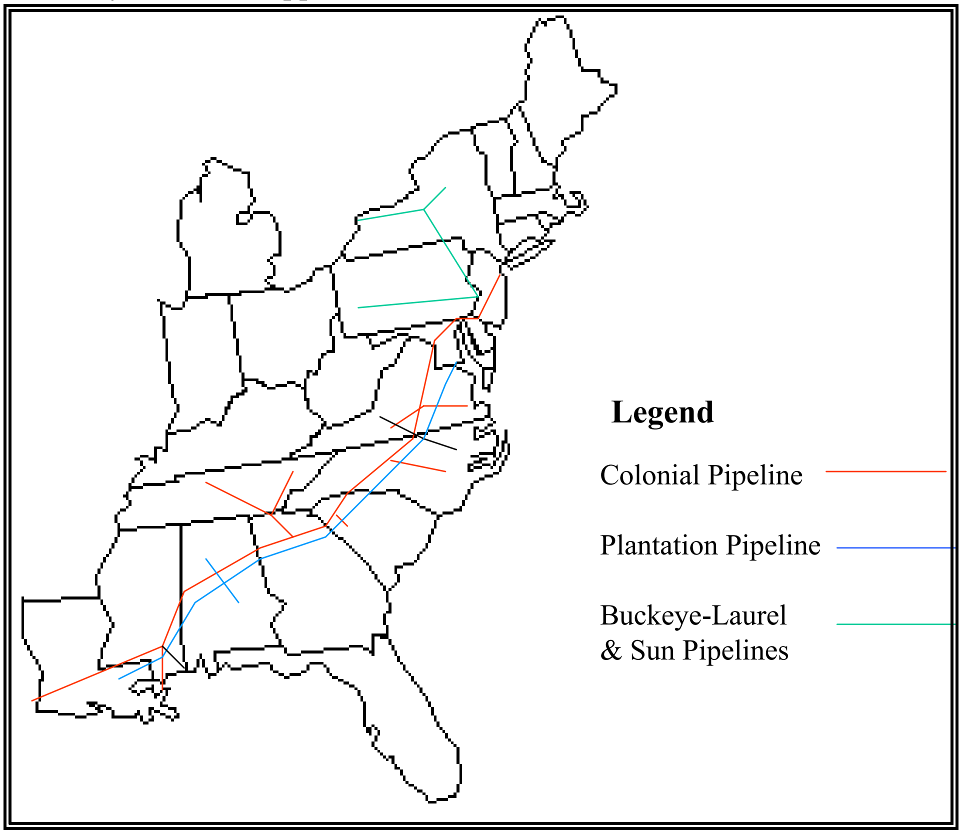
[R] "Paying for" refers to the volume of heating oil bearing the costs related to the marker requirements where these requirements are needed to make the small refiner and credit provisions enforceable.

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

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

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

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



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

Magnitude of Heating Oil Demand:

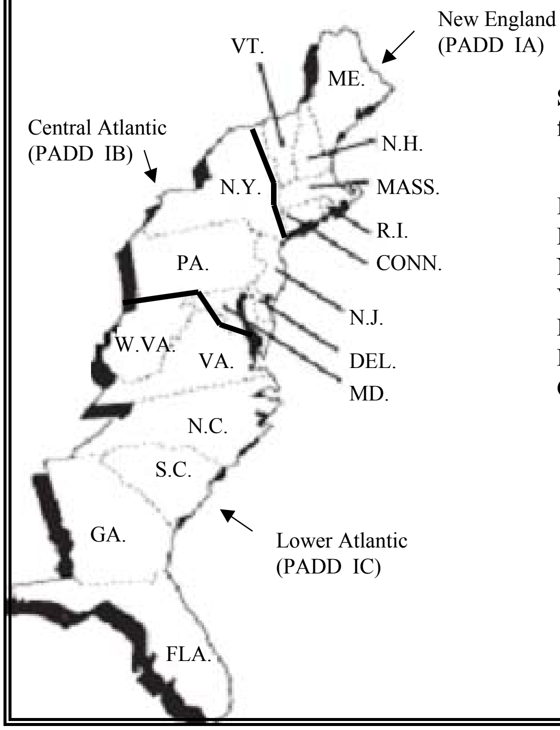
Figure 5.5.1.4-3 shows the residential heating oil use in PADD I by state and by the sub-districts in PADD I.[S]

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

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

Residential Use of No. 2 Distillate in PADD I

PADD I Refining District



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

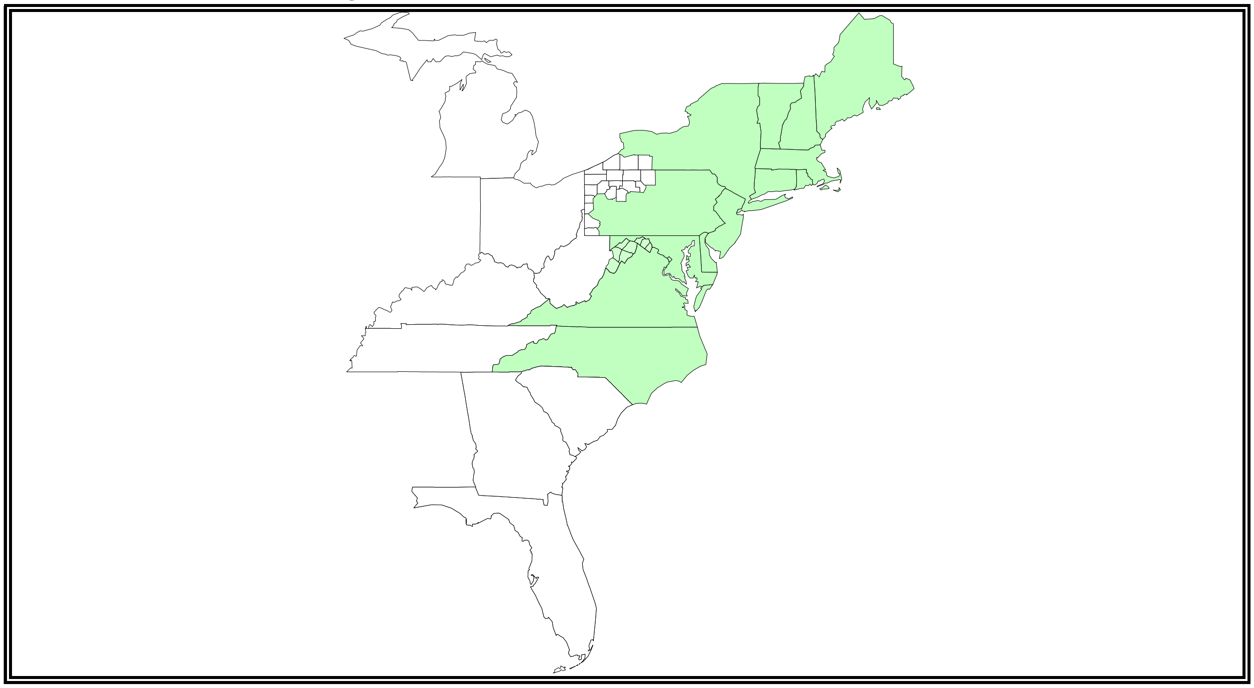
A critical factor in defining the boundary of the Northeast/Mid-Atlantic Area is evaluating its impact on small refiners' access to the small-refiner provisions. Our evaluation of the location of small refiners who will likely use these provisions indicates that one such small refiner's distribution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

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

Conclusion:

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

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



5.5.2 Limiting Sulfur Contamination

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

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

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

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

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

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

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

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

Ensuring a Suitable Market for Diesel Fuel Recovered from Pipeline Interface

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

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

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

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

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

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

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

The Potential Impact on Transmix Processors

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

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

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

5.6 Feasibility of the Use of a Marker in Heating Oil

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.7 Impacts on the Engineering and Construction Industry

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

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

[FF] ibid

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

5.7.1 Design and Construction Resources Related to Desulfurization Equipment

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

Table 5.7-1
Design and Construction Factors for Desulfurization Equipment

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

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

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

5.7.2 Number and Timing of Revamped and New Desulfurization Units

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

Table 5.7-2
Number of Gasoline and Highway Diesel Desulfurization Units Becoming Operational[a45]

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

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

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

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

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

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

Table 5.7-3
Number and Timing of NRLM Desulfurization Units

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

5.7.3 Timing of Desulfurization Projects Starting up in the Same Year

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

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

5.7.4 Timing of Design and Construction Resources Within a Project

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

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

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

Table 5.7-5
Distribution of Personnel Requirements Throughout the Project

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

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

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

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

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

5.7.5 Projected Levels of Design and Construction Resources

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

Table 5.7-7
Maximum Monthly Demand for Personnel

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

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

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

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

Table 5.7-8
Annual Front End Engineering Personnel Demand

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

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

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

Table 5.7-9
Annual Detailed Engineering Personnel Demand

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

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

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

Table 5.7-10
Construction Worker Personnel Demand

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.9 Desulfurization Effect on Other Non-Highway Diesel Fuel Properties

5.9.1 Fuel Lubricity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.9.2 Volumetric Energy Content

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

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

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

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

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

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

[a] See Section 5.3 regarding the use of conventional hydrodesulfurization , and the Process Dynamics Isotherming process to meet the new sulfur standards.
[b] NR = nonroad diesel fuel, L = locomotive diesel fuel, and M = marine diesel fuel.
[c] HS refers to high-sulfur diesel fuel at the current uncontrolled average sulfur level of approximately 3000 ppm.

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

5.9.3 Fuel Properties Related to Storage and Handling

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

5.9.4 Cetane Index and Aromatics

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

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

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

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

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

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

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

5.9.5 Other Fuel Properties

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5A.3 Sulfur Levels that Nonroad Engines Can Tolerate

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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CHAPTER 6: Estimated Engine and Equipment Costs

CHAPTER 6: Estimated Engine and Equipment Costs

This chapter presents the engine and equipment costs we have estimated for meeting the new engine emissions standards. Section 6.1 includes a brief outline of the methodology used to estimate the engine and equipment costs. Sections 6.2 and 6.3 present the projected costs of the individual technologies we expect manufacturers to use to comply with the new emissions standards, along with a discussion of fixed costs such as research and development (R&D), tooling, certification, and equipment redesign. Section 6.4 summarizes these costs and Section 6.5 details cost estimates for several example pieces of equipment. A complete presentation of the aggregate cost of compliance for engines and equipment is in Chapter 8.

Note that the costs presented here are for those nonroad engines and equipment that are mobile nonroad equipment and are, therefore, subject to nonroad engine standards. These costs would not apply for that equipment that is stationary—some portion of some equipment segments such as generator sets, pumps, compressors—and not subject to nonroad engine standards. The reader should know that some nonroad diesel equipment is not covered by nonroad engine standards. Those nonroad engines that receive permits from local authorities as stationary source emitters (i.e., some gensets, pumps, compressors, etc.) are not covered by nonroad engine standards. In most cases, for what are very similar products, some fraction will be permitted as stationary sources while others remain mobile sources.

To maintain consistency in the way our emission reductions, costs, and cost-effectiveness estimates are calculated, our cost methodology for engines and equipment relies on the same projections of new nonroad engine growth as those used in our emissions inventory projections. Our NONROAD emission inventory model includes estimates of future engine populations that are consistent with the future engine sales used in our cost estimates. The NONROAD model inputs include an estimate of what percentage of gensets sold in the U.S. are "mobile" and, thus, subject to the nonroad standards, and what percentage are "stationary" and not subject to the nonroad standards. These percentages vary by power category and are documented in "Nonroad Engine Population Estimates," EPA Report 420-P-02-004, December 2002. For gensets >750 horsepower, NONROAD assumes 100 percent are stationary and, therefore, not subject to the new nonroad standards. For gensets <750 horsepower, we have assumed other percentages of mobile versus stationary. During our discussions with engine manufacturers after the proposal, it became apparent not only that our estimate for >750 horsepower gensets may not be correct and many are indeed mobile, but also that some of our estimates for <750 horsepower gensets may also not be correct and many more than we estimate may indeed be mobile. If true, this increased percentage of mobile gensets will be subject to the new nonroad standards. Unfortunately, we have not received sufficient data to make a conclusive change to the NONROAD model and, therefore, for the above described purpose of maintaining consistency, we have not included the costs or the emissions reductions in our official estimates for this final rule. In Chapter 8, Appendix A, we present a sensitivity analysis that includes both an estimate of the costs and emissions reductions that would result from including a higher percentage of gensets as mobile machines and subject to the new standards.

Note also that the costs presented here do not include potential savings associated with our engine ABT program or our Transition Program for Equipment Manufacturers. In addition, we have assumed that engine companies who are eligible for the small business engine manufacturer specific provisions *do not* take advantage of the unique flexibilities the rule provides for them, which includes the opportunity to delay compliance with the Tier 4 emission standards for a full three model years. While we fully expect companies to use them to reduce compliance costs, we do not factor them into the cost analysis because they are voluntary programs. This analysis of compliance costs relates to regulatory requirements that are part of the nonroad Tier 4 final rule. Unless noted otherwise, all costs are in 2002 dollars.

6.1 Methodology for Estimating Engine and Equipment Costs

This analysis makes several simplifying assumptions regarding how manufacturers will comply with the new emission standards. First, in each power category, we assume a single technology recipe, as discussed in Chapter 4. However, we expect that each manufacturer will evaluate all possible technology avenues to determine how to best balance costs while ensuring compliance. As noted, for developing cost estimates, we have assumed that the industry does not use either the transition program for equipment manufacturers or averaging, banking, and trading, both of which offer the opportunity for significant cost reductions. Given these simplifying assumptions, we believe the projections presented here probably overestimate the costs of the different approaches toward compliance that manufacturers may ultimately take.

For smaller nonroad engines—those under 75 hp—many of the anticipated emission-control technologies will be applied for the first time. Therefore, we have sought input from a large section of the regulated community regarding the future costs of applying these technologies to diesel engines. Under contract with EPA, ICF Consulting provided questions to several engine and parts manufacturers regarding costs associated with emission-control technologies for diesel engines. The responses to these questions were used as a first step toward estimating the costs for many of the technologies we believe manufacturers will use. These costs form the basis for our estimated costs for "traditional" engine technologies such as EGR and fuel-injection systems.[1] Note that, while these technologies are expected to be added to <75hp engines for the first time, they are being added, or will be, to >75hp engines to meet the Tier2/3 standards. We have used the same methodology to develop the costs for these technologies for <75hp engines as was used to develop the costs for >75hp engines.[2]

Costs for exhaust emission-control devices (for example, catalyzed diesel particulate filters (CDPF), NOx adsorbers, and diesel oxidation catalysts (DOC)) were estimated using the methodology used in our HD2007 rulemaking. In that rulemaking effort, ICF Consulting, under contract to EPA, provided surveys to nine engine manufacturers seeking information relevant to estimating the costs for and types of emission-control technologies that might be enabled with low-sulfur diesel fuel. The survey responses were used as the first step in estimating the costs for advanced emission-control technologies anticipated for meeting the HD2007 standards.[3] We then built upon these costs based on input from members of the Manufacturers of Emission Controls Association. Because the anticipated emission-control technologies are the same as expected for highway engines, and because the suppliers of the technologies are the same for nonroad engines as for highway engines, we have used that analysis as the basis for estimating the costs of these technologies in this rulemaking.

Costs of control include variable costs (for incremental hardware costs, assembly costs, and associated markups) and fixed costs (for tooling, R&D, and certification). For technologies sold by a supplier to the engine manufacturers, costs are either estimated based on a direct cost to manufacture the system components plus a 29 percent markup to account for the supplier's overhead and profit or, when available, based on estimates from suppliers on expected total costs to the manufacturers (inclusive of markups).[4] Estimated variable costs for new technologies include a markup to account for increased warranty costs. Variable costs are additionally marked up to account for both manufacturer and dealer overhead and carrying costs. The manufacturer's carrying cost was estimated to be four percent of the direct costs to account for the capital cost of the extra inventory and the incremental costs of insurance, handling, and storage. The dealer's carrying cost was estimated to be three percent of their direct costs to account for the cost of capital tied up in inventory. We adopted this same approach to markups in the HD2007 rule, based on industry input.[5]

We have also identified various factors that cause cost impacts to decrease over time, making it appropriate to distinguish between near-term and long-term costs. Research in the costs of manufacturing has consistently shown that, as manufacturers gain experience in production, they are able to apply innovations to simplify machining and assembly operations, use lower cost materials, and reduce the number or complexity of component parts.[6] This analysis incorporates the effects of this learning curve as described in Section 6.2.2.

Fixed costs for engine R&D are estimated to be incurred over the five-year period preceding introduction of the engine.[A] Fixed costs for tooling and certification are estimated to be incurred one year ahead of initial production. Fixed costs for equipment redesign[B] are estimated to be incurred over a two-year period preceding introduction of the piece of equipment, while equipment tooling costs are estimated to be incurred one year ahead of initial production. All fixed cost expenditures are amortized using a seven percent capital cost to reflect the time value of money. Engine fixed costs are then "recovered" over a five-year amortization period including the same seven percent cost of capital. This is true except where a phase-in of a new standard occurs in which case the fixed costs are recovered during the phase-in years and then

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[A] There is one exception to this – for engine R&D conducted to support the new standards for <75 horsepower engines in the 2008 model year, we have used a four year period (i.e., 2004 through 2007) over which to spread the R&D expenditures.

[B] Throughout this analysis we use the term "redesign" to refer to all work needed to complete the equipment modifications we believe will be necessary to accommodate the engine changes that will result from the new engine standards.

during the five years following 100 percent compliance.[C] Equipment fixed costs are recovered over a 10-year amortization period including the same seven percent captial cost; the longer amortization period for equipment fixed costs reflects the longer product cycle for equipment. We have also included lifetime operating costs where applicable. These include costs associated with the higher cost fuel, expected fuel economy impacts, increased maintenance demands resulting from the addition of new emission-control hardware, and expected savings associated with lower oil-change maintenance costs as a result of the low-sulfur fuel.

A simplified overview of the methodology used to estimate engine and equipment costs is as follows:

- For fixed costs (i.e., R&D, redesign, tooling, certification), we estimate the total dollars that industry will spend. We then calculate the total dollars that they will recover in each year of the program following implementation. These annual recovered costs represent our estimate of fixed costs associated with this final rule. In Section 6.5 and in some engine-related fixed cost tables in Section 6.2.1, we also present an estimate of per-unit fixed costs. These per-unit fixed costs are impacted by the way we have broken up the power categories in this cost analysis and by other factors (for example, the engine prices we have estimated) as discussed in more detail below. Because we do not know how manufacturers recover their costs on a per-unit basis, we present these per-unit fixed costs for informational purposes only. We do not use these per-unit fixed cost estimates in our cost-per-ton calculations; instead, we use the annual cost of recovery totals in the aggregate cost-per-ton calculations presented in Chapter 8.

- For engine variable costs (i.e., emission-control hardware), we first estimate the cost per piece of technology/hardware. As described in detail in Section 6.2.2, emission-control hardware costs tend to be directly related to engine characteristics—for example, emission-control devices are sized according to engine displacement so costs vary by displacement; fuel-injection systems vary in cost according to how many fuel injectors are required so costs vary by number of cylinders. This way we are able to determine a variable cost equation as a function of engine displacement or as a function of the number of cylinders. We then consider each unique engine's baseline technology package using a database from Power Systems Research of all nonroad equipment sold in the United States.[7] That database lists engine characteristics for every one of over 4,500 unique equipment models sold in the United States and provides the sales of each piece of equipment. Using the baseline engine characteristics of each engine, the projected technology package for that engine, and the

[C] We have estimated a "recovered" cost for all engine and equipment fixed costs to provide for a per-unit analysis of the cost of the final rule. In general, in environmental economics, it is more conventional to simply count the total costs of the program (i.e., opportunity costs) in the year they occur. However, this approach does not directly estimate a per-unit production cost since fixed costs occur before the standards take effect and, therefore, prior to the production of new compliant engines. In our methodology, fixed costs grow at a seven percent rate until they can be "recovered" on complying units. Note that the approach used here results in a higher estimate of the total costs of the program since the recovered costs include a seven percent capital cost to reflect the time value of money. Our intent is to reflect the cost of capital investments made in emissions control rather than investments made in other activities.

variable cost equations described in Section 6.2, we calculate a variable cost for the engine in each of the over 4,500 unique equipment models sold in the United States. This variable cost per engine is then multiplied by that engine's projected sales in each year for the years after the new standards take effect. We then total the annual costs for all engines to get the fleetwide variable costs per year. These fleetwide variable costs per year are then used in the cost-per- ton calculations presented in Chapter 8.

- Note that the cost-per-ton calculation (see Chapter 8 of this RIA for our cost-per-ton analysis) is never impacted by how many power categories we use in our cost analysis. We sometimes break up the fleet into more power categories than would seem reasonable given the structure of the emission standards. We do this for several reasons: (1) phase-ins of standards and/or different levels of baseline versus new standards sometimes force such breakouts; and, (2) greater stratification (i.e., breaking up the 75 to 175 hp range and the 175 to 750 hp range) provides a better picture for use in our estimate of potential recovery of fixed costs. Importantly, the number of power categories used does not impact the total costs estimated as a result of the new emission standards, and these are the total costs used to calculate a cost-per-ton number.

Engine costs are presented first – fixed costs, variable costs, then operating costs. Equipment costs follow – fixed costs then variable costs. A summation of engine and equipment costs follows these discussions. Variable cost estimates presented here represent an expected incremental cost of the engine or piece of equipment in the model year of introduction. Variable costs in subsequent years decrease as a result of several factors, as described below. All costs are presented in 2002 dollars.

6.2 Engine-Related Costs

6.2.1 Engine Fixed Costs

6.2.1.1 Engine and Emission-Control Device R&D

The technologies described in Chapter 4 represent those technologies we believe will be used to comply with the Tier 4 emission standards. These technologies are also part of an ongoing research and development effort geared toward compliance with the HD2007 standards and, to some extent, the current and future light-duty diesel vehicle standards in the US and in Europe. Those engine manufacturers making R&D expenditures toward compliance with highway emission standards will have to undertake some R&D effort to transfer emission-control technologies to engines they wish to sell into the nonroad market. These R&D efforts will allow engine manufacturers to develop and optimize these new technologies for maximum emission-control effectiveness, while continuing to design engines with good performance, durability, and fuel efficiency characteristics. However, many nonroad engine manufacturers are not part of the ongoing R&D effort toward compliance with highway emission standards because they do not sell engines into the highway market. These manufacturers are expected to learn from the R&D work that has already occurred and will continue through the coming years through their contact with highway manufacturers, emission-control device manufacturers, and the independent engine research laboratories conducting relevant R&D. Despite these opportunities for learning, we expect the R&D expenditures for these nonroad-only manufacturers to be higher than for those manufacturers already conducting R&D in response to the HD2007 rule and the light-duty diesel requirements in the US and Europe.

We are projecting that several technologies will be used to comply with the Tier 4 emission standards. We are projecting that NOx adsorbers and CDPFs will be the most likely technologies used to meet the new emission standards for engines over 75 hp and, for engines between 25 and 75 hp, that CDPFs will be used in 2013 to meet the new PM standard. The fact that these technologies are being developed for implementation in the highway market before the emission standards in this final rule take effect, and the fact that engine manufacturers have several years to comply with the Tier 4 standards, ensures that the technologies used to comply with the nonroad standards will undergo significant development before reaching production. This ongoing development will likely lead to reduced costs in three ways. First, we expect research will lead to enhanced effectiveness for individual technologies, allowing manufacturers to use simpler packages of emission-control technologies than we would predict currently, given the current state of development. Second, we anticipate that the continuing effort to improve the emission-control technologies will include innovations that allow lower-cost production. And finally, we believe manufacturers will focus research efforts on any drawbacks, such as fuel economy impacts or maintenance costs, in an effort to minimize or overcome any potential negative effects.

We anticipate that manufacturers will introduce a combination of primary technology upgrades to meet the new emission standards. Achieving very low NOx emissions requires basic research on NOx emission-control technologies and improvements in engine management. Manufacturers are expected to address the challenge by optimizing the engine and exhaust emission-control system to realize the best overall performance. This will entail optimizing the engine and emission control system for both emissions and fuel economy performance in light of the presence of the new exhaust emission control devices and their ability to control pollutants previously controlled only via in-cylinder means or with exhaust gas recirculation. The NOx adsorber technology in particular is expected to benefit from re-optimization of the engine management system to better match the NOx adsorber's performance characteristics. The majority of the dollars we have estimated for research is expected to be spent on developing this synergy between the engine and NOx exhaust emission-control systems. Therefore, for engines where we project use of both a CDPF and a NOx adsorber (i.e., 75 to 750 hp), we have attributed two-thirds of the R&D expenditures to NOx control, and one-third to PM control.[D]

[D] In order to avoid inconsistencies in the way our emission reductions, and cost-effectiveness estimates are calculated, our cost methodology for engines and equipment relies on the same projections of new nonroad engine growth as those used in our emissions inventory projections. Our NONROAD emission inventory model includes estimates of future engine populations that are consistent with the future engine sales used in our cost estimates. The NONROAD model inputs include an estimate of what percentage of gensets sold in the U.S. are "mobile" and, thus, subject to the nonroad standards, and what percentage are "stationary" and not subject to the nonroad standards. These percentages vary by power category and are documented in "Nonroad Engine Population Estimates," EPA

For this analysis, we have estimated two elements to engine R&D: (1) corporate R&D, or that R&D conducted by manufacturers using test engines to learn how NOx and PM control technologies work and how they work together in a system; and, (2) engine line specific R&D, or that R&D done to tailor the corporate R&D knowledge to each particular engine line. To distinguish between these two R&D elements, here we refer to the former as corporate R&D and the latter as engine line R&D.

With respect to the former of these R&D elements—corporate R&D—we begin with our HD2007 rule. In that rule, we estimated that each engine manufacturer would expend $35 million for R&D toward successfully implementing catalyzed diesel particulate filters (CDPF) and NOx adsorbers. For this analysis, we express all monetary values in 2002 dollars which means our HD2007 starting point equates to $36.1 million. For their nonroad R&D efforts on >75 hp engines – those engines where we project that compliance will require a CDPF and a NOx adsorber or CDPFs-only (engines >750 hp) – engine manufacturers that also sell into the highway market will incur some level of R&D effort but not at the level incurred for the highway rule. In many cases, the engines used by highway manufacturers in nonroad products are based on the same engine platform as those engines used in highway products. However, power and torque characteristics are often different, so manufacturers will need to expend some effort to accommodate those differences. For these manufacturers, we have estimated that they will incur an average R&D expense of $3.6 million not including the engine line R&D. This $3.6 million R&D expense allows for the transfer of learning from highway R&D to their nonroad engines. For reasons noted above, two-thirds of this R&D is attributed to NOx control and one-third to PM control for 75 to 750 hp engines; for the portion of this R&D that is allocated to engines >750 hp, all of this R&D is attributed to PM control.

For those manufacturers that sell larger engines only into the nonroad market, and where we project those engines to add a CDPF and a NOx adsorber (75 to 750 hp) or a CDPF-only (>750 hp), we believe they will incur a corporate R&D expense approaching that incurred by highway manufacturers for the highway rule although not quite at the same level[E]. Nonroad

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Report 420-P-02-004, December 2002. For gensets >750 horsepower, NONROAD assumes 100 percent are stationary and, therefore, not subject to the new nonroad standards. For gensets <750 horsepower, we have assumed other percentages of mobile versus stationary. During our discussions with engine manufacturers after the proposal, it became apparent not only that our estimate for >750 horsepower gensets may not be correct and many are indeed mobile, but also that some of our estimates for <750 horsepower gensets may also not be correct and many more than we estimate may indeed be mobile. If true, this increased percentage of mobile gensets will be subject to the new nonroad standards. Unfortunately, we have not received sufficient data to make a conclusive change to the NONROAD model to include the potentially increased percentages of mobile gensets and, therefore, for the above described purpose of maintaining consistency, we have not included their costs or their emissions reductions in our official estimates for this final rule (costs and emissions reductions for the current percentages in the NONROAD model are included in our estimates for the final rule). Instead, we present a sensitivity analysis in Chapter 8 of the RIA that includes both an estimate of the costs and emissions reductions that would result from including a higher percentage of gensets as mobile equipment and subject to the new standards.

[E] Note that, while >750 hp mobile machine engines are not expected to add a NOx adsorber to comply with the new engine standards, we have considered that the corporate R&D conducted for engines expected to add both a NOx adsorber and a CDPF will apply for engines >750 hp given the general similarity between large engines above and below manufacturers will be able to learn from the R&D efforts already underway for both the highway rule and for the Tier 2 light-duty highway rule (65 FR 6698), and the light-duty and heavy-duty diesel requirements in Europe. This learning may come from seminars, conferences, technical publications regarding diesel engine technology (e.g., Society of Automotive Engineers technical papers), and contact with highway manufacturers, emission-control device manufacturers, and the independent engine research laboratories conducting relevant R&D. Therefore, we have estimated an average expenditure of 70 percent of that spent by highway manufacturers in their highway efforts. This lower number—$25.3 million versus $36.1 million in the highway rule—reflects the transfer of knowledge to nonroad manufacturers from the many other stakeholders in the diesel industry. As noted above, two-thirds of this R&D is attributed to NOx control and one-third to PM control. This value does not include the engine line R&D.

Note that the $3.6 million and $25.3 million estimates represent our estimate of the average corporate R&D expected by manufacturers. Each manufacturer may have more or less than these average figures.

For manufacturers selling smaller engines that we project will add only a CDPF (i.e., 25 to 75 hp engines in 2013), we have estimated that their average R&D will be roughly one-third that incurred by manufacturers conducting CDPF/NOx adsorber R&D. We believe this is a reasonable estimate because CDPF technology is further along in its development than is NOx adsorber technology and, therefore, a 50/50 split is not appropriate. Using this estimate, the average corporate R&D incurred by manufacturers that already have been selling engines into both the highway and the nonroad markets will be $1.2 million not including engine line R&D, and the average corporate R&D for manufacturers selling engines only into the nonroad market will be roughly $8.3 million not including engine line R&D. All this R&D is attributed to PM control.

For manufacturers selling engines that will add only a DOC or will make only some engine-out modification (i.e., to meet the PM standard for engines under 75 hp in 2008), we have estimated that their average corporate R&D will be roughly one-half the amount estimated for their CDPF-only R&D. Application of a DOC should require very little R&D effort because these devices have been used for years and because they require no special fueling strategies or operating conditions to operate properly. Nonetheless, to avoid underestimating costs, we have estimated that the R&D incurred by manufacturers selling any engines into both the highway and nonroad markets will be roughly $600,000 not including engine line R&D, and the corporate R&D for manufacturers selling engines only into the nonroad market will be roughly $4.2 million not including engine line R&D. Because these R&D expenditures are strictly for meeting a PM standard, they are fully attributed to PM control.

All these corporate R&D estimates are outlined in Table 6.2-1.

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750 hp. We have included additional engine line R&D for all engines, including those >750hp, that is unique from this corporate R&D estimate.

Table 6.2-1
Estimated Corporate R&D Expenditures by Type of Manufacturer
Totals per Manufacturer over Five Years
($Million)

	R&D for DOC/engine-out Engines	R&D for CDPF&NOx Adsorber Engines	R&D for CDPF-only Engines
Horsepower range	0<hp<75	hp≥75	25≤hp<75
For new standards starting in year:	2008	2011 (175-750hp) 2012 (75-175hp) 2015 (>750hp)	2013
Manufacturer sells into both highway and nonroad markets	$0.6	$3.6	
Manufacturer sells only into the nonroad market	$4.2	$25.3	
Manufacturer has already done CDPF&NOx Adsorber R&D			$1.2
Manufacturer has not done CDPF&NOx Adsorber R&D			$8.3
% Allocated to PM	100%	33%	100%
% Allocated to NOx		67%	

Some manufacturers may actually incur more than one of the corporate R&D amounts shown in Table 6.2-1. For example, we would estimate that a manufacturer with engines in both the 25-75 hp range and the 175-750 hp range that sells only into the nonroad market would incur $30.7 million ($4.2 + $25.3 + $1.2). Likewise, we would estimate that a manufacturer with engines only in the 25-75 hp range that sells only into the nonroad market would incur $8.3 million. This way, we have estimated a unique corporate R&D expenditure for each manufacturer. To do this, we used certification data for the 2002 model year along with our best understanding of which manufacturers sell into both the highway and nonroad markets and which sell only into the nonroad market.[F]

[F] We have used the 2002 model year certification data for consistency with the analysis done for the proposal which was done at a time when the 2002 model year was the most recent year for which complete certification data was available. Throughout this analysis, we assume the manufacturers that certified engines for 2002 are the manufacturers that will be certifying engines to the new Tier 4 standards.

When certifying engines, manufacturers project the sales of each engine they certify.[G] Using the projected sales information, we were able to determine how many engine sales each manufacturer expects to have in each of the power categories of interest. As a result, not every manufacturer is expected to incur all the R&D costs shown in Table 6.2-1. For example, some manufacturers do not certify engines under 75 hp. Such a manufacturer will not incur R&D costs for CDPF-only engines or for those engines expected to add a DOC or make only engine-out changes. Also, some engine manufacturers produce and sell engines to specifications developed by other manufacturers. Such joint venture manufacturers or wholly owned manufacturers do not conduct engine-related R&D but simply manufacture an engine designed and developed by another manufacturer. For such manufacturers, we have assumed no engine R&D expenditures, given that we believe they will conduct no R&D themselves and will instead rely on their joint venture partner. This is true unless the parent company has no engine sales in the power categories covered by the partner company. Under such a situation, we have accounted for the necessary R&D by attributing it to the parent company. For example, Perkins is an engine manufacturer wholly owned by Caterpillar so we have attributed no R&D costs to Perkins. However, Perkins sells engines in power categories that Caterpillar does not. As a result, we have attributed R&D costs to Caterpillar for conducting R&D that will benefit Perkins engines. We have identified nine manufacturers to whom we have attributed no R&D because of a joint partner agreement.[H] For some of these (such as Perkins), we have attributed R&D costs to their parent for the engines they will sell, and some are effectively the same company as their parent (for example, Detroit Diesel and their parent DaimlerChrysler, New Holland and their parent CNH). In the end, it is not important to our analysis to what manufacturer the R&D is allocated because we have attempted to estimate the total R&D that will be spent by the entire industry.

We have also estimated that some manufacturers will choose not to invest in R&D for the U.S. nonroad market due to low volume sales that cannot justify the expense. We have identified three such manufacturers to whom we have attributed no R&D due to the cost of that R&D relative to our best estimate of the revenues they receive from engine sales to which the new NRT4 standards would apply.[I] This is not to say that we believe these manufacturers will cease to do business or even choose to leave the market; it only means that, given their low U.S.

[G] Projected sales information is confidential business information. We cannot present this information here nor can we present details of calculations that use projected sales data since back calculating could shed light on the projected sales data.

[H] Detroit Diesel and VM Motori were treated as part of DaimlerChrysler; IVECO, New Holland, and CNH were treated as one; Kirloskar and Kukje were treated as partners of Cummins; Mitsubishi Motors Corporation and Mitsubishi Heavy Industries are treated as one company; Perkins R&D is attributed to Caterpillar; and, Volvo Construction Equipment and Volvo Penta AB are treated as one company.

[I] Estimated engine prices are shown in Table 6.2-3. We multiplied these prices by the manufacturer's projected sales volume to determine if projected revenues from engine sales will exceed our estimated R&D costs. If not, we have assumed that the manufacturer would not invest in the R&D and would instead license the R&D from another manufacturer. While this would result in costs to the licensing manufacturer, it would also result in profits to the licensor; it would therefore not result in increased costs associated with the new emission standards.

sales volumes, we believe it is unlikely that they will conduct the necessary R&D themselves. Instead, they will probably license the technology from another manufacturer, which will serve to increase their own costs but reduce the net costs incurred by the licensing manufacturer, all while having no impact on the total costs of the rule. Determining which manufacturers will or will not invest in R&D is based on projected sales data, so we cannot share the manufacturers' names. It is important to note that the total projected sales for all three engine manufacturers was 77 engines in the 2002 model year.

Lastly, some certifying manufacturers do not appear to actually make engines. Instead, they purchase engines from another engine manufacturer and then certify them as their own. We have identified eight such certifying manufacturers and have attributed no R&D to these eight.[J]

Excluding the manufacturers we have identified as being in a joint partner arrangement or as unlikely to invest in R&D, there remain 20 manufacturers expected to invest in CDPF&NOx Adsorber R&D, 27 manufacturers expected to invest in CDPF-only R&D, and 28 manufacturers expected to invest in DOC/engine-out R&D. The total estimated corporate R&D expenditures are shown in Table 6.2-2.

Table 6.2-2
Estimated Industry-wide Corporate R&D Expenditures for the NRT4 Standards[a]

	DOC/engine-out R&D[b]	CDPF+NOx Adsorber R&D[b, c]	CDPF-only R&D[b]	Corporate R&D Total[b]
Expenditures during Years	2004-2007	2006-2014	2008-2012	2004-2014
Horsepower	0<hp<75	≥75 hp	25≤hp<75	all hp
Total Industry-wide Corporate R&D Expenditures	$37.2	$121.8	$46.7	$205.7
Corporate R&D for PM	$37.2	$40.2	$46.7	$124.1
Corporate R&D for NOx	—	$81.6	—	$81.6

[a] Dollar values are in millions of 2002 dollars.
[b] Corporate R&D attributable to US sales resulting from this final rule (see discussion in text). Engine line R&D is presented in Table 6.2-3. Total R&D – corporate R&D plus engine line R&D – is presented in Table 6.2-4.
[c] This includes corporate R&D for >750 hp engines.

To this corporate R&D estimate, we have added an engine line R&D element. This engine line R&D will cover costs for a manufacturer to tailor the knowledge gained through corporate R&D to each particular engine line in their mix. Based on confidential comments submitted during the public comment period and our analysis of them, we have estimated these costs to be

[J] These eight are: Alaska Diesel Electric; American Jawa; Eastern Tools and Equipment; Escorts, Ltd.; Harvest Drivemaster USA; International Tractors; Northern Tool and Equipment; Same Deutz-Fahr Group.

$1 million for each engine line in the 25-75 hp range (to meet the 2013 standards), $3 million for each engine line from 75-750 hp, and $6 million for those engine lines over 750 hp. We have assumed no engine line R&D for <75 hp engines to meet the 2008 standards because we do not believe that the relatively simple addition of a DOC or the modifications impacting engine-out emissions will require such a R&D effort. We have determined the number of engine lines by considering that, typically, the same basic diesel engine design can be increased or decreased in size by simply adding or subtracting cylinders. As a result, a four-, six-, or eight-cylinder engine may be produced from the same basic engine design. While these engines have different total displacement, they each have the same displacement per cylinder. Using the PSR database, we grouped each engine manufacturer's engines into distinct engine lines using increments of 0.5 liters per cylinder. This way, engines having similar displacements per cylinder are grouped together and are considered to be one engine line. Table 6.2-3 presents the number of engine lines for which we have estimated this engine line R&D expenditure along with the total industry-wide engine line R&D we have estimated.

Table 6.2-3
Estimated Industry-wide Engine Line R&D Expenditures for the NRT4 Standards[a]

Expenditures during Years	2008-2012	2006-2010	2007-2011	2010-2014	2006-2014
Horsepower	25<hp<75	175-750 hp	75≤hp<175	>750 hp	All
Engine Lines	21	52[b]	28	3	104
Engine Line R&D per Line	$1.0	$3.0	$3.0	$6.0	–
Engine Line R&D Total[c]	$8.8	$65.7	$35.4	$7.6	$117.5
Engine Line R&D for PM[c]	$8.8	$21.7	$11.7	$7.6	$49.8
Engine Line R&D for NOx[c]	–	$44.0	$23.7	–	$67.7

[a] Dollar values are in millions of 2002 dollars.
[b] This excludes 16 engine lines – those engine lines considered in the HD2007 rule. We have not included these highway engine lines since manufacturers will be conducting engine line R&D to meet the HD2007 standards.
[c] Dollar amounts shown here are those amounts attributable to US sales, as discussed in the main text.

We have estimated that all engine R&D expenditures—corporate R&D plus engine line R&D—occur over a five year span preceding the first year any emission-control device is introduced into the market. The one exception to this being corporate R&D done for the 2008 standards which would be incurred over a four year span beginning today. Those expenditures are then recovered by the engine manufacturer during any phase-in years and then over a five-year span following full introduction of the technology. Since PM standards take effect without a multi-year phase-in, most PM costs are recovered for five years following the first year of implementation. Most NOx costs are recovered over the two- or three-year phase-in and then five years following complete implementation, or a total of seven or eight years. We include a cost of seven percent when amortizing engine R&D expenditures.

Our R&D estimates represent the cost to develop advanced aftertreatment-based emission-control systems enabled by 15 ppm sulfur fuel. We are projecting that manufacturers will need to do this R&D to sell engines in Europe, Japan, Australia, and Canada because we expect that similar emission standards will be required in a similar time frame for each of these regions or countries.[8] Therefore, we have attempted to attribute the costs of R&D to the total engine sales for these regions. Since we do not have sales data for every manufacturer showing what percent of their engines are sold in the United States relative to these other regions, we have used Gross Domestic Product (GDP) as a surrogate for sales.[K,9] As a result, we have attributed only a portion of the R&D expenditures to engine sales within the United States. The United States' GDP is 42 percent of the total GDP from all the countries that are expected to adopt Tier 4 or similar emission standards for nonroad diesel engines.[L] Therefore, we have attributed 42 percent of the total R&D costs to U.S. sales.[M] Note that all engine R&D costs for <25 hp engines have been attributed to U.S. sales since other countries are not expected to have similar standards on these engines (though, as noted in the preamble for this final rule, the European Commission may revisit this issue in their 2007 Nonroad standards review).

The total estimated R&D attributable to US sales associated with the NRT4 engine standards—corporate R&D presented in Table 6.2-2 and engine line R&D presented in Table 6.2-3—is shown in Table 6.2-4.

[K] We considered using revenue and income data for nonroad engine/equipment companies that might show what percent of those business metrics were US based versus non-US based. However, we were not able to find information on all of the more than 50 nonroad diesel engine companies and the more than 600 nonroad diesel equipment companies. In fact, we were able to locate information on only 10 nonroad engine/equipment companies because many companies are not publicly traded in the US or do not present revenue and income data on a geographic basis. The results of our research are contained in a memorandum to the docket (see Charmley, April 7, 2004, EDOCKET OAR-2003-0012-0927). The limited data set generated by that research shows geographic distribution of revenue and income that is not inconsistent with our 42 percent distribution.

[L] According to the Worldbank, in 2000, the European countries of Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, The Netherlands, Portugal, Spain, Sweden, and the United Kingdom had a combined GDP of $7.8 trillion; Australia's GDP was $0.4 trillion; Canada's GDP was $0.7 trillion; Japan's GDP was $4.7 trillion; and the U.S. GDP was $9.9 trillion; for a total GDP of $23.5 trillion (www.worldbank.org).

[M] This is already factored into the costs shown in Tables 6.2-2 through 6.2-4, but is not factored into the costs shown in Table 6.2-1.

Table 6.2-4
Estimated Total R&D Expenditures for the NRT4 Standards[a]

	DOC/engine-out R&D[b]	CDPF+NOx Adsorber R&D[b, c]	CDPF-only R&D[b]	Total R&D[b]
Expenditures during Years	2004-2007	2006-2014	2008-2012	2004-2014
Horsepower	0<hp<75	≥75 hp	25≤hp<75	all hp
Total Industry-wide R&D Expenditures[c]	$37.2	$230.5	$55.5	$323.2
Total R&D for PM[c]	$37.2	$81.2	$55.5	$173.9
Total R&D for NOx[c]	—	$149.3	—	$149.3

[a] Dollar values are in millions of 2002 dollars.
[b] Total R&D – corporate R&D plus engine line R&D.
[c] Dollar amounts shown here are those amounts attributable to US sales, as discussed in the main text.

We have weighted R&D recovery according to estimated revenues for engines sold in each power category. For example, CDPF&NOx Adsorber R&D benefits all engines over 75 hp. However, we have assumed that engines in the 175-750 hp range must introduce the new technologies in 2011, while engines from 75 to 175 hp will introduce it a year later. As a result, R&D costs are assumed to be recovered on engines in the 175-750 hp range between 2011 and 2015/2018 and on 75 to 175 hp engines between 2012 and 2016/2018. R&D costs for >750 hp engines are assumed to be recovered between 2015-2019. Delaying implementation dates for these engines, or a subset of these engines, would not impact our estimated R&D expenditures or their recovery but would, instead, only affect the timing of their recovery. To weight the costs between engines in these categories, we have used revenue-weighting rather than a more simplistic sales-weighting under the belief that manufacturers will attempt to recover more costs where more revenues occur. Revenue-weighting is simply an estimated price multiplied by a unit sales figure. The revenue weightings we have used are shown in Table 6.2-5.

Using this methodology, we have estimated the total R&D expenditures associated with the new emission standards to vary from $9 to $57 million per year, with an average of $27 million per year and a total of $323 million. Total R&D recovery on U.S. sales is estimated at $452 million. All estimated R&D costs are shown in Table 6.2-6. Note that the engine sales numbers shown in Table 6.2-6 are discussed in greater detail in Chapter 8, where we present aggregate costs to society.

Table 6.2-5
Revenue Weightings Used to Allocate R&D Cost Recovery

Horsepower	2000 Sales	Estimated Engine Price	Revenue-Weighted Recovery of R&D in the Indicated Years					
			PM	2008-2012	2011-2015	2012-2016	2013-2017	2015-2019
			NOx	N/A	2011-2018	2012-2018	N/A	N/A
0<hp<25	119,159	$1,500		22%				
25≤hp<50	132,981	$2,900		46%			59%	
50≤hp<75	93,914	$2,900		32%			41%	
75≤hp<100	68,665	$5,200				12%		
100≤hp<175	112,340	$5,200				19%		
175≤hp<300	61,851	$10,300			30%	21%		
300≤hp<600	34,095	$31,000			49%	34%		
600≤hp≤750	2,752	$80,500			10%	7%		
hp>750	2,785	$80,500			11%	7%		100%
Total	628,542			100%	100%	100%	100%	100%

Table 6.2-6

Estimated R&D Costs Incurred (Non-Annualized) and Recovered (Annualized) -- expressed in $2002

Millions of dollars, except engine sales and per engine costs

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
0<hp<25	Estimated US Sales	131,507	135,623	139,739	143,855	147,971	152,087	156,203	160,319	164,435	168,551	172,667	176,783	180,899	185,015	189,131	193,247	197,363	
	PM Costs Incurred		$2.0	$2.0	$2.0	$2.0													$8.2
	NOx Costs Incurred																		$0.0
	PM Costs Recovered						$2.2	$2.2	$2.2	$2.2	$2.2								$11.0
	NOx Costs Recovered																		$0.0
	Per Engine Cost						$15	$14	$14	$13	$13								
25<=hp<50	Estimated US Sales	143,496	147,001	150,506	154,011	157,516	161,021	164,526	168,031	171,536	175,041	178,546	182,051	185,556	189,061	192,566	196,071	199,576	
	PM Costs Incurred		$4.3	$4.3	$4.3	$4.3	$6.5	$6.5	$6.5	$6.5	$6.5								$49.6
	NOx Costs Incurred																		$0.0
	PM Costs Recovered						$4.6	$4.6	$4.6	$4.6	$4.6	$9.1	$9.1	$9.1	$9.1	$9.1			$68.7
	NOx Costs Recovered																		$0.0
	Per Engine Cost						$29	$28	$27	$27	$26	$51	$50	$49	$48	$47			
50<=hp<75	Estimated US Sales	100,051	102,097	104,142	106,188	108,234	110,279	112,325	114,371	116,416	118,462	120,507	122,553	124,599	126,644	128,690	130,736	132,781	
	PM Costs Incurred		$3.0	$3.0	$3.0	$3.0	$4.6	$4.6	$4.6	$4.6	$4.6								$35.0
	NOx Costs Incurred																		$0.0
	PM Costs Recovered						$3.3	$3.3	$3.3	$3.3	$3.3	$6.5	$6.5	$6.5	$6.5	$6.5			$48.5
	NOx Costs Recovered																		$0.0
	Per Engine Cost						$29	$29	$28	$28	$27	$54	$53	$52	$51	$50			
75<=hp<100	Estimated US Sales	73,162	74,662	76,161	77,660	79,159	80,659	82,158	83,657	85,157	86,656	88,155	89,654	91,154	92,653	94,152	95,652	97,151	
	PM Costs Incurred					$1.5	$1.5	$1.5	$1.5	$1.5									$7.7
	NOx Costs Incurred					$1.6	$1.6	$3.1	$3.1	$3.1	$1.6	$1.6							$15.6
	PM Costs Recovered										$2.2	$2.2	$2.2	$2.2	$2.2				$10.8
	NOx Costs Recovered										$2.2	$2.2	$4.4	$4.4	$4.4	$2.2	$2.2		$21.8
	Per Engine Cost										$50	$49	$73	$72	$70	$23	$23		
100<=hp<175	Estimated US Sales	119,303	121,625	123,946	126,267	128,588	130,909	133,230	135,551	137,872	140,193	142,514	144,836	147,157	149,478	151,799	154,120	156,441	
	PM Costs Incurred					$2.5	$2.5	$2.5	$2.5	$2.5									$12.5
	NOx Costs Incurred					$2.5	$2.5	$5.1	$5.1	$5.1	$2.5	$2.5							$25.5
	PM Costs Recovered										$3.5	$3.5	$3.5	$3.5	$3.5				$17.6
	NOx Costs Recovered										$3.6	$3.6	$7.1	$7.1	$7.1	$3.6	$3.6		$35.7
	Per Engine Cost										$51	$50	$74	$72	$71	$24	$23		
175<=hp<300	Estimated US Sales	66,093	67,507	68,921	70,335	71,749	73,163	74,577	75,991	77,405	78,819	80,233	81,647	83,061	84,475	85,889	87,303	88,717	
	PM Costs Incurred				$3.3	$3.3	$3.3	$3.3	$3.3										$16.7
	NOx Costs Incurred				$3.6	$3.6	$3.6	$7.2	$7.2	$3.6	$3.6	$3.6							$36.1
	PM Costs Recovered									$4.7	$4.7	$4.7	$4.7	$4.7					$23.4
	NOx Costs Recovered									$5.1	$5.1	$5.1	$10.1	$10.1	$5.1	$5.1	$5.1		$50.6
	Per Engine Cost									$126	$124	$121	$181	$178	$60	$59	$58		
300<=hp<600	Estimated US Sales	35,403	35,839	36,275	36,711	37,147	37,583	38,019	38,455	38,891	39,327	39,763	40,199	40,635	41,071	41,507	41,943	42,379	
	PM Costs Incurred				$5.5	$5.5	$5.5	$5.5	$5.5										$27.6
	NOx Costs Incurred				$6.0	$6.0	$6.0	$11.9	$11.9	$6.0	$6.0	$6.0							$59.7
	PM Costs Recovered									$7.7	$7.7	$7.7	$7.7	$7.7					$38.7
	NOx Costs Recovered									$8.4	$8.4	$8.4	$16.7	$16.7	$8.4	$8.4	$8.4		$83.7
	Per Engine Cost									$414	$410	$405	$609	$602	$204	$202	$200		
600<=hp<=750	Estimated US Sales	2,902	2,952	3,002	3,052	3,102	3,152	3,202	3,252	3,302	3,352	3,402	3,452	3,502	3,552	3,602	3,652	3,702	
	PM Costs Incurred				$1.2	$1.2	$1.2	$1.2	$1.2										$5.8
	NOx Costs Incurred				$1.3	$1.3	$1.3	$2.5	$2.5	$1.3	$1.3	$1.3							$12.5
	PM Costs Recovered									$1.6	$1.6	$1.6	$1.6	$1.6					$8.1
	NOx Costs Recovered									$1.8	$1.8	$1.8	$3.5	$3.5	$1.8	$1.8	$1.8		$17.6
	Per Engine Cost									$1,023	$1,007	$993	$1,487	$1,465	$494	$487	$481		
>750hp	Estimated US Sales	2,938	2,989	3,040	3,091	3,142	3,193	3,244	3,295	3,346	3,397	3,448	3,499	3,550	3,601	3,652	3,703	3,754	
	PM Costs Incurred				$0.7	$0.7	$0.7	$0.7	$2.2	$1.5	$1.5	$1.5	$1.5						$10.9
	NOx Costs Incurred																		$0.0
	PM Costs Recovered									$0.9	$0.9	$0.9	$0.9	$3.1	$2.1	$2.1	$2.1	$2.1	$15.3
	NOx Costs Recovered																		$0.0
	Per Engine Cost									$278	$274	$270	$266	$861	$591	$582	$574	$567	
Allhp	PM Costs Incurred		$9.3	$9.3	$20.0	$24.0	$25.8	$25.8	$27.3	$16.7	$12.6	$1.5	$1.5						$173.9
	NOx Costs Incurred				$10.8	$14.9	$14.9	$29.9	$29.9	$19.0	$14.9	$14.9							$149.3
	Total Costs Incurred		$9.3	$9.3	$30.8	$38.9	$40.8	$55.7	$57.2	$35.7	$27.6	$16.5	$1.5						$323.2
	PM Costs Recovered						$10.1	$10.1	$10.1	$25.0	$30.7	$36.2	$36.2	$38.3	$23.4	$17.7	$2.1	$2.1	$242.1
	NOx Costs Recovered									$15.2	$20.9	$20.9	$41.9	$41.9	$26.7	$20.9	$20.9		$209.5
	Total Costs Recovered						$10.1	$10.1	$10.1	$40.2	$51.6	$57.2	$78.1	$80.2	$50.1	$38.7	$23.1	$2.1	$451.5

6.2.1.2 Engine-Related Tooling Costs

Once engines are ready for production, new tooling will be required to accommodate the assembly of the new engines. In the HD2007 rule, we estimated approximately \$1.6 million per engine line for tooling costs associated with CDPF/NOx adsorber systems. For the Tier 4 standards, we have estimated that nonroad-only manufacturers will incur the same amount – \$1.65 million expressed in 2002 dollars – for each engine line that requires a CDPF/NOx adsorber system. These costs are assigned equally to NOx control and PM control. We have estimated the same tooling costs as in the HD2007 rule because we expect Tier 4 engines to use the same technologies (i.e., a CDPF and a NOx adsorber). For those systems requiring only a CDPF, we have estimated one-half that amount, or \$825,000 per engine line. For those systems requiring only a DOC or some engine-out modifications, we have estimated one-half the CDPF-only amount, or \$412,500 per engine line. Tooling costs for CDPF-only and for DOC engines are attributed solely to PM control.

For those manufacturers selling into both the highway and nonroad markets, we have started with the same \$1.65 million baseline discussed above. For those engines requiring a CPDF/NOx adsorber system (i.e., those over 75 hp) we have adjusted that \$1.65 million baseline by 50 percent. We believe this 50 percent adjustment is reasonable since many nonroad engines over 75 hp are produced on the same engine line with their highway counterparts. For such lines, tooling costs will be negligible. For engine lines without a highway counterpart, the \$1.65 million tooling cost applies. For highway manufacturers selling into both the highway and the nonroad markets, we have estimated a 50/50 split of nonroad engine product lines (i.e., 50 percent with highway counterparts and 50 percent without) and therefore applied a 50 percent factor to the \$1.65 million baseline. These tooling costs are split evenly between NOx control and PM control. For those engine lines requiring only a CDPF (i.e., those between 25 and 75 hp), we have estimated the same tooling cost as used for nonroad-only manufacturers, or \$825,000. Similarly, the tooling costs for DOC and/or engine-out engine lines has been estimated to be \$412,500. We have used the same tooling costs as the nonroad-only manufacturers for engines under 75 hp because these engines tend not to have a highway counterpart. Tooling costs for CDPF-only and for DOC engines are attributed solely to PM control.

We project that engines between 25 and 50 hp will apply EGR systems to meet the new NOx standards for 2013. For these engines, we have included an additional tooling cost of \$41,300 per engine line, consistent with the EGR-related tooling cost estimated for 50 to 100 hp engines in our Tier 2/Tier 3 rulemaking which specified the same NOx standards. This tooling cost is applied equally to all engine lines in that power range, regardless of the markets into which the manufacturer sells. We have applied this tooling cost equally because engines in this power range do not tend to have highway counterparts. We expect EGR systems to be added to engines between 25 and 50 hp to meet the new NOx standard, so tooling costs for EGR systems are attributed solely to NOx control.

We have also estimated some tooling costs for >750 horsepower engines to meet the 2011 standards. We have estimated this amount at ten times the amount for 25 to 50 horsepower engines, or $413,000 per engine line. This cost was not in the proposal since NOx adsorbers were being projected for all >750 horsepower engines. We have applied this tooling to all engine lines >750 horsepower, regardless of what markets into which a manufacturer sells, since such engines clearly have no highway counterpart. We have attributed this cost to NOx control.

Tooling costs per engine line and type of manufacturer are summarized in Table 6.2-7.

Table 6.2-7
Estimated Tooling Expenditures per Engine Line by Type of Manufacturer[a]

	DOC/engine-out Engines	CDPF-only Engines	CDPF and NOx Adsorber Engines	EGR Engines[b]	EGR Engines
Horsepower range	0<hp<75	25≤hp<75	75≤hp<750	>750hp	25≤hp<50
For new standards starting in	2008	2013	2011/2012	2011	2013
Manufacturer sells into both highway and nonroad markets	$412,500	$825,000	$825,000	$413,000	$41,300
Manufacturer sells only into the nonroad market	$412,500	$825,000	$1,650,000	$413,000	$41,300
% Allocated to PM	100%	100%	50%	0%	0%
% Allocated to NOx	0%	0%	50%	100%	100%

[a] Dollar values are in millions of 2002 dollars.
[b] To remain conservative in our cost estimate, we have assumed that all engines >750hp add cooled EGR in 2011. We would expect manufacturers to use a less costly means of control if it allows them to meet the new standard (see section 4.1.2 of this RIA for more information regarding our estimates of EGR use).

As noted, we have applied tooling costs by engine line assuming that engines in the same line are produced on the same production line. Typically, the same basic diesel engine design can be increased or decreased in size by simply adding or subtracting cylinders. As a result, a four-, six-, or eight-cylinder engine may be produced from the same basic engine design. While these engines have different total displacement, they each have the same displacement per cylinder. Using the PSR database, we grouped each engine manufacturer's engines into distinct engine lines using increments of 0.5 liters per cylinder. This way, engines having similar displacements per cylinder are grouped together and are considered to be built on the same production line. Note that a tooling expenditure for a single engine line may cover engines over several power categories. To allocate the tooling expenditure for a given production line to a specific power range, we have used sales-weighting within that engine line.

We have applied the above tooling costs to all manufacturers that appear to actually make engines. We have not eliminated joint venture manufacturers because these manufacturers still need to invest in tooling to make the engines, even if they do not conduct any R&D. Doing this, we determined there to be 62 manufacturers expected to invest in tooling for a total of 133 engine lines. Of these, 19 manufacturers sell into both the highway and nonroad markets and sell a total of 56 engine lines, while 43 manufacturers sell only into the nonroad market and sell a total of 77 engine lines. For the same reasons as explained for R&D costs, we have attributed a portion of the tooling costs to U.S. sales and a portion to sales in other countries expected to have similar levels of emission control; tooling costs for <25 hp engines are attributed only to US sales since other countries are not expected to have similar standards on <25 hp engines. All tooling costs are assumed to be incurred one year before the standard they support and are then recovered over a five-year period following introduction of the new standard. We include a cost of seven percent when amortizing engine tooling costs.

Using this methodology, we estimate the total tooling expenditures attributable to this final rule at $74 million. Total tooling recovery on U.S. sales is estimated at $91 million. All estimated tooling costs are shown in Table 6.2-8.

Table 6.2-8

Estimated Tooling Costs Incurred (Non-Annualized) and Recovered (Annualized) -- expressed in $2002

Millions of dollars, except engine sales and per engine costs

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
0<hp<25	Estimated US Sales	147,971	152,087	156,203	160,319	164,435	168,551	172,667	176,783	180,899	185,015	189,131	193,247	197,363	
	PM Costs Incurred	$5.2													$5.2
	NOx Costs Incurred														$0.0
	PM Costs Recovered		$1.3	$1.3	$1.3	$1.3	$1.3								$6.4
	NOx Costs Recovered														$0.0
	Per Engine Cost		$8	$8	$8	$8	$8								
25<=hp<50	Estimated US Sales	157,516	161,021	164,526	168,031	171,536	175,041	178,546	182,051	185,556	189,061	192,566	196,071	199,576	
	PM Costs Incurred	$5.9					$4.3								$10.1
	NOx Costs Incurred						$0.5								$0.5
	PM Costs Recovered		$1.4	$1.4	$1.4	$1.4	$1.4	$1.0	$1.0	$1.0	$1.0	$1.0			$12.4
	NOx Costs Recovered							$0.1	$0.1	$0.1	$0.1	$0.1			$0.6
	Per Engine Cost		$9	$9	$9	$8	$8	$7	$6	$6	$6	$6			
50<=hp<75	Estimated US Sales	108,234	110,279	112,325	114,371	116,416	118,462	120,507	122,553	124,599	126,644	128,690	130,736	132,781	
	PM Costs Incurred	$4.1					$3.0								$7.2
	NOx Costs Incurred														$0.0
	PM Costs Recovered		$1.0	$1.0	$1.0	$1.0	$1.0	$0.7	$0.7	$0.7	$0.7	$0.7			$8.7
	NOx Costs Recovered														$0.0
	Per Engine Cost		$9	$9	$9	$9	$9	$6	$6	$6	$6	$6			
75<=hp<100	Estimated US Sales	79,159	80,659	82,158	83,657	85,157	86,656	88,155	89,654	91,154	92,653	94,152	95,652	97,151	
	PM Costs Incurred					$2.8									$2.8
	NOx Costs Incurred					$2.8									$2.8
	PM Costs Recovered						$0.7	$0.7	$0.7	$0.7	$0.7				$3.4
	NOx Costs Recovered						$0.7	$0.7	$0.7	$0.7	$0.7				$3.4
	Per Engine Cost						$16	$15	$15	$15	$15				
100<=hp<175	Estimated US Sales	128,588	130,909	133,230	135,551	137,872	140,193	142,514	144,836	147,157	149,478	151,799	154,120	156,441	
	PM Costs Incurred					$4.5									$4.5
	NOx Costs Incurred					$4.5									$4.5
	PM Costs Recovered						$1.1	$1.1	$1.1	$1.1	$1.1				$5.5
	NOx Costs Recovered						$1.1	$1.1	$1.1	$1.1	$1.1				$5.5
	Per Engine Cost						$16	$16	$15	$15	$15				
175<=hp<300	Estimated US Sales	71,749	73,163	74,577	75,991	77,405	78,819	80,233	81,647	83,061	84,475	85,889	87,303	88,717	
	PM Costs Incurred				$11.0										$11.0
	NOx Costs Incurred				$11.0										$11.0
	PM Costs Recovered					$2.7	$2.7	$2.7	$2.7	$2.7					$13.4
	NOx Costs Recovered					$2.7	$2.7	$2.7	$2.7	$2.7					$13.4
	Per Engine Cost					$69	$68	$67	$66	$65					
300<=hp<600	Estimated US Sales	37,147	37,583	38,019	38,455	38,891	39,327	39,763	40,199	40,635	41,071	41,507	41,943	42,379	
	PM Costs Incurred				$6.1										$6.1
	NOx Costs Incurred				$6.1										$6.1
	PM Costs Recovered					$1.5	$1.5	$1.5	$1.5	$1.5					$7.4
	NOx Costs Recovered					$1.5	$1.5	$1.5	$1.5	$1.5					$7.4
	Per Engine Cost					$76	$75	$74	$74	$73					
600<=hp<=750	Estimated US Sales	3,102	3,152	3,202	3,252	3,302	3,352	3,402	3,452	3,502	3,552	3,602	3,652	3,702	
	PM Costs Incurred				$0.5										$0.5
	NOx Costs Incurred				$0.5										$0.5
	PM Costs Recovered					$0.1	$0.1	$0.1	$0.1	$0.1					$0.6
	NOx Costs Recovered					$0.1	$0.1	$0.1	$0.1	$0.1					$0.6
	Per Engine Cost					$72	$71	$70	$69	$68					
>750hp	Estimated US Sales	3,142	3,193	3,244	3,295	3,346	3,397	3,448	3,499	3,550	3,601	3,652	3,703	3,754	
	PM Costs Incurred								$1.0						$1.0
	NOx Costs Incurred				$0.5										$0.5
	PM Costs Recovered									$0.3	$0.3	$0.3	$0.3	$0.3	$1.3
	NOx Costs Recovered					$0.1	$0.1	$0.1	$0.1	$0.1					$0.6
	Per Engine Cost					$38	$37	$37	$36	$107	$71	$70	$69	$68	
All hp	PM Costs Incurred	$15.2			$17.6	$7.3	$7.3		$1.0						$48.4
	NOx Costs Incurred				$18.1	$7.3	$0.5								$25.9
	Total Costs Incurred	$15.2			$35.6	$14.6	$7.8		$1.0						$74.3
	PM Costs Recovered		$3.7	$3.7	$3.7	$8.0	$9.8	$7.8	$7.8	$8.1	$3.8	$2.0	$0.3	$0.3	$59.1
	NOx Costs Recovered					$4.4	$6.2	$6.3	$6.3	$6.3	$1.9	$0.1			$31.6
	Total Costs Recovered		$3.7	$3.7	$3.7	$12.4	$16.0	$14.2	$14.2	$14.4	$5.7	$2.2	$0.3	$0.3	$90.6

6.2.1.3 Engine Certification Costs

Manufacturers will incur more than the normal level of certification costs during the first few years of implementation because engines will need to be certified to the new emission standards using new test procedures. Consistent with our recent standard setting regulations, we have estimated engine certification costs at $60,000 per new engine certification to cover testing and administrative costs.[10] The $60,000 certification cost per engine family was used for engines in the 25 to 75 hp range certifying to the 2008 standards. For 25 to 75 hp engines certifying to the 2013 standards, and for 75-750 hp engines certifying to the appropriate standards, we have added costs to cover the new test procedures for nonroad diesel engines (i.e., the transient test and the NTE);[N] these costs were estimated at $31,500 per engine family. For engines >750 hp, the certification costs used were $87,000 per family since these engines will not be certifying over the new transient test procedure. For engines <25 hp, we have assumed (for cost purposes) that all engines will certify to the transient test and the NTE in 2008. We believe manufacturers may choose to do this rather than certifying all engines again in 2013 when the transient test and NTE requirements actually begin for those engines (and the rules explicitly provide the option of certifying these engines starting in 2008 using these tests). This assumption results in higher certification costs in 2008 than if these engines certified only to the steady-state standard. However, we believe manufacturers may choose to do this because it would avoid the need to recertify all <25 hp engines again in 2013. Certification costs (for engines in all hp ranges) apply equally to all engine families for all manufacturers regardless of the markets into which the manufacturer sells.

To determine the number of engine families to be certified, we used our certification database for the 2002 model year. That database provides the number of engine families and the associated power rating of each. We grouped those power ratings into the nine ranges shown in Table 6.2-9. We have chosen these nine power categories because: (1) phasing in standards and having different levels of baseline and complying emission levels force such breakouts; and, (2) greater stratification (i.e., breaking up the 75 to 175 hp range and the 175 to 750 hp range) provides a better picture of cost recovery because it more accurately matches the number of engine families (certification costs) with the level of engine sales (cost recovery). Some engine families will undergo more than one certification process due to the structure of new emission standards in the final rule. Table 6.2-9 shows the number of engine families in each power range and the year for they are subject to new emission standards, along with the total certification expenditures for those standards.

The cost expenditures shown in Table 6.2-9 are estimated to occur one year before the year shown in the table. The years shown in the table coincide with the years for which the new standards begin, thereby requiring engine certification. Half the 175 to 750 hp engine families

[N] Note that the transport refrigeration unit (TRU) test cycle is an optional duty cycle for steady-state certification testing specifically tailored to the operation of TRU engines. Likewise, the ramped modal cycles are available test cycles that can be used to replace existing steady-state test requirements for nonroad constant-speed engines, generally. Manufacturers of these engines who opt to use one of these test cycles would incur no new costs above those estimated here and may incur less cost.

certified for 2011 must again be certified in 2014 when the NOx phase-in becomes 100 percent. For 25 to 50 hp engines in 2013, half the certification costs are attributed to PM and half are attributed to NOx, due to the new PM and NOx standards for those engines in that year; all the certification costs for 50 to 75 hp engine families are attributed to PM because only a new PM standard applies in that year for those engines.

Note that these certification costs may overestimate actual costs because they assume all engines are certified as a result of the new emission standards in this final rule. However, some engines would have been scheduled for new certification independent of this final rule due to design changes or power increases among other possible reasons. For such engines, the incremental certification cost would be those costs associated with the new test procedures and would not include certification costs associated with the existing test procedure. However, to remain conservative, here we have applied the full certification costs to all engine families. Given the magnitude of certification costs relative to other costs in this final rule, this has little impact on the costs per ton of emissions reduced or the cost/benefit results.

Table 6.2-9
Number of Engine Families, Estimated
Certification Costs, and Allocation of Certification Costs[a]

Power range	Model Year for New Emission Standards							
	2008	2011	2012	2013		2014		2015
0<hp<25	102							
25≤hp<50	132			132				
50≤hp<75	88				88			
75≤hp<100			55				28	
100≤hp<175			73				37	
175≤hp<300		102				51		
300≤hp<600		64				32		
600≤hp≤750		9				5		
hp>750[a]		40						40
Total families	322	215	128	132	88	88	64	40
Total Cert Costs	$22.5	$19.5	$11.7	$12.1	$8.1	$8.0	$5.9	$3.5
% Allocated to PM	100%	50%	50%	50%	100%	0%	0%	50%
% Allocated to NOx	0%	50%	50%	50%	0%	100%	100%	50%

[a] Dollar values are in millions of 2002 dollars.

To estimate recovery of certification expenditures, we have attributed the expenditures to engines sold in the specific power range and spread the recovery of costs over U.S. sales within that category. Expenditures are incurred one year before the emission standard for which the certification is conducted, and are then recovered over a five-year period following the certification. We include a cost of seven percent when amortizing engine certification costs. We have spread these certification costs only over the engines sold in the United States because U.S. EPA certification is not presumed to fulfill the certification requirements of other countries. Total certification expenditures are estimated at $91 million. Recovery of certification costs is estimated at $111 million. All estimated certification expenditures and the recovery of those expenditures are shown in Table 6.2-10.

Table 6.2-10

Estimated Certification Costs Incurred (Non-Annualized) and Recovered (Annualized) -- expressed in $2002

Millions of dollars, except engine sales and per engine costs

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
0<hp<25	Estimated US Sales	147,971	152,087	156,203	160,319	164,435	168,551	172,667	176,783	180,899	185,015	189,131	193,247	197,363	
	PM Costs Incurred	$9.3													$9.3
	NOx Costs Incurred														$0.0
	PM Costs Recovered		$2.3	$2.3	$2.3	$2.3	$2.3								$11.4
	NOx Costs Recovered														$0.0
	Per Engine Cost		$15	$15	$14	$14	$14								
25<=hp<50	Estimated US Sales	157,516	161,021	164,526	168,031	171,536	175,041	178,546	182,051	185,556	189,061	192,566	196,071	199,576	
	PM Costs Incurred	$7.9					$6.0								$14.0
	NOx Costs Incurred						$6.0								$6.0
	PM Costs Recovered		$1.9	$1.9	$1.9	$1.9	$1.9	$1.5	$1.5	$1.5	$1.5	$1.5			$17.0
	NOx Costs Recovered							$1.5	$1.5	$1.5	$1.5	$1.5			$7.4
	Per Engine Cost		$12	$12	$11	$11	$11	$16	$16	$16	$16	$15			
50<=hp<75	Estimated US Sales	108,234	110,279	112,325	114,371	116,416	118,462	120,507	122,553	124,599	126,644	128,690	130,736	132,781	
	PM Costs Incurred	$5.3					$8.1								$13.3
	NOx Costs Incurred														$0.0
	PM Costs Recovered		$1.3	$1.3	$1.3	$1.3	$1.3	$2.0	$2.0	$2.0	$2.0	$2.0			$16.3
	NOx Costs Recovered														$0.0
	Per Engine Cost		$12	$11	$11	$11	$11	$16	$16	$16	$16	$15			
75<=hp<100	Estimated US Sales	79,159	80,659	82,158	83,657	85,157	86,656	88,155	89,654	91,154	92,653	94,152	95,652	97,151	
	PM Costs Incurred					$2.5									$2.5
	NOx Costs Incurred					$2.5		$2.2							$4.7
	PM Costs Recovered						$0.6	$0.6	$0.6	$0.6	$0.6				$3.1
	NOx Costs Recovered						$0.6	$0.6	$1.2	$1.2	$1.2	$0.5	$0.5		$5.8
	Per Engine Cost						$14	$14	$20	$19	$19	$6	$6		
100<=hp<175	Estimated US Sales	128,588	130,909	133,230	135,551	137,872	140,193	142,514	144,836	147,157	149,478	151,799	154,120	156,441	
	PM Costs Incurred					$3.3									$3.3
	NOx Costs Incurred					$3.3		$3.6							$7.0
	PM Costs Recovered						$0.8	$0.8	$0.8	$0.8	$0.8				$4.1
	NOx Costs Recovered						$0.8	$0.8	$1.7	$1.7	$1.7	$0.9	$0.9		$8.5
	Per Engine Cost						$12	$11	$17	$17	$17	$6	$6		
175<=hp<300	Estimated US Sales	71,749	73,163	74,577	75,991	77,405	78,819	80,233	81,647	83,061	84,475	85,889	87,303	88,717	
	PM Costs Incurred				$4.7										$4.7
	NOx Costs Incurred				$4.7			$5.0							$9.7
	PM Costs Recovered					$1.1	$1.1	$1.1	$1.1	$1.1					$5.7
	NOx Costs Recovered					$1.1	$1.1	$1.1	$2.4	$2.4	$1.2	$1.2	$1.2		$11.8
	Per Engine Cost					$29	$29	$28	$43	$42	$14	$14	$14		
300<=hp<600	Estimated US Sales	37,147	37,583	38,019	38,455	38,891	39,327	39,763	40,199	40,635	41,071	41,507	41,943	42,379	
	PM Costs Incurred				$2.9										$2.9
	NOx Costs Incurred				$2.9			$2.8							$5.7
	PM Costs Recovered					$0.7	$0.7	$0.7	$0.7	$0.7					$3.6
	NOx Costs Recovered					$0.7	$0.7	$0.7	$1.4	$1.4	$0.7	$0.7	$0.7		$6.9
	Per Engine Cost					$37	$36	$36	$52	$52	$16	$16	$16		
600<=hp<=750	Estimated US Sales	3,102	3,152	3,202	3,252	3,302	3,352	3,402	3,452	3,502	3,552	3,602	3,652	3,702	
	PM Costs Incurred				$0.4										$0.4
	NOx Costs Incurred				$0.4			$0.2							$0.6
	PM Costs Recovered					$0.1	$0.1	$0.1	$0.1	$0.1					$0.5
	NOx Costs Recovered					$0.1	$0.1	$0.1	$0.2	$0.2	$0.1	$0.1	$0.1		$0.8
	Per Engine Cost					$61	$60	$59	$74	$73	$15	$15	$15		
>750hp	Estimated US Sales	3,142	3,193	3,244	3,295	3,346	3,397	3,448	3,499	3,550	3,601	3,652	3,703	3,754	
	PM Costs Incurred				$1.7				$1.7						$3.5
	NOx Costs Incurred				$1.7				$1.7						$3.5
	PM Costs Recovered					$0.4	$0.4	$0.4	$0.4	$0.8	$0.4	$0.4	$0.4	$0.4	$4.2
	NOx Costs Recovered					$0.4	$0.4	$0.4	$0.4	$0.8	$0.4	$0.4	$0.4	$0.4	$4.2
	Per Engine Cost					$254	$250	$246	$243	$478	$236	$232	$229	$226	
All hp	PM Costs Incurred	$22.5			$9.7	$5.9	$14.1		$1.7						$54.0
	NOx Costs Incurred				$9.7	$5.9	$6.0	$13.9	$1.7						$37.2
	Total Costs Incurred	$22.5			$19.5	$11.7	$20.1	$13.9	$3.5						$91.2
	PM Costs Recovered		$5.5	$5.5	$5.5	$7.9	$9.3	$7.2	$7.2	$7.7	$5.3	$3.9	$0.4	$0.4	$65.8
	NOx Costs Recovered					$2.4	$3.8	$5.3	$8.7	$9.1	$6.7	$5.3	$3.8	$0.4	$45.4
	Total Costs Recovered		$5.5	$5.5	$5.5	$10.2	$13.1	$12.5	$15.9	$16.7	$12.0	$9.1	$4.2	$0.8	$111.2

6.2.2 Engine Variable Costs

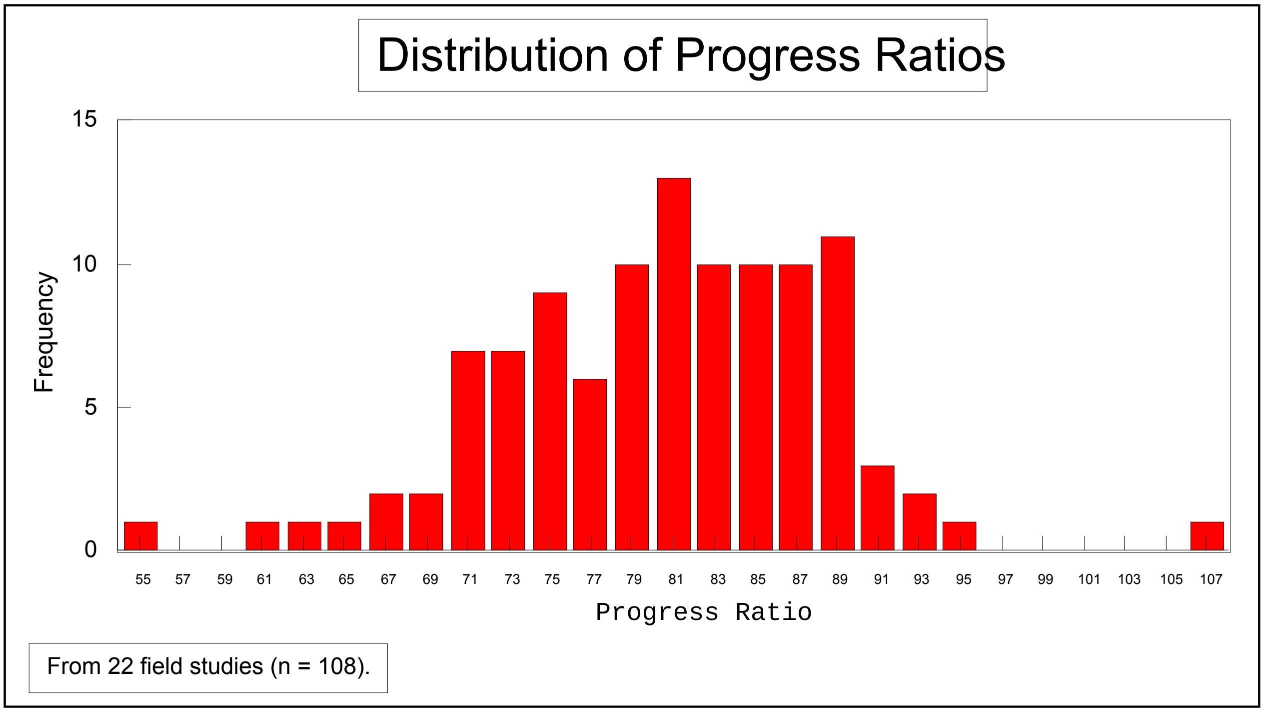
Engine variable costs are those costs for new hardware required to meet the new emission standards. In this section, we present our estimates of engine variable costs. Because of the wide variation of engine sizes in the nonroad market, we have chosen an approach that results not in a specific cost per engine for engines within a given power range, but rather a set of equations that can be used to determine the variable costs for any engine provided its displacement and number of cylinders are known. As a result, we do not present here a cost of, say, $50 per engine for engines in the 25 to 50 power range, but instead present cost equations that can be used to determine the variable costs for an engine having, for example, a 0.5 liter engine with two cylinders. We believe this is a more comprehensive approach because it allows the reader to calculate costs more precisely for whatever engine(s) they are interested in. Further, variable costs can vary quite significantly within a given power range unless the range is kept very small. To state an average variable cost for a range such as 175 to 300 hp is far less precise than what we present here. Using the equations presented in this section, we have then estimated the engine variable costs for certain specific pieces of equipment and for the sales weighted average piece of equipment. These estimates can be found in Section 6.5.

The discussion here considers both near-term and long-term cost estimates. We believe there are factors that cause variable hardware costs to decrease over time, making it appropriate to distinguish between near-term and long-term costs. Research in the costs of manufacturing has consistently shown that as manufacturers gain experience in production, they are able to apply innovations to simplify machining and assembly operations, use lower cost materials, and reduce the number or complexity of component parts, all of which allows them to lower the per-unit cost of production. These effects are often described as the manufacturing learning curve.[11]

The learning curve is a well documented phenomenon dating back to the 1930s. The general concept is that unit costs decrease as cumulative production increases. Learning curves are often characterized in terms of a progress ratio, where each doubling of cumulative production leads to a reduction in unit cost to a percentage "p" of its former value (referred to as a "p cycle"). Organizational learning, which brings about a reduction in total cost, is caused by improvements in several areas. Areas involving direct labor and material are usually the source of the greatest savings. Examples include, but are not limited to, a reduction in the number or complexity of component parts, improved component production, improved assembly speed and processes, reduced error rates, and improved manufacturing process. These all result in higher overall production, less scrappage of materials and products, and better overall quality. As each successive p cycle takes longer to complete, production proficiency generally reaches a relatively stable plateau, beyond which increased production does not necessarily lead to markedly decreased costs.

Companies and industry sectors learn differently. In a 1984 publication, Dutton and Thomas reviewed the progress ratios for 108 manufactured items from 22 separate field studies representing a variety of products and services.[12] The distribution of these progress ratios is shown in Figure 6.2-1. Except for one company that saw *increasing* costs as production continued, every study showed cost savings of at least five percent for every doubling of production volume. The average progress ratio for the whole data set falls between 81 and 82 percent. Other studies (Alchian 1963, Argote and Epple 1990, Benkard 1999) appear to support the commonly used p value of 80 percent, i.e., each doubling of cumulative production reduces the former cost level by 20 percent.

Figure 6.2-1
Distribution of Progress Ratios



The learning curve is not the same in all industries. For example, the effect of the learning curve seems to be less in the chemical industry and the nuclear power industry where a doubling of cumulative output is associated with 11 percent decrease in cost (Lieberman 1984, Zimmerman 1982). The effect of learning is more difficult to decipher in the computer chip industry (Gruber 1992).

We believe the learning curve is appropriate to consider in assessing the cost impact of diesel engine emission controls. The learning curve applies to new technology, new manufacturing operations, new parts, and new assembly operations. Nonroad diesel engines currently do not use any form of NOx aftertreatment and have used diesel particulate filters only in limited application. These are therefore new technologies for nonroad diesel engines and will involve some new manufacturing operations, new parts, and new assembly operations beyond those anticipated in response to the HD2007 rule. Since this will be a new product, we believe this is an appropriate situation for the learning curve concept to apply. Opportunities to reduce unit labor and material costs and increase productivity (as discussed above) will be great. We believe a similar opportunity exists for the new control systems that will integrate the function of the engine and emission-control technologies. While all nonroad diesel engines beginning with Tier 3 compliance are expected to have the basic components of this system—advanced engine control modules (computers), advanced engine air management systems (cooled EGR, and variable geometry turbocharging), and advanced electronic fuel systems including common rail systems— they will be applied in some new ways in response to the Tier 4 standards. Additionally some new components will be applied for the first time. These new parts and new assemblies will involve new manufacturing operations. As manufacturers gain experience with these new systems, comparable learning is expected to occur with respect to unit labor and material costs. These changes require manufacturers to start new production procedures, which will improve with experience.

We have applied a p value of 80 percent beginning with the first year of introduction of any new technology. That is, variable costs were reduced by 20 percent for each doubling of cumulative production following the year in which the technology was first introduced in a given power range of engines. This way, learning is applied at the start of 2013 for engines over 175 hp and in 2014 for engines between 75 to 175 hp because of the one-year difference in their first year of compliance (i.e., the first year in which new technologies are introduced). Because the timing of the emission standards in this final rule follows that of the HD2007 rule, we have used the first stage of learning done via that rule as the starting point of learning for nonroad engines. In other words, the first learning phase for highway engines serves as the baseline level of learning for nonroad engines. We have then applied one additional learning step from there. In the HD2007 rule, we applied a second learning step following the second doubling of production that occurs at the end of the 2010 model year. We could have chosen that point as our baseline case for nonroad and then applied a single learning curve effect from there. Instead, we have chosen to use as our nonroad baseline the first learning step from the highway rule so that, with our single nonroad learning step, we have costs consistent with those costs estimated for highway diesel engines. In the long term, after applying the nonroad learning curve, our cost estimates for CDPFs and NOx adsorbers are the same for similar nonroad and highway diesel engines. This approach is consistent with the approach taken in our Tier 2 light-duty highway rule and the HD2007 rule for heavy-duty gasoline engines. There, compliance was being met through improvements to existing technologies rather than the development of new technologies. We argued in those rules that, with existing technologies, there is less opportunity for lowering production costs. For that reason, we applied only one learning curve effect. The situation is similar for nonroad engines. Because these will be existing technologies by the time they are introduced into the market, there would arguably be less opportunity for learning than there will be for the highway engines where the technologies are first introduced.

Another factor that plays into our near-term and long-term cost estimates is that for warranty claim rates. In our HD2007 rule, we estimated a warranty claim rate of one percent. Subsequent to that rule, we learned from industry that repair rates can be as much as two to three times higher during the initial years of production for a new technology relative to later years.[13] For this analysis, we have applied what we have learned in our warranty estimates by using a three percent warranty claim rate during the first two years and then one percent warranty claim rate thereafter. This difference in warranty claim rates, in addition to the learning effects discussed above, is reflected in the different long-term costs relative to near-term costs.

6.2.2.1 NOx Adsorber System Costs

The NOx adsorber system anticipated for Tier 4 is the same technology as for highway applications. For the NOx adsorber to function properly, a systems approach that includes a reductant metering system and control of engine air-fuel ratio is also necessary. Many of the new air handling and electronic system technologies developed in order to meet the Tier 2/Tier 3 nonroad diesel engine standards can be applied to accomplish the NOx adsorber control functions as well. Some additional hardware for exhaust NOx or O_2 sensing and for fuel metering probably will be required. The cost estimates include a DOC for clean-up of hydrocarbon emissions that occur during NOx adsorber regeneration events.

We have used the same methodology to estimate costs associated with NOx adsorber systems as was used in our HD2007 rulemaking. The basic components of the NOx adsorber catalyst are well known and include the following material elements:

- an oxidation catalyst, typically platinum-based;
- an alkaline earth metal to store NOx, typically barium-based;
- a NOx reduction catalyst, typically rhodium-based;
- a substrate upon which the catalyst washcoating is applied; and,
- a can to hold and support the substrate.

Examples of these material costs are summarized in Table 6.2-11 and represent costs to the engine manufacturers inclusive of supplier markups. The manufacturer costs shown in Table 6.2-11 (as well as Tables 6.2-13 and 6.2-18 for CDPF systems and DOCs, respectively) include additional markups to account for both manufacturer and dealer overhead and carrying costs. The application of overhead and carrying costs are consistent with the approach taken in the HD2007 rulemaking. In that rule, we used an approach to estimating the markup for catalyzed emission-control technologies based on input from catalyst manufacturers. Specifically, we were told that device manufacturers could not mark up the cost of the individual components within their products because those components consist of basic commodities (for example, precious metals used in the catalyst could not be arbitrarily marked up because of their commodity status). Instead, manufacturing entities could mark up costs only where they add a unique value to the product. In the case of catalyst systems, we were told that the underlying cost of precious metals, catalyst substrates, PM filter substrates, and canning materials were well known to both buyer and seller and no markup or profit recovery for those component costs could be derived by the catalyst manufacturer. In essence, these are components to which the supplier provides little value-added engineering. The one component that was unique to each catalyst manufacturer (i.e., the component where they add a unique value) was the catalyst washcoat support materials. This mixture (which is effectively specialized clays) serves to hold the catalytic metals in place and to control the surface area of the catalytic metals available for emission control. Although the commodity price for the materials used in the washcoat is almost negligible (i.e., perhaps one or two dollars), we have estimated a substantial cost for washcoating based on the engineering value added by the catalyst manufacturer in this step. This is reflected in the costs presented for NOx adsorber systems, CDPF systems, and DOCs. This portion of the cost estimate – the washcoating – is where the catalyst manufacturer recovers the fixed cost for research and development as well as realizes a profit. To these manufacturer costs, we have added a four percent carrying costs to account for the capital cost of the extra inventory, and the incremental costs of insurance, handling, and storage. A dealer carrying cost in included to cover the cost of capital tied up in extra inventory. Considering input received from industry, we have adopted this approach of estimating individually the manufacturer and dealer markups in an effort to better reflect the value each entity adds at various stages of the supply chain.[14] Also included is our estimate of warranty costs for the NOx adsorber system.

Table 6.2-11. NOx Adsorber System Costs

	NOx Adsorber Costs ($2002)							
Horsepower	9 hp	33 hp	76 hp	150 hp	250 hp	503 hp	660 hp	1000 hp
Engine Displacement (Liter)	0.39	1.50	3.92	4.70	7.64	18.00	20.30	34.50
Material and Component Costs								
Catalyst Volume (Liter)	0.59	2.25	5.88	7.05	11.46	27.00	30.45	51.75
Substrate	$3	$12	$32	$38	$62	$147	$166	$282
Washcoating and Canning	$13	$52	$135	$162	$263	$620	$700	$1,189
Platinum	$16	$62	$163	$195	$318	$748	$844	$1,434
Rhodium	$3	$11	$28	$34	$55	$129	$145	$246
Alkaline Earth Oxide, Barium	$1	$1	$1	$1	$1	$1	$1	$1
Catalyst Can Housing	$9	$9	$9	$9	$13	$18	$18	$18
Direct Labor Costs								
Estimated Labor hours	2	2	2	2	2	2	2	2
Labor Rate ($/hr)	$30	$30	$30	$30	$30	$30	$30	$30
Labor Cost	$45	$45	$45	$45	$45	$60	$60	$60
Labor Overhead @ 40%	$18	$18	$18	$18	$18	$24	$24	$24
Total Direct Costs to Mfr.	$109	$210	$431	$502	$775	$1,747	$1,957	$3,254
Warranty Cost -- Near Term (3% claim rate)	$9	$17	$34	$39	$59	$131	$146	$244
Mfr. Carrying Cost -- Near Term	$4	$8	$17	$20	$31	$70	$78	$130
Total Cost to Dealer -- Near Term	$122	$235	$482	$561	$865	$1,948	$2,182	$3,628
Dealer Carrying Cost -- Near Term	$4	$7	$14	$17	$26	$58	$65	$109
DOC for cleanup -- Near Term	$105	$132	$192	$211	$286	$459	$497	$734
Baseline Cost to Buyer -- Near Term	$231	$375	$688	$789	$1,177	$2,465	$2,745	$4,471
Cost to Buyer w/ Highway learning -- Near Term	$206	$326	$589	$674	$999	$2,064	$2,295	$3,724
Warranty Cost -- Long Term (1% claim rate)	$3	$6	$11	$13	$20	$44	$49	$81
Mfr. Carrying Cost -- Long Term	$4	$8	$17	$20	$31	$70	$78	$130
Total Cost to Dealer -- Long Term	$116	$224	$459	$535	$826	$1,861	$2,084	$3,466
Dealer Carrying Cost -- Long Term	$3	$7	$14	$16	$25	$56	$63	$104
DOC for cleanup -- Long Term	$99	$125	$182	$201	$272	$437	$474	$700
Baseline Cost to Buyer -- Long Term	$219	$356	$656	$752	$1,123	$2,354	$2,621	$4,270
Cost to Buyer w/ Highway learning -- Long Term	$195	$310	$561	$642	$952	$1,970	$2,191	$3,556
Cost to Buyer w/ Nonroad learning -- Long Term	$176	$273	$485	$554	$816	$1,664	$1,848	$2,985

We have estimated the cost of this system based on information from several reports.[15, 16, 17] The individual estimates and assumptions used to estimate the cost for the system are documented in the following paragraphs.

NOx Adsorber Catalyst Volume

The Engine Manufacturers Association was asked as part of a contractor work assignment to gather input from their members on likely technology solutions including the NOx adsorber catalyst.[18] The respondents indicated that the catalyst volume for a NOx adsorber catalyst may range from 1.5 times the engine displacement to as much as 2.5 times the engine displacement based on current washcoat technology. Based on current lean burn gasoline catalyst designs and engineering judgment, we have estimated that the NOx adsorber catalyst will be sized on average 1.5 times the engine displacement. This is consistent with the size of the NOx adsorber catalyst on the Toyota Avensis diesel passenger car (60 prototypes of a planned 2003 production car are being tested in Europe), which is sized at 1.4 times engine displacement.[19]

NOx Adsorber Substrate

The ceramic flow-through substrates used for the NOx adsorber catalyst were estimated to cost $5.27 ($1999) per liter during our HD2007 rule. This cost estimate was based on a relationship developed for current heavy-duty gasoline catalyst substrates.[20] We have converted that value to $5.44 ($2002) using the PPI for Motor Vehicle Parts and Accessories, Catalytic Convertors.[21]

NOx Adsorber Washcoating and Canning

We have estimated a "value-added" engineering and material product, called washcoating and canning, based on feedback from members of the Manufacturers of Emission Control Association (MECA).[22] By using a value-added component that accounts for fixed costs (including R&D), overhead, marketing and profits from likely suppliers of the technology, we can estimate this fraction of the cost for the technology apart from other components that are more widely available as commodities (e.g, precious metals and catalyst substrates). Based on conversations with MECA, we understand this element of the product to represent the catalyst manufacturer's value added and, therefore, their opportunity for markup. As a result, the washcoating and canning costs shown in Table 6.2-11 represent costs with manufacturer markups included.

NOx Adsorber Precious Metals

The total precious metal content for the NOx adsorber is estimated to be 50 g/ft^3 with platinum representing 90 percent of that total and rhodium representing 10 percent. The costs for rhodium and platinum used in this analysis are the 2002 average prices of $839 per troy ounce for rhodium and $542 per troy ounce for platinum, as reported by Johnson Matthey.[23]

NOx Adsorber Alkaline Earth Metal – Barium

The cost for barium carbonate (the primary NOx storage material) is assumed to be less than \$1 per catalyst as estimated in "Economic Analysis of Diesel Aftertreatment System Changes Made Possible By Reduction of Diesel Fuel Sulfur Content."

NOx Adsorber Can Housing

The material cost for the can housing is estimated based on the catalyst volume plus 20 percent for transition cones, plus 20 percent for scrappage (material purchased but unused in the final product) and a price of \$1.01 per pound for 18 gauge stainless steel as estimated in a contractor report to EPA and converted into \$2002.[24]

NOx Adsorber Direct Labor

The direct labor costs for the catalyst are estimated based on an estimate of the number of hours required for assembly and established labor rates. Additional overhead for labor was estimated as 40 percent of the labor rate.[25]

NOx Adsorber Warranty

We have estimated both near-term and long-term warranty costs. Near-term warranty costs are based on a three percent claim rate and an estimate of parts and labor costs per incident, while long-term warranty costs are based on a one percent claim rate and an estimate of parts and labor costs per incident. The labor rate is assumed to be \$50 per hour with four hours required per claim, and parts costs are estimated to be 2.5 times the original manufacturing cost for the component. The calculation of near-term warranty costs for the 9 hp engine shown in Table 6.2-11 is as follows:

$$[(\$3 + \$13 + \$16 + \$3 + \$1 + \$9)(2.5) + (\$50)(4\text{hours})](3\%) = \$9$$

NOx Adsorber Manufacturer and Dealer Carrying Costs

The manufacturer's carrying cost was estimated at 4 percent of the direct costs. This reflects primarily the costs of capital tied up in extra inventory, and secondarily the incremental costs of insurance, handling and storage. The dealer's carrying cost was estimated at 3 percent of the incremental cost, again reflecting primarily the cost of capital tied up in extra inventory.[26]

NOx Adsorber DOC for System Clean-up

Included in the costs for the NOx adsorber system are costs for a diesel oxidation catalyst (DOC) for clean-up of possible excess hydrocarbon emissions that might occur as a result of system regeneration (removal of stored NOx and reduction to N_2 and O_2). The methodology used to estimate DOC system costs is consistent with the methodology outlined here for NOx adsorber systems and is presented below in Section 6.2.2.3. Important to note here is that the DOC costs shown in Table 6.2-11 are lower in the long term because of the lower warranty claim rate—three percent in the near term and one percent in the long term; learning effects, as discussed below, are not applied to DOC costs.

NOx Adsorber Cost Estimation Function

Using the example NOx adsorber costs shown in Table 6.2-11, we calculated a linear regression to determine the NOx adsorber system cost as a function of engine displacement. This way, the function can be applied to the wide array of engines in the nonroad fleet to determine the total or per engine costs for NOx adsorber hardware. The functions calculated for NOx adsorber system costs used throughout this analysis are shown in Table 6.2-12. Note that Table 6.2-11 shows NOx adsorber system costs for engines under 75 hp. We do not anticipate any engines under 75 hp will apply NOx adsorber systems to comply with the new emission standards. Nonetheless, the costs shown were used to generate the equations shown in Table 6.2-12. Because of the linear relationship between engine displacement and NOx adsorber system size (and, therefore, cost), including the costs for these smaller engines does not inappropriately shift the cost equation downward.

Table 6.2-12
NOx Adsorber System Costs as a Function of
Engine Displacement (x represents engine displacement in liters)
$2002

Near-Term Cost Function	$103(x) + $183	R^2=0.9998
Long-Term Cost Function	$83(x) + $160	R^2=0.9997

Table 6.2-12 shows both a near-term and a long-term cost function for NOx adsorber system costs. The near-term function incorporates the near-term warranty costs determined using a three percent claim rate, while the long-term function incorporates the long-term warranty costs determined using a one percent claim rate. Additionally, the long-term function incorporates learning curve effects for certain elements of the NOx adsorber system (i.e., learning effects were not applied to the DOC portion of the NOx adsorber system, for reasons discussed below). In the HD2007 rule, we applied two learning effects of 20 percent. Here, we have assumed one learning effect of 20 percent as a baseline level of learning; this represents learning done as a result of the HD2007 rule. After a single doubling of production (i.e., two years), we have then applied a single *nonroad* learning effect of 20 percent. Note that the equations shown in Table 6.2-12 include costs for a clean-up DOC; results generated using the DOC cost estimation equations presented in Table 6.2-16 should *not* be added to results generated using the equations in Table 6.2-12 to determine NOx adsorber system costs.

6.2.2.2 Catalyzed Diesel Particulate Filter Costs

As with the NOx adsorber system, the anticipated CDPF system for Tier 4 is the same as that used for highway applications, except that we are projecting that some form of active regeneration system will be employed as a backup to the passive regeneration capability of the

CDPF. For the CDPF to function properly, a systems approach that includes a reductant metering system and control of engine air-fuel ratio is also necessary. Many of the new air handling and electronic fuel system technologies developed in order to meet the Tier 2/Tier 3 nonroad engine standards can be applied to accomplish the CDPF control functions as well. Nonroad applications are expected to present challenges beyond those of highway applications with respect to implementing CDPFs. For this reason, we anticipate that some additional hardware beyond the diesel particulate filter itself may be required to ensure that CDPF regeneration occurs. For some engines this may be new fuel control strategies that force regeneration under some circumstances, while in other engines it might involve an exhaust system fuel injector to inject fuel upstream of the CDPF to provide necessary heat for regeneration under some operating conditions. The cost estimates for such a regeneration system are presented in Section 6.2.2.3.

We have used the same methodology to estimate costs associated with CDPF systems used in our HD2007 rulemaking (although here, for nonroad engines, we have included costs for a regeneration system that was not part of the cost estimate in the HD2007 rule). The basic components of the CDPF are well known and include the following material elements:

- an oxidation catalyst, typically platinum-based;
- a substrate upon which the catalyst washcoating is applied and upon which PM is trapped;
- a can to hold and support the substrate; and,
- a regeneration system to ensure regeneration under all operating conditions (see Section 6.2.2.3).

Examples of these material costs are summarized in Table 6.2-13 and represent costs to the engine manufacturers inclusive of supplier markups. The total direct cost to the manufacturer includes an estimate of warranty costs for the CDPF system. Hardware costs are additionally marked up to account for both manufacturer and dealer overhead and carrying costs. The manufacturer’s carrying cost was estimated to be four percent of the direct costs accounting for the capital cost of the extra inventory, and the incremental costs of insurance, handling, and storage. The dealer’s carrying cost was marked up three percent reflecting the cost of capital tied up in inventory. Considering input received from industry, we have adopted this approach of estimating individually the manufacturer and dealer markups in an effort to better reflect the value added at each stage of the supply chain.[27]

Table 6.2-13. Catalyzed Diesel Particulate Filter (CDPF) System Costs

	Catalyzed Diesel Particulate Filter (CDPF) Costs ($2002)							
Horsepower	9 hp	33 hp	76 hp	150 hp	250 hp	503 hp	660 hp	1000 hp
Average Engine Displacement (Liter)	0.39	1.50	3.92	4.70	7.64	18.00	20.30	34.50
Material and Component Costs								
Filter Volume (Liter)	0.59	2.25	5.88	7.05	11.46	27.00	30.45	51.75
Filter Trap	$36	$139	$364	$437	$710	$1,673	$1,886	$3,206
Washcoating and Canning	$13	$52	$135	$162	$263	$620	$700	$1,189
Platinum	$11	$42	$109	$130	$212	$499	$563	$956
Filter Can Housing	$7	$7	$7	$7	$10	$14	$14	$14
Differential Pressure Sensor	$46	$46	$46	$46	$46	$46	$93	$93
Direct Labor Costs	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Labor hours	2	2	2	2	2	2	4	4
Labor Rate ($/hr)	$30	$30	$30	$30	$30	$30	$30	$30
Labor Cost	$60	$60	$60	$60	$60	$60	$120	$120
Labor Overhead @ 40%	$24	$24	$24	$24	$24	$24	$48	$48
Total Direct Costs to Mfr.	$198	$370	$746	$867	$1,326	$2,937	$3,424	$5,626
Warranty Cost -- Near Term (3% claim rate)	$12	$24	$53	$62	$96	$217	$247	$412
Mfr. Carrying Cost -- Near Term	$8	$15	$30	$35	$53	$117	$137	$225
Total Cost to Dealer -- Near Term	$218	$409	$828	$963	$1,475	$3,271	$3,808	$6,264
Dealer Carrying Cost -- Near Term	$7	$12	$25	$29	$44	$98	$114	$188
Savings by removing muffler	-$46	-$46	-$46	-$46	-$46	-$46	-$46	-$46
Baseline Cost to Buyer -- Near Term	$178	$375	$806	$945	$1,473	$3,323	$3,876	$6,405
Cost to Buyer w/ Highway learning -- Near Term	$142	$300	$645	$756	$1,178	$2,658	$3,101	$5,124
Warranty Cost -- Long Term (1% claim rate)	$4	$8	$18	$21	$32	$72	$82	$137
Mfr. Carrying Cost -- Long Term	$8	$15	$30	$35	$53	$117	$137	$225
Total Cost to Dealer -- Long Term	$210	$393	$793	$922	$1,411	$3,126	$3,643	$5,989
Dealer Carrying Cost -- Long Term	$6	$12	$24	$28	$42	$94	$109	$180
Savings by removing muffler	-$46	-$46	-$46	-$46	-$46	-$46	-$46	-$46
Baseline Cost to Buyer -- Long Term	$170	$359	$770	$903	$1,407	$3,174	$3,706	$6,122
Cost to Buyer w/ Highway learning -- Long Term	$136	$287	$616	$722	$1,125	$2,539	$2,965	$4,898
Cost to Buyer w/ Nonroad learning -- Long Term	$109	$229	$493	$578	$900	$2,031	$2,372	$3,918

CDPF Volume

During development of our HD2007 rule, the Engine Manufacturers Association was asked as part of a contractor work assignment to gather input from their members on catalyzed diesel particulate filters for heavy-duty highway applications.[28] The respondents indicated that the particulate filter volume may range from 1.5 times the engine displacement to as much as 2.5 times the engine displacement based on their experiences at that time with cordierite filter technologies. The size of the diesel particulate filter is selected largely based on the maximum allowable flow restriction for the engine. Generically, the filter size is inversely proportional to its resistance to flow (a larger filter is less restrictive than a similar smaller filter). In the HD2007 rule and here, we have estimated that the diesel particulate filter will be sized to be 1.5 times the engine displacement based on the responses received from EMA and on-going research aimed at improving filter porosity control to give a better trade-off between flow restrictions and filtering efficiency.

CDPF Substrate

CDPFs can be made from a wide range of filter materials including wire mesh, sintered metals, fibrous media, or ceramic extrusions. The most common material used for CDPFs for heavy-duty diesel engines is cordierite. Here we have based our cost estimates on the use of silicon carbide (SiC) even though it is more expensive than other filter materials. In the HD2007 rule, we estimated that CDPFs will consist of a cordierite filter costing $30 per liter. To remain conservative in our cost estimates for nonroad applications, we have assumed the use of silicon carbide filters costing double that amount, or $60 per liter.[O] This cost is directly proportional to filter volume, which is proportional to engine displacement. This $60 value is then converted to $2002 using the PPI for Motor Vehicle Parts and Accessories, Catalytic Convertors.[29] The end result being a cost of $62 per liter.

CDPF Washcoating and Canning

These costs were done in a consistent manner as done for NOx adsorber catalyst systems, as discussed above.

CDPF Precious Metals

The total precious metal content for catalyzed diesel particulate filters is estimated to be 30 g/ft^3 with platinum as the only precious metal used in the filter. As done for NOx adsorbers, we have used a price of $542 per troy ounce for platinum.

CDPF Can Housing

The material cost for the can housing is estimated based on the CDPF volume plus 20 percent for transition cones, plus 20 percent for scrappage (material purchased but unused in the final product) and a price of $1.01 per pound for 18 gauge stainless steel as estimated in a contractor report to EPA and converted into $2002.[30]

CDPF Differential Pressure Sensor

We have assumed that the catalyzed diesel particulate filter system will require the use of a differential pressure sensor to provide a diagnostic monitoring function of the filter. A contractor report to EPA estimated the cost for such a sensor at $45.[31] A PPI adjusted cost of $46 per sensor has been used in this analysis.

[O] Note that we are being especially conservative with respect to >750 horsepower mobile machines where we believe that manufacturers may in fact use a wire mesh substrate rather than the SiC substrate we have costed and, indeed, we have based the level of the 2015 PM standard on this use of wire mesh substrates. We have chosen to remain conservative in our cost estimates by assuming use of a SiC substrate for all engines.

CDPF Direct Labor

Consistent with the approach for NOx adsorber systems, the direct labor costs for the CDPF are estimated based on an estimate of the number of hours required for assembly and established labor rates. Additional overhead for labor was estimated as 40 percent of the labor rate.[32]

CDPF Warranty

We have estimated both near-term and long-term warranty costs. Near-term warranty costs are based on a three percent claim rate and an estimate of parts and labor costs per incident, while long-term warranty costs are based on a one percent claim rate and an estimate of parts and labor costs per incident. The labor rate is assumed to be $50 per hour with two hours required per claim, and parts cost are estimated to be 2.5 times the original manufacturing cost for the component.

CDPF Manufacturer and Dealer Carrying Costs

Consistent with the approach for NOx adsorber systems, the manufacturer's carrying cost was estimated at 4 percent of the direct costs. This reflects primarily the costs of capital tied up in extra inventory, and secondarily the incremental costs of insurance, handling and storage. The dealer's carrying cost was estimated at 3 percent of the incremental cost, again reflecting primarily the cost of capital tied up in extra inventory.[33]

Savings Associated with Muffler Removal

CDPF retrofits are currently often incorporated in, or are simply replacements for, the muffler for diesel-powered vehicles and equipment. One report noted that, "Often, the trap could be mounted in place of the muffler and had the same dimensions. Thus, rapid replacement was possible. The muffling effect was often even better."[34] We have assumed that applying a CDPF allows for the removal of the muffler due to the noise attenuation characteristics of the CDPF. We have accounted for this savings and have estimated a muffler cost of $46. The $46 estimate is an average for all engines; the actual savings will be higher for some and lower for others.

CDPF System Cost Estimation Function

Using the example CDPF costs shown in Table 6.2-13, we calculated a linear regression to determine the CDPF system cost as a function of engine displacement. This way, the function can be applied to the wide array of engines in the nonroad fleet to determine the total or per engine costs for CDPF system hardware. The functions calculated for CDPF system costs used throughout this analysis are shown in Table 6.2-14.

Table 6.2-14
CDPF System Costs as a Function of
Engine Displacement (x represents engine displacement in liters)
$2002

Near-term Cost Function	$146(x) + $75	R^2=0.9997
Long-term Cost Function	$112(x) + $57	R^2=0.9997

The near-term and long-term costs shown in Table 6.2-14 change due to the different warranty claim rates and the application of a 20 percent learning curve effect.

6.2.2.3 CDPF Regeneration System Costs

The CDPF regeneration system is likely to include an O_2 sensor, a means for exhaust air to fuel ratio control (one or more exhaust fuel injectors or in-cylinder means), a temperature sensor and possibly a means to control mass flow through a portion of the catalyst system (for example, for a "dual-bed" system). Incremental costs for a CDPF regeneration system, along with several other costs discussed below, were developed by ICF Consulting under contract to EPA.[35] The cost estimates developed by ICF for a CDPF regeneration system are summarized in Table 6.2-15.

Table 6.2-15.
CDPF Regeneration System – Costs to the Manufacturer

ICF Estimated Regeneration System Costs to Manufacturers ($2002)								
Horsepower	20	35	80	150	250	400	650	1000
Displacement (L)	1	2	3	6	8	10	16	24
CDPF Regeneration System Costs	$265	$279	$293	$384	$408	$431	$530	$676

Using these costs, we then estimated costs to the buyer using the same learning curve effects and warranty claim rate factors discussed above. These results are presented in Table 6.2-16.

Table 6.2-16.
CDPF Regeneration System – Costs to the User

EPA Estimate of CDPF Regeneration System Costs ($2002)								
Horsepower	20	35	80	150	250	400	650	1000
Displacement (L)	1	2	3	6	8	10	16	24
CDPF Regeneration System Costs	$265	$279	$293	$384	$408	$431	$530	$676
Warranty Cost – Near Term (3% claim rate)	$23	$24	$25	$32	$34	$35	$43	$54
Mfr. Carrying Cost (4%) – Near Term	$11	$11	$12	$15	$16	$17	$21	$27
Total Cost to Dealer – Near Term	$298	$314	$330	$432	$458	$484	$593	$756
Dealer Carrying Cost (3%) – Near Term	$9	$9	$10	$13	$14	$15	$18	$23
Total Cost to Buyer – Near Term	$307	$323	$340	$445	$471	$498	$611	$779
Warranty Cost – Long Term (1% claim rate)	$8	$8	$8	$11	$11	$12	$14	$18
Mfr. Carrying Cost (4%)– Long Term	$11	$11	$12	$15	$16	$17	$21	$27
Total Cost to Dealer – Long Term	$283	$298	$313	$410	$435	$460	$565	$721
Dealer Carrying Cost (3%) – Long Term	$8	$9	$9	$12	$13	$14	$17	$22
Subtotal	$291	$307	$323	$423	$448	$474	$582	$742
Total Cost to Buyer – Long-Term w/ learning	$233	$246	$258	$338	$359	$379	$466	$594

As noted above, the CDPF regeneration system is expected to consist of an O_2 sensor, a temperature sensor, and probably a pressure sensor. The costs shown in Table 6.2-16 assume none of these sensors or other pieces of hardware exist and, more importantly, they assume the fuel control systems present in the engine are not capable of the sort of precise fuel control that could perform many of the necessary functions of the regeneration system without any additional hardware. For this reason, we consider the costs shown in Table 6.2-16 to be representative of the costs for an engine with an indirect-injection (IDI) fuel system. For a direct-injection (DI) fuel system, we expect that many of the functional capabilities for which costs were generated will be handled by the existing fuel system. For example, we are assuming that all DI engines will either convert to a fuel system capable of late injection or will already have a fuel system capable of late injection. Late injection is one of the primary means of using fuel strategies to force a CDPF regeneration event. Our cost estimates associated with conversion to such fuel systems are discussed below. Because the regeneration system costs for DI engines are lower than for an IDI engine, we have estimated that the regeneration system costs for a DI engine are half of those presented in Table 6.2-16.

Also, note that the air handling, electronic, and fuel system hardware used for backup active CDPF regeneration is expected to be used in common with the NOx adsorber regeneration system. We have accounted for these costs here (as a CDPF regeneration system) because CDPFs are required on a broader range of engines and, for many engines, earlier than are NOx adsorbers.

CDPF Regeneration System Cost Estimation Function

Using the example regeneration system costs shown in Table 6.2-16, we calculated a linear regression to determine the CDPF regeneration system cost as a function of engine displacement. This way, the function can be applied to the wide array of engines in the nonroad fleet to determine the total costs for CDPF regeneration system hardware. The functions calculated for CDPF regeneration system costs used throughout this analysis are shown in Table 6.2-17.

Table 6.2-17
CDPF Regeneration System Costs as a Function of
Engine Displacement (x represents engine displacement in liters)
$2002

IDI Engine	Near-term Cost Function	$20(x) + $293	R^2=0.9916
	Long-term Cost Function	$16(x) + $223	R^2=0.9916
DI Engine	Near-term Cost Function	$10(x) + $147	R^2=0.9916
	Long-term Cost Function	$8(x) + $111	R^2=0.9916

Note that these costs—either the IDI or the DI costs, depending on the type of engine—are incurred for any engine adding a CDPF. The near-term and long-term costs shown in Table 6.2-17 change due to the different warranty claim rates and the application of a 20 percent learning curve effect.

6.2.2.4 Diesel Oxidation Catalyst (DOC) Costs

The NOx adsorber regeneration and desulfation functions may produce undesirable by-products in the form of momentary increases in HC emissions or in odorous hydrogen sulfide (H_2S) emissions. We have assumed that manufacturers may choose to apply a diesel oxidation catalyst (DOC) downstream of the NOx adsorber technology to control these potential products. The DOC serves a "clean-up" function to oxidize any HC and H_2S emissions to more desirable products. As discussed below, for our cost analysis we have also projected that engines under 75 hp will add a DOC to comply with the 2008 PM standards, not to serve a "clean-up" function but rather to serve as the primary means of emission control.

Our estimates of DOC costs are shown in Table 6.2-18. The individual component costs for the DOC were estimated in the same manner as for the NOx adsorber systems and CDPF systems, as discussed above. However, no learning effects were applied to DOCs because we believe DOCs have been manufactured for a long enough time period such that learning has already taken place.

Table 6.2-18.
Diesel Oxidation Catalyst (DOC) Costs

	Diesel Oxidation Catalyst Costs ($2002)							
Horsepower	9 hp	33 hp	76 hp	150 hp	250 hp	503 hp	660 hp	1000 hp
Average Engine Displacement (Liter)	0.39	1.50	3.92	4.70	7.64	18.00	20.30	34.50
Material and Component Costs								
Catalyst Volume (liter)	0.39	1.50	3.92	4.70	7.64	18.00	20.30	34.50
Substrate	$2	$8	$21	$26	$42	$98	$110	$188
Washcoating and Canning	$61	$76	$107	$117	$155	$208	$220	$294
Platinum (5 g/ft3)	$1	$5	$12	$14	$24	$55	$63	$106
Catalyst Can Housing	$4	$4	$4	$4	$7	$15	$17	$30
Direct Labor Costs								
Estimated Labor hours	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Rate ($/hr)	$30	$30	$30	$30	$30	$30	$30	$30
Labor Cost	$15	$15	$15	$15	$15	$15	$15	$15
Labor Overhead @ 40%	$6	$6	$6	$6	$6	$6	$6	$6
Total Direct Costs to Mfr.	$90	$114	$166	$182	$248	$398	$432	$638
Warranty Cost -- Near Term (3% claim rate)	$8	$10	$14	$15	$20	$31	$34	$49
Mfr. Carrying Cost -- Near Term	$4	$5	$7	$7	$10	$16	$17	$26
Total Cost to Dealer -- Near Term	$102	$128	$186	$205	$277	$445	$483	$713
Dealer Carrying Cost -- Near Term	$3	$4	$6	$6	$8	$13	$14	$21
Total Cost to Buyer -- Near Term	$105	$132	$192	$211	$286	$459	$497	$734
Warranty Cost -- Long Term (1% claim rate)	$3	$3	$5	$5	$7	$10	$11	$16
Mfr. Carrying Cost -- Long Term	$4	$5	$7	$7	$10	$16	$17	$26
Total Cost to Dealer -- Long Term	$96	$122	$177	$195	$264	$425	$460	$680
Dealer Carrying Cost -- Long Term	$3	$4	$5	$6	$8	$13	$14	$20
Total Cost to Buyer -- Long Term	$99	$125	$182	$201	$272	$437	$474	$700

DOC Cost Estimation Function

Similar to what was done for NOx adsorber systems and CDPFs, we used the example costs shown in Table 6.2-18 to determine a cost function with engine displacement as the dependent variable. This way, the function can be applied to the wide array of engines in the nonroad fleet to determine the total or per unit costs for DOC hardware, whether that hardware be a stand alone emission-control technology or as part of a NOx adsorber system. The cost functions for DOCs used throughout this analysis are shown in Table 6.2-19. Note that the NOx adsorber cost estimation equations shown in Table 6.2-12 include costs for a clean-up DOC; results generated using the DOC cost estimation equations presented in Table 6.2-19 should *not* be added to results generated using the equations in Table 6.2-12 to determine NOx adsorber system costs.

Table 6.2-19
DOC Costs as a Function of
Engine Displacement (x represents engine displacement in liters)
$2002

Near-term Cost Function	$18(x) + $116	R^2=0.9944
Long-term Cost Function	$18(x) + $110	R^2=0.9944

6.2.2.5 Closed-Crankcase Ventilation (CCV) System Costs

Consistent with our HD2007 rule, we are removing the provision that allows turbocharged nonroad diesel engines to vent crankcase gases directly to the environment. Such engines are said to have an open crankcase system. We project that this requirement to close the crankcase on turbocharged engines will force manufacturers to rely on engineered closed crankcase ventilation systems that filter oil from the blow-by gases before routing them into either the engine intake or the exhaust system upstream of the CDPF. We expect these systems to be the same as those expected for highway engines and have estimated their costs in the same manner as done in our HD2007 rule. The estimated initial costs of these systems are as shown in Table 6.2-20. These costs are incurred only by turbocharged engines.

Table 6.2-20.
Closed Crankcase Ventilation (CCV) System Costs

	Closed Crankcase Ventilation (CCV) System Costs ($2002)							
Horsepower	9 hp	33 hp	76 hp	150 hp	250 hp	503 hp	660 hp	1000 hp
Average Engine Displacement (Liter)	0.39	0.93	3.92	4.7	7.64	18	20.3	34.5
Cost to Manufacturer	$28	$29	$34	$35	$41	$59	$64	$89
Warranty Cost -- Near Term (3% claim rate)	$5	$5	$6	$6	$6	$7	$8	$10
Mfr. Carrying Cost -- Near Term	$1	$1	$1	$1	$2	$2	$3	$4
Total Cost to Dealer -- Near Term	$34	$35	$41	$42	$48	$69	$74	$103
Dealer Carrying Cost -- Near Term	$1	$1	$1	$1	$1	$2	$2	$3
Total Cost to Buyer -- Near Term	$35	$36	$42	$44	$50	$71	$76	$106
Warranty Cost -- Long Term (1% claim rate)	$2	$2	$2	$2	$2	$2	$3	$3
Mfr. Carrying Cost -- Long Term	$1	$1	$1	$1	$2	$2	$3	$4
Total Cost to Dealer -- Long Term	$30	$31	$37	$39	$44	$64	$69	$96
Dealer Carrying Cost -- Long Term	$1	$1	$1	$1	$1	$2	$2	$3
Cost to Buyer w/ Nonroad Learning -- Long Term	$25	$26	$31	$32	$37	$53	$57	$79

CCV Cost Estimation Function

As discussed above, an equation was developed as a function of engine displacement to calculate total or per unit CCV costs. These functions are shown in Table 6.2-21. Note that these costs will be incurred only by turbocharged engines.

Table 6.2-21
CCV Costs as a Function of
Engine Displacement (x represents engine displacement in liters)
$2002

Near-term Cost Function	$2(x) + $34	$R^2=1$
Long-term Cost Function	$2(x) + $24	$R^2=1$

6.2.2.6 Variable Costs of Conventional Technologies for Engines under 75 hp and over 750 hp

For the smaller engines, we have projected a different technology mix for complying with the applicable emission standards. As explained in Chapter 4 of the RIA, we are projecting that engines will comply either by adding a DOC or by making some engine modifications resulting in engine-out emission reductions to comply with the 2008 PM standards. For our cost analysis, we have assumed that all engines will add a DOC. Manufacturers will presumably choose the least costly approach that provides the necessary emission control. If engine-out modifications are less costly than a DOC, the analysis overestimates the costs associated with meeting these standards. If the DOC proves to be less costly, then our estimate is representative of what most manufacturers presumably will do. Therefore, we have assumed that, beginning in 2008, all engines under 75 hp will add a DOC. Note that, as discussed in Chapter 4, some engines under 75 hp already meet the new PM standards (i.e., such engines will not have to make any changes nor incur any incremental hardware costs for 2008), which also contributes to the likely overestimate of costs. Our cost estimates for DOCs are presented above in Section 6.2.2.4.

As discussed in Chapter 4, we have also projected that some engines in the 25 to 75 hp range will have to make changes to their engines to incorporate more conventional engine technology, such as electronic common rail fuel injection, to meet the demands of the newly added CDPF. These costs were assumed for direct-injection (DI) engines. For indirect-injection (IDI) engines in this power range, we believe manufacturers will comply not through a fuel system upgrade to electronic common rail, but through the addition of a CDPF regeneration system to ensure regeneration of the CDPF. The costs for CDPF regeneration systems are discussed above in Section 6.2.2.3.

In the 25 to 50 hp range, we believe all engines will add cooled EGR to meet NOx standards. For our cost analysis, this is also true for engines over 750 hp. Note that engines over 750 hp are also assumed to add the previously discussed emission-control technologies, i.e., a CDPF system and some sort of CDPF regeneration system.

We project that manufacturers will add CCV systems to all these engines that are turbocharged, both large and small. The costs for CCV systems are presented in Section 6.2.2.5.

6.2.2.6.1 Electronic Common Rail Fuel-Injection System Costs for DI Engines

Cost estimates for fuel-injection systems were developed by ICF Consulting under contract to EPA.[36] Table 6.2-22 presents the costs to manufacturers as estimated by ICF for fuel-injection systems.

Table 6.2-22
Fuel-Injection System – Costs to Manufacturers

	Fuel System Costs ($2002)					
	Baseline System			New System		
Horsepower	20 hp	35 hp	80 hp	20 hp	35 hp	80 hp
Displacement (L)	1	2	3	1	2	3
# of Cylinders/Injectors	2	3	4	2	3	4
Type of Fuel System	Mech	Mech	ER	ECR	ECR	ECR
High Pressure Fuel Pump	$340	$340	$350	$340	$340	$350
Fuel Injectors (each)	$16	$16	$25	$80	$80	$80
Cost for Injectors (total)	$32	$48	$100	$160	$240	$320
Fuel Rail				$100	$100	$100
Computer			$300	$280	$280	$280
Sensors, Wiring, Bearings, etc.	$68	$82	$189	$231	$625	$639
Total Fuel System Cost	$440	$470	$939	$1,111	$1,205	$1,309
Incremental Cost				$671	$735	$370

Mech=Mechanical Fuel Injection; ER=Electronic Rotary Injection; ECR=Electronic Common Rail Injection

Note that engines in the 50 to 75 hp range (represented in Table 6.2-22 by the 80 hp engine) are assumed to have electronic rotary fuel-injection systems as a baseline configuration while smaller engines are assumed to have mechanical fuel injection (see section II.A of the preamble and section 4.1 of the RIA for more discussion on why this is a valid assumption). On an incremental basis, the costs for common rail fuel injection are much lower when working from an electronic rotary baseline because the electronic fuel pump and the computer are already part of the system. This explains the large difference in fuel system costs for the 80 hp engine relative to the 20 and 35 hp engines.

The costs shown in Table 6.2-22 show consistency for all elements across the power range. This is because most of the cost elements – fuel pump, costs per injector, and a computer – have little to no relation to engine size or engine displacement. The primary cost element that changes for each of the example engines shown is that for the total cost of injectors. For this reason, the costs can be more easily understood by separating the per injector cost out from the rest of the system. This was done for the costs shown in Table 6.2-23, which also builds on the manufacturer costs shown in Table 6.2-22 to generate costs to the user in the same manner as done for other hardware system costs, as discussed above. We have broken out the fuel system costs this way to make possible a cost equation that applies to all engines. Unlike the other cost equations we have generated, the cost equation for fuel systems uses the number of injectors (i.e., the number of cylinders) as the dependent variable rather than using engine displacement. This equation is presented below in Section 6.2.2.6.3.

Table 6.2-23
Incremental Fuel System Costs – Costs to the User

EPA Estimated Incremental Fuel System Costs for DI Engines ($2002)						
Horsepower	20		35		80	
Number of Cylinders (# of injectors)	2		3		4	
	per Injector	Remaining System	per Injector	Remaining System	per Injector	Remaining System
Cost to Manufacturer	$65	$551	$65	$551	$56	$152
Warranty Cost -- Near Term (3% claim rate)	$8	$44	$8	$44	$7	$14
Mfr. Carrying Cost (4%) -- Near Term	$3	$22	$3	$22	$2	$6
Total Cost to Dealer -- Near Term	$75	$617	$75	$617	$65	$173
Dealer Carrying Cost (3%) -- Near Term	$2	$19	$2	$19	$2	$5
Total Cost to Buyer -- Near Term	$78	$636	$78	$636	$67	$178
Warranty Cost -- Long Term (1% claim rate)	$3	$15	$3	$15	$2	$5
Mfr. Carrying Cost (4%)-- Long Term	$3	$22	$3	$22	$2	$6
Total Cost to Dealer -- Long Term	$70	$588	$70	$588	$60	$163
Dealer Carrying Cost (3%) -- Long Term	$2	$18	$2	$18	$2	$5
Subtotal	$72	$605	$72	$605	$62	$168
Total Cost to Buyer -- Long-Term w/ learning	$58	$484	$58	$484	$50	$134

Remaining System includes the fuel pump, fuel rail, computer, wiring, and necessary sensors.

Note that these costs are projected to be incurred only on 25 to 75 hp DI engines. Note also that, in determining aggregate variable costs for fuel-injection systems, we have attributed half of the costs to the Tier 4 standards. We have done this for two reasons: penetration of electronic fuel systems into the market and user benefits associated with the new fuel systems. First, we are projecting that, by 2008, some engines in the 25 to 75 hp range will already be equipped with electronic fuel systems independent of this rule. This is due to the natural progression of electronic fuel systems currently available in larger power engines into some of the smaller power engines. In fact, recent certification data prove that this is already happening, as discussed in section 4.1.4 of this RIA. During our discussions with some engine companies, they have indicated that they intend to use electronic fuel system technologies to comply with the existing Tier 3 standards in the 50 to 100 hp range. These manufacturers have informed us that these electronic fuel systems will also be sold on engines in the 25 to 50 hp range for those engine product lines built on the same platform as engines over 50 hp. In addition, there are end-user benefits associated with electronic fuel systems, such as better torque response, lower noise, easier servicing via on-board diagnostics, and better engine startability. Because we are not able to predict the precise level of penetration of electronic fuel systems, nor are we able to quantify the monetary value of the end-user benefits, we have accounted for these two effects by attributing half of the costs of the electronic fuel systems to the Tier 4 standards.

6.2.2.6.2 Cooled EGR System Costs

Cost estimates for cooled EGR systems were developed by ICF Consulting under contract to EPA.[37] The incremental manufacturer costs for cooled EGR systems are shown in Table 6.2-24.

Table 6.2-24
Cooled EGR System – Costs to Manufacturers

ICF Estimated Cooled EGR System Costs to Manufacturers ($2002)			
Horsepower	20	35	1000
Displacement (L)	1	2	24
EGR Cooler	$36	$63	$289
EGR Bypass	$15	$16	$30
Electronic EGR Valve	$14	$15	$88
EGR Total Cost to Manufacturer	$66	$95	$413

Building on these manufacturer costs, we estimated the costs to the user assuming the warranty claim rates and learning effects already discussed. These results are shown in Table 6.2-25. Included in these costs are costs associated with additional cooling that may be needed to reject the heat generated by the cooled EGR system or other in-cylinder technologies. These costs were not included in the proposal. Such additional cooling might take the form of a larger radiator and/or a larger or more powerful cooling fan. Based on cost estimates from our Nonconformance Penalty rule (67 FR 51464). In the support document for the NCP rule,[38] we estimated the costs associated with such additional cooling at $130 for a light heavy-duty vehicle (~200hp) and $300 for a heavy heavy-duty vehicle (~500hp), inclusive of *vehicle* manufacturer mark ups. Here, we have used these values to generate a curve with horsepower as the dependent variable. That curve is $0.60 + $16.7(x), with an R^2=1 and where "x" represents horsepower. Using this curve and the horsepowers shown in Table 6.2-25 we were able to estimate the costs for additional cooling. The results shown in Table 6.2-25 include a three percent dealer carrying cost.

Table 6.2-25
Cooled EGR System – Costs to the User

EPA Estimated Cooled EGR Costs ($2002)			
Horsepower	20	35	1000
Displacement (L)	1	2	24
EGR System Cost to Manufacturer	$66	$95	$413
Warranty Cost -- Near Term (3% claim rate)	$8	$10	$34
Mfr. Carrying Cost (4%) -- Near Term	$3	$4	$17
Total Cost to Dealer -- Near Term	$77	$109	$463
Dealer Carrying Cost (3%) -- Near Term	$2	$3	$14
EGR System Cost to Buyer -- Near Term	$79	$112	$477
Warranty Cost -- Long Term (1% claim rate)	$3	$3	$11
Mfr. Carrying Cost (4%)-- Long Term	$3	$4	$17
Total Cost to Dealer -- Long Term	$71	$102	$441
Dealer Carrying Cost (3%) -- Long Term	$2	$3	$13
Subtotal	$73	$105	$454
EGR System Cost to Buyer -- Long Term w/ learning	$59	$84	$363
Heat rejection cost to Buyer (incl 3% dealer carrying cost) – Near Term	$29	$38	$610
Heat rejection cost to Buyer (incl 3% dealer carrying cost) – Long Term	$23	$31	$488
Total EGR-related Costs to Buyer -- Near-term	$108	$151	$1,087
Total EGR-related Costs to Buyer -- Long-term	$82	$115	$851

Despite the presence of cost data for a 20hp engine in Table 6.2-25, we are projecting that only engines in the 25 to 50 hp range (in 2013) and engines over 750 hp will need to add cooled EGR (in 2011), or use some other equally effective approach having presumably similar costs, to comply with the new engine standards. All the costs associated with these systems have been attributed to compliance with the new emission standards (i.e., we have not attributed any costs to user benefits).

6.2.2.6.3 Conventional Technology Cost Estimation Functions

In the same manner as already described for exhaust emission-control devices, we were able to calculate cost equations for cooled EGR systems (inclusive of additional cooling). For fuel systems, rather than a linear regression, we simply expressed the fuel system costs as a function of the number of fuel injectors, and then added on the costs associated with the rest of the system. The rest of the system includes the fuel pump, the computer, wiring and sensors, which should not change relative to engine size or displacement. This way, the functions could be applied to the wide array of engines in the nonroad fleet to determine the total costs or per unit costs for this hardware. The cost estimation functions for these technologies are shown in Table 6.2-26.

Table 6.2-26
Costs for Conventional Technologies as a
Function of the Indicated Parameter (x represents the dependent variable)
$2002

Technology	Applicable Hp Range	Dependent Variable	Equation	R^2
Fuel System Costs – DI Only				
Near Term	25≤hp<50	# of cylinders	$78(x) + $636	—[a]
Long Term	25≤hp<50		$58(x) + $484	
Near Term	50≤hp<75		$67(x) + $178	—[a]
Long Term	50≤hp<75		$50(x) + $134	
Cooled EGR System (inclusive of additional cooling)				
Near Term	25≤hp<50; >750hp	displacement	$43(x) + $65	1
Long Term	25≤hp<50; >750hp		$33(x) + $48	1

[a]Not applicable because a linear regression was not used.

6.2.2.7 Summary of Engine Variable Cost Equations

Engine variable costs are discussed in detail in Sections 6.2.2.1 through 6.2.2.6. For engine variable costs, we have generated cost estimation equations as a function of engine displacement or number of cylinders. These equations are summarized in Table 6.2-27. Note that not all equations were used for all engines; equations were used in the manner shown in Table 6.2-27. We have calculated the aggregate engine variable costs and present them later in this chapter and in Chapter 8.

Table 6.2-27
Summary of Cost Equations for
Engine Variable Costs (x represents the dependent variable)

Engine Technology	Time Frame[a]	Cost Equation	Dependent Variable (x)	How Used
NOx Adsorber System	Near term Long term	\$103(x) + \$183 \$83(x) + \$160	Displacement[b]	>75 hp engines according to phase-in of NRT4 NOx std.
CDPF System	Near term Long term	\$146(x) + \$75 \$112(x) + \$57	Displacement	>25 hp engines according to NRT4 PM std.
CDPF Regen System – IDI engines	Near term Long term	\$20(x) + \$293 \$16(x) + \$223	Displacement	IDI engines adding a CDPF
CDPF Regen System – DI engines	Near term Long term	\$10(x) + \$147 \$8(x) + \$111	Displacement	DI engines adding a CDPF
DOC	Near term Long term	\$18(x) + \$116 \$18(x) + \$110	Displacement	<25 hp engines beginning in 2008; 25-75 hp engines 2008 thru 2012
CCV System	Near term Long term	\$2(x) + \$34 \$2(x) + \$24	Displacement	All turbocharged engines when they first meet a Tier 4 PM std.
Cooled EGR System w/ additional cooling	Near term Long term	\$43(x) + \$65 \$33(x) + \$48	Displacement	25-50 hp engines beginning in 2013; >750hp engines beginning in 2011
Common Rail Fuel Injection (mechanical fuel system baseline)	Near term Long term	\$78(x) + \$636 \$58(x) + \$484	# of cylinders/ injectors	25-50 hp DI engines when they add a CDPF
Common Rail Fuel Injection (electronic rotary fuel system baseline)	Near term Long term	\$67(x) + \$178 \$50(x) + \$134	# of cylinders/ injectors	50-75 hp DI engines when they add a CDPF

[a] Near term = years 1 and 2; Long term = years 3+. Explanation of near term and long term is in Section 6.1.
[b] Displacement refers to engine displacement in liters.

6.2.3 Engine Operating Costs

We are projecting that a variety of new technologies will be introduced to enable nonroad engines to meet the Tier 4 emission standards. Primary among these are advanced emission-control technologies and low-sulfur diesel fuel. The technology enabling benefits of low-sulfur diesel fuel are described in Chapter 4. The incremental cost for low-sulfur fuel is described in Chapter 7 and is not presented here. The new emission-control technologies are themselves expected to introduce additional operating costs in the form of increased fuel consumption and increased maintenance demands. Operating costs are estimated over the life of the engine and are expressed in terms of cents/gallon of fuel consumed. In Section 6.5 we present these lifetime operating costs as a net present value (NPV) in 2002 dollars for several example pieces of equipment.

A note of clarification needs to be added here. In Chapter 8 we present aggregate operating costs. Every effort is made to be clear what costs are related to (1) the incremental increase in the cost of fuel (due to the lower sulfur level), and (2) what costs are related to the expected change in maintenance demands and the expected change in fuel consumption. The operating costs discussed in this section are only the latter—maintenance related costs and/or savings and fuel consumption costs. Increased costs associated with the lowering of sulfur in nonroad diesel fuel are discussed in detail in Chapter 7. The cent-per-gallon costs presented in Chapter 7, along with the cent-per-gallon costs and savings presented here, are then combined with projected fuel volumes to generate the aggregate costs of the fuel program in this final rule.

Total operating costs include the following elements: the change in maintenance costs associated with applying new emission controls to the engines; the change in maintenance costs associated with low-sulfur fuel such as extended oil-change intervals (extended oil change intervals results in maintenance savings); the change in fuel costs associated with the incrementally higher costs for low-sulfur fuel (see Chapter 7), and the change in fuel costs due to any fuel consumption impacts associated with applying new emission controls to the engines. This latter cost is attributed to the CDPF and its need for periodic regeneration, which we estimate may result in a small increase in fuel consumption, as discussed in more detail below. Maintenance costs associated with the new emission controls on the engines are expected to increase, since these devices represent new hardware and therefore new maintenance demands. Offsetting this cost increase will be a cost savings due to an expected increase in oil-change intervals, because low-sulfur fuel is far less corrosive than current nonroad diesel fuel. Less corrosion corresponds with a slower acidification rate (i.e., less degradation) of the engine lubricating oil and therefore more operating hours between oil changes.

6.2.3.1 Operating Costs Associated with Oil-Change Maintenance for New and Existing Engines

We estimate that reducing fuel sulfur to 500 ppm will reduce engine wear and oil degradation to the existing fleet of nonroad diesel engines, as well as locomotive and marine diesel engines. Reducing fuel sulfur to 15 ppm will further reduce engine wear and oil degradation. These improvements provide a savings to users of this equipment. The cost savings will also be realized by the owners of future nonroad engines that are subject to the emission standards in this final rule. As discussed below, these maintenance savings have been estimated to be greater than 3 cents/gallon when comparing current uncontrolled fuel to 15 ppm sulfur fuel.

We have identified a variety of benefits from the low-sulfur diesel fuel. These benefits are summarized in Table 6.2-28.

Table 6.2-28.
Engine Components Potentially Affected by Lower Sulfur Levels in Diesel Fuel

Affected Components	Effect of Lower Sulfur	Potential Impact on Engine System
Piston Rings	Reduced corrosion wear	Extended engine life and less frequent rebuilds
Cylinder Liners	Reduced corrosion wear	Extended engine life and less frequent rebuilds
Oil Quality	Reduced deposits, reduced acid build-up, and less need for alkaline additives	Reduce wear on piston ring and cylinder liner and less frequent oil changes
Exhaust System (tailpipe)	Reduced corrosion wear	Less frequent part replacement
Exhaust Gas Recirculation System	Reduced corrosion wear	Less frequent part replacement

The monetary value of these benefits over the life of the equipment will depend upon the length of time that the equipment operates on low-sulfur diesel fuel and the degree to which engine and equipment manufacturers specify new maintenance practices and the degree to which equipment operators change engine maintenance patterns to take advantage of these benefits. For equipment near the end of its life in the 2008 time frame, the benefits will be quite small. However, for equipment produced in the years immediately preceding the introduction of 500 ppm sulfur fuel, the savings will be substantial. Additional savings will be realized in 2010 with the introduction of 15 ppm sulfur fuel.

We estimate the single largest savings will be the impact of lower sulfur fuel on oil-change intervals. We have estimated the extension of oil-change intervals realized by 500 ppm sulfur fuel in 2007 and the additional extension resulting from 15 ppm sulfur fuel in 2010. These estimates are based on our analysis of publically available information from nonroad engine manufacturers. Due to the wide range of diesel fuel sulfur levels that nonroad engines may currently see around the world, engine manufacturers specify different oil-change intervals as a function of diesel sulfur levels. We have used these data as the basis for our analysis. Taken together, when compared with the relatively high sulfur levels in current nonroad diesel fuel, we estimate the use of 500 ppm sulfur fuel will enable an oil-change interval extension of 31 percent, while 15 ppm sulfur fuel will enable an oil-change interval extension of 35 percent relative to current products.[39]

We present here a fuel cost savings attributed to the oil-change interval extension in terms of a cent-per-gallon operating cost. Table 6.2-29 shows the calculation of cent-per-gallon savings for various power segments of the nonroad fleet, and the locomotive and marine segments, for both the 500 ppm fuel and the 15 ppm fuel. The brake specific fuel consumption (BSFC), average hp, average activity, and average load factor data shown in the table are from our nonroad model.[40] The existing and new NRLM fleets will realize the savings associated with the

500 ppm fuel for the years 2007 through 2010, and the the savings associated with the 15 ppm fuel program for the years 2010 and beyond. We estimate that an oil-change interval extension of 31 percent enabled by 500 ppm sulfur fuel results in a weighted savings in fuel operating costs of 2.9 cents/gallon for the nonroad fleet. We project an additional weighted cost savings of 0.3 cents/gallon for the oil-change interval extension enabled by 15 ppm sulfur. Note that the weighted savings are determined using the fuel use weightings shown in Table 6.2-29. For locomotive and marine engines, these savings are 1 cent/gallon and 0.1 cent/gallon for the 500 ppm step and the 15 ppm step, respectively.

Thus, for the nonroad fleet as a whole, beginning in 2010, nonroad equipment users can realize an operating cost savings of 3.2 cents/gallon relative to current engines. For a typical 100 hp nonroad engine, this represents a net present value lifetime savings of more than $500. For locomotive and marine engines the savings are estimated at 1.1 cents/gallon, which represents a net present value lifetime savings of more than $2000.

Table 6.2-29. Oil-Change Maintenance Savings for Existing and New Nonroad, Locomotive, and Marine Engines ($2002)

Oil Change Savings due to Low S	Units	Nonroad Engines								Locomotive	Marine
Rated Power	hp	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<175	175<=hp<300	300<=hp<600	600<=hp<750	>750hp		
BSFC	lbm/hp-hr	0.408	0.408	0.408	0.390	0.367	0.367	0.367	0.367	0.367	0.367
Fuel Density	lbm/gallon	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Population Weighted Avg. Horsepower	hp	16	37	60	109	234	413	694	1282	1282	1282
Population Weighted Avg. Activity	hrs/year	523	582	764	675	537	619	947	1130	1130	1130
Population Weighted avg. Load Factor	% full load	0.41	0.44	0.40	0.47	0.57	0.57	0.56	0.57	0.57	0.57
Sump Oil Capacity	L	1.58	3.62	5.83	10.55	22.68	40.07	67.33	124.32	124.32	124.32
Base Oil Change Interval -- 3000 ppm S	hrs	250	250	250	250	250	250	250	250	250	250
Control Oil Change Interval -- 500 ppm S	hrs	327.5	327.5	327.5	327.5	327.5	327.5	327.5	327.5	327.5	327.5
Labor Cost Per Oil Change	$	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$100.00	$100.00	$100.00
Cost of Oil Per Oil Change	$	$3.16	$7.25	$11.65	$21.11	$45.35	$80.13	$134.66	$248.65	$248.65	$248.65
Cost of Oil Filter Per Oil Change	$	$18.00	$18.00	$18.00	$18.00	$35.00	$35.00	$35.00	$70.00	$70.00	$70.00
Total Cost Per Oil Change	$	$71.16	$75.25	$79.65	$89.11	$130.35	$165.13	$219.66	$418.65	$418.65	$418.65
Fuel Consumption in 3000 ppm Oil Interval	gallons	96	237	349	699	1732	3043	5044	9463	9463	9463
Fuel Consumption in 500 ppm Oil Interval	gallons	125	310	457	916	2269	3986	6608	12396	12396	12396
Oil Change Cost/Gallon fuel in 3000 ppm Interval	$/gallon	$0.74	$0.32	$0.23	$0.13	$0.08	$0.05	$0.04	$0.04	$0.04	$0.04
Oil Change Cost/Gallon fuel 500 ppm Interval	$/gallon	$0.57	$0.24	$0.17	$0.10	$0.06	$0.04	$0.03	$0.03	$0.03	$0.03
Cost Differential -- 3000 to 500 ppm S	$/gallon	$0.176	$0.075	$0.054	$0.030	$0.018	$0.013	$0.010	$0.010	$0.010	$0.010
Control Oil Change Interval -- 15 ppm S	hrs	337.5	337.5	337.5	337.5	337.5	337.5	337.5	337.5	337.5	337.5
Labor Cost Per Oil Change	$	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$100.00	$100.00	$100.00
Cost of Oil Per Oil Change	$	$3.16	$7.25	$11.65	$21.11	$45.35	$80.13	$134.66	$248.65	$248.65	$248.65
Cost of Oil Filter Per Oil Change	$	$18.00	$18.00	$18.00	$18.00	$35.00	$35.00	$35.00	$70.00	$70.00	$70.00
Total Cost Per Oil Change	$	$71.16	$75.25	$79.65	$89.11	$130.35	$165.13	$219.66	$418.65	$418.65	$418.65
Fuel Consumption in 500 ppm Oil Interval	gallons	125	310	457	916	2269	3986	6608	12396	12396	12396
Fuel Consumption in 15 ppm Oil Interval	gallons	129	320	471	944	2338	4108	6809	12774	12774	12774
Oil Change Cost/Gallon fuel in 500 ppm Interval	$/gallon	$0.57	$0.24	$0.17	$0.10	$0.06	$0.04	$0.03	$0.03	$0.03	$0.03
Oil Change Cost/Gallon fuel in 15 ppm Interval	$/gallon	$0.55	$0.24	$0.17	$0.09	$0.06	$0.04	$0.03	$0.03	$0.03	$0.03
Cost Differential -- 500 to 15 ppm S	$/gallon	$0.017	$0.007	$0.005	$0.003	$0.002	$0.001	$0.001	$0.001	$0.001	$0.001
Cost Differential -- 3000 to 15 ppm S	$/gallon	$0.193	$0.082	$0.059	$0.033	$0.020	$0.014	$0.011	$0.011	$0.011	$0.011
Fuel Use Weightings	% total	1.8%	5.2%	9.2%	31.6%	23.1%	18.8%	4.1%	6.2%		

(1) Oil-change intervals are from William Charmley memo to docket.[41]
(2) Labor costs are from ICF Consulting under contract to EPA.[42]
(3) Oil use estimates are based on sump volumes scaled to engine displacement and, as such, they show differences for each power category. The labor and filter costs are average values over a broad power range and, as such, may overstate the cost for some engines while understating the costs for others.

The savings shown in Table 6.2-29 will occur without additional new cost to the equipment owner beyond the incremental cost of the low-sulfur diesel fuel although these savings are dependent on changes to existing maintenance schedules. Such changes seem likely given the magnitude of the potential savings. We have not estimated the value of the savings from the other benefits listed in Table 6.2-28. Therefore, we believe the 3.2 cents/gallon savings underestimates actual cost savings as it accounts only for the impact of low-sulfur fuel on oil-change intervals.

Operating costs (savings) associated with oil-change maintenance are split evenly between NOx and PM control.

6.2.3.2 Operating Costs Associated with CDPF Maintenance for New CDPF-Equipped Engines

The maintenance demands associated with the addition of new CDPF hardware are discussed in Section 4.1.1.3.4. To avoid underestimating costs, we have used a maintenance interval of 3,000 hours for engines under 175 hp and 4,500 hours for engines over 175 hp, both of which are the minimum allowable maintenance intervals specified in our regulations (i.e., manufacturers are precluded by regulation from requiring more frequent maintenance, and we believe they may require less frequent maintenance than these minimum allowable maintenance intervals). We have estimated costs associated with the maintenance at $65 for engines up to 600 hp and $260 per event for engines over 600 hp. The calculations for CDPF maintenance are shown in Table 6.2-30. Weighting the savings in each power range by the fuel-use weightings shown in the table, we can calculate the fleet weighted maintenance costs as 0.6 cents/gallon, which will be incurred only by new engines equipped with a CDPF. Operating costs associated with CDPF maintenance are attributed entirely to PM control.

Table 6.2-30
CDPF Maintenance Costs for New CDPF-Equipped Engines ($2002)

PM Filter Maintenance Costs	Units	Nonroad Engines							
Rated Power	hp	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<175	175<=hp<300	300<=hp<600	600<=hp<750	>750hp
BSFC	lbm/hp-hr	0.408	0.408	0.408	0.390	0.367	0.367	0.367	0.367
Fuel Density	lbm/gallon	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Population Weighted Avg. Horsepower	hp	16	37	60	109	234	413	694	1282
Population Weighted Avg. Activity	hrs/year	523	582	764	675	537	619	947	1130
Population Weighted avg. Load Factor	% full load	0.409	0.441	0.404	0.468	0.573	0.570	0.562	0.571
Filter Maintenance Interval	hours		3,000	3,000	3,000	4,500	4,500	4,500	4,500
Filter Maintenance Cost Materials	$/event		$0	$0	$0	$0	$0	$0	$0
Filter Maintenance Labor	$/event		$65	$65	$65	$65	$65	$130	$260
Total Filter Maintenance Cost per event	$/event		$65	$65	$65	$65	$65	$130	$260
Fuel Use Between Maintenance Interval	gallons/period		2,844	4,185	8,391	31,174	54,767	90,791	170,326
Maintenance Cost	$/gallon		$0.023	$0.016	$0.008	$0.002	$0.001	$0.001	$0.002
Fuel Use Weightings	% total	1.8%	5.2%	9.2%	31.6%	23.1%	18.8%	4.1%	6.2%

Labor costs are from ICF Consulting under contract to EPA.[43]

6.2.3.3 Operating Costs Associated with Fuel Economy Impacts on New Engines

6.2.3.3.1 What Are the Estimated Fuel Economy Impacts?

The high efficiency emission-control technologies expected to be applied to meet the PM standards for engines greater than 25 hp and the NOx standards for engines greater than 75 hp involve wholly new system components integrated into engine designs and calibrations and, as such, may be expected to change the fuel consumption characteristics of the overall engine design. After reviewing the likely technology options available to the engine manufacturers, we believe the integration of the engine and exhaust emission-control systems into a single synergistic emission-control system will lead to nonroad engines that can meet demanding emission-control targets with only a small impact on fuel consumption. Technology improvements have historically eliminated these marginal impacts in the past and it is our expectation that this kind of continuing improvement will eliminate the modest impact estimated here. However, because we cannot project the time frame for this improvement to be realized, we have included this impact in our cost estimates for the full period of the program to avoid underestimating costs.

6.2.3.3.1.1 CDPF Systems and Fuel Economy

Diesel particulate filters are anticipated to provide a step-wise decrease in diesel particulate (PM) emissions by trapping and oxidizing the diesel PM. The trapping of the very fine diesel PM is accomplished by forcing the exhaust through a porous filtering media with extremely small openings and long path lengths.[P] This approach results in filtering efficiencies for diesel PM greater than 90 percent but requires additional pumping work to force the exhaust through these small openings. The impact of this additional pumping work on fuel consumption is dependent on engine operating conditions. At low exhaust flow conditions (i.e., low engine load, low turbocharger boost levels), the impact is so small that it typically cannot be measured, while at very high load conditions, with high exhaust flow conditions, the fuel economy impact can be as large as one to two percent.[44,45] We have estimated that the average impact of this increased pumping work will be equivalent to an increase fuel consumption of approximately one percent.[46]

Under conditions typical of much of nonroad engine operation, the soot stored in the PM filter will be regenerated passively using the heat of the exhaust gas promoted by catalyst materials. We have performed an analysis of the expected exhaust temperatures for several typical in-use operating cycles, as described in Section 4.1.3. That analysis shows that for a many nonroad engines passive regeneration can be expected. Under some conditions, including very low ambient temperatures, or extended low load operation, the exhaust temperature of the engine may not be hot enough to ensure complete passive regeneration. We believe some manufacturers will address this situation by employing active backup regeneration systems that

[P] Typically, the filtering media is a porous ceramic monolith or a metallic fiber mesh. We refer to it as a “filter trap” in Table 6.2-13.

provide supplemental heat to initiate regeneration, as discussed in Section 4.1. Also, as explained in Section 6.2.2.3, we are conservatively costing active regeneration systems for all engines using a CDPF system. We have done this because we think it is unlikely that nonroad engine manufacturers will be able to accurately predict which engines will be operated in a manner conducive to passive regeneration and which engines will require periodic active regeneration. There will be no fuel economy impact for nonroad engines that have an active regeneration technology but experience passive regeneration in use. Examples of current active PM filter systems that do not benefit from low-sulfur diesel fuel, nor catalytic coatings to promote regeneration, require additional fuel supplementation of approximately two percent for active filter regeneration.[47] Given the new requirements for clean diesel fuel in this final rule, the ability to use catalytic coatings to promote soot oxidation, and the fact that many kinds of nonroad equipment are expected to operate in a way that passive regeneration will occur, we believe the average fuel economy impact of the backup regeneration systems will be no more than one percent.

We have projected that engines between 25 hp to 75 hp will comply with the PM standard of 0.02 g/bhp-hr using a CDPF system including a backup active regeneration system. The NOx control systems expected in this power category are not advanced catalyst-based systems and, as such, have limited ability to recover fuel economy through timing advance or other in-cylinder NOx control strategies, as discussed below. We therefore project that a two percent fuel economy impact (i.e., one percent due to backpressure and one percent due to use of backup regeneration systems) will occur for engines between 25 hp and 75 hp. We believe manufacturers will overcome this impact in the long term through continuing technology refinement, as has historically happened. However, to avoid underestimating costs, we have included this two percent impact for the duration of the program.

For engines under 25 hp we have projected no need to use CDPF technologies to comply with the PM standards in the final rule. We therefore estimate no fuel consumption impact from the CDPF for this category.

We believe engines all engines between 75 hp and 750 hp and mobile gensets above 750hp will use integrated NOx and PM control technologies to comply with the new emission standards. The advanced catalyst-based emission-control technology that we project industry will use to meet the new NOx standard offers the opportunity to improve fuel economy, as described in the following section. Based on those projected improvements, we have estimated a net impact on fuel consumption of one percent for engines between 75 and 750 hp as well as gensets >750 hp with CDPF technology and NOx technology. Future technology improvements are likely to recover this fuel consumption impact; however, to avoid underestimating costs, we have assumed that a one-percent fuel consumption impact persists for the duration of the emission-control program.

At this time we are not setting a NOx standard for nonroad mobile machine engines >750 hp based on the use of advanced NOx catalyst based technologies (see Preamble Section II.A). These engines, like the smaller engines between 25 and 75 hp, are projected to use diesel particulate filter technologies to meet the Tier 4 PM standards. Therefore like the 25 to 75 hp engines, we are estimating that nonroad mobile machines above 750 hp will have a two percent fuel economy impact (i.e., one percent due to backpressure and one percent due to use of backup regeneration systems). We believe manufacturers will overcome this impact in the long term through continuing technology refinement, as has historically happened. However, to avoid underestimating costs, we have included this two percent impact for the duration of the program.

6.2.3.3.1.2 NOx Control and Fuel Economy

NOx adsorbers are expected to be the primary technology to reduce NOx emissions for engines between 75 and 750 hp as well as for mobile gensets above 750 hp. NOx adsorbers work by storing NOx emissions under fuel-lean operating conditions (normal diesel engine operating conditions) and then by releasing and reducing the stored NOx emissions over a brief period of fuel-rich engine operation. This brief periodic NOx release and reduction step is directly analogous to the catalytic reduction of NOx over a gasoline three-way catalyst. For this catalyst function to occur, the engine exhaust constituents and conditions must be similar to normal gasoline exhaust constituents. That is, the exhaust must be fuel rich (devoid of excess oxygen) and hot (over 250ºC). Although it is anticipated that nonroad diesel engines, like highway diesel engines, can be made to operate in this way, it is anticipated that fuel economy during operation under these conditions will be worse than normal. This increase in fuel consumption can be minimized by carefully controlling engine air-fuel ratios using the control systems we anticipate will be used to meet the Tier 3 emission standards. The lower the engine air-fuel ratio, the lower the amount of fuel that must be added to reach rich conditions. In the ideal case where the engine air-fuel ratio is at the stoichiometric level and additional fuel is required only as a NOx reductant, the fuel economy penalty is nearly zero. We are projecting that practical limitations on controlling engine air-fuel ratio will mean that the NOx adsorber release and reduction cycles will lead to a one percent decrease in the engine fuel economy.[48] We estimate that this fuel economy impact can be regained through optimization of the engine-PM trap-NOx adsorber system, as discussed below.

In addition to the NOx release and regeneration event, another step in NOx adsorber operation may affect fuel economy. As discussed earlier, sulfur affects NOx adsorbers even at the low fuel-sulfur levels we are adopting. As discussed in Chapter 4, this effect can (and must) be reversed through a periodic “desulfation” event. The desulfation of the NOx adsorber is accomplished in a similar manner to the NOx release and regeneration cycle described above. However, it is anticipated that the desulfation event will require extended operation of the diesel engine at rich conditions.[49] This rich operation will, like the NOx regeneration event, require an increase in the fuel consumption rate and will cause an associated decrease in fuel economy. This loss in fuel consumption is directly proportional to the amount of sulfur in diesel fuel. The frequency of desulfation is therefore a function of the fuel sulfur level and the fuel consumption rate. Since the desulfation frequency and the associated fuel consumption impacts are proportional only to fuel rate and to fuel sulfur levels, the projected fuel consumption impacts at 15 ppm sulfur are the same for both highway and nonroad diesel engines. With a 15 ppm fuel sulfur cap, we are projecting that fuel consumption for desulfation will increase by no more than one percent, which we believe can be regained through optimization of the engine-CDPF-NOx adsorber system, as discussed below.

While NOx adsorbers impact fuel economy by requiring nonpower-producing fuel consumption to function properly, they are not unique among NOx control technologies in this way. In fact, NOx adsorbers are likely to have a very favorable tradeoff between NOx emissions and fuel economy compared with our projected technologies for meeting Tier 3 NOx standards—cooled EGR and injection timing retard. EGR requires the delivery of exhaust gas from the exhaust manifold to the intake manifold of the engine and causes a decrease in fuel economy for two reasons. The first of these reasons is that a certain amount of work is required to pump the EGR from the exhaust manifold to the intake manifold; this necessitates the use of intake throttling or some other means to accomplish this pumping. The second of these reasons is that heat in the exhaust, which is normally partially recovered as work across the turbine of the turbocharger, is instead lost to the engine coolant through the cooled EGR heat exchanger. In the end, cooled EGR is approximately 50 percent effective at reducing NOx below the current Tier 2 NOx levels. Injection timing retard is another strategy that can be employed to control NOx emissions. By retarding the introduction of fuel into the engine, and thus delaying the start of combustion, both the peak temperature and pressure of the combustion event are decreased; this lowers NOx formation rates and, ultimately, NOx emissions. Unfortunately, this also significantly decreases the thermal efficiency of the engine (lowers fuel economy) while also increasing PM emissions. As an example, retarding injection timing eight degrees can decrease NOx emissions by 45 percent, but this occurs at a fuel economy penalty of more than seven percent.[50]

Nonroad diesel engines generally rely primarily on charge-air-cooling and injection timing control (retarding injection timing) to meet Tier 2 NOx+NMHC emission standards. For Tier 3 compliance, we expect that engine manufacturers will use a combination of cooled EGR and injection timing control to meet the NOx standard. Because of the more favorable fuel economy trade-off for NOx control with EGR compared with timing control, we forecast that less reliance on timing control will be needed for Tier 3 than for Tier 2. Fuel economy will therefore not change even at this lower NOx level. Similarly for the 25-50 hp engines subject to a Tier 4 NOx standard of 3.3 g/hp-hr, we believe the NOx standard will not cause a change in fuel consumption. NOx adsorbers have a significantly more favorable trade-off between NOx emissions and fuel economy compared with cooled EGR or timing retard.[51] We expect NOx adsorbers to be able to accomplish a greater than 90 percent reduction in NOx emissions, while themselves consuming significantly less fuel than that lost through alternative NOx control strategies such as retarded injection timing.[Q] We therefore expect manufacturers to take full advantage of the NOx control capabilities of the NOx adsorber and project that they will decrease reliance on the more expensive (from a fuel economy standpoint) technologies, especially injection timing retard. We therefore predict that the fuel economy impact currently associated with NOx control from timing retard will be decreased by at least three percent. In other words, through the application of advanced NOx emission-control technologies, which are

[Q] We have estimated the fuel consumption rate for NOx regeneration and desulfation of the NOx adsorber as approximately 2 percent of total engine fuel consumption. This differs from an EPA contractor report by EF&EE estimating the total consumption to be approximately 2.5 percent of total fuel consumption. Additionally the contractor's estimate of NOx adsorber efficiency ranges from 80 to 90 percent, while we believe over 90 percent control is possible, as discussed in Chapter 4.

enabled by the use of low-sulfur diesel fuel, we expect the NOx trade-off with fuel economy to continue to improve significantly when compared with current technologies. This will result in much lower NOx emissions and potentially overall improvements in fuel economy. Improvements could easily offset the fuel consumption of the NOx adsorber itself and, in addition, at least half of the fuel economy impact projected to result from the application of the CDPF technology. Consequently, we are projecting a one percent fuel economy impact to result from this rule for engines between 75 and 750 hp as well as mobile gensets above 750 hp.

6.2.3.3.1.3 Fuel Economy Impacts for Engines without Advanced Emission-Control Technologies (engines under 25 hp)

The new NOx emission standard for engines under 25 hp is unchanged from the current Tier 2 level. The PM standard, however, decreases by almost 50 percent. We believe manufacturers will achieve this significant PM reduction through improvements in combustion system design, improvements in fuel system design and utilization, and through the use of diesel oxidation catalysts (DOCs). DOCs are expected to have no measurable effect on fuel consumption. However, changes to the engine designed to reduce PM emissions can lead to a reduction in fuel consumption, at least for direct-injected diesel engines. The potential range for improved fuel economy for engines of this size is unknown but experience with changes to engine design that improve combustion and reduce PM suggest that the improvement may be significant. However, because of the difficulty in projecting the future ratio of direct-injected and indirect-injected diesel engines for this portion of the nonroad market and the first order affect that this ratio has on average fleet consumption we have not attempted to account for this potential fuel economy improvement in our cost analysis. We therefore estimate no change in fuel consumption in our cost analyses for engines under 25 hp.

6.2.3.3.2 Costs Associated with these Fuel Economy Impacts

To calculate the costs associated with these fuel economy impacts, we have used a diesel fuel price, minus taxes, of 60 cents/gallon. To that, we have added the incremental cost per gallon for 15 ppm fuel. These incremental fuel costs are discussed in Chapter 7 as 7.0 cents/gallon. Using this 67 cent value, we apply the estimated fuel economy impact of an engine – 1% where both a CDPF and a NOx adsorber are added, and 2% where a CDPF is added and no NOx adsorber is present. This results in an increased operating cost for 75-750 hp engines of 0.67 cents/gallon (1% × 67 cents/gallon) for CDPF/NOx adsorber equipped engines and 1.34 cents/gallon for CDPF-only engines (2% × 67 cents/gallon). For 25-75 hp engines, and for >750 hp engines, where we estimate a two percent fuel economy impact, the estimated incremental cost is 1.34 cents/gallon. Importantly, these fuel economy impacts are incurred only on new engines; existing engines that do not meet the NRT4 standards will not see any fuel economy impact.

Operating costs associated with fuel economy impacts are attributed only to PM control.

6.2.3.4 Operating Costs Associated CCV Maintenance on New Engines

For CCV systems, we have used a maintenance interval of 675 hours for all engines and a cost per maintenance event of $8 to $48 for small to large engines. The 675 maintenance interval is chosen as twice the oil-change maintenance interval. CCV maintenance is assumed to be done during every other oil-change event; this results in $0 labor cost for CCV maintenance. The calculation of operating costs associated with CCV maintenance is shown in Table 6.2-31. The new CCV requirements apply only to turbocharged engines (naturally aspirated engines already have a closed crankcase requirement) so there are two cent/gallon values shown in Table 6.2-31 within each power range. The first value is the cent/gallon cost for a turbocharged engine while the weighted cent/gallon cost within the power range (i.e., weighted by the percentage of turbocharged engines). Using the fuel use weightings, we can calculate the fleetwide cent/gallon cost using these latter costs within each power range. The result is a 0.2 cent/gallon cost.

Operating costs associated with CCV maintenance are attributed evenly to NOx and PM control.

Table 6.2-31
Closed Crankcase Ventilation System
Maintenance Costs for New Turbocharged Engines ($2002)

CCV Maintenance Costs	Units	Nonroad Engines							
Rated Power	hp	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<175	175<=hp<300	300<=hp<600	600<=hp<750	>750hp
BSFC	lbm/hp-hr	0.408	0.408	0.408	0.390	0.367	0.367	0.367	0.367
Fuel Density	lbm/gallon	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Population Weighted Avg. Horsepower	hp	16	37	60	109	234	413	694	1282
Population Weighted Avg. Activity	hrs/year	523	582	764	675	537	619	947	1130
Population Weighted avg. Load Factor	% full load	0.409	0.441	0.404	0.468	0.573	0.570	0.562	0.571
CCV Filter Replacement Interval	hours	675	675	675	675	675	675	675	675
CCV Filter Replacement Cost	$/event	$8	$8	$8	$8	$10	$12	$24	$48
Filter Maintenance Labor	$/event	$0	$0	$0	$0	$0	$0	$0	$0
Total Filter Maintenance Cost per event	$/event	$8.00	$8.00	$8.00	$8.00	$9.60	$12.00	$24.00	$48.00
Fuel Use Between Maintenance Interval	gallons/period	259	640	942	1,888	4,676	8,215	13,619	25,549
Turbcharged Fleet Fraction	[%]	0%	2%	9%	62%	99%	100%	100%	100%
Maintenance Cost for engines adding CCV	$/gallon	$0.031	$0.013	$0.008	$0.004	$0.002	$0.001	$0.002	$0.002
Maintenance Cost - weighted for all engines	$/gallon	$0.000	$0.000	$0.001	$0.003	$0.002	$0.001	$0.002	$0.002
Fuel Use Weightings	% total	1.8%	5.2%	9.2%	31.6%	23.1%	18.8%	4.1%	6.2%

6.3 Equipment-Related Costs

Costs of control to equipment manufacturers include fixed costs (those costs for equipment redesign and for tooling), and variable costs (for new hardware and increased equipment assembly time). According to the PSR Sales Database for the year 2000,[52] there are approximately 600 nonroad equipment manufacturers using diesel engines in several thousand different equipment models. We realize that the time needed for equipment manufacturers to make the necessary changes on such a large number of equipment models will vary significantly from manufacturer to manufacturer and from application to application. One of the goals of the transition program for equipment manufacturers is to reduce the potential for anomalously high costs for individual equipment models by providing significant additional time (up to seven years) for developing less costly designs or to align the changes with an already scheduled redesign. To remain conservative in our cost estimates, we have not factored into the analysis the significant potential cost savings associated with these provisions; Section 6.3.3 explores the potential cost savings of the transition program for equipment manufacturers.

6.3.1 Equipment Fixed Costs

6.3.1.1 Equipment Redesign Costs

The projected modifications to equipment resulting from the new emission standards relate to the need to package emission-control hardware that engine manufacturers will incorporate into their engines. As noted in Section 6.2, the additional emission-control hardware is proportional in size to engine displacement by a 4:1 ratio (1.5 × engine displacement for both the CDPF and the NOx adsorber, and 1.0 × displacement for the DOC that is part of the NOx adsorber system). We expect that equipment manufacturers will have to redesign their equipment to accommodate this new volume of hardware. Some redesigns will be major in scale, while others will be minor. For example, redesign may simply involve bolting the new devices onto the existing design, but in most cases we expect devices to be designed into the piece of equipment in a way that their presence would not be obvious to the casual observer and, in fact, for some equipment they may simply replace the existing muffler with no redesign needed. Additionally, a redesign to accommodate a DOC (1.0 × engine displacement) should be less intensive than a redesign to accommodate a CDPF/NOx adsorber system. Finally, for engines in the 75-750 hp range where the final rule phases in new NOx standards, we assume that the redesign effort for those final pieces of complying equipment (i.e., when the phase-in goes from 50 percent to 100 percent) will be less costly than the first redesign effort.

6.3.1.1.1 Schedule of Equipment Redesigns

The final rule includes a varying compliance dates for different engines, as shown in Table 6.3-1. For this analysis, because we are assuming no use of the transition program for equipment manufacturers, we assume that the timing of equipment redesigns will correlate with the timing of new emission standards (assuming no use banking under the engine ABT program). This results in a redesign schedule as shown in Table 6.3-1. We have noted the percentage of equipment models we estimate will be redesigned in years for which new emission standards are implemented. The table also notes the estimated percentage that will be major or minor redesign efforts. We also note what percentage of the redesign costs are allocated to PM and to NOx.

Table 6.3-1
Equipment Redesign Assumptions for Equipment Manufacturers

Power	Engine Standard Dates	Pollutant Allocation	Percent of Equipment Models Undergoing Minor Redesign	Percent of Equipment Models Undergoing Major Redesign
0<hp<25	2008	100% PM	100%	
25≤hp<50	2008	100% PM	100%	
	2013	50% PM 50% NOx		100%
50≤hp<75	2008	100% PM	100%	
	2013	100% PM		100%
75≤hp<175	2012	50% PM 50% NOx		100%
	2014	100% NOx	50%	
175≤hp≤750	2011	50% PM 50% NOx		100%
	2014	100% NOx	50%	
>750 hp	2011	100% NOx	100%	
	2015	100% PM		100%

Note that we have assumed all equipment redesigns for the 75 to 750 hp range are major in the first year of new emission standards and minor in the last year. The costs associated with such minor redesign efforts are assumed to be half those associated with major redesign efforts. We believe this is appropriate because equipment manufacturers will expend less effort to redesign those pieces equipment needing to add only the NOx adsorber (in those years where the NOx phase-in schedule changes from 50 percent to 100 percent) for three reasons: (1) these models will already have been redesigned for the CDPF system and will already incorporate the necessary electronic systems into their design; (2) equipment manufacturers will presumably have gained experience during the major redesign phase that should make the minor redesign phase more efficient; and (3) manufacturers that are aware of the future requirement will be able to make provisions in the first redesign that account for future needs. Therefore, the second redesign effort should be less intensive.

Our equipment redesign cost estimates were developed based on our meetings and conversations with engine and equipment manufacturers, specific redesign cost estimates provided by equipment manufacturers for the redesign of equipment to accommodate engines meeting the Tier 2 standards, and our engineering judgment as needed. The following section details our assessment of costs to equipment manufacturers.

6.3.1.1.2 Costs of Equipment Redesigns

While developing our equipment redesign cost estimates for the Tier 4 standards, we met with a wide range of equipment manufacturers. This included equipment manufacturers with annual revenues less than $50 million and engineering staffs of less than 10 employees, equipment manufacturers with annual revenues on the order of $200 million and engineering staffs on the order of 50 employees, and equipment manufacturers with annual revenue well in excess of $1 billion with annual research and development budgets of more than $100 million and engineering staffs of more than 500 employees.

During these meetings and discussions, it became apparent to us that, in spite of the significant engine technology differences between Tier 2/Tier 3 and Tier 4, the impact on equipment design and the need for redesign are similar. That is, for Tier 2, many engines have added electronic fuel systems, turbocharging, and charge-air-cooling. In addition, many Tier 2 engines rely on retarded fuel injection to lower NOx emissions, which therefore increases heat rejection and requires the equipment manufacturers to install larger radiators and fans. The process of equipment redesign for Tier 2 involved engineering work to accommodate these new components (for example, charge-air-coolers, turbochargers, larger radiators and fans) and electronic fuel systems. In many respects, this is similar to what will be required for Tier 4, where engines still without electronic fuel systems will require them, and equipment manufacturers will need to integrate aftertreatment systems (as compared with charge-air-coolers, turbochargers, larger radiators and fans). However, we believe that equipment redesigns attributable to Tier 4 are more likely to occur early in the design cycle than many design changes attributable to the Tier 2/3 rules.

Some companies we met with before the proposal gave us specific redesign cost information for the existing nonroad standards and, in some cases, projections for equipment redesigns necessary to integrate aftertreatment (these data are confidential business information). We also received redesign cost estimates from several equipment manufacturers during the Tier2/3 rulemaking regarding their projected costs for the Tier 2 standards (these data are confidential business information). The information provided to us through these various channels showed that there is a very wide range of cost estimates and actual cost data for redesigning nonroad equipment for the Tier 2 standards. In general, we learned that very large companies tend to allocate significantly more resources to equipment redesign than the medium or small companies.

We have used all this information and data, and our engineering judgment, to develop the redesign cost estimates presented in Table 6.3-2. This table presents fixed cost per motive and nonmotive equipment model (motive equipment is that with some form of propulsion system while nonmotive equipment, such as air compressors, generator sets, hydraulic power units, irrigation sets, pumps, compressors, and welders, has none) for each power group. In general, nonmotive equipment has fewer design demands than does motive equipment – no operator line-of-sight demands, fewer serviceability constraints, and almost no impact (collision) concerns. As a result, we have estimated a lower redesign cost for nonmotive equipment relative to motive equipment.

Table 6.3-2
Estimated Equipment Redesign Costs Per Model
($2002)

Power	Motive	Nonmotive
0<hp<25	$53,100	$53,100
25≤hp<75		
2008	$53,100	$53,100
2013	$199,125	$79,650
75≤hp<100	$371,700	$106,200
100≤hp<175	$531,000	$106,200
175≤hp<300	$531,000	$106,200
300≤hp<600	$796,500	$106,200
600≤hp≤750	$796,500	N/A
>750hp		
2011	$106,200	N/A
2015	$796,500	N/A

Using the PSR database we were able to determine the number of equipment models and the type of equipment model (motive versus nonmotive). We distinguished motive from nonmotive using our Nonroad Model definition of stationary applications. Nonmotive applications include air compressors, generator sets, pumps, hydraulic power units, irrigation sets, and welders. All other applications are considered motive. Table 6.3-3 shows the number of equipment models we have estimated to be redesigned. Note that the models shown in Table 6.3-3 are not necessarily all models but are instead the unique models that had 2000 model year sales. The determination of unique models was based on manufacturer name (i.e., a Caterpillar skid/steer loader is unique from a Bobcat skid/steer loader) and the market segment to which the model belonged (i.e., an agricultural tractor is unique from a construction backhoe) and the engine displacement. Therefore, while a manufacturer may consider two pieces of construction equipment with the same base engine, one with and one without a turbocharger, to be two distinct models, we consider that one model for the sake of equipment redesign.

Table 6.3-3
Number of Motive vs. Nonmotive Equipment Models
to be Redesigned

Power Range	Motive	Nonmotive	Total
0<hp<25	245	268	513
25≤hp<50	407	177	584
50≤hp<75	277	146	423
75≤hp<100	354	153	507
100≤hp<175	662	244	906
175≤hp<300	648	241	889
300≤hp<600	386	188	574
600≤hp≤750	80	0	80
<750hp	86	0	86
Total	3,145	1,417	4,563

Equipment redesign costs are estimated to occur during the two year period prior to the start of the new emission standards for which the redesign is done. As done for engine fixed costs, we have attributed only a portion of the equipment redesign costs to sales within the United States. This is appropriate because we believe these efforts will be needed to sell equipment not only in the United States, but also in Australia, Canada, Japan, and the countries of the European Union. As discussed in Section 6.2.1.1, we have therefore attributed 42 percent of the equipment fixed costs to U.S. sales. This is true with the exception of the <25hp range where we do not expect other countries to have standards as low as the NRT4 standards and, as a result, all redesign costs in this power range are attributed to today's rule. Table 6.3-4 shows the total redesign cost expenditures attributable to US sales for each power range.

Table 6.3-4
Equipment Redesign Expenditures
Attributable to US Sales ($2002)

Year Incurred	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2006	$ 6,810,075	$ 7,752,600	$ 5,615,325							$ 20,178,000
2007	$ 6,810,075	$ 7,752,600	$ 5,615,325							$ 20,178,000
2008										$ -
2009						$ 184,841,100	$ 163,707,300	$ 31,860,000	$ 4,566,600	$ 384,975,000
2010				$ 73,915,200	$ 188,717,400	$ 184,841,100	$ 163,707,300	$ 31,860,000	$ 4,566,600	$ 647,607,600
2011		$ 47,570,963	$ 33,393,263	$ 73,915,200	$ 188,717,400					$ 343,596,825
2012		$ 47,570,963	$ 33,393,263	$ 18,478,800	$ 47,179,350	$ 46,210,275	$ 40,926,825	$ 7,965,000		$ 241,724,475
2013				$ 18,478,800	$ 47,179,350	$ 46,210,275	$ 40,926,825	$ 7,965,000	$ 34,249,500	$ 195,009,750
2014									$ 34,249,500	$ 34,249,500
Total to US Sales	$ 13,620,150	$ 46,471,793	$ 32,767,214	$ 77,610,960	$ 198,153,270	$ 194,083,155	$ 171,892,665	$ 33,453,000	$ 32,605,524	$ 800,657,730

Table 6.3-5
Expenditures for Changes to Product Support Literature
Attributable to US Sales ($2002)

Year Incurred	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2006	$ 1,006,245	$ 2,631,105	$ 1,858,500							$ 5,495,850
2007	$ 1,006,245	$ 2,631,105	$ 1,858,500							$ 5,495,850
2008										$ -
2009						$ 4,080,735	$ 2,548,800	$ 424,800	$ 228,330	$ 7,282,665
2010				$ 2,285,955	$ 4,163,040	$ 4,080,735	$ 2,548,800	$ 424,800	$ 228,330	$ 13,731,660
2011		$ 2,631,105	$ 1,858,500	$ 2,285,955	$ 4,163,040					$ 10,938,600
2012		$ 2,631,105	$ 1,858,500	$ 1,142,978	$ 2,081,520	$ 2,040,368	$ 1,274,400	$ 212,400		$ 11,241,270
2013				$ 1,142,978	$ 2,081,520	$ 2,040,368	$ 1,274,400	$ 212,400	$ 456,660	$ 7,208,325
2014									$ 456,660	$ 456,660
Total to US Sales	$ 2,012,490	$ 4,420,256	$ 3,122,280	$ 2,880,303	$ 5,245,430	$ 5,141,726	$ 3,211,488	$ 535,248	$ 575,392	$ 27,144,614

6.3.1.2 Costs Associated with Changes to Product Support Literature

Equipment manufacturers are also expected to modify product support literature (dealer training manuals, operator manuals, service manuals, etc.) due to the product changes resulting from the new emission standards. For each product line of motive applications, we estimated that the level of effort needed by equipment manufacturers to modify the support literature will be about 100 hours—75 hours of junior engineering time, 20 hours of senior engineering time, and 5 hours of clerical time—which amounts to about $10,620 in $2002. We projected that the level of effort needed by equipment manufacturers to modify support literature for each nonmotive application product line will be about 50 hours (distributed similarly), which is equivalent to about $5,310. With the exception of the <25hp costs, we have attributed only a portion of the product support literature costs to US sales as described above for equipment redesign costs. Table 6.3-5 presents the total costs per power category for changes to support literature.

6.3.1.3 Total Equipment Fixed Costs

The annual equipment fixed costs for each power category are shown in Table 6.3-6. As described above and with the exception of <25 hp expenditures, we have attributed only a portion of the equipment fixed costs to sales within the United States. This is appropriate because we believe these efforts will be needed to sell equipment not only in the United States, but also in Australia, Canada, Japan, and the countries of the European Union. As discussed in Section 6.2.1.1, we have therefore attributed 42 percent of the equipment fixed costs to U.S. sales.

The analysis projects that the expenditures will be incurred over a two-year period before the first year of the emission standards. The costs were then amortized over ten years at a seven percent rate beginning with the first year of the engine standard. The ten-year period for amortization, as opposed to the five-year period used for engine costs, reflects the longer product development cycles for equipment relative to engines.

Table 6.3-6
Recovered (Annualized) Equipment Fixed Costs per Power Category ($2002)

Year Recovered	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2008	$ 2,303,637	$ 1,285,326	$ 925,132	$ -	$ -	$	$ -	$ -	$ -	$ 4,514,096
2009	$ 2,303,637	$ 1,285,326	$ 925,132	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,514,096
2010	$ 2,303,637	$ 1,285,326	$ 925,132	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,514,096
2011	$ 2,303,637	$ 1,285,326	$ 925,132	$ -	$ -	$ 23,385,312	$ 20,579,679	$ 3,996,309	$ 593,531	$ 53,068,927
2012	$ 2,303,637	$ 1,285,326	$ 925,132	$ 9,432,408	$ 23,875,320	$ 23,385,312	$ 20,579,679	$ 3,996,309	$ 593,531	$ 86,376,654
2013	$ 2,303,637	$ 7,499,489	$ 5,288,701	$ 9,432,408	$ 23,875,320	$ 23,385,312	$ 20,579,679	$ 3,996,309	$ 593,531	$ 96,954,385
2014	$ 2,303,637	$ 7,499,489	$ 5,288,701	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 593,531	$ 117,689,513
2015	$ 2,303,637	$ 7,499,489	$ 5,288,701	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 121,985,546
2016	$ 2,303,637	$ 7,499,489	$ 5,288,701	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 121,985,546
2017	$ 2,303,637	$ 7,499,489	$ 5,288,701	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 121,985,546
2018	$ -	$ 6,214,163	$ 4,363,569	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 117,471,450
2019	$ -	$ 6,214,163	$ 4,363,569	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 117,471,450
2020	$ -	$ 6,214,163	$ 4,363,569	$ 11,861,250	$ 29,972,978	$ 29,357,921	$ 25,803,473	$ 5,008,533	$ 4,889,563	$ 117,471,450
2021	$ -	$ 6,214,163	$ 4,363,569	$ 11,861,250	$ 29,972,978	$ 5,972,609	$ 5,223,794	$ 1,012,223	$ 4,296,033	$ 68,916,619
2022	$ -	$ 6,214,163	$ 4,363,569	$ 2,428,843	$ 6,097,658	$ 5,972,609	$ 5,223,794	$ 1,012,223	$ 4,296,033	$ 35,608,892
2023	$ -	$ -	$ -	$ 2,428,843	$ 6,097,658	$ 5,972,609	$ 5,223,794	$ 1,012,223	$ 4,296,033	$ 25,031,160
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,296,033	$ 4,296,033
Total	$ 23,036,370	$ 74,994,887	$ 52,887,014	$ 118,612,501	$ 299,729,780	$ 293,579,210	$ 258,034,732	$ 50,085,325	$ 48,895,635	$ 1,219,855,455

6.3.2 Equipment Variable Costs

In addition to the incrementally higher cost of new engines estimated in Sections 6.2.1 and 6.2.2, equipment manufacturers will need to purchase hardware to mount the new exhaust emission-control devices within each newly redesigned piece of equipment. Note that the redesign costs we have already discussed are for changes in equipment design to accommodate aftertreatment devices. We assume that there are minimal changes to the variable costs for the redesigned elements of the equipment (i.e., the redesigned elements cost roughly the same as before) because they serve the same function and have the same amount of materials. Here, we estimate the costs associated with the new hardware that will be necessary – new brackets, bolts, and sheet metal – for mounting and housing (shrouding) the new aftertreatment devices.

New brackets and bolts will be required to secure the aftertreatment devices within the piece of equipment. Additionally, increased labor ($29/hour) and overhead costs (40%) will be incurred to install these devices. Table 6.3-7 shows the costs we have used per piece of equipment ($/machine as shown in the table). Total costs per power range were calculated using these costs and equipment sales in the year 2000.

Table 6.3-7
Costs for Brackets and Bolts and Associated Labor for Equipment ($2002)

Brackets/bolts/etc.

	devices added	new sets of brackets/bolts per device	$/set	$/machine
0<hp<25	1	0	$2	$0
25<=hp<75				
2008	1	0	$0	$0
2013	1	2	$2	$4
75<=hp<175	2	2	$5	$21
175<=hp<300	2	2	$5	$21
300<=hp<=750	2	2	$11	$42
>750hp	2	2	$11	$42

Labor

	device added	hrs to install	subtotal ($)	overhead	Total
0<hp<25	DOC	0	$0	$0	$0
25<=hp<75					
2008	DOC	0	$0	$0	$0
2013	DPF	0.25	$7	$3	$10
75<=hp<175	DPF&NOxAds	0.5	$14	$6	$20
175<=hp<300	DPF&NOxAds	0.75	$22	$9	$30
300<=hp<=750	DPF&NOxAds	1.5	$43	$17	$61
>750hp	DPF	1	$29	$12	$40

Note to Table 6.3-7: We have assumed the addition of two devices for engines >750hp when only a CDPF is being added. It may have been more appropriate to assume one device but that the number of brackets and bolts needed would be twice that for other engines (i.e., four sets rather than two) given the size of the device. Applying two smaller CDPFs needing two sets of brackets and bolts leads to the same resultant cost for brackets and bolts.

Sheet metal costs vary by size of the aftertreatment devices being added which, in turn, vary by engine displacement as described in section 6.2. The amount of sheet metal for the shroud was determined using the engine displacement per equipment model information in the 2002 PSR Sales Database. The volume of the CDPF and NOx adsorber aftertreatment was calculated for each unique equipment model (as described in section 6.3.1.1.2) in the PSR database with an engine between 75 and 750 hp (1.5 times engine displacement for the CDPF and 1.5 times engine displacement for the NOx adsorber). The DOC was assumed to fit in place of the muffler. The volume of the aftertreatment was then converted to the volume of a cube and two inches were added to each dimension for space between the aftertreatment and the shroud. Sheet metal was assumed to cover four sides of the aftertreatment with no cover for the bottom or equipment facing side of the shroud. Sheet metal was assumed to cost $1.14 per square foot for hot rolled steel. The sheet metal cost for each model was multiplied by the total sales for that model using the 2000 sales information in the 2002 PSR Sales Database.

Summing these variable costs for each equipment model—sheet metal costs plus costs for bolts, brackets, and labor—within each power range and then dividing by sales within the power range gives a rough estimate of the costs we have estimated for a piece of equipment. It is important to realize that this is weighted value within each power range determined by calculating a unique cost for each piece of equipment, multiplying that cost by its sales, and then totaling those costs within each power range. Table 6.3-8 shows the sales weighted equipment variable costs within each power range. A twenty-nine percent manufacturer markup is also included in the final cost estimates shown in Table 6.3-8.

Table 6.3-8
Sales Weighted Variable Costs per Piece of Equipment by Power Range[a]
Totals include a 29% Manufacturer Markup ($2002)

Power Range	Year	Total
0<hp<25	2008	$0
25≤hp<50	2013	$20
50≤hp<75	2013	$21
75≤hp<100	2012	$60
100≤hp<175	2012	$61
175≤hp<300	2011	$77
300≤hp<600	2011	$146
600≤hp≤750	2011	$154
>750 hp	2011	$123

[a] These costs do not include the engine variable costs described in section 6.2.

As shown in Table 6.3-8, we have estimated equipment variable costs to be zero for equipment with engines under 25 hp, under the expectation that an added DOC will replace the existing muffler and make use of the same bracket/bolt/labor used for the muffler. This is also expected for engines in the 25 to 75 hp range from 2008 through 2012 when, for our cost anlaysis, only a DOC is being used by the engine manufacturer for compliance; additional bolts and labor costs are included for the addition of a CDPF beginning in 2013.[R] While we have assumed the CDPF will simply replace the muffler, there will be additional bracket/bolt/labor demands due to the greater weight of the CDPF relative to the replaced muffler.

[R] Note that for costing purposes we have assumed that a DOC is used on all engines under 75 hp to comply with the 2008 standards, although test data show that some engines already meet the new emission standards without a DOC.

6.3.3 Potential Impact of the Transition Provisions for Equipment Manufacturers

As discussed in Section III.B of the preamble, we are extending, and in some respects are expanding, the transition program for equipment manufacturers (TPEM) that was developed in the 1998 final rule. The TPEM is an important component of this final rule because of the flexibility it provides for equipment manufacturers. However, as explained earlier, because the program is optional, we have not included the potential impacts of TPEM on the estimated costs of the Tier 4 program. Nevertheless, this section discusses how the TPEM program may substantially reduce equipment manufacturer costs.

The TPEM can reduce equipment manufacturer costs in two ways. First, it allows equipment manufacturers to continue to sell limited numbers of equipment with non-Tier 4 engines even after the Tier 4 standards go into effect. Any engine price increase associated with the Tier 4 standards will therefore not be incurred by the equipment manufacturer or by the end user during the time frame the manufacturers use the TPEM. Second, the TPEM allows manufacturers to schedule equipment design cycles to coincide with any redesign necessary because of EPA's emission standards. We believe this is the most significant cost savings impact of the TPEM. This is due to the fact that many equipment manufacturers have a several small-volume model lines. Using the TPEM program, companies can delay the redesign costs associated with Tier 4 engines for up to seven years on a limited number of products.

We performed a detailed analysis on an equipment manufacturer-by-equipment manufacturer basis of the more than 6,000 equipment models and 600 equipment manufacturers in an industry-wide database (the Power Systems Research database).[53] This analysis looked at each equipment manufacturer's product offerings by power category and the estimated 2000 U.S. sales of each equipment model. We used this database to analyze how equipment manufacturers can use TPEM to maximize the number of equipment models with delayed redesign until the eighth year of the program (as discussed in Section III.B of the preamble, TPEM provisions allow equipment manufacturers to sell products with uncertified engines until seven years after the applicable Tier 4 standard is implemented.). We specifically analyzed the percent-of-production allowance and the small-volume allowance programs being adopted for the Tier 4 rule (as discussed in the preamble). The results are shown in Table 6.3-9. (It should be noted that the newly adopted technical hardship flexibility provision, which potentially allows an additional 70 percent of equipment manufacturer's sales in a power category to use non-Tier 4 engines for a limited time provided an appropriate case-by-case demonstration of extreme technical hardship is made to EPA, likewise could have associated cost savings.)

Table 6.3-9
Potential Impact of TPEM Program on Equipment Models and Sales (all equipment companies)

Equipment Models/ Equipment Sales	Engine Power Category					
	<25 hp	25< hp <70[a]	70[a]< hp <175	175< hp <750	>750 hp	All Power Categories
Percent of all equipment models that could use TPEM for full-seven years	56%	61%	66%	71%	80%	66%
Percent of equipment sales that could use TPEM for full-seven years	7%	10%	13%	12%	21%	10%

[a] Note that the power ranges are 25-75 hp and 75-175 hp. This analysis was done using 70 hp as a cut-point. We believe the results of this analysis would not have been significantly different if the power outpoint had been 75 hp.

This analysis indicates that if fully utilized by equipment manufacturers, 66 percent of nonroad diesel equipment models can use the TPEM program to delay an equipment redesign necessary for the Tier 4 standards for seven years. Without the TPEM program, equipment manufactures would need to redesign all their equipment models using a nonroad diesel engine in the first year of the engine standard implementation. As an example of the flexibility offered by the TPEM program, Table 6.3-9 indicates that for engines between 25 and 75 hp, 61 percent of all equipment models in this power range can take advantage of the TPEM (i.e., the percent of production allowance and the small volume allowance options) to delay an equipment redesign for seven years. It is important to note that while the TPEM can substantially reduce equipment redesign costs, it is expected to have a much smaller impact on the emission reductions of the program. While the TPEM can allow equipment companies to continue selling products with the previous tier standards on many equipment models, the total sales that can be impacted by the TPEM (i.e., the percent of production allowance and the small volume allowance options), which is also shown in Table 6.3-9, is estimated to be no higher than ten percent for no more than seven years.

The analysis presented in Table 6.3-9 is based on the equipment produced by a wide range of equipment manufacturers, both very large, multi-billion dollar corporations as well as small companies who produce a limited number of products. We have performed a similar analysis using only those equipment companies whose data is contained in the PSR database which we were able to identify as small businesses. In some respects the TPEM program, while available to all equipment manufacturers, was designed specifically to benefit small businesses. Within the PSR database, we were able to identify 337 small businesses who together produce more than 2,500 different equipment models. This data was analyzed as described above for Table 6.3-9. The results are shown in Table 6.3-10.

Table 6.3-10
Potential Impact of TPEM Program on Equipment Models and Sales of Small Business Equipment Manufacturers

Equipment Models/ Equipment Sales	Engine Power Category					
	<25 hp	25< hp <70[a]	70[a]< hp <175	175< hp <750	>750 hp	All Power Categories
Percent of all equipment models that could use TPEM for full-seven years	69%	74%	78%	86%	93%	79%
Percent of equipment sales that could use TPEM for full-seven years	17%	24%	29%	51%	76%	26%

[a] Note that the power ranges are 25-75 hp and 75-175 hp. This analysis was done using 70 hp as a cut-point. We believe the results of this analysis would not have been significantly different if the power outpoint had been 75 hp.

The results in Table 6.3-10 show that in all power categories, the TPEM program provides more flexibility for small business equipment companies than for the equipment industry as a whole. In every power category, the number of equipment models which small companies can delay redesigning for the full seven years is greater than for the industry as a whole, and for the power categories which will likely require engine aftertreatment (i.e., >25hp), approximately 75 percent or more of the equipment models could delay redesign for a full seven years. The actual equipment sales for all of the small business equipment companies which could use the TPEM program under this analysis is 26 percent of the total sales, but in reality this is less than 3 percent of the total nonroad diesel market, as small business companies have a relatively small portion of the total nonroad diesel equipment sales.

6.4 Summary of Engine and Equipment Costs

Details of our engine and equipment cost estimates were presented in Sections 6.2 and 6.3. Here we summarize the cost estimates. Section 6.4.1.1 summarizes the total engine fixed costs. Section 6.4.1.2 summarizes the engine variable cost equations for estimating engine variable costs. Section 6.4.1.3 summarizes the engine operating costs. Section 6.4.2.1 summarizes the total equipment fixed costs and 6.4.2.2 summarizes the estimated equipment variable costs. Section 6.4.3 presents these costs on a per unit basis. Note that all present value costs presented here are 30-year numbers (the net present values in 2004 of the stream of costs/reductions occurring from 2007 through 2036, expressed in $2002).

6.4.1 Engine Costs

6.4.1.1 Engine Fixed Costs

Engine fixed costs include costs for engine R&D, tooling, and certification. These costs are discussed in detail in Section 6.2.1. The total estimated engine fixed costs are summarized in Table 6.4-1. The table also includes 30-year net present values using both a three percent and a seven percent social discount rate.

Table 6.4-1
Summary of Engine Fixed Costs ($2002)

	Incurred Costs ($Million)	Recovered Cost ($Million)	30 Year NPV of Recovered Cost at 3% ($Million)	30 Year NPV of Recovered Cost at 7% ($Million
Engine R&D	$323	$452	$336	$233
Engine Tooling	$74	$91	$70	$50
Engine Certification	$91	$111	$84	$60
Total	$489	$653	$490	$343

6.4.1.2 Engine Variable Costs

Engine variable costs are discussed in detail in Section 6.2.2. For engine variable costs, we have generated cost estimation equations as a function of engine displacement or number of cylinders (see Table 6.2-27). Using these equations, we have calculated the costs for each nonroad diesel engine sold in the year 2000, multiplied that cost by its projected sales during the 30 year period following implementation of the NRT4 program, and then added the future annual costs for each engine to arrive at annual costs during each of those 30 years. We present those annual engine variable costs in Chapter 8. Table 6.4-2 shows the 30-year net present value of those annual costs assuming a three percent social discount rate and a seven percent social discount rate.

Table 6.4-2
30-Year Net Present Value of Engine Variable Costs
($2002)

	30 Year NPVat 3% ($Million)	30 Year NPVat 7% ($Million)
Engine Variable Costs	$13,562	$6,871

6.4.1.3 Engine Operating Costs

Engine operating costs are discussed in detail in Section 6.2.3. Table 6.4-3 summarizes engine operating costs, excluding costs associated with the desulfurization of diesel fuel; these costs are presented in Chapter 7.

Table 6.4-3
Engine Operating Costs Associated with the NRLM Fuel Program
(cents/gallon of 15ppm fuel consumed)

Power category	Oil-Change Savings	CDPF Maintenance	CCV Maintenance	CDPF Regeneration[a]	Net Operating Costs[b]
0<hp<25	(19.3)	0.0	0.0	0.0	(19.3)
25≤hp<50	(8.2)	2.3	0.0	1.3	(4.6)
50≤hp<75	(5.9)	1.6	0.1	1.3	(2.9)
75≤hp<175	(3.3)	0.8	0.3	0.7	(1.5)
175≤hp<300	(2.0)	0.2	0.2	0.7	(0.9)
300≤hp<600	(1.4)	0.1	0.1	0.7	(0.5)
600≤hp<750	(1.1)	0.1	0.2	0.7	(0.1)
>750 hp	(1.1)	0.2	0.2	1.3	0.6
Locomotive/Marine	(1.1)	--	--	--	(1.1)

[a] A one or two percent fuel consumption increase, a 60 cent/gallon baseline fuel price, and a 7.0 cent/gallon incremental fuel cost.
[b] The incremental costs for low-sulfur fuel are presented in Chapter 7.

Engines that make up the existing fleet will realize the oil-change savings shown in Table 6.4-3 while incurring none of the other operating costs, because these engines will not have CDPF or CCV systems. New engines would incur all the costs and savings shown in Table 6.4-3.

Table 6.4-3 shows operating costs on a cent-per-gallon basis. Lifetime engine operating costs vary by the amount of fuel consumed. We have calculated lifetime operating costs for some example types of equipment and present those in Section 6.5. Aggregate operating costs (the annual total costs) are presented in Chapter 8 and the 30-year net present value of the NRLM fleet operating costs are shown in Table 6.4-4.

Table 6.4-4
30-Year Net Present Value of NRLM Fleetwide Engine Operating Costs
Excluding Fuel Costs
($2002)

	30 Year NPV at 3% ($Million)	30 Year NPV at 7% ($Million)
Engine Operating Costs (a negative value indicates a savings)	-$4,517	-$2,745

6.4.2 Equipment Costs

6.4.2.1 Equipment Fixed Costs

Equipment fixed costs are discussed in detail in Section 6.3.1. Table 6.4-5 shows the estimated equipment fixed costs associated with the Tier 4 emission standards. These figures include estimated costs for equipment redesign and generation of new product support literature.

Table 6.4-5
Summary of Equipment Fixed Costs ($2002)

	Incurred Costs ($Millions)	Recovered Costs ($Millions)	30 Year NPV of Recovered Cost at 3% ($Million)	30 Year NPV of Recovered Cost at 7% ($Million)
Redesign	$801	$1,180	$819	$518
Product Literature	$27	$40	$28	$18
Total	$828	$1,220	$847	$537

6.4.2.2 Equipment Variable Costs

Equipment variable costs are discussed in detail in Section 6.3.2. Using the costs presented there we have calculated the variable costs for the equipment sold in the year 2000 and then projected those costs over the 30 year period following implementation of the NRT4 program. We present those annual equipment variable costs in Chapter 8. Table 6.4-6 shows the 30-year net present value of those annual costs assuming a three percent and a seven percent social discount rate.

Table 6.4-6
30-Year Net Present Value of Equipment Variable Costs
($2002)

	30 Year NPV at 3% ($Million)	30 Year NPV at 7% ($Million)
Equipment Variable Costs	$434	$217

6.4.3 Engine and Equipment Costs on a Per Unit Basis

For the Nonroad Diesel Economic Impact Analysis Model (NDEIM, see Chapter 10), we need engine and equipment costs per unit sold. These per unit costs serve as inputs to the model to determine how the cost increases might impact the quantity of units sold. The costs presented here in Chapter 6 are aggregated in Chapter 8 into annual fleetwide costs during a 30 year period following implementation of the NRT4 program. The annual fleetwide engine fixed costs by power category are shown in Table 8.2-1. The costs presented there represent the annual recovered costs associated with engine R&D, tooling, and certification (note that these costs are also presented in Tables 6.2-6, 6.2-8, 6.2-10, and 6.3-6. As explained earlier in this chapter, the recovered engine R&D costs are revenue weighted, meaning that we have attributed the total industry costs for engine R&D according to our best estimate of revenues from engine sales. Doing this does not impact the resultant total cost of the new Tier 4 standards and only impacts how the costs are allocated to each power range. Such an allocation is of importance only when trying to determine the per unit cost as we are here. Manufacturers may choose to recover their investments in ways different than we have estimated, although recovering investments based on revenues seems like the most likely probability.

Table 6.4-7 shows the per unit costs using this methodology. The values shown in the table are simply the result of dividing the annual costs by power range shown in Table 8.2-1 by the engine sales by power range shown in Table 8.1-1. The costs per unit change from year to year because engine standards are implemented differently in each power category. As more engines across more power categories phase-in to a new set of engine standards, the engine R&D costs are recovered according to a different revenue weighting. Note also that tooling costs within each power range can vary year to year on a per unit basis. This occurs because there are many engine platforms that span different power ranges. Therefore, tooling expenditures done for an engine platform that spans the 100-175 hp and the 175-300 hp ranges would be recovered only on the 175-300 hp engines in 2011 and then on both 100-175 hp and 175-300 hp engines beginning in 2012. Engine fixed costs per unit become zero after several years because the fixed costs invested have been completely recovered.

We can get the engine variable costs per unit in much the same way by dividing the aggregate engine variable costs by power range shown in Table 8.2-3 by the engine sales by power range shown in Table 8.1-1. The results are shown in Table 6.4-8. Note that the engine variable costs per unit continue indefinitely and do not go to zero as do the engine fixed costs shown in Table 6.4-7. Note also that, by 2020, the engine variable costs are not longer changing due to phase-ins, learning curves, or other factors.

Equipment fixed and variable costs per unit can be generated in the same way. Tables 8.3-1 and 8.3-3 present the annual fleetwide equipment fixed and equipment variable costs by power category. Dividing these costs by sales (Table 8.1-1) results in the per unit costs shown in Tables 6.4-9 and 6.4-10 for equipment fixed and equipment variable costs per unit, respectively.

Table 6.4-7
Estimated Engine Fixed Costs per Unit ($2002)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0<hp<25	$ 38	$ 37	$ 36	$ 35	$ 34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25<=hp<50	$ 49	$ 48	$ 47	$ 46	$ 45	$ 74	$ 73	$ 71	$ 70	$ 69	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50<=hp<75	$ 50	$ 49	$ 49	$ 48	$ 47	$ 76	$ 75	$ 73	$ 72	$ 71	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75<=hp<100	$ -	$ -	$ -	$ -	$ 80	$ 78	$ 108	$ 106	$ 104	$ 29	$ 28	$ -	$ -	$ -	$ -	$ -	$ -
100<=hp<175	$ -	$ -	$ -	$ -	$ 78	$ 77	$ 106	$ 105	$ 103	$ 29	$ 29	$ -	$ -	$ -	$ -	$ -	$ -
175<=hp<300	$ -	$ -	$ -	$ 225	$ 220	$ 217	$ 290	$ 285	$ 74	$ 73	$ 72	$ -	$ -	$ -	$ -	$ -	$ -
300<=hp<600	$ -	$ -	$ -	$ 527	$ 521	$ 515	$ 735	$ 727	$ 220	$	$ 216	$ -	$ -	$ -	$ -	$ -	$ -
600<=hp<=750	$ -	$ -	$ -	$ 1,156	$ 1,138	$ 1,122	$ 1,630	$ 1,606	$ 509	$ 218 502	$ 495	$ -	$ -	$ -	$ -	$ -	$ -
>750hp	$ -	$ -	$ -	$ 570	$ 561	$ 553	$ 545	$ 1,447	$ 897	$ 884	$ 872	$ 860	$ -	$ -	$ -	$ -	$ -

Table 6.4-8
Estimated Engine Variable Costs per Unit ($2002)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0<hp<25	$ 129	$ 129	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123
25<=hp<50	$ 147	$ 147	$ 139	$ 139	$ 139	$ 887	$ 887	$ 675	$ 675	$ 675	$ 675	$ 675	$ 675	$ 675	$ 675	$ 675	$ 675
50<=hp<75	$ 167	$ 167	$ 158	$ 158	$ 158	$ 837	$ 837	$ 636	$ 636	$ 636	$ 636	$ 636	$ 636	$ 636	$ 636	$ 636	$ 636
75<=hp<100	$	$ -	$ -	$ -	$ 1,133	$ 1,133	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122	$ 1,122
100<=hp<175	$ -	$ -	$ -	$ -	$ 1,375	$ 1,375	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351
175<=hp<300	$ -	$ -	$ -	$ 1,981	$ 1,981	$ 1,536	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937	$ 1,937
300<=hp<600	$ -	$ -	$ -	$ 2,609	$ 2,609	$ 2,021	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545	$ 2,545
600<=hp<=750	$ -	$ -	$ -	$ 4,944	$ 4,944	$ 3,825	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807	$ 4,807
>750hp	$ - -	$ -	$ -	$ 1,973	$ 1,973	$ 1,543	$ 1,543	$ 8,335	$ 8,335	$ 6,734	$ 6,734	$ 6,734	$ 6,734	$ 6,734	$ 6,734	$ 6,734	$ 6,734

Table 6.4-9

Estimated Equipment Fixed Costs per Unit ($2002)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0<hp<25	$ 15	$ 15	$ 14	$ 14	$ 14	$ 13	$ 13	$ 13	$ 12	$ 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25<=hp<50	$ 8	$ 8	$ 8	$ 7	$ 7	$ 42	$ 41	$ 40	$ 40	$ 39	$	$ 31	$ 31	$ 30	$ 30	$ -	$ -
50<=hp<75	$ 8	$ 8	$ 8	$ 8	$ 8	$ 44	$ 43	$ 42	$ 42	$ 41	$ 32	$ 33	$ 32	$ 32	$ 31	$ -	$ -
75<=hp<100	$ -	$ -	$ -	$ -	$ 109	$ 107	$ 132	$ 130	$ 128	$ 126	$ 33 124	$ 122	$ 120	$ 118	$ 24	$ 24	$ -
100<=hp<175	$ -	$ -	$ -	$ -	$ 170	$ 168	$ 207	$ 204	$ 201	$ 197	$ 194	$ 192	$ 189	$ 186	$ 37	$ 37	$ -
175<=hp<300	$ -	$ -	$ -	$ 302	$ 297	$ 291	$ 360	$ 353	$ 348	$ 342	$ 336	$ 331	$ 326	$ 65	$ 64	$ 63	$ -
300<=hp<600	$ -	$ -	$ -	$ 529	$ 523	$ 518	$ 642	$ 635	$ 628	$ 622	$ 615	$ 609	$ 603	$ 121	$ 120	$ 118	$ -
600<=hp<=750	$ -	$ -	$ -	$ 1,210	$ 1,192	$ 1,175	$ 1,451	$ 1,430	$ 1,410	$ 1,390	$ 1,371	$ 1,353	$ 1,335	$ 266	$ 263	$ 259	$ -
>750hp	$ -	$ -	$ -	$ 177	$ 175	$ 172	$ 170	$ 1,377	$ 1,358	$ 1,339	$ 1,320	$ 1,302	$ 1,285	$ 1,114	$ 1,100	$ 1,085	$ 1,072

Table 6.4-10

Estimated Equipment Variable Costs per Unit ($2002)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0<hp<25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25<=hp<50	$ -	$ -	$ -	$ -	$ -	$ 20	$ 20	$ 16	$ 16	$ 16	$	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16
50<=hp<75	$ -	$ -	$ -	$ -	$ -	$ 21	$ 21	$ 17	$ 17	$ 17	$ 16	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17
75<=hp<100	$ -	$ -	$ -	$ -	$ 45	$ 45	$ 48	$ 48	$ 48	$ 48	$ 17	$ 48	$ 48	$ 48	$ 48	$ 48	$ 48
100<=hp<175	$ -	$ -	$ -	$ -	$ 46	$ 46	$ 49	$ 49	$ 49	$ 49	$ 48	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49
175<=hp<300	$ -	$ -	$ -	$ 58	$ 58	$ 46	$ 62	$ 62	$ 62	$ 62	$ 49	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62
300<=hp<600	$ -	$ -	$ -	$ 110	$ 110	$ 88	$ 117	$ 117	$ 117	$ 117	$ 62 117	$ 117	$ 117	$ 117	$ 117	$ 117	$ 117
600<=hp<=750	$ -	$ -	$ -	$ 116	$ 116	$ 92	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123	$ 123
>750hp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123	$ 123	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98

6.5 Weighted Average Costs for Example Types of Equipment

6.5.1 Summary of Costs for Some Example Types of Equipment

To better illustrate the engine and equipment cost impacts for this final rule, we have chosen several types of equipment and present the estimated costs for them using weighted average inputs—horsepower, displacement, number of cylinders, etc. Using these sales weighted inputs, we can calculate the costs for these types of equipment in several power ranges and better illustrate the cost impacts of the new emission standards. For the weighted average inputs, we have used the PSR database and determined the sales weighted averages of various parameters of interest. These results are shown in Table 6.5-1. We can use the sales weighted average inputs shown in Table 6.5-1 along with the engine variable cost equations presented in Table 6.4-2 to generate the sales weighted average engine variable costs within each power range (doing so will match the costs presented in Table 6.4-8). For engine fixed costs per unit and equipment fixed and variable costs per unit, we can use the costs per unit presented in Tables 6.4-7, 6.4-9, and 6.4-10, respectively.

These results are presented in Table 6.5-2. Costs presented are near-term and long-term costs for the final standards to which engines in each power category must comply. Long-term costs include only variable costs and therefore represent costs after all fixed costs have been recovered. Note that not all engines in each power category would incur all the costs shown in the table. For example, only turbocharged engines will add a CCV system as a result of the NRT4 final rule—it is important to remember that the costs presented in Table 6.5-2 are sales weighted averages within each power range. Included in Table 6.5-2 are estimated operating costs for each power range, again using the sales weighted average inputs shown in Table 6.5-1 along with information presented in Tables 6.2-29 through 6.2-31 and the fuel economy impacts discussed in section 6.2.3.3.

We can compare these sales weighted average costs by power range to the typical price of various types of equipment—construction, agricultural, pumps & compressors, gensets & welders, refrigeration & A/C, general industrial, and lawn & garden. We have estimated the prices of these equipment using a linear relationship between the price for these types of equipment and their power.[54] Table 6.5-3 shows the resultant equipment prices. Table 6.5-4 shows the near-term and long-term costs (Table 6.5-2) as a percentage of equipment prices (Table 6.5-3).

Table 6.5-1
Sales Weighted Average Inputs for Engine & Equipment Costs ($2002)

	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp
Sales Weighted Displacement (L)	0.753	1.650	2.592	3.872	4.916	7.773	10.755	21.854	41.968
Sales Weighted # Cylinders	2.2	3.1	3.8	4.0	4.7	6.0	6.1	9.5	11.8
Sales Weighted Hp	16.9	36.6	57.1	83.3	126.6	224.8	363.7	728.7	1335.3
% Naturally Aspirated	100%	98%	91%	75%	13%	1%	0%	0%	0%
% Turbo	0%	2%	9%	25%	87%	99%	100%	100%	100%
% DI	33%	41%	85%	98%	100%	100%	100%	100%	100%
% IDI	67%	59%	15%	2%	0%	0%	0%	0%	0%

%DI and %IDI refer to the percentage of engines that have a direct injection fuel system and the percentage that have an indirect injection fuel system.

Table 6.5-2
Sales Weighted Average Near-Term and Long-Term Costs by Power Category[a]
($2002, for the final emission standards to which the equipment must comply)

	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750 hp
Near-term costs calculated in the year:	2008	2013	2013	2012	2012	2011	2011	2011	2015
Engine variable costs									
Fuel System	$0	$182	$184	$0	$0	$0	$0	$0	$0
EGR	$0	$136	$0	$0	$0	$0	$0	$0	$1,451
CCV*	$0	$1	$3	$10	$39	$49	$56	$79	$91
CDPF	$0	$316	$454	$642	$795	$1,213	$1,649	$3,274	$6,218
CDPF regen system	$0	$259	$198	$190	$197	$226	$256	$370	$575
NOx adsorber	$0	$0	$0	$583	$691	$986	$1,294	$2,442	$0
DOC	$129	$0	$0	$0	$0	$0	$0	$0	$0
Engine Fixed Costs									
R&D	$15	$51	$54	$50	$51	$126	$414	$1,023	$861
Tooling	$8	$7	$6	$16	$16	$69	$76	$72	$107
Cert	$15	$16	$16	$14	$12	$29	$37	$61	$478
Equipment Variable Costs	$0	$20	$21	$45	$46	$58	$110	$116	$123
Equipment Fixed Costs	$15	$42	$44	$109	$170	$302	$529	$1,210	$1,377
Near-term Total Engine & Equipment Costs	$180	$1,030	$980	$1,660	$2,020	$3,060	$4,420	$8,650	$11,280
Long-term Total Engine & Equipment Costs in the year 2030	**$120**	**$700**	**$650**	**$1,170**	**$1,400**	**$2,000**	**$2,660**	**$4,930**	**$6,830**
Operating Costs (discounted lifetime $)									
Fuel Costs	$110	$260	$650	$910	$1,390	$2,290	$4,890	$11,780	$23,110
Oil Change Costs (Savings)	-$310	-$310	-$550	-$430	-$660	-$640	-$980	-$1,900	-$3,790
System regenerations	$0	$50	$120	$90	$130	$220	$470	$1,130	$4,430
CCV maintenance	$0	$0	$10	$30	$50	$70	$100	$300	$620
CDPF maintenance	$0	$90	$140	$100	$150	$70	$80	$240	$500
Total Incremental Operating Costs (Savings)	**-$200**	**$90**	**$370**	**$710**	**$1,070**	**$2,000**	**$4,560**	**$11,550**	**$24,870**
Baseline Operating Costs (fuel and oil only)	$2,170	$3,410	$7,630	$9,490	$13,400	$21,360	$44,980	$108,430	$212,720

a. Near-term costs include both variable costs and fixed costs; long-term costs include only variable costs and represent those costs that remain following recovery of all fixed costs.
b. For 25 to 75 hp engines, CCV costs in 2013 will be long term because CCV systems are first required in 2008.

Table 6.5-3
Sales Weighted Average Prices for Various Types of Equipment ($2002)

	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp
Construction Equipment	$ 18,000	$ 29,700	$ 31,600	$ 57,900	$ 122,700	$ 247,300	$ 431,400	$ 717,500	$ 976,900
Agricultural Equipment	$ 6,900	$ 14,400	$ 22,600	$ 33,400	$ 69,100	$ 125,900	$ 175,900	NA	NA
Pumps & Compressors	$ 6,000	$ 12,200	$ 10,600	$ 12,500	$ 23,800	$ 37,500	$ 81,000	NA	NA
GenSets & Welders	$ 6,800	$ 8,700	$ 8,300	$ 18,000	$ 21,400	$ 33,500	$ 39,500	NA	NA
Refrigeration & A/C	$ 12,500	---	---	NA	NA	NA	NA	NA	NA
General Industrial	$ 17,300	$ 42,300	$ 56,400	$ 74,300	$ 116,900	$ 141,700	$	$ 268,800	$ 421,900
Lawn & Garden	$ 9,300	$ 21,500	$ 33,100	$ 38,500	$ 29,900	$ 52,700	$ 176,700	NA	NA

85,100

Table 6.5-4
Estimated Costs as a Percentage of New Equipment Price

	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp
Near-term Cost to Price Ratio									
Construction Equipment	1%	3%	3%	3%	2%	1%	1%	1%	1%
Agricultural Equipment	3%	7%	4%	5%	3%	2%	3%		
Pumps & Compressors	3%	8%	9%	13%	8%	8%	5%		
GenSets & Welders	3%	12%	12%	9%	9%	9%	11%		
Refrigeration & A/C	1%								
General Industrial	1%	2%	2%	2%	2%	2%	3%	3%	3%
Lawn & Garden	2%	5%	3%	4%	7%	6%	5%		
Long-term Cost to Price Ratio									
Construction Equipment	1%	2%	2%	2%	1%	1%	1%	1%	1%
Agricultural Equipment	2%	5%	3%	4%	2%	2%	2%		
Pumps & Compressors	2%	6%	6%	9%	6%	5%	3%		
GenSets & Welders	2%	8%	8%	7%	7%	6%	7%		
Refrigeration & A/C	1%								
General Industrial	1%	2%	1%	2%	1%	1%	2%	2%	2%
Lawn & Garden	1%	3%	2%	3%	5%	4%	3%		

* Note that the above percentages include equipment cost estimates that are averaged across all equipment types (i.e, motive and non-motive equipment). Our redesign estimates for non-motive equipment are lower than for motive equipment (see Table 6.3-2). Therefore, the near-term percentages for non-motive equipment types (e.g., gensets, pumps, etc.), are skewed slightly high just as the near-term percentages for motive equipment types are skewed slightly low. As a result, the long-term percentages, that represent the percentages after all fixed costs like engine R&D and equipment redesign have been recovered and are no longer part of the estimated cost, are probably better representations of the possible effect of the rule on equipment prices.

6.5.2 Method of Generating Costs for a Specific Piece of Equipment

To facilitate the effort to duplicate this example analysis for specific pieces of equipment, this section will briefly describe the necessary steps to create the cost analysis based on the information in this document.

The first step required to develop an estimate of our projected cost for control under the Tier 4 program is to define certain characteristics of the engine in the piece of equipment for which a cost estimate is desired. Specifically, the following items must be defined:

- displacement of the engine (i.e., the cylinder swept volume) in liters;
- type of aspiration (i.e., turbocharged or naturally aspirated);
- number of cylinders;
- type of combustion system used by the engine (i.e., indirect-injection, IDI, or direct-injection, DI);
- model year of production; and,
- the power category of the engine.

With this information and the data tables elsewhere in this document, it is possible to estimate the costs of meeting the new standards for any particular piece of equipment.

As an example, we will estimate the cost of compliance for a 76 hp backhoe in the year 2012. The first step is to define our engine characteristics, as shown in Table 6.5-6.

Table 6.5-6
Engine and Equipment Characteristics of an Example Cost Estimate

76 hp Backhoe Example		
Model Year	2012	reader defined
Displacement (liters)	3.9	application specific
Cylinder (number)	4	application specific
Aspiration	Turbocharged	application specific
Combustion System	Direct Injection	application specific
Power Category	75 to 175 hp	regulations define the standards and the timing of the standards

For engines produced in the early years of the program, an accounting of the fixed costs needs to be made. Fixed costs include the engine fixed cost for research and development, tooling, and certification as well as equipment fixed includes including redesign and manual costs. These fixed costs are reported in this chapter on a per engine/piece of equipment basis in each year of the program for which a fixed cost is applied. The necessary numbers to calculate the fixed costs can simply be read from these tables.

Table 6.5-3
Fixed Costs for an Example Cost Estimate

2012 76hp Backhoe Example		
Engine R&D	$50	Table 6.2-6 Engine R&D Costs (per engine)
Engine Tooling	$16	Table 6.2-8 Engine Tooling Costs (per engine)
Engine Certification	$14	Table 6.2-10 Engine Certification Costs (per engine)
Total Engine Fixed	$80	Summation (see also Table 6.4-7)
Total Equipment Fixed	$109	Table 6.4-9 Equipment Fixed Cost per Unit
Total Fixed Costs	$189	Summation

The engine variable costs are related to specific engine technology characteristics in a series of linear equations described in table 6.2-27. The table includes all the different variable cost components for different size ranges of engines meeting applicable emission standards. It includes a description of the particular engine categories for which the costs are incurred. The simplest approach to estimating the variable costs is to repeat the table and then to simply zero out any components that do not apply for a particular example (see Table 6.5-4 below).

Table 6.5-4
Summary of Cost Equations for Engine Variable Costs
for a 76hp Backhoe Example (x represents the dependent variable)

Engine Technology	Time Frame[a]	Cost Equation	Dependent Variable (x)	How Used
NOx Adsorber System	Near term Long term	\$103(x) + \$183 \$83(x) + \$160	Displacement[b]	>75 hp engines according to phase-in of NRT4 NOx std.
2012 76hp Backhoe	2012 is Near Term	\$103 (3.9)+\$183 = \$585	3.9 liters	In 2012 a 76 hp engine in the NOx phase-in set will require a NOx adsorber
CDPF System	Near term Long term	\$146(x) + \$75 \$112(x) + \$57	Displacement	>25 hp engines according to NRT4 PM std.
2012 76hp Backhoe	2012 is Near Term	\$146(3.9)+\$75= \$644	3.9 liters	In 2012 all 76hp engines are projected to require CDPFs
CDPF Regen System – IDI engines	Near term Long term	\$20(x) + \$293 \$16(x) + \$223	Displacement	IDI engines adding a CDPF
2012 76hp Backhoe	2012 is Near Term	not applicable	3.9 liters	The example engine has a direct-injection combustion system, not indirect-injection
CDPF Regen System – DI engines	Near term Long term	\$10(x) + \$147 \$8(x) + \$111	Displacement	DI engines adding a CDPF
2012 76hp Backhoe	2012 is Near Term	\$10(3.9)+\$147= \$186	3.9 liters	The example engine is a DI engine and has a CDPF
DOC	Near term Long term	\$18(x) + \$116 \$18(x) + \$110	Displacement	<25 hp engines beginning in 2008; 25-75 hp engines 2008 thru 2012
2012 76hp Backhoe	2012 is Near Term	not applicable	3.9 liters	Example engine rated power is greater than 75 hp
CCV System	Near term Long term	\$2(x) + \$34 \$2(x) + \$24	Displacement	All turbocharged engines when they first meet a Tier 4 PM std.
2012 76hp Backhoe	2012 is Near Term	\$2(3.9)+\$34= \$42	3.9 liters	The example engine is turbocharged
Cooled EGR System	Near term Long term	\$43(x) + \$65 \$33(x) + \$48	Displacement	25-50 hp engines beginning in 2013; >750hp engines beginning in 2011
2012 76hp Backhoe	2012 is Near Term	not applicable	3.9 liters	Example rated power is greater than 50 hp
Common Rail Fuel Injection (mechanical fuel system baseline)	Near term Long term	\$78(x) + \$636 \$58(x) + \$484	# of cylinders/ injectors	25-50 hp DI engines when they add a CDPF
2012 76hp Backhoe	2012 is Near Term	not applicable	3.9 liters	Example rated power is greater than 50 hp
Common Rail Fuel Injection (electronic rotary fuel system baseline)	Near term Long term	\$67(x) + \$178 \$50(x) + \$134	# of cylinders/ injectors	50-75 hp DI engines when they add a CDPF
2012 76hp Backhoe	2012 is Near Term	not applicable	3.9 liters	Example rated power is greater than 75 hp

[a] Near term = years 1 and 2; Long term = years 3+. Explanation of near term and long term is in Section 6.1.
[b] Displacement refers to engine displacement in liters.

Summing the applicable variable costs estimated in table 6.5-4 gives a total engine variable cost for the 76hp Backhoe example of $1457 (Note that this value of $1457 differs from the value shown in Table 6.4-8 due to that value being based on only 50 percent of engines in this power range adding a NOx adsorber in 2012). The equipment variable costs are presented in table 6.4-10 and are referenced by engine power category. For the 76hp example here, the estimated equipment variable costs are $45.

Having estimated the engine and equipment fixed and variable costs it is possible to estimate the total new product costs (excluding operating costs changes) by simply totaling the fixed and variable costs estimated here. The resulting total is $1691 ($189 + $1457 + $45, note that rounding may result in slightly different results). Typically we have presented these total cost estimates to the nearest ten dollars.

6.5.3 Costs for Specific Examples from the Proposal

In the proposal, we developed costs and prices for several specific example pieces of equipment. Here we recreate that analysis using the costs presented above for the final rule. Table 6.5-5 shows these results. For this table, we have used the same engine and equipment related inputs (power, displacement, etc.) as was used in Table 6.5-1 of the draft RIA to facilitate the comparison.[S]

[S] Another important point here is that we have used the same load factor, activity, and fuel consumption inputs, etc., that were used in the draft RIA to ensure a fair comparison of operating cost differences between the draft analysis and the final analysis. Note also that the inputs used for the values shown in Table 6.5-5 are for the specific pieces of equipment and are not the sales weighted inputs used to generate the operating costs shown in Table 6.5-2, this explains the different results.

Table 6.5-5
Near Term and Long Term Costs for Several Example Pieces of Equipment[a]
($2002, for the final emission standards to which the equipment must comply)

	GenSet	Skid/Steer Loader	Backhoe	Dozer	Ag Tractor	Dozer	Off-Highway Truck
Horsepower	9 hp	33 hp	76 hp	175 hp	250 hp	503 hp	1000 hp
Displacement (L)	0.4	1.5	3.9	10.5	7.6	18	28
# of cylinders/injectors	1	3	4	6	6	8	12
Aspiration	natural	natural	turbo	turbo	turbo	turbo	turbo
Fuel System	DI	DI	DI	DI	DI	DI	DI
Incremental Engine & Equipment Cost Long Term Near Term	 $120 $180	 $790 $1,160	 $1,200 $1,700	 $2,560 $3,770	 $1,970 $3,020	 $4,140 $6,320	 $4,670 $8,610
Estimated Equipment Price[b]	$4,000	$20,000	$49,000	$238,000	$135,000	$618,000	$840,000
Incremental Operating Costs[c]	-$80	$70	$610	$2,480	$2,110	$7,630	$20,670
Baseline Operating Costs (Fuel & Oil only)[c]	$940	$2,680	$7,960	$27,080[d]	$23,750	$77,850	$179,530

a. Near-term costs include both variable costs and fixed costs; long-term costs include only variable costs and represent those costs that remain following recovery of all fixed costs.
b. Updated prices for the final analysis taken from, "Price Database for New Non-road Equipment," memorandum from Zuimdie Guerra to docket A-2001-28.[55]
c. Present value of lifetime costs.
d. This value corrects an error that existed in the draft RIA where we incorrectly reported the baseline operating cost as $77,850 (the value for the 503 hp dozer).

6.6 Residual Value of Platinum Group Metals

One element not considered in our cost analysis is the residual value of the platinum group metals (PGMs) in the aftertreatment devices that may be added to comply with the new engine standards. These devices cannot be lawfully removed at the end of an engine's life and reused on a new engine or piece of equipment due to deterioration and/or agglomeration of the PGMs. However, virtually all of the PGMs contained in the devices will remain there and can be removed and recycled back into the open market for use in new aftertreatment devices. This represents a residual value to these metals much like the residual value to many other parts of a truck headed for scrappage. Typically, today, the item of greatest residual value would be the engine which can be removed from an old vehicle/truck prior to scrappage, rebuilt, and then sold back into the market. This same thing can be expected to happen with the PGMs installed in the aftertreatment devices.

From experts in the field,[56, 57] we learned that there are as many as 50 major used/spent auto catalyst collection sites in the United States. Further, roughly 80 percent of spent auto catalysts are recycled in the US (only 30 percent are recycled currently in Europe, a percentage that will presumably increase as more PGM containing devices are used in Europe). We also learned that only one to two percent of platinum is lost during the recovery process and the same is true for paladium. For rhodium, as much as 10 percent is lost during the recovery process.

We can estimate the residual value of PGMs being used to comply with the Tier 4 standards by using the PGM loadings and the aftertreatment device volumes we have estimated will be used (see section 6.2.2). Doing this results in a 30-year net present value, assuming a three percent discount rate, of $3 billion (using the NRT4 PGM prices). This is roughly 20 percent of the $13.6 billion engine variable costs we have estimated. But, according to experts in the field, we cannot expect all of this value to be returned to the market. To be conservative, we have assumed that 80 percent of aftertreatment devices would be recycled and that 98 percent of the platinum in those devices would be recovered and returned to the market while only 90 percent of the rhodium would be recovered and returned to the market. Further, we have assumed that ten percent of the residual value would be kept by the recycler to cover costs associated with recycling the material (i.e., energy use, labor, and profit).[58] We must also consider the time gap between installation on a new truck and recovery. For these calculations, we used the average lifetimes by power category from our NONROAD model and assumed that, at the end of those lifetimes, 80 percent of devices would be recovered. In this way, we calculate a net present value of PGMs recovered in the year they first enter the new truck market. We have done this for each of the 30 years following implementation of the Tier 4 standards giving us a series of present values of recovered PGMs for each of 30 years. Note that, when accounting for the latency period between the new equipment purchase and the ultimate recycling, we have used a seven percent discount rate rather than three percent. Had we used a three percent rate, the savings would have been higher. Table 6.6-1 shows these results along with the total annual engine variable costs for comparison (see Table 8.2-3).

The table shows that the residual value of PGMs could amount to a 30-year net present value savings of roughly $1.2 billion, assuming a three percent social discount rate. Note that, while we have estimated the residual value at $1.2 billion versus PGM use of $3 billion, this does not mean that only 40 percent of PGMs are actually returned to the market. Instead, it means that the present value of PGMs recovered are 40 percent of the value of those initially used. By our estimation, nearly 80 percent of platinum will be recovered (98% of 80%) and just over 70 percent of rhodium will be recovered (90% of 80%). Note also that, to remain conservative in our cost estimates, we have not used these estimates in any of our cost per ton or our benefit-cost analyses. We have presented them here only for the information of the reader.

Table 6.6-1
Potential Impact of PGM Recovery on Costs
($Millions of 2002 dollars)

Year	Engine Variable Costs (including PGMs)	PGM Costs	PV of PGMs Recovered
2008	$ 62	$ 2	$ (1)
2009	$ 63	$ 2	$ (1)
2010	$ 61	$ 2	$ (1)
2011	$ 340	$ 59	$ (22)
2012	$ 637	$ 113	$ (46)
2013	$ 798	$ 130	$ (54)
2014	$ 864	$ 186	$ (76)
2015	$ 839	$ 193	$ (79)
2016	$ 852	$ 196	$ (80)
2017	$ 860	$ 199	$ (82)
2018	$ 873	$ 202	$ (83)
2019	$ 887	$ 205	$ (84)
2020	$ 900	$ 208	$ (85)
2021	$ 913	$ 211	$ (87)
2022	$ 927	$ 214	$ (88)
2023	$ 940	$ 217	$ (89)
2024	$ 954	$ 220	$ (90)
2025	$ 967	$ 223	$ (92)
2026	$ 980	$ 226	$ (93)
2027	$ 994	$ 229	$ (94)
2028	$ 1,007	$ 232	$ (95)
2029	$ 1,021	$ 234	$ (97)
2030	$ 1,034	$ 237	$ (98)
2031	$ 1,048	$ 240	$ (99)
2032	$ 1,061	$ 243	$ (100)
2033	$ 1,074	$ 246	$ (102)
2034	$ 1,088	$ 249	$ (103)
2035	$ 1,101	$ 252	$ (104)
2036	$ 1,115	$ 255	$ (105)
30 Yr NPV at 3%	$ 13,562	$ 2,996	$ (1,231)
30 Yr NPV at 7%	$ 6,871	$ 1,488	$ (611)

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CHAPTER 7: Estimated Costs of Low-Sulfur Fuels

CHAPTER 7: Estimated Costs of Low-Sulfur Fuels

This chapter presents the methodology and costs, and discusses the possible price impacts, for supplying nonroad, locomotive and marine (NRLM) diesel fuel under the final two step program. It also presents similar information for various sensitivity cases analyzed. Section 7.1 contains our analysis of the volume of NRLM diesel fuel and other distillate fuels which are affected by this program. This section also presents our estimates of the sulfur levels of NRLM diesel fuel and other fuels impacted, which is used in our emissions analysis. Section 7.2 discusses our methodology for estimating the refining costs. We present our refining cost estimates for the final rule program as well as several sensitivity cases. We also compare our cost estimates to other parties. Section 7.3 contains our estimate of the cost of adding lubricity additive to NRLM diesel fuel. Section 7.4 presents our analysis of the cost of distributing diesel fuel under this program. Section 7.5 contains a summary of the refining and distribution cost for the final rule NRLM program. Section 7.6 discusses the potential price impacts of the final NRLM program.

Table 7-1 summarizes the number of refineries we estimate will be affected by the final NRLM fuel program, as well as the total volume of NRLM fuel affected.

Table 7-1
Number of Refineries and Refining Costs for the Final NRLM Program

	Year of Program	500 ppm Fuel		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36[a]	0	0	0
	2010-2012	26	13	32	2
	2012-2014	15	13	47	2
	2014-2020	0	0	63	15
Production Volume (Million gallons per year in 2014)	2007-2010	13,327	0	0	0
	2010-2012	3,792	393	8,598	335
	2012-2014	728	393	12,247	335
	2014-2020	0	0	13,030	728

Table 2 summarizes the per gallon refining, distribution and lubricity additive costs during the various phases of the final NRLM fuel program.

Table 7-2
Summary of Fuel Costs for NRLM Fuel Control Options (cents per gallon, $2002)

Option	Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
Final Rule	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.7	0.6	3.3
	500 ppm NRLM	2012-14	2.9	0.6	3.5
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.8	1.2	7.0

Table 7-3 and 7-4 summarize the potential price impacts of the final NRLM fuel program during the initial 500 ppm phase (2007-2010) and the final 15 ppm phase (2014 and beyond). Due to the uncertainty in projecting price impacts from cost estimates, we develop three potential price impacts to indicate the range of possible outcomes.

Table 7-3
Range of Possible Total Diesel Fuel Price Increases (cents per gallon)[a]

	Lower Limit	Mid-Range Estimate	Upper Limit
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.9	1.8	4.5
PADD 2	3.0	2.5	3.8
PADD 4	3.7	3.5	6.1
PADD 5	1.2	1.5	1.5
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	7.7	6.3	9.8
PADD 2	7.6	7.9	11.2
PADD 4	8.2	13.0	13.9
PADD 5	5.1	6.8	7.2

[a] At a wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

7.1 Production and Consumption of NRLM Diesel Fuel

7.1.1 Overview

This subsection describes how we estimated the distillate fuel production and demand for land-based nonroad engines, locomotives, and marine vessels that will be affected by the requirements of this final rule. This analysis also estimates the volumes of the highway diesel fuel and heating oil[A] pools which also affect or are affected by the final NRLM fuel program. Fuel production and demand are estimated for various geographic regions of interest. We begin by estimating production and consumption of various distillate fuels in 2001. We then project these volumes to 2014, which is the year in which we project per gallon costs. We selected 2014, as IRS guidelines allow refinery equipment to be depreciated over 15 years and 2014 represents the mid-point in the depreciation life of new hydrotreaters built for the 2007 500 ppm NRLM fuel cap. NRLM fuel demand is projected to increase steadily in the future. As the number of domestic refineries is not projected to increase, the economy of scale will gradually improve over time. Selecting 2014 as the year in which to project per gallon fuel costs provides a reasonable estimate of the average economies of scale which will exist with the hydrotreaters constructed in response to the rule.

These NRLM production and consumption estimates are developed for the final NRLM fuel program, as well as for a number of alternative scenarios. We then develop a set of production and consumption estimates for NRLM fuel for each year from 1996 to 2040, which are used to estimate annual emission reductions (see Chapter 3) and fuel-related costs (Sections 7.2 through 7.5 below). Finally, we estimate how the final rule and the various alternative scenarios affect the sulfur content of the various types of distillate fuel, which is again used to estimate annual emission reductions associated with each of these scenarios.

It is important early on in this discussion to define distillate fuel and how it is used. Distillate fuel is often split into three groups according to the range of temperatures at which the hydrocarbons comprising the fuel boil (boiling range). No. 1 distillate fuel is the lightest fuel, or has the lowest boiling range. Common No. 1 distillate fuels are jet fuel, No. 1 diesel fuel, and kerosene (also known as No. 1 fuel oil). No. 2 distillate fuel is somewhat heavier and has a higher boiling range, though there is significant overlap between No. 1 and No. 2 distillate fuels. No. 2 distillate fuels are usually excellent diesel fuels. Finally, No. 4 distillate fuel is the heaviest of the three, having the highest boiling range.[B] No. 4 distillate fuel is generally a poor diesel fuel and can only be used in slower speed diesel engines. This rule does not address the sulfur content of No. 4 distillate fuel. Thus, we will not address No. 4 distillate fuels in this analysis. All of these distillate fuels boil at higher temperatures than gasoline, though there is some overlap between the heaviest compounds in gasoline and the lightest compounds in No. 1 distillates.

The vast majority of the fuel used in NRLM engines falls into the No. 2 distillate fuel category. As will be seen below, a very small volume of No. 1 distillate fuel is used to fuel

[A] The term heating oil as used here represents fuel used for stationary source purposes including home heating industrial boilers, and electrical generation.

[B] There is also a No. 6 fuel, but this is usually considered a heavy fuel or heavy oil and not included in "distillate."

NRLM engines.[C] Also No. 1 distillate fuel is often blended into No. 2 distillate fuels in the winter in cold climates to avoid fuel gelling. Thus, we will address the impact of this rule on No. 1 distillate fuel in this analysis, though the primary focus will be on No. 2 distillate fuels.

The American Society of Testing and Materials (ASTM) defines three No. 2 distillate fuels: 1) low sulfur No. 2-D, 2) high sulfur No. 2-D, and 3) No. 2 fuel oil. Low sulfur No. 2-D fuel must contain 500 ppm sulfur or less, have a minimum cetane number of 40, and have a minimum cetane index limit of 40 (or a maximum aromatic content of 35 volume percent). These specifications match those set by EPA for highway diesel fuel, so essentially these ASTM limits are legal specifications. Per ASTM, both high sulfur No. 2-D and No. 2 fuel oil (heating oil) must contain no more than 5000 ppm sulfur,[D] and currently averages about 3000 ppm. The ASTM specifications for high sulfur No. 2-D fuel also include a minimum cetane number specification of 40. The ASTM specifications for high sulfur No. 2-D and No. 2 fuel oil only have the force of law in those states which have incorporated the ASTM standards in their state laws or regulations. There are no federal standards currently for these two high sulfur fuel.

We will break down No. 2-D distillate fuel into three fuels, according to the way we regulate its quality: highway diesel fuel, NRLM diesel fuel, and heating oil. Operators of highway diesel engines must use low sulfur highway diesel fuel engines, though the low sulfur fuel can be and is used in other applications. As will be discussed further below, highway diesel fuel must currently meet a 500 ppm sulfur cap. Starting in 2006, 80% of highway diesel fuel volume will have to meet a 15 ppm cap, with 100% having to do so in 2010. NRLM diesel fuel is that fuel used in nonroad, locomotive and marine diesel engines and is the fuel primarily affected by this rule. Heating oil is all other No. 2 distillate fuel. It includes No. 2 fuel oil used in boilers, furnaces and turbines. It also includes No. 2 diesel fuel used in stationary diesel engines (e.g., for electricity generation). Heating oil is not covered by the NRLM fuel standards, but is affected because of limitations in the fuel distribution system.

We base our estimates of historical distillate fuel demand used in this analysis on EPA's Nonroad Model (NONROAD) and the Energy Information Administration's (EIA) Fuel Oil and Kerosene Sales (FOKS) report for 2001. NONROAD estimates diesel fuel consumption by the land-based nonroad engines based on the sales, scrappage and use of nonroad engines. FOKS contains detailed, comprehensive distillate fuel sales to highway vehicles and ten non-highway sectors. We use FOKS to estimate the consumption of highway, marine, and locomotive diesel fuel and heating oil, given the nonroad diesel fuel consumption from NONROAD.

We base future demand for nonroad diesel fuel again on estimates from NONROAD. Future demand for highway diesel fuel and the other non-highway sectors (locomotive, marine and heating oil) is based on estimates from EIA's Annual Energy Outlook (AEO) for 2002.

[C] No. 1 distillate fuels is mostly consumed in jet engines and tends to cost more than No. 2 distillate fuels. Since diesel engines can burn either fuel, No. 2 distillates are their preferred choice.

[D] Some states, particularly those in the Northeast, limit the sulfur content of No. 2 fuel oil to 2000 - 3000 ppm.

The methodology used for the final rule differs somewhat from that used in the NPRM. For the NPRM, we used different methodologies to estimate distillate fuel demand for the purpose of estimating emissions and for estimating fuel-related costs. For emissions, we used a methodology very similar to that being used for this final rule. However, for fuel cost estimation, we did not use NONROAD to estimate nonroad fuel consumption. We derived all of our fuel consumption estimates from FOKS and AEO, although we projected future nonroad fuel consumption with NONROAD. To avoid this inconsistency, we decided to utilize the same methodology for both emission and cost estimation purposes. As discussed in Section 2.3.2.2 of the Summary and Analysis document for this rule, we decided to use NONROAD to estimate nonroad fuel consumption for both emission and cost estimation purposes. In addition, the analysis for this final rule utilizes more recent information from FOKS 2001 and AEO 2002, as opposed to FOKS 2000 and AEO 2001, which were used in the analysis for the NPRM.

We estimate historic production of distillate fuel in these pools by starting with downstream demand. We used Information from EIA's Petroleum Supply Annual on the sales of highway diesel fuel and high sulfur distillate from refinery racks and terminals. The volume of highway diesel fuel supplied at terminals is compared to that consumed in highway vehicles to estimate the percentage of highway fuel which is used in other applications. We call highway fuel used in other applications "spillover." We then adjust the terminal level supply of highway diesel fuel to represent shifts in the volume of various fuels during distribution, particularly through pipelines. These shifts are referred to as "downgrades." The result is an estimate of production needed by refineries and importers to supply demand in the various sectors.

The sulfur level of the various distillate fuels produced at refineries is primarily controlled by applicable EPA standards. These of course vary depending on the regulatory scenario being evaluated. We also consider the impact of the small refiner provisions, which usually allow the sale of higher sulfur fuel into a particular market than would otherwise be the case. The spillover of highway fuel into non-highway sectors also affects the sulfur content of these fuels, as do the downgrades that occur during distribution. Our estimate of in-use sulfur levels of the various distillate fuels begins with in-use survey data and then adjusts these levels for changes in the sulfur content of fuel being produced, spillover and downgrades during distribution.

The two primary regulatory scenarios evaluated are: 1) a reference case, which assumes no NRLM sulfur standards and 2) the final NRLM fuel program. In addition, we evaluate several sensitivity cases:

- NRLM control only to 500 ppm in 2007 (no second step to 15 ppm),

- nonroad fuel control to 15 ppm in 2010, but keeping locomotive and marine (L&M) fuel at 500 ppm indefinitely (the proposal or NPRM case),[E] and

[E] The increment of the final rule program to this regulatory scenario is the basis for our 500 ppm to 15 ppm locomotive and marine incremental analysis.

- the final NPRM fuel program with the volume of nonroad diesel fuel derived from FOKS and AEO 2003 instead of NONROAD.

7.1.2 Distillate Fuel Production and Demand in 2001

This section describes our estimates of total production and demand by region for the various distillate fuels. The primary regions of interest are the different refining districts called PADDs.[F] There are five PADDs: 1) the East Coast, 2) the Midwest, 3) the Gulf Coast, 4) the Mountain states and 5) the West Coast, Alaska and Hawaii. Because the Alaskan and Hawaiian fuel markets are mostly distinct from the rest of PADD 5 and because California applies distinct specifications to diesel fuel sold in that state, we split PADD 5 into four pieces: the states of California, Hawaii and Alaska and the remainder of PADD 5. We will refer to this remainder of PADD 5 as PADD 5-O (with "O" denoting "other" than the specific states listed).

We begin with estimating the demand for each type distillate fuel, highway, NRLM and heating oil. We then estimate how much highway fuel was supplied at the terminal level to estimate spillover of highway fuel into the other sectors. Finally, we estimate downgrade of higher quality fuels to lower quality fuels during distribution to back-calculate the volume of each fuel produced by refineries.

7.1.2.1 2001 Distillate Demand

We obtain our estimate of total distillate demand from EIA's FOKS report for 2001.[1] This report presents results of a national statistical survey of approximately 4,700 fuel suppliers, including refiners and large companies that sell distillate fuels for end use (rather than resale). The sample design involves classification of fuel suppliers based on sales volume with subsamples in individual classes optimized to improve sample precision. Distillate fuels surveyed that are relevant to this analysis include diesel and heating oils in grades No. 1, No. 2 and No. 4. The survey requests respondents to report estimates of fuel sold for eleven "end uses" that correspond to broad economic sectors. These eleven sectors are highway, industrial, off-highway (construction and other), farm, military, railroad, marine vessel, commercial, residential, oil company and electric utility. Suppliers presumably determine the applicable sector by the type of entity which purchases the fuel (e.g., farmers buy fuel for farming). FOKS is therefore not a direct measure of how fuel is used, but a measure of who buys fuel. However, for most of these sectors it should provide a reasonable estimate. The reader is referred to Section 2.3.2.2 of the Summary and Analysis document for this rule for a more detailed description of FOKS and the fuel user surveys which provide an independent assessment of its accuracy.

FOKS presents two sets of fuel demand estimates. The first, labeled unadjusted, includes adjustments to reflect estimates of highway fuel use from the Federal Highway Administration.

[F] The Department of Energy split up the nation into five districts, called Petroleum Allocation for Defense Districts, or PADDs, during the 1970's. The regions primarily reflect where refineries get their crude oil.

The second, labeled adjusted, includes further adjustments to reflect distillate fuel use to generate electricity and to match total distillate demand to total distillate fuel supply, as estimated in EIA's Petroleum Supply Annual (PSA). EIA's PSA reports an aggregation of the volumes of fuels sold by primary suppliers, which includes refinery racks and terminals. As the PSA figures represent recorded sales from all primary suppliers, and not a survey of representative suppliers, it is a more accurate estimate of total distillate fuel supply than the total demand estimated in FOKS. Because of this, we use the adjusted FOKS demand estimates here. Thus, while we refer to total distillate fuel demand as being taken from FOKS, it is just as accurate to say that it comes from PSA.

Of the eleven economic sectors evaluated by FOKS, we are interested primarily in three: highway, railroad and marine vessels. Little fuel used in these sectors involves nonroad equipment or heating oil. The remaining eight sectors all include significant portions of nonroad fuel use and heating oil use. Because of this, we use the EPA NONROAD model to estimate nonroad fuel use and assume that the remainder is heating oil.

Table 7.1.2-1 shows total distillate fuel demand from the 2001 FOKS report, as well as total demand for highway, railroad and marine fuel from this same report.[G] Nonroad diesel fuel demand was taken from the draft NONROAD2004 model (see Chapter 3 for a detailed description of this model). Heating oil demand was set so that the total fuel demand from the five sectors equaled total fuel demand.

Table 7.1.2-1
Total Distillate Demand in 2001 by Region (million gallons)

End Use		Region							
		1	2	3	4	5-O*	AK	HI	CA
Highway		10,284	10,947	5,743	1,570	1,901	111	33	2,627
Railroad		506	1,051	883	223	100	4	0	183
Marine		461	318	1,153	0	23	67	20	52
Other	Nonroad	2,935	4,174	1,409	597	631	25	32	783
	Heating Oil	7,363	602	1,744	78	45	205	129	(41)
Total Demand		21,549	17,092	10,932	2,468	2,700	412	214	3,604

* Represents the states of AZ, NV, OR, and WA.

For this analysis, we made several small modifications to the fuel demand estimates shown in 2001 FOKS. We made one adjustment to the estimate of highway fuel demand. FHWA

[G] Since the volume of No. 4 distillate fuel is small compared to total distillate use, we did not attempt exclude No. 4 distillate use from the 2001 FOKS estimate of total distillate demand. Because of the methodology used, any incremental volume of No. 4 distillate fuel shows up as heating oil demand in Table 7.1.2-1.

estimates highway fuel demand based on fuel excise tax receipts. Individuals and businesses that purchase highway fuel for off-highway use can request a refund of this excise tax on their income tax forms. FHWA adjusts their estimates for these refund requests. However, it is possible that not everyone who uses taxed, highway diesel fuel for non-highway use files for a refund. For example, many businesses own fleets of both highway and nonroad equipment. Some owners or operators, particularly rentals, might find it expedient or necessary to purchase at least some of their nonroad diesel fuel at retail outlets such as gas stations, where high sulfur diesel fuel is usually not available. It is plausible that some fraction of the fuel attributed by FHWA to highway use is actually used for non-highway purposes. This fuel would likely be used by construction and commercial nonroad equipment users, as they are the most likely to refuel their nonroad engines at retail fuel outlets.

To gain a better understanding of this issue, EPA provided a grant to the Northeast States for Coordinated Air Use Management (NESCAUM) to conduct a survey of diesel fuel use in construction equipment in New England.[2] The survey was designed to develop methods to estimate emission inventories for construction equipment. The study area included two counties, one in Massachusetts and one in Pennsylvania. Equipment owners in selected sectors were targeted, including construction, equipment rental, wholesale trade, and government (local highway departments). Surveyors administered a questionnaire requesting information about fuel purchases and associated tax-credits. Owners reported quantities and proportions of high-sulfur (dyed and untaxed) and low-sulfur (undyed and taxed) diesel fuel purchased over the previous year. Owners who reported purchases of undyed diesel fuel for use in construction equipment were also requested to indicate whether they applied for tax credits for which they were eligible under state or federal law. The survey showed that approximately 20 percent of all diesel fuel purchased for use in "construction" was undyed diesel fuel for which the purchaser had not applied for a tax refund.

To ensure that this type of adjustment was not already included in the FOKS estimates, we confirmed with FHWA that they only subtract tax refunds from the total tax receipts from highway diesel fuel sales.[3, 4] In other words, they assume that all purchasers of taxed diesel fuel for non-highway use request a refund. Similarly, we confirmed with EIA that they do not make a similar type of adjustment.[5]

To estimate the volume of nonroad diesel fuel classified as highway fuel demand in FOKS, we applied the results of the NESCAUM survey to the FOKS estimates of construction fuel demand plus a portion of commercial fuel demand. As discussed in Section 7.1.3. below, fuel demand in the commercial sector is broken out by the type of distillate purchased. One of these fuel types is high sulfur diesel fuel, which we believe is primarily used in nonroad equipment. We believe that the results of the NESCAUM are equally applicable to these types of nonroad equipment, as they tend to be used away from the business' primary location (e.g., lawn and garden equipment). However, because the survey only covered two counties, the results are not necessarily representative of the entire U.S. Extrapolating the results to the entire U.S. is therefore uncertain. Given that we lack any other estimate, we decided to use the results of the NESCAUM survey with an ad hoc adjustment, where the percentage of unrefunded highway fuel used is assumed to be 10%, as opposed to the surveyed 20%.

Table 7.1.2-2 shows the volume of construction and commercial, high sulfur diesel fuel, and the portion believed to be made up from unrefunded highway fuel by region. We reduced the total construction volume by 5% to not base our estimates of unrefunded fuel on that portion which is estimated to be used as heating oil (see below). On a nationwide average, this unrefunded highway fuel represents 0.7% of total highway fuel demand. As will be shown below, we reduce the volume of highway fuel demand in each region by the volume shown in Table 7.1.2-2.

Table 7.1.2-2
Unrefunded Use of Taxed Highway Fuel in Nonroad Equipment in 2001 (million gallons)

	Region							
	1	2	3	4	5-O	HI	AK	CA
Total Construction*	550	602	448	124	87	4	7	264
Nonroad Portion (0.95)	523	572	425	118	83	3	7	251
Unrefunded Fuel (10%)	52	57	43	12	8	0.3	0.7	25
Commercial: #2 High Sulfur Diesel Fuel *	203	155	71	8	19	2	21	3
Unrefunded Fuel (10%)	20	16	7	1	2	0.2	2	0.3
Total Unrefunded Fuel	73	73	50	13	10	1	3	25

* FOKS 2001

While we believe that this highway fuel is used in nonroad engines, we did not increase the nonroad fuel demand shown in Table 7.1.1-1 above. This adjustment is not necessary since the NONROAD model projects fuel use for the entire in-use nonroad equipment fleet and does not consider where the fuel is purchased. As will be seen below, the result is that this reduction in highway fuel demand causes an analogous increase in the demand for heating oil under our methodology.

We also made minor adjustments to the FOKS estimates for diesel fuel demand for locomotive engines and marine vessels. Based on guidance from EIA staff, 5% of the fuel purchased by railroads is heating oil, under our definitions described above.[6] Thus, we reduced the railroad fuel demand from FOKS by 5%. We further reduced the railroad fuel demand by an additional 1%, which represents fuel believed to be used in nonroad diesel engines in railyards and which is already included in the nonroad fuel demand estimates from NONROAD.[7] The FOKS estimates of fuel demand for marine vessels were multiplied by 90%, to remove the use of heating oil and No. 4 distillate fuel included in the FOKS estimates. Again, this was based on guidance from EIA staff.[8]

Table 7.1.2-3 shows the FOKS and NONROAD estimates of distillate fuel demand, the adjustments made and the final estimates. Only the revised estimate of heating oil demand is shown, as this is simply back-calculated from the total demand for the other fuels and total distillate demand.

Table 7.1.2-3
Adjusted Distillate Demand by Region in 2001 (million gallons)

End Use	Region							
	1	2	3	4	5-O	AK	HI	CA
FOKS Highway	10,284	10,947	5,743	1,570	1,901	111	33	2,627
Unrefunded fuel (0.7%)	73	73	50	13	10	3	1	25
Revised Highway	10,211	10,873	5,694	1,557	1,890	108	32	2602
FOKS Railroad	506	1,051	883	223	100	4	0	183
Revised Railroad	476	989	831	209	94	4	0	172
FOKS Marine	461	318	1,153	0	23	67	20	52
Revised Marine	415	286	1,037	0	20	60	18	46
Nonroad	2,935	4,174	1,409	597	631	25	32	783
Heating Oil	7,511	769	1,961	105	64	214	132	0
Total	21,549	17,092	10,932	2,468	2,700	412	214	3,604

7.1.2.2 2001 Distillate Fuel Production

Refiners do not produce exactly the same volume of fuel which is consumed. This is especially true for the specific categories of distillate fuel. The largest difference occurs with highway diesel fuel. All fuel used in highway diesel engines must meet EPA's 500 ppm sulfur cap. Other distillate fuel does not. However, fuel meeting the highway diesel fuel specification can be used in the other four categories. As is shown below, this occurs to a significant extent. We refer to this as spillover. Thus, the production of highway diesel fuel tends to be much larger than is actually consumed in highway diesel engines. More importantly for this rule, the highway fuel used in NRLM engines already meets the sulfur caps of the final NRLM fuel program. Thus, this spillover fuel faces no new production or distribution costs due to this rule.

Also, a certain amount of mixing occurs when fuel is shipped in pipelines, particularly at the interface between fuel batches. The properties of this interface material are a blend of the properties of the two distinct fuel batches. Generally, this interface material does not meet the specification of one of the two fuels and is cut into the batch of the lower quality fuel. We refer to the volume of the higher quality fuel that is lost to the lower quality fuel as downgrade. However, sometimes this interface does not meet the specifications of either fuel and has to be segregated from both batches and reprocessed. This downgraded material is referred to as transmix.

Downgrade can both increase and decrease the supply of distillate fuel relative to that which was produced by refineries. We consider these changes in the supply various distillate fuels below when estimating the cost of providing NRLM fuel meeting the final NRLM sulfur standards.

Spillover

Spillover is the volume of highway diesel fuel supplied which exceeds highway diesel fuel demand and is thus used by off-highway users. We estimate spillover volume by subtracting diesel fuel consumption by highway vehicles from the total supply of low-sulfur, highway fuel. We already estimated highway fuel consumption by highway engines (see Table 7.1.2-3 above). We obtain highway fuel supply to each region from EIA's Petroleum Marketing Annual 2001.[9] It should be noted that PMA estimates distillate fuel supply from primary suppliers, which are primarily refinery racks and terminals. Thus, any downgrades occurring in pipelines have already occurred. However, fuel sales by transmix processors are included in PMA. Thus, any distillate fuel recovered from transmix processing is also included in PMA. Table 7.1.2-4 shows the spillover volumes in each region based on the above information.

Table 7.1.2-4
Highway Fuel Spillover in 2001 (million gallons)

	1	2	3	4	5-O	AK	HI	CA	U.S.
Total Supply	10,596	12,549	6,532	2,067	2,206	111	45	3,568	37,674
Highway Engine Demand	10,211	10,873	5,694	1,557	1,890	108	32	2,602	32,967
Spillover	385	1,676	838	510	316	3	13	966	4,707

Information on the use of this spillover of highway fuel in the individual nonroad, locomotive, marine, and heating oil markets does not exist. Therefore, we assume that this spillover represents the same percentage of total demand for each fuel category within a region. Table 7.1.2-5 shows spillover, total non-highway distillate demand, and the percentage of spillover to non-highway distillate demand by region.

Table 7.1.2-5
Spillover As Percentage of the Non-Highway Distillate Demand, 2001 (million gallons)

	1	2	3	4	5-O	AK	HI	CA
Spillover	385	1,676	838	510	316	3	13	9
Non-Highway Distillate Demand	11,337	6,218	5,238	911	809	303	182	1,001
Spillover (% of Non-Highway Demand)	3.4	26.9	16.0	55.9	38.9	1.0	7.1	100

As can be seen, the degree of spillover varies widely across the U.S. Spillover is very low in Alaska and Hawaii, because of the absence of fuel product pipelines. Spillover is also very low in

PADD 1, because of its large demand for high sulfur heating oil. This large demand causes high sulfur distillate to be available nearly everywhere, particularly in the northern portion of PADD 1. Thus, there is little reason for highway fuel to be used in non-highway applications. Spillover is relatively high in PADD 4 due to the fact that several pipelines in the region do not carry high sulfur distillate. Finally, spillover is very high in California, as that State requires the use of 500 ppm fuel in nonroad engines.

The final issue is the distribution of this spillover into the four high sulfur distillate markets: nonroad, locomotive, marine, and heating oil. Differences do exist in the way that these fuels are typically shipped, particularly for locomotive and marine fuel. This could affect the relative volume of spillover added to that market. However, data are not available which indicate any difference in the distribution of spillover. Thus, except for the unrefunded use of highway fuel in the construction and commercial sectors, we assume that the spillover is distributed into the four high sulfur distillate markets in proportion to their total demand. Consistent with the way the NESCAUM survey was conducted, we assume that the portion of spillover coming from unrefunded use of highway fuel is all nonroad fuel demand.

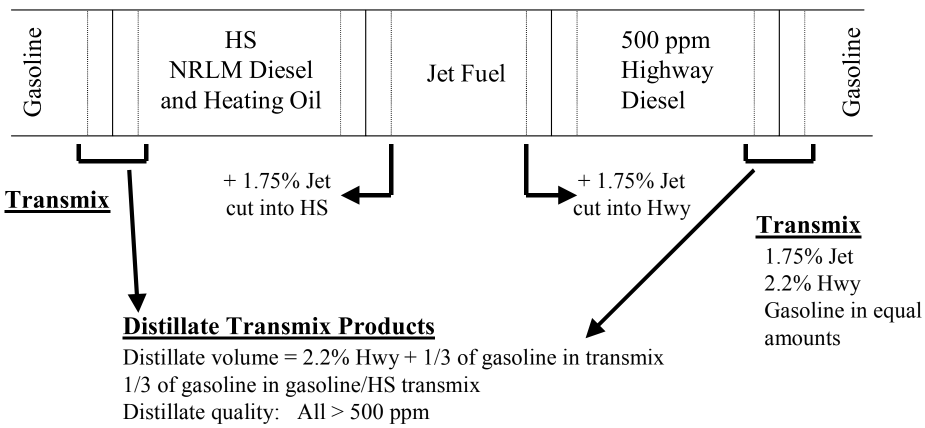
Downgrade

When fuel is shipped through pipelines, the batch of one fuel flows immediately next to a batch of another fuel. As the fuel flows through the pipeline, the two fuels start to mix at the interface of the two batches. This interface takes on a character of its own and its properties are a blend of the properties of the two fuels. The mixture is commonly called interface material or simply interface. Depending on the properties of the two fuels and the stringency of the specifications what each fuel must meet, this interface material can simply be cut in half and blended into the two batches of fuel. In this case, there is no loss of volume in either batch. However, usually one of the two fuels is of higher quality than the other and the interface is blended into the lower quality batch. In this case, the lower quality fuel gains volume, while the higher quality fuel loses volume. This loss of volume is called downgrade.

The loss of higher quality fuel volume through downgrade means that more of this fuel must be produced than implied by demand. Likewise, the gain of lower quality fuel volume through downgrade means that less of this fuel must be produced than implied by demand. The latter is particularly important after the control of NRLM fuel sulfur content, as heating oil demand (a sink for high sulfur downgrade) in some of the regions is quite limited. Also, the sulfur content of downgrade will differ from that of fuels produced at refineries. Thus, the relative volume of downgrade being sold in each fuel market will affect the average in-use sulfur content of that fuel and the emission reductions resulting from this NRLM rule.

Figure 7.1-1 shows the order in which petroleum fuels are typically shipped through pipelines today.[10] Jet fuel is often “wrapped” with high sulfur distillate and highway diesel fuel. The sides of the batches of high sulfur distillate and highway diesel fuel not adjacent to jet fuel are often adjacent to gasoline of some type. The order of fuels can vary from pipeline to pipeline. However, the specific order will generally not affect the volumes and quality of downgrade estimated here. According to our methodology, the size of the various interfaces are generally independent of the adjacent fuels and any distillate fuel lost to transmix is recovered by transmix processors. The only difference might be the percentage of downgraded distillate which is able to be sold to the 500 ppm highway fuel market versus the high sulfur distillate market. While this breakdown affects current fuel supply, it is not an issue once diesel fuel must meet a 15 ppm cap.

Figure 7.1-1 Pipeline Sequence and Fate of the Interface Between Fuel Pipeline Batches in 2001



At the interface between these different fuels there is a mixing zone which results in the two fuels contaminating each other. There are two different ways this mixed fuel between the two fuels is dealt with by the pipeline companies. One way that pipeline companies deal with the interface between the two fuels is to simply downgrade the mixture into the batch of fuel with the lowest quality. Pipeline companies have informed us that the entire interface zone between jet fuel and highway diesel fuel and also the interface zone between jet fuel and high sulfur distillate is simply "cut" into the batches of highway diesel fuel and high sulfur distillate, respectively, by timing their valve actions. This can occur because jet fuel would generally comply with the specifications of the other two pools.[H]

The second way to handle this interface occurs when the specifications governing the quality of each fuel prevents the interface from being blended into either fuel. This always occurs between a batch of gasoline and a batch of any distillate fuel. Even a small amount of gasoline would cause diesel fuel to exceed its flashpoint limit. Similarly, a small amount of diesel fuel would cause gasoline to exceed its endpoint limits. In this case, the interface is commonly referred to as transmix. Transmix must be separated from either batch, is usually stored in a transmix tank with other types of transmix, and then shipped to a transmix processor. The

[H] The sulfur content of jet fuel often exceeds 500 ppm. However, adding a small volume jet fuel to highway diesel fuel usually will not cause the sulfur content of the highway diesel fuel to exceed 500 ppm.

physical characteristics of pipeline mixing indicate that the interface would generally contain roughly even quantities of gasoline and distillate. We assume that this is the case here.

The transmix processor distills the transmix to produce a reprocessed gasoline and distillate fuel. However, there is some overlap between the lower temperature boiling components of distillate, particularly jet fuel and the higher temperature boiling components of gasoline. The lower temperature boiling components of distillate have a particularly low octane number. If any significant quantity of distillate is mixed with the gasoline product, the cost of raising the octane number to back to 87 or higher is economically prohibitive. Therefore, transmix processors operate their distillation columns so that roughly one-third of the original gasoline contained in the transmix leaves with distillate product.

We are not concerned with the gasoline produced by transmix processors here. However, the gasoline portion of the original transmix which enters the distillate pool in this fashion affects both the volume and sulfur content of the distillate fuel pool and is, thus, relevant to this discussion.

The distillate portion of current transmix can consist of highway diesel fuel, jet fuel and high sulfur distillate, plus the heaviest components of gasoline. Because most pipelines carry high sulfur distillate fuel currently and jet fuel often exceeds 500 ppm sulfur, and because most facilities have only one tank for storing transmix from all interfaces, we assume that the distillate produced from transmix is usually sold as high sulfur distillate. Thus, per Figure 7.1-1, the highway diesel fuel portion of transmix is shifted to high sulfur distillate supply.

The next step in our assessment of downgrade is to estimate its volume. The jet fuel downgrade is easiest to estimate because, assuming the shipping order shown in Figure 7.1-1, it is simply cut into each adjacent pool. We polled several pipeline companies to obtain an estimate on the quantity of jet fuel downgraded today. Their estimates of the volume of jet fuel downgraded during distribution ranged from 1% to 7%.[11] We assumed that the national average downgrade percentage was near the mid-point of this range, or 3.5%. Per Figure 7.1-1, half of this volume is shifted to the highway fuel market and half is shifted to the high sulfur distillate market. Table 7.1.2-6 shows this shift.

Table 7.1.2-6
Types of Downgrade and Their Volumes in 2001

Interface	Original Fuel	Destination	Volume
Jet Fuel Interface	Jet Fuel	Highway Diesel Fuel	1.75% of jet fuel demand
		High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Neutral
	Gasoline	High Sulfur Distillate	Equivalent to 0.58% of jet fuel demand
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	High Sulfur Distillate	2.2% of highway diesel fuel supply
	Gasoline	High Sulfur Distillate	Equivalent to 0.73% of highway diesel fuel supply

The other downgrades occur through the creation of transmix and its processing. Starting with high sulfur distillate fuel, some of the volume of this fuel is lost to transmix. However, transmix processors return all of the distillate portion of the original transmix to their distillate product. As stated above, we assume that all the distillate produced by transmix processors contains more than 500 ppm sulfur and is sold to the high sulfur distillate market. Thus, the volume of high sulfur distillate which is lost to transmix is eventually returned to the high sulfur distillate market by transmix processors. The result is no net loss or gain in the high sulfur distillate market through its mixture with gasoline. This is shown in Table 7.1.2-6.

While the high sulfur distillate portion of this transmix returns to the fuel pool from which it came, the gasoline which abuts high sulfur distillate in the pipeline does not all return to gasoline supply. The heaviest portion of this gasoline moves from the gasoline market to the high sulfur distillate market. We were not able to obtain a direct estimate of the volume of gasoline lost in this manner or the volume of high sulfur distillate shifted to transmix. Thus, we estimate this volume by comparing it to the volume of jet fuel moved to the high sulfur distillate pool. As mentioned above, the mixing properties of all these fuels are fairly similar. They also have flowed through the pipeline over the same distance (i.e., all these fuels are major products which tend to flow the entire length of the pipeline). Thus, it is reasonable to assume that the interface on either side of the batch of high sulfur distillate has the same volume. If 1.75% of jet fuel is lost to high sulfur distillate on one side of the batch, then the same volume of high sulfur distillate will be lost to transmix on the other side of the batch. Likewise, the same volume of gasoline will be lost to this transmix through the interface with high sulfur distillate. The percentages of gasoline and high sulfur distillate lost will not be the same as the size of the jet fuel, gasoline and high sulfur distillate batches will likely differ, since their total demands vary widely. However, the absolute volumes of jet fuel, gasoline and high sulfur distillate contributing to the interfaces should be very similar.

As mentioned above, two-thirds of the gasoline portion of transmix leaves the transmix processor as naphtha and returns to the gasoline pool. However, the other one-third leaves as distillate. As mentioned above, we assume that it does so as high sulfur distillate today. Thus, a volume of gasoline equivalent to one-third of 1.75% of jet fuel demand (or 0.58% of jet fuel demand) is shifted from gasoline to the high sulfur distillate fuel market. This is shown in Table 7.1.2-6.

This leaves the downgrade of highway diesel fuel. In the Final RIA for the 2007 highway diesel rule, we estimated that a clean cut on one side of highway diesel fuel batches would downgrade 2.2% of the supply of highway diesel fuel.[1] We have applied this estimate in this analysis, as well. In Figure 7.1-1, this 2.2% loss occurs via the creation of transmix with gasoline. We assume that the volume of gasoline contributing to this transmix is the same, 2.2% of highway diesel fuel supply. All of the highway diesel fuel leaves the transmix processor as high sulfur distillate. One-third of the gasoline (equivalent to 0.73% of highway diesel fuel supply) does so, as well. These downgrades are shown in Table 7.1.2-6.

The volumes of the various types of downgrade shown in Table 7.1.2-6 fall into two groups. The first are a function of jet fuel demand, while the second are a function of highway diesel fuel supply. To simplify our calculations, we aggregated the volumes of these two types of downgrades to create just two categories of downgrades, jet-based downgrade and highway fuel-based downgrade. Jet-based downgrade consists of the jet fuel lost to both the highway and high sulfur distillate fuel supplies. It also includes the gasoline lost to the high sulfur distillate pool via interface with high sulfur distillate fuel in the pipeline. In total, the jet-based downgrade represents 4.08% of jet fuel demand. Of this 4.08%, 1.75% shifts to highway diesel fuel supply, while 2.33% shifts to high sulfur distillate supply. Highway fuel-based downgrade consists of the highway diesel fuel and gasoline which is shifted to high sulfur distillate supply via the interface between highway diesel fuel and gasoline in the pipeline. This downgrade consists of 2.93% of highway diesel fuel supply.

The relative volumes of jet fuel demand and highway diesel fuel supply vary across the various regions of the country being evaluated here. Thus, the relative volumes of the two types of downgrade will vary, as well. Table 7.1.2-7 shows the demand for jet fuel and highway diesel fuel, the volume of each type of downgrade and the portions of these downgrades shifted to highway and high sulfur distillate fuel. Since the States of Alaska and Hawaii have no product pipelines, we assumed no downgrade occurs there.

[1] When highway diesel fuel must meet a 15 ppm cap standard starting in 2006, we project that the amount of downgrade will increase to protect the cleaner highway diesel fuel. We discuss this in the next section.

Table 7.1.2-7
Downgrade Generation and Disposition in 2001 (Million gallons)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
Jet-Based Downgrade								
Jet Fuel Demand (PMA)	4,585	3,776	6,095	562	1,580	1,014	325	3,772
Downgrade Loss	187	154	249	23	64	0	0	154
To Highway Fuel	80	66	107	10	28	0	0	66
To High Sulfur Fuel	107	88	142	13	37	0	0	88
Highway Fuel Based Downgrade								
Highway Fuel Supply	10,596	12,549	6,532	2,067	2,206	111	45	3,568
Downgrade Loss	310	368	191	61	65	0	0	105
Net Highway Fuel Loss*	233	276	144	45	49	0	0	78
High Sulfur Fuel Gain	310	368	191	61	65	0	0	105

* The difference is due to downgrade from gasoline.

The final issue is how the new supply of high sulfur distillate is apportioned among the four uses of high sulfur distillate fuel: nonroad, locomotive, marine, and heating oil. Data are not available which indicate any difference in the final disposition of high sulfur distillate fuel produced from transmix compared to that produced by refineries. Thus, we assume that the spillover is equally distributed into the four non-highway distillate markets in proportion to their demand.

Production

Distillate fuel production must be sufficient to supply demand, considering changes in supply during distribution. Since the net loss in highway fuel produced is 2.2%, highway fuel production must be 2.2% higher than that indicated in EIA's PMA for 2001. Likewise, the production of high sulfur distillate fuel is lower than the estimate of supply from PMA, due to the addition of some gasoline, jet fuel and highway diesel fuel. The balance of production, gains and losses during distribution and final supply are shown in Table 7.1.2-8.

Table 7.1.2-8
Distillate Production and Demand in 2001 (million gallons)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 500 ppm	10,840	12,847	6,622	2,115	2,227	111	45	34,806	3,468	38,275
	Spillover to Non-hwy	-383	-1,656	-831	-504	-312	-3	-13	-3,701	-830	-4,532
	Hwy Downgrade	-327	-387	-202	-64	-68	0	0	-1,048	-95	-1,143
	Jet Downgrade	81	69	105	10	43	0	0	309	59	368
	Demand	10,211	10,873	5,694	1,557	1,890	108	32	30,366	2,602	32,968
Non-road	Production HS	2,672	2,725	1,064	215	289	22	29	7,016	0	7,015
	Hwy Spillover	151	1,130	255	332	245	3	3	2,118	675	2,787
	Jet Downgrade	28	61	38	9	45	0	0	181	61	242
	Hwy Downgrade	83	258	53	41	53	0	0	489	72	561
	Demand	2,935	4,174	1,409	597	631	25	32	9,803	783	10,586
Loco-motive	Production HS	445	658	651	77	44	4	0	1,878	0	1,879
	Hwy Spillover	13	255	125	114	36	0	0	543	142	685
	Jet Downgrade	5	15	22	3	7	0	0	51	14	65
	Hwy Downgrade	14	62	32	15	8	0	0	131	17	148
	Demand	476	989	831	209	94	4	0	2,604	172	2,776
Marine	Production HS	388	190	813	0	9	60	17	1,478	0	1,477
	Hwy Spillover	11	74	156	0	8	0	1	250	38	288
	Jet Downgrade	43	4	28	0	1	0	0	37	4	41
	Hwy Downgrade	12	18	40	0	2	0	0	72	4	77
	Demand	415	286	1,037	0	20	60	18	1,838	46	1,884
Heating Oil	Production HS	7,014	511	1,537	39	30	214	123	9,469	0	9,469
	Hwy Spillover	207	198	295	57	24	0	9	791	0	791
	Jet Downgrade	72	11	52	2	5	0	0	142	0	142
	Hwy Downgrade	218	48	76	7	5	0	0	356	0	356
	Demand	7,511	769	1,961	105	64	214	132	10,757	0	10,757

7.1.3 Distillate Fuel Production and Demand in 2014

As described in Section 7.2.1, we estimate the cost per gallon of desulfurizating NRLM fuel using refinery specific production volumes indicative of 2014. This is the mid-point of the useful life of hydrotreating equipment built in 2007, per IRS depreciation guidelines. Thus, using production volumes from 2014 provides a reasonable estimate of the economies of scale of hydrotreating expected to exist over the life of new equipment built in response to this rule.[J] As was the case for 2001, we begin with estimating future demand, and then estimate the fuel production necessary to satisfy this demand considering spillover and downgrades.

[J] In Chapter 8, we project the cost of replacing the hydrotreaters built in 2007. In doing so, we did not increase the estimated refinery-specific production volumes to represent growth in NRLM fuel demand beyond 2022 (2007 plus the 15 year life of the equipment). This overestimates the cost of replacement equipment to a small extent.

7.1.3.1 Distillate Fuel Demand in 2014

We derive our estimates of growth in highway, locomotive and marine fuel demand from 2001 to 2014 from EIA's AEO for 2003.[12] Table 7.1.3-1 shows the projected growth in demand for these three fuels, as well as projected growth for jet fuel demand. The fuel demand in each of these three categories in 2001 (shown in Table 7.1.2-8) were multiplied by the respective growth factors to estimate fuel demand in 2014. This implicitly assumes that the same growth rate applies in each region.

Table 7.1.3-1
Projected Growth in Highway, Locomotive and Marine Fuel Demand: EIA 2003 AEO

	Highway	Locomotive	Marine	Jet Fuel
Demand in 2001 (trillion BTU)	5440	630	340	3960
Demand in 2014 (trillion BTU)	7840	710	390	2970
Growth Factor to 2014	1.44	1.13	1.14	1.34

Nonroad fuel demand in 2014 was estimated using the draft NONROAD2004 model, as was done for 2001. Nonroad fuel demand in 2014 is estimated to be 14,379 million gallons per year, which represents a 36% increase over 2001.

We projected the growth in heating oil demand from information contained in the 2003 AEO 2003, along with our own estimates of the heating oil portion of each of the economic sectors tracked in AEO. In its 2003 AEO, EIA projects the demand of petroleum fuels from 2001-2025 based on historical demand and econometric and engineering forecasts. AEO does not provide forecasts for heating oil demand as we define it here. Thus, we estimate the heating oil portion of the fuel demand in each economic sectors tracked in AEO. We then weighted the growth in the fuel demand in each of the economic sectors by its contribution to total heating oil demand in 2001. Table 7.1.3.2 shows distillate fuel demand in each of the economic sectors tracked by AEO. (Highway fuel use is not shown, since there is no heating oil use in this category.) The estimates of demand were taken from the 2001 FOKS report. FOKS breaks down fuel use by fuel type for several of the sectors. We believe that the use of distillate fuel varies depending on the type of fuel being consumed (e.g., low sulfur diesel fuel, high sulfur diesel fuel, high sulfur fuel oil) The FOKS breakdown allows us to apply distinct heating oil percentages to each sector and fuel type combination. The information presented in Table 7.1.3-2 describes the process we used to estimate the source of heating oil demand in 2001.

Table 7.1.3-2
Source of Heating Oil Demand: 2001

End Use	Fuel Grade	Distillate Fuel		Heating Oil	
		FOKS Volume (1000 gal)	Percent Heating Oil	Volume (1000 gal)	Percent Heating Oil Pool
Farm	diesel	3,351	0	0	0
	distillate	77	100	77	0.7
Construction	distillate	2,086	5	104	0.9
Other/(Logging)	distillate	428	5	21	0.2
Industrial	No. 2 fuel oil	354	100	354	3.2
	No. 4 distillate	44	100	44	0.4
	No. 1 distillate	44	60	26	0.2
	No. 2 low-S diesel	849	0	0	0
	No. 2 high-S diesel	1,033	0	0	0
Commercial	No. 2 fuel oil	1,546	100	1,546	14.1
	No. 4 distillate	200	100	200	1.8
	No. 1 distillate	63	80	50	0.5
	No. 2 low-S diesel	1,212	0	0	0
	No. 2 high-S diesel	483	0	0	0
Oil Company	distillate	820	50	410	3.7
Military	diesel	310	0	0	0
	distillate	36	100	36	0.4
Electric Utility	distillate	1,510	0	1,510	13.8
Railroad	distillate	2,952	5	148	1.3
Vessel Bunkering	distillate	2,093	10	209	1.9
On-Highway	diesel	33,130	0	0	0
Residential	No. 2 fuel oil	6,151	100	6,151	55.9
	No. 1 distillate	112	100	112	1.0
Total		58,971		10,998	100

The key figures in Table 7.1.3-2 are the percentages of each economic sector and fuel type combination which we believe falls into our definition of heating oil. These percentages were derived using the same methodology which we use in Section 7.1.4 below to derive an estimate of nonroad fuel demand from FOKS fuel demand estimates. The difference here is that we are not focused on nonroad fuel demand, but on heating oil demand. In most of the economic sectors shown in Table 7.1.3-2, if the fuel is not nonroad fuel, it is heating oil. The exceptions to this are: 1) locomotive and marine vessel fuel, where the fuel that is not heating oil is locomotive or marine fuel, respectively, and low sulfur diesel commercial fuel, which is highway fuel which is not subject to highway fuel excise taxes (e.g., school buses).

As shown in Table 7.1.3-2, we multiply the total fuel demand for that specific economic sector and fuel type by its heating oil percentage to estimate the volume of heating oil demanded in that sector-fuel type combination. We then divide that heating oil demand by total heating oil demand to derive the percentage of total heating oil demand represented by that sector-fuel type combination. The information presented in Table 7.1.3-3 describes the next step in this process. Table 7.1.3-3 shows the total distillate fuel demand in 2001 and 2014 from 2003 AEO and the ratio of these fuel demand volumes.

Table 7.1.3-3
Projected Growth in Heating Oil Demand: 2001 to 2014

Category	2001 Distillate Demand *	2014 Distillate Demand *	Ratio of 2014 to 2001 Distillate Demand	Percent of Total Heating Oil Demand
Farm	469	533	1.14	0.7
Construction	238	274	1.15	0.9
Logging/Other	55.6	59.9	1.08	0.2
Industrial	1,130	1,270	1.12	3.8
Commercial	460	490	1.07	16.4
Oil Company	6.2	0	0	3.7
Military	101	124	1.22	0.4
Electric Utility	170	90	0.70	13.8
Railroad	628	707	1.13	1.3
Vessel Bunkering	345	394	1.14	1.9
Residential	910	880	0.97	56.9
Weighted Ave.	-	-	0.93	

* Trillion BTU from the 2003 AEO.

We weighted the growth in each sector's distillate fuel demand by that sectors' contribution to 2001 heating oil demand. For farm, industrial, commercial, residential and military, the contributions of the various fuel types shown in Table 7.1.3-2 were combined for use in Table 7.1.3-3. The result is that heating oil demand is projected to shrink by 7% between 2001 and 2014. Thus, we multiplied the heating oil demand in each region shown in Table 7.1.2-8 by 0.93 to estimate heating oil demand in 2014. Table 7.1.3-4 shows the resulting distillate demands projected for 2014 for the five fuel categories. Table 7.1.3-4 also shows jet fuel demand in 2014, which represents a 34% increase over those shown in Table 7.1.2-7.

Table 7.1.3-4
Distillate Demand in 2014 (million gallons)

End Use	Region								
	1	2	3	4	5-O	AK	HI	CA	U.S.
Highway	14,722	15,676	8,210	2,245	2,725	157	46	3,752	47,533
Nonroad	3,987	5,670	1,914	810	857	34	43	1,064	14,379
Railroad	536	1,114	935	236	106	5	0	194	3,126
Marine	475	327	1,187	0	23	69	21	53	2,155
Heating Oil	6,970	714	1,820	98	59	199	122	0	9,982
Total No. 2 Distillate Demand	26,690	23,501	14,066	3,389	3,770	464	232	5,063	77,175
Jet Fuel	6,143	5,060	9,313	753	2,117	1,359	436	5,054	30,235

7.1.3.2 Future Distillate Fuel Production

The primary purpose of projecting production of the various types of distillate fuel in 2014 is to factor in appropriate economies of scale for the investment in new desulfurization equipment to comply with the NRLM sulfur standards. We use 2014 production volumes to estimate these costs for all of the steps of the final NRLM fuel program, because 2014 represents the mid-point of the life of refinery equipment for the purposes of calculating annual depreciation under IRS guidelines. The five steps for which production volumes were estimated are:

1) Reference Case (i.e., no NRLM Program),
2) Final NRLM fuel Program: 2007-2010,
3) Final NRLM fuel Program: 2010-2012,
4) Final NRLM fuel Program: 2012-2014, and
5) Final NRLM fuel Program: 2014 and beyond

7.1.3.2.1 Reference Case; no NRLM Fuel Program

There are two distinct periods which define the reference case which assumes that the NRLM fuel program was not promulgated. One is during the period between 2007 and 2010 when the highway diesel fuel program's temporary compliance option is in effect. During this time, consistent with the refiners' pre-compliance reports under the highway fuel program, we assume 5% of highway diesel fuel will be produced at 500 ppm.[13] The remainder will be 15 ppm fuel. The second period is after 2010 when the highway diesel fuel program's temporary compliance option expires and all highway diesel fuel must meet a 15 ppm cap. During both of these periods, NRLM fuel would continue to be high sulfur diesel fuel.

California has implemented its own sulfur standards for highway and nonroad diesel fuel pool starting in 2006. Thus, nonroad diesel fuel in California was assumed to already meet the 15 ppm standard in the reference case. While California will not be regulating the locomotive and marine diesel fuel quality as part of its regulation, our analysis shows that the locomotive and marine diesel fuel demand will be met using spillover and the low sulfur diesel fuel downgrade once the nonroad pool is regulated to 15 ppm. Therefore, EPA's NRLM program is not expected to have any impact on the production or distribution of locomotive and marine diesel fuel in that State.[K]

We project the production volume of highway diesel fuel in 2014 using a slightly different methodology than we used for 2001 production. For 2001, we started with supply and demand and calculated spillover. Downgraded volume was then added to estimate total production. For 2014, we start with highway fuel demand, add the spillover of highway fuel into non-highway fuel markets based on 2001 estimates, and add the volume of highway fuel which is downgraded to lower quality fuel.

The demand for highway diesel fuel was estimated in the previous section. Regarding spillover, we assume that the same constraints in the distribution system which cause most spillover to occur today will continue in the future. This means that the volume of highway fuel spilling over into each of the four non-highway fuel markets will grow as each of these markets grows. Thus, we have increased the spillover volumes shown in Table 7.1.2-5 for the nonroad, locomotive, marine and heating oil markets by the 2001 to 2014 growth factors for these fuels shown in Tables 7.1.3-1 and 7.1.3-3 (and a factor of 1.36 for nonroad fuel). The net effect of this assumption is that the percentage of demand represented by spillover in each of the four non-highway fuel markets is the same in 2014 as in 2001. Table 7.1.3-5 shows the demand for highway fuel, spillover into each of the four non-highway fuel markets, and the resultant supply of highway fuel needed to provide for this demand and spillover.

[K] Our conclusion that California will not be affected by the NRLM program is based on our nationwide analysis on how fuels are produced and distributed throughout the U.S. focusing on areas outside of California. It is possible that California fuel production and distribution is different enough that some fuel would in fact be affected by this rulemaking.

Table 7.1.3-5
Spillover of Highway Fuel in 2014 (million gallons)

End Use	Region							
	1	2	3	4	5-O	AK	HI	CA
Highway Demand	14,722	15,676	8,210	2,245	2,725	157	46	3,752
Spillover								
Nonroad	206	1,535	345	451	333	4	4	1,054
Railroad	15	287	141	129	40	0	0	0
Marine	13	84	179	0	9	0	1	0
Heating Oil	192	184	274	53	22	0	8	0
Total Spillover	425	2,090	939	633	404	4	13	1,298
Highway Supply	15,247	17,911	9,127	2,900	3,111	161	60	4,978

As mentioned above, the State of California has promulgated regulations requiring that nonroad fuel meet a 15 ppm cap, as well as highway fuel, in 2006. We have categorized this 15 ppm nonroad fuel as highway fuel to better distinguish between 15 ppm fuel which would be produced prior to this NRLM rule and that which will be produced because of this rule. Because 15 ppm nonroad fuel in California will be produced with or without this rule, we have classified it as highway fuel in our presentation. Thus, any production of 15 ppm nonroad fuel shown below will be due to this rule and not due to California regulations.

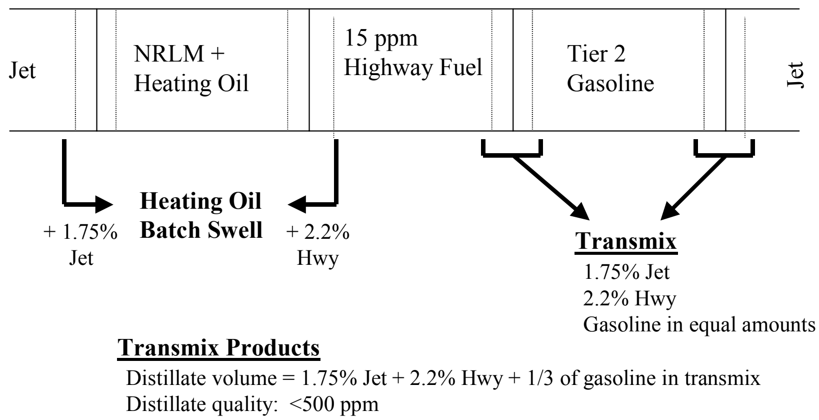
The next step is to estimate the volume of downgrade into and out of the various fuel supply pools, as was done for 2001. In the Final RIA for the 2007 highway diesel rule, we projected that the downgrade of 15 ppm highway diesel fuel would increase to 4.4% from the current estimated level of 2.2%. Thus, we assume that 4.4%[L] of the supply of highway fuel shown in Table 7.1.3-5 will be downgraded to a lower quality distillate.

The implementation of the 15 ppm highway fuel cap in 2006 could affect sequencing in some pipelines. Most pipelines will simply replace their 500 ppm highway fuel with 15 ppm highway fuel. However, some pipelines will continue to carry a 500 ppm highway fuel through mid-2010. In the Final RIA of the highway rule, we projected that roughly 40% of fuel markets would include a 500 ppm fuel to distribute the roughly 20% of highway fuel which would be at 500 ppm. However, the highway pre-compliance reports indicate a much lower percentage of highway fuel which likely be produced at 500 ppm. Because of this and for simplicity, we assume that most pipelines would not carry 500 ppm highway fuel absent the NRLM rule. However, we believe that the sequencing of fuels in pipelines will still likely change from that

[L] Due to a miscalculation, the highway diesel fuel downgrade is estimated to be 4.5% instead of 4.4% for all analyses after 2010. The overestimated highway downgrade volume overestimates the costs of the program.

shown in Figure 7.1.1. In particular, we believe that pipelines would not wrap 15 ppm highway fuel with jet fuel and heating oil, but would wrap it with heating oil and gasoline, as shown in Figure 7.1-2. With the sequence shown in Figure 7.1-1, the interface between jet fuel and 15 ppm highway fuel could not be cut into either fuel, but would have to be segregated and added to the heating oil storage tank. With the sequence in Figure 7.1-2, all of the distillate-distillate interfaces can be cut into heating oil and the only interfaces requiring segregation and processing are those containing gasoline and distillate, as is currently the case.

Figure 7.1-2 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Carry Heating Oil; Prior to NRLM Rule: 2006+



The change in sequencing affects the types of downgrade which will occur. Table 7.1.3-6 shows these downgrades and their volumes. Overall 3.5% of jet fuel volume is still downgraded to the distillate market. In addition, gasoline volume equivalent to 0.58% of jet fuel demand and 0.73% of highway fuel supply will also be downgraded to the distillate market. The volume of high sulfur distillate supplied should again not be affected. Only the volume of highway fuel downgraded will increase, from 2.2% to 4.4% of total supply. We assume that the jet fuel and highway diesel fuel interfaces with high sulfur distillate will be cut directly into the batch of high sulfur distillate. Therefore, half of the jet fuel downgrade and half of the highway diesel fuel downgrade will be cut directly into batches of high sulfur distillate. The remaining downgrades are mixed with gasoline and sent to transmix processors, where distillate fuel is recovered and sold. Due to the Tier 2 sulfur standards applicable to gasoline in 2004 and beyond and the 15 ppm highway diesel fuel cap, the sulfur content of distillate produced by transmix processors will decrease dramatically. As described in Section 7.7 below, we estimate that the sulfur content of distillate produced by transmix processors will be well below 500 ppm. The 500 ppm highway diesel fuel market should command a price premium over high sulfur distillate fuel during this timeframe. Therefore, we assume that this distillate will be sold to the 500 ppm highway diesel fuel market.

Table 7.1.3-6
Types of Downgrade and Their Volumes for the Reference Case: 2006-2010

Interface	Original Fuel	Destination	Volume
Jet Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Jet Fuel	High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Highway Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.58% of jet fuel demand
Highway Diesel Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Highway Diesel Fuel	High Sulfur Distillate	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Highway Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.73% of highway diesel fuel supply

We obtained future demand for jet fuel from 2003 AEO. There, EIA projects a 34% increase in jet fuel demand compared to demand in 2001. We applied this nationwide increase to the 2001 jet fuel demand by region shown in Table 7.1.2-7. The resultant 2014 jet fuel demand by region is summarized in Table 7.1.3-7.

Table 7.1.3-7
Downgrade Generation and Disposition for the Reference Case: 2006-2010 (Million gallons)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
Jet-Based Downgrade								
Jet Fuel Demand (PMA)	6,144	5,060	8,167	753	2,117	1,359	435	5,054
To High Sulfur Fuel	108	89	143	13	37	24	8	88
To 500 ppm Fuel	143	118	190	18	49	32	10	118
Total Downgrade	251	206	333	31	86	55	18	206
Highway Fuel Based Downgrade								
Highway Fuel Supply	15,825	18,487	9,527	2,981	3,254	161	60	5,223
To High Sulfur Fuel	348	407	210	66	72	4	1	115
To 500 ppm Fuel	464	542	279	87	95	5	2	153
Total Downgrade	812	948	489	153	167	8	3	268

The downgraded jet fuel and highway diesel fuel are cut directly into batches of high sulfur distillate being carried in the pipeline. Therefore, it is reasonable to assume that this downgrade would be distributed just as the rest of the high sulfur distillate supply. Thus, we allocate this downgrade to the four high sulfur distillate markets in proportion to the demand for each of these fuels in each region. The final projections of production, spillover, downgrade and demand for 2006-2010 for the Reference Case which assumes no implementation of this NRLM rule are shown in Table 7.1.3-8.

Table 7.1.3-8
Distillate Supply and Demand for the Reference Case: 2006-2010 (million gallons in 2014)[M]

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	14,363	16,648	8,616	2,658	2,928	152	56	45,436	4,978	50,377
	Production 500 ppm	866	1,213	532	219	200	8	4	3,029	0	3,066
	Spillover to Non-hwy	-425	-2090	-939	-633	-404	-4	-13	-4508	-1053	-5561
	Hwy Downgrade	-680	-724	-379	-104	-126	0	0	-2012	-173	-2185
	Jet Downgrade to 500 ppm	126	90	137	11	52	0	0	416	0	416
	15 ppm Hwy Downgrade to 500 ppm	453	452	235	62	73	0	0	1,276	0	1,276
	Demand 15 ppm	13,306	14,169	7,420	2,029	2,463	149	44	39,580	3,752	43,332
	Demand 500 ppm	1,416	1,508	790	216	262	8	2	4,201	0	4,201
Non-road	Production HS	3,626	3,726	1,445	290	408	30	39	9,565	10	9,575
	Hwy Spillover	206	1,535	345	450	333	4	3	2,877	1,054	3,930
	Jet Downgrade to 500*	2	9	6	2	6	0	0	25	0	25
	Hwy Downgrade to 500*	6	44	10	12	9	0	0	82	0	82
	Jet Downgrade to HS	32	59	40	8	42	0	0	181	0	181
	Hwy Downgrade to HS	115	297	68	47	59	0	0	586	0	586
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production HS	500	755	739	90	53	5	0	2,143	0	2,143
	Hwy Spillover	14	287	141	128	40	0	0	611	0	611
	Jet Downgrade to HS	5	12	20	2	5	0	0	45	144	189
	Hwy Downgrade to HS	16	60	35	14	7	0	0	133	217	350
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production HS	443	222	938	0	12	69	20	1,704	0	1,704
	Hwy Spillover	13	84	179	0	9	0	1	287	0	287
	Jet Downgrade to HS	4	3	26	0	1	0	0	35	46	81
	Hwy Downgrade to HS	15	18	44	0	2	0	0	78	59	137
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,514	484	1,440	37	30	199	114	8,819	0	8,819
	Hwy Spillover	191	184	274	53	22	0	8	734	0	734
	Jet Downgrade to HS	57	8	39	1	3	0	0	108	0	108
	Hwy Downgrade HS	206	38	67	6	4	0	0	321	0	321
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

* Highway and jet downgrade to 500 ppm spillover pool. This is not shown for other PADDs.

[M] Due to a miscalculation , the jet fuel downgrade is about 10 percent lower than if calculated as described. This error results in slightly overestimating the cost and the benefits of the program. This miscalculation occurred in all the volume analyses prior to 2010.

In 2010, the temporary compliance option of the highway program ends. Therefore, there would not be any 500 ppm highway fuel, only 15 ppm highway fuel and high sulfur distillate. The pipeline sequence shown in Figure 7.1-2 applies. All of the downgrade volumes shown in Table 7.1.3-6 would still apply. No downgraded distillate fuel would meet a 15 ppm cap. Therefore, all the downgraded distillate would be shifted to the high sulfur distillate market. As for 2006-2010, we assume that this downgrade is distributed to the four high sulfur distillate markets in proportion to the demand for each fuel in each region. The projections of production, spillover, downgrade and demand for 2010 and beyond for the Reference Case which assumes no implementation of this NRLM rule are shown in Table 7.1.3-9.

Table 7.1.3-9
Distillate Supply and Demand for the Reference Case: 2010+ (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15	15,825	18,487	9,527	2,981	3,254	161	60	50,294	5,223	55,517
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-1,053	-5,561
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production HS	3,401	3,235	1,275	221	242	30	39	8,443	10	8,453
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	1,054	3,930
	Jet Downgrade	108	199	133	28	142	0	0	610	0	610
	Hwy Downgrade	272	702	160	111	140	0	0	1,385	0	1,385
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production HS	469	647	646	66	30	5	0	1,863	0	1,863
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	15	40	69	8	18	0	0	150	144	294
	Hwy Downgrade	38	140	81	33	18	0	0	310	217	527
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production HS	416	190	820	0	7	69	20	1,521	0	1,521
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	13	12	86	0	4	0	0	114	46	161
	Hwy Downgrade	33	41	103	0	4	0	0	181	59	241
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,097	414	1,257	27	17	199	114	8,125	0	8,125
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	194	25	131	3	10	0	0	364	0	364
	Hwy Downgrade	488	90	158	14	10	0	0	759	0	759
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.3.2.2 Final NRLM Fuel Program: 2007-2010

Demand for the various categories of distillate fuel are assumed to not change under the final NRLM fuel program. Therefore, the fuel demand estimates shown in Table 7.1.3-5 apply to this scenario, as well as prior to the NRLM rule. We also assume that spillover will not be affected by the NRLM rule, because spillover occurs where only one fuel is available and this fuel will still be 15 ppm highway fuel. Thus, the production of highway fuel and the spillover of this fuel to the NRLM and heating oil markets will be the same as shown in Tables 7.1.3-5 and 7.1.3-8.

With the initiation of the NRLM fuel program in 2007, 500 ppm NRLM fuel will be widely distributed and available. Thus, pipeline sequencing will be affected. While most 500 ppm fuel is likely to be NRLM fuel, the widespread distribution of 500 ppm NRLM fuel will also facilitate the distribute of 500 ppm highway fuel. In areas with relatively small heating oil markets, such as PADDs 2 and 4 and California, we assume that the heating oil volume will be too small to justify pipelines handling a separate high sulfur distillate fuel for this market. Thus, 500 ppm NRLM fuel will replace high sulfur distillate in the common carrier distribution systems in these regions. Generally, this means that most heating oil in these regions will meet a 500 ppm cap.

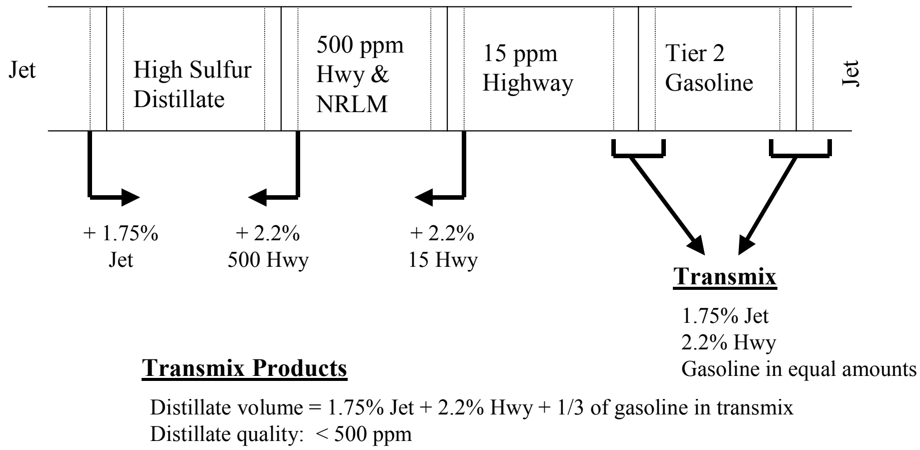
Outside of PADDs 2 and 4, we believe that the heating oil market is either sufficiently large or the distribution system is sufficiently flexible to allow the distribution of high sulfur distillate fuel to this market. The pipelines in PADD 1 are expected to carry heating oil for the large market there, and PADD 3 pipelines are expected to carry heating oil, in part, to supply the PADD 1 market. The heating oil market in the Pacific Northwest is not large. However, this area has a fairly simple distribution system and much of this heating oil consumption is believed to be on the coast. Thus, we believe that it would be feasible for a refiner to produce and distribute high sulfur distillate fuel to this market, though this distribution will not likely be by pipeline. The same is true for Hawaii. Table 7.1.3-10a summarizes these assumptions for the various regions.

Table 7.1.3-10a
Production and Distribution of High Sulfur Distillate: Final NRLM Rule: 2007-2010

	PADDs 1&3	PADDs 2 & 4	PADD 5-O	AK and HI	CA
High Sulfur Distillate in Pipelines	Yes	No	No	No pipelines	No
High Sulfur Distillate Produced for Heating Oil Market	Yes	No	Yes	Yes	No

Figures 7.1-3 depicts pipeline sequencing with 500 ppm NRLM fuel and heating oil both being carried. As shown in Table 7.1.3-10, this applies to pipelines in PADDs 1 and 3.

Figure 7.1-3 Pipeline Sequence and Fate of the Interface Between Fuel Batches in Areas that Carry Heating Oil; After NRLM Rule: 2007 - 2010



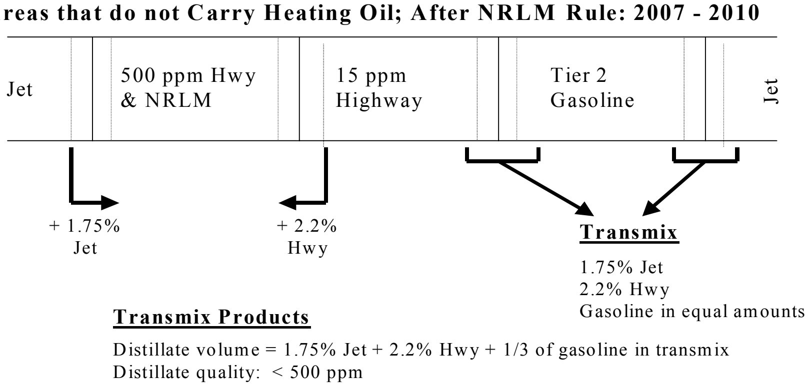
In this case, 15 ppm highway diesel fuel is downgraded directly to batches of 500 ppm fuel in the pipeline. A similar volume of 500 ppm fuel will be downgraded to high sulfur heating oil. Thus, there will be essentially no net loss of 500 ppm fuel from its batch during distribution. The loss of 15 ppm highway fuel is essentially shifted to high sulfur distillate. The interfaces containing gasoline and distillate are not affected, relative to that occurring prior to the NRLM rule. Thus, the net downgrade of 15 ppm highway diesel fuel, jet fuel and heavy gasoline is the same as that prior to the NRLM rule during this timeframe. The distillate fuel produced from transmix should still contain less than 500 ppm sulfur and can be sold to either the highway or NRLM fuel market. We generally presumed that this fuel would be sold to the highway fuel market, given the higher prices likely to exist there. However, under the designate and track provisions of the final NRLM rule, the total volume of highway fuel cannot increase during shipment. Thus, the net loss of 15 ppm highway fuel to the high sulfur distillate market must be greater than the increase in 500 ppm highway fuel from transmix distillate. Therefore, we limited the volume of transmix distillate shifted to the 500 ppm highway fuel market to the volume of 15 ppm highway fuel lost. Any remaining 500 ppm fuel produced from transmix was sent to the 500 ppm NRLM market. A detailed description of these downgrades and their volumes is shown in Table 7.1.3-10.

Table 7.1.3-10
Types of Downgrade and Their Volumes Under the NRLM Rule: 2007-2010
Pipelines Carrying Both 500 ppm NRLM Fuel and High Sulfur Distillate (PADDs 1 and 3)

Interface	Original Fuel	Destination	Volume
Jet Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Jet Fuel	High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Highway Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.58% of jet fuel demand
Highway Diesel Fuel-500 ppm NRLM Fuel Interface	Highway Diesel Fuel	500 ppm NRLM Fuel	2.2% of highway diesel fuel supply
500 ppm NRLM Fuel - High Sulfur Distillate Interface	500 ppm NRLM Fuel	High Sulfur Distillate	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Highway Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.73% of highway diesel fuel supply

Figure 7.1-4 depicts pipeline sequencing in systems that no longer carry high sulfur heating oil. This applies to pipelines in PADDs 2, 4 and 5.

Figure 7.1-4 Pipeline Sequence and Fate of the Interface Between Batches in Areas that do not Carry Heating Oil; After NRLM Rule: 2007 - 2010



The absence of high sulfur distillate in the pipeline affects the types of downgrade occurring. Both downgraded 15 ppm highway diesel fuel and jet fuel are cut directly into batches of 500 ppm fuel in the pipeline. The interfaces containing gasoline and distillate are not affected by the NRLM rule during this timeframe. As discussed in Section 7.1.6, the sulfur level of the distillate produced by transmix operators is estimated to be less than 500 ppm.

We made different assumptions regarding the disposition of this downgrade in the four applicable regions due to varying circumstances existing in each one. Because of the small size of the heating oil market in PADDs 2 and 4 (see Table 7.1.3-8), we assume that refiners will not produce high sulfur distillate fuel for the heating oil market. Thus, in these areas, we assume that this downgraded distillate will preferentially fulfill remaining heating oil demand. This might entail some additional distribution costs to reach all heating oil users, but no sulfur content testing would be required. If the volume of downgrade exceeded heating oil demand in these areas, we assumed that the downgrade would then be used in the 500 ppm highway fuel market, up to the volume of 15 ppm highway fuel lost during distribution(due to designate and track limitations). Any remaining downgrade distillate was assumed to be used as 500 ppm NRLM fuel, in proportion to each region's demand for nonroad, locomotive and marine fuel.

In California, we also assumed that refiners would not produce high sulfur distillate fuel for the heating oil market. However, California's regulations require that all highway and nonroad fuel meet a 15 ppm cap in this timeframe. Also, we project essentially no demand for heating oil in California. Thus, all downgrade distillate was assumed to be used in the L&M markets, in proportion to the demand for each fuel.

Finally, in PADD 5-O, we assumed that refiners could produce high sulfur distillate for the heating oil market, but that this would not be shipped inland in pipelines. Therefore, we assumed that the downgrade distillate would not be used to fulfill heating oil demand, but would be used as 500 ppm highway fuel up to the point allowed by the designate and track procedures. The remainder would then be used as 500 ppm NRLM fuel, in proportion to the region's demand for nonroad, locomotive and marine fuel. Table 7.1.3-11 summarizes these priorities of downgrade use in PADDs 2, 4, and 5 from 2007 - 2010 uncer the fuel rule provisions.

Table 7.1.3-11
Use of Distillate Downgrade by Region: Final NRLM Rule: 2007 to 2010

	PADD 2	PADD 4	PADD 5-O	CA
1st Priority	HO	HO	500 ppm Highway *	L&M
2nd Priority	500 ppm Highway *	500 ppm Highway *	500 ppm NRLM	-
3rd Priority	500 ppm NRLM	500 ppm NRLM	-	-

* Volume limited by loss of 15 ppm highway fuel

Table 7.1.3-12 shows the sources of downgrades and their volumes.

Table 7.1.3-12
Types of Downgrade and Their Volumes Under the NRLM Rule: 2007-2010
Pipelines Not Carrying High Sulfur Distillate (PADDs 2, 4, 5-O, California)

	Original Fuel	Quality of Downgrade *	Volume
Jet Fuel- 500 ppm Diesel Fuel	Jet Fuel	500 ppm Diesel Fuel	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Diesel Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Diesel Fuel	Equivalent to 0.58% of jet fuel demand
15 ppm Highway Diesel Fuel- 500 ppm Diesel Fuel Interface	Highway Diesel Fuel	500 ppm Diesel Fuel	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Diesel Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Diesel Fuel	Equivalent to 0.73% of highway diesel fuel supply

* Destination of the new 500 ppm diesel fuel varies by region.

One last effect of the NRLM rule during the 2007-2010 timeframe is the provision for small refiners to be able to sell high sulfur distillate fuel to the NRLM market. If a small refiner chooses to produce 500 ppm NRLM fuel, then they can sell credits to other refiners, which allows them to produce and market high sulfur NRLM fuel. In either case, the volume of fuel potentially affected by this provision is the production of high sulfur distillate fuel by small refiners. The production of both highway fuel and high sulfur distillate by small refiners is addressed in Section 7.2.1. Since so much of the fuel produced in PADD 3 is distributed to PADD 1, we spread the volume of PADD 3 small refiner fuel over the two PADDs in proportion to the demand for NRLM fuel in the two PADDs.[N] Within each PADD we assume that the high sulfur, small refiner NRLM fuel is blended into the nonroad, locomotive and marine markets in proportion to the demand in each market. The volume of small refiner fuel is summarized in Table 7.1.3-13.

[N] The final NRLM rule includes an Northeast/Mid-Atlantic Area within which no high sulfur NRLM fuel can be sold. This area covers the most of the Northeast and Middle Atlantic states. Thus, it might be difficult for the levels of small refiner fuel assumed here to be sold in PADD 1 under these provisions. If this were the case, this small refiner fuel would likely stay in PADD 3. The net result would be that the sulfur content of NRLM fuel in PADD 1 would decrease and that in PADD 3 would increase. The net nationwide impact would be negligible.

Table 7.1.3-13
Small Refiner NRLM Fuel: 2007-2010 (million gallons)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
420	140	291	0	60	104	0	0

The final projections of production, spillover, downgrade and demand under the final NRLM fuel program from 2007-2010 are shown in Table 7.1.3-14.

Table 7.1.3-14
Distillate Supply and Demand: Final Rule: 2007-2010 (million gallons in 2014)[O]

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	14,363	16,648	8,616	2,658	2,928	152	56	45,436	4,760	50,196
	Production 500 ppm	866	1,213	532	219	200	8	4	3,029	0	3,029
	Spillover to Non-Hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Dwngr 15 ppm	-678	-714	-375	-101	-124	0	0	-1,991	-173	-2,164
	Jet Downgrade	130	107	139	15	52	0	0	437	0	437
	Hwy Downgrade	466	542	239	85	73	0	0	1,378	0	1,378
	Demand 15 ppm	13,284	13,986	7,357	1,973	2,427	148	44	39,219	3,752	42,971
	Demand 500 ppm	1,438	1,690	853	271	299	8	3	4,562	0	4,562
Non-road	Production 500 ppm	3,448	4,025	1,402	329	330	0	39	9,573	10	9,584
	Small Refiner Fuel	333	111	135	0	52	30	0	661	0	661
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	0	11	5	59	0	0	75	0	75
	Hwy Downgrade	0	0	19	26	83	0	0	129	0	129
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco motive	Production 500 ppm	476	805	710	98	41	0	0	2,130	0	2,130
	Small Refiner Fuel	46	22	69	0	7	5	0	148	0	148
	Hwy Spillover	15	287	141	129	40	0	0	611	0	612
	Jet Downgrade	0	0	6	1	7	0	0	15	141	159
	Hwy Downgrade	0	0	10	8	10	0	0	28	213	245
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	421	236	901	0	9	0	20	1,588	0	1,588
	Small Refiner Fuel	41	7	87	0	1	69	0	205	0	205
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	0	7	0	2	0	0	9	46	55
	Hwy Downgrade	0	0	13	0	2	0	0	15	59	74
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,329	0	1,210	0	37	199	115	7,888	0	7,888
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	98	88	124	7	0	0	0	316	0	316
	Hwy Downgrade	351	442	212	38	0	0	0	1,043	0	1,043
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

[O] Due to a miscalculation , the jet fuel downgrade is about 10 percent lower than if calculated as described. This error results in slightly overestimating the costs and the benefits of the program. This miscalculation occurred in all the volume analyses prior to 2010.

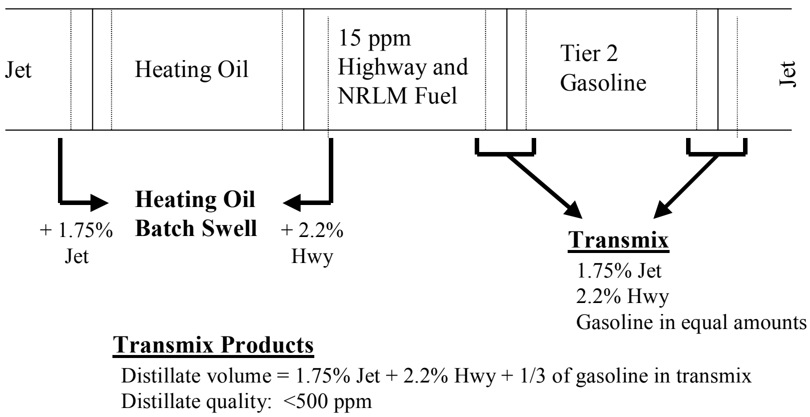
7.1.3.2.3 Final Rule Program - 2010 to 2012

Beginning in mid-2010, two regulatory requirements change: 1) the temporary compliance option under the highway fuel program ends and all highway fuel must meet a 15 ppm cap and 2) nonroad fuel must meet a 15 ppm cap (L&M fuel continues to meet a 500 ppm cap). However, downgraded 500 ppm fuel produced during shipment of 15 ppm highway diesel fuel and jet fuel (or produced by small refiners or with small refiner credits) can continue to be sold to the NRLM fuel markets outside of the Northeast/Mid-Atlantic Area. Within the Northeast/Mid-Atlantic Area, downgraded 500 ppm fuel produced during shipment of 15 ppm fuel and jet fuel can only be sold to the L&M fuel market.

As was the case from 2007-2010, the demand for each distillate fuel and the spillover of highway fuel into these markets are assumed to remain unchanged from those occurring prior to the NRLM rule (see Table 7.1.3-5). With the application of the 15 ppm cap on nonroad fuel in 2010, 500 ppm fuel is not likely to be widely distributed through pipelines. Thus, pipeline sequencing will again be affected. All pipelines will continue to carry 15 ppm fuel, now for both the highway and NRLM markets. Pipelines serving PADD 1 will continue to carry high sulfur distillate for the heating oil market. However, due to the small size of the heating oil markets elsewhere (or the lack of pipelines, as in Alaska and Hawaii), we do not expect that pipelines other than those serving PADD 1 will carry high sulfur distillate. While some pipelines are likely to carry some 500 ppm L&M or small refiner fuel, this is likely to be in proprietary shipments and not as a fungible product. Thus, in assessing pipeline sequencing, we assume that no 500 ppm fuel will be regularly present.

Figure 7.1-5 shows the pipeline sequence for the pipelines in PADDs 1 and 3 which are expected to carry high sulfur heating oil in the 2010-2012 timeframe (applies to the period 2012 - 2014 period as well).

Figure 7.1-5 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Carry Heating Oil; After NRLM Rule: 2010-2012



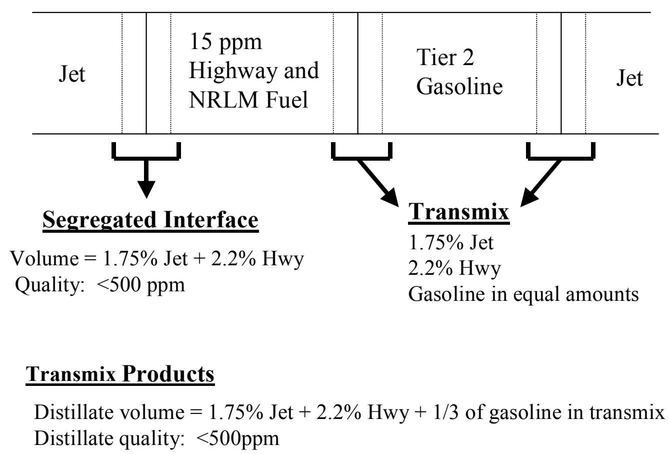
The primary difference between the sequencing in these pipelines in 2010-2012 and 2007-2010 is the elimination of 500 ppm fuel. However, as discussed in Section 7.1.3.2.2, there was no net gain or loss in the size of the 500 ppm batch, as it gained fuel from the adjacent batch of 15 ppm fuel and lost the same volume of 500 ppm fuel to the adjacent batch of high sulfur heating oil. Now, in the absence of the 500 ppm batch, the loss of 15 ppm fuel is cut directly to the heating oil batch in 2010-2012. The quality of the distillate produced from transmix is also the same as in 2007-2010. Thus, the volumes and quality of distillate downgrades remain unchanged from 2007-2010.

The destination of these downgrades changes, however, due to the elimination of the 500 ppm highway fuel market. The downgrades of jet fuel and 15 ppm fuel which are cut directly into the heating oil batch still go directly to the heating oil market. The 500 ppm downgrade material produced from transmix now is assumed to be used in only the NRLM markets, in proportion to the demand for nonroad, locomotive and marine fuel in PADD 3. In most of PADD 1, the Northeast/Mid-Atlantic Area provisions of the final rule prohibit the use of 500 ppm fuel in the nonroad market. As the volume of downgrade produced from transmix in PADD 1 was significantly less than L&M fuel demand, we assumed that all of the distillate produced from transmix in PADD 1 was used in the L&M fuel market from 2010-2012.

It should be noted that we continue to assume that 4.4% of highway diesel fuel supply will be downgraded to protect the quality of 15 ppm diesel fuel. We do not apply the 4.4% downgrade to the new volume of 15 ppm NRLM diesel fuel supply, because the new 15 ppm NRLM fuel is assumed to simply increase the size of the existing batches of 15 ppm highway diesel fuel and not increase the number of interfaces created.

Figure 7.1-6 shows the pipeline sequence for the pipelines in PADDs 2, 4 and 5 which are not expected to carry high sulfur heating oil in the 2010-2012 timeframe (applies to the period 2012 - 2014 period as well).

Figure 7.1-6 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Do Not Carry Heating Oil; After NRLM Rule: 2010-2012



The primary difference between the sequencing in these pipelines in 2010-2012 and 2007-2010 is again the elimination of 500 ppm fuel. Now, in the absence of the 500 ppm batch, the interface between the batch of jet fuel and the batch of 15 ppm fuel can no longer be cut into either fuel. The jet fuel specifications will not allow the addition of No. 2 distillate material due its higher aromatic levels and higher boiling points. The 15 ppm cap will not allow the blending of jet fuel with its much higher sulfur levels. Thus, this interface will have to be segregated from both adjacent batches and stored separately at the terminal. We do not expect that this jet-highway fuel interface will be mixed with other transmix which contains some gasoline. Transmix processors simply separate gasoline from distillate material via distillation. Adding a mixture of jet fuel and highway fuel to a transmix distillation column will just cause all of this material to flow to the distillate product. No separation will occur. Thus, there is no benefit to offset the cost of shipping this distillate transmix to the transmix processor and distilling it. Instead we expect that the terminal will store this interface in a separate tank and sell it directly to a market which can use 500 ppm fuel. In the 2010-2012 timeframe, this is either the NRLM fuel market or the heating oil market. As assumed for 2007-2010 in Section 7.1.3.2.2, in PADDs 2 and 4 from 2010-2012, we assume that this 500 ppm interface will be sold first to the heating oil market and then to the NRLM markets, in proportion to demand. In California, it will be sold to the L&M market. In PADD 5 outside of California, it will be sold to the NRLM markets, in proportion to demand.

The volume of the downgrade from jet fuel and 15 ppm highway fuel to this 500 ppm interface does not change from 2007-2010, as there was no net change in the size of the 500 ppm batch in 2007-2010. The quality of the distillate produced from transmix is also the same as in 2007-2010. Thus, the volumes and quality of distillate downgrades remain unchanged from those in 2007-2010. Table 7.1.3-15 summarizes the destination of downgrade from 2010 to 2012.

Table 7.1.3-15
Blending of Downgrade Under the NRLM Rule: 2010 to 2012

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	CA
1st Priority	HO & L&M	HO	HO & NRLM	HO	NRLM	L&M
2nd Priority	-	NRLM	-	NRLM	-	-

Finally, small refiners can produce and sell 500 ppm fuel to the NRLM markets during this timeframe. We assume that this fuel is generally not distributed in pipelines, so it does not affect the product shipment sequences shown in Figures 7.1-5 and 7.1-6. We expect that the volume of this 500 ppm small refiner fuel will decrease somewhat relative to that in 2007-2010. This occurs because we do not believe that a small refiner would invest to produce 500 ppm NRLM fuel for four years unless they also planned to produce 15 ppm NRLM fuel after 2014. Therefore, we assumed that only those small refiners which our cost analysis shows as competitive with other refiners in producing 15 ppm diesel fuel would produce 500 ppm NRLM fuel in the 2010-2014 timeframe. We assume that the 500 ppm small refiner fuel which is exempted from the 15 ppm nonroad sulfur standard is blended into the nonroad pool. As in 2007-2010, we combined small refiner fuel production in PADDs 1 and 3 and then apportioned it to the two PADDs based on the relative demands for NRLM fuel in each PADD.[P] The volume of 500 ppm small refiner fuel expected to be exempted in each region is summarized in Table 7.1.3-16.

Table 7.1.3-16
Small Refiner Fuel Exempted by Region: 2010 - 2012 (million gallons in 2014)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
261	140	165	4	60	30	0	0

The final projections of production, spillover, downgrade and demand for 2010-2012 under this final NRLM rule are shown in Table 7.1.3-17.

[P] Given the low likelihood that small refiner fuel would be shipped through pipelines, it would have been more realistic to assume that small refiner fuel produced in PADD 3 would be consumed in that region. This has no impact on the nationwide emission reductions projected here. However, a greater volume of small refiner fuel would have been slightly higher emissions of sulfur dioxide and sulfate PM in PADD 3 and slightly lower emissions in PADD 1.

Table 7.1.3-17
Distillate Supply and Demand: Final Rule: 2010-2012 (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,498	3,477	1,215	245	200	0	39	8,674	10	8,684
	Small Refiner Fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	195	723	684	74	33	5	0	1,714	0	1,714
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	76	18	43	5	14	0	0	157	144	301
	Hwy Downgrade	251	85	67	28	19	0	0	450	217	667
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	173	212	868	0	7	69	20	1,349	0	1,349
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	67	5	54	0	3	0	0	130	46	176
	Hwy Downgrade	222	25	85	0	4	0	0	337	59	396
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	436	215	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045

7.1.3.2.4 Final Rule Program - 2012 to 2014

Beginning in mid-2012, the sulfur cap applicable to L&M fuel changes from 500 ppm to 15 ppm. Also, 500 ppm fuel produced during shipment of 15 ppm fuel (and by small refiners or using small refiner credits) can continue to be sold to the NRLM fuel markets outside of the Northeast/Mid-Atlantic Area. However, within the Northeast/Mid-Atlantic Area, downgraded distillate or small refiner fuel containing more than 15 ppm sulfur can only be sold as heating oil.

As was the case for 2007-2010 and 2010-2012, the demand for each distillate fuel and the spillover of highway fuel into these markets are assumed to remain unchanged from those occurring in the Reference Case (see Table 7.1.3-5). Since we assumed that 500 ppm L&M fuel would not be widely distributed as a fungible fuel from 2010-2012, the pipeline sequencing described in Figures 7.1-5 and 7.1-6 continue to apply. Thus, the types and volumes of downgrade generated in 2010-2012 will continue in 2012-2014.

The destination of these downgrades stays the same outside of the Northeast/Mid-Atlantic Area, as downgraded distillate can continue to be sold to the NRLM market through 2014 (and to the L&M fuel market thereafter). Within the Northeast/Mid-Atlantic Area, however, downgraded distillate can no longer be sold to the L&M fuel market. Thus, starting in mid-2012, the downgraded distillate generated in the Northeast/Mid-Atlantic Area shifts from the L&M market to the heating oil market, where it displaces high sulfur distillate. This also causes the volume of L&M fuel which must be produced to the 15 ppm cap to be larger than that needed under the 500 ppm cap. The small refiner fuel exempted and blended into the 15 ppm sulfur NRLM diesel fuel pool remains the same as in 2010-2012 except for Alaska. The volume of small refiner fuel eligible for exemptions in Alaska is limited by the volume of the 15 ppm market. The additional production of 15 ppm fuel to satisfy the locomotive and marine market in 2012 in Alaska increases the volume of small refiner fuel exempted there to the total production of NRLM diesel fuel. The volume of small refiner fuel exempted is summarized in Table 7.1.3-18.

Table 7.1.3-18
Small Refiner Fuel Exempted by Region: 2012 - 2014 (million gallons in 2014)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
261	140	165	4	60	104	0	0

The final projections of production, spillover, downgrade and demand for 2012-2014 under this final NRLM rule are shown in Table 7.1.3-19.

Table 7.1.3-19
Distillate Supply and Demand: Final Rule: 2012-2014 (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,054
	Spillover to Non-hw	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,574	3,506	1,278	246	209	0	39	8,851	10	8,861
	Small Refiner Fuel	207	111	74	3	52	30	0	477	0	477
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco motive	Production 15 ppm	493	701	647	73	26	0	0	1,931	0	1,931
	Small Refiner Fuel	29	22	37	1	7	5	0	100	0	100
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	18	43	5	14	0	0	82	144	226
	Hwy Downgrade	0	85	67	28	19	0	0	203	217	421
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	437	205	820	0	7	0	20	1,489	0	1,489
	Small Refiner Fuel	25	7	48	0	3	69	0	150	0	150
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	6	54	0	3	0	0	63	46	109
	Hwy Downgrade	0	26	85	0	4	0	0	116	59	175
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	5,697	0	1,193	0	37	199	114	7,240	0	7,240
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	252	94	137	7	0	0	0	490	0	490
	Hwy Downgrade	830	436	215	37	0	0	0	1,518	0	1,518
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.3.2.5 Final Rule Program - 2014 and Beyond

The primary changes occurring in 2014 are: 1) the end of the small refiner provisions and 2) the prohibition on the use of any 500 ppm fuel in the nonroad fuel market. These changes have no effect on fuel demand in any of the markets of interest here. Spillover of highway fuel into the other markets is also assumed to be unaffected, with one exception, as discussed below. As pipelines still carry the same fuels, the volume of each fuel downgraded is also unaffected.

Only the use of 500 ppm downgrade changes, as this fuel can no longer be sold into the nonroad fuel market. Therefore, we assumed that it would be used in either the L&M fuel market or the heating oil market according to the same relative priorities described in Table 7.1.3-15. In a few cases, the volume of downgrade exceeds the demand for all L&M fuel and heating oil in a region, considering the historical level of highway fuel spillover. In those cases, we reduced the volume of spillover of highway fuel into these markets until demand for non-spillover fuel equaled that of the available downgrade. If the volume of available downgrade exceeded total demand for L&M fuel and heating oil in a region (i.e., zero spillover), we assume that the excess downgrade fuel will be returned to a refinery and be reprocessed into 15 ppm fuel. The projections of production, spillover, downgrade and demand for 2014 and beyond under this NRLM rule are shown in Table 7.1.3-20.

Table 7.1.3-20
Distillate Supply and Demand: Final Rule: 2014 and Beyond (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,781	4,136	1,568	321	336	30	39	10,211	10	10,221
	Hwy Spillover	206	1,535	345	490	404	4	4	2,986	835	3,821
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reprocessed Downgrade	0	0	0	0	116	0	0	116	219	335
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco motive	Production 15 ppm	522	142	443	0	0	5	0	1,111	0	1,111
	Hwy Spillover	15	287	141	90	0	0	0	532	0	532
	Jet Downgrade	1	122	137	24	46	0	0	328	144	472
	Hwy Downgrade	0	563	215	122	60	0	0	960	217	1,177
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	462	243	894	0	0	69	20	1,687	0	1,687
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	0	0	45	0	61	0	0	105	46	151
	Hwy Downgrade	0	0	70	0	78	0	0	149	59	208
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	5,697	0	1,193	0	0	199	114	7,202	0	7,202
	Hwy Spillover	192	184	274	53	0	0	8	712	0	712
	Jet Downgrade	252	94	137	7	26	0	0	516	0	516
	Hwy Downgrade	830	436	215	37	33	0	0	1,552	0	1,552
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4 Sensitivity Cases

Distillate fuel production and demand were estimated for three sensitivity cases. The first sensitivity case represents an indefinite 500 ppm cap on NRLM fuel that takes effect in 2007 (i.e., no subsequent 15 ppm cap). The second sensitivity case analyzes the proposed rule, which would not require locomotive and marine diesel fuel be desulfurized to 15 ppm. The last sensitivity case analyzes the final rule, but bases the demand for nonroad fuel on information from EIA reports rather than EPA's draft NONROAD2004 model.

7.1.4.1 NRLM Regulated to 500 ppm Indefinitely

To support the legal justification of the 500 ppm cap on NRLM fuel in 2007, we evaluate the costs and benefits of this standard in the absence of a subsequent 15 ppm cap on NRLM fuel. Here, we estimate the production and demand for the various distillate fuels in 2014 under this indefinite 500 ppm cap on NRLM fuel.

During the period from 2007 to 2010, distillate fuel production and demand under this indefinite 500 ppm NRLM fuel cap are assumed to be the same as under the FRM (see Table 7.1.3-14). After 2010, the only differences are the end of the small refiner provisions for producing high sulfur NRLM fuel and the end of the temporary compliance option under the highway fuel program. These two changes are assumed to not affect the demand for the various distillate fuels, nor the spillover of highway fuel into the NRLM fuel and heating oil markets.

The types and volumes of distillate downgrade is not affected, since 500 ppm NRLM fuel will still be carried in all pipelines. However, the disposition of this downgraded distillate is affected slightly, since 500 ppm downgraded distillate can no longer be sold into the 500 ppm highway market. The disposition of downgraded distillate as summarized in Tables 7.1.3-10 through 7.1.3-12 still apply except for the removal of 500 ppm highway fuel as an option for use of this downgraded distillate. The final projections of production, spillover, downgrade and demand for 2010 and beyond under this NRLM rule are shown in Table 7.1.4-1.

Table 7.1.4-1
Distillate Fuel Supply and Demand in 2010 and Beyond (million gallons in 2014)
NRLM at 500 ppm Indefinitely

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 500 ppm	3,293	3,617	1,351	249	261	30	39	8,839	10	8,849
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	114	92	84	18	115	0	0	424	0	424
	Hwy Downgrade	375	427	133	93	149	0	0	1,177	0	1,177
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	454	723	685	73	33	5	0	1,973	0	1,973
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	16	18	43	5	14	0	0	98	144	242
	Hwy Downgrade	52	85	67	28	19	0	0	255	217	472
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	402	211	869	0	7	69	20	1,578	0	1,578
	Hwy Spillover	13	84	179	0	9	0	1	286	53	339
	Jet Downgrade	14	6	54	0	3	0	0	77	46	123
	Hwy Downgrade	46	26	85	0	4	0	0	161	59	221
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4.2 Proposed Rule - 500 ppm NRLM Cap in 2007; 15 ppm Nonroad Fuel Cap in 2010

This second sensitivity case evaluates the NRLM fuel program proposed in the NPRM. This case is the same as that proposed, except that the Northeast/Mid-Atlantic Area provisions were added not allowing small refiner fuel and downgrade to be used in the 15 ppm nonroad diesel fuel pool in most of PADD 1 after 2010. Thus, from 2007 to 2012, the program is the same as the final NRLM fuel program. After 2012, the difference is that L&M fuel remains at 500 ppm and that the Northeast/Mid-Atlantic Area restrictions would apply to only the nonroad pool in PADD 1, not the NRLM pool as is the case for the final NRLM program. Since there are no differences between this case and the final NRLM program during the period from 2007 to 2010 the distillate production and demand estimates shown in Table 7.1.3-14 are assumed to apply here, as well.

From 2010 to 2012, there are no differences in the regulatory requirements of the proposed and final NRLM fuel programs. Thus, distillate fuel demand, spillover of highway fuel to non-highway markets, and the types and volume of downgrade are the same under both programs. The small refiner fuel volume exempted from the 15 ppm sulfur standard and is blended into the nonroad diesel fuel pool. The small refiner fuel volume is the same as that summarized in Table 7.1.3-16. Nothing changes in 2012 under the proposed NRLM program. Thus, the production, downgrade, spillover and demand volumes are the same over the entire period from 2010 to 2014. The final projections of production, spillover, downgrade and demand for 2010 to 2014 under this proposed rule sensitivity case are shown in Table 7.1.4-2.

Table 7.1.4-2
Distillate Fuel Supply and Demand in 2010 - 2014 (million gallons in 2014)
15 ppm Nonroad Cap, 500 ppm L&M Cap

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,498	3,477	1,215	245	200	0	39	8,674	10	8,684
	Small Refiner Fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	195	723	684	74	33	5	0	1,714	0	1,714
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	76	18	43	5	14	0	0	157	144	301
	Hwy Downgrade	251	85	67	28	19	0	0	450	217	667
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	173	212	868	0	7	69	20	1,349	0	1,349
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	67	5	54	0	3	0	0	130	46	176
	Hwy Downgrade	222	25	85	0	4	0	0	337	59	396
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	436	215	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045

After 2014, the small refiner provisions end and downgraded distillate can no longer be sold to the nonroad fuel market. Downgrade can only be used in the L&M and heating oil markets.

The final projections of production, spillover, downgrade and demand for 2014 and beyond for the proposed rule are shown in Table 7.1.4-3.

Table 7.1.4-3
Distillate Fuel Supply and Demand in 2014 and Beyond (million gallons in 2014)
15 ppm Nonroad Cap, 500 ppm L&M Cap

	Fuel Type	1	2	3	4	5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,781	4,136	1,568	323	338	30	39	10,215	10	10,225
	Hwy Spillover	206	1,535	345	488	404	4	4	2,985	835	3,820
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reprocessed Downgrade	0	0	0	0	116	0	0	116	219	335
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	195	142	443	0	0	5	0	816	0	816
	Hwy Spillover	15	287	141	90	0	0	0	1,106	0	1,106
	Jet Downgrade	76	122	137	24	46	0	0	399	144	543
	Hwy Downgrade	251	563	215	122	60	0	0	1,183	217	1,401
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	172	243	894	0	0	69	20	1,398	0	1,398
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	67	0	45	0	61	0	0	173	46	219
	Hwy Downgrade	222	0	70	0	78	0	0	371	59	430
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	0	199	114	7,819	0	7,819
	Hwy Spillover	192	184	274	53	0	0	8	712	0	712
	Jet Downgrade	108	94	137	7	26	0	0	373	0	373
	Hwy Downgrade	357	436	215	37	33	0	0	1,079	0	1,079
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4.3 Final NRLM Fuel Program With Nonroad Fuel Demand Derived from EIA FOKS and AEO

This sensitivity case evaluates the final NRLM fuel program assuming a reduced level of nonroad fuel demand. As discussed in Section 2.4.5 of the Summary and Analysis document for this rule, a number of commenters claimed that EPA's NONROAD model overestimates nonroad fuel demand. To ensure that uncertainties in the level of nonroad fuel demand do not affect the decisions being made in this NRLM rule, we evaluate the cost, emission reductions and cost effectiveness of the final NRLM fuel program using an estimate of nonroad fuel demand derived from EIA's FOKS and AEO reports. Thus, the first step in this sensitivity analysis is to derive this lower nonroad fuel demand. Then, we will discuss how this affects spillover, downgrade and production of the various distillate fuels.

We based nonroad fuel demand for the purpose of estimating fuel costs in the NPRM on the information contained in EIA's FOKS and AEO reports. The methodology used here is essentially the same as that used in the NPRM. The primary difference is the use of more recent EIA FOKS and AEO reports. In the NPRM, we used the 2000 FOKS and 2002 AEO reports. Here, we use the 2001 FOKS and 2003 AEO reports. We start with our derivation of nonroad fuel demand in 2001 using 2001 FOKS and then adjust this estimate for growth using 2003 AEO.

7.1.4.3.1 Nonroad Fuel Demand in 2001 Derived from EIA FOKS

This section describes our methodology for deriving nonroad fuel demand from information collected and projections made by EIA. For a more detailed description of the EIA FOKS information collection process and how estimates of nonroad fuel can be derived from it, the reader is referred to the draft RIA for this rule. As described in Section 7.1.2, EIA's FOKS estimates distillate demand in eleven economic sectors. FOKS also breaks down the distillate demand for several of these sectors according to the physical type of distillate used. Table 7.1.4-4 presents the "adjusted" estimated of distillate fuel demand for PADD 1 from the 2001 FOKS report.

Table 7.1.4-4
Nonroad Fuel Demand, PADD 1 Estimates from 2001 FOKS

End Use	Fuel Grade	Distillate* (M gal)	Diesel (%)	Diesel (M gal)	Nonroad (%)	Nonroad (M gal)
Farm	diesel	447	100	447	100	447
	distillate	41	0	0	0	0
Construction	distillate	550	95	523	100	523
Other/(Logging)	distillate	149	95	142	100	142
Industrial	No. 2 fuel oil	226	0	0	0	0
	No. 4 distillate	40	0	0	0	0
	No. 1 distillate	1	40	0.4	100	0.4
	No. 2 low-S diesel	118	100	118	100	118
	No. 2 high-S diesel	374	100	374	100	374
Commercial	No. 2 fuel oil	1,369	0	0	0	0
	No. 4 distillate	200	0	0	0	0
	No. 1 distillate	2	40	0.8	50	0.4
	No. 2 low-S diesel	450	100	450	0	0
	No. 2 high-S diesel	203	100	203	100	203
Oil Company	distillate	21	50	10.5	100	11
Military	diesel	45	100	45	85	38
	distillate	28	0	0	0	0
Electric Utility	distillate	564	100	564	0	0
Railroad	distillate	506	95	481	1.0	5
Vessel Bunkering	distillate	461	90	415	0	0
On-Highway	diesel	10,284	100	10,284	0.7	73
Residential	No. 2 fuel oil	5,464	0	0	0	0
	No. 1 distillate	5	0	0	0	0
Total		21,548	-	14,058		1,934

The key step in our methodology is the estimation of the portion of each sector's fuel demand that is used in nonroad engines. These percentages are summarized in Table 7.1.4-4. We describe these estimates below.

Farm. FOKS estimates fuel demand in this sector for two fuel grades: "diesel fuel" and "distillate." We assume that 100 percent of the diesel fuel represents nonroad use, and 100 percent of the distillate represents uses other than in nonroad engines, such as heating and crop drying.

Construction/Other Off-Highway(Logging). For the construction and logging/other-non-highway end uses, we assume that 95 percent of the total distillate sold is diesel fuel, and that 100 percent of the diesel fuel is used in nonroad engines.

Industrial. FOKS breaks down distillate sales in this sector into five individual fuel grades: No. 1 distillate, low sulfur No. 2 diesel, high sulfur No. 2 diesel fuel, high sulfur No. 2 fuel oil and No. 4 distillate. No. 4 distillate is not covered by the NRLM rule and is rarely used in nonroad engines, if at all. Therefore, we exclude all sales of No. 4 distillate from our estimate of nonroad fuel use. Since sales of No. 2 diesel fuel and No. 2 fuel oil are categorized separately, we assume that no No. 2 fuel oil is used in diesel engines. Thus, no No. 2 fuel oil sales are assumed to fall into nonroad fuel demand. Conversely, we assume that all No. 2 diesel fuel, low-sulfur and high-sulfur, is used in diesel engines and that all of this diesel fuel represents nonroad use. As will be seen below, the low sulfur diesel fuel in the commercial sector is most often used in highway vehicles owned by "commercial" entities not subject to highway excise taxes. We are not aware of any "industrial" entities which are not subject to the excise tax. Thus, should an industrial entity use this low sulfur diesel fuel in a highway vehicle that it owns, this use would be included in the FOKS estimate of highway diesel fuel sales, since the latter is based on excise tax receipts. Therefore, it is reasonable to assume that the low sulfur diesel fuel is not used in highway vehicles. The industrial sector does not include either locomotives or marine vessels. Thus, the non-highway diesel engines must be either nonroad engines or stationary diesel engines likely used for power generation. We assume that the latter use is negligible. For the remaining category, No. 1 distillate, diesel and fuel oil are not distinguished. After consulting with EIA staff, we estimate that 40 percent of No. 1 distillate sales represent diesel fuel, that 100 percent of this diesel represents nonroad use, and that the remainder represents No. 1 fuel oil used in other applications, such as space heating.

Commercial. As with the industrial end use, distillate sales in this sector are reported by fuel grade. As in the industrial sector, we assume that none of the No. 2 fuel oil, and No. 4 fuel represents nonroad diesel fuel. However, in the commercial sector, we assume that all low sulfur diesel fuel sold is used in highway vehicles. This sector includes school-bus and government (local, state and federal) fleets. Fuel used by these fleets are exempt from the federal excise tax, as is fuel for nonroad use. Thus, we assume that none of the low-sulfur No. 2 diesel fuel sold to this sector is used in nonroad engines. As in the industrial sector, we assume that 100 percent of the high-sulfur No. 2 diesel fuel sold is used in nonroad engines. Also as in the industrial sector, after consultation with EIA staff, we estimate that 40 percent of the No. 1 distillate sold is diesel fuel. However, due to the presence of public fleet fuel use in this sector, we estimate that only 50 percent of this diesel fuel is used in nonroad engines.

Oil Company. Sales to this sector include fuel purchased for drilling and refinery operations. We assume that 50 percent of the reported distillate is diesel fuel, and that all of this diesel fuel is used in nonroad equipment. We assume that the remainder represents other uses such as underground injection under pressure to fracture rock.

Military. Fuel sales to the military are reported as being either diesel fuel or distillate. We assume that 85 percent of diesel fuel sales is used in 'non-tactical' nonroad equipment, and that none of the distillate sales represents nonroad use. We assume that 15% of the diesel fuel is not used in nonroad engines because the NONROAD model does not attempt to represent fuel use or emissions from 'tactical' military equipment, such as tanks and personnel carriers because they are not covered by EPA emission standards.

Railroad. We believe that the vast majority of fuel sales to railroads is used by locomotives. Based on guidance from a major railroad, we assume that a small fraction (1%) of reported fuel sales is used in nonroad equipment operated by railroads.

Electric Utility, *Vessel Bunkering* and *Residential.*, We assume that all of the fuel sold to these sectors falls into our definition of marine fuel or heating oil and that none of it is used in nonroad engines..

The EIA FOKS report presents fuel sales by sector for each region of interest here. Thus, we applied the diesel fuel and nonroad percentages shown in Table 7.1.4-4 to the fuel sales in each sector and region to estimate nonroad fuel demand. The results are summarized in Table 7.1.4-5.

Table 7.1.4-5
2001 Nonroad Fuel Consumption Derived From EIA FOKS (million gallons)

End Use	Fuel Grade	Region							
		1	2	3	4	5-O	AK	HI	CA
Farm	diesel	447	1,764	627	155	90	0	7	281
	distillate	0	0	0	0	0	0	0	0
Construction	distillate	523	572	425	118	83	7	3	251
Other/(Logging)	distillate	142	66	136	21	23	3	0	17
Industrial	No. 2 fuel oil	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0
	No. 1 distillate	0.5	8	1	4	0.2	4	0	0
	No. 2 low-S diesel	118	210	196	175	101	2	2	44
	No. 2 high-S diesel	374	355	204	15	66	13	0.6	5
Commercial	No. 2 fuel oil	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0
	No. 1 distillate	0.5	7	0.3	2	0.4	2	0	0
	No. 2 low-S diesel	0	0	0	0	0	0	0	0
	No. 2 high-S diesel	203	155	71	8	19	21	3	3
Oil Company	distillate	11	26	344	10	1.5	14	0	4
Military	diesel	38	15	105	4	50	5	22	24
	distillate	0	0	0	0	0	0	0	0
Electric Utility	distillate	0	0	0	0	0	0	0	0
Railroad	distillate	5	10	8	2	1	0.04	0	2
Subtotal		1,862	3,188	2,119	514	436	69	38	611
Highway (Retail Purchases)	diesel	73	73	50	13	10	3	1	25
Total		1,934	3,261	2,169	527	446	72	39	636

Table 7.1.4-5 shows that, according to the above methodology, the farm, construction, commercial, and industrial categories are the largest consumers of nonroad diesel fuel. Nonroad fuel use on farms is concentrated in PADD 2 (the Midwest), while nonroad fuel demand in the other sectors is spread out more evenly across the nation.

We replaced the year 2001 nonroad fuel demand estimates shown in Table 7.1.2-3 from EPA's NONROAD model with those shown in the last line of Table 7.1.4-5. We recalculated the heating oil demand in each region so that the total fuel demand in the five categories matched the total distillate demand shown. Table 7.1.4-6 shows the revised estimates of fuel demand by region for each of the five usage categories.

Table 7.1.4-6
2001 Distillate Fuel Demand as Derived From EIA FOKS (million gallons)

	Region							
EPA Use Category	1	2	3	4	5-O	AK	HI	CA
Highway Fuel	10,211	10,873	5,694	1,557	1,890	108	32	2,602
Nonroad Fuel	1,934	3,261	2,169	527	446	72	38	637
Locomotive Fuel	476	989	831	209	94	4	0	172
Marine Fuel	415	286	1,037	0	20	60	18	46
Heating Oil	8,512	1,682	1,202	175	249	167	125	146
Total Demand	21,549	17,092	10,932	2,468	2,700	412	214	3,604

The volume of spillover of highway fuel into the four non-highway fuel categories is the same as that shown in Table 7.1.2-5. We considered the volume of unrefunded fuel for this case as well. Since we are basing nonroad fuel demand in this sensitivity case on information contained in FOKS, we adjust both the highway fuel demand and the nonroad fuel demand for unrefunded use of highway fuel in nonroad equipment. The volume of unrefunded fuel is the same as that used for the final rule case, shown in Table 7.1.2-2. The types and volume percentages of downgrade of highway fuel, jet fuel and gasoline are the same as those shown in Table 7.1.2-6. However, we do not show a complete breakdown of production, spillover, downgrade and demand for each usage category and region for 2001 (analogous to that shown in Table 7.1.2-8), since these figures are not used directly in the estimates of either costs, nor emission reductions in this sensitivity analysis.

7.1.4.3.2 Nonroad Fuel Demand in 2014 Derived from EIA AEO 2003

We developed an estimate of nonroad fuel demand in 2014 from EIA's AEO 2003 report. We began with a detailed set of distillate fuel consumption estimates for the various economic sectors presented in AEO 2003. AEO 2003 presents distillate fuel consumption estimates at roughly three levels of detail, as shown in Table 7.1.4-7 below.

Table 7.1.4-7
Distillate Fuel Consumption Demand within AEO 2003

First Level	Second Level	Third Level	Nonroad Fuel Percentage
Total	Transportation	Highway	0.7%
		Rail	1%
		Marine	0%
		Military	76%
	Residential	Residential	0%
	Commercial	Commercial	14%
	Industrial	Farm	98%
		Oil Company	50%
		Construction	95%
		Other *	82%
	Electricity Generation	Electricity Generation	0%

* Not explicitly shown in AEO 2003. Backcalculated from total "Industrial" fuel use.

At the third level of detail from AEO 2003, we utilized distillate fuel consumption estimates from AEO to estimate future nonroad demand. The one exception was the "other" industrial sector. This estimate was obtained by subtracting the demand in the farm, construction and oil company sectors from that in the total industrial sector. We converted all these estimates of fuel consumption from AEO from quadrillion BTU per year to gallons per year using EIA's conversion factor of 138,700 BTU/gal. When available, we estimated the nonroad percentage of each sector's total distillate fuel consumption using the same methodology which we used with the FOKS estimates above. These estimates are available for all the sectors except commercial, "other" industrial, farm, and military. The estimates of the nonroad portion of total distillate demand for these four sectors depended on the type of distillate fuel consumed, such as low sulfur diesel fuel, kerosene, etc. AEO 2003 does not provide projections broken down by the type of distillate fuel, only total distillate. In these cases, we used the nonroad diesel fuel fractions found from the analysis of the 2002 FOKS.[Q] All of these nonroad fuel percentages are shown in Table 7.1.4-8.

Table 7.1.4-8 presents total distillate demand by sector for 2002 and projected total distillate demand for 2014 from AEO 2003, the percentage of each fuel demand that is assumed to be nonroad, and the resulting 2014 nonroad fuel demand by sector.

Table 7.1.4-8
2002 and 2014 Nonroad Diesel Fuel Demand: 2003 AEO (million gallons per year)

Category	Total Distillate Demand		Nonroad Diesel (%)*	Nonroad Diesel Fuel Demand	
Year	2002	2014	2002 & 2014	2002	2014
Commercial	3244	3533	14%	458	498
Other Industrial	2653	3331	82%	2164	2717
Highway	32,242	48,839	0.7%	221	257
Oil Company	43	0	50%	22	0
Farm	3403	3843	98%	3320	3749
Railroad	3669	4196	1%	35	40
Military	800	894	76%	607	678
Construction	1687	1983	95%	1603	1884
Total	---	---	---	8428	9823

* Derived by applying EPA estimates of nonroad fuel use to FOKS 2002 fuel sales.

As shown in Table 7.1.4-8, from information contained in both FOKS 2002 and AEO 2003, total nonroad fuel demand in 2014 is projected to be 9.82 billion gallons per year. This represents a 17% increase over the 8.43 billion gallons demand estimated for 2002, or 1.37% per year linear growth from a 2002 base. The growth rates embedded in AEO 2003 vary slightly from year to year and decade to decade. However, as the purpose of this analysis is simply to evaluate the sensitivity of the cost effectiveness of the NRLM rule to uncertainty in nonroad fuel consumption, we have applied this 1.37% growth rate from 2001 through the final year of analysis, 2040. We based the growth rate off of fuel consumption in 2002, rather than 2001, because FOKS 2002 shows a significant drop in distillate fuel consumption in 2002. The AEO 2003 estimates reflect this decrease in 2002 and projects relatively steady growth starting from 2002. Thus, reflecting

[Q] The projection of nonroad fuel demand using the NONROAD model was already complete and subsequent analyses of emission benefits, monetized benefits and economic impacts were underway when FOKS 2002 was issued in late November 2003. Therefore, it was not possible to utilize FOKS 2002 for the primary estimates presented in this Final RIA. However, it was possible to utilize this more recent information for this sensitivity analysis.

this drop in nonroad diesel fuel consumption in 2002 and steady growth thereafter better reflects the AEO 2003 projections. Projecting growth from 2001 would have reduced the annual growth rate considerably, over-predicting fuel consumption prior to 2014 and under-predicting fuel consumption after 2014.

We used the same 2001-2014 growth ratios for the other four fuel use categories as shown in Tables 7.1.3-1 and 7.1.3-3. These growth ratios were applied to the demand volumes in Table 7.1.4-7 to estimate fuel demand in 2014. We increased the 2001 nonroad fuel consumption of 9.084 billion gallons (shown in Table 7.1.4-7) by 8.14%, which is the total increase between the 2014 fuel demand of 9.823 billion gallons shown in Table 7.1.4-8 and 2001 nonroad fuel demand. These volumes are summarized in Table 7.1.4-9.

Table 7.1.4-9
2014 Distillate Fuel Demand based on AEO 2003 and FOKS 2002 (million gallons)

	Region							
EPA Use Category	1	2	3	4	5-O	AK	HI	CA
Highway Fuel	14,738	15,693	8,221	2,248	2,728	157	47	3,758
Nonroad Fuel	2,104	3,603	2,394	581	492	78	43	691
Locomotive Fuel	536	1114	935	236	106	5	0	194
Marine Fuel	475	327	1187	0	23	69	21	53
Heating Oil	7,898	1,561	1,115	162	231	155	116	136

The volume of spillover of highway fuel into the four non-highway fuel categories is the same as that shown in Table 7.1.3-5. The types and volume percentages of downgrade of highway fuel, jet fuel and gasoline are the same as those shown in Table 7.1.3-6. Jet fuel demand is the same as shown in Table 7.1.3-7. We also used the same methodology to assign downgrade to the various distillate markets. Finally, the volume of NRLM fuel produced by small refiners is the same as that shown in Table 7.1.3-16.

We do not show a complete breakdown of production, spillover, downgrade and demand for each usage category and region for 2010-2014 or 2014 and beyond in a Reference Case (which assumes no implementation of this nonroad rule). This is not necessary because we used a different methodology to estimate the emission reductions for this case than for the final rule case which did not require the estimation of reference case sulfur levels. Tables 7.1.4-10 through 7.4.1-13 present the estimates of distillate demand and production for the four time periods relevant to this nonroad rule: 2007-2010, 2010-2012, 2012-2014, and 2014 and beyond, respectively.

Table 7.1.4-10
Distillate Supply and Demand: Final Rule: 2007-2010 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO [R]

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	14,347	16,382	8,589	2,601	2,882	152	56	45,030	4,547	49,577
	Prod 500 ppm	860	1822	540	199	181	8	4	3595	0	3595
	Spillover	-388	-1798	-910	-553	-336	-3	-13	-4001	-622	-4623
	Hwy Downgrade 15	-679	-717	-375	-101	-125	0	0	-1,997	-173	-2,170
	Jet Downgrade	129	106	139	15	51	0	0	440	0	440
	Hwy Downgrade	465	534	239	83	71	0	0	1,392	0	1,392
	Demand 15 ppm	13,303	14,048	7,358	1,987	2,441	149	44	39,328	3,752	43,080
	Demand 500 ppm	1,433	1,642	861	261	286	8	3	4,494	0	4,494
Non-road	Production 500 ppm	1,825	2,606	1,807	261	139	28	41	6,706	7	6,712
	Small Refiner Fuel	211	100	212	3	48	49	0	623	0	623
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	0	14	0	51	0	0	65	0	65
	Hwy Downgrade	0	0	23	2	72	0	0	97	0	97
	Reproc. Downgrade	0	0	0	0	0	0	0	0	95	95
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	10,339
Loco-motive	Production 500 ppm	468	797	698	105	29	2	0	2,098	0	2,098
	Small Refiner Fuel	54	31	82	1	10	3	0	181	0	181
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	0	5	0	11	0	0	16	85	102
	Hwy Downgrade	0	0	9	1	15	0	0	25	110	135
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	414	234	886	0	6	25	20	1,585	0	1,585
	Small Refiner Fuel	48	9	104	0	2	44	0	207	0	207
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	0	6	0	2	0	0	9	64	74
	Hwy Downgrade	0	0	11	0	3	0	0	15	83	98
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	7,233	28	612	0	144	155	109	8,280	0	8,953
	Hwy Spillover	217	402	168	89	87	0	8	971	8	980
	Jet Downgrade	98	187	124	11	0	0	0	419	56	475

[R] The jet and highway-based downgrade volumes shown in this table were over-estimated by 10% and 2%, respectively.

	Hwy Downgrade	351	944	212	63	0	0	0	1,569	72	1,641
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-11
Distillate Supply and Demand: Final Rule: 2010-2012 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1,798	-910	-553	-336	-3	-13	-4,001	-622	-4,623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Non-road	Production 15 ppm	1,835	2,630	1,970	265	182	51	41	6,974	7	6,981
	Small Refiner fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	145	1,047	431	344	280	3	4	2,256	614	2,870
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Proc. Downgrade	0	0	0	0	0	0	0	0	96	96
	Demand	2,263	3,816	2,537	616	522	84	45	9,884	715	10,599
Loco-motive	Production 15 ppm	195	821	589	0	0	5	0	1,610	0	1,610
	Hwy Spillover	15	287	141	126	14	0	0	582	0	582
	Jet Downgrade	76	1	80	18	40	0	0	215	85	300
	Hwy Downgrade	250	5	126	92	52	0	0	525	110	635
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	173	241	747	0	0	69	20	1,250	0	1,250
	Hwy Spillover	13	84	179	0	3	0	1	280	0	280
	Jet Downgrade	67	0	102	0	9	0	0	178	65	244
	Hwy Downgrade	222	1	160	0	11	0	0	394	84	479
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	7,217	0	595	0	0	155	108	8,076	0	8,076
	Hwy Spillover	217	402	168	89	44	0	8	928	8	936
	Jet Downgrade	108	206	137	12	81	0	0	544	56	601
	Hwy Downgrade	356	953	215	62	105	0	0	1,691	72	1,764
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-12
Distillate Supply and Demand: Final Rule: 2012-2014 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1798	-910	-553	-336	-3	-13	-4001	-622	-4623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Non-road	Production 15 ppm	1,903	2,554	1,690	182	25	24	41	6,419	7	6,425
	Small Refiner Fuel	143	100	118	3	48	53	0	455	0	455
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	9	97	13	103	0	0	222	0	222
	Hwy Downgrade	0	42	152	68	133	0	0	395	0	395
	Proc. Downgrade	0	0	0	0	0	0	0	0	95	95
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	9,622
Loco-motive	Production 15 ppm	487	781	653	73	5	1	0	2,001	0	2,001
	Small Refiner Fuel	34	31	46	1	10	3	0	125	0	125
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	3	38	5	22	0	0	69	85	178
	Hwy Downgrade	0	13	60	28	29	0	0	129	109	322
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	432	229	828	0	1	22	20	1,532	-95	1,597
	Small Refiner Fuel	30	9	58	0	2	47	0	147	0	147
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	1	47	0	5	0	0	53	65	137
	Hwy Downgrade	0	4	74	0	6	0	0	84	84	137
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,602	65	595	4	144	155	108	7,674	0	7,674
	Hwy Spillover	217	402	168	89	87	0	8	971	8	979
	Jet Downgrade	251	194	137	11	0	0	0	593	56	665
	Hwy Downgrade	828	899	215	58	0	0	0	2,001	72	2,073
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-13
Distillate Supply and Demand: Final Rule: 2014 and Beyond (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1,798	-910	-553	-336	-3	-13	-4,001	-622	-4623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Non-road	Production 15 ppm	2,036	2,706	2,056	260	229	77	41	7,404	7	7,411
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reproc. Downgrade	0	0	0	0	0	0	0	0	96	96
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	10,339
Loco-motive	Production 15 ppm	522	755	443	0	0	5	0	1,723	0	1,723
	Hwy Spillover	15	287	141	129	0	0	0	516	0	516
	Jet Downgrade	0	13	136	18	46	0	0	214	85	298
	Hwy Downgrade	0	59	215	95	60	0	0	429	110	539
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	462	243	894	0	0	69	20	1,688	0	1,688
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	0	0	45	0	10	0	0	55	65	120
	Hwy Downgrade	0	0	70	0	13	0	0	83	84	167
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,602	66	595	4	8	155	108	7,538	0	7,538
	Hwy Spillover	217	402	168	89	87	0	8	971	134	1,106
	Jet Downgrade	251	194	137	11	74	0	0	667	56	723
	Hwy Downgrade	828	898	215	58	95	0	0	2,095	72	2,167
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

The primary difference resulting from estimating nonroad fuel demand using FOKS and AEO is that nonroad demand is lower (and therefore, heating oil demand is larger) in PADDs 2, 4, and 5. This eliminates the need to reprocess any downgraded fuel after 2014 when this fuel can only be used in the L&M fuel and heating oil markets.

7.1.5 Methodology for Annual Distillate Fuel Demand: 1996 to 2040

The environmental impact and cost-effectiveness analyses presented in this Final RIA require estimates of fuel demand from 1996 through 2040. This section presents the methodology used to develop these estimates. The actual levels of fuel demand are presented in Section 7.1.6 along with the sulfur contents of the various fuels on an annual basis.

In this section, we develop a set of year-over-year (compound) growth rates from 1996-2040 for the four non-highway fuel categories. We did not address highway fuel demand, as this is not affected by this NRLM rule. For nonroad, locomotive and marine fuels, we obtained annual estimates of fuel demand for as much of this time period as was available. We then calculated year-over-year growth rates over the period of time that the data were available. Finally, we extrapolated or interpolated these growth rates to cover any years for which specific fuel demand projections were not available.

We obtained our estimates of annual fuel demand by nonroad engines from EPA's NONROAD emission model. These estimates of fuel demand and the resulting annual growth rates are shown in Table 7.1.5-1. As can be seen, NONROAD projects a linear increase in fuel consumption over time. This results in a slightly decreasing year-over-year growth rate over time.

Table 7.1.5-1
Annual Growth In the Demand of Nonroad and Locomotive Fuel

Year	Nonroad Fuel Demand (million gallons)	Annual Growth Rate	Locomotive Fuel Demand		Annual Growth Rate
			(trillion btu)	(million gallons)	
1996	9,158			3072	
1997	9,450	1.032			0.969
1998	9,742	1.031			0.968
1999	10,024	1.029			0.967
2000	10,319	1.030	609.2	2692	0.966
2001	10,613	1.028	628.4		1.032
2002	10,906	1.028	610.2		0.971
2003	11,200	1.027	617.0		1.011
2004	11,493	1.026	621.4		1.007
2005	11,787	1.026	626.1		1.008
2006	12,078	1.025	638.9		1.020
2007	12,370	1.024	650.2		1.018
2008	12,661	1.024	657.4		1.011
2009	12,952	1.023	666.3		1.014
2010	13,244	1.023	676.9		1.016
2011	13,537	1.022	689.7		1.019
2012	13,830	1.022	696.6		1.010
2013	14,123	1.021	702.1		1.008
2014	14,416	1.021	707.6		1.007
2015	14,709	1.020	713.5		1.008
2016	14,999	1.020	721.1		1.011
2017	15,289	1.020	727.7		1.009
2018	15,579	1.019	733.1		1.007
2019	15,869	1.019	740.3		1.010
2020	16,159	1.018	745.4		1.007
2021	16,449	1.018	749.2		1.005
2022	16,739	1.018	755.9		1.009
2023	17,029	1.017	762.6		1.009
2024	17,319	1.017	769.2		1.009
2025	17,609	1.017	776.6		1.010
2026	17,897	1.016	-		1.008
2027	18,185	1.016	-		1.008
2028	18,473	1.016	-		1.008
2029	18,761	1.016	-		1.008
2030	19,049	1.015	-		1.008
2031	19,337	1.015	-		1.008
2032	19,625	1.015	-		1.008
2033	19,912	1.015	-		1.008
2034	20,201	1.015	-		1.008
2035	20,489	1.014	-		1.008
2036	20,777	1.014	-		1.007
2037	21,065	1.014	-		1.007
2038	21,353	1.014	-		1.007
2039	21,641	1.014	-		1.007
2040	21,928	1.013	-		1.007

Locomotive diesel fuel growth rates for the period from 1996 to 2000 were estimated from historic estimates of fuel consumption taken from the 1996 and 2000 FOKS reports. We assume that locomotive diesel fuel demand decreased linearly between 1996 and 2000. We assume a constant linear growth rate for this time period, as this seemed most consistent with EIA's projection of growth in locomotive fuel demand in the post-2000 time period. For the period after 2000, we use the annual demand for locomotive diesel fuel projected by EIA in the AEO 2003 to calculate year-over-year growth rates from 2000 to 2025 (the last projection year in AEO 2003). Beyond 2025, we assume that locomotive fuel demand grows linearly at the average rate of growth between 2021 and 2025. The FOKS and AEO estimates of fuel demand and the year-over-year growth rates for locomotive diesel fuel are summarized in Table 7.1.5-1.

According to EIA FOKS reports, the demand for marine diesel fuel decreased slightly between 1996 and 2001. We estimated annual demand for marine diesel fuel for 1997-2000 by assuming a constant compound growth rate between 1996 and 2001. (Constant compound growth is more consistent with EIA's projection of growth in marine fuel demand in the post-2000 time period than constant linear growth.) For the period after 2000, we use the annual demand for marine diesel fuel projected by EIA in the AEO 2003 to calculate a year-over-year growth rates 2000 to 2025 (the last projection year in AEO 2003). Beyond 2025, we assume that marine fuel demand grows at a constant compound growth rate between 2001 and 2025, which was 1.3%. The FOKS and AEO estimates of fuel demand and the year-over-year growth rates for marine diesel fuel are summarized in Table 7.1.5-2.

Table 7.1.5-2
Annual Growth in the Demand for Marine Diesel Fuel

Year	Marine Fuel Consumption		Annual Growth Rate
	AEO 2003 (trillion BTU)	FOKS 2001 (million gallons)	
1996	-	1960	
1997	-	-	0.992
1998	-	-	0.992
1999	-	-	0.992
2000	-	-	0.992
2001	344.6	1884	0.992
2002	338.4	-	0.982
2003	342.6	-	1.012
2004	346.1	-	1.010
2005	348.4	-	1.007
2006	356.5	-	1.023
2007	361.7	-	1.015
2008	366.7	-	1.014
2009	371.1	-	1.012
2010	375.7	-	1.012
2011	381.2	-	1.015
2012	386.1	-	1.013
2013	389.6	-	1.009
2014	394.3	-	1.012
2015	398.7	-	1.011
2016	402.5	-	1.010
2017	407.0	-	1.011
2018	413.1	-	1.015
2019	420.1	-	1.017
2020	425.0	-	1.012
2021	430.2	-	1.012
2022	437.2	-	1.016
2023	442.1	-	1.011
2024	448.0	-	1.013
2025	453.2	-	1.012
2026	-	-	1.013
2027	-	-	1.013
2028	-	-	1.013
2029	-	-	1.013
2030	-	-	1.013
2031	-	-	1.013
2032	-	-	1.013
2033	-	-	1.013
2034	-	-	1.013
2035	-	-	1.013
2036	-	-	1.013
2037	-	-	1.013
2038	-	-	1.013
2039	-	-	1.013
2040	-	-	1.013

We applied a simpler approach to estimating the growth in the demand for heating oil for a number of reasons. One, this rule does not regulate the sulfur content of heating oil. Two, EIA does not present estimates of heating oil demand, as it is defined here. Three, heating oil demand between 2001 and 2014 is very close to zero. Thus, the effect of differing assumptions regarding the shape of this growth, such as linear versus compound, have a negligible effect on any extrapolated growth.

As shown in Table 7.1.3-3, heating oil demand declined by 7% from 2001 to 2014. We assumed that this decline was occurring at a constant compound rate, which we calculated to be -0.006% for this time period. We assumed that this decline would continue through 2040.

7.1.6 Annual Distillate Fuel Demand and Sulfur Content

In this section we estimate the sulfur content of the various types of distillate fuel prior to this rule and how they are affected by the NRLM rule. We then present year-by-year estimates of both distillate fuel demand and sulfur content for the purpose of estimating the environmental benefits of this rule.

7.1.6.1 Sulfur Content

The sulfur content of high sulfur distillate before and after this NRLM rule is used in two ways in this regulatory impact analysis: 1) to estimate the reductions in emissions of sulfur dioxide and sulfate PM, and 2) to estimate the cost of desulfurizing this fuel to meet 500 and 15 ppm caps. In this section we estimate the current sulfur content of the four non-highway distillate fuels by region. We then estimate how these sulfur contents change during the various phases of the final NRLM fuel program. Finally, we estimate the sulfur content of these fuels for two sensitivity cases: 1) a long-term 500 ppm sulfur NRLM program and 2) the proposed NRLM fuel program (15 ppm nonroad fuel and 500 ppm L&M fuel in 2010).

We estimate the current sulfur content of high sulfur distillate from diesel fuel survey data collected by TRW Petroleum Technologies (TRW) at its facility in Bartlesville, Oklahoma. This facility was formerly known as the National Institute for Petroleum and Energy Research (NIPER)). Surveys performed for 1999 through 2002 were published by TRW. Surveys prior to 1999 were published by the NIPER. We evaluated their survey data from 1996 through 2002. As the methodology of conducting the surveys and the presentation of the data have not changed over this time period, we will simply refer to these surveys as TRW surveys.

No comments were received on our methodology for estimating the sulfur content of high sulfur distillate for the NPRM. However, we have made three changes to that analysis which we believe improve the estimate. The first is to include the 2002 survey data, which is now available. The second is to include sample data which were assigned a production volume by TRW. The third is to adjust the sample data for the addition of downgraded jet fuel, highway diesel fuel and heavy gasoline during distribution.

TRW collects sulfur data voluntarily provided by domestic refiners, including a refiner located in the Virgin Islands. These refiners analyze the sulfur content of their diesel fuel production and submit the results to TRW. TRW states that the survey results reflect the average quality of distillate fuel produced at refineries for use in each geographical area. However, TRW also states that the data may not be representative of the full range of sulfur content of these fuels at their point of use. This appears to be due to either TRW or refiners reporting the average quality of their high sulfur diesel fuel versus a set of individual samples, in addition to the effect of convenience sampling.

TRW presents survey results for five geographic regions containing 16 districts. According to TRW, these areas are based on fuel distribution systems, refinery locations, centers of population, temperature zones, and arteries of commerce. A map of the regions and districts is shown in Figure 7.1-6 below. Each sample is assigned to both a region and to one or more districts. We primarily use the TRW district assignments, as they provide a more precise indication of where the fuel was eventually sold. A map of the Petroleum Administration Defense Districts (PADDs) is shown for comparison in Figure 7.1-7. Since all of our estimates for distillate production and demand were developed by PADD (with PADD 5 split up further), we assigned each TRW district to one or more PADDs as described in Table 7.1.6-1.

Figure 7.1-7 TRW Fuel Survey Regions and Districts

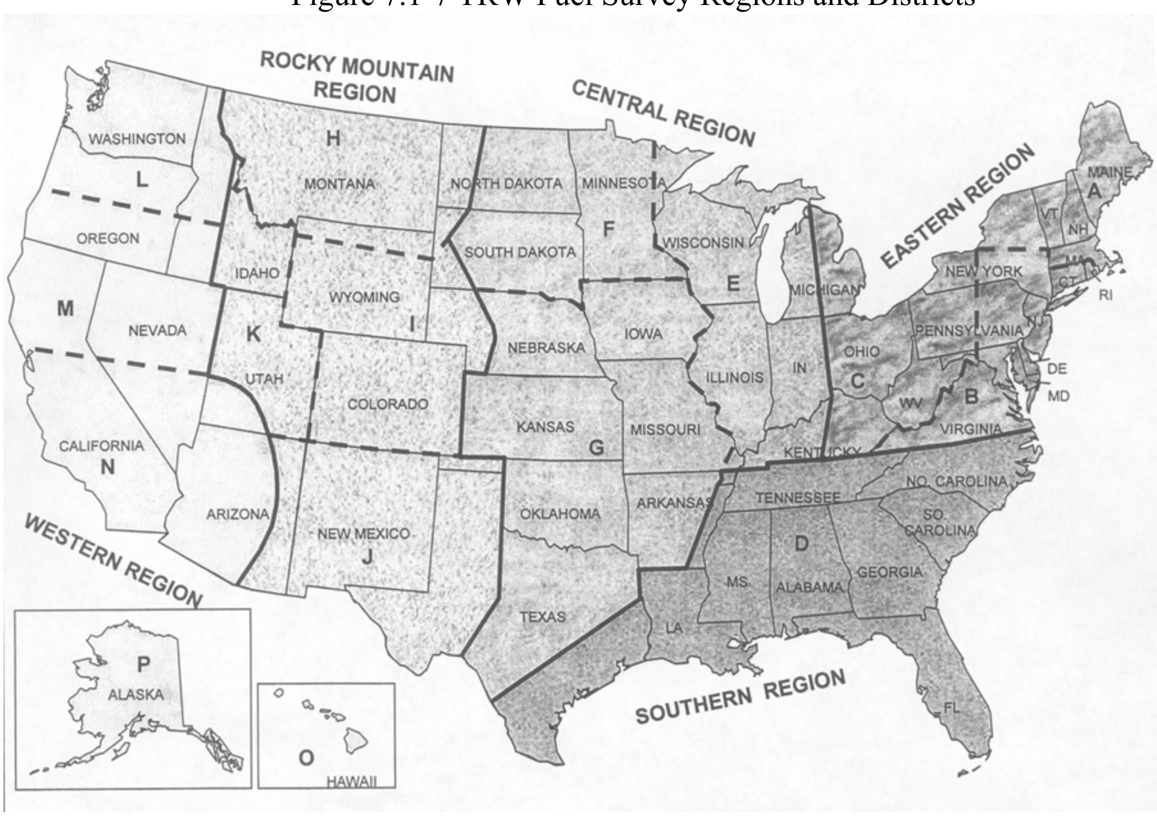


Figure 7.1-8. Petroleum Administration for Defense Districts (PADDs)

Table 7.1.6-1
Assignments of TRW Regions and Districts to PADDs

Region	TRW District	Assigned PADD
Eastern	A	1
	B	1
	C	1, 2
Southern	D	1, 3
Central	E	2
	F	2
	G	2
Rocky Mountain	H	4
	I	4
	J	3
	K	4
Western	L	5
	M	5
	N	5
	O	5
	P	5

TRW provides a rough indication of the annual volume of fuel represented by each sulfur measurement by assigning each data point one of four numbers. Table 7.1.6-2 presents the numbering system used by TRW and the range of diesel fuel production represented by each numeral assignment. In order to weight the sulfur measurements by volume, we assigned an average volume to each range. These averages are also shown in Table 7.1.6-2.

Table 7.1.6-2
Production Volumes of Fuel Sulfur Samples

TRW Sample Quantity Number	Fuel Volume (Barrels Per Year)	
	TRW: Range	EPA: Assumed Average Volume
1	Over 1,500,000	1,500,000
2	500,000 to 1,500,000	1,000,000
3	50,000 to 500,000	275,000
4	Under 50,000	50,000

Within each region, the TRW reports generally list the sulfur samples by their Sample Quantity Number, starting with 1 and moving to 2, 3, and 4. Thus, the sulfur data representing the largest fuel batches are listed first and those representing the smallest fuel batches are listed last. However, some sulfur data points in the TRW reports do not have a Sample Quantity Number. These data points always appear at either top of the list or the bottom of the list. When the data missing a Sample Quantity Number appeared at the top of the list, we assigned that data a production volume of 2 million barrels per year. When the data appeared at the bottom of the list, we assigned it a volume of 25,000 barrels per year. In the analysis performed for the NPRM, we excluded this data from the analysis.

The survey reports often list the same sample number under more than one region. Each of these listings shows the districts in both regions. For example, Sample 45 may be listed in both the Eastern and Central Regions. Both listing show C2 and E2, indicating that 0.5-1.0 million barrels of fuel were shipped that year to Districts C and E. Since both districts are listed under both regions, we assumed that this was in fact only one data point and that 0.5-1 million barrels were shipped to District C in the Eastern Region and that 0.5-1 million barrels were shipped to District E in the Central Region, not twice this volume.

In this case, the numeral 2 was assigned to each district, so we assumed that 0.5-1 million barrels of fuel were provided to each district. In some cases, two or more districts are listed with only a single numeral following the district letter (i.e., C, E 2). In this case, we assumed that the total volume of fuel produced was 0.5-1 million barrels and that this volume was split between the two districts. TRW indicates that the district receiving the most fuel was listed first, etc. However, lacking any quantitative information about the relative volumes of fuel supplied to each district, we simply assumed that each district received the same proportion.

TRW segregates their reporting of fuel quality by fuel type, namely No. 1 diesel fuel, No. 2 highway diesel fuel and No. 2 off-highway diesel fuel. We focused solely on the data for No. 2 off-highway diesel fuel. However, we assumed that off-highway diesel fuel with a sulfur content of less than 500 ppm was highway diesel fuel "spillover." These data were excluded from this analysis since we account for the lower sulfur content of spillover fuel separately below.

After applying the PADD assignments shown in Table 7.1.6-1, we volume weighted the sulfur data in each PADD using the average volumes shown in Table 7.1.6-2 in order to derive a PADD average sulfur content for each calendar year. These PADD averages are shown in Table 7.1.6-3.

Table 7.1.6-3
Sulfur Content of High Sulfur Diesel Fuel

PADD	Year	Volume (bbls/year)	Sulfur (ppm)	PADD Average
1	1996	7,170,833	3,482	2,925
	1997	13,250,000	2,601	
	1998	5,887,500	2,418	
	1999	4,137,500	3,257	
	2000	10,525,000	2,691	
	2001	4,437,500	3,061	
	2002	2,662,500	4,343	
2	1996	4,158,333	3,497	2,973
	1997	5,100,000	3,008	
	1998	2,775,000	2,241	
	1999	2,912,500	1,717	
	2000	10,412,500	2,939	
	2001	5,212,500	3,854	
	2002	1,000,000	1,620	
3	1996	2,420,833	4,539	3,776
	1997	4,500,000	3,945	
	1998	2,387,500	5,004	
	1999	3,000,000	4,177	
	2000	3,387,500	4,361	
	2001	1,775,000	4,298	
	2002	2,387,500	4,359	
4	1996	275,000	4,100	2,549
	1997	275,000	1,000	
	1998	275,000	3,400	
	1999	275,000	2,000	
	2000	275,000	2,600	
	2001	275,000	2,340	
	2002	275,000	2,400	
5	1996	2,050,000	3,076	2,566
	1997	3,550,000	2,268	
	1998	1,550,000	3,077	
	1999	1,550,000	2,065	
	2000	2,175,000 *	2,566 *	
	2001	2,175,000 *	2,566 *	
	2002	2,175,000 *	2,566 *	
U.S.	1996	16,075,000	3,623	3,030
	1997	26,675,000	2,710	
	1998	12,875,000	2,669	
	1999	11,875,000	2,818	
	2000	26,775,000	2,886	
	2001	14,375,000	3,440	
	2002	8,500,000	3,510	

* No data reported. Estimated from the average from 1996-1999.

We next calculated a national average sulfur content for each year. This was done by weighting the PADD average sulfur contents in each year by the volume of fuel represented by all the samples in that PADD. No data were reported for the Western Region for 2000, 2001 and 2002. Thus, we substituted the 1996-1999 average production volume and sulfur content for these missing years when calculating the national average for 1999-2002. These national averages are also shown in Table 7.1.6-3. It should be noted that these national average sulfur contents were not used in either the emissions nor cost analysis. The emission and cost analyses used the PADD average sulfur contents. However, we present them here for illustrative purposes and to simply the evaluation of the presence of any temporal trends in the sulfur content of high sulfur diesel fuel.

We examined the annual average sulfur contents for possible trends. However, as indicated by the national averages shown in Table 7.1.6-3, the sulfur content of high sulfur diesel fuel seems to vary randomly. Therefore, we average the data once more across calendar years, again using the fuel volumes represented by all the samples from each year. As shown in Table 7.1.6-3, this overall average sulfur content is 3030 ppm.

While the TRW reports indicate that the sulfur data was supplied by refiners, we assume that these sulfur levels are actually those existing at the point-of-use (i.e. retail). Thus, this average sulfur content of 3030 ppm is used in Chapter 3 to project emissions of sulfur dioxide and sulfate PM from the burning of NRLM fuel and heating oil. Because of the absence of a trend in the 1996-2002 data, we assume that these sulfur contents will not change in the future, absent NRLM fuel standards.

In order to project desulfurization costs, however, an estimate of the current sulfur content of NRLM fuel at the refinery is needed. As discussed in Sections 7.1.2 and 7.1.3, small volumes of jet fuel, highway diesel fuel and heavy gasoline become mixed with high sulfur distillate during pipeline shipment. These other fuels generally contain less sulfur than high sulfur diesel fuel, so the sulfur content of high sulfur diesel fuel actually decreases during shipment. In order to better estimate desulfurization costs, we estimated the sulfur content of high sulfur diesel fuel prior to this mixing during shipment.

The volumes of high sulfur distillate produced at refineries and the volume of material downgraded to high sulfur distillate is estimated in Sections 7.1.2 and 7.1.3 (see, for example, Tables 7.1.2-8 and 7.1.3-8). Here, we estimate the sulfur content of these various materials so that the combination matches the PADD average sulfur contents shown in Table 7.1.6-3.

Table 7.1.2-6 shows the types of downgrades and their volumes and destinations. This table shows that 1.75% of jet fuel demand, 2.2% of highway diesel fuel production, and a volume of heavy gasoline equivalent to 0.58% of jet fuel demand and 0.73% of highway diesel fuel production is shifted to high sulfur distillate during pipeline shipment. We estimate that jet fuel averages 550 ppm sulfur.[14] From the Final RIA for the highway diesel rule, highway diesel fuel averages 340 ppm sulfur. The sulfur level of today's gasoline, before the Tier 2 rule has been implemented, averages about 300 ppm. The vast majority of this sulfur is contained in the naphtha produced in the fluidized catalytic cracker (FCC naphtha). The sulfur content of FCC naphtha increases significantly with distillation temperature. Therefore, we estimate that the heaviest one-third of gasoline distilled into transmix contains essentially all the sulfur in the whole gasoline. Thus, we estimate the sulfur level of the heaviest one-third of gasoline to be about 900 ppm.

As described in Section 7.1.2, to simplify the analysis of downgrade distillate volume, we combined the jet fuel downgrade with the portion of the heavy gasoline downgrade which was dependent on jet fuel demand. Of this jet-based downgrade, jet fuel represents 75% (1.75/(1.75+0.58)) and heavy gasoline represents 25% (0.58/(1.75+0.58)). Weighting the sulfur content of jet fuel and heavy gasoline by these percentages produces an average sulfur content of 638 ppm.

Likewise, we combined the highway diesel fuel downgrade with the portion of the heavy gasoline downgrade which was dependent on highway diesel fuel production. Of this highway-based downgrade, highway diesel fuel represents 75% (2.2/(2.2+0.73)) and heavy gasoline represents 25% (0.73/(2.2+0.73)). Weighting the sulfur content of jet fuel and heavy gasoline by these percentages produces an average sulfur content of 480 ppm.[S]

Table 7.1.6-4 presents the levels of high sulfur distillate production and demand, as well as the volumes of downgraded material which are added to this fuel during distribution. All of these figures were taken directly from Table 7.1.2-8. Table 7.1.6-4 also shows the sulfur content of high sulfur diesel fuel at retail (from Table 7.1.6-3) and of the two types of downgrade, as discussed above. We determined the sulfur content of high sulfur distillate at the refinery which, when combined with the volumes and sulfur content of the two types of downgrade, matched the sulfur content from the TRW surveys. The sulfur content of high sulfur distillate at the refinery gate in each PADD are shown in Table 7.1.6-4. Because there are no product pipelines in Alaska and Hawaii, we assume that there is no downgrade in these areas. Also, because we assumed 100% spillover into the high sulfur distillate market in California, there is no high sulfur distillate in California pipelines to receive this downgrade. Distillate downgrade is assumed to be used directly as L&M fuel. Thus, we assume that the sulfur content of 2,570 ppm for high suflur distillate in PADD 5 applies at both retail and the refinery in Alaska, Hawaii, and California.

[S] The distillate sulfur contents presented at the end of this section for 1996-2006 assume that jet-based downgrade contains 700 ppm rather than 638 ppm and that highway-based downgrade contains 560 ppm rather than 480 ppm. These errors have a very small effect on the final sulfur content of high sulfur distillate fuels during these years. As the NRLM fuel program has no effect during these years, neither the costs nor benefits associated with this rule are affected.

Table 7.1.6-4
Sulfur Content of High Sulfur Diesel Fuel at Refineries in 2001

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK, HI, CA
High Sulfur Distillate Fuel Volume						
Demand	10,955	4,562	4,407	408	497	486
Jet-Based Downgrade	95	80	123	12	51	0
Highway-Based Downgrade	327	387	202	64	68	0
Refinery Production	10,533	4,095	4,082	332	378	486
High Sulfur Distillate Sulfur Content (ppm)						
At Retail	2,930	2,970	3,780	2,550	2,570	2,570
Jet-Based Downgrade	638	638	638	638	638	638
Highway-Based Downgrade	480	480	480	480	480	480
Sulfur level of HS Dist Pool at Refineries	3,041	3,295	4,059	3,102	3,280	2,570

As can be seen, downgrade occurring in pipelines decreases the sulfur content of high sulfur distillate by as little as 111 ppm in PADD 1 and as much as 710 in PADD 5-O. The difference is due to the very small volume of downgrade relative to the demand for high sulfur distillate in PADD 1, with the opposite being true in PADD 5-O.

After completion of this analysis, we discovered that the TRW data represented sulfur levels at the refinery and not downstream. Thus, the TRW sulfur levels should have been used to estimate desulfurization costs in Section 7.2.2 and the adjustments shown in Table 7.1.6-4 should have been used to estimate lower sulfur levels downstream. The result of this error is an overestimation of the baseline sulfur content of high sulfur distillate by roughly 150 ppm on average. Given the limited data set and the resulting year-to-year variation, the resulting estimate is still well within the range of possible actual sulfur levels. This 150 ppm difference, if real, results in an overestimation of the cost to produce 500 ppm NRLM fuel of roughly 0.02 cent per gallon (i.e., roughly 1%) and an overestimation of the sulfur dioxide and sulfate PM emission reductions due to the 500 ppm NRLM fuel cap of roughly 4-5%.

The next step in this analysis is to project the sulfur content of the various distillate fuels during the various phases of the final NRLM fuel program, as well as under the two sensitivity cases. We assume that the sulfur content of NRLM fuel produced under 15 and 500 ppm caps will be the same as those we estimate for highway diesel fuel produced under the same standards. Thus, we assume that NRLM fuel produced to meet a 500 ppm cap will contain 340 ppm sulfur. We assume that NRLM fuel produced to meet a 15 ppm cap will contain 7 ppm sulfur at the refinery. However, as discussed in the Final RIA for the highway diesel rule, we assume that this fuel will contain 11 ppm at the time of final sale. This increase of 4 ppm is due to very small volumes of higher sulfur fuel being incorporated into batches of 15 ppm diesel fuel during shipment. This volume is by necessity very small compared to the volume of pipeline interface. Thus, this 4 ppm increase in 15 ppm fuel during shipment does not affect our estimation of the creation and disposition of downgrade created in the pipeline during shipment.

As just mentioned, highway fuel in the pipeline will contain between 7 and 11 ppm sulfur. We assume that the highway fuel contributing to interface contains 11 ppm sulfur. We assume that the sulfur content of jet fuel will remain 550 ppm in the future. Under the Tier 2 standards, gasoline will average 30 ppm sulfur. With this degree of sulfur control, essentially all the sulfur in gasoline will be in the heavy portion of FCC naphtha. Thus, we apply the same factor of 3 discussed above and estimate that the heaviest one-third of gasoline will contain 90 ppm sulfur.

Prior to the NRLM rule, the volume of jet-based downgrade stays the same as that shown in Table 7.1.6-4 (compare the jet-based downgrade in Table 7.1.2-6 (2001) to that in Table 7.1.3-6 (2014 prior to the NRLM rule)). Only the sulfur levels change. A 75%/25% weighting of the sulfur content of jet fuel (550 ppm) and heavy gasoline (90 ppm) produces an average sulfur content of 435 ppm.

As indicated in Table 7.1.3-6, the volume of highway-based downgrade increases significantly with the onset of the 15 ppm highway program, due to the need to make more protective interface cuts to maintain the quality of this fuel. As described in Table 7.1.3-6, 2.2% of highway diesel fuel supply will be cut directly into high sulfur distillate fuel. We assume that this highway fuel contains 11 ppm sulfur. Also, 2.2% of highway fuel supply plus a volume of heavy gasoline equivalent to 0.73% of highway fuel supply will be processed as transmix and added to the 500 ppm highway fuel supply. This downgrade will have an average sulfur content of 31 ppm (25% of 90 ppm plus 75% of 11 ppm).[T]

Under the NRLM fuel program, after 2007, some pipelines are projected to continue carrying heating oil, while others are expected to drop this fuel. For those pipelines still carrying heating oil (PADDs 1 and 3), the sulfur content of jet-based downgrade will continue to be 435 ppm, as described above. The sulfur content of the highway-based downgrade to high sulfur distillate and 500 ppm diesel fuel will continue to be 11 ppm and 31 ppm, respectively, as described above.[U]

[T] The distillate sulfur contents presented at the end of this section assume that jet-based downgrade in this time period contains 400 ppm rather than 435 ppm and that highway-based downgrade contains 35 ppm rather than 31 ppm. The net effect of these partially offsetting errors on the final sulfur content of high sulfur distillate fuels in the base case is very minor.

[U] TRW also surveys the quality of distillate fuel oil. These surveys which we received after completion of this analysis, show national average sulfur levels of roughly 2200 ppm, versus 3000 ppm for high sulfur diesel fuel. However, it is not clear how much distillate actually burned in heating oil uses is defined as heating oil at the refinery and how much is defined as diesel fuel. Thus, we chose not to use the heating oil survey results here. However, given that at least a portion of the heating oil market must meet state sulfur caps of 2000-4000 ppm, extrapolation of the diesel fuel survey results to heating oil probably over-estimates the sulfur content to some degree. Given that the sulfurous emission reductions from heating oil are only ancillary to the benefits of this rule, this likely small degree of overestimation is not critical. However, the heating oil related benefits are a large portion

For those pipelines not carrying heating oil, the nature of the downgrade and its disposition changes, as shown in Table 7.1.3-12. For these pipelines (all PADDs except 1 and 3), all of the jet-based downgrade is combined, as is the highway-based downgrade. The total jet-based downgrade consists of 3.5% of jet fuel demand and a volume of heavy gasoline equivalent to 0.58% of jet fuel demand. This is a 6:1 ratio of jet fuel to gasoline. With jet fuel at 550 ppm and heavy gasoline at 90 ppm, the average sulfur content of the jet-based downgrade is 485 ppm. Similarly, the total highway-based downgrade consists of 4.4% of highway fuel supply and a volume of heavy gasoline equivalent to 0.73% of highway fuel supply. This is a 6:1 ratio of highway fuel to gasoline. With highway fuel at 11 ppm and heavy gasoline at 90 ppm, the average sulfur content of the highway-based downgrade is 22 ppm.[V] While the disposition of this downgrade changes during the various phases of the NRLM fuel program, the sulfur content of these two types of downgrade remain the same.

7.1.4.2 Distillate Fuel Demand and Sulfur Content by Year

We present the final estimates of distillate fuel demand and sulfur content for each year from 1996-2040 in this section. We develop these estimates by combining:

1) The sulfur contents developed in Section 7.1.4.1 with
2) The sources of each distillate fuel's supply in 2014 developed in Sections 7.1.2 (Reference Case), 7.1.3 (after implementation of the final NRLM fuel program), and 7.1.4 (sensitivity cases), and
3) The growth in distillate fuel demand developed in Section 7.1.5.

We did this for the entire U.S. (50-state) and for 48 states (the U.S. minus the states of Alaska and Hawaii). The results are summarized in Tables 7.1.6-5 to 7.1.6-12. In all cases, we assume that a new sulfur standard becomes effective on June 1. Therefore, the average sulfur levels in any transition year is a 5:7 weighting of the previous year's sulfur level and the following year's sulfur level.

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of the incremental benefits of associated with the 15 ppm cap for L&M fuel. Thus, we address the possibility of a lower sulfur content for heating oil in Section 8.3, where we evaluate the incremental cost effectiveness of the 15 ppm cap for L&M fuel.

[V] The distillate sulfur contents presented at the end of this section assume that jet-based downgrade in this time period contains 470 ppm rather than 485 ppm and that highway-based downgrade contains 25 ppm rather than 22 ppm. The net effect of these partially offsetting errors on the final sulfur content of high sulfur distillate fuels in the base case is minor.

Table 7.1.6-5 Annual Distillate Fuel Demand and Sulfur Content for the Reference Case; U.S. minus AK and HI (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,243	2,818	2,437	1,868	2,904	4,686	2,623	10,116	2,860
2007	12,272	2,214	2,868	2,424	1,895	2,893	4,763	2,611	10,058	2,853
2008	12,562	2,214	2,900	2,424	1,921	2,893	4,821	2,611	10,000	2,853
2009	12,851	2,214	2,939	2,424	1,944	2,893	4,883	2,611	9,943	2,853
2010	13,140	2,159	2,986	2,254	1,968	2,712	4,954	2,436	9,886	2,722
2011	13,430	2,120	3,043	2,133	1,997	2,583	5,039	2,312	9,829	2,628
2012	13,721	2,120	3,073	2,133	2,023	2,583	5,096	2,312	9,772	2,628
2013	14,012	2,120	3,097	2,133	2,041	2,583	5,138	2,312	9,716	2,628
2014	14,302	2,120	3,121	2,133	2,066	2,583	5,187	2,312	9,661	2,628
2015	14,593	2,120	3,148	2,133	2,089	2,583	5,236	2,313	9,605	2,628
2016	14,881	2,120	3,181	2,133	2,109	2,583	5,290	2,313	9,550	2,628
2017	15,169	2,120	3,210	2,133	2,132	2,583	5,342	2,313	9,495	2,628
2018	15,456	2,120	3,234	2,133	2,164	2,583	5,398	2,314	9,441	2,628
2019	15,744	2,120	3,266	2,133	2,201	2,583	5,466	2,314	9,386	2,628
2020	16,032	2,120	3,288	2,133	2,226	2,583	5,515	2,315	9,333	2,628
2021	16,319	2,120	3,305	2,133	2,254	2,583	5,559	2,316	9,279	2,628
2022	16,607	2,120	3,335	2,133	2,290	2,583	5,625	2,316	9,226	2,628
2023	16,895	2,120	3,364	2,133	2,316	2,583	5,680	2,317	9,173	2,628
2024	17,183	2,120	3,393	2,133	2,347	2,583	5,740	2,317	9,120	2,628
2025	17,470	2,120	3,426	2,133	2,374	2,583	5,800	2,317	9,068	2,628
2026	17,756	2,120	3,453	2,133	2,405	2,583	5,858	2,318	9,016	2,628
2027	18,042	2,120	3,481	2,133	2,436	2,583	5,917	2,319	8,964	2,628
2028	18,328	2,120	3,508	2,133	2,467	2,583	5,976	2,319	8,913	2,628
2029	18,613	2,120	3,536	2,133	2,499	2,583	6,035	2,320	8,861	2,628
2030	18,899	2,120	3,564	2,133	2,532	2,583	6,095	2,320	8,811	2,628
2031	19,185	2,120	3,591	2,133	2,564	2,583	6,155	2,321	8,760	2,628
2032	19,470	2,120	3,619	2,133	2,598	2,583	6,216	2,321	8,710	2,628
2033	19,756	2,120	3,646	2,133	2,631	2,583	6,277	2,322	8,660	2,628
2034	20,042	2,120	3,674	2,133	2,665	2,583	6,339	2,322	8,610	2,628
2035	20,328	2,120	3,701	2,133	2,700	2,583	6,401	2,323	8,561	2,624
2036	20,613	2,120	3,729	2,133	2,735	2,583	6,463	2,324	8,511	2,628
2037	20,899	2,120	3,756	2,133	2,770	2,583	6,526	2,324	8,463	2,628
2038	21,185	2,120	3,784	2,133	2,806	2,583	6,590	2,325	8,414	2,628
2039	21,470	2,120	3,811	2,133	2,842	2,583	6,653	2,325	8,366	2,628
2040	21,756	2,120	3,839	2,133	2,879	2,583	6,718	2,326	8,318	2,628

Table 7.1.6-6 Annual Distillate Fuel Demand and Sulfur Content: Final NRLM Rule: U.S. minus AK and HI (million gallons and ppm)					
	Nonroad	Locomotive	Marine	L&M	Heating Oil

Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,243	2,818	2,435	1,868	2,902	4,686	2,621	10,116	2,860
2007	12,272	1,127	2,868	1,225	1,895	1,469	4,763	1,321	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	155	2,986	177	1,968	208	4,954	189	9,886	2,424
2011	13,430	30	3,043	45	1,997	39	5,039	43	9,829	2,349
2012	13,721	30	3,073	45	2,023	39	5,096	43	9,772	2,349
2013	14,012	19	3,097	45	2,041	39	5,138	43	9,716	2,349
2014	14,302	11	3,121	61	2,066	33	5,187	49	9,661	2,336
2015	14,593	11	3,148	72	2,089	28	5,236	54	9,605	2,327
2016	14,881	11	3,181	72	2,109	28	5,290	54	9,550	2,327
2017	15,169	11	3,210	72	2,132	28	5,342	54	9,495	2,327
2018	15,456	11	3,234	72	2,164	28	5,398	54	9,441	2,327
2019	15,744	11	3,266	72	2,201	28	5,466	54	9,386	2,327
2020	16,032	11	3,288	72	2,226	28	5,515	54	9,333	2,327
2021	16,319	11	3,305	72	2,254	28	5,559	54	9,279	2,327
2022	16,607	11	3,335	72	2,290	28	5,625	54	9,226	2,327
2023	16,895	11	3,364	72	2,316	28	5,680	54	9,173	2,327
2024	17,183	11	3,393	72	2,347	28	5,740	54	9,120	2,327
2025	17,470	11	3,426	72	2,374	28	5,800	54	9,068	2,327
2026	17,756	11	3,453	72	2,405	28	5,858	54	9,016	2,327
2027	18,042	11	3,481	72	2,436	28	5,917	54	8,964	2,327
2028	18,328	11	3,508	72	2,467	28	5,976	54	8,913	2,327
2029	18,613	11	3,536	72	2,499	28	6,035	54	8,861	2,327
2030	18,899	11	3,564	72	2,532	28	6,095	54	8,811	2,327
2031	19,185	11	3,591	72	2,564	28	6,155	54	8,760	2,327
2032	19,470	11	3,619	72	2,598	28	6,216	54	8,710	2,327
2033	19,756	11	3,646	72	2,631	28	6,277	54	8,660	2,327
2034	20,042	11	3,674	72	2,665	28	6,339	54	8,610	2,327
2035	20,328	11	3,701	72	2,700	28	6,401	54	8,561	2,327
2036	20,613	11	3,729	72	2,735	28	6,463	54	8,511	2,327
2037	20,899	11	3,756	72	2,770	28	6,526	54	8,463	2,327
2038	21,185	11	3,784	72	2,806	28	6,590	54	8,414	2,327
2039	21,470	11	3,811	72	2,842	28	6,653	54	8,366	2,327
2040	21,756	11	3,839	72	2,879	28	6,718	54	8,318	2,327

Table 7.1.6-7 Annual Distillate Fuel Demand and Sulfur Content: NRLM to 500 ppm in 2007, no 15 ppm Step; U.S. minus AK and HI (million gallons and ppm)

	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871

1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,242	2,818	2,435	1,868	2,902	4,686	2,621	10,116	2,860
2007	12,272	1,126	2,868	1,225	1,895	1,469	4,763	1,323	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	276	2,986	293	1,968	348	4,954	315	9,886	2,526
2011	13,430	237	3,043	245	1,997	280	5,039	259	9,829	2,523
2012	13,721	237	3,073	245	2,023	280	5,096	259	9,772	2,523
2013	14,012	237	3,097	245	2,041	280	5,138	259	9,716	2,523
2014	14,302	237	3,121	245	2,066	280	5,187	259	9,661	2,523
2015	14,593	237	3,148	245	2,089	280	5,236	259	9,605	2,523
2016	14,881	237	3,181	245	2,109	280	5,290	259	9,550	2,523
2017	15,169	237	3,210	245	2,132	280	5,342	259	9,495	2,523
2018	15,456	237	3,234	245	2,164	280	5,398	259	9,441	2,523
2019	15,744	237	3,266	245	2,201	280	5,466	259	9,386	2,523
2020	16,032	237	3,288	245	2,226	280	5,515	259	9,333	2,523
2021	16,319	237	3,305	245	2,254	280	5,559	259	9,279	2,523
2022	16,607	237	3,335	245	2,290	280	5,625	259	9,226	2,523
2023	16,895	237	3,364	245	2,316	280	5,680	259	9,173	2,523
2024	17,183	237	3,393	245	2,347	280	5,740	259	9,120	2,523
2025	17,470	237	3,426	245	2,374	280	5,800	259	9,068	2,523
2026	17,756	237	3,453	245	2,405	280	5,858	259	9,016	2,523
2027	18,042	237	3,481	245	2,436	280	5,917	259	8,964	2,523
2028	18,328	237	3,508	245	2,467	280	5,976	259	8,913	2,523
2029	18,613	237	3,536	245	2,499	280	6,035	259	8,861	2,523
2030	18,899	237	3,564	245	2,532	280	6,095	259	8,811	2,523
2031	19,185	237	3,591	245	2,564	280	6,155	259	8,760	2,523
2032	19,470	237	3,619	245	2,598	280	6,216	259	8,710	2,523
2033	19,756	237	3,646	245	2,631	280	6,277	259	8,660	2,523
2034	20,042	237	3,674	245	2,665	280	6,339	259	8,610	2,523
2035	20,328	237	3,701	245	2,700	280	6,401	259	8,561	2,523
2036	20,613	237	3,729	245	2,735	280	6,463	259	8,511	2,523
2037	20,899	237	3,756	245	2,770	280	6,526	260	8,463	2,523
2038	21,185	237	3,784	245	2,806	280	6,590	260	8,414	2,523
2039	21,470	237	3,811	245	2,842	280	6,653	260	8,366	2,523
2040	21,756	237	3,839	245	2,879	280	6,718	260	8,318	2,523

Table 7.1.6-8 Proposed Rule Program: NRLM to 500 ppm in 2007,
Nonroad Only to 15 ppm in 2010; U.S. minus AK and HI (million gallons and ppm)

	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,242	2,818	2,437	1,868	2,904	4,686	2,623	10,116	2,860
2007	12,272	1,127	2,868	1,226	1,895	1,469	4,763	1,323	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	152	2,986	293	1,968	343	4,954	313	9,886	2,526
2011	13,430	25	3,043	245	1,997	270	5,039	255	9,829	2,523
2012	13,721	25	3,073	245	2,023	270	5,096	255	9,772	2,523
2013	14,012	25	3,097	245	2,041	270	5,138	255	9,716	2,516
2014	14,302	17	3,121	200	2,066	259	5,187	224	9,661	2,512
2015	14,593	11	3,148	168	2,089	252	5,236	202	9,605	2,512
2016	14,881	11	3,181	168	2,109	252	5,290	202	9,550	2,512
2017	15,169	11	3,210	168	2,132	252	5,342	202	9,495	2,512
2018	15,456	11	3,234	168	2,164	252	5,398	202	9,441	2,512
2019	15,744	11	3,266	168	2,201	252	5,466	202	9,386	2,512
2020	16,032	11	3,288	168	2,226	252	5,515	202	9,333	2,512
2021	16,319	11	3,305	168	2,254	252	5,559	202	9,279	2,512
2022	16,607	11	3,335	168	2,290	252	5,625	202	9,226	2,512
2023	16,895	11	3,364	168	2,316	252	5,680	202	9,173	2,512
2024	17,183	11	3,393	168	2,347	252	5,740	202	9,120	2,512
2025	17,470	11	3,426	168	2,374	252	5,800	203	9,068	2,512
2026	17,756	11	3,453	168	2,405	252	5,858	203	9,016	2,512
2027	18,042	11	3,481	168	2,436	252	5,917	203	8,964	2,512
2028	18,328	11	3,508	168	2,467	252	5,976	203	8,913	2,512
2029	18,613	11	3,536	168	2,499	252	6,035	203	8,861	2,512
2030	18,899	11	3,564	168	2,532	252	6,095	203	8,811	2,512
2031	19,185	11	3,591	168	2,564	252	6,155	203	8,760	2,512
2032	19,470	11	3,619	168	2,598	252	6,216	203	8,710	2,512
2033	19,756	11	3,646	168	2,631	252	6,277	203	8,660	2,512
2034	20,042	11	3,674	168	2,665	252	6,339	203	8,610	2,512
2035	20,328	11	3,701	168	2,700	252	6,401	204	8,561	2,512
2036	20,613	11	3,729	168	2,735	252	6,463	204	8,511	2,512
2037	20,899	11	3,756	168	2,770	252	6,526	204	8,463	2,512
2038	21,185	11	3,784	168	2,806	252	6,590	204	8,414	2,512
2039	21,470	11	3,811	168	2,842	252	6,653	204	8,366	2,512
2040	21,756	11	3,839	168	2,879	252	6,718	204	8,318	2,512

Table 7.1.6-9 Annual Distillate Fuel Demand and Sulfur Content for the Reference Case; U.S. (million gallons and ppm)

	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,244	2,823	2,437	1,949	2,888	4,772	2,621	10,452	2,849
2007	12,339	2,214	2,873	2,424	1,977	2,878	4,850	2,609	10,392	2,842
2008	12,629	2,214	2,904	2,424	2,005	2,878	4,909	2,609	10,332	2,842
2009	12,920	2,214	2,944	2,424	2,029	2,878	4,972	2,609	10,273	2,842
2010	13,210	2,160	2,990	2,255	2,054	2,705	5,044	2,438	10,214	2,712
2011	13,503	2,121	3,047	2,134	2,084	2,581	5,131	2,316	10,155	2,624
2012	13,795	2,121	3,077	2,134	2,111	2,581	5,188	2,316	10,097	2,624
2013	14,087	2,121	3,102	2,134	2,130	2,581	5,232	2,316	10,039	2,624
2014	14,379	2,121	3,126	2,134	2,156	2,581	5,282	2,316	9,982	2,624
2015	14,672	2,121	3,152	2,134	2,180	2,581	5,332	2,317	9,924	2,624
2016	14,961	2,121	3,186	2,134	2,200	2,581	5,386	2,317	9,867	2,624
2017	15,250	2,121	3,215	2,134	2,225	2,581	5,440	2,317	9,811	2,624
2018	15,539	2,121	3,239	2,134	2,258	2,581	5,497	2,318	9,754	2,624
2019	15,829	2,121	3,271	2,134	2,297	2,581	5,567	2,318	9,698	2,624
2020	16,118	2,121	3,293	2,134	2,323	2,581	5,617	2,319	9,643	2,624
2021	16,407	2,121	3,310	2,134	2,352	2,581	5,662	2,320	9,587	2,624
2022	16,986	2,121	3,339	2,134	2,390	2,581	5,730	2,320	9,532	2,624
2023	17,275	2,121	3,369	2,134	2,417	2,581	5,786	2,321	9,478	2,624
2024	17,564	2,121	3,398	2,134	2,449	2,581	5,847	2,321	9,423	2,624
2025	17,852	2,121	3,431	2,134	2,478	2,581	5,909	2,321	9,369	2,624
2026	18,139	2,121	3,458	2,134	2,510	2,581	5,968	2,322	9,315	2,624
2027	18,426	2,121	3,486	2,134	2,542	2,581	6,028	2,322	9,262	2,624
2028	18,714	2,121	3,514	2,134	2,575	2,581	6,089	2,323	9,209	2,624
2029	19,001	2,121	3,541	2,134	2,608	2,581	6,150	2,324	9,156	2,624
2030	19,575	2,121	3,569	2,134	2,642	2,581	6,211	2,324	9,103	2,624
2031	19,288	2,121	3,596	2,134	2,676	2,581	6,273	2,325	9,051	2,624
2032	19,575	2,121	3,624	2,134	2,711	2,581	6,335	2,325	8,999	2,624
2033	19,863	2,121	3,651	2,134	2,746	2,581	6,497	2,326	8,947	2,624
2034	20,150	2,121	3,679	2,134	2,781	2,581	6,460	2,326	8,896	2,624
2035	20,437	2,121	3,707	2,134	2,817	2,581	6,524	2,327	8,845	2,624
2036	20,724	2,121	3,734	2,134	2,854	2,581	6,588	2,328	8,794	2,624
2037	21,012	2,121	3,762	2,134	2,891	2,581	6,652	2,328	8,744	2,624
2038	21,299	2,121	3,789	2,134	2,928	2,581	6,717	2,329	8,694	2,624
2039	21,586	2,121	3,817	2,134	2,966	2,581	6,783	2,329	8,644	2,624
2040	21,873	2,121	3,844	2,134	3,004	2,581	6,849	2,330	8,594	2,624

Table 7.1.6-10 Annual Distillate Fuel Demand and Sulfur Content: Final NRLM Rule: U.S. (million gallons and ppm)

	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,886	4,772	2,620	10,452	2,849
2007	12,339	1,130	2,873	1,228	1,977	1,500	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	157	2,990	178	2,054	242	5,044	204	10,214	2,420
2011	13,503	30	3,047	46	2,084	49	5,131	47	10,155	2,343
2012	13,795	30	3,077	46	2,111	49	5,188	47	10,097	2,343
2013	14,087	30	3,102	46	2,130	49	5,232	47	10,039	2,343
2014	14,379	19	3,126	61	2,156	36	5,282	51	9,982	2,337
2015	14,672	11	3,152	71	2,180	27	5,332	53	9,924	2,333
2016	14,961	11	3,186	71	2,200	27	5,386	53	9,867	2,333
2017	15,250	11	3,215	71	2,225	27	5,440	53	9,811	2,333
2018	15,539	11	3,239	71	2,258	27	5,497	53	9,754	2,333
2019	15,829	11	3,271	71	2,297	27	5,567	53	9,698	2,333
2020	16,118	11	3,293	71	2,323	27	5,617	53	9,643	2,333
2021	16,407	11	3,310	71	2,352	27	5,662	53	9,587	2,333
2022	16,697	11	3,339	71	2,390	27	5,730	53	9,532	2,333
2023	16,986	11	3,369	71	2,417	27	5,786	53	9,478	2,333
2024	17,275	11	3,398	71	2,449	27	5,847	53	9,423	2,333
2025	17,564	11	3,431	71	2,478	27	5,909	53	9,369	2,333
2026	17,852	11	3,458	71	2,510	27	5,968	53	9,315	2,333
2027	18,139	11	3,486	71	2,542	27	6,028	53	9,262	2,333
2028	18,426	11	3,514	71	2,575	27	6,089	53	9,209	2,333
2029	18,714	11	3,541	71	2,608	27	6,150	53	9,156	2,333
2030	19,001	11	3,569	71	2,642	27	6,211	53	9,103	2,333
2031	19,288	11	3,596	71	2,676	27	6,273	53	9,051	2,333
2032	19,575	11	3,624	71	2,711	27	6,335	53	8,999	2,333
2033	19,863	11	3,651	71	2,746	27	6,497	53	8,947	2,333
2034	20,150	11	3,679	71	2,781	27	6,460	52	8,896	2,333
2035	20,437	11	3,707	71	2,817	27	6,524	52	8,845	2,333
2036	20,724	11	3,734	71	2,854	27	6,588	52	8,794	2,333
2037	21,012	11	3,762	71	2,891	27	6,652	52	8,744	2,333
2038	21,299	11	3,789	71	2,928	27	6,717	52	8,694	2,333
2039	21,586	11	3,817	71	2,966	27	6,783	52	8,644	2,333
2040	21,873	11	3,844	71	3,004	27	6,849	52	8,594	2,333

Table 7.1.6-11 Annual Distillate Fuel Demand and Sulfur Content: NRLM to 500 ppm in 2007, no 15 ppm Step; U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,906	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,906	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,886	4,772	2,620	10,452	2,849
2007	12,339	1,130	2,873	1,227	1,977	1,502	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	278	2,990	295	2,054	378	5,044	329	10,214	2,525
2011	13,503	237	3,047	245	2,084	282	5,131	260	10,155	2,522
2012	13,795	237	3,077	245	2,111	282	5,188	260	10,097	2,522
2013	14,087	237	3,102	245	2,130	282	5,232	260	10,039	2,522
2014	14,379	237	3,126	245	2,156	282	5,282	260	9,982	2,522
2015	14,672	237	3,152	245	2,180	282	5,332	260	9,924	2,522
2016	14,961	237	3,186	245	2,200	282	5,386	260	9,867	2,522
2017	15,250	237	3,215	245	2,225	282	5,440	260	9,811	2,522
2018	15,539	237	3,239	245	2,258	282	5,497	260	9,754	2,522
2019	15,829	237	3,271	245	2,297	282	5,567	260	9,698	2,522
2020	16,118	237	3,293	245	2,323	282	5,617	260	9,643	2,522
2021	16,407	237	3,310	245	2,352	282	5,662	260	9,587	2,522
2022	16,697	237	3,339	245	2,390	282	5,730	260	9,532	2,522
2023	16,986	237	3,369	245	2,417	282	5,786	260	9,478	2,522
2024	17,275	237	3,398	245	2,449	282	5,847	260	9,423	2,522
2025	17,564	237	3,431	245	2,478	282	5,909	260	9,369	2,522
2026	17,852	237	3,458	245	2,510	282	5,968	260	9,315	2,522
2027	18,139	237	3,486	245	2,542	282	6,028	261	9,262	2,522
2028	18,426	237	3,514	245	2,575	282	6,089	261	9,209	2,522
2029	18,714	237	3,541	245	2,608	282	6,150	261	9,156	2,522
2030	19,001	237	3,569	245	2,642	282	6,211	261	9,103	2,522
2031	19,288	237	3,596	245	2,676	282	6,273	261	9,051	2,522
2032	19,575	237	3,624	245	2,711	282	6,335	261	8,999	2,522
2033	19,863	237	3,651	245	2,746	282	6,497	261	8,947	2,522
2034	20,150	237	3,679	245	2,781	282	6,460	261	8,896	2,522
2035	20,437	237	3,707	245	2,817	282	6,524	261	8,845	2,522
2036	20,724	237	3,734	245	2,854	282	6,588	261	8,794	2,522
2037	21,012	237	3,762	245	2,891	282	6,652	261	8,744	2,522
2038	21,299	237	3,789	245	2,928	282	6,717	261	8,694	2,522
2039	21,586	237	3,817	245	2,966	282	6,783	261	8,644	2,522
2040	21,873	237	3,844	245	3,004	282	6,849	261	8,594	2,522

Table 7.1.6-12 Annual Distillate Fuel Demand and Sulfur Content: Proposed Rule Program: 500 ppm NRLM ppm in 2007, 15 ppm Nonroad Only in 2010; U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,888	4,772	2,621	10,452	2,849
2007	12,339	1,130	2,873	1,228	1,977	1,502	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	163	2,990	295	2,054	373	5,044	326	10,214	2,525
2011	13,503	40	3,047	245	2,084	273	5,131	256	10,155	2,522
2012	13,795	40	3,077	245	2,111	273	5,188	256	10,097	2,522
2013	14,087	40	3,102	245	2,130	273	5,232	256	10,039	2,522
2014	14,379	23	3,126	200	2,156	255	5,282	223	9,982	2,516
2015	14,672	11	3,152	169	2,180	242	5,332	199	9,924	2,511
2016	14,961	11	3,186	169	2,200	242	5,386	199	9,867	2,511
2017	15,250	11	3,215	169	2,225	242	5,440	199	9,811	2,511
2018	15,539	11	3,239	169	2,258	242	5,497	199	9,754	2,511
2019	15,829	11	3,271	169	2,297	242	5,567	199	9,698	2,511
2020	16,118	11	3,293	169	2,323	242	5,617	199	9,643	2,511
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2033	19,863	11	3,651	169	2,746	242	6,497	200	8,947	2,511
2034	20,150	11	3,679	169	2,781	242	6,460	200	8,896	2,511
2035	20,437	11	3,707	169	2,817	242	6,524	200	8,845	2,511
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2037	21,012	11	3,762	169	2,891	242	6,652	200	8,744	2,511
2038	21,299	11	3,789	169	2,928	242	6,717	201	8,694	2,511
2039	21,586	11	3,817	169	2,966	242	6,783	201	8,644	2,511
2040	21,873	11	3,844	169	3,004	242	6,849	201	8,594	2,511

7.2 Refining Costs

The most significant cost involved in providing diesel fuel meeting more stringent sulfur standards is the cost of removing the sulfur at the refinery. In this section, we describe the methodology used and present the estimated costs for refiners to:

- comply with the 2007 Nonroad, Locomotive, and Marine (NRLM) 500 ppm diesel fuel sulfur standards and the 15 ppm nonroad diesel fuel standard in 2010 and the 15 ppm L&M standard in 2012,
- comply with other NRLM diesel fuel sulfur sensitivity cases considered, and
- comply with the 2006 sulfur standards already adopted for highway diesel fuel (an update of a previous cost analysis).

Finally, we compare our estimated costs with those developed by Mathpro (for the Engine Manufacturers Association) and Baker and O'Brien (for the American Petroleum Institute).

7.2.1 Methodology

7.2.1.1 Overview

This section describes the methodology used to estimate the refining cost of reducing diesel fuel sulfur content. Costs are estimated based on two distinct desulfurization technologies: conventional hydrotreating and the Process Dynamics IsoTherming process. Conventional hydrotreating cost estimates were based on information from two vendors, while the cost estimates for the more advanced process was made from information provided by the respective vendor. For both technologies, costs are estimated for each U.S. refinery currently producing distillate fuel. Conventional hydrotreating technology was projected to be used to desulfurize distillate to meet a 500 ppm sulfur cap. A mix comprised of advanced desulfurization technology with some conventional hydrotreating technology was projected to be used to meet the 15 ppm sulfur cap. This mix of technology varied depending on the timing of the 15 ppm sulfur standard. To meet the 500 ppm and 15 ppm sulfur standards, refiners are expected to desulfurize to 340 ppm and 7 ppm, respectively.

Refining costs were developed for revamping existing hydrotreaters that produce low-sulfur diesel fuel, as well as new, grass roots desulfurization units. The lower revamped costs were primarily used when streams or parts of streams were already desulfurized (i.e., highway), while the grassroots costs applied normally for untreated streams (mostly nonroad). In both cases, costs were developed for our refinery cost model and used to estimate the desulfurization cost for each refinery in the United States producing distillate fuel in 2001. These refinery-specific costs consider the volume of distillate fuel produced, the composition of this distillate fuel, and the location of the refinery (e.g., Gulf Coast, Rocky Mountain region, etc.). The estimated composition of each refinery's distillate included the fraction of hydrotreated and nonhydrotreated straight-run distillate, light cycle oil (LCO), other cracked stocks (coker, visbreaker, thermal cracked) and hydrocracked distillate, and the cost to desulfurize each of those stocks. The cost information provided by the various vendors was used to develop the desulfurization cost for each blendstock; however, when lacking, engineering judgment was used to develop the needed specific cost estimate. The average desulfurization cost for each refinery was based on the volume-weighted average of desulfurizing each of those blendstocks. The production volumes used were those indicative of 2014, a midyear of the estimated 15 year project life of the year 2007 capital investments by the refining industry.

7.2.1.2 Basic Cost Inputs for Specific Desulfurization Technologies

To obtain a comprehensive basis for estimating the cost of desufurizing diesel fuel, over the past few years we have held meetings with a large number of vendors of desulfurization technologies. These firms include: Criterion Catalyst, UOP, Akzo Nobel, Haldor Topsoe, and Process Dynamics. We have also met with numerous refiners of diesel fuel considering the use of these technologies and reviewed the literature on this subject. The information and estimates described below represent the culmination of these efforts. See Chapter 5 of the RIA for a more complete discussion of conventional hydrotreating and Process Dynamics Isotherming, as well as other desulfurization technologies evaluated in the course of this rulemaking.

The information used in our refinery cost model for estimating the cost of meeting 500 and 15 ppm sulfur caps using conventional hydrotreating is presented first. The cost methodology for conventional hydrotreating was developed for the HD2007 rulemaking for highway diesel fuel. Only the final process-design parameters are presented here. For a complete description of the methodology used to develop the cost estimates for conventional hydrotreating, consult Chapter 5 of the HD2007 Regulatory Impact Analysis.[15] The few variations from the HD2007 methodology are described below.

Next we present the methodology and resulting cost information used for developing the refinery costs for the Process Dynamics IsoTherming processs. In this case, we begin by presenting the estimates of the process-design parameters provided by the developers of this process. These projections are then evaluated to produce sets of process-design parameters that can be used to estimate the cost of meeting 500 ppm and 15 ppm NRLM diesel fuel standards for each domestic refiner. The resulting refining cost projections are presented and discussed in Section 7.2.2.

7.2.1.2.1 Conventional Desulfurization Technology

The cost of desulfurizing diesel fuel includes the capital cost related to designing and constructing the desulfurization unit, as well as the cost of operating the unit. We were able to obtain fairly complete sets of such process-design parameters from two out of the five or six licensors of conventional desulfurization technologies[16,17,18]. These designs addressed the production of 15 ppm diesel fuel by retrofitting existing hydrotreaters originally designed to produce 500 ppm diesel fuel, as well as building new, grass roots units. These two sets of process-design parameters were also used to estimate the cost of hydrotreating high-sulfur diesel fuel down to 500 ppm.

In addition to the information obtained from these two vendors, we reviewed similar information submitted to the National Petroleum Council (NPC) by Akzo Nobel, Criterion, Haldor Topsoe, UOP and IFP for its study of diesel fuel desulfurization costs and discussed them with the vendors.[19] These submissions were generally not as comprehensive as those provided by the two vendors mentioned above. In all cases, these submissions corroborated the costs from the two vendors.

All the vendors identified operating pressures sufficient to produce fuel meeting a 15 ppm sulfur cap under 900 psi. Most of the vendors projected that 650 psi is sufficient, while others indicated that pressures well below 1000 psi are sufficient. A contractor for API indicated that they believe a 850 psi unit is enough to meet a 15 ppm cap, though lower-pressure units would not be sufficient. We therefore based our estimate of capital cost on two different vendor submissions based on units operating at 650 and 900 psi.

Based on the information obtained from the two vendors of conventional hydrotreating technologies, as well as that obtained from Process Dynamics, we project that refiners will use conventional hydrotreating to produce NRLM diesel fuel meeting the 500 ppm standard in 2007. This unit would include heat exchangers, a fired pre-heater, a reactor, a hydrogen compressor and a make up compressor, and both high-pressure and low-pressure strippers. The refinery would also need a source of new hydrogen, an amine scrubber and a sulfur plant. Most refineries already have sources of hydrogen, an amine scrubber and a sulfur plant. However, considering the hydrogen demand for complying with Tier 2 sulfur standards for gasoline and the 15 ppm cap on highway diesel sulfur, no residual refinery production hydrogen is expected to exist. We therefore project that any new hydrogen demand will likely be produced from the addition of a new steam reforming hydrogen plant using natural gas as the feedstock, either on-site or by a third party. Likewise, a refinery's amine scrubber and sulfur plant would need modest expansion.

Producing diesel fuel meeting a 15 ppm standard generally requires much greater reactor volume and a larger hydrogen capacity, both in terms of compressor capacity and ability to introduce this hydrogen into the reactor, than are required to meet a 500 ppm cap. Since the 15 ppm sulfur cap for nonroad diesel fuel follows the 500 ppm NRLM sulfur cap by only three years and L&M by 5 years, we project that refiners will design any new hydrotreaters built for 2007 to be easily retrofitted with additional equipment, such as a second reactor, a hydrogen compressor, a recycle scrubber, an inter-stage stripper and other associated process hardware. The technical approach described by each vendor to achieve a 15 ppm sulfur cap (average level of 7-8 ppm) is summarized in Table 7.2.1-1.

Table 7.2.1-1
Modifications Necessary to Reduce 500 ppm Sulfur Levels to 15 ppm

Diesel Fuel Sulfur Level	Vendor A	Vendor B
7-8 ppm (15 ppm cap)	Change to a more active catalyst Install recycle gas scrubber Modify compressor Install a second reactor, high pressure (900 psi) Use existing hot oil separator for inter-stage stripper	Change to a more active catalyst Install a recycle gas scrubber Install a second reactor (650 psi) Install a color reactor Install an interstage stripper

It is important to note that back when the highway rulemaking was being promulgated, the vendors of conventional hydrotreating technology believed that a high pressure interstage stripper was needed for each hydrotreating unit to meet the 15 ppm sulfur cap standard, and included the costs for such a unit in their cost estimates. However, since that time the vendors are no longer recommending that the 15 ppm hydrotreaters include such a stage in the desulfurization process thus negating the need for the associated piece of capital. Our costs estimates are nevertheless still based on the vendor capital cost estimates which include the interstage stripper. Thus, the capital costs on which this rulemaking is based are, with respect to this single factor, somewhat conservative compared to the costs which refiners would likely incur to comply with the 15 ppm sulfur standard.

The vendors assumed that the existing highway desulfurization unit in place could be utilized (revamped) to comply with the 15 ppm sulfur standards. This includes hydrotreater sub-units necessary for desulfurization. Revamping the highway unit saves on both capital and operating costs for a two-stage revamp compared with whole new grassroots unit. These sub-units include heat exchangers, a heater, a reactor filled with catalyst, two or more vessels used for separating hydrogen and any light ends produced by cracking during the desulfurization process, a compressor, and sometimes a hydrogen recycle gas scrubber. The desulfurization subunits listed here are discussed in detail in Chapter 5.

To estimate the cost of meeting the NRLM diesel fuel sulfur standards, it was necessary to evaluate three situations refiners may face: (1) producing NRLM diesel fuel meeting a 15 ppm cap from diesel fuel already being hydrotreated to meet a 500 ppm cap (i.e., a highway revamp), (2) producing NRLM diesel fuel meeting a 15 ppm cap from high-sulfur distillate (i.e., grass roots 15 ppm hydrotreater), and (3) producing 15 ppm NRLM diesel fuel meeting a 500 ppm cap by replacing the existing hydrotreater with a grass roots 15 ppm hydrotreater. Sets of process-design parameters for the first two of these desulfurization configurations were developed for the HD2007 rule and summarized in the Regulatory Impact Analysis.[20] As discussed above, only the results of the previous derivations are presented below. The third configuration was not addressed for the highway diesel fuel rule, as highway diesel fuel was already meeting a 500 ppm cap. The section that develops the process-design parameters for this third configuration includes a short description of the methodology used in its development, as it is very similar to those used to develop the first two sets of process-design parameters.

One straightforward adjustment was made to all the capital costs developed for the HD2007 rule. The capital costs developed for that rule were in terms of 1999 dollars. These costs were updated to represent 2002 dollars by increasing them by 2.5 percent to reflect inflation in construction costs occurring between 1999 and 2002.[21]

7.2.1.2.1.1 Revamping to Process 500 ppm Diesel Fuel to Meet a 15 ppm Cap

The process-design projections developed in this section apply to a revamp of an existing desulfurization unit with additional hardware to enable the combined older and new unit to meet a 15 ppm sulfur cap. The portion of these projections that apply to operating costs are also relevant if a refiner decides to replace an existing diesel fuel desulfurization unit with a new grassroots unit. In this case, the entire capital cost of the grass roots unit is incurred. However, the incremental operating costs would be those of the new grass roots unit, less those of the existing hydrotreater (which are developed in this section).

The process-design parameters shown below were taken directly from those shown in the HD2007 Regulatory Impact Analysis, with two adjustments. The first adjustment relates to the amount of desulfurization required from the current low sulfur diesel pool, while the second adjustment relates to the amount of fuel gas consumed in the process.

Diesel fuel complying with the current 500 ppm sulfur standard typically contains 340 ppm sulfur. We expect refiners complying with the 500 ppm NRLM diesel fuel sulfur cap also to desulfurize down to roughly 340 ppm sulfur. Thus, in revamping an existing 500 ppm hydrotreater to comply with a 15 ppm cap, refiners will have to desulfurize from about 340 ppm down to 7 ppm. This is analogous to what we assumed in the analysis for the HD2007 rule. After the highway diesel fuel rule was finalized, however, it became evident that the vendor projections assumed a starting sulfur level of 500 ppm and not 340 ppm. Thus, the vendor projections assumed more desulfurization would be needed than is the case here. Based on a curve of hydrogen consumption versus initial and final sulfur level developed in the Regulatory Impact Analysis supporting the proposed HD2007 program, reducing the initial sulfur level from 500 ppm to 340 ppm reduces hydrogen consumption by 3.5 percent.[22] We assumed that all cost-related parameters (capital cost,[W] catalyst cost, yield losses, and utilities) will be reduced by the same 3.5 percent.

For the second adjustment, the fuel gas rates were adjusted to account for the heat produced by the saturation of the aromatic compounds that occurs during desulfurization. In the Draft RIA for the NPRM, we presumed that the highly aromatic blendstocks, which are LCO and coker, would consume more fuel gas than straight run distillate, which has much less aromatics. However, because the aromatic compounds are exothermic in the hydrotreating reactor, they actually contribute some heat which lowers the heat load compared to straight run distillate. Furthermore, when updating the fuel gas consumption values, we found and corrected an error in

[W] Capital costs are also affected, as a higher starting sulfur level requires a larger reactor to provide a greater residence time to remove the sulfur and a larger compressor for the greater volume of hydrogen which must be fed to the reactor.

our interpretation of fuel gas consumption information from one of the two vendors which provided us with the unit operations information for their diesel fuel desulfurization technology. The error was that we had interpreted that vendor's information to read as thousands of British thermal units (BTUs) per day instead of millions of BTUs per day.

Some of the information from one of the two vendors (which was referred to as Vendor A in the 2007 Highway Final Rule) was used to estimate the relative heat demand for the two mixed distillate streams. The heat demand information was presented as million BTU per hour a 25,000 bbl/day grassroots unit producing 15 ppm diesel. We converted this estimate to BTU/bbl and summarized the values in Table 7.2.1-2.

Table 7.2.1-2
Fuel Gas Demand for a 15 ppm Grassroots Unit (BTU/bbl)

67% cracked stocks, 33% SR	1100
20% cracked stocks, 80% SR	1480

The above table shows a 380 btu/bbl difference in heat consumption between the two feeds for a grassroots unit. Based on this information, we were able to estimate that cracked stocks require only 56 percent of the heat input of straight run stocks. The fuel gas consumption estimate for the cracked stocks (LCO and coker light gas oil) is 920 btu/bbl while the fuel gas consumption for straight run gas oil is 1640 btu/bbl. Since this is the heat consumption for only Vendor A, it was necessary to merge the fuel gas consumption information from Vendor B. Vendor B reported fuel gas consumption of 16,000 btu/bbl. This value is much higher probably because it incorporates the fuel gas used to generate steam for pumping. Because both vendors were providing cost estimates on the same feeds (69 percent straight run 31 percent cracked stocks) to achieve the same desulfurization target, it is likely that both were assuming similar levels of aromatics saturation, thus we assume that both vendors would estimate a similar absolute difference in heat consumption between the different blendstocks. To estimate an average heat consumption representing the heat consumption estimates from both vendors, we averaged the average heat for the two vendors (assuming an average of 1320 btu/bbl for Vendor A) resulting in an average heat consumption of 8660 btu/bbl. Assuming that the heat consumed by each blendstock maintains the same differential as that calculated based on Vendor A's information alone, the heat consumed is 8880 btu/bbl for straight run and 8160 for cracked stocks which maintains the same 720 btu/bbl difference from above.

Since we need to estimate the incremental fuel gas demand for a unit treating diesel fuel meeting a 500 ppm cap standard to comply with a 15 ppm cap standard for this section, the fuel consumption information from Vendors A and B was evaluated for this sulfur reduction increment. Both vendors show essentially zero fuel gas consumption for this interval, yet aromatics are still being saturated similar to about half the increment of going from untreated to 15 ppm sulfur. Thus, half the difference in fuel gas consumed for cracked stocks and straight run was assumed for this interval with a typical blend of diesel fuel (69 percent straight run and 31 percent cracked stocks) having a zero net fuel gas consumption. Thus, cracked stocks are estimated to require -250 btu/bbl of fuel gas and straight run is estimated to require 110 btu/bbl of fuel gas for a difference of 360 scf/bbl or half of that for a grassroots unit.

Table 7.2.1-3 presents the process-design parameters for desulfurizing 500 ppm sulfur diesel fuel to meet a 15 ppm standard.

Table 7.2.1-3
Process Projections for Revamping an Existing Diesel Fuel Hydrotreater Desulfurizing Diesel Fuel Blendstocks from 500 ppm Cap to 15 ppm Cap

	Straight-Run	Other Cracked Stocks	Light Cycle Oil
Capacity (BPSD)	25,000	25,000	25,000
Capital Cost (ISBL) ($million)	16	19	22
Liquid Hour Space Velocity (hr^{-1})	1.25	0.7	0.6
Hydrogen Consumption (scf/bbl)	96	230	375
Electricity (kW-hr/bbl)	0.4	0.7	0.8
HP Steam (lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	110	-250	-250
Catalyst Cost ($/BPSD)	0.2	0.4	0.5
Yield Loss (wt%)			
Diesel	1.0	1.9	2.1
Naphtha	-0.7	-1.3	-1.4
LPG	-0.04	-0.07	-0.08
Fuel Gas	-0.04	-0.11	-0.13

7.2.1.2.1.2 Process-Design Projections for a Grassroots Unit Producing 15 ppm Fuel

The process-design parameters presented in this section were taken directly from those derived in the HD2007 Regulatory Impact Analysis. These costs apply primarily to refineries currently producing only, or predominantly, high-sulfur diesel fuel. In addition, the capital cost portion of these costs apply to a refinery replacing an existing hydrotreater with a grassroots unit instead of revamping their existing hydrotreater. In this case, these refiners would incur the capital costs outlined here, but their operating costs would be based on a revamp, as described above. Most refineries currently producing high-sulfur distillate fuel also produce some highway diesel fuel. In this case, we project costs reflecting those of a revamp and a grass roots unit. The methodology for this merging of the two costs is described in Section 7.2.1.5 below.

Table 7.2.1-4 presents the process-design parameters for desulfurizing high-sulfur distillate fuel to meet a 15 ppm standard in a grassroots unit.

Table 7.2.1-4
Process Projections for Installing a New Grassroots Unit for Desulfurizing Untreated Distillate Fuel Blendstocks to Meet a 15 ppm Standard

	Straight-Run	Other Cracked Stocks	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	32	38	43
Liquid Hour Space Velocity (Hr^{-1})	0.8	0.5	0.4
Hydrogen Consumption (SCF/bbl)	240	850	1100
Electricity (KwH/bbl)	0.6	1.1	1.2
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	8880	8160	8160
Catalyst Cost ($/BPSD)	0.3	0.6	0.8
Yield Loss (%)			
Diesel	1.5	2.9	3.3
Naphtha	-1.1	-2.0	-2.3
LPG	-0.06	-0.11	-0.12
Fuel Gas	-0.06	-0.17	-0.20

Unlike processing highway diesel fuel, which is assumed to contain 340 ppm sulfur, the sulfur content of high-sulfur distillate fuel can vary dramatically from refinery to refinery and region to region. To account for varying starting sulfur levels, an adjustment in hydrogen consumption. The basis for the amount of sulfur needing to be removed is that the starting feed, comprised of 69 percent straight-run, 23 percent LCO and 8 percent cracked stocks, contains 9000 ppm sulfur (0.9 weight percent). However, as described below in Section 7.2.1.3, the average concentration of sulfur in the overall distillate pool, and especially the untreated part of the pool, varies by PADD. After estimating this sulfur level, we adjusted the hydrogen consumption for this varying sulfur level. (According to Vendor B, removing sulfur from diesel fuel consumes 125 scf/bbl for each weight percent of sulfur removed.[23]) We did not adjust the hydrogen consumption for the other qualities, mono- and poly-aromatics and olefins, but assumed that the hydrogen consumption from saturating olefins and aromatics, or from breaking aromatic rings would depend more on whether the feedstock had been previously hydrotreated or not, and less on whether the starting sulfur level was 5000 or 8000 ppm. Since sulfur removal consumes less than half the hydrogen of desulfurizing from untreated 9000 ppm sulfur feedstocks to 15 ppm,[X] the adjustment is always less than 50 percent. The adjustment is applied as an adjustment ratio to each untreated blendstock type for a refinery with a distillate hydrotreater. The adjustment ranged from 0.80 for PADD 5, which has an estimated untreated distillate sulfur level of 3010 ppm, to 1.0 for PADD 3, which has an estimated untreated distillate sulfur level of 9,350 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our adjustment to account for differing starting sulfur levels assumes that they currently blend only unhydrotreated blendstocks into the distillate that comprises the high-sulfur pool. Thus, we are making our adjustments based on a lower starting sulfur level. Our adjustment for these refineries ranged from 0.79 for PADD 4, which has an estimated untreated sulfur level of 2550 ppm, to 0.83 for PADD 3, which has a starting sulfur level of 3780 ppm. The various hydrogen consumption adjustment values are summarized in Table 7.2.1-5.

Table 7.2.1-5
Hydrogen Consumption Adjustment Factors: Grassroots Units

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.84	0.89	1.0	0.81	0.80
No Distillate HT	0.80	0.80	0.83	0.79	0.79

7.2.1.2.1.3 Desulfurizing High-Sulfur Distillate Fuel to a 500 ppm Cap

Finally, we needed to provide inputs for our cost model for desulfurizing untreated, high-sulfur distillate to meet a 500 ppm sulfur standard, which is the first step of our two-step program. These inputs are estimated by simply subtracting the inputs for the revamped unit for desulfurizing 500 ppm diesel fuel down to 15 ppm from the inputs for a grassroots unit for desulfurizing untreated diesel fuel down to 15 ppm. The untreated to 500 ppm inputs for our refinery cost model are summarized in Table 7.2.1-6.

[X] Much of the hydrogen consumption is due to the saturation of olefins, or partial saturation of aromatics.

Table 7.2.1-6
Process Projections for Installing a New Unit for Desulfurizing
Untreated Diesel Fuel Blendstocks to Meet a 500 ppm Sulfur Standard

	Straight-Run	Coker Distillate	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	15	18	21
Liquid Hour Space Velocity (Hr^{-1})	2.4	1.9	1.3
Hydrogen Consumption (SCF/bbl)	144	620	725
Electricity (KwH/bbl)	0.2	0.4	0.4
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	8770	8410	8410
Catalyst Cost ($/BPSD)	0.1	0.2	0.3
Yield Loss (%)			
Diesel	0.5	1.1	1.2
Naphtha	-0.4	-0.7	-0.8
LPG	-0.02	-0.04	-0.04
Fuel Gas	-0.02	-0.06	-0.07

Again, a hydrogen consumption adjustment was made for starting sulfur levels that differ from 9000 ppm. In this case, the hydrogen adjustment ended up being larger than the grassroots desulfurization unit as the adjustment to the hydrogen consumption for going from untreated to 500 ppm comprises a larger percentage of the total hydrogen consumption. This adjustment is for a refinery with a distillate hydrotreater. The adjustment is applied as an adjustment ratio to each unhydrotreated blendstock type and it ranged from 0.69 for PADD 5, which has an estimated untreated distillate sulfur level of 3010 ppm, to 1.0 for PADD 3, which has an estimated untreated distillate sulfur level of 9,350 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our analysis does not assume that they currently hydrotreat any of the distillate that comprises the high-sulfur pool. Thus, we estimate a somewhat lower starting sulfur level. Our adjustment for these refineries ranged from 0.67 for PADD 4, which has an estimated untreated sulfur level of 2550 ppm, to 0.73 for PADD 3, which has a starting sulfur level of 3780 ppm. The various hydrogen consumption adjustment values are summarized in Table 7.2.1-7.

Table 7.2.1-7
Hydrogen Consumption Adjustment Factors: High Sulfur to 500 ppm

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.75	0.83	1.0	0.70	0.69
No Distillate HT	0.69	0.69	0.73	0.67	0.67

7.2.1.2.1.4 Hydrocrackate Processing and Tankage Costs

We believe refineries with hydrocrackers will have to invest some capital and incur some operating costs to ensure that recombination reactions at the exit of the second stage of their hydrocracker do not cause the diesel fuel being produced by their hydrocracker to exceed the standard. The hydrocracker is a very severe hydrotreating unit capable of hydrotreating its product from thousands of ppm sulfur to nearly zero ppm sulfur; however, hydrogen sulfide recombination reactions that occur at the end of the cracking stage, and fluctuations in unit operations, such as temperature and catalyst life, can result in the hydrocracker diesel product having up to 30 ppm sulfur in its product stream.[24 25] Thus, refiners may need to install a finishing reactor for the diesel stream produced by the hydrocracker. According to vendors, this finishing reactor is a low-temperature, low-pressure hydrotreater that can desulfurize the simple sulfur compounds formed in the cracking stage of the hydrocracker.

Additionally, since the 15 ppm diesel sulfur standard is very stringent, we take into account tankage that will likely be needed. We believe refiners could store high-sulfur batches of highway diesel fuel or nonroad diesel fuel during a shutdown of the diesel fuel hydrotreater. Diesel fuel production would cease in the short term, but the rest of the refinery could remain operative. To account for this, we provided for the cost of installing a tank that would store ten days of 15 ppm sulfur diesel production, sufficient for a ten-day emergency turnaround, which is typical for the industry; the estimated cost for a 270,000 barrel storage tank is $3 million.[26] The cost of the land needed for this tank is assumed to be negligible relative to the cost of the tank. This amount of storage should be adequate for most unanticipated turnarounds. We presumed that each refinery will need to add such storage, though for some refineries, off-spec diesel fuel could also be sold as high-sulfur heating oil or fuel oil.

The cost inputs for the storage tank and the finishing reactor are summarized in Table 7.2.1-8.

Table 7.2.1-8
Process Operations Information for Additional
Units used in the Desulfurization Cost Analysis

	Diesel Storage Tank	Distillate Hydrocracker Post Treat Reactor
Capacity	50,000 bbls	25,000 (bbl/day)
Capital Cost (MM$)	0.75	5.7[27]
Electricity (KwH/bbl	—	0.98
HP Steam (Lb/bbl)	—	4.2
Fuel Gas (BTU/bbl)	—	18
Cooling Water (Gal/bbl)	—	5
Operating Cost ($/bbl)	none[a]	see above

[a] No operating costs are estimated directly; however both the ISBL to OSBL factor and the capital contingency factor used for desulfurization processes is used for the tankage as well, which we believe to be excessive for storage tanks so it is presumed to cover the operating cost.

Refiners will also likely invest in a diesel fuel sulfur analyzer.[28] A sulfur analyzer at the refinery provides nearly real-time information regarding the sulfur levels of important streams in the refinery and facilitate operational modifications to prevent excursions above the sulfur cap. Based on information from a manufacturer of such an analyzer, the analyzer costs about $50,000, with an additional $5,000 estimated for installation.[29] Compared with the capital and operating cost of desulfurizing diesel fuel, the cost for this instrumentation is far below 1 percent of the total cost of this program. Because the cost is so small, the cost of an analyzer was assumed covered as a cost contingency described in Section 7.2.1.4.1.

7.2.1.2.2 Process Dynamics IsoTherming

Process Dynamics has licensed a technology called IsoTherming, which is designed to desulfurize both highway and non-highway distillate fuel. At our request, Process Dynamics provided basic design parameters that can be used to project the cost of using their process to meet tighter sulfur caps,[30] which is summarized in the process information table. Subsequently, EPA spoke to a Linde engineer responsible for implementing the IsoTherming unit at the Giant refinery.[31] The hydrogen and utility consumption information obtained earlier from Process Dynamics was adjusted based on these comments, as described in the text further below.

Specifically, Process Dynamics provided design parameters for a revamp of an existing highway desulfurization unit to meet a 15 ppm standard. The revamp involves putting an IsoTherming unit upstream of the existing highway diesel fuel hydrotreater. Thus, when applying the Process Dynamics unit in our cost estimates for meeting the 15 ppm standard, the new Process Dynamics unit itself is assumed to be used as a first stage. As described in more detail in Chapter 5 of the RIA, this configuration takes the most advantage of the inherent benefits of the Process Dynamics IsoTherming desulfurization process.

Process Dynamics provided to EPA process information for the IsoTherming process based on three revamp situations. In the first revamp design, the feedstock consisted of 60 percent straight-run and 40 percent LCO. The unhydrotreated sulfur level was just under 2000 ppm and both the existing hydrotreater and the IsoTherming unit operated at 600 psi. In the second design, the feedstock consisted of 60 percent straight-run, 30 percent LCO and 10 percent light-coker gas oil with an unhydrotreated sulfur level of 9950 ppm. The existing hydrotreater and the IsoTherming unit operated at 950 psi. In the third design, the feedstock was the same as in the second, but the IsoTherming unit was designed to operate at 1500 psi, while the conventional hydrotreating unit operated at 950 psi.

We largely based our cost projections for the IsoTherming process on the second design. The unhydrotreated sulfur level of more than 9000 ppm is more typical for most refiners than 2000 ppm. The 950 psi design pressure for the IsoTherming unit was also thought to preferable to 1500 psi for most refiners. The higher-pressure unit reduces capital and catalyst costs, but higher hydrogen consumption offsets much of the cost savings. The higher-pressure reactors and compressors also have a longer delivery time and there would likely be fewer fabricators. Thus, given that the savings associated with the higher pressure unit were small, we decided to focus on the 950 psi design.

The information provided by Process Dynamics for the 950 psi IsoTherming desulfurization unit is summarized in Table 7.2.1-9. The operation and product quality of the IsoTherming unit is shown separatly from those for the existing conventional hydrotreater. Again, prior to the revamp, the conventional hydrotreater would have processed this feedstock down to roughly 340 ppm sulfur.

Table 7.2.1-9
Process Dynamics IsoTherming Revamp
Design Parameters to Produce 10 ppm Sulfur Diesel Fuel

	Feed Quality	IsoTherming Unit and its Product Quality	Conventional Hydrotreater and Final Product Quality
LCO vol %	30		
Straight-Run vol %	60		
Light-Coker Gas Oil vol%	10		
Sulfur ppm	9950	850	10
Nitrogen	340	38	2
API gravity (degrees)	33.98	34.42	35.84
Cetane Index	44.5	48.5	50.8
H_2 Consumption (scf/bbl)		320	100
Relative H_2 Consumption		75	25
LHSV (hr^{-1})		15/15	3
Relative Catalyst Volume		45	100
Reactor Delta T		15	15
H_2 Partial Pressure		950	950
Electricity (kW)		1525	
Natural Gas (mmbtu/hr)		0	
Steam (lb/hr)		0	

7.2.1.2.2.1 Hydrotreating High-Sulfur Distillate Fuel to 15 ppm

The design parameters provided by Process Dynamics involve the revamp of an existing conventional hydrotreater currently producing highway diesel fuel (i.e., less than 500 ppm sulfur) to produce diesel fuel with a sulfur level well below 15 ppm. Before addressing this situation, however, we will use the Process Dynamics revamp design to project the costs of an IsoTherming unit that processes unhydrotreated distillate fuel (e.g., 3400-10,000 ppm sulfur) down to 7-8 ppm sulfur. This type of unit was not projected to be used under the two-step fuel program. However, we considered such a sulfur reduction step for alternative programs, for which costs are also estimated later in this chapter.

Also, as was done for conventional hydrotreating, we develop cost estimates for applying the IsoTherming process to three individual blendstocks—straight-run, LCO and light-coker gas oil—to be able to project desulfurization costs for individual refineries whose diesel fuel compositions vary dramatically.

We have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: In this section, we estimate the hydrogen consumption to process individual refinery streams from their uncontrolled levels down to 7-8 ppm sulfur. Process Dynamics provided hydrogen consumption estimates for desulfurizing a mixed feedstock of 60 percent straight-run, 30 percent LCO and 10 percent coker distillate, but not for specific refinery streams. Additionally, Process Dynamics provided information for a hybrid desulfurization unit comprised of a Process Dynamics IsoTherming unit revamping a conventional highway hydrotreater. For the proposed rule, we used the hydrogen consumption values provided by Process Dynamics to estimate the hydrogen consumption for the IsoTherming unit for the individual diesel fuel blendstocks which we model. This information resulted in a hydrogen consumption which was somewhat lower than that of conventional hydrotreating. After the proposal, we asked the Linde engineers to provide their most recent estimate of the hydrogen consumption values for the IsoTherming process based on the in-use data from their commercial demonstration unit. The resulting hydrogen consumption estimates for the IsoTherming process are similar to that of conventional hydrotreating. Consequently, for the final rule analysis we set the hydrogen consumption of the Process Dynamics IsoTherming process to be the same as conventional hydrotreating. The resulting hydrogen consumptions were 1100 scf/bbl for LCO, 850 scf/bbl for other cracked stocks, and 240 scf/bbl for straight-run.

Consistent with the methodology used for conventional hydrotreating, we developed adjustments to each blendstock hydrogen consumption values to reflect differing unhydrotreated sulfur levels. We assumed that the hydrogen consumption for IsoTherming process varied in the same proportions as those for conventional hydrotreating because the treated feed sulfur levels were about the same. Thus, the same hydrogen adjustment factors were used as for conventional hydrotreating, and they can be found in Table 7.2.1-5 and Table7.2.1-7.

Utilities and Yield Losses: We next established the IsoTherming utility inputs for individual blendstocks. The Process Dynamics IsoTherming process saves a substantial amount of heat input by conserving the heat of reaction that occurs in the IsoTherming reactors. This conserved energy is used to heat the feedstock to the unit. This differs from conventional hydrotreating that normally rejects much of this energy to avoid coking the catalyst. According to Process Dynamics, this allows the IsoTherming process to operate with negligible external heat input. In the highway hydrotreater revamp, which is the source of the information provided by Process Dynamics, the existing heater for the highway hydrotreater was hardly needed after the IsoTherming process was added. However, there is still the need for a small heater to heat up the feedstock during unit startup. This affects capital costs. However, when averaged over production between start-ups (generally at least two years), the little amount of fuel used during start-up is negligible. Thus, we estimate no need for either fuel or steam with the IsoTherming process.

As shown in Table 7.2.1-9, Process Dynamics estimated electricity demand to be 1525 kilowatts per 20,000 bbl/day unit in their early estimate of the demands for their unit. However, since the commercial demonstration unit has been operating, Process Dynamics has collected information on the actual electrical consumption of the IsoTherming unit. Process Dynamics engineers estimate that the electrical consumption is about that same as conventional hydrotreating. Thus, for desulfurizing untreated diesel fuel down to 15 ppm, we set the electricity demand as the same as conventional hydrotreating. Thus, we estimate electricity demand at 0.6, 1.1 and 1.2 kW-hr/bbl for straight-run, light-coker gas oil, and LCO, respectively.

This is a decline in electricity consumption compared to the values which Process Dynamics reported in their original document. That the IsoTherming unit would consume the same (or potentially less) electricity as conventional hydrotreating is reasonable considering that no recycle compressor is needed with this technology because large excesses of hydrogen are not fed to the IsoTherming reactor. Recycle compressors are a large electricity consumer. This electricity savings is somewhat offset because of the increased liquid pumping demands required to recycle the diesel fuel through the reactors. While some savings are likely, Process Dynamics suggested we assume that the electricity costs are about the same as conventional hydrotreating.

Process Dynamics did not estimate the specific yield losses for the IsoTherming process. On our request for further information, Process Dynamics indicated that their process causes slightly less than half of the yield loss of conventional hydrotreating. Thus, the yield loss of the Process Dynamics unit was projected to be 50 percent that of conventional hydrotreating, which is proportional to the relative catalyst volume. The resulting projected yield losses are shown in Table 7.2.1-10 below:

Table 7.2.1-10
Estimated Yield Loss for a Process Dynamics IsoTherming Grassroots Unit

Fuel Type	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel Fuel	0.75	1.45	1.65
Naphtha	-0.55	-1.00	-1.15
LPG	-0.03	-0.055	-0.06
Fuel Gas	-0.03	-0.085	-0.10

Catalyst Costs: The catalyst cost for the Process Dynamics process was estimated based on the relative catalyst volume compared with conventional hydrotreating. As shown in Table 7.2.1-9, Process Dynamics indicated that the catalyst volume for the new IsoTherming reactors contained only 45 percent of the volume of the new conventional hydrotreating reactors that Process Dynamics projects would be needed to revamp the existing hydrotreater to produce 10 ppm fuel. We assumed that this same relationship holds for a stand-alone IsoTherming unit. Thus, we multiplied the catalyst costs for conventionally hydrotreating specific blendstocks (shown in Table 7.2.1-4) by 45 percent. The resulting IsoTherming catalyst costs were 0.14, 0.27 and 0.36 $/BPSD for straight-run, light-coker gas oil and LCO, respectively.

Capital Costs: The last aspect of the IsoTherming process to be determined on a per-blendstock basis is its capital cost. Process Dynamics's initial submission of process-design parameters did not include an estimate of the capital cost. We developed our own estimate from the process equipment included, compared with those involved in conventional hydrotreating. As indicated in Table 7.2.1-9, the catalyst volume of the two IsoTherming reactors unit (combined LHSV of 7.5) is roughly 8 times smaller than that of a conventional hydrotreating revamp (LHSV of 0.9 per LHSVs for individual blendstocks from Table 7.2.1-4). Also, because the IsoTherming reactors use a much higher flowrate and is a totally liquid process (no need for both gas and liquid in the reactor), it eliminates the need for an expensive distributor. As mentioned above, the feed pre-heater can be much smaller and less durable, since it is required only for startup. Finally, the IsoTherming process does not require an amine scrubber to scrub the H_2S from the recycle hydrogen stream.

Based on these differences, we estimated that the total capital cost of a stand-alone IsoTherming unit is two-thirds that for a conventional hydrotreater. Thus, the capital costs for a 25,000 bbl per day conventional hydrotreater were reduced by one-third. The resulting IsoTherming capital costs for a 25,000 BPSD unit were \$21, \$25, and \$29 million for treating straight-run, light-coker gas oil and LCO, respectively. The estimated overall capital cost for the specific feed composition shown in Table 7.2.1-9 is \$900 per BPSD for the IsoTherming unit, versus \$1400 per BPSD for a conventional hydrotreater. More recently, Linde indicated that the capital cost will be roughly \$800 per barrel for a 25,000 bbl per day unit.[32] For this analysis, we consequently retained the two-thirds factor relative to conventional hydrotreating (\$900 per BPSD).

Summary of Process-Design Parameters: Table 7.2.1-11 summarizes the design parameters used for using the Process Dynamics IsoTherming process to desulfurize untreated distillate fuel to 10 ppm.

Table 7.2.1-11
Process Parameters for a Stand-Alone IsoTherming
25,000 BPSD Unit to Produce 10 ppm Sulfur Fuel from Untreated Distillate Fuel

	Straight-Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	21	25	29
Hydrogen Demand (scf/bbl)	240	850	1100
Electricity Demand (kwh/bbl)	0.6	1.1	1.2
Fuel Gas Demand (btu/bbl)	220	-500	-500
Catalyst Cost ($/bpsd)	0.15	0.29	0.44
Yield Loss (wt%): Diesel Naphtha LPG Fuel Gas	0.75 -0.55 -0.03 -0.03	1.45 -1.00 -0.055 -0.085	1.65 -1.15 -0.06 -0.10

7.2.1.2.2.2 Desulfurizing 500 ppm Sulfur Diesel Fuel to Meet a 15 ppm Sulfur Cap

The derivation of process design parameters for a IsoTherming unit revamp of a conventional hydrotreater is much more straightforward than that of a stand-alone IsoTherming unit, as the design parameters provided by Process Dynamics in Table 7.2.1-9 were for a revamp. The revamp would occur by placing the new Process Dynamics IsoTherming unit as a first stage (uncontrolled to under 500 ppm), before the existing highway highway, thus converting the highway hydrotreater to treating diesel fuel from several hundred ppm to under 15 ppm. Similar to how we characterized the cost inputs above, we have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: Determining the incremental hydrogen consumption of a Process Dynamics IsoTherming revamp of a conventional hydrotreater requires that the existing hydrogen consumption of the existing conventional hydrotreater be accounted for. As described above, we now estimate that the hydrogen consumption of the Process Dynamics unit to be the same as the conventional hydrotreating unit for the same service. Thus, there would be no change in hydrogen consumption when the Process Dynamics unit replaces the conventional hydrotreating unit for treating diesel fuel from uncontrolled levels down to 500 ppm sulfur. The conventional hydrotreater's new role would be to desulfurize 500 ppm sulfur down to 15 ppm sulfur. The new service of the conventional hydrotreater will define the hydrogen consumption for this Process Dynamics IsoTherming revamp of the conventional hydrotreater unit. The hydrogen consumption of a conventional hydrotreater for treating 500 ppm diesel fuel down to 15 ppm is contained in Table 7.2.1-6 above, which is 96, 230 and 375 standard cubic feet per minute of hydrogen for straight run, coker, and LCO, respectively.

Utilities and Yield Losses: The electricity consumption for a Process Dynamics IsoTherming revamp of a conventional hydrotreater follows the same logic as that for hydrogen. Again the Process Dynamics unit is assumed to have the same electrical demand as the conventional hydrotreater for desulfurizing untreated diesel fuel down to 500 ppm. Thus, the incremental electricity demand for this revamp is the electrical demand for the conventional hydrotreater in its new 500 ppm to 15 ppm service. The electric demand of a conventional hydrotreater for treating 500 ppm diesel fuel down to 15 ppm is contained in Table 7.2.1-6 above, which is 0.4, 0.7 and 0.8 kilowatt hours per barrel for straight run, coker, and LCO, respectively.

Estimating fuel gas consumption for a Process Dynamics revamp of a conventional hydrotreater is more complex because the Process Dynamics unit's fuel gas consumption is not the same as a conventional hydrotreater for desulfurizing undesulfurized diesel fuel down to 500 ppm. This calculation is best shown in Table 7.2.1-12. The table shows the addition of the Process Dynamics unit for desulfurizing each undesulfurized blendstock to 500 ppm, the subtraction of the conventional hydrotreater for the same increment of sulfur control for each blendstock, the addition of the conventional hydrotreater now treating 500 ppm diesel fuel down to 15 ppm for each blendstock, and the net change in fuel gas consumption.

Table 7.2..1-12
Estimate of Fuel Gas Consumption of an IsoTherming Revamp; 500 ppm to 15 ppm

	Straight Run	Coker	LCO
IsoTherming Unit: High Sulfur to 500 ppm (added)	110	-250	-250
Conv. HT: High Sulfur to 500 ppm (subtracted)	8770	8410	8410
Conv. HT 500 ppm to 15 ppm (added)	110	-250	-250
Net Fuel Gas Consumption	-8550	-8910	-8910

As mentioned above, Process Dynamics did not provide estimates of yield losses for the IsoTherming process. Using engineering judgement based on the relative exposure to the catalyst (the Process Dynamics unit only uses 45 percent of the catalyst as a conventional hydrotreater), we estimated that a stand-alone IsoTherming unit would reduce yield losses by 45 percent compared to a stand-alone convention hydrotreater. We applied this factor to the conventional hydrotreater yield loss to estimate the Process Dynamics yield loss. Table 7.2.1-6 shows that the yield loss for straight run feed is 1.0 percent for a conventional hydrotreating revamp (500 ppm to 15 ppm) and Table 7.2.1-4 shows a 1.5 percent loss for a grass roots conventional hydrotreater (uncontrolled to 15 ppm). Thus, the original highway fuel hydrotreater (uncontrolled to 500 ppm) has a yield loss of 0.5 percent for straight run, consistent with that shown in Table 7.2.1-3.

If the IsoTherming revamp reduces the yield loss by 45 percent, its yield loss for straight run is 55 percent of 1.5 percent, or 0.82 percent. Subtracting out the 0.5 percent loss of the original highway hydrotreater means that the IsoTherming revamp had an incremental yield loss of 0.32 percent, or 32 percent of the 1.0 percent yield loss projected for the conventional hydrotreating revamp. Thus, we projected that all of the yield losses shown in Table 7.2.1-13 for a conventional hydrotreating revamp would be only 32 percent as large for an IsoTherming revamp.

Table 7.2.1-13
Estimated Yield Loss for a Process Dynamics IsoTherming Revamp

Fuel Type	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel Fuel	0.32	0.61	0.70
Naphtha	-0.22	-0.42	-0.48
LPG	-0.01	-0.02	-0.03
Fuel Gas	-0.01	-0.035	-0.04

Catalyst Costs: Consistent with the relative catalyst cost for a stand-alone IsoTherming unit, we project that the catalyst cost for an IsoTherming revamp would be 45 percent of that for a conventional hydrotreating revamp.

Capital Costs: Consistent with the relative capital cost for a stand-alone IsoTherming unit, we project that the capital cost for an IsoTherming revamp would be 45 percent of that for a conventional hydrotreating revamp.

Summary of Process Design Parameters: The inputs into our cost model for treating already treated non-highway diesel fuel by the individual refinery streams which is presumed to be 340 ppm is summarized in Table 7.2.1-14.

Table 7.2.1-14
Process Projections for an IsoTherming Revamp
of a Conventional Hydrotreater to Meet a 15 ppm Cap Standard

	Straight Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	10.6	12.5	14.5
Unit Size (bbl/stream Day)	25,000	25,000	25,000
Hydrogen Demand (scf/bbl)	96	230	375
Electricity Demand (kwh/bbl)	0.4	0.7	0.8
Fuel Gas Demand (btu/bbl)	-8550	-8910	-8910
Catalyst Cost ($/bpsd)	0.09	0.18	0.23
Yield Loss (wt%)			
Diesel	0.25	0.48	0.55
Naphtha	-0.18	-0.33	-0.38
LPG	-0.01	-0.02	-0.02
Fuel Gas	-0.01	-0.03	-0.03

7.2.1.2.3 Characterization of Vendor Cost Estimates

Applicability to Specific Refineries: The information provided by the vendors is based on typical diesel fuels or diesel fuel blendstocks. However, in reality, diesel fuel (especially LCO, and to a lesser degree other cracked stocks) varies in desulfurization difficulty based on the amount of sterically hindered compounds present in the fuel, which is determined by the endpoint of diesel fuel, and also by the type of crude oil being refined and other unit processes. The vendors provided cost information based on diesel fuels with T-90 distillation points which varied from 605 ˚F to 630 ˚F, which would roughly correspond to distillation endpoints of 655 ˚F to 680 ˚F. These endpoints can be interpreted to mean that the diesel fuel would, as explained in Chapter V above, contain sterically hindered compounds. Other diesel fuels or diesel fuel blendstocks, such as a straight run diesel fuel with a lower end boiling point, are lighter and would not contain sterically hindered compounds. However, a summer time diesel fuel survey for 1997 shows that the endpoint of highway diesel fuel varies from 600 ˚F to 700 ˚F, thus the lighter diesel fuels would contain no sterically hindered compounds, and the heavier diesel fuels would contain more.[33] Our analysis attempts to capture the cost for each refinery to produce highway diesel fuel which meets the 15ppm cap sulfur standard, however, we do not have specific information for how the highway diesel endpoints vary from refinery to refinery, or from season to season. Similarly, we do not have information on what type of crude oil is being processed by each refinery as the quality of crude oil being processed by a refinery affects the desulfurization difficulty of the various diesel fuel blendstocks. Diesel fuel processed by a particular refiner can either be easier or more difficult to treat than what we estimate depending on how their diesel fuel endpoint compares to the average endpoint of the industry, and depending on the crude oil used. For a nationwide analysis, we believe it is appropriate to base our cost analysis for each refinery on what we estimate would be typical or average qualities for each diesel fuel blendstock. Some estimates of individual refinery costs will be high, others will be low, but be representative on average.

Accuracy of Vendor Estimates: We have heard from refiners in the past that the vendor costs are optimistic and need to be adjusted higher to better assess the costs. While the vendors costs may be optimistic, we believe that there are a multitude of reasons why the cost estimates could be optimistic and adjusting these estimates isn't necessary.

First, in specific situations, capital costs can be lower than what the vendors project for a generic refinery. Many refiners own used reactors, compressors, and other vessels which can be employed in a new or revamped diesel hydrotreating unit. We do not know to what extent that additional hydrotreating capacity can be met by employing used vessels, however, we believe that at least a portion of the capital costs can be offset by used equipment. Additionally, the vendors of conventional hydrotreating which provided cost estimate information for our analysis based their capital costs on the inclusion of an interstage stripper to strip out the hydrogen sulfide between the first and second reactor stages (see Chapter 5 of the RIA). However, vendors today are saying that interstage strippers are not necessary. Thus, the capital costs upon which our conventional hydrotreating costs are based are conservative, which offsets optimism on the part of the vendors.

There are also operational changes which refiners can make to reduce the difficulty and the cost of desulfurizing highway diesel fuel. Based on the information which we received from vendors and as made apparent in our cost analysis which follows, refiners with LCO in their diesel fuel would need to hydrotreat their highway diesel pool more severely resulting in a higher cost to meet the cap standard. We believe that these refiners could potentially avoid some or much of this higher cost by pursuing two specific options. The first option which we believe these refiners would consider would be to shift LCO to heating oil which does not face such stringent sulfur control. The more lenient sulfur limits which regulate heating oil provide room for blending in substantial amounts of LCO. The refineries which could take advantage of shifting LCO to the heating oil pool are those in the Northeast and on the Gulf Coast which have access to the large heating oil market in the Northeast. If refiners could not shift all the LCO to the heating oil pool because of market limitations, refiners could distill its LCO into light and heavy fractions and only shift the heavy fraction to the heating oil pool. Essentially all of the sterically hindered compounds distill above 630°F, so if refiners undercut their LCO to omit these compounds, they would cut out about 30 percent of their LCO. We expect that refiners could shift the same volume of non-LCO distillate from these other distillate pools to the NRLM pool to maintain current production volumes of all fuels. The T-90 maximum established by ASTM may limit the amount of LCO, and especially heavy LCO, which can be moved from NRLM diesel fuel into the heating oil pool. Another option, of course, would be to move this dirty distillate fraction into number 4 or number 6 marine bunker fuel. For those refineries which could trade the heavy portion of LCO with other blendstocks in the heating oil pool from their own refinery or other refineries, we presume that those refiners could make the separations cheaply by using a splitting column for separating the undercut LCO from the uncracked heavy gasoil in the FCC bottoms.

Another option for refineries which are faced with treating LCO in its nonroad diesel fuel would be to sell off or trade their heavy LCO to refineries with a distillate hydrocracker. This is a viable option only for those refineries which are located close to another refinery with a distillate hydrocracker. The refinery with the distillate hydrocracker would upgrade the purchased LCO into gasoline or high quality diesel fuel. To allow this option, there must be a way to transfer the heavy LCO from the refinery with the unwanted LCO to the refinery with the hydrocracker, such as a pipeline or some form of water transport. We asked a refinery consultant to review this option. The refinery consultant corroborated the idea, but commented that the trading of blendstocks between refineries is a complicated business matter which is not practiced much outside the Gulf Coast, and that the refineries with hydrocrackers that would buy up and process this low quality LCO may have to modify their distillate hydrocrackers.[34] The modification which may be needed would be due to the more exothermic reaction temperature of treating LCO which could require refiners to install additional quenching in those hydrocrackers. Additionally, LCO can demand 60 to 80 percent more hydrogen for processing than straight run material. The refiners which could potentially take advantage of selling or trading their LCO to these other refineries are mostly located in the Gulf Coast where a significant number of refineries have hydrocrackers and such trading of blendstocks is common. However, there are other refineries outside of the Gulf Coast which could take advantage of their very close location to another refinery with a distillate hydrocracker. Examples for these refining areas where a hydrocracker could be shared include the Billings, Montana area and Ferndale, Washington.

As we summarized in Chapter 5, catalysts are improving and expected to continue to improve. Our costs are based on vendor submissions and incorporate the most advanced new catalysts available at that time. However, there are several new lines of catalysts available now which are more active than the previous lines of catalysts upon which our costs are based. As catalysts continue to improve, the cost of desulfurizing diesel fuel will continue to decrease.

In summary, while some contend that the vendor cost estimates are optimistically low, there are a number of reasons why we believe the cost of desulfurizing diesel fuel to meet the 15 ppm cap standard may be even lower than estimated. Vendors are expected to continue to improve their desulfurization technology such as the activity of their catalysts. Also, refiners have several cost cutting options at their disposal, such as using existing spare equipment, to lower their capital costs which is not considered here. Also, refiners may be able to resort to either of two operational options to reduce the amount of LCO in their highway diesel fuel.

We are aware that there are potentially other capital and operating costs in the refinery which would contribute the projected cost of desulfurizing diesel fuel beyond that provided to us by the vendors. For example, refiners may need to expand their amine plant or their sulfur plant to enable the processing of the sulfur compounds removed from diesel fuel. Then the small amount of additional sulfur compounds treated would incur additional operating costs. Thus, as described below, we adjusted the projected capital and operating costs upward to account for these other potential costs which we have not accounted for explicitly.

7.2.1.3 Refinery-Specific Inputs

There are a number of reasons why we estimated refining costs on a refinery-specific basis. First, it provides more precise and realistic estimates of desulfurization costs, as some differences between individual refineries can be represented (e.g., distillate fuel composition, production volumes, etc.). These costs are approximate, as we do not have precise data on the distillate composition for all U.S. refineries. While we do know historic distillate production levels, we do not know how these will change in the future. Still, the distribution of costs across refineries facillitated by the factors developed in this section will provide much more insight into how desulfurization costs can vary between refineries. The alternative would be to estimate desulfurization costs for the average U.S. refinery and assume that this cost applied to all refineries. Given the wide range in refinery capacities and their relative production of highway diesel fuel and high sulfur distillate, the national average approach would be overly simplistic.

Second, a refinery specific approach to costs allows us to better represent the potential interactions between the 15 ppm cap for highway diesel fuel and the NRLM sulfur caps associated with this rule. We recently received refiners' plans regarding their compliance with the 15 ppm highway diesel fuel sulfur cap. Being projections, these plans are subject to change. However, these projections allow us to reasonably estimate the ways in which refiners might take advantage of efforts to comply with the highway fuel standards in complying with the NRLM standards.

Third, the refinery specific costs can be combined into a distribution of costs for the entire refining industry. This distribution of costs allows us to better estimate the number of refineries likely to be affected by this rule. It also provides insight into the range of costs likely to be experienced by refineries, particularly the difference in costs between those facing the lowest costs and those facing the highest costs. This will also provide greater insight into how NRLM diesel fuel prices might be affected by this rule, as well as refiners' ability to recover capital costs.

Fourth, the development of refinery specific costs allows us to better estimate how small refiners might be affected by this rule, in particular how their costs differ from their larger competitors.

Of the many factors which affect desulfurization costs, there are four which vary significantly from refinery to refinery and which we have estimated quantitatively:

1) the composition of its no. 2 distillate pool (e.g., the percentages of LCO and other cracked stocks),
2) the percentage of its no. 2 distillate which is already being hydrotreated,
3) the volume of no. 2 distillate
4) which specific refineries are most likely to produce lower sulfur NRLM fuel.

The following four subsections discuss how we developed refinery-specific factors for each of these four factors.

7.2.1.3.1 Composition of Distillate Fuel by Refinery

In section 7.2.1.2, we developed desulfurization costs as a function of the blend stocks comprising the diesel fuel being processed, as well as other factors. In this section, we describe how we estimated each refinery's distillate blendstock diesel composition.

Refiners do not publish blendstock composition data, nor do they submit it to regulators as part of any regulatory requirements. The only available information is an industry survey conducted in 1996, which published compositional data for all the surveyed refiners within a PADD. Thus, we developed a methodology to estimate each refinery's diesel fuel composition from the aggregated data available from 1996. We then revised these compositions to reflect changes in the capacities of those types of equipment which produce distillate blendstock which have occurred since that time. Finally, we applied one further change to the compositional data which we believe will occur as a result of the 15 ppm highway fuel cap.

The only available data on the composition of diesel blend stocks is from a survey conducted by API and NPRA in 1996. This survey was sent to all domestic refiners and the responses covered 79 percent of the total distillate produced by domestic refineries in 1996. The blendstock composition of highway diesel fuel and No. 2 high sulfur distillate fuel were surveyed separately. The blendstock composition of the combined pool can also be estimated by volume weighting the compositions of the two distillate pools.

Table 7.2.1-15 summarizes the survey results for highway diesel fuel, high sulfur distillate fuel and the combined distillate pool for refiners outside of California. California refiners were excluded due to the unique specifications which California distillate must meet, namely low aromatics and high cetane limits. Also, due to the fact that California has already passed regulations requiring 15 ppm nonroad fuel, this NRLM rule will have a small impact on California refiners. The survey also included whether or not the particular blendstock was hydrotreated. This hydrotreating information will be used in the next section which addresses the hydrotreated fraction of each refinery's distillate. According to the cost estimation methodology described above, desulfurization costs depend on blendstock composition and overall hydrotreated fraction, but not on the specific blendstocks which are hydrotreated. Therefore, we do not consider whether the particular blendstock has been hydrotreated here.

Table 7.2.1-15
Distillate Composition (Excluding California Refiners): 1996 API/NPRA Survey (vol%)

	Highway Diesel Fuel	High Sulfur Distillate	All No. 2 Distillate
Straight Run	64%	63%	64%
LCO	23%	22%	22%
Other Cracked Stocks	9%	5%	8%
Hydrocrackate	4%	10%	6%

As can be seen, the composition of national average highway fuel and high sulfur distillate are quite similar. This led us to assume, for the purpose of this analysis, that each refinery sent the same fraction of LCO and other cracked stocks to its highway fuel and high sulfur distillate pools. This same information was used as the basis for our cost projections presented in the NPRM for this rule.

The next step in this analysis was to determine how each refinery's distillate pool might differ in composition. For example, some refineries do not have an FCC unit. Thus, their distillate would contain no LCO. Others do not have cokers, hydrocrackers, etc. Thus, we allocated the volume of each blendstock in the national distillate pool to each refinery in proportion to the capacity of its equipment which produces each blendstock. As described in Section 5.1, LCO is produced in FCC units, hydrocrackate is produced by hydrocrackers and other cracked stocks are primarily produced by cokers, as well as other thermal cracking units.

While general rules of thumb are available which estimate the volume of distillate produced in each of these units, in most cases, we have sufficient information available to estimate, on a national average basis, these conversion factors. EIA's Petroleum Supply Annual for 1996 states that domestic refiners produced a total of 3.06 million barrels per day of No. 2 distillate in 1996. By multiplying this volume by the percentages of LCO, other cracked stocks, and hydrocrackate in all No. 2 distillate from Table 7.2.1-15 above, we can estimate the total volume of each of these blendstocks which was produced in 1996. EIA also publishes the capacity of each refinery's processing units. By summing these up, we can estimate the total FCC, coker and thermal cracking and hydrocracker units existing in domestic refineries in 1996.

The situation with cokers and other thermal crackers is somewhat more complex, as the conversion of feedstock into distillate does not tend to be the same in these units. Thus, their capacities cannot simply be summed and assumed to have the same conversion rate. One industry consultant estimated that delayed cokers tend to convert 30 percent of their feedstock into distillate, while fluidized cokers, visbreakers, and other thermal crackers are less efficient in this regard, converting only 15 percent. Thus, we assumed that the conversion rate for other thermal crackers was half that of cokers. Practically, we effected this assumption by discounting the capacity of other thermal crackers by a factor of two before adding them to coking capacity.

Prior to making this comparison, however, one more adjustment must be made. Refiners outside of California with hydrocrackers typically feed LCO and other cracked stocks to their hydrocracker. Straight run distillate might also be fed to a hydrocracker which produces gasoline blendstock. However, we believe that after 2006, the 15 ppm highway diesel fuel cap will encourage refiners to shift as much LCO and other cracked stocks as possible to their hydrocrackers. Thus, for refineries with hydrocrackers and FCC units, we assumed that any LCO produced would be sent to the hydrocracker, up to the capacity of the hydrocracker.[Y] Similarly, for refiners with hydrocrackers and cokers or other thermal crackers, we assumed that any other cracked stocks produced would be sent to the hydrocracker, up to the capacity of the

[Y] This assumes that both the FCC unit and the hydrocracker operate at the same percent of capacity, which is reasonable.

hydrocracker minus any LCO sent to the hydrocracker. Table 7.2.1-16 summarizes this information.

Table 7.2.1-16
Conversion of Heavy Oils to Distillate in 1996

	Total U.S. Refining Capacity (BPD)	Total Distillate Blendstock Produced (BPD)	Percentage of Capacity Converted to Blendstock
FCC Units (LCO)			
Total	4,936,940	1,053,610	---
After Shift to Hydrocrackers	2,951,287	643,043	22%
Coking and other thermal crackers * (Other cracked stocks)			
Total	2,664,400	400,193	---
After Shift to Hydrocrackers	1,771,505	256,728	15%
Hydrocracker (hydrocrackate)	927,390	177,265	19%

* 100% of coker capacity plus 50% of the capacity of other thermal crackers

By taking the ratio of the volume of distillate blendstock produced to the total capacity of the type of equipment which produces it, we can estimate the percentage of this capacity which is converted into each type of blendstocks. These percentage are also shown in Table 7.2.1-16. It should be noted that these figures are likely lower than the conversions which would be actually seen during unit operation. The conversions shown in Table 7.2.1-16 are based on rated unit capacity and actual distillate production. Units typically operate at less than capacity over the course of a year. This utilization percentage does not need to be explicitly considered here as the unit capacity for each refinery and that for the nation as a whole are both on a nameplate rating basis. Use of a capacity utilization rate would simply adjust both figures and cancel out within the methodology.

Since we know the capacity of the various unit in each refinery in 1996, we could estimate the volume of each blendstock produced by each U.S. refinery in 1996 by multiplying these capacities by the above conversion factors. However, many refineries have increased the capacities of various units since 1996. As we are using these blendstock compositions to project desulfurization costs in 2007 and beyond, it would be desirable to reflect the impact of these changes in capacity in our analysis. The latest data are from 2002. Thus, we multiplied each refinery's 2002 unit capacities (per EIA) by the above conversion factors to estimate the volume of each blendstock produced by each refinery in this year.

This is a marked improvement from the NPRM analysis. In the NPRM, we used refinery unit capacities existing in the year 2000 (as estimated in the Oil and Gas Journal). These 2000 capacities were combined with the 1996 API/NPRA survey results and distillate production data from 2000 to develop an analogous set of conversion factors. The use of 1996 unit capacities to develop the conversion factors is more consistent with the survey results. The use of 2002 unit capacities incorporates two additional years of changes in refinery configurations into the analysis.

We also decided to use unit capacities as estimated by EIA in lieu of those published by the Oil and Gas Journal. Reviewing both sets of unit capacities, particularly that for hydrotreating capacity used in Section 7.2.1.3.2 below, we found greater consistency between the production volumes of various distillate fuels, as well as between the capacities of the various units, with the EIA estimates than with those published by the Oil and Gas Journal. Therefore, we decided to use the EIA estimates for this final NRLM rule analysis. Also, in the NPRM, the use of distillate compositions from 1996 and unit capacities from 2000 was inconsistent to some degree and the above methodology eliminates this problem.

In addition, the use of 2002 unit capacities provides an automatic adjustment for changes in refinery configurations from 1996 to 2002. In the NPRM, our methodology basically assumed that the overall distillate composition in 1996 continued unchanged into the future. One of the comments we received on the NPRM cost estimates was that we had under-estimated desulfurization costs by assuming that the 1996 distillate composition was not changing over time. The commenters pointed out that the average crude oil being processed in domestic refineries was getting heavier (lower API gravity) and more sour (higher sulfur) over time, which would negatively affect distillate composition from the point of view of desulfurization. They suggested that we should adjust our mix of blendstocks and the amount of sulfur needing to be removed to account for this trend.

We reviewed the quality of the U.S. crude oil slate between 1996 and 2002 and indeed found that the API gravity of average crude oil had decreased by 2.3 percent from 31.1 to 30.4. (The sulfur content of crude oil also increased, but this will be considered in Section 7.2.1.3.2 below when we estimate the percentage of NRLM fuel which is hydrotreated prior to this rule.) Heavier crude oils tend to produce heavier feedstocks to the FCC, coker and hydrocrackers, which can affect the conversion of these feedstocks into distillate. The yield of LCO from an FCC unit tends to vary inversely with conversion,[Z] with higher volumes of LCO produced at lower conversion rates. Heavier crude oils generally produce a heavier FCC feed stock which lowers FCC conversion. This would tend to increase the production of LCO from FCC units. The same would be generally true for cokers and other thermal cracking units.

However, since 1996 refiners have made several process changes which tend to increase FCC conversion. Since 1996, FCC feed hydrotreating capacity has increased by 24 percent, while FCC capacity only increased by 6 percent.[35] FCC feed hydrotreating reduces the density (increases the API gravity) of the FCC feedstock, which increases conversions and decreases

[Z]FCC conversion is defined as the volume percent of FCC feed throughput that is converted to products lighter than LCO and clarified oil/slurry oil, ((FCC feed - LCO product-slurry oil product)/ FCC feed)*100, per volume basis.

LCO yields in the FCC unit. Also, hydrocracking capacity has increased by 20 percent. Since these units can process poor quality LCO, this mitigates the effect of heavier crude oils. According to several FCC technology licensors, refiners are also using more active FCC catalysts and have added or upgraded their FCC process technologies since 1996. These changes should also increase FCC conversions and decreases LCO yields. Thus, changes have occurred since 1996 which both increase and decrease the production of LCO from FCC units. It is not possible to quantitatively estimate the impact of each of these changes, nor the net change in LCO yield. In general, we believe that the impact of heavier crude oil is smaller than the impact of newer FCC technology and increased FCC hydrotreating capacity. Thus, the inability to quantitatively account for these changes should not lead to an under-estimation of desulfurization costs. However, due to the compensating nature of these changes, we believe that the overall change in the quantity and quality of LCO and other cracked stocks being produced today is small and would not significantly affect desulfurization costs.

Also, the processing of heavier crude oil has led the U.S. refining industry to increase capacity of cokers and hydrocrackers relative to crude oil processing capacity. As mentioned above, our methodology automatically adjusted distillate composition for this trend. Thus, we believe that our current methodology reflects current crude oil quality as much as possible using available information. While our methodology does not account for future changes in crude oil quality, the changes seen below between 1996 and 2002 are quite small and indicate that changes likely in the future would also be very small.

Table 7.2.1-17 shows how updating these estimates from 1996 to 2002 affected national average distillate composition outside of California.

Table 7.2.1-17
National Average Distillate Composition Excluding California (Vol%)

	1996	2002
Straight Run	65%	62%
LCO	21%	21%
Other Cracked Stocks	8%	10%
Hydrocrackate	6%	7%

We made one last adjustment to distillate composition to reflect a shift we believe will occur when the 15 ppm sulfur cap begins to apply to highway diesel fuel in 2006. As shown in Table 7.2.1-17 above, the API/NPRA survey found that the hydrocrackate fraction of high sulfur distillate was much greater than that in highway diesel fuel. The reason for this is not obvious, as the low sulfur level of hydrocrackate would presumably been valuable in producing 500 ppm highway fuel. It may be that most highway fuel has be hydrotreated regardless of the percentage of hydrocrackate added, and the use of hydrocrackate in high sulfur distillate allows a significant portion of this fuel to avoid hydrotreating. In any event, the primary properties which differ between highway diesel fuel and high sulfur distillate are sulfur content and cetane number and refiners can use a wide range of blendstock compositions to meet these specification.

When the 15 ppm cap starts to apply to highway diesel fuel, however, the economic incentive to blend hydrocrackate into highway diesel fuel will increase dramatically. Thus, we believe that refiners will shift hydrocrackate from high sulfur distillate to highway diesel fuel. However, most high sulfur distillate is either NRLM diesel fuel or sold as either NRLM fuel or heating oil. Thus, it must have a minimum cetane number of 40. Therefore, we did not believe that it would be feasible for a refiner to shift unhydrotreated LCO or other cracked stocks from highway diesel fuel to high sulfur distillate. Therefore, we assumed that refiners would only shift hydrotreated blendstocks to compensate for the hydrocrackate shift. We assumed that the composition of this shift would reflect the refinery's average distillate composition (i.e., percentage of straight run, LCO and other cracked stocks). We assumed that a refiner would shift all of their hydrocrackate to highway diesel fuel as long as there was sufficient hydrotreated material to shift from highway fuel to high sulfur distillate. (The hydrotreated fraction of each refinery's distillate is discussed in the next section.) For all except five refineries, all of the hydrocrackate was shifted to highway fuel. Three refiners lacked sufficient volume of hydrotreated blendstocks for all their hydrocrackate to be shifted. Two refiners produced less highway diesel fuel than their estimated production of hydrocrackate. Overall, the hydrocrackate portion of highway diesel fuel increased to 8.9 percent, while that for high sulfur distillate decreased to 1.6 percent.

The final compositions of highway and high sulfur distillate after implementation of the 15 ppm sulfur cap on highway fuel, but prior to this NRLM rule are shown below in Table 7.2.1-18. These national averages were calculated by 1) applying the above conversion factors to each refinery's unit capacities to estimate the volume of each blendstock being produced by that refinery, 2) spreading the volume of each blendstock to the refinery's highway diesel fuel and high sulfur distillate fuel pools in proportion to the refinery's production of each of the two fuels pool (as estimated in Section 7.2.3.3 below), 3) shifting hydrocrackate to highway fuel in return for other hydtrotreated blendstocks, as discussed above, 4) summing the volumes of each blendstock type in each fuel pool across all refineries and 5) dividing these blendstock volumes by the total production of highway and high sulfur fuel, respectively. We used each refinery's projected distillate composition to estimate its cost of meeting the 500 and 15 ppm NRLM sulfur caps, not the national average composition.

Table 7.2.1-18
Distillate Composition: After Implementation of the 15 ppm Highway Fuel Sulfur Cap*

	Highway Diesel Fuel	High Sulfur Distillate	All No. 2 Distillate
Straight Run	61%	66%	62%
LCO	20%	23%	21%
Other Cracked Stocks	10%	9%	10%
Hydrocrackate	9%	2%	7%

*excludes California.

In order to provide an indication of the range of distillate compositions which we projected using this methodology, we developed distributions of the percentages of LCO and other cracked stocks in various refiners distillate. These are shown in Table 7.2.1-19 below.

Table 7.2.1-19
Distribution of LCO and Other Cracked Stocks in High Sulfur Distillate Prior to the NRLM Rule (U.S. Refineries Producing High Sulfur Distillate)

	Percentage of LCO and Other Cracked Stocks in the Distillate Pool								
	0%	<10%	<20%	<25%	<30%	<40%	<50%	<80%	100%
LCO									
Number of Refineries	47	48	53	60	76	92	96	99	101
Cumulative % of High Sulfur Distillate Volume	35	36	45	49	71	87	94	98	100
Other Cracked Stocks									
Number of Refineries	71	73	79	87	92	97	101	101	101
Cumulative % of High Sulfur Distillate Volume	53	61	66	85	88	90	100	100	100

As shown above, in 2002, high sulfur distillate fuel produced by U.S. refineries contains between zero to over 80 percent LCO. Forty-seven U.S. refineries, which produce about 35 percent of the high sulfur distillate in the U.S., blend no LCO into their distillate. The high sulfur distillate from the remaining 54 refineries averages about 33 percent LCO by volume. On average, high sulfur distillate contains 21.1 percent LCO in 2002 versus 21.3 percent in 1996. This reflects the fact that FCC unit capacity grew slightly less between 1996 and 2002 than total domestic distillate production volume.

Similarly, we estimate that about half of the high sulfur distillate fuel in the U.S, which is produced by 71 refineries, does not contain any other cracked stocks from cokers, visbreakers and thermal crackers. Of the refineries which produce other cracked stocks, their distillate fuel contains an average of 20.0 percent of other cracked stocks in 2002. On average, the estimated percentage of other cracked stocks being blended into high sulfur distillate increased slightly from 9.2 percent in 1996 to 9.4 percent in 2002. Thus, coking capacity increased slightly faster than total distillate production.

7.2.1.3.2 Sulfur Content and Hydrotreated Fraction of High Sulfur Distillate

Like distillate composition, per the cost methodology developed above, the sulfur content and hydrotreated fraction of high sulfur distillate affects the cost of desulfurization. There are two effects. One relates to the amount of hydrogen consumed in hydrotreating. The other relates to the capital cost of a hydrotreater.

Regarding hydrogen consumption, in addition to removing sulfur, hydrotreating also saturates olefins and most poly-nuclear aromatics. These latter effects occur almost regardless of the degree of sulfur reduction. Thus, distillate which is being hydrotreated today has already had its olefins and poly-nuclear aromatics removed. Thus, subsequent hydrotreating of already hydrotreated blendstocks to reduce sulfur further in response to this NRLM rule does not consume hydrogen related to olefin or poly-nuclear aromatic saturation. The other effect relates to the capital investment needed to meet the 500 ppm NRLM cap in 2007. Material that is already being hydrotreated to 500 ppm or less need not be treated at all during the first step of the NRLM fuel program.

As mentioned in Section 7.2.1.2.1.2, we were not able to incorporate the change in hydrogen consumption due to olefin and poly-nuclear aromatic saturation associated with changing degrees of current hydrotreating. Differences in total hydrogen consumption between various refineries should only be a few tenths of a penny per gallon. Thus, the use of an average level of olefin and poly-nuclear aromatic saturation lessened the refinery-specific nature of our estimates to a slight degree.

Regarding capital costs, we were able to incorporate differences in expected capital investment needed to desulfurize unhydrotreated and hydrotreated blendstocks to meet the 2007 500 ppm NRLM cap. This improved our ability to predict overall desulfurization costs, the number of refineries affected by the NRLM rule and how small refiners might be differentially impacted by the rule.

In addition to whether a blendstock has been previously hydrotreated or not, the starting sulfur content also affects the volume of hydrogen needed to reduce sulfur to meet a 500 ppm cap. In the NPRM, we started with the 1996 API/NPRA fuel quality survey to obtain estimates of the portion of highway and high sulfur distillate which receives at least some hydrotreating. We then used in-use fuel survey data to estimate the sulfur level of high sulfur distillate produced in 1996. Assuming that the sulfur content of the hydrotreated portion of this fuel was the same as that for highway diesel fuel (340 ppm), we then back-calculated the sulfur content of the non-hydrotreated portion of high sulfur distillate, so that the blend matched the in-use sulfur level of finished high sulfur distillate. We then assumed that these 1996 estimates also applied to current and future high sulfur distillate prior to the NRLM rule.

We received comment on the NPRM that the sulfur content of crude oil had been increasing since the 1996 API/NPRA survey was conducted. The commenters argued that this would increase the sulfur content of high sulfur distillate and increase desulfurization costs. Therefore, we have expanded the methodology used in the NPRM analysis to estimate both the sulfur content and hydrotreated fraction of high sulfur distillate.

We first reviewed data on the sulfur content of crude oils processed by U.S. refineries and found that sulfur content had indeed increased. We have incorporated this increase in crude oil sulfur content into the estimates developed in this section. However, as described in Section 7.1 above, there is no evidence so suggest that the sulfur content of high sulfur distillate has increased since 1996. Thus, it is likely that a greater percentage of the volume of high sulfur distillate blendstocks are being hydrotreating than was the case in 1996. We have incorporated a change in the hydrotreated fraction from 1996 into this analysis, as well. Finally, we also reviewed the hydrotreating and hydrocracking capacities of U.S. refineries in 1996 and 2002, as well as the relative production of highway diesel fuel and high sulfur distillate to confirm that sufficient hydrotreating capacity exists to hydrotreat a greater fraction of high sulfur distillate blendstocks.

Table 7.2.1-20 presents many of the primary inputs for our analysis. These estimates are intended to represent high sulfur distillate produced in the year 2002, but without consideration of an increase in crude oil sulfur content. Due to the significant differences in hydrotreating percentages seen across PADDs, we incorporated these PADD-specific estimates as much as possible.

Table 7.2.1-20
Quality of High Sulfur Distillate from
Non-California Refineries: "2002" Prior to Consideration of Increased Crude Oil Sulfur

	PADD				
	1	2	3	4	5
High Sulfur Distillate Pool					
Sulfur content (ppm)	2925	2973	3776	2549	2566
% Hydrotreated *	27	31	44	17	2
High Sulfur Distillate Produced by Refineries with Hydrotreaters					
% of high sulfur distillate pool	81	70	95	40	48
% Hydrotreated	33	45	46	43	4
Sulfur content of portion not hydrotreated (ppm)	4214	5081	6739	4237	2646

* Assumed to be the same as in 1996 API/NPRA survey.

The sulfur content of the high sulfur distillate pool in each PADD were taken from Table 7.1-40 in Section 7.1 above. A direct estimate of the portion of the 2002 distillate pool which is hydrotreated is not available. Therefore, we assumed that this figure has not changed since the API/NPRA survey. This necessitates the consideration of increased sulfur content between 1996 and 2002, which is addressed below. As can be seen, a significant percentage of high sulfur distillate received some hydrotreating in 1996, despite the fact that the final sulfur level is 2000 ppm or more. This is likely necessary to improve the stability of untreated LCO, as well as meet applicable cetane and sulfur specifications with blend stocks which can exceed 10,000 ppm sulfur and have a cetane number of less than 15 prior to hydrotreating. The PADD with the highest percentage of hydrotreated high sulfur distillate is PADD 3, while the lowest is PADD 5 (outside of California). Within PADD 5, Alaska's refineries are believed to have the lowest hydrotreated percentage (zero), since none of the Alaskan refineries have distillate hydrotreaters.

The hydrotreated blendstocks sent to the high sulfur distillate pool are assumed to be part of a larger pool of hydrotreated blendstocks also used to produce highway diesel fuel. We believe that this is reasonable because many refiners likely only have a single hydrotreater and they are simply blending more hydrotreated material into their highway diesel fuel than into their high sulfur distillate. In this case, we assume that all of the hydrotreated material contains 340 ppm sulfur, the current average sulfur level for highway diesel fuel. Some larger refiners likely have two or more hydrotreaters which could be treating highway diesel fuel blendstocks and high sulfur distillate blendstocks differently. However, in this case, we have no way of estimating the sulfur levels of either the hydrotreated or non-hydrotreated portions of the high sulfur distillate. Thus, we assumed that the 340 ppm sulfur content applied to all hydrotreated blendstocks. Overall, this assumption has little effect on the estimation of NRLM desulfurization costs. As will be seen below, we have estimates of both the hydrotreated fraction of high sulfur distillate and of its final sulfur level. If the sulfur level of hydrotreated blendstocks going to the high sulfur distillate pool contain more than 340 ppm sulfur, the the sulfur content of the non-hydrotreated portion of the pool much contain less sulfur than estimated below. The total amount of sulfur requiring removal is the same in either case.

Some refiners do not have a distillate hydrotreater. Therefore, the percentage of their high sulfur distillate which is hydrotreated is zero. In order for the entire high sulfur distillate pool to be hydrotreated to the degree shown in Table 7.2.1-17, the portion of distillate produced by refiners with distillate hydrotreaters must be higher. In order to estimate these percentages, we reviewed EIA data for both distillate production and distillate hydrotreating capacity. The former data are confidential and were received directly from EIA. The latter came from their 2002 Petroleum Supply Annual. For each PADD, we determined the percentage of all high sulfur distillate produced by refiners with distillate hydrotreaters. These figures are shown in Table 7.2.1-20 above. We calculated the percentage of the high sulfur distillate pool produced by refineries with hydrotreaters by dividing the hydrotreated percentage for the entire pool by the percentage of distillate produced by refineries with hydrotreaters. These higher hydrotreated percentages are shown on the second to the last line of Table 7.2.1-20.

As discussed above, we assume that the sulfur content of the hydrotreated portion of high sulfur distillate is the same as that of highway diesel fuel, or 340 ppm. As discussed in Chapter 5, the sulfur content of hydrocrackate is very low, less than 50 ppm. Knowing the final sulfur level and the percentage of hydrotreated blendstock in high sulfur distillate from Table 7.2.1-20 above (which includes hydrocrackate) and the percentage of hydrocrackate from Table 7.2.1-18, we can back-calculate the sulfur content of the unhydrotreated blendstocks comprising the rest of the high sulfur distillate pool. These sulfur levels are also shown in Table 7.2.1-20.

The final step is to incorporate the effect of an increase in crude oil sulfur content. Table 7.2.1-21 shows the average sulfur content of crude oil processed in each PADD in both 1996 and 2002. As can be seen, crude oil became more sour in all but PADD 1.

Table 7.2.1-21
Sulfur Content of Crude Oil Processed by U.S. Refineries (weight %)

PADD	1996	2002	Percent Change
1	0.94	0.86	-8.5
2	1.08	1.31	21.3
3	1.22	1.65	35.3
4	1.31	1.40	6.9
5 (Non-California)	1.14	1.22	7.0
Overall	1.15	1.41	22.6

* Annual crude properties from EIA's Petroleum Supply Annual 1996 and 2002

We next used published information to estimate how changes in crude oil sulfur content would impact the sulfur level of unhydrotreated distillate blendstocks.[AA] Table 7.2.1-22 depicts estimated sulfur contents for straight run distillate for a variety of crude oils containing both 1.15 and 1.41 weight percent sulfur.

Table 7.2.1-22
Straight Run Middle Distillate Sulfur Content (ppm) *

Crude Oil Sulfur Content	Sweet U.S. Crude Oil	West Texas Crude Oil	California Crude Oil	Middle East Crude Oil	Venezuelan Crude Oil	Average of All Crude Oils
1.15 wt %	4400	6400	7800	4500	3500	5330
1.41 wt %	5400	7800	9800	5300	4400	6540
Change in Distillate Sulfur	22.7%	21.9%	25.6%	17.7%	25.7%	22.7%

* Middle distillate assumed to have mid-boiling point of 500 F.

As can be seen, the 22.6 percent increase in crude oil sulfur content is estimated to increase the sulfur content of straight run distillate by 17.7-25.7 percent, with an average increase of 22.7 percent. Thus, on average, the sulfur content of straight run distillate increases to essentially the same degree as that of the crude oil. Therefore, it is reasonable to assume that the increases in crude oil sulfur content shown in Table 7.2.1-21 above increased the sulfur content of straight run distillate proportionally. In addition, we assume that the sulfur content of the other blendstocks, namely LCO and other cracked stocks, also increased to the same degree.

As discussed in Section 7.1 above, the average sulfur content of high sulfur distillate does not appear to have changed substantially since 1996. A significant portion of this distillate is

[AA] Petroleum Refining Fourth Edition, Gary Handewerk, 2001, pages 41 to 45.

produced by refineries without distillate hydrotreating, where an increase in crude oil sulfur would by necessity have been reflected in their distillate production. This implies that the increases in crude oil sulfur content occurred primarily at refineries with distillate hydrotreating capacity. To account for this, we adjusted the changes in crude oil sulfur shown for the percentage of high sulfur distillate produced by refiners with hydrotreaters. For example, crude oil sulfur in PADD 2 increased by 21.3 percent. Of all the distillate produced in PADD 2, 70 percent was produced by refineries with distillate hydrotreaters. Therefore, if the crude oil sulfur at the refineries producing the other 30 percent of high sulfur distillate did not change, the crude oil sulfur at refineries with hydrotreaters increased by 30 percent (21.3/0.7). The results for all five PADDs are shown in Table 7.2.1-23 below.

Table 7.2.1-23
Quality of High Sulfur Distillate from Non-California Refineries: 2002 and Beyond

	PADD				
	1	2	3	4	5
High Sulfur Distillate Pool					
Sulfur content (ppm)	2925	2973	3776	2549	2566
% Hydrotreated	20	41	58	21	83
High Sulfur Distillate Produced by Refineries with Hydrotreaters					
Increase in crude oil sulfur content	-11%	30%	37%	17%	15%
% of high sulfur distillate pool	81	70	95	40	48
% Hydrotreated	25	58	61	52	17
Sulfur content of portion not hydrotreated (ppm)	3771	6623	9248	4964	3034

The next step was to increase the sulfur content of the unhydrotreated distillate at refineries with hydrotreaters by the same percentage that crude oil sulfur increased. For example, in PADD 2, the sulfur content of 5081 ppm was increased by 30 percent to yield a final non-hydrotreated distillate sulfur content of 6623 ppm. The sulfur content of the 2002 high sulfur distillate is the same as that shown in Table 7.2.1-23 and the sulfur content of the hydrotreated distillate is 340 ppm. Therefore, the percentage of high sulfur distillate at these refineries which is hydrotreated can be calculated. For example, in PADD 2, a mix of 42 percent hydrotreated distillate at 340 ppm and 58 percent unhydrotreated distillate at 6623 produces a pool of high sulfur distillate at 2973 ppm. Finally, given the percent of all high sulfur distillate being produced by refineries with hydrotreaters (for PADD 2, 70 percent), the portion of the entire high sulfur distillate pool which is hydrotreated can be calculated. For example, for PADD 2, the portion of the entire high sulfur distillate pool which is hydrotreated is 41 percent, the product of the the percent of all high sulfur distillate being produced by refineries with hydrotreaters (70 percent) and the hydrotreated percentage of high sulfur distillate at those refineries with hydrotreaters (58 percent). These figures are summarized in Table 7.2.1-23 above.

High sulfur distillate produced by refineries without hydrotreaters is assumed to have sulfur contents equal to the average high sulfur distillate produced in that PADD. High sulfur distillate produced by refineries with hydrotreaters is a mix of unhydrotreated blendstocks at the sulfur levels shown in Table 7.2.1-23 and hydrotreated blendstock containing 340 ppm sulfur. The average sulfur content of this distillate is also the average sulfur content of the high sulfur distillate produced in that PADD. We assume that these hydrotreated percentages and sulfur contents remain constant beyond 2002.

A comparison of the hydrotreated portion of all high sulfur distillate in 1996 (Table 7.2.1-20) and 2002 (Table 7.2.1-23) shows that except in PADD 1, we are projecting that a significant increase in the degree of hydrotreating has occurred. This implies that refiners built new hydrotreaters or expanded existing hydrotreaters during this time period. We desired to confirm that this in fact occured. The first step in this confirmation was to estimate the increased capacity of distillate hydrotreating. The second step was to show that this increase was sufficient to provide for the increased production of highway diesel fuel, as well as the increase in the hydrotreated percentage of high sulfur distillate.

Table 7.2.1-24 presents hydrotreating and hydrocracking capacity at U.S. refineries located outside of California in 1996 and 2002, according to EIA's Petroleum Supply Annual reports from these two years (assuming an annual average utilization rate of 90 percent). Both processes produce distillate blendstocks which likely meet the 500 ppm highway fuel cap and which have had their olefins and some aromatics removed, reducing the cost of further hydrotreating. As described above, hydrocrackers are assumed to convert roughly 21 percent of their feed to distillate.

Table 7.2.1-24
Effective Non-California Distillate Hydrotreating and Hydrocracker Capacity 1996 to 2002

	Distillate Hydrotreating	Hydrocrackers
1996 Capacity	3,108,285	834,651
2002 Capacity	3,380,323	1,003,050
Increase in capacity	272,038	168,399
Increase in low sulfur distillate	272,038	35,869*

* 90 percent of rated capacity. Hydrocrackers assumed to convert 21 percent of feedstock to distillate.

As can be seen, the total capacities of both processes increased substantially. In total, these capacity expansions increased the production capacity of low sulfur distillate by 307,900 barrels per day.

Table 7.2.1-25 shows the distillate fuel production in 1996 and 2002, again from EIA's Petroleum Supply Annual reports. We show the production of jet fuel and kerosene, since much of the volume of these No. 1 distillate fuels is also hydrotreated and the above distillate hydrotreating capacities do not distinguish between No. 1 and No. 2 distillates.

Table 7.2.1-25
Non-California Distillate Production (BPD)

	Jet Fuel and Kerosene *	Highway Diesel Fuel	High Sulfur Distillate
1996	1,577,000	1,842,797	1,213,490
2002	1,571,000	2,298,507	964,184
Increase	-6,000	455,710	-249,307

* Jet fuel includes production from California refineries.

As can be seen, the production of jet fuel and kerosene was essentially constant in 1996 and 2002. Thus, we assume that no additional hydrotreating capacity was used in the production of jet fuel and kerosene in 2002 versus 1996. It is possible that the increased sulfur content of crude oil occurring over this 6 year period caused refiners to increase a greater percentage of the No. 1 distillate blendstocks used to produce these two fuels. However, no data are available to estimate this effect. Since the sulfur standards for these No.1 distillate fuels are not stringent, the overall change in hydrotreating should be small.

As also shown in Table 7.2.1-25, the production of highway diesel fuel increased by nearly 25 percent, while the production of high sulfur distillate decreased by 20 percent. As described above, the hydrotreated fraction of highway fuel was 83.8 percent in 1996. Thus, the production of 455,710 barrels per day more highway diesel fuel likely utilized 382,000 (455,710 * 0.838) barrels per day of effective hydrotreating or hydrocracking capacity. However, as discussed below, crude oil sulfur levels increased between 1996 and 2002 by nearly 20 percent. Thus, to be conservative, we will also consider the possibility that 100 percent of this additional production of highway diesel fuel was hydrotreated. Thus, we estimate that the production of 455,710 barrels per day more highway diesel fuel might have utilized as much as 455,710 barrels per day of effective hydrotreating or hydrocracking capacity. Combining these two estimates to produce a range, the additional production of highway diesel fuel utilized 74,100-147,810 more barrels per day of effective hydrotreating and hydrocracking capacity than the 307,000 barrels per day of effective capacity which was added between 1996 and 2002.

Regarding the production of high sulfur distillate, two factors changed, volume and percentage which was hydrotreated. In 1996, 1.213 million BPD of high sulfur distillate was produced, 34 percent of which was hydrotreated. In 2002, 0.964 million BPD of high sulfur distillate was produced, 41 percent of which was hydrotreated. This implies a net reduction of hydrotreated volume of 20,300 BPD. This provides some but not all of the hydrotreating capacity needed to produce the additional highway fuel. The shortfall ranges from 53,800-127,510 barrels per day of effective hydrotreating capacity.

We believe that this remaining hydrotreating capacity needed to produce the additional highway diesel fuel likely came from an increase in the utilization of hydrotreating capacity between 1996 and 2002. The API/NPRA survey showed that only 78 percent of the total rated hydrotreating capacity was utilized in 1996. We believe that full utilization can be closer to 90 percent. (Crude oil utilization rates today are over 95 percent.) A 12 percent increase in the utilization rate of hydrotreating capacity in 1996 would be 373,000 barrel per day. This far exceeds the 53,800-127,510 barrel per day shortfall estimated above. Thus, we conclude that the increase in overall hydrotreating percentage of high sulfur distillate are reasonable.

7.2.1.3.3 Refinery Specific Distillate Production Volumes

In the NPRM, we projected refinery's volumes of no. 2 distillate fuel in two steps. First, we obtained each refinery's production of no. 2 distillate fuel in 2000 from EIA. (This data is considered confidential and is based on information which refiners are required to submit to EIA periodically.) These production volumes include a breakdown of how much fuel was certified to meet the 500 ppm highway fuel sulfur cap and how much fuel was not so certified. Second, these year 2000 production volumes were increased to represent 2008 production using EIA projections from their 2002 AEO report. We applied separate growth rates for highway diesel fuel and high sulfur distillate. We assumed that refineries would not change their relative production of highway diesel fuel and high sulfur distillate except as reflected in the distinct national average growth projections for the two fuels.

For the final rule, we have made a number of changes to improve this portion of our cost analysis. First, since the NPRM analysis was conducted, we received refiners' projection of the volume of 15 and 500 ppm highway diesel fuel which they plan to produce in 2006-2010. In some cases, these volumes differ significantly from their historic production of highway diesel fuel. Thus, we have incorporated these projections into our projection of refineries' relative production of highway diesel fuel and high sulfur distillate prior to the implementation of this rule. Second, we have shifted our base year for historic production volumes from 2000 to 2002 to reflect more recent data available from EIA. Third, we have shifted the future year for which we project desulfurization costs from 2008 to 2014. Fourth, and finally, we are using EIA projections of distillate production growth from their 2003 AEO report[36], instead of their 2002 AEO report. The methodology for estimating refinery specific production volumes of highway diesel fuel and high sulfur distillate is described in more detail below, as well as the results of this analysis.

As described above, the first step was to estimate each refinery's historic production volumes of highway diesel fuel and high sulfur distillate. Except for using more recent 2002 data from EIA, versus 2000 in the NPRM, this step was identical to that performed in the NPRM analysis.

The second step increased these 2002 production volumes of highway and high sulfur distillate fuel to represent growth through 2014. We chose 2014, because it represents the mid-point of the life of the desulfurization equipment build in response to this rule (per IRS rules, this equipment has a 15 year life). We obtained EIA's projected growth factors for domestic production of these two fuels over this time period, which were consistent with those underlying their 2003 AEO projections. EIA projects that highway fuel production will increase 42.1 percent over this time period, while production of high sulfur distillate will only increase 8.1 percent. Each refinery's 2002 production volumes of these two fuels werw increases by these percentages to represent their likely production in 2014. The sum of the production volumes for the two fuels was taken to be each refinery's total distillate production in 2014. It should be noted that the combination of these two growth rates results in a greater increase in the production of distillate fuel from domestic refineries than indicated by the growth in crude oil consumption by these refineries (typically assumed to be the driver of increased fuel production). This difference occurs because EIA projects that domestic refiners will increasingly process heavy oils in addition to virgin crude oils. This step was analogous to that performed in the NPRM, with the exception that growth was projected to 2014 instead of 2008. The historic and future production volumes by PADD are shown in Table 7.2.1-26.

Table 7.2.1-26
U.S. Distillate Fuel Production: AEO 2003 (BPSD) *

	2002			2014		
	Highway Fuel	High Sulfur Distillate	Total Distillate	Highway Fuel	High Sulfur Distillate	Total Distillate
PADD 1	239,375	223,063	462,438	337,936	241,161	579,098
PADD 2	647,170	159,688	806,858	913,637	172,644	1,086,281
PADD 3	1,245,605	520,142	1,765,747	1,758,473	562,345	2,320,818
PADD 4	129,397	29,973	159,370	182,676	32,404	215,080
PADD 5	396,475	95,775	492,250	559,720	103,546	663,266
Total	2,658,022	1,028,641	3,686,663	3,752,442	1,112,100	4,864,542

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

The third step differed from the NPRM analysis in that we utilized refiners' confidential projections of how they planned to produce highway diesel fuel in 2006-2010 under the upcoming 2007 highway diesel fuel program. Under this program, refiners must submit their projected production volumes of 15 and 500 ppm diesel fuel to EPA every year starting in 2003 (called a pre-compliance report). EPA would then publish aggregated results to help refiners optimize their compliance plans and better ensure sufficient supply of highway diesel fuel under the rule. Shell oil's refinery in Bakersfield, California and Carribean Petroleum's refinery in Puerto Rico were removed from the analysis due to recent shutdowns or plans to shut down.

The highway diesel fuel program begins to take effect in June 2006. Some refiners submitted 2006 production volumes on an annualized basis, while others submitted volumes for just the seven months affected by the program. To avoid these differences, we focused on refiners' projections for 2007, the first full calendar year affected by the program. We assumed these projections, made by refiners, represented the best estimate of future production levels of highway diesel fuel on a refinery-specific basis. While refiners projected their production volumes for highway diesel fuel, they did not have to submit their plans for producing high sulfur distillate. Therefore, we estimated their production of high sulfur distillate subtracting their production of highway diesel fuel from our estimate of the refinery' total production of No. 2 distillate from step two above.

The fourth and final step was to put refiner's projected 2007 highway diesel fuel production volumes on the same basis as these 2014 total distillate volumes in order to back-calculate a high sulfur distillate volume. To do this, we assumed that the refiners' highway pre-compliance reports represented the absolute volumes which they planned to produce in 2007 including any increases in total distillate production which might occur due to refinery debottlenecking, new or expanded heavy oil processing capacity, etc. Using information supplied in a number of these reports, it appeared that some refiners simply estimated their 2007 production volumes by applying some fraction to their historical 2002 production volumes. However, it is possible that other refiners did include such planned capacity increases. Overall, our methodology could under-estimate highway fuel production in 2007 to some degree, but we believe that the degree of this under-estimation should be small. We then increased these 2007 highway fuel production volumes by EIA's projected increase in total domestic highway diesel fuel production between 2007 and 2014, which is 14.5 percent

We then compared the total projected production of highway diesel fuel in 2007 in each PADD to the projected demand for highway diesel fuel developed in section 7.1 above. Again, in both cases, the volumes are representative of those expected for 2014. The highway diesel fuel sulfur standards are those representative of 2007 prior to this NRLM rule. Production and demand for PADDs 1 and 3 were combined, due to the large volume of fuel which PADD 3 refiners ship to PADD 1. The results are shown in Table 7.2.1-27.

Table 7.2.1-27
Projected Production of Highway Fuel in 2007 (Thousand BPD in 2014)

	PADD's 1 & 3	PADD 2	PADD 4	PADD 5
Required Highway Fuel Production *	1,588.3	1,162.4	187.5	530.9
Projected Production: 15 ppm Highway Fuel	1,878.0	914.8	148.4	468.2
Projected Production: 500 ppm Highway Fuel	62.5	49.5	4.1	20.3
Projected Production: All Highway Fuel	1940.5	964.3	152.5	488.5
Shortfall	-352.2	198.1	35.0	42.4
Additional Production of Highway Fuel				
Current highway fuel refiners with excess 500 ppm capacity	0	0	0	2.2 (1)
15 ppm highway fuel produced from high sulfur distillate	0	0	41.8 (4)**	40.5 (4)
Final 15 ppm Highway Fuel Production	1,723.9	914.8	190.2	508.7
Final 500 ppm Highway Fuel Production	62.5	49.5	4.1	22.5
Final Total Highway Fuel Production	1,786.4	964.3	194.3	531.2

* Demand from highway vehicles, spillover of highway fuel to other markets plus highway fuel lost during distribution.
** Number of refineries producing this fuel is shown in parenthesis.

As can be seen, projected 2007 production of highway diesel fuel in PADDs 1 and 3 significantly exceeds projected demand, while the opposite is true in PADDs 2, 4 and 5. PADD 3 refiners currently supply much of PADD 2's diesel fuel consumption. A comparison of current shipments from PADD 3 to PADD 2 shows that these shipments far exceed the 198,000 barrel per day shortfall projected for PADD 2. Therefore, we assumed that PADD 3 refineries would balance demand for highway fuel in PADD 2. However, PADD 3 currently supplies little or no fuel to PADDs 4 and 5. Therefore, we assumed that additional refineries would have to produce highway diesel fuel in 2007 to satisfy demand. A comparison of 2002 production of highway diesel fuel and refiners' projected production in 2007 revealed one refinery in PADD 5 which had excess capacity to produce 500 ppm diesel fuel using its current hydrotreater. Therefore, we assumed that this refinery would likely produce 500 ppm highway diesel fuel in 2007 by purchasing credits from other refiners. We projected that the remaining shortfalls would be made up by refiners constructing new desulfurization capacity to process high sulfur distillate to 15 ppm. We assumed that these refineries would go straight to 15 ppm for two reasons. First, as long as they were investing to produce highway diesel fuel, they would likely design their equipment to meet the 15 ppm cap, which would affect all highway fuel in 2010. Second, whether or not these refiners invested to produce 500 ppm highway diesel fuel in 2006 and revamped this equipment in 2010 to produce 15 ppm highway diesel fuel has no effect on the cost of other refiners producing NRLM fuel under this NRLM fuel rule. It was simpler to assume these refiners invested in one step rather than two.

This left an excess highway fuel production of 154,100 barrels per day in PADDs 1 and 3 beyond that necessary to meet the shortfall in PADD 2. We assumed that refiners would adjust their plans to produce 15 ppm highway diesel fuel in 2007 based on the results of the refiners' pre-compliance reports. Therefore, we assumed that this excess production would not in fact occur. To represent this on a refinery specific basis, we assumed that the refiners estimated to have the highest cost of producing 15 ppm fuel in PADDs 1 and 3 would decide not to produce this fuel until the 154,100 barrel per day excess was eliminated. We also assumed that this excess production capacity would be available to produce 500 ppm NRLM fuel in 2007 with only incremental operation costs, no capital cost. This would be the case for excess 15 ppm fuel capacity deriving from a revamp of an existing hydrotreater. However, it would not be the case for grass roots 15 ppm fuel capacity which never was built. Thus, this assumption might have led to a slight underestimation of the cost of 500 ppm NRLM fuel from 2007-2010. We believe that the degree of this underestimation is small.

Having developed refinery-specific projections of both total and highway distillate production, we assumed that the difference was high sulfur distillate. The resulting total production volumes for 2007 (projected to year 2014) by PADD and for the nation are shown in Table 7.2.1-28.

Table 7.2.1-28
"2007" Refiner's Production of Distillate Fuels (Thousand BPD in 2014) *

PADD	Highway Fuel	High Sulfur Distillate	Total Distillate
1&3	1,786	1,116	2,903
2	964	122	1,086
4	194	21	215
5	531	132	663
Total	3,476	1,391	4,867

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

We repeated this analysis using refiners' projections of their production of highway diesel fuel in 2010. One limitation in doing so is that the refiners' pre-compliance reports for 2010 only apply to the first half of 2010 when they can still use banked credits to produce some 500 ppm highway fuel. We are more interested here in the last half of 2010, when all highway fuel must meet a 15 ppm cap and NRLM fuel will also have to meet a 15 ppm cap under the final NRLM program. To accommodate this difference, we assumed that refiners would simply continue producing 15 ppm fuel at the same rate as they did in the first half of 2010. We also assumed that refiners would convert production of 500 ppm highway fuel to high sulfur distillate starting on June 1, 2010 absent the NRLM fuel standards contained in this rule.

As was done for the 2007 projections, we then increased these 2010 highway fuel production volumes by EIA's projected increase in total domestic highway diesel fuel production between 2010 and 2014, which is 11.0 percent. The results are shown in Table 7.2.1-29 below.

Table 7.2.1-29
Projected Production and Demand for Highway Fuel in 2010 (Thousand BPD in 2014)

	PADD's 1 & 3	PADD 2	PADD 4	PADD 5
Required Highway Fuel Production *	1,651.9	1,205.3	194.2	567.2
Projected 15 ppm Highway Fuel Production	2008.3	959.5	153.7	474.1
Shortfall	-356.4	245.8	40.6	93.2
Additional Production of 15 ppm Highway Fuel				
Produced from high sulfur distillate			41.8 (4) **	93.2 (7)
Final Production of 15 ppm Highway Fuel	1942.4	914.8	195.5	567.3

* Demand from highway vehicles, spillover of highway fuel to other markets plus highway fuel lost during distribution.
** Number of refineries producing this fuel is shown in parenthesis.

As for 2007, the projected volume of highway diesel fuel in 2010 by PADD 1 and 3 refiners exceeds projected demand (plus downgrades in the distribution system), while those of the other PADDs are less than projected demand. In PADDs 4 and 5, we again assumed that additional refineries would produce 15 ppm highway diesel fuel from their high sulfur distillate. The number of PADD 4 refiners was the same as in 2007. In PADD 5, seven additional refineries were assumed to produce 15 ppm highway diesel fuel, three more than in 2007.

PADD 2's shortfall was again assumed to be supplied from PADD 3. Again, we assumed that a number of PADD 1 and 3 refiners would decide not to produce 15 ppm highway fuel so that these PADD's production would match demand, after supplanting PADD 2's supply. In doing this, we also assumed that one PADD 2 refinery would decide not to produce 15 ppm highway fuel due its much higher desulfurization costs compared to other PADD 2 refineries and PADD 3 refineries able to supply that area via pipeline transport.

Having the refinery-specific projections of both total and highway distillate production, we assumed that the difference was high sulfur distillate. The resulting total production volumes for 2010 (grown to year 2014) by PADD and for the nation are shown in Table 7.2.1-30 below.

Table 7.2.1-30
"2010" Refiner's Production of Distillate Fuels Projected (Thousand BPD in 2014)

	Highway Fuel	High Sulfur Distillate	Total Distillate
PADD's 1&3	1,942	960	2,903
PADD 2	915	172	1,086
PADD 4	196	20	215
PADD 5	567	96	663
Total	3,620	1,247	4,867

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

Note that we made no changes in the production volumes of distillate fuel to account for any reduction in wintertime blending of kerosene that might occur as a result of the 15 ppm highway or NRLM sulfur caps. Kerosene added to 15 ppm diesel fuel must itself meet a 15 ppm sulfur. Sometimes, kerosene is added at the refinery and the winterized diesel fuel is sold or shipped directly from the refinery. At other times, the kerosene blending is done at the terminal, downstream of the refinery. The former approach may mean adding kerosene to more diesel fuel than actually requires it. The latter approach requires that a distinct 15 ppm kerosene grade be produced and distributed. Much of this 15 ppm kerosene might be used in applications not requiring 15 ppm sulfur content. Adding pour point depressant is an alternative to blending kerosene. This can be done very flexibly at the terminals in areas facing very cold weather. Thus, we expect that the use of pour point depressants will increase and the terminal blending of kerosene will decrease. For kerosene blended into winter diesel fuel, the kerosene can simply be added to the distillate being fed to the hydrotreater and desulfurized along with the rest of the 15 ppm diesel fuel pool.

In summary, the primary purpose of developing these future production volumes is to reasonably project the economies of scale of the desulfurization equipment being constructed in response to the NRLM fuel program, including the interaction of this program with the 2007 highway fuel program. Larger capacity equipment costs more than smaller equipment in total, but is less expensive on a per gallon basis. Operating costs are not affected, as these are proportional to volume. In the NPRM we projected production volumes for calendar year 2008, as this was the first full year that the NRLM sulfur caps were effective. However, we now believe that 2014 is more reasonable, because the assumed life of desulfurization equipment is 15 years and 2014 marks the mid-point of the life of equipment built in 2007.

7.2.1.3.4 Selection of Refineries Producing 500 and 15 ppm NRLM Fuel

We used two basic criteria to select those refineries most likely to produce 500 and 15 ppm NRLM fuel under this NRLM rule. The first criterion was refineries' ability to avoid producing lower sulfur NRLM fuel (i.e., continue producing high sulfur heating oil). The second criterion was the estimated cost of compliance. We assumed that those refineries facing the lowest desulfurization costs in a given region would be the most likely to invest. A key factor in estimating desulfurization costs on a refinery specific basis is whether the refinery: 1) would be able to produce 500 or 15 ppm NRLM fuel with its existing hydrotreater, 2) would be able to revamp an existing hydrotreater to produce NRLM fuel, or 3) would have to build a grass roots hydrotreater to produce NRLM fuel. These three factors are described below.

7.2.1.3.4.1 Geographic and Logistic Limitations Affecting the Production of Heating Oil

It goes without saying that refiners have to be able to market the fuels which they produce. That is the nature of business. This includes the No. 2 distillate that they produce. Most No. 2 distillate volume comes directly from the crude oil itself. It is not feasible, or economical, to convert all this distillate fuel to other products. Thus, under this NRLM rule, refiners basically have three choices for this distillate; produce 15 ppm highway diesel fuel, produce 500 and 15 ppm NRLM fuel (depending on the time period) or produce high sulfur heating oil. Producing high sulfur heating oil should require no change in current refinery configurations, as all of the No. 2 distillate produced today essentially meets heating oil specifications.

However, as alluded to above, refiners must be able to deliver their fuel to the geographical market where it is consumed. The market for high sulfur distillate will decrease by 50 percent upon the implementation of this NRLM rule. Over two-thirds of all high sulfur distillate use after 2010 will be concentrated in the Northeast. Thus, PADD 1 refineries should have no difficulty in selling high-sulfur distillate to this market if they desired. Likewise, PADD 3 refineries which are connected to one of the two large pipelines running from the Gulf Coast to the Northeast (Plantation and Colonial) or which have access to ocean transport should also be able to market high sulfur distillate. In addition, selected markets in PADD 5, such as Hawaii, also have significant heating oil demand, so some PADD 5 refineries were also assumed to have the flexibility to continue producing high-sulfur distillate if they desired.

As discussed in Section 7.1 above, however, the heating oil markets in PADDs 2 and 4 will be very small after the NRLM rule takes effect. Thus, we believe that it is unlikely that pipelines in these PADDs will continue to carry heating oil as a fungible product. Therefore, we do not believe that refineries located in PADDs 2 and 4 will have the option of choosing to avoid complying with the NRLM fuel program by producing high sulfur distillate. To the degree that they are not already producing 15 ppm highway diesel fuel, they will have to take steps to produce 500 ppm and 15 ppm NRLM fuel. The same is true for refineries located in PADDs 3 and 5 which do not have access to a large local market for heating oil or which are not connected to efficient transport to the Northeast. The final NRLM rule does not require that these refineries produce NRLM fuel, *per se.* We simply believe that this is a reasonable assumption for cost-estimation purposes.

We reviewed the geographical location of each domestic refinery and those of pipelines serving the Northeast and identified those falling into the two groups described above. The number of refineries projected to have no choice but to produce NRLM diesel fuel is shown in

Table 7.2.1-31 along with the total number of refineries projected to produce high-sulfur distillate fuel after implementation of the 2007 highway diesel rule. These projections consider the small refiner provisions included in the NRLM final rule. These provisions reduce the number of refineries projected to have to produce 500 ppm NRLM fuel in 2007, as small refiners are assumed to be able to sell high sulfur diesel fuel to the NRLM market.

Table 7.2.1-31
Number of Refineries Lacking the Option to Produce Heating Oil

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Prior to NRLM Rule Implementation considering Fully Implemented Highway Diesel Program					
Refineries Producing Some High-Sulfur Distillate Fuel	13	17	37	8	17
Starting June 1, 2007 (Considers Small Refiner Provisions)					
Must produce 500 NRLM fuel	0	14	4	7	0
Refineries Producing Some High-Sulfur Distillate Fuel	13	3	33	1	17
Starting June 1, 2010 (Considers Small Refiner Provisions)					
Must produce 15 Nonroad fuel	0	6	0	3	0
Must produce 500 NRLM fuel	1	11	9	5	5
Refineries Producing Some High-Sulfur Distillate Fuel	12	0	28	0	12
Starting June 1, 2012 (Considers Small Refiner Provisions)					
Must produce 15 NRLM fuel	0	14	4	7	0
Must produce 500 NRLM fuel	1	3	5	1	5
Refineries Producing Some High-Sulfur Distillate Fuel	12	0	28	0	12

We repeated this analysis for 2010. The number of refineries producing some high sulfur distillate fuel in 2010 is less than in 2007, as additional refineries produce either 15 or 500 ppm NRLM fuel. The number of refineries projected to have to produce NRLM fuel in 2010 due to distribution system constraints increases over that in 2007 due to the expiration of the small refiner provisions. While we project that the vast majority of 15 ppm nonroad fuel will be produced by those refineries facing the lowest desulfurization costs, we project that a few refineries will have to invest to produce 15 ppm nonroad fuel because of limited ability to distribute higher sulfur fuel to the L&M and heating oil markets. These refineries produce a large volume of 500 ppm NRLM fuel in 2007 and are not directly connected to a pipeline or navigable waterway. Given the volume of fuel involved, we decided that shipping all of it via rail was also not economically feasible long term. The number of these constrained refineries is much fewer than those which we project will be unable to distribute all of their distillate fuel to the heating oil market and thus had to produce make 500 ppm NRLM fuel in 2007.

In 2012, the number of refineries that must produce NRLM fuel is the same as 2010. However in 2012, the non-small refineries that we project have to produce 500 ppm L&M fuel in 2010 invest further to produce 15 ppm L&M fuel.

In 2014, the only change is the expiration of the small refiner provisions. The small refineries producing 500 ppm nonroad fuel in 2012 invest to produce 15 ppm NRLM fuel. The refinery estimates for years 2007-2012 are shown in Table 7.2.1-31.

Table 7.2.1-32 shows how the NRLM fuel volume produced by these refineries compares with the total required NRLM fuel production volume during the 2007-2010 period. This table starts with the total demand for NRLM fuel, as well as the volume of highway fuel used in the NRLM fuel markets as developed in Section 7.1. Table 7.2.1-32 also shows the volume of high sulfur distillate projected for small refiners which are able to sell high sulfur diesel fuel to the NRLM market during this period. Subtracting the volumes of highway spillover and small refiner fuel from total demand results in the net volume of 500 ppm NRLM fuel which needs to be produced in response to this NRLM rule. The 500 ppm fuel volumes from refineries having to produce this fuel are then shown, along with any remaining volume. It should be noted that we have excluded demand for NRLM fuel in California from Table 7.2.1-32 and the analogous tables for 2010, 2012 and 2014. Nonroad fuel sold in California is already required to meet a 15 ppm cap in this timeframe per State regulation. L&M fuel demand in California is totally satisfied by spillover of highway fuel and downgrade. Thus, we project no on-purpose production of L&M fuel for use in California. However, distillate production from two California refineries which current produce high sulfur distillate fuel is considered in satisfying NRLM fuel demand in PADD 5.

Table 7.2.1-32
500 ppm NRLM Fuel Production: 2007-2010 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Fuel Spillover	898	1,906	580	381	3,765
Fuel Produced Under Small Refiner Provisions	671	139	5	165	980
NRLM Requiring Desulfurization	7,465	5,066	461	613	13,605
Refineries Having to Produce 500 ppm NRLM Fuel	281	2,549	303	0	3,133
Remaining Production of 500 ppm NRLM Diesel Fuel	7,184	2,517	158	613	10,472

* Excludes NRLM fuel demand in California.

As can be seen, more than enough 500 ppm fuel will be produced in PADDs 2 and 4 by refineries having to produce this fuel. This is a direct result of assuming that no refinery in either of these PADDs will be able to market all of their current high sulfur distillate fuel solely as heating oil. Significant volumes of 500 ppm NRLM fuel will still have to be produced by PADD 1, 3 and 5 refineries. As discussed above, we assume that the refineries facing the lowest desulfurization costs in each PADD will choose to invest to produce any remaining fuel demand in that PADD.

It should be noted that we evaluated small refiners' ability to distribute their production volume of high-sulfur NRLM diesel fuel, even if they do not have access to a common carrier pipelines carrying this fuel. Starting with the total demand for NRLM diesel fuel in each PADD in 2014 from Section 7.1 above, we divided this demand by the square mileage of each PADD to estimate NRLM diesel fuel demand per square mile. We then determined the area over which each small refiner would have to distribute its high-sulfur NRLM fuel to maintain its current high sulfur distillate production level. In all cases, assuming a circular shaped area, the radius of the circle was 100 miles or less. As this is easily within trucking distance, we concluded that it was reasonable to assume that all small refiners can continue selling all their high-sulfur distillate fuel as either high-sulfur distillate fuel or heating oil, and delay producing any 500 ppm NRLM diesel fuel until at least 2010.

Table 7.2.1-33 presents the same breakdown of nonroad fuel supply for the period 2010-2012, with the implementation of the 15 ppm cap. Just over 20% of nonroad fuel demand is satisfied by highway spillover and just under 10% by distribution downgrade. Small refiner 500 ppm fuel supplies roughly 5% of the market, with the remainder being new 15 ppm fuel production. Less than 10% of the new 15 ppm nonroad fuel production is by refineries having no economic choice but to do so, the vast majority of 15 ppm nonroad fuel is produced by refineries with the lowest cost of production. The volume of 15 ppm nonroad fuel that has to be produced by refineries with no other economic choice is significantly than was the case for 500 ppm NRLM fuel in 2007. This occurs, because the L&M market is much larger than the heating oil market in PADDs 2, 4 and 5 and most refineries can ship their fuel via pipeline or waterway to the L&M market.

Table 7.2.1-33
15 ppm Nonroad Fuel Production: 2010-2012 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total Nonroad Fuel Demand	5901	5,670	810	934	13,315
Highway Spillover	551	1,535	451	341	2,878
Distribution Downgrade	217	519	111	264	1,111
Small Refiner Volume (500 ppm nonroad fuel)	419	139	5	165	728
New Production of 15 ppm Nonroad Fuel	4,714	3,477	243	164	8,598
Refineries Having to Produce 15 ppm Nonroad Fuel	0	631	157	0	728
Remaining Production of 15 ppm Nonroad Fuel	4,714	2,846	86	164	7,810

* Excludes NRLM fuel demand in California.

Table 7.2.1-34 presents the same breakdown of L&M fuel supply for the period 2010-2012. Just under 20% of nonroad fuel demand is satisfied by highway spillover and another 20% by distribution downgrade. We project that small refiner 500 ppm fuel will be used in the nonroad fuel market, where it has an economic advantage. Distribution of this fuel should be economically feasible, given the small volumes involved and the ubiquitous nature of the nonroad fuel market. Thus, no L&M fuel is supplied by small refiners during this time frame. Thus, roughly 60% of 500 ppm L&M fuel is being produced for the L&M market. Nearly 80% of this 500 ppm L&M fuel production is by refineries which are unable to economically distribute heating oil, so they have to produce a lower sulfur fuel. In PADDs 2 and 4, the volume of 500 ppm fuel produced by refineries with no other economic choice is greater than the remaining demand for L&M fuel. We assumed that the excess production of 500 ppm fuel refineries in the eastern and southern regions of PADD 2 could be satisfy L&M demand in PADDs 1 and 3, respectively. This still leaves a significant volume of 500 ppm L&M fuel needing to be produced by refineries in PADDs 1 and 3. We assumed that excess 500 ppm fuel in PADD 4 would be used in the heating oil market. As usual, we assumed that refineries with the lowest desulfurization costs in PADDs 1,3 and 5 would invest to produce the remaining 500 ppm fuel demand.

Table 7.2.1-34
500 ppm NRLM Fuel Production: 2010-2012 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total L&M Fuel Demand	3,133	1,441	236	224	5,034
Highway Fuel Spillover	347	371	129	50	897
Distribution Downgrade	866	134	33	40	1,073
NRLM Requiring Desulfurization	1,920	936	74	134	3,064
Refineries Having to Produce 500 ppm L&M Fuel	281	1,918	153	0	2,352
Remaining Production of 500 ppm NRLM Diesel Fuel	1,639	(982)	(79)	134	712
500 ppm Nonroad Fuel Produced by Small Refiners	419	139	5	165	728
Total New 500 ppm Production	2,058	(843)	(74)	299	1,440

* Excludes NRLM fuel demand in California.

Table 7.2.1-35 presents the same breakdown of 15 ppm NRLM fuel volumes for the period 2012-2014 when the L&M standard goes to 15 ppm.

Table 7.2.1-35
15 ppm NRLM Fuel Production: 2012-2014 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Spillover	898	1,906	579	390	3,773
Distribution Downgrade	467	685	147	304	1,603
Fuel Produced Under Small Refiner Provisions	419	139	5	165	728
Production of 15 ppm NRLM Fuel	7,250	4,381	316	300	12,247
Refineries Having to Produce 15 ppm NRLM Fuel	281	2,549	310	0	3,140
Remaining Production of 15 ppm NRLM Fuel	6,969	1,832	6	300	9,107

* Excludes NRLM fuel demand in California.

Finally, Table 7.2.1-36 presents the same breakdown of 15 ppm NRLM fuel volumes for the 2014 and beyond. The required production volumes of 15 ppm NRLM fuel in 2014 are larger than those in 2012, as the small refiner provisions expire and downgraded 15 ppm fuel can no longer be sold to the nonroad fuel market.

Table 7.2.1-36
15 ppm Nonroad Fuel Production: 2014 and Beyond (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Spillover	898	1,906	579	390	3,773
Downgraded “500 ppm” NRLM Fuel	467	685	146	246	1,544
Fuel Produced Under Small Refiner Provisions	0	0	0	0	0
New Volume of 15 ppm Nonroad Fuel	7,668	4,520	321	523	13,032
Refineries Having to Produce 15 ppm NRLM Fuel	701	2,688	315	165	3,869
Remaining Production of 15 ppm NRLM Fuel	6,967	1,832	6	358	9,163

* Excludes NRLM fuel demand in California.

Sensitivity Case: Long-Term 500 ppm NRLM cap. Table 7.2.1-37 presents an analogous set of 500 ppm NRLM production volumes for 2010 assuming that no 15 ppm NRLM fuel cap was implemented. (This situation is analyzed to allow the long-term analysis of the 500 ppm NRLM diesel fuel cap independent of the 15 ppm nonroad diesel fuel cap). The primary difference between these volumes and those for 2007 above is the absence of the small-refiner volume and fuel to the NRLM pool from distribution downgrade.

Table 7.2.1-37
500 ppm NRLM Fuel Production: 2010 and beyond* (million gallons per year in 2014)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
NRLM Diesel Fuel Demand	9,034	7,111	1,046	1,159	18,350
Distribution Downgrade	1,084	685	147	304	2,220
Highway Spillover	898	1,906	579	390	3,773
Base High-Sulfur NRLM Demand	7,052	4,520	320	465	12,357
Fuel Produced Under Small Refiner Provisions	0	0	0	0	0
Volume Having to Produce 500 ppm NRLM Fuel	701	2,688	315	165	3,869
Remaining Demand for 500 ppm NRLM Diesel Fuel	6,351	1,832	5	300	8,488

[a] After all small refiner provisions have expired.

Sensitivity Case: 15 ppm Nonroad and 500 ppm L&M Fuel

This case examines the proposed fuel control program, which is identical to that being promulgated, except that locomotive and marine fuel remains at 500 ppm indefinitely. The only difference in the geographical constraints assumed to exist is that PADD 2 refiners were allowed to continue producing 500 ppm locomotive and marine fuel in 2010 and beyond. The result was that some 15 ppm nonroad fuel being consumed in PADD 2 is being produced in PADD 3. This shipment of 15 ppm fuel from PADD 3 to PADD 2 occurs under the final NRLM fuel program, as well.

7.2.1.3.4.2 Low Sulfur NRLM Fuel Via Existing, Revamped or Grass Roots Hydrotreater

This section presents the methodology that we used to determine what actions refiners would likely take to produce 500 and 15 ppm NRLM diesel fuel during the implementation of the NRLM diesel fuel program. The timing of the various steps in both the highway and NRLM fuel programs are summarized in Table 7.2.1-38.

Table 7.2.1-38
Sequence of Sulfur Caps for Highway and NRLM Fuel

	Highway Fuel	Non-Small Refiners		Small Refiners
		Nonroad Fuel	L&M Fuel	
June 1, 2006 - May 31, 2007	80 vol% 15 ppm 20 vol% 500 ppm	High Sulfur	High Sulfur	High Sulfur
June 1, 2007- May 31, 2010	80 vol% 15 ppm 20 vol% 500 ppm	500 ppm	500 ppm	High Sulfur
June 1, 2010 - May 31, 2012	15 ppm	15 ppm	500 ppm	500 ppm
June 1, 2012 - May 31, 2014	15 ppm	15 ppm	15 ppm	500 ppm
June 1, 2014 and beyond	15 ppm	15 ppm	15 ppm	15 ppm

In Section 7.2.1.3.3, we describe how we coupled refiners' projected highway fuel volumes with historic total distillate production fuel volumes and EIA future growth rates for highway and high sulfur distillate fuels to project each refinery's production of highway and high sulfur distillate fuel prior to this NRLM fuel program. The issue in this section is the steps which refiners have to take to produce 15 and 500 ppm NRLM fuel beyond this baseline to comply with the NRLM standards. The primary question answered in this section is whether they will be able to revamp an existing hydrotreater, or must build a new hydrotreater. For 15 ppm highway fuel, we basically assumed, as we did in the Final RIA for the 2007 highway fuel program, that 80 percent of 15 ppm highway fuel volume would be produced using revamped hydrotreaters. The remaining 20 percent would be produced with new, grass-roots units. The remainder of this section develops analogous projections for the production of 500 ppm and 15 ppm NRLM fuel during the various steps of the NRLM fuel program.

To facilitate this discussion, we divided refineries which are projected to produce some high sulfur distillate after 2010 into three categories:

1) "Highway" refineries: refineries which produce 95 percent or more of their total distillate production as 15 ppm highway diesel fuel;[BB]
2) "High Sulfur" refineries: refineries which produce 90 percent or more of their total distillate production as high sulfur distillate;
3) "Mix" refineries: refineries which produce some high sulfur distillate and which do not fall into categories one or two above.

Table 7.2.1-39 presents the percentages of high-sulfur distillate fuel production that falls in the categories described above. The number of refineries in each category is further broken down as to whether or not it currently has a distillate hydrotreater. This latter aspect is relevant to desulfurization costs as discussed in Section 7.2.1.3.2 above.

Table 7.2.1-39
Distribution of High-Sulfur Distillate Production (%) [a]

	High-Sulfur Refineries		Mixed Refineries Producing 15 ppm Highway Fuel in 2006		Mixed Refineries Producing 15 ppm Highway in 2010		Highway Refineries	
	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT
Number of Refineries	10	25	37	11	1	0	7	1
Percent of Nonroad Fuel	31	15	38	14	1	0	1	0

[a] " W/Dist HT" means refineries currently having a distillate hydrotreater
"No Dist HT means refineries that do not currently have a distillate hydrotreater

The next three sub-sections address how we project that each of these groups of refineries could produce either 500 or 15 ppm NRLM fuel. The final sub-section summarizes the results.

Highway Refineries: This category primarily includes refineries which are projected to produce 95 percent or more of their the No. 2 distillate fuel in 2010 to the 15 ppm highway standard prior to this NRLM rule. Refineries producing 100 percent highway fuel have no distillate fuel left from which to produce 500 or 15 ppm NRLM fuel. Thus, with one exception, they are ignored in this analysis. The exception is that the refiners' pre-compliance reports showed an excess supply of 15 ppm highway fuel in PADDs 1 and 3. Production of NRLM fuel by highway refineries presumed to supply this excess is addressed slightly differently below.

Refineries in this category produce a very small amount of high-sulfur distillate fuel compared with their volume of highway diesel fuel. This small volume of high-sulfur distillate fuel is likely either off-specification diesel fuel or opportunistic sales to the non-highway diesel

[BB] We also included a few refineries which project producing 15 ppm highway fuel in 2010, but whose highway fuel is not needed to fulfill highway fuel demand in 2010.

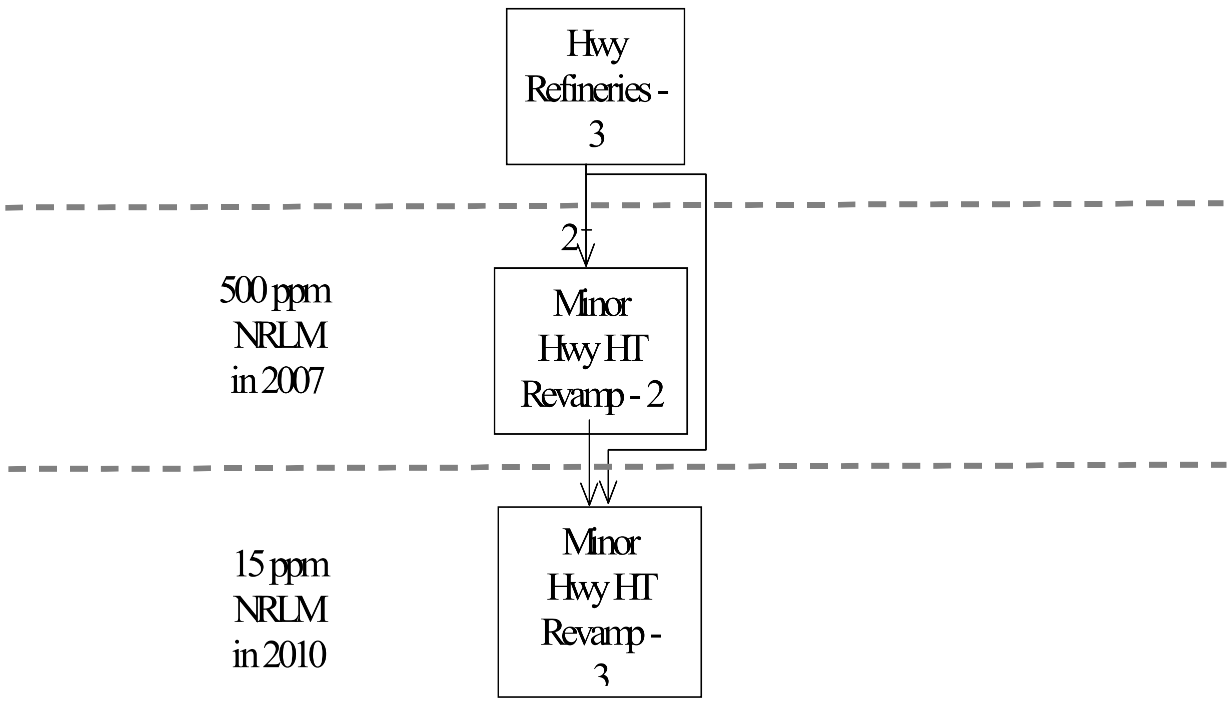
fuel market because of advantageous prices, market relationships, etc. Thus, we assumed that the refinery could incorporate this high-sulfur distillate into its highway hydrotreater design. The incremental capital cost assigned to the NRLM diesel fuel program was assumed to be the difference between the capital cost associated with a grass-roots hydrotreater sized to process all the refinery's distillate fuel and that for a grass-roots hydrotreater sized to treat just the highway diesel fuel volume. Thus, this approach assumed that the incremental cost of this small increase in capacity could occur at a high degree of economy of scale, but would also encompass the full cost of hydrotreating from uncontrolled levels to 7 ppm. We did this because it seems reasonable to assume that a refinery producing so much highway fuel would design its 15 ppm hydrotreater in such a way that it could be modified to process all the refinery's distillate. This is particularly true given the public attention given to the need for 15 ppm nonroad diesel fuel over the past few years.

This approach is applied to both the production of 500 and 15 ppm NRLM fuel. While incorporating the production of 500 ppm NRLM fuel into a 15 ppm highway fuel hydrotreater is not necessarily straightforward, the net effect of our assumption here is that roughly half the capital cost to produce 15 ppm NRLM fuel at these refineries is required to produce 500 ppm NRLM fuel. This seems reasonable. Also, this assumption only affects capital costs, not operating costs, as the latter are only a function of the distillate composition and refinery location (i.e., PADD).

As described in Section 7.2.1.3.3 above, the highway pre-compliance reports showed that an excess of 15 ppm fuel capacity was likely in PADD 3 in 2007. Thus, we assumed that this capacity could supply 500 ppm NRLM to PADDs 1, 2 and 3 through 2010 at a relatively low cost. To approximate these "low" costs we assumed that 500 ppm NRLM fuel could be produced by these hydrotreaters at the national average cost of the remainder of the 500 ppm NRLM fuel.

Figure 7.2-6 presents a flowchart of this process for highway refineries.

Figure 7.2-6
"Highway" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
Number in box equals number of refineries.

Mix Refineries: Mix refineries produce substantial volumes of both highway and high sulfur distillate fuels prior to the NRLM rule. Because of the substantial volumes of both fuels being produced, we assumed that the 15 ppm hydrotreater being used to produce highway fuel could not be revamped to incorporate production of 500 or 15 ppm NRLM fuel. Thus, with one exception, we assumed that the production of 500 ppm NRLM fuel by mix refineries would require would require a grass roots hydrotreater. The later production of 15 ppm NRLM fuel was assumed to be a revamp of this 500 ppm hydrotreater, given that the 500 ppm unit was designed knowing that the nonroad and L&M caps would soon be 15 ppm. Thus, with two exceptions, there are no presumed synergies between the highway and NRLM fuel programs for these refineries.

One exception to this assumption involved the way certain refineries are expected to produce their 15 ppm highway fuel. As described above, we project that 80 percent of 15 ppm highway fuel can be produced via a revamp of the existing highway fuel hydrotreater. The remaining 20 percent of highway fuel volume will be produced with a new grass roots hydrotreater. In these latter cases, the current highway hydrotreater will be available to produce 500 ppm NRLM fuel at no capital cost.

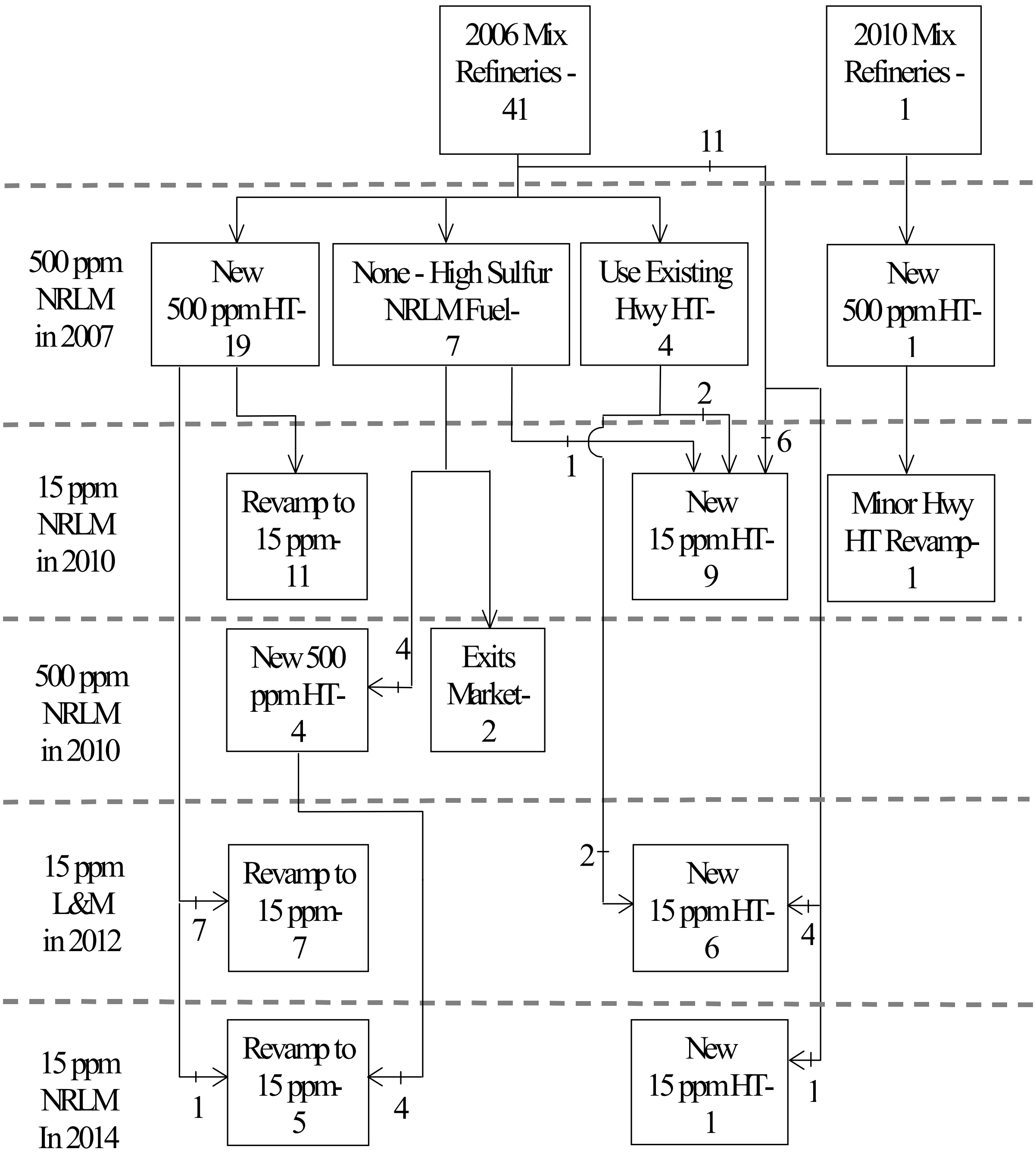
We did not attempt to identify the specific refineries which were likely to build a new grass roots hydrotreater for 15 ppm highway fuel production. This decision depends on many factors, most of which involve proprietary data. Thus, we assumed that 20 percent of the highway fuel from highway refiners and 20 percent of the highway fuel from mix refiners was being produced with a new grass roots unit. We assumed that 20 percent of the high sulfur distillate production from mix refiners could be produced with these hydrotreaters at no capital cost. Then in 2010 and 2012, new grass roots units would be required to produce 15 ppm nonroad and 15 ppm L&M fuel, as was assumed for the other mix refineries.

The other exception was a single refinery which projected that they would not begin producing 15 ppm highway diesel until 2010. In this case, there would be sufficient leadtime for these refineries to combine their plans to produce 15 ppm highway fuel with those to produce 15 ppm NRLM fuel.[CC] This provides an opportunity for economy of scale by combining both highway and NRLM fuel volumes in a single process unit, as well as affording an opportunity for the use of advanced desulfurization technology.

Figure 7.2-7 presents a flowchart of this process for mix refineries.

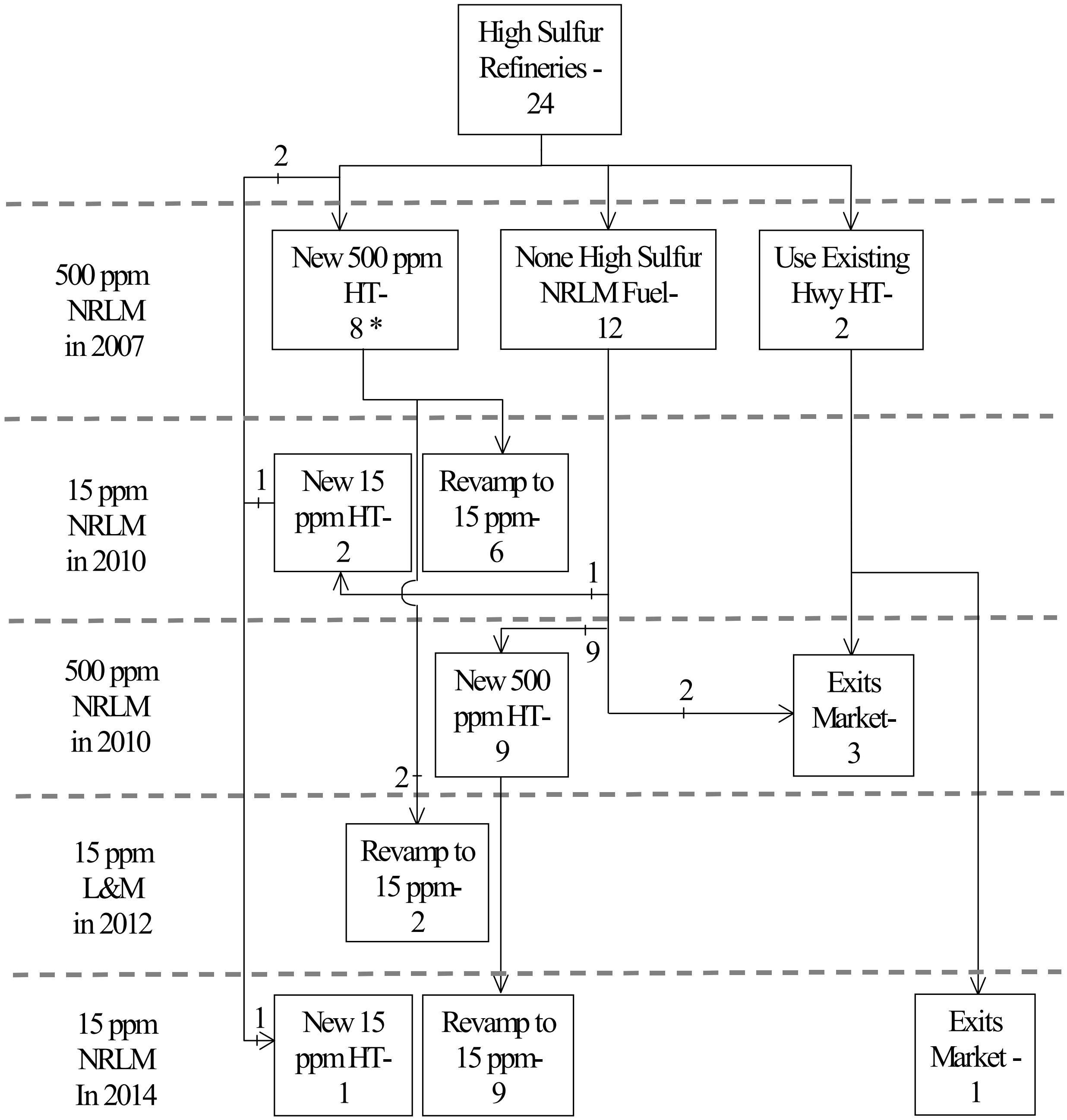
[CC] The calculation of incremental capital costs in this situation is not straightforward. We provided an example calculation below to better explain our methodology in Section 7.2.1.5.3 of the Draft RIA to this rule. The reader interested in the details of this calculation is referred to that discussion.

Figure 7.2-7
"Mix" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
L&M = Locomotive and Marine diesel fuel
Number in box equals number of refineries.

Figure 7.2-8
"High Sulfur" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
L&M = Locomotive and Marine diesel fuel
Number in box equals number of refiners.
* One refinery installs a new HT and also uses it's existing Highway HT to make 500 ppm fuel

High Sulfur Refineries: These refineries are projected to produce little or no 15 ppm highway fuel in 2010 in response to the 2007 highway diesel rule. Therefore, we assume that any 500 ppm NRLM fuel produced would require a grass-roots hydrotreater. The production of 15 ppm NRLM fuel was assumed to be a revamp of this 500 ppm hydrotreater, given that the 500 ppm unit was designed knowing that the nonroad and L&M caps would soon be 15 ppm. Thus, there are no presumed synergies between the highway and NRLM fuel programs for these refineries.

One exception to this approach is a set of three refineries which currently produce highway diesel fuel, but project in their pre-compliance reports to cease highway fuel production in 2006. Because they produce no highway fuel after 2006, by definition these refineries fall into the high sulfur refinery category. However, they clearly have the hydrotreating capacity to produce 500 ppm fuel up to their current highway fuel production. We assumed that this hydrotreating capacity was available at no capital cost to produce 500 ppm NRLM fuel in 2007. We also assumed that a grass roots hydrotreater would be needed to produce 15 ppm fuel in either 2010 for nonroad or for 2012 for L&M, as these refiners' decisions to leave the highway market likely indicated an inability to produce 15 ppm fuel via a revamp. As it turns out, only two of these three refineries had sufficient hydrotreating capacity from the highway hydrotreater to treat all their distillate production. Thus, we assumed that the third refiner would have to construct a new grass roots hydrotreater to produce 500 ppm NRLM fuel.

Figure 7.2-8 presents a flowchart of this process for high sulfur refineries.

We presume that these refineries must build a new hydrotreater in 2007 to desulfurize their current high-sulfur distillate to 500 ppm. However, due to the significant amount of lead time available, we project that these refiners can design a revamp to desulfurize all their distillate fuel to 15 ppm in 2010 or 2012 if they choose to do so.

Summary of Results: Overall, for the final NRLM fuel program, we project that 63 refineries will invest to make 15 NRLM diesel fuel by 2014. Table 7.2.1-40 summarizes the steps which we expect refineries affected by the NRLM rule to take in meeting the highway and NRLM sulfur caps in the relevant time periods. We have separated refineries into three categories, depending on the relative proportion of highway and high sulfur distillate fuel that they produce after the 2007 highway fuel program, but prior to this NRLM fuel rule.

Table 7.2.1-40
Interaction Between Compliance with the 2007 Highway and Final NRLM Fuel Programs:
Refiners Projected to Produce Some High Sulfur Distillate Fuel in 2007 Prior to the NRLM Fuel Program

Refineries that	Year and Fuel Control	Highway Refiners	Mix 2006 Refiners[a]			Mix 2010 Refiners[a]			High Sulfur Refiners[a]			Total
		Units	New Units	Revamp Units	None	New Units	Revamp Units	None	New Units	Revamp Units	None	
Modifications to comply with the 15 ppm Highway Standard (Baseline)*	2006	3	13(6)[a]	26								
	2010	0					1					
	Total	3	39			1			22			65
New Modifications to comply with NRLM Standards.	2007 500 ppm NRLM	2	19(2)	0	4	1(1)	0	0	8	0	2	36[b]
	2010 500 ppm NRLM	0	4(2)	0	0	0	0	0	9	0	0	13
	2010 15 ppm NR	3	9(1)	11(3)	0	0	0	1	2	6	0	32
	2012 15 ppm L&M	0	6(0)	7(0)	0	0	0	1	0	2	0	15
	2014 15 ppm NRLM	0	1(0)	5(2)	0	0	0	0	1	9	0	16

[a] Numbers in parentheses are a subset for each category and represent mix refineries that currently have no highway diesel fuel hydrotreater.
[b] Two high sulfur refiners use their "idled" hwy hydrotreater to make 500 ppm NRLM fuel and exit the NRLM market when the NRLM sulfur standard is lowered to 15 ppm.

As shown in Table 7.2.1-40, we project that 36 refiners would produce 500 ppm NRLM fuel in 2007. Of these 36 refineries:

- 28 will install new hydrotreaters
- 2 “highway” refiners would perform a relatively minor revamp to their highway distillate hydrotreaters, and
- 7 refineries could produce 500 ppm NRLM diesel fuel with an “idled” highway hydrotreater..

Twenty-six of the refineries that produce 500 ppm NRLM fuel have indicated that they will produce 15 ppm highway fuel in 2006 and are categorized as follows; twenty-three 2006 mix refineries, 2 highway refineries and one 2010 mix refinery. The seven refiners who use their “idled” treaters to produce NRLM are categorized as follows; four were projected to build a new hydrotreater to produce 15 ppm highway diesel fuel and will use their old highway treater to produce 500 ppm NRLM fuel. The other three refineries currently produce 500 ppm highway fuel, but indicated in their pre-compliance report that they would no longer produce highway diesel fuel starting in 2006. (Thus, these refineries were categorized as high sulfur refineries for the purpose of this analysis). One of these three refineries was also projected to install a new hydrotreater to process additional high sulfur distillate, as the capacity of their existing hydrotreater was not sufficient to process all their high sulfur distillate volume.

For all of the refineries using their “idled” highway unit, we used their operating cost to desulfurize each refineries high sulfur distillate to 500 ppm as the cost for complying with NRLM standard. Additionally, four refineries in PADD’s 1&3 were assumed to invest to fulfill supply shortfalls in PADD 2. We also assumed that excess hydrotreater capacity from the highway fuel program in PADD’s 1&3 is used to supply 500 ppm NRLM volume demand. This amounted to about 20 percent of the national NRLM demand.

In 2010, we project that 32 refineries will produce 15 ppm nonroad fuel while 26 refineries will produce 500 ppm NRLM (one refinery produces 15 ppm nonroad and 500 ppm L&M fuel). Thus, a total of 57 refineries produce NRLM fuel which is 21 more than produced 500 ppm NRLM fuel in 2007, despite the volume of fuels being similar. There are two reason for the additional refinery participation in 2010. One, the increase in the number of refineries affected is the availability of idled “highway” hydrotreaters for 500 ppm fuel production in 2007. The capacity of these hydrotreaters is relatively large, so a few of these refineries can produce a large volume of 500 ppm NRLM fuel in 2007. However, these refineries’ costs to produce 15 ppm is not always competitive with other refineries in their PADD. Thus, many of these refineries are not projected to produce 15 ppm nonroad fuel in 2010. Their volume of nonroad fuel is replaced by other refineries producing less volume per refinery. Two, small refineries invest to produce 500 ppm NRLM fuel due to the expiration of the small refiners provisions which allow high sulfur distillate to be sold to the 500 ppm NRLM market. Thus, the total number of refineries producing 15 nonroad fuel and 500 ppm L&M in 2010 increases.

In 2012, we project that an additional 15 refineries will invest to produce 15 ppm fuel when the L&M sulfur cap is lowered to 15 ppm. This is 15 additional refineries producing 15 ppm fuel than in 2010. Fifteen refineries continue to produce 500 ppm NRLM fuel.

In 2014, with the expiration of the small refiner provisions, and additional 16 refineries invest to produce 15 ppm NRLM fuel.

7.2.1.4 Summary of Cost Estimation Factors

This section presents a variety of costs, such as those for electricity and natural gas, as well as cost adjustment factors.

7.2.1.4.1 Capital Cost Adjustment Factors

Unit Capacity: The capital costs supplied by the vendors of desulfurization technologies apply to a particular volumetric capacity. We adjust these costs to represent units with lower or higher volumetric capacity using the "sixth tenths rule."[DD] According to this rule, commonly used in the refining industry, the capital cost of a piece of equipment varies in proportion to the ratio of the new capacity to the base capacity taken to some power, typically 0.6. This allows us to estimate how the capital cost might vary between refineries due to often large differences in the amount of distillate fuel they are desulfurizing.

Stream Day Basis: The EIA data for the production of distillate by various refineries are on a calendar basis. In other words, it is simply the annual distillate production volume of the period of interest divided by the number of days in the period. However, refining units are designed on a stream day basis. A stream day is a calendar day in which the unit is operational, or is expected to be operational. Refining units must be able to process more than the average daily throughput due to changes in day-to-day operations, to be able to handle seasonal difference in diesel fuel production and to be able to re-treat off-specification batches. The capital costs for the desulfurization technologies were provided on a stream day basis.

Actual refining units often operate 90 percent of the time, or in other words, can process 90 percent of their design capacity over the period of a year. However, when designing a new unit, it is typical to assume a lower operational percentage. We assumed that a desulfurization unit will be designed to meet its annual production target while operating only 80 percent of the time. This means that the unit capacity in terms of stream days must be 20 percent greater than the required calendar day production.

Off-site and Construction Location Costs: The capital costs provided by vendors do not include off-site costs, such as piping, tankage, wastewater treatment, etc. They also generally assume construction on the Gulf Coast, which are the lowest in the nation. Off-site costs are typically assumed to be a set percentage of the on-site costs.

[DD] The capital cost is estimated at this other throughput using an exponential equation termed the "six-tenths rule." The equation is as follows: $(Sb/Sa)^e \times Ca = Cb$, where Sa is the size of unit quoted by the vendor, Sb is the size of the unit for which the cost is desired, e is the exponent, Ca is the cost of the unit quoted by the vendor, and Cb is the desired cost for the different sized unit. The exponential value "e" used in this equation is 0.9 for splitters and 0.65 for desulfurization units (Peters and Timmerhaus, 1991).

The off-site cost factors and construction location cost factors used in this analysis were taken from Gary and Handewerk.[37] The offsite factors provided by Gary and Handewerk apply to a new desulfurization unit. Off-site costs are much lower for a revamped unit, as the existing unit is already connected to the other units of the refinery, utilities, etc. Thus, we reduced the off-site factors for revamped units by 50 percent.[38]

The off-site factors vary by refinery capacity, while the construction location factors vary between regions of the country.[39] In our analysis of the costs for the Tier 2 gasoline sulfur rule, we estimated the average of each factor for each PADD. There, all the naphtha desulfurization units were new units. Thus, the PADD-average off-site factors developed for that rule were simply divided by two to estimate PADD-average factors for revamped units here. The resulting factors are summarized in Table 7.2.1-41.

Table 7.2.1-41
Offsite and Construction Location Factors

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Offsite Factor					
- New Unit	1.26	1.26	1.20	1.30	1.30
- Revamped Unit	1.13	1.13	1.10	1.15	1.15
Construction Location Factor	1.5	1.3	1	1.4	1.2

Additional Capital Costs: There are also likely some capital costs associated with equipment not included in either the vendor's estimates, nor the general off-sites. Examples include expansions of the amine and sulfur plants to address the additional sulfur removed, a new sulfur analyzer. Additionally, there are other capital costs that occur due to unpredictable events, such as material and product price changes, cost data inaccuracies, errors in estimation and other unforseen expenses. In the NPRM, we accounted for these costs, by increasing the capital costs (after off-sites adjustment) by 18 percent. A factor of 15 percent is often used for this type of analysis.[40] However, we increased this factor to 18 percent to include the costs of starting up a new unit.[41]

We received comment that this factor was not sufficient to include the more sizeable increases in sulfur plant capacity associated with this NRLM sulfur control. In several recently developed fuel programs, such as the Tier 2 gasoline and 2007 highway diesel fuel programs, the sulfur reduction per gallon was only roughly 300 ppm. Here, the reduction is more than 3000 ppm. Therefore, the cost of expanded sulfur processing capacity was sufficient small in these previous programs to be appropriately accounted for within the 18 percent factor. In this rule, much more sulfur is being removed from the fuel in the form of hydrogen sulfide, which needs to be converted to elemental sulfur in the refinery. In Section 6.2 of the Summary and Analysis of Comments, we evaluated the cost of sulfur plant expansions and developed a new set of capital cost contingency factors which more appropriately account for these costs. These revised contingency factors are shown in Table 7.2.1-42 below.

Table 7.2.1-42
Final Capital Cost Contingency Factors (% of Hydrotreater Costs Including Off-Sites)

	Capital Contingency Factor for Debottleneck Sulfur Plant	Capital Contingency Factor for New Sulfur Plant
NRLM fuel Desulfurized from Uncontrolled Sulfur to 500 ppm Standard		
Conventional - New Unit	29	53
Process Dynamics - New Unit	34	69
NRLM fuel Desulfurized from Uncontrolled Sulfur to 15 ppm Standard		
Conventional - New Unit	22	38
Process Dynamics - New Unit	26	49
NRLM fuel Desulfurized from 500ppm to 15 ppm Standard		
Conventional - Revamped Unit	18	25
Conventional - New Unit *	17	21
Process Dynamics - Revamp Unit	18	31

* Current highway hydrotreater was used to produce 500 ppm NRLM Fuel

We applied the above contingency factors to each refinery depending on whether or not it had an existing sulfur plant. We obtained this information from the 2002 EIA Petroleum Supply Annual.

Capital Amortization: The economic assumptions used to amortize capital costs over production volume and the resultant capital amortization factors are summarized below in Table 7.2.1-43.[42] These inputs to the capital amortization equation are used in the following section on the cost of desulfurizing diesel fuel to convert the capital cost to an equivalent per-gallon cost.[EE]

Table 7.2.1-43
Economic Cost Factors Used in Calculating the Capital Amortization Factor

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0 %	7%	0.11
Capital Payback	10 Years	15 Years	39 %	6% 10%	0.12 0.16

The capital amortization scheme labeled Societal Cost is used most often in our estimates of cost made below. It excludes the consideration of taxes. The other two cost amortization schemes include corporate taxes, to represent the cost as the regulated industry might view it. The lower rate of return, 6 percent, represents the rate of return for the refining industry over the

[EE] The capital amortization factor is applied to a one-time capital cost to create an amortized annual capital cost that occurs each year for the 15 years of the economic and project life of the unit. This implicitly assumes that refiners will reinvest in desulfurization capacity after 15 years at the same capital cost, amortized annual cost, and amortized cost per gallon.

past 10 to 15 years. The higher rate of return, 10 percent, represents the rate of return expected for an industry having the general aspects of the refining industry.

7.2.1.4.2 Fixed Operating Costs

Operating costs based on the cost of capital are called fixed operating costs. These costs are termed fixed, because they are normally incurred whether or not the unit is operating or shutdown. Fixed operating costs normally include maintenance needed to keep the unit operating, building costs for the control room and any support staff, supplies stored such as catalyst, property taxes and insurance.

We included fixed operating costs equal to 6.7 percent of the otherwise fully adjusted capital cost (i.e., including offsite costs and adjusting for location factor and including the capital cost contingency) and this factor was adjusted upwards using the operating cost contingency factor.[43] The breakdown of the base fixed operating cost percentage is as follows:

Maintenance costs: 3 percent
Buildings: 1.5 percent
Land: 0.2 percent
Supplies: 1 percent
Insurance: 1 percent.

Annual labor costs were taken from the refinery model developed by the Oak Ridge National Laboratory (ORNL).[44] This model has often been used by the Department of Energy to estimate transportation fuel quality and the impact of changes in fuel quality on refining costs. Labor costs are very small, on the order of one thousandth of a cent per gallon.

7.2.1.4.3 Utility and Fuel Costs

Utility and fuel costs, which comprise the bulk of what is usually called variable operating costs, only accrue as the unit is operating and are zero when the unit is not operating. These costs are usually based on calendar day capacity and include utility and fuel costs associated with operating a hydrotreater. Additionally, we assign diesel product losses (diesel that is cracked to gas and gasoline) that occur during hydrotreating to the variable operating costs. These losses where described in Section 7.2.1.2 above along with the other aspects of conventional and IsoTherming hydrotreating technologies.

We received comments that the utility and fuels (primarily natural gas) prices did not reflect future prices that will likely exist due to the changing supply and demand balance for ths fuel. In the NPRM, we based future natural gas prices on the five year average price between 1995 and 2001. It now appears that the high natural gas prices existing over the past few years are likely to remain, at least to some degree. Prices have shifted from the $1.5-2.25 per mmBTU range existing during the 1990's to much higher levels.

Thus, for the final rule, we decided to base natural gas prices, as well as those for other fuels and utilities on EIA's price projections contained in their 2003 AEO. These price projections are based on long term economic modeling and consider various market impacts of supply and demand dynamics on fuels and utility prices, i.e. growth in GDP, known fuels regulations, costs of refining products, increased industrial uses, etc. AEO 2003 presents these prices for every year from 2000 to 2025. For simplicity, we chose to use 2014 as a reasonable approximation of the range of prices likely to occur throughout the period of this analysis. This is also the same year for which we project refinery fuel production volumes. Table 7.2.1-44 presents these AEO prices.

Table 7.2.1-44
Fuel and Utility Prices in 2014: 2003 AEO

	2003 AEO - Future Prices	
Fuel and Utility	Price	AEO Table No.
LPG	$35.49 per bbl	12
Gasoline	$1.406 per gallon *	12
Highway Diesel	$1.390 per gallon *	12
High Sulfur Diesel	$0.865 per gallon	12
Electricity	$0.0440 per kilowatt-hour	8
Natural Gas	$4.15 per mmBTU	3

* Includes excise taxes.

These fuel and utility prices represent national averages. The highway fuels include excise taxes. We removed these taxes in our analysis.[FF] Also, we desired to reflect differences in fuel and utility costs across the various PADDs. Therefore, we developed a methodology to adjust these national average prices to reflect this variability, while still producing the same national average price when re-averaged across the U.S.

To do this, we evaluated how prices (excluding taxes) varied by PADD in 2001. For LPG, gasoline and diesel fuels, this information was available by PADD. However, for natural gas and electricity, it was available by state. Thus, for these two fuels, we averaged the prices for all the states within each PADD. In all cases, we then assumed that these PADD-specific variations would be maintained in the future on a relative basis.

For LPG, motor gasoline and diesel fuels, we obtained prices (excluding taxes) from EIA's 2001 Petroleum Marketing Annual. Table 7.2.1-45 provides a summary of the specific places within the EIA 2001 report where we obtained the 2001 pricing information. Future prices were determined assuming that each PADD's price in 2001 would change in direct proportion to the change in the AEO national average price (including taxes) from 2001 to 2014. The results are presented in Table 7.2.1-45.

[FF] Table EN-1 EIA Petroleum Marketing Annual 2002.

Table 7.2.1-45
2001 Fuel Prices: Petroleum Marketing Annual: 2001 ($/gallon)

	LPG	Gasoline	Highway Diesel Fuel	High Sulfur Diesel Fuel
PMA Table No.	38 (Industrial Users)	31 (Sales for Resale)	41 (Sales for Resale)	41 (Sales for Resale)
PADD 1	0.626	0.862	0.768	0.761
PADD 2	0.589	0.898	0.829	0.820
PADD 3	0.502	0.814	0.742	0.730
PADD 4	0.588	0.943	0.875	0.851
PADD 5	0.658	1.003	0.826	0.794
National Avg.	0.556	0.888	0.794	0.771

We also obtained state-specific electricity prices and natural gas prices data from the EIA. Electricity prices were obtained from EIA's Electricity Power Annual, 2000 and 2001.[GG] Natural gas prices were obtained EIA's Natural Gas Navigator.[HH] In order to smooth out significant price volatility between various regions, we averaged electricity prices across two years (2000-2001) and averaged natural gas prices across 5 years (1997-2001). We estimated the average price for refineries in each PADD by weighting the state-specific prices by the volume of crude oil that refiners process in each state. This approach reflects geographic breakdown of the relative electricity and natural gas usage that would occur from additional hydrotreating. We obtained refinery raw crude throughput from EIA's 2001 Petroleum Supply Annual. We assumed that these historical PADD-specific price differentials would be maintained in the future. The PADD-specific historical prices for electricity and natural gas are summarized in Table 7.2.1-46.

[GG] Table 7.4 and Figure 7.7.

[HH] Industrial prices.

Table 7.2.1-46
Historical Fuel Prices: EIA

	Electricity (c/kW-hr)	Natural Gas ($ per mmBTU)
PADD 1	6.4	4.65
PADD 2	4.4	4.64
PADD 3	4.6	3.33
PADD 4	3.7	4.16
PADD 5	6.6	4.39
National Avg.	5.1	3.96

The national average fuel and utility prices shown in Table 7.2.1-47 below were then multiplied by the ratios of the historical PADD-specific differences to the historical national average price shown in Tables 7.2.1-45 and 7.2.1-46.

Finally, we assumed that steam was generated from natural gas at an efficiency of 50 percent.[45] We assumed that natural gas feedstocks costs dominated the overall cost, so that on a BTU basis steam cost twice that of natural gas. The steam cost per pound was estimated by dividing this cost per mmBTU by the heat content of steam at 300 psi (809 BTU per pound). The resultant PADD-specific future fuel and utility prices are shown in Table 7.2.1-47.

Table 7.2.1-47
Summary of 2014 Fuel and Utility Prices for Variable Operating Cost Estimations

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Electricity (cents per kilowatt-hour)	5.51	3.78	3.99	3.24	5.77
LPG (dollars per barrel)	20.98	19.74	16.82	19.71	22.05
Highway Diesel (cents per gallon)	79.1	85.4	76.4	90.1	85.1
Non-highway Diesel (cents per gallon)	72.4	78.1	69.5	81.1	75.6
Gasoline (dollars per barrel)	31.9	33.7	31.2	35.6	41.5
Steam (cents per pound @ 300 psi)	0.35	0.35	0.25	0.31	0.33
Natural Gas ($/Mmbtu)	4.9	4.8	3.5	4.4	4.6

* Prices using EIA's AEO 2003.

7.2.1.4.4 Hydrogen Costs

Hydrogen costs were estimated for each PADD based on the capital and operating costs of installing or revamping a hydrogen plant fueled with natural gas. The primary basis for these costs is a technical paper published by Air Products, which is a large provider of hydrogen to refineries and petrochemical plants.[46] The particular design evaluated was a 50 million scf/day steam methane reforming hydrogen plant installed on the Gulf Coast. The capital cost includes a 20 percent factor for offsites. The process design parameters from this paper are summarized in the Table 7.2.1-48.

Table 7.2.1-48
Process Design Parameters for Hydrogen Production *

Cost Component	Dollars per thousand standard cubic feet ($/MSCF)
Natural Gas	1.18
Utilities	
Electricity	0.03
Water	0.03
Steam	-0.07
Capital/Fixed Operating Charges	0.83
Total Product Cost	2.00

* Natural Gas @ $2.75/MMBTU; Steam @ $4.00/M lbs; Electricity @ $0.045 KWH

The estimates shown in Table 7.2.1-48 were adjusted to reflect natural gas and utility costs in each PADD (shown in Table 7.2.1-46). Changes in the value of steam production and the cost of water were ignored, as these costs are very small. The capital cost and fixed operating costs were increased by 8 percent to reflect inflation from 1998 to 2001.

We also adjusted the capacity of the hydrogen plant to reflect the capacity which would be typical for each PADD. The hydrogen plant capacity for PADD 3 represents the average of the existing hydrogen plants in the PADD and several third party units producing 100 million scf/day of hydrogen. For other PADDs, the average plant size was based on the average of refinery-based hydrogen plants within that PADD, obtained from the Oil and Gas Journal.[47] We incorporated PADD-specific offsite and construction location factors from Table 7.2.1-41, again assuming a 50-50 mix of new and revamped units. Table 7.2.1-49 summarizes the average plant size and the offsite and location factors for the installation of hydrogen plant capital for each PADD.

Table 7.2.1-49
Summary of Capital Cost Factors used for Estimating Hydrogen Costs by PADD

PADD	Capacity (million scf/day)	Offsite Factor	Construction Location Factor
1	15	1.19	1.5
2	34	1.19	1.3
3	65	1.15	1.0
4	19	1.38	1.4
5 Excluding CA and AK	15	1.23	1.2
Alaska	15	1.23	2.0

The adjusted hydrogen costs in each PADD are summarized in Table 7.2.1-50.

Table 7.2.1-50
Estimated Hydrogen Costs by PADD

PADD	Cost ($/1000 scf)
1	3.56
2	3.01
3	2.09
4	3.33
5 Excluding CA and AK	3.19
AK	3.97

7.2.1.4.5 Other Operating Cost Factors

Similar to the 15 percent contingency factor for capital costs, we included a 10 percent contingency factor to account for operating costs beyond those directly related to operating the desulfurization unit.[48] This factor accounts for the operating cost of processing additional hydrogen sulfide in the amine plant, additional sulfur in the sulfur plant, and other costs that may be incurred but not explicitly accounted for in our cost analysis. We then increased this factor by 2 percent to account for reprocessing of off-specification material (actual "off-spec" allowance is 1/2-1 percent). We adjusted the operating costs to account for as much as 5 percent of all batches to be re-processed. However, this is a conservative assumption for this cost analysis. Furthermore, since this material will have been desulfurized to a level close to the 15 ppm cap, the operating costs for reprocessing it should be much lower the second time around.

We also believe refinery managers will have to place a greater emphasis on the proper operation of other units within their refineries, not just the new diesel fuel desulfurization unit, to consistently deliver diesel fuel under the new standards. For example, meeting a stringent sulfur requirement will require that the existing diesel hydrotreater and hydrocracker units operate as expected. Also, the purity and volume of hydrogen coming off the reformer and the hydrogen plant are important for effective desulfurization. Finally, the main fractionator of the FCC unit must be carefully controlled to avoid significant increases in the distillation endpoint, as this can increase the amount of sterically hindered compounds sent to the diesel hydrotreater.

Improved control of each of these units may involve enhancements to computer-control systems, as well as improved maintenance practices.[49] Refiners may be able to recoup some or all of these costs through improved throughput. However, even if they cannot do so, these costs are expected to be less than 1 percent of those estimated below for diesel fuel desulfurization.[50] [51] No costs were included in the cost analysis for these potential issues.

7.2.1.5 Projected Use of Advanced Desulfurization Technologies

In Chapter 5, we projected the mix of technologies used to comply with a program being implemented in any year. This projection took into account the factors that affect the decisions by refiners in choosing a new technology. The projected mix of technologies for certain important years is summarized in Table 7.2.1-51 for the reader's benefit.

Table 7.2.1-51
Projected Use of Advanced Desulfurization Technologies for Future Years

	2007	2010	2012+
Conventional Technology	100	40	40
Process Dynamics Isotherming	0	60	60

7.2.2 Refining Costs

In this section, we present the refining costs for the final NRLM diesel fuel program. As described in Section 7.2.1, the costs to produce 500 ppm fuel were estimated using conventional technology, while those for 15 ppm fuel were projected using both conventional and advanced desulfurization technologies. All costs assume the economies of scale for the production of refineries projected to exist in 2014. Each refinery's projected costs consider their projected production of highway diesel fuel under the 2007 highway fuel program, as well as estimates of its distillate blendstock composition and location (i.e., PADD). Per gallon refining costs assume a 7 percent before tax rate of return on capital. The sensitivity of these costs to 6 percent and 10 percent after tax rates of return are also evaluated.

The refining costs for the 15 ppm sulfur cap on highway diesel fuel are presented first. While the determination of most of the refineries projected to produce highway fuel was made using the refiners' highway fuel pre-compliance reports, additional highway fuel was needed in PADDs 4 and 5. This was determined using the projected refinery-specific costs of producing 15 ppm fuel. As these costs incorporate several updates since the publication of the Final RIA for the 2007 highway diesel rule, we thought it appropriate to summarize these updated costs here.

The next section presents refining costs for the final NRLM fuel program. First, the overall costs of the program are summarized. Then, refining costs for the four main time periods of the program are presented: 1) 2007-2010, 2) 2010-2012, 3) 2012-2014, and 4) 2014 and beyond. All of these costs are based on NRLM fuel production volumes expected to exist in 2014, the mid-point of the life of desulfurization equipment built in 2007. All per gallon costs presented in this section are then applied to the volume of NRLM diesel fuel actually being desulfurized under the final fuel program. These costs would not apply to NRLM diesel fuel already meeting highway diesel fuel sulfur standards (i.e., spillover fuel).

In addition, we also present refining costs for a number of sensitivity cases:

1) Increasing the rate of return on capital to 6-10 percent after taxes,
2) No assumed use of advanced desulfurization technology,
3) A long term 500 ppm cap for NRLM fuel (i.e., no subsequent 15 ppm cap),
4) Nonroad fuel at 15 ppm and locomotive and marine fuel at 500 ppm indefinitely, and
5) The final NRLM fuel program with lower NRLM fuel demand.

Finally, we present the stream of capital costs which would be required by the NRLM fuel program, in the context of other environmental requirements facing refiners in the same timeframe, due to the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program.

7.2.2.1 15 ppm Highway Diesel Fuel Program

The refining costs associated with compliance with the 15 ppm highway diesel cap were estimated for 2006 and 2010. As the methodology used to project these costs differs somewhat from that used in the Final RIA for the 2007 highway diesel rule, the costs presented here also differ and represent an update to those costs. The projected costs for producing 15 ppm highway diesel fuel are summarized in Table 7.2.2-1.

Table 7.2.2-1
Highway Diesel Desulfurization Costs to Meet a 15 ppm Cap Standard
($2002, 7% ROI before taxes)*

	Refineries Initially Producing 15 ppm Fuel in: 2006	2010	All Refineries
Number of Refineries	96	4	100
15 ppm Fuel Production (million gal/yr in 2014)	53,495	2,022	55,517
Total Capital Cost ($Million)	6,060	120	6,180
Average Capital Cost per Refinery ($Million)	63.1	30.9	61.8
Average Operating Cost per Refinery ($Million/yr)	15.3	10.6	15.1
Total Cost (c/gal)	4.0	3.2	4.0

* Includes impact of highway fuel that is down graded in the distribution system.

As can be seen, we project that 96 refiners will invest to produce 15 ppm highway fuel in 2006, with a total capital cost of $6.06 billion ($63.1 million per refinery). The average cost to produce 15 ppm highway diesel fuel is 4.0 cents per gallon. These costs assume that all the 15 ppm fuel is being produced using conventional hydrotreating.

We project that 4 additional refineries will invest to produce 15 ppm highway diesel fuel in 2010, as the temporary compliance option expires. The required capital cost will be $120 million ($30.9 million per refinery). The average cost for 15 ppm fuel newly produced in 2010 is 3.2 cents per gallon, which is 0.8 cents lower than 15 ppm fuel first produced in 2006. The use of advanced technology acts to lower the cost of refiners initially entering the market in 2010. Additionally, 3 of the 4 refineries entering in 2010 desulfurize their high sulfur distillate and existing highway diesel volume in a single hydrotreater, resulting in lower costs due to economies of scale.

Overall, 100 refineries produce the 15 ppm diesel fuel under the 2007 highway diesel fuel program, with a total capital cost of $6.18 billion ($61.8 million per refinery). The average refining cost in 2010 will be 4.0 cents per gallon of fuel.

7.2.2.2 Costs for Final Two Step Nonroad Program

The final NRLM fuel program requires that NRLM fuel meet a 500 ppm sulfur cap in 2007, with a further reduction to 15 ppm in 2010 for nonroad and 2012 for L&M. Small refiners have until 2010 to meet the 500 ppm cap, and until 2014 to meet the 15 ppm cap for NRLM fuels. However, “small refiner” fuel cannot be sold in a designated region basically comprising the Northeast and Mid-Atlantic regions. Small refiners can also choose to produce NRLM fuel which meets the above standards on time and sell “credits” to other refiners, who can then sell NRLM fuel under the delayed standards. Also, 15 ppm fuel which is contaminated during distribution and still meets a 500 ppm cap can be sold to the NRLM market through 2014, and to the locomotive and marine fuel markets indefinitely.

In this section, we first present an overall summary of the costs of the entire final NRLM fuel program. Then we present in greater detail the refining costs for the four distinct time periods of the final NRLM fuel program: 1) the 500 ppm NRLM cap in 2007, 2) the 15 ppm nonroad cap and 500 ppm L&M cap in 2010 (and 500 ppm cap for small refiner nonroad fuel), 3) 15 ppm NRLM cap in 2012 (and 500 ppm ppm cap for small refiners), and 4) the 15 ppm NRLM diesel fuel program in 2014. Following these presentations, we present projected costs for the various sensitivity cases.

Overall, for the final NRLM fuel program, we project that 63 refineries will invest to make 15 NRLM diesel fuel by 2014. A summary of the projected refining costs for the various steps in the final NRLM fuel program is presented in Table 7.2.2-2.

Table 7.2.2-2
Number of Refineries and Refining Costs for the Final NRLM Program

	Year of Program	500 ppm Fuel		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36[a]	0	0	0
	2010-2012	26	13	32	2
	2012-2014	15	13	47	2
	2014-2020	0	0	63	15
Production Volume (Million gallons per year in 2014)	2007-2010	13,327	0	0	0
	2010-2012	3,792	393	8,598	335
	2012-2014	728	393	12,247	335
	2014-2020	0	0	13,030	728
Refining Costs (c/gal)	2007-2010	1.9[a]	0	0	0
	2010-2012	2.7	3.7	5.0	5.2
	2012-2014	2.9	3.7	5.6	5.2
	2014-2020	0	0	5.8	6.9

[a] In 2007-10, refinery counts do not include 500 ppm NRLM fuel from excess capacity in 15 ppm highway hydrotreaters, and a few idled highway hydrotreaters. However, refining costs do include this fuel.

As can be seen, the per gallon cost of producing 500 ppm and 15 ppm diesel fuels throughout the various phases of the NRLM fuel program will be 1.9-2.9 and 5.0-5.8 cents, respectively. We project that the cost of the 500 ppm cap for small refiners will be 3.7 cents per gallon, or 28 percent greater than that for the average refiner. We project that the cost of the 15 ppm cap for small refiners will be 6.9 cents per gallon, or 19 percent greater than that for the average refiner. Table 7.2.2-3 presents a summary of the capital and annual costs for average and small refiners.

Table 7.2.2-3
Refining Costs for the Final NRLM Program Fully Implemented in 2014
($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	63	15
Total Refinery Capital Cost ($Million)	2,280	250
2007	310	0
2010	1,170	150
2012	590	0
2014	210	100
Average Refinery Capital Cost ($Million)	36.2	16.7
Average Refinery Operating Cost ($Million/yr)	8.1	2.2

As can be seen, total capital costs would be $2,280 million for the entire final 15 ppm NRLM fuel program (average of $36.2 million per refinery). Total capital costs for the 15 small refineries would be $250 million (average of $16.7 million per refinery).

7.2.2.2.1 Refining Costs in Year 2007

We project that 36 refiners would produce 500 ppm NRLM fuel in 2007. The cost of the 500 ppm NRLM cap in 2007 is summarized in Table 7.2.2-4 below.

Table 7.2.2-4
Refining Costs in 2007 for 500 ppm NRLM Diesel Fuel
($2002, 7% ROI before taxes)[a]

	All Refineries
Number of Refineries	36
Total Refinery Capital Cost ($Million)	310
Average Refinery Capital Cost ($Million)	8.6
Average Refinery Operating Cost ($Million/yr)	4.9
Amortized Capital Cost (c/gal)	0.3
Operating Cost (c/gal)	1.6
Cost Per Affected Gallon (c/gal)	1.9

We project that the total capital cost will be $310 million (an average of $10.3 million for each of the 30 refineries actually building new equipment). The total refining cost for the 500 ppm NRLM diesel fuel sulfur cap is 1.9 cents per gallon of affected fuel volume, including both operating and amortized capital costs.

7.2.2.2.2 Refining Costs in Year 2010

We project that 32 refineries will produce 15 ppm nonroad fuel in 2010. This is four fewer refineries than produced 500 ppm NRLM fuel in 2007, as some refineries continue to produce 500 ppm L&M fuel. The total refining costs to produce 15 ppm nonroad fuel in 2010 are presented in Table 7.2.2-5. Separate costs are shown for all refineries, refineries not owned by small refiners, and for those owned by small refiners.

Table 7.2.2-5
Total Refining Costs in 2010 for 15 ppm Nonroad Diesel Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refinery
Number of Refineries	32	30	2
Incremental Capital Cost ($Million)	1,090	1,030	59
Average Refinery Capital Cost ($Million)	34	32.2	30
Average Refinery Operating Cost ($Million/yr)	9.0	8.7	10.8
Capital Cost (c/gal)	1.6	1.6	1.9
Operating Cost (c/gal)	3.4	3.4	3.3
Cost Per Affected Gallon (c/gal)	5.0	5.0	5.2

The incremental capital cost in 2010 to produce 15 ppm nonroad fuel is $1,090 million. The average cost of producing 15 ppm nonroad diesel fuel is 5.0 cents per gallon. This is 3.1 cents per gallon more than the average cost to produce 500 ppm NRLM fuel in 2007. This incremental cost of 3.1 cents per gallon is lower than the 4.0 cent per gallon cost estimated above for the 15 ppm highway diesel fuel cap. This difference is due to several factors which have opposing impacts. There are three factors that tend to increase the cost of 15 ppm nonroad fuel compared to that of 15 ppm highway fuel. One, the vast majority of relatively inexpensive hydrocrackate was assumed to used in the highway diesel pool. Two, refiners projecting to produce 15 ppm highway fuel based on pre-compliance report data and cost projections tend to be those that face lower costs (greater economies of scale, low LCO fractions, etc.). Three, 80 percent of current 500 ppm highway fuel hydrotreaters assumed to be revamped to produce 15 ppm diesel fuel, while the figure is lower for nonroad fuel. While we project that all the new hydrotreaters built in 2007 to produce 500 ppm NRLM fuel can be revamped to 15 ppm fuel production, we assume that none of the existing highway hydrotreaters producing 500 ppm NRLM fuel in 2007 can be revamped to produce 15 ppm fuel. This lowers the overall revamp percentage to less than 80 percent. However, balancing these factors is our projection that a significant percentage of refiners will use the Process Dynamics and other advanced desulfurization technologies in 2010, versus 2006 when the vast majority of 15 ppm highway fuel will first be produced. This one factor essentially compensates for the other three factors in the other direction.

As implied in Table 7.2.2-5, most small refiners participating in the NRLM fuel market produced 500 ppm NRLM fuel in 2010. However, two small refiner's costs for producing 15 ppm fuel were competitive with the other refineries in producing sufficient volumes of fuel to satisfy market demand. These small refiners were assumed to sell their credits to non-small refineries, allowing them to produce 500 ppm nonroad fuel in 2010.

A significant volume of 500 ppm nonroad fuel will also be produced in 2010 under the small refiner provisions. The remaining 500 ppm fuel production is for the L&M fuel market. The costs of producing 500 ppm diesel fuel in 2010 are presented in Table 7.2.2-6.

Table 7.2.2-6
Refining Costs in 2010 for 500 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries in 2010	Non-Small Refineries in 2010	Small Refineries in 2010
Number of Refineries	26	13	13
Total Refinery Capital Cost ($Million)	197	107	90
Average Refinery Capital Cost ($Million)	7.6	8.3	6.9
Average Refinery Operating Cost ($Million/yr)	3.7	6.7	0.8
Capital Cost (c/gal)	0.5	0.3	1.9
Operating Cost (c/gal)	2.2	2.3	2.1
Cost Per Affected Gallon (c/gal)	2.7	2.6	3.7

We project that 26 refineries will produce 500 ppm NRLM fuel in 2010 at an average cost of 2.7 cents per gallon. Thirteen of these refineries are owned by small refiners and are the only refineries that newly invest in 2010 for new hydrotreaters to produce 500 ppm fuel. Thirteen non-small refineries who produce 500 ppm NRLM fuel in 2007 would continue to produce 500 ppm NRLM fuel in 2010. Two of these non-small refiners produce 500 ppm fuel using credits generated by small refiners producing 15 ppm nonroad fuel in 2010. The small refiners per gallon costs are 37 percent more than the average of refiners producing fuel in 2010. The costs for refiners that enter the market in 2010 are lowered by the non-small refineries.

7.2.2.2.3 Refining Costs in Year 2012

In 2012, L&M fuel produced or imported must meet a 15 ppm cap. However, 500 ppm fuel produced during the distribution of cleaner fuels can be sold to the NRLM markets which reduces the volume of fuel that must be desulfurized to a 15 ppm standard. Additionally, the provisions that allow small refiners to sell 500 ppm fuel into the NRLM markets also continue. The cost of producing 15 ppm NRLM fuel in 2012 is shown in Table 7.2.2-7.

Table 7.2.2-7
Total Refinery Costs in 2012 to Produce 15 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	47	45	2
Total Refinery Capital Cost ($Million)	1,980	1,920	59
Average Refinery Capital Cost ($Million)	42.1	42.7	30
Average Refinery Operating Cost ($Million/yr)	9.6	9.8	5.5
Capital Cost (c/gal)	1.8	1.8	1.9
Operating Cost (c/gal)	3.8	3.8	3.3
Cost Per Affected Gallon (c/gal)	5.6	5.6	5.2

We project that 47 refineries would produce 15 ppm NRLM fuel, or 15 more than in 2010. The total refining cost measured from today's high sulfur level would be 5.6 cents per gallon, or 0.6 cent per gallon more than in 2010. Small refineries would have average cost of 5.2 cents per gallon, or 7 percent lower than the average non-small refineries.

The 15 ppm costs for the 15 refineries first producing 15 ppm L&M in 2012 are presented in Table 7.2.2-8. All of these 15 refineries are non-small refineries and have an incremental capital investment of $590 million. The average cost of producing 15 ppm L&M diesel fuel is 7.3 cents per gallon. This is 5.4 cents per gallon more than the average cost to produce 500 ppm NRLM fuel in 2007. This incremental cost of 5.4 cents per gallon is higher than the 4.0 cent per gallon cost estimated above for the 15 ppm highway diesel fuel cap. As mentioned for the 2010 15 ppm nonroad costs, several factors tend to increase the cost to desulfurize NRLM fuels to a 15 ppm standard compared to that of 15 ppm highway fuel. The incremental desulfurization costs are higher for L&M fuel because a large portion of the lowest cost refiners were selected to invest in 2010 for 15 ppm nonroad fuel production leaving higher costs refiners producing L&M and high sulfur distillate fuels. Thus in 2012, L&M 15 ppm fuel is produced from these remaining refineries with higher desulfurization costs.

Table 7.2.2-8
Refining Costs for 15 ppm L&M Fuel for Refiners Initially Complying in 2012
($2002, 7% ROI before taxes)

	All Refineries (Non-small)
	Total
Number of Refineries	15
Incremental Refinery Capital Cost ($Million)	590
Average Refinery Capital Cost ($Million)	39.1
Average Refinery Operating Cost ($Million/yr)	11.5
Capital Cost (c/gal)	1.9
Operating Cost (c/gal)	5.1
Cost Per Affected Gallon (c/gal)	7.0

Of the 15 additional refineries producing 15 ppm L&M fuel in 2012, six will install a new grass roots hydrotreater as they did not invest to make 500 ppm L&M fuel prior to this time. The remaining 9 refineries will revamp their new nonroad hydrotreater built in 2007 or 2010. The average refinery that produces 15 ppm L&M diesel fuel for the first time in 2012 will make a capital investment of $39.1 million.

7.2.2.2.4 Refining Costs in Year 2014

In 2014, all NRLM diesel fuel produced must meet a 15 ppm cap. Additionally in 2014, the provisions allowing 15 ppm fuel that is downgraded to 500 ppm sulfur level in the distribution system to be sold to the nonroad fuel market expire, though this fuel can continue to be sold into the locomotive and marine market. Thus, the volume of 15 ppm NRLM diesel fuel produced increases over the total volume of 15 and 500 ppm NRLM fuel produced in 2010. The cost of producing 15 ppm NRLM fuel in 2014 is shown in Table 7.2.2-9.

Table 7.2.2-9
Total Refinery Costs in 2014 to Produce 15 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	63	48	15
Total Refinery Capital Cost ($Million)	2,280	2,030	250
Average Refinery Capital Cost ($Million)	36.2	42.5	16.5
Average Refinery Operating Cost ($Million/yr)	8.1	10.6	2.2
Capital Cost (c/gal)	1.9	1.7	3.1
Operating Cost (c/gal)	3.9	4.0	3.8
Cost Per Affected Gallon (c/gal)	5.8	5.7	6.9

We project that 63 refineries would produce 15 ppm NRLM fuel, or 16 more than in 2010. The total refining cost measured from today's high sulfur level would be 5.8 cents per gallon, or 0.2 cent per gallon more than in 2010. Small refineries would have an average cost of 6.9 cents per gallon, or 19 percent higher than the average non-small refineries.

The 15 ppm costs for the 16 refineries first producing 15 ppm nonroad fuel in 2014 are presented in Table 7.2.2-10. The incremental capital investment for these 16 refineries in 2014 was $210 million. Of this $210 million, $100 million will be spent by small refiners.

Table 7.2.2-10
Refining Costs for 15 ppm NRLM Fuel for Refiners Initially Complying in 2014
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
	Total	Total	Total
Number of Refineries	16	3	13
Total Refinery Capital Cost ($Million)	300	110	190
Average Refinery Capital Cost ($Million)	18.9	36.9	14.6
Average Refinery Operating Cost ($Million/yr)	4.5	16.5	1.7
Capital Cost (c/gal)	2.4	1.4	3.9
Operating Cost (c/gal)	5.2	5.8	4.0
Cost Per Affected Gallon (c/gal)	7.6	7.2	7.9

Of the 16 additional refineries producing 15 ppm NRLM fuel in 2014, 13 are owned by small refiners. Two of the 16 refineries will install a new grass roots hydrotreater as they did not invest to make 500 ppm NRLM fuel prior to this time. The remaining 14 of 16 refineries will revamp their new nonroad hydrotreater built in 2007 or 2010. The average refinery that produces 15 ppm nonroad diesel fuel for the first time in 2014 faces a capital investment of $18.9 million, while the investment for the average small refiner is smaller at $14.6 million.

7.2.2.3 Refining Costs for Sensitivity Cases

7.2.2.3.1 Total Refining Costs at Different Rates of Return on Investment

The costs presented in the previous section all assumed a 7 percent before tax rate of return on investment. We also estimated total refining costs for the final NRLM fuel program using two alternative rates of return on investment: 1) 6 percent per year after taxes, and 2) 10 percent per year after taxes. The 6 percent rate is indicative of the economic performance of the refining industry over the past 10-15 years. The 10 percent rate is indicative of economic performance of an industry like refining which would attract additional capital investment. The total per gallon cost of producing 15 ppm NRLM fuel in 2014 using all three rates of return are shown in Table 7.2.2-11.

Table 7.2.2-11
Refining Costs in 2014 for 15 ppm NRLM Fuel in 2014 (cents per gallon, $2002)

Societal Cost: 7% ROI before Taxes	5.8
Capital Payback: (6% ROI, after Taxes)	6.1
Capital Payback: (10% ROI, after Taxes)	6.9

As can be seen, the difference in the assumed rate of return on investment increases the societal cost by 0.3-1.1 cents per gallon.

7.2.2.3.2 15 ppm Nonroad Diesel Fuel with Conventional Technology

The use of advanced technology is expected to reduce the cost of producing 15 ppm diesel fuel compared to conventional hydrotreating. To determine the sensitivity of our cost estimates to the level of advanced technology projected, we developed costs for producing 15 ppm NRLM diesel fuel with only the use of conventional hydrotreating. We did not vary the specific refineries projected to produce 15 ppm NRLM fuel in 2014 from those described in the previous section. Total refining costs to produce 15 ppm NRLM diesel fuel in 2014 using conventional technology are shown in Table 7.2.2-12.

Table 7.2.2-12
Total Refining Costs in 2014 to Produce 15 ppm NRLM Diesel Fuel
with Conventional Technology ($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	63	15
Total Refinery Capital Cost ($Million)	2,730	290
Average Refinery Capital Cost ($Million)	42.7	19.2
Average Refinery Operating Cost ($Million/yr)	10.6	2.6
Capital Cost (c/gal)	2.2	3.7
Operating Cost (c/gal)	4.9	4.5
Cost Per Affected Gallon Cost (c/gal)	7.1	8.2

The total cost to produce 15 ppm nonroad diesel fuel in 2014 with conventional technology would be 7.1 cents per gallon, or 22 percent higher than the 5.8 cent per gallon cost with a mix of conventional and advanced technology. Total capital costs would be $2,730 million with conventional technology, about 20 percent higher than the $2,286 million investment including use of advanced technology (see Table 7.2-40). Operating costs would be 16 percent higher with conventional technology, $10.0 million as compared to $8.6 million with use of advanced technology. The same relative comparisons apply to the impact of advanced technology on the capital costs faced by small refiners. All of these figures represent the total cost of producing 15 ppm diesel fuel from high sulfur diesel fuel.

7.2.2.3.3 Proposed Two Step NRLM Program: Nonroad Fuel to 15 ppm in 2010 and Locomotive and Marine at 500 ppm Indefinitely

This section presents the refining costs of the NRLM program which EPA proposed: nonroad fuel at 15 ppm and locomotive and marine fuel at 500 ppm. The refining impacts of this program are shown in Tables 7.2.2-13.

Table 7.2.2-13
Refining Impacts for the Proposed Two Step NRLM Fuel Program [a]
15 ppm Nonroad Fuel in 2010 and 500 ppm Locomotive and Marine Fuel Indefinitely

	Year of Program	500 ppm Fuel [b]		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries[a]	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36	0	0	0
	2010-2014	26	13	32	2
	2014+	20	8	40	7
Refining Costs (c/gal)	2007-2010	1.9	0	0	0
	2010-2014	2.7	3.7	5.0	5.2
	2014+	2.7	3.0	5.2	7.0

[a] Includes small refiners.

[b] In 2007-10, refinery counts do not include 500 ppm NRLM fuel from excess 15 ppm highway hydrotreaters, and a few idled highway hydrotreaters. However, refining costs do include this fuel. One refiner produces 15 & 500 ppm fuel.

Under this sensitivity case, we project that 59 refineries would eventually invest to make either 15 ppm nonroad or 500 ppm locomotive and marine fuel by 2014. The total cost of producing 500 ppm NRLM fuel in 2007 is the same as that under the final NRLM program, as the two programs are identical. In 2014, the cost of 500 ppm locomotive and marine fuel would be 2.7 cents per gallon, or sightly higher than the range for 500 ppm NRLM fuel under the final NRLM program (1.9-2.4 cents per gallon).

The total cost for producing 15 ppm fuel in this program are lower than the final NRLM program costs (5.8 cents per gallon in 2014). Less volume of 15 ppm fuel is produced and the incremental per gallon costs are less than the final programs per gallon cost. This lowers the average cost.

Table 7.2.2-14 presents a side-by-side comparison of some of the key refining impacts of the proposed and final NRLM fuel programs.

Table 7.2.2-14
Refining Costs for Two Step Program with 500 ppm Locomotive and Marine fuel versus Final NRLM Program ($2002, 7% ROI before taxes)

	Two Step Program with 15 ppm Nonroad Fuel and 500 ppm Locomotive and Marine Fuel		Final NRLM program	
	All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries	60	15	63	15
Total Refinery Capital Cost ($Million)	1,680	180	2,280	250
2007	310	0	310	0
2010	1,240	140	1,170	150
2012	0	0	590	0
2014	130	40	210	100
Average Refinery Capital Cost ($Million)	28.5	12.1	36.2	16.7
Average Refinery Operating Cost ($Million/yr)	6.8	1.6	8.1	2.2

Overall, the 15 ppm cap on locomotive and marine fuel in our final NRLM fuel program increases total capital investment by $600 million and increases the cost of the incremental volume of L&M fuel by 5.2 cents per gallon (from 2.7 to 7.9 cents per gallon). Table 7.2.2-15 presents the incremental refining impacts of the 15 ppm cap on locomotive and marine fuel over those of the 500 ppm cap.

Table 7.2.2-15
Refinery Impacts in 2014 for a 15 ppm Versus 500 ppm Cap on Locomotive and Marine Fuel ($2002, 7% ROI before taxes)

	All Refineries
Number of Affected Refiners	23
Total Incremental Capital, $MM	600
Incremental Fuel Cost 500ppm to 15 ppm, (c/gal)	5.2
Total Fuel Cost , (c/gal)	7.9

The 5.2 cent per gallon cost to reduce L&M fuel sulfur from 500 to 15 ppm is higher than the 3.5 cent per gallon cost for nonroad fuel, because we assumed that the refiners facing the lowest desulfurization costs would produce 15 ppm nonroad fuel, if L&M fuel sulfur remained at 500 ppm. Thus, 15 ppm L&M fuel is produced from the remaining refineries that are projected to face higher desulfurization costs.

7.2.2.3.4 Refining Costs for a 500 ppm NRLM Only Program

This section presents refining costs for a long-term 500 ppm cap on NRLM fuel (i.e., no subsequent 15 ppm cap). We evaluated costs in 2010, after any small refiner provisions would have expired. These costs are summarized in Table 7.2.2-16.

Table 7.2.2-16
Refining Costs for a Stand-alone 500 ppm NRLM Diesel Fuel Standard
($2002, 7% ROI before taxes)[a]

	All Refineries	Nonsmall Refineries	Small Refineries
Number of Refineries	57	41	16
Total Refinery Capital Cost ($Million)	480	360	120
Average Refinery Capital Cost ($Million)	8.4	8.8	7.7
Average Refinery Operating Cost ($Million/yr)	3.6	4.7	1.0
Capital Cost (c/gal)	0.4	0.3	1.5
Operating Cost (c/gal)	1.6	1.6	1.7
Cost Per Affected Gallon (c/gal)	2.0	1.9	3.2

[a] Equivalent to the costs of the 500 ppm NRLM cap in 2010 without the 15 ppm nonroad cap.

The overall refining cost of a 500 ppm NRLM fuel cap would be 2.0 cents per gallon. We project that 57 refineries would produce this fuel with a total capital investment of $480 million. On average, the refining cost for small refiners would be about 60 percent higher than that of non-small refiners at 3.2 cents per gallon.

7.2.2.3.5 EIA-Based Demand for NRLM Fuel

In Chapter 2 of the Summary and Analysis of Comments, we discuss the uncertainty in current and future demand for NRLM fuel, particularly that used in land-based nonroad equipment. While we base our primary cost estimates on fuel demands as predicted by EPA's NONROAD emission model, we decided to evaluate the sensitivity of both costs and benefits to an alternative level of fuel demand. Here, we present the refining costs assuming that the EIA-based fuel demands are more accurate than those from NONROAD.

The total refining costs to produce 500 and 15 ppm NRLM diesel fuel from 2007-2014 for the two sets of fuel demands are summarized in Table 7.2.2-17.

Table 7.2.2-17
Total Refining Costs of NRLM Fuel from 2007-2014 With Varying Fuel Demands
(Cents per gallon, $2002, 7% ROI before taxes)

	EIA-Based Fuel Demand	EPA NONROAD Fuel Demand
500 ppm NRLM fuel: 2007-2010	1.9	1.9
500 ppm NRLM fuel: 2010-2012	2.8	2.7
500 ppm NRLM fuel: 2012-2014	3.0	2.9
15 ppm Nonroad fuel: 2010-2012	5.0	5.0
15 ppm NRLM fuel: 2012-2014	5.6	5.6
15 ppm NRLM fuel: 2014+	5.7	5.8

As can be seen, reducing NRLM fuel demand has little impact on per gallon refining costs. The only differences shown are a slight increase in 500 ppm costs from 2010-2014 and a slight decrease in 15 ppm fuel costs after 2014. The former effect occurs because the incremental 500 ppm NRLM fuel volume is coming from relatively low cost Gulf Coast refineries. While the same effect exists in 2014 with respect to 15 ppm fuel costs, the effect of the reduced demand in reducing costs in other refining areas is larger. Table 7.2.2-18 provides a more detailed breakdown of the final refining impacts of the 15 ppm NRLM cap in 2014 for the two sets of fuel demands.

Table 7.2.2-18
Refining Impacts of 15 ppm NRLM Fuel in 2014 With Varying Fuel Demands
($2002, 7% ROI before taxes)

	EIA-Based Fuel Demand	*EPA NONROAD Fuel Demand*
# of Refiners	55	63
Total Refinery Capital Cost ($Million)	1,870	2,280
Average Capital Cost ($Million)	33.9	36.2
Operating Cost ($Million/yr)	7.5	8.1
Capital Cost (c/gal)	1.9	1.9
Operating Cost (c/gal)	3.8	3.9
Cost Per Gallon (c/gal)	5.7	5.8

As the EIA-based methodology reduces NRLM fuel demand, only 55 refineries would invest to produce NRLM fuel in 2014 versus 63 using the EPA NONROAD Model estimates. The total 15 ppm NRLM fuel cost would be 5.7 cents per gallon, or 0.1 cents per gallon less than that to satisfy NONROAD fuel demand. Total capital costs would be $1,870 million, or about 18 percent less than the $2,280 million investment needed to produce the additional fuel volume.

7.2.2.4 Capital Investments by the Refining Industry

Refiners must raise capital to invest in new desulfurization equipment to produce the 500 ppm and 15 ppm diesel fuel which would be required under the final NRLM fuel program. The previous sections estimated the total capital cost associated with the final and various sensitivity cases. Refiners expend this capital over a several year period prior to the time which the new equipment must be used. This section estimates how much capital would have to be expended in specific years under the final and alternative programs. These yearly expenditures are then added to those required by other fuel quality programs being implemented in the same timeframe and compared to historic capital expenditures made by the refining industry.

Two fuel quality regulations are being implemented in the same timeframe as this NRLM fuel program: The Tier 2 gasoline sulfur program and the 2007 highway diesel fuel sulfur program. 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 promulgated in the rule.[II] The 2007 highway diesel rule modified that phase in schedule by provided certain refiners more time to meet the Tier 2 gasoline sulfur standards. In the 2007 highway diesel rule, we projected the stream of capital investments required by the U.S. refining industry for both the modified Tier 2 standards and the 15 ppm highway diesel fuel sulfur program. We updated the allocation and amount of capital expenditures for the highway diesel rule to reflect when each refiner would invest. The new total capital costs for the 2007 highway diesel fuel program are discussed in section 7.2.2.1 above. In projecting the stream of capital expended for a particular project, we assume 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 stream of projected capital investment related to the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program rule are shown in Table 7.2.2-19.

[II] 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. Adjusted to 2002 dollars using Chemical Engineering Plant Cost Index.

Table 7.2.2-19
Capital Expenditures for Gasoline and Highway Diesel Fuel Desulfurization
($Billion, $2002)[a]

Calendar Year	Tier 2 Gasoline Sulfur Program	2007 Highway Diesel Program	Total
2002	1.76		1.76
2003	1.15		1.15
2004	0.88	1.82	2.70
2005	0.61	3.03	3.64
2006	0.16	1.21	1.37
2007	0.06		0.06
2008	0.06	0.43	0.49
2009	0.02	0.71	0.73
2010		0.28	0.28

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

The two diesel fuel programs have implementation dates of June 1 of various years for fuel leaving the refinery. For this start up date, we assumed that 30 percent of the capital cost was expended in the calendar year two years prior to start up, 50 percent was expended in the year prior to start up and the remaining 20 percent was expended in the year of start up. We repeated this analysis for the final NRLM program. The results are summarized in Table 7.2.2-20 below.

Table 7.2.2-20
Capital Expenditures for the Final NRLM Fuel Program with
Tier 2 Gasoline Sulfur and 2007 Highway Diesel Fuel Programs
($Billion, $2002)

Calendar Year	Final NRLM Fuel Program		
	Tier 2 and Highway Diesel	NRLM Program	Total[a]
2002	1.76		1.76
2003	1.15		1.15
2004	2.70		2.70
2005	3.64	0.09	3.75
2006	1.37	0.16	1.53
2007	0.06	0.06	0.12
2008	0.49	0.35	0.84
2009	0.73	0.59	1.32
2010	0.28	0.41	0.69
2011		0.29	0.29
2012		0.18	0.18
2013		0.11	0.11
2014		0.04	0.04

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

As can be seen, capital investments peak in 2005 for the Tier 2 and Highway diesel programs. The final NRLM program increases this peak by just $90 million, or about 2 percent. Thereafter, capital requirements drop dramatically but peak a second time in year 2009 due to the 15 ppm highway and nonroad standard. The second peak is less than 36 percent of the capital outlays that occur in year 2005. Considering all programs, when capital investment requirements are the highest, they are caused by the Tier 2 gasoline sulfur and 2007 highway diesel fuel programs. Compared to Tier 2 and the hwy diesel program, the capital investment requirements for the final NRLM fuel program are much smaller and are more spread out over time.

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.[JJ] Total capital investment by refiners for other purposes was in the $2-3 billion per year range during this time frame. API estimates somewhat higher capital investments for environmental purposes, with peaks of about $3 billion in 1992-1993.[KK] Based on these two sources, during the early 90's, the US refining industry invested over 20 billion dollars in capital for environmental controls for their refining and marketing operations, representing about one half of the total capital expenditures made by refiners for operations.

The capital required for the Tier 2 gasoline, 2007 highway diesel fuel and the final NRLM fuel program is about 73 percent of the historic peak level of investment for meeting environmental programs experienced during 1992-1994.[52] Additionally, most of the capital outlays for all of the about mentioned fuels programs are spread out over an eight year time period. Given that the capital required by the final NRLM fuel program contributes less than 2 percent to the required investment in the peak year of 2005, we do not expect that the industry would have difficulty raising this amount of capital, although we recognize that it does require the need to continue to raise and devote capital over a longer period of time.

7.2.2.5 Other Cost Estimates for Desulfurizing Highway Diesel Fuel

Two other studies have estimated a cost of producing 15 ppm NRLM fuel, one by Mathpro and another by Baker and O'Brien (BOB). These two studies are discussed below.

Mathpro: For the Engine Manufacturers Association and with input by the American Petroleum Institute, Mathpro used a notional refinery model to estimate the national average costs of desulfurizing nonroad diesel fuel after implementation of the 15 ppm standard for highway diesel fuel. The cost estimate from this study is presented here and compared with our costs.

In a study conducted for the EMA, MathPro, Inc. first estimated the cost of desulfurizing diesel fuel to meet a 15 ppm highway diesel fuel sulfur standard followed by two-step nonroad standards of 500 ppm and 15 ppm.[53, 54] MathPro assumed that desulfurization will occur entirely with conventional hydrotreating, and refining operations and costs were modeled using their ARMS modeling system with technical and cost data provided by Criterion Catalyst Company LP, Akzo-Nobel Chemicals Inc., and Haldor Topsoe, Inc. The Mathpro refinery model estimated costs based on what Mathpro terms a "notional" refinery. The notional refinery is configured to be typical of the refineries producing highway diesel fuel for PADDs 1, 2, and 3, and also represent the desulfurization cost for those three PADDs based on the inputs used in the refinery model. The Mathpro notional refinery model maintained production of highway diesel fuel at their base levels.

[JJ] "The Impact of Environmental Compliance Costs on U.S. Refining profitability," EIA, May 16, 2003.

[KK] U. S. Petroleum Refining, Assuring the Adequacy and Affordability of Cleaner Fuels, A Report by the National Petroleum Council, June 2000.

Mathpro made several estimates in their study to size their diesel desulfurization units for estimating the capital cost, and these estimates were similar to those included in our methodology. The calendar day volume was adjusted to stream day volume using a 10 percent factor to account for variances in day-to-day operations, and another 10 percent to account for variance in seasonal demand. In addition, Mathpro applied a factor that falls somewhere in the range of 1 to 8 percent for sizing the desulfurization unit larger for reprocessing off-spec material to meet different sulfur targets. Since meeting a 500 ppm standard is not very stringent, Mathpro likely assumed that a desulfurization unit will be sized larger by 1 to 4 percent. For meeting the 15 ppm standard, which is relatively stringent compared with the 500 ppm sulfur level studied, Mathpro likely assumed the desulfurization unit would be sized larger by 5 to 8 percent. On-site investment was adjusted to include offsite investment using a factor of 1.4. In the final report, capital costs were amortized at a 15 percent after-tax rate of return.

The Mathpro cost study analyzed the costs to comply with the highway program based on 5 different investment scenarios. Before deriving the best nonroad desulfurization cost estimate using the Mathpro cost study, we must describe the various investment scenarios. The titles of the scenarios are listed here:

1. No Retrofitting - Inflexible
2. No Retrofitting - Flexible
3. Retrofitting - De-rate/Parallel
4. Retrofitting - Series
5. Economies of Scale

Scenarios 1 and 2 do not allow retrofitting, which means the existing highway diesel hydrotreater must be removed from service and a new grassroots unit desulfurizing untreated distillate down to under 15 ppm takes its place. The difference between scenarios 1 and 2 is that scenario 1 does not allow some flexibilities that may be available to the refining industry. One flexibility is that the volume of hydrocracker units is not limited to the used capacity as listed in the 1997 API/NPRA survey, but instead the throughput can be as much as 8 percent higher, which is half the available capacity available in the API/NPRA survery. Another flexibility is that jet fuel exceeds specifications and instead of limiting the qualities to current levels, they are instead allowed to become heavier by 0.5 API or by 3 points on the E375 distillation curve and stay within the jet fuel specifications. Allowing jet fuel to get heavier allows the refinery model to bring some of these lighter jet fuel blendstocks into the highway diesel fuel pool, which lowers the desulfurization cost. The flexibilities are allowed in the rest of the scenarios as well.

Scenarios 3 and 4 allow taking advantage of the existing highway desulfurization unit by keeping it in place and installing additional capital including additional reactor volume, which allows the combined used and new capital to achieve the 15 ppm standard.
The difference between scenarios 3 and 4 is that Scenario 3 derates the existing hydrotreater, which reduces the volume treated by that unit so it can achieve 15 by itself; another unit being fed by a low throughput is then added in parallel, which allows it to meet the 15 ppm standard. Scenario 4 installs the new capital in series with the existing hydrotreater with both units handling the entire feed rate.

Scenario 5 allows the debottlenecking of existing capacity to treat a larger volume while producing the same specifications. Scenario 5 also allows a single unit to be installed to handle the desulfurization of multiple refineries in refining centers, which provides an important economy of scale for the desulfurization investment costs to that group of refineries.

While these various investment scenarios were devised to show how different investment scenarios affect the cost for the HD2007 rule, they have implications for the nonroad rule as well. For meeting the standard for nonroad diesel fuel of 500 ppm, the used highway units freed up in Scenarios 1 and 2 can thus be converted over to nonroad service, which dramatically reduces the capital cost of compliance; this supplements the existing nonroad capacity. However, for Scenario 2, the installed grassroots capacity installed for the HD2007 rule decreased after the capital was already installed and a larger volume of existing hydrotreating capacity removed from highway desulfurization service was put into place to supplement the nonroad hydrotreating capacity already in place. For Scenario 3, the needed nonroad capacity is formed by adding grassroots capacity. For Scenario 4, the necessary nonroad hydrotreating capacity is formed by increasing the existing unit capacity used, relying on some expansion of existing units and adding some processing unit capacity in series with existing capacity. The nonroad hydrotreating capacity for meeting the 500 ppm standard is realized for Scenario 5 similar to Scenario 4, except no expansion of existing units occurs, but instead more capacity from existing highway units is relied upon.

For meeting the 15 ppm cap sulfur standard for nonroad diesel fuel, the refinery model invested in nonroad capital either along the same lines as the 500 ppm case, or else invested much differently. For Scenario 1 and 2, the refinery model installed grassroots units only, even replacing some existing hydrotreating capacity that was likely being used for some mild desulfurization of nonroad diesel fuel. For Scenario 2, the volume of grassroots desulfurization capacity was slightly lower than Scenario 1, probably due to the increased flexibility granted by the refinery model. For Scenario 3, the refinery model added some new grassroots unit capacity compared with the 500 ppm case, probably derating the capacity of the remaining 500 ppm and new 500 ppm capacity. For Scenario 4, the refinery model added more series unit capacity and more expansion capacity. Finally for Scenario 5, the refinery model increased the series processing unit capacity and added some expansion capacity.

The new or existing hydrotreating capacity used for meeting the 500 ppm and 15 ppm nonroad standards incremental to meeting the highway 15 ppm sulfur standard is shown in Table 7.2.2-21.

Table 7.2.2-21
Mathpro Capital Investments (bbl/day) for Desulfurizing Highway and Nonroad Diesel Fuel

		No Retr Inflex	No Retr Flex	Retr De-rate	Retr Series	Econ of Scale
Reference Case	Existing Cap	34.9	34.9	34.9	34.9	34.9
Highway 15 ppm Cap Std	Existing Unit	8.2	8.2		31.1	31.1
	Expansion					
	De-rated			17.8		
	Series Unit			15.4	29.4	29.4
	Grassroot Unit	30.2	29.3			
Nonroad Meeting a 500 ppm Standard	Existing Unit	16.5	19.4		35.0	38.0
	Expansion				2.9	
	De-rated			17.8		
	Series Unit				34.1	34.0
	Grassroot Unit	30.1	27.6	23.7		
Nonroad Meeting a 15 ppm Standard	Existing Unit				35.0	38.0
	Expansion				4.9	1.9
	De-rated			17.8		
	Series Unit				39.1	39.1
	Grassroot Unit	50.4	49.3	26.5		

We next determined which Mathpro case best approximated the investment scenarios we are using in our 500 ppm cost analysis, but we will summarize first summarize how our cost model estimates investments will occur. As described earlier in this section, some refineries will comply with the highway HD2007 rule in 2006 by putting in a new hydrotreater and thus idling an existing hydrotreater (i.e., 20 percent of the mixed highway and nonroad refineries that have a distillate hydrotreater and comply with the highway requirements in 2006). Other refiners have said that they will exit the highway market altogether, thus freeing up their existing 500 ppm treater. We believe that the refineries exiting the highway market would use these treaters to desulfurize NRLM diesel fuel. Adding up the volumes from these two sources of existing hydrotreating capacity, we estimate that 30 percent of NRLM will be desulfurized with existing hydrotreaters. Furthermore, we estimated that 39 percent of NRLM fuel is already hydrotreated and blended into high sulfur distillate. We project that this hydrotreating will continue with the use of existing hydrotreaters. Thus, the fraction of NRLM diesel fuel meeting the 500 ppm sulfur standard in 2007 with the use of existing capital is expected to be 69 percent. The balance of the NRLM volume, which comprises 31 percent, is expected to be desulfurized with a new hydrotreater installed for startup in 2007.

We examined the Mathpro investment cases to match the investment scenarios in our cost analysis. There were no cases that matched our scenario exactly, but we found two Mathpro cases that, together, roughly matched our investment scenario. The first is the No Retrofit Inflexible case, which met the nonroad requirements exclusively through using existing capacity (with half of it already in place before the standard applied, which matches our investment scenario). The second case is the Retrofitting Derating case, which met the nonroad requirements through new capital investment. Our analysis for complying with the 500 ppm sulfur standard was based on 69 percent of the nonroad volume being produced by refineries using existing hydrotreaters and 31 percent with new units, so the Mathpro costs were weighted 69 percent No Retrofit Inflexible costs and 31 percent Retrofit DeRate costs.

We then examined the Mathpro 15 ppm cases to determine which would best match our 15 ppm scenario. Since we already described the Mathpro cases for estimating the incremental cost for going from meeting the 500 ppm standard to meeting the 15 ppm sulfur standard, we needed identify the case which best matches our 500 ppm to 15 scenario. As discussed earlier in this section, our 15 ppm scenario has new nonroad diesel fuel hydrotreating units being installed in 2010. Since we estimated that 31 percent of the volume of NRLM in 2007 is complied with using new units, we project that 31 percent of the NRLM diesel fuel would meet the 15 ppm sulfur by revamping their new 2007 treaters. The balance of the NRLM volume are projected to comply with the 15 ppm standard with grassroots units which are installed to desulfurize uncontrolled distillate fuel down to 15 ppm, with an operating cost credit for the uncontrolled to 500 ppm step. Of the Mathpro cases summarized above, the first two cases, which don't allow revamps and either allow or don't allow operational flexibility, install grassroots units for obtaining the 15 ppm standard. We decided to use Mathpro's case one, since the second Mathpro case apparently allowed backsliding in the highway grassroots units needed for complying with the HD2007 rule when the 500 ppm standard was being met, which we don't think is possible because the highway investments will be too far along before the nonroad program is finalized.

Case one, however, needed to be adjusted to better model our projections on how refiners would invest. Mathpro's case one was associated with the replacement of the existing hydrotreating capacity, all of which was likely used by the refinery model for desulfurizing nonroad down to 500 ppm. However, we believe 31 percent of the existing nonroad desulfurization capacity can be revamped instead of having to be replaced. Thus, we adjusted the Mathpro capital costs to remove 31 percent of the grassroots hydrotreating capacity which we believe would be revamped instead. We accomplished this by estimating what percent of the capital costs is necessary for complying with 15 ppm standard and which portion was necessary for replacing the expected portion of existing nonroad desulfurization capital. The nonroad diesel fuel volume needed to be treated in Mathpro's notional refinery model is 9 thousand barrels per day. According to Mathpro, the capital needed to be installed to treat the nonroad pool down to 15 ppm is increased by 10 percent to handle peak throughput rates, and then by another 10 percent to handle peak seasonal rates and then by another 8 percent to handle reprocessing of off-spec batches. Thus, the 9,000 barrels per day nonroad volume is increased to about 11,800 barrels per day, which represents Mathpro's estimated capital capacity. We subtracted 11,800 bpd from the total volume of grassroots capacity added, which was 20,300 bpd, to yield a total of 8,500 barrels per day of replaced capital capacity; we assumed this will be untreated to 500 ppm nonroad hydrotreated capacity. Since we projected that 69 percent of this existing capacity to be replaced, with the 31 percent being new units in 2007 and not replaced, we maintained 69 percent of 8,500 bpd, or an additional 5,865 barrels of the new nonroad hydrotreating capacity. We therefore maintained 17,665 bpd of the original 20,300 bpd of additional capacity added in Mathpro case one. To estimate a revised cost for Mathpro's case one we multiplied the capital charge by a ratio of 17,665/20,300. No adjustment was necessary for the variable operating cost.

In addition to the differences and adjustments as described above, there are several other differences between our cost analysis and the cost analysis made by Mathpro that were adjusted or deserve mentioning. First, the MathPro costs as reported in their final report are based on a 15 percent return on investment (ROI) after taxes. As stated above, our costs are calculated based on a 7 percent ROI before taxes, so to compare our cost analysis with the cost analysis made by Mathpro, we adjusted the Mathpro costs to reflect the rate of return on capital investment that we use. Second, the MathPro estimate includes a cost add-on (called an ancillary cost) for reblending and reprocessing offspec diesel fuel or for storing nontreated diesel fuel. While this is conceptually an appropriate adjustment to estimate the cost to the refining industry, it appears that some of the reblending costs in the MathPro study appear to be transfer payments,[LL] not costs. We did not include these costs in our cost comparison. Third, MathPro assumed that all new hydrogen demand is met with new hydrogen plants installed in the refinery, which does not consider the advantage of hydrogen purchased from a third party that can be produced cheaper in many cases. As a result, their hydrogen cost may be exaggerated, which would tend to increase costs. In fact, Mathpro's hydrogen is priced at $3.60 per million standard cubic feet ($/MSCF). However the hydrogen costs in our analysis is about $2.70 per MSCF. Finally, we note that the MathPro study took into consideration the need for lubricity additives, but did not address costs that might be incurred in the distribution system. When we compared out costs with Mathpro's, we did not include any costs that would be incurred in the distribution system not even lubricity additive costs. For comparing the aggregate capital costs, the Mathpro aggregate capital costs for the chosen cases were adjusted using the undesulfurized nonroad, locomotive, and marine diesel fuel volumes for 2007 and for undesulfurized nonroad diesel fuel for 2010. The undesulfurized volumes we used for making the adjustments are presented in Section 7.1. A comparison of Mathpro's costs and our costs to desulfurize highway diesel fuel to meet a 500 ppm sulfur standard and then a 15 ppm sulfur standard is shown below in Table 7.2.2-22.

[LL] A transfer payment is when money changes hands, but no real resources (labor, natural resources, manufacturing etc.) are consumed.

Table 7.2.2-22
Comparison of Mathpro's and EPA's Refining Costs for Meeting a
500 ppm and a 15 ppm Nonroad Diesel Fuel Sulfur Standard
(7% ROI before taxes, no lubricity additive costs nor distribution costs included)

Fuel Standard	Type of Cost	Mathpro's Costs	EPA's Costs	
		No Advanced Tech	Advanced Tech in 2010	No Advanced Tech
500 ppm Cap Std.	Per-gallon Cost (c/gal)	2.1	2.2	2.2
	Total Capital Cost (billion$)	580	310	310
15 ppm Cap Std. Incremental to 500 ppm Std. *	Per-gallon Cost (c/gal)	3.9	3.6	4.9
	Total Capital Cost (billion$)	2300	1970	2420
Uncontrolled to 15 ppm	Per-gallon Cost (c/gal)	6.0	5.8	7.1
	Total Capital Cost (billion$)	2870	2280	2730

* Fully phased-in costs in 2014

Baker and O'Brien Study: The Baker and O'Brien (BOB) study was conducted for API to estimate the costs and supply impacts of two possible NRLM fuel control programs. BOB first estimated how refiners would respond to future diesel fuel requirements absent any NRLM fuel controls. These requirements included EPA's 2007 highway fuel program and the California and Texas fuel programs.[MM] This was referred to as the Base Case in the report. The two NRLM fuel programs evaluated were:

1) Study Case- One step NRLM fuel program:
   15 ppm cap for all NRLM fuel in 2008

2) Sensitivity Case- Two step NRLM fuel program:
   500 ppm cap for all NRLM fuel by 2008
   15 ppm cap for nonroad fuel in 2010

BOB initiated their study prior to the NPRM, so they did not know exactly what NRLM fuel program would be proposed. Their two cases were designed to bracket what they believed were likely possible proposals. As it turns out, the final NRLM fuel program reflects portions of both cases. The final NRLM fuel program is a two step program, like the sensitivity case. The final 15 pm cap applies to all NRLM fuel like the study case, though in the final NRLM fuel program, significant volumes of NRLM fuel can be 500 ppm fuel resulting from contamination in the distribution system.

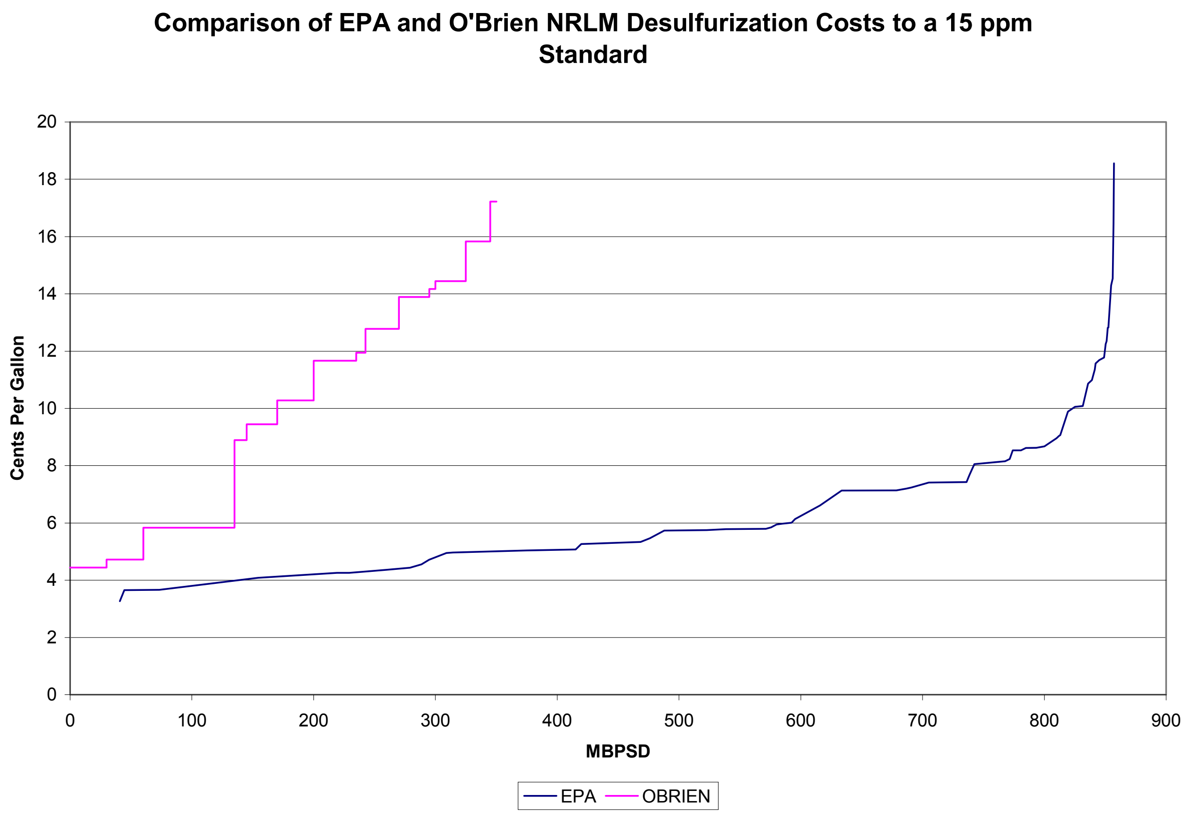
[MM] BOB assumed that refiners producing diesel fuel for Texas would have to produce the same fuel as currently being produced in California. In addition, they assumed that 100 percent of highway fuel sold in both states would have to meet a 15 ppm cap starting in mid-2006.

The fuel supply impacts of the BOB study are addressed in Section 4.6.3.1 of the Summary and Analysis of Comments document. The focus here is on their projected cost to produce low sulfur NRLM fuel. BOB did not estimate the cost of producing 500 ppm NLRM fuel under the Sensitivity Case. They only stated that roughly 300,000 bbl per day of 500 ppm diesel fuel could be produced essentially for free from idled highway hydrotreaters. This is very similar to our findings in Section 7.2.1 above. The primary difference is that we only consider the capital cost to be free, since these hydrotreaters would not be operated (i.e., zero operating cost) absent this NRLM fuel program.

BOB developed cost estimates for 15 ppm NRLM fuel, but not for 15 ppm fuel produced under the highway program. BOB did not use projected costs per gallon of producing 15 ppm fuel to predict which refineries would likely produce 15 ppm fuel under either the highway or NRLM programs. Instead, as outlined in their report, BOB made first assumed that refiners would defer USLD capital investment whenever they had a reasonable alternative, such as selling heating oil or exporting high sulfur diesel fuel. BOB also assumed that some refiners would not be able to raise or justify the capital expenditures for ULSD and would discontinue operations. In addition, BOB predicted that a sizeable number of domestic refineries would close as a result of the highway and NRLM fuel programs. As a result of these assumptions, BOB projected that domestic refiners would only produce 200,000-300,000 bbl per day of 15 ppm NRLM fuel out their estimated demand of 700,000 bbl per day.

BOB presented their cost estimates for 15 ppm NRLM for both the study and sensitivity cases. As the study case most closely approximates the fully implemented final NRLM program, we chose to compare our fully implemented NRLM costs to those of BOB's study case. As BOB only presented per gallon costs graphically, we present both sets of cost estimates in graphical form in Figure 7.2.2.5-1.

Figure 7.2.2-8-1



As mentioned above, BOB projects relatively little 15 ppm NRLM fuel production compared to demand, and compared to that projected by EPA. From the BOB report, the difference in volume is caused by sizeable exports of high sulfur distillate from coastal refineries and a number of refinery shutdowns in the Midwest and Mountain regions of the U.S. From the information provided in the report, we cannot determine which refineries were projected to export or close. Therefore, we cannot perform any more precise comparison of per gallon costs than that provided in Figure 7.2.2.5-1. From this comparison, it is quite possible that BOB and EPA are projecting roughly similar costs for many individual refineries. In this case, the difference between the two cost curves would be the removal of a number of larger refineries with EPA-projected costs in the 4-8 cent per gallon range. This would compress the EPA cost curve into something more like the BOB cost curve. Even with this assumption, it appears that BOB is projecting that some refineries with NRLM production volumes of 10-15,000 bbl per day have costs in the 10-17 cent per gallon range. While above 10 cents per gallon, all the refineries in the EPA analysis have very small NRLM production volumes.

While BOB does not present any further detail regarding their per gallon costs, they do provide additional detail regarding their capital and operating costs. Regarding capital costs, BOB's projected capital investments by domestic refiners are summarized in Table 7.2.2-23.

Table 7.2.2-23
BOB and EPA Capital Cost of Desulfization

	Capital Investment ($ billion)	Production Volume (1000 bbl per day) *	Investment per bbl/day production
BOB			
Highway	7.15	2934	$2437
15 ppm NRLM (Study Case)	0.55	208	$2644
EPA			
Highway	6.18	3605	$1714
15 ppm NRLM	2.28	841	$2711

* BOB volumes are in 2010, EPA volumes are in 2014

The primary figures is this table that we want to focus on are those in the last column, which show the capital cost to add one barrel per day of 15 ppm fuel production capacity. As can be seen, BOB projects significantly higher costs for 15 ppm highway fuel. This is likely due to different assumptions regarding the probability that refiners will be able to revamp their existing 500 ppm hydrotreater to produce 15 ppm fuel. However, this difference will not be discussed further, as the cost of 15 ppm highway fuel is not the focus of this comparison.

Moving to NRLM fuel, BOB's estimated capital cost for 15 ppm NRLM fuel production are within a few percent of EPA's projection on a per barrel of production basis. BOB assumes that all refiners will use conventional hydrotreating technology to produce 15 ppm highway and NRLM fuel. EPA projects that roughly 60 percent of the volume of 15 ppm NRLM fuel produced will utilize advanced technology for the step from 500 ppm to 15 ppm. This would tend to reduce EPA's projected capital costs relative to those of BOB. However, our capital costs include the cost of new hydrogen plants and expanded sulfur plant capacity. BOB treated hydrogen as a utility and simply included the full cost of producing hydrogen (operating plus capital costs) in the price that refiners would have to pay. This difference would tend to increase our capital costs relative to those of BOB. Finally, BOB's source of capital costs was a study by the National Energy Technology Laboratory for EIA. NETL used many of the same sources which we cite in Section 7.2.1 for the capital cost of conventional hydrotreating. However, NETL increased their capital cost projections from these sources by 33 percent, based on discussions with refiners. (The details of these discussions were not provided, so no comment can be made about the appropriateness of this adjustment.) Therefore, it is likely that BOB's primary capital cost inputs for conventional hydrotreating are roughly 33 percent higher than those described in Section 7.2.1 above. As the NETL study dates from mid-2001, it was unable to incorporate later information, such as the successful operation of the Process Dynamics IsoTherming demonstration unit. Overall, we believe that our capital cost estimates are reasonable in light of the BOB analysis. First, for conventional hydrotreating, we used the same primary cost inputs. Second, the 33 percent adjustment by NETL was based on discussions with refiners which we cannot evaluate. Third, it is appropriate to include advanced technologies which have been demonstrated at the commercial level. Fourth, the inclusion of capital costs for hydrogen plants and expanded sulfur plants provides a more complete estimate of the total capital investment required by the refining industry and their suppliers.

Regarding operating costs, hydrogen costs tend to dominate these costs. Thus, we will focus our comparison there. Hydrogen costs are a function of the volume of hydrogen needed to desulfurize a gallon of diesel fuel and the price of hydrogen. Regarding the former, BOB based their hydrogen consumption estimates on a number of studies, including one which we cite in Section 7.2.1 (Figures 31 in the BOB report). One of these estimates, that made by IFP, projects hydrogen consumptions over twice those of the other studies. We evaluated this estimate in our Draft and Final RIAs for the 2007 highway diesel rule, along with a number of other estimates. There, based on changes in other fuel properties, we determined that this estimate was based on very conservative assumptions concerning the level of aromatic saturation and modest cracking that would occur when desulfurizing diesel fuel to 7 ppm sulfur and decided not to use it any further. As four out of five vendors projected that this level of saturation would not be necessary, we decided not to incorporate this estimate into our cost methodology.

The IFP estimates appear to have a significant impact on the BOB hydrogen consumption estimates, as BOB's hydrogen consumption model over-predicts all of the other data used to develop the model. Also, subsequent discussions with IFP staff indicate that their more recent estimates (the original estimate was made prior to 2000) are more in line with those of the other vendors.

In Figure 9 of the BOB study, they present their estimated hydrogen consumption for three different diesel fuel compositions for a grass roots conventional hydrotreater designed to produce 15 ppm diesel fuel. We used our methodology developed in Section 7.2.1 to estimate hydrogen consumption for these same feeds for a grass roots hydrotreater. Table 7.2.2-24 shows both the EPA and BOB estimates of hydrogen consumption.

Table 7.2.2-24
EPA and BOB 15 ppm Hydrogen Consumption: Grassroots Diesel Hydrotreater

BOB Feed Case	Feed Composition	Hydrogen Consumption, scf/bbl	
		EPA	BOB
1	100% Straight Run	240	510
2	50% Straight Run, 35% LCO 15% LCGO	582	778
3	70% LCO, 30% LCGO	1025	1091

As can be seen, the BOB estimates are significantly higher than our estimates, particularly for the 100 percent straight run distillate. We compared BOB's 510 scf/bbl estimate for this case with the hydrogen consumptions which BOB presents in an appendix where it compares the predictions of its hydrogen model to the vendor estimates (Figure 31 in the BOB report). There, BOB shows five cases where the diesel fuel being hydrotreated is 100 percent straight run. BOB shows that its hydrogen model predicts hydrogen consumptions of 244-268 scf/bbl for these feedstocks. This is roughly half that which they show in Figure 9. No explanation for this discrepancy is presented in the report. However, if the hydrogen consumptions shown in BOB's Figure 9 were actually used in their cost estimations, then they appeared to have over-estimated hydrogen costs even compared to their own model validations.

With respect to hydrogen costs, BOB assumed that hydrogen would cost twice the cost of natural gas. They did not state whether this was on a Btu basis, or a scf basis. Other information presented in the study implies that it was on a scf basis. As BOB projected future natural gas prices of roughly $3 per mmBTU (equivalent to $3 per 1000 scf), this implies that BOB projected hydrogen costs of $6 per 1000 scf. In Section 7.2.1, we describe how we estimate hydrogen costs. There, we use a future natural gas price of $4.15 per mmBtu, well above that used by BOB. However, using this natural gas price, we estimate hydrogen costs of $2.20-3.90 per 1000 scf. As described in Section 7.2.1, we base these costs on a new hydrogen plant typical of the size of hydrogen plants in the region today, or by an even mix of new plants or third party plats for the hydrogen supplied in the Gulf Coast. We also adjusted for variations in natural gas costs, typical plant capacities, location factors and off-site factors all differing according to the region of the country in which the refinery is located. It is unclear where BOB obtained its rule of thumb on hydrogen prices. It may have been accurate when natural gas prices were much lower than today and capital costs comprised a much larger percentage of total costs. However, this rule of thumb does not appear to be appropriate at today's natural gas prices. Thus, it appears, though one cannot be sure given the lack of detail in the report, that BOB significantly over-estimated hydrogen costs.

7.3 Cost of Lubricity Additives

Our evaluation of the potential impact of the non-highway diesel sulfur standards on fuel lubricity is described in Section 5.9. We conclude that the increased need for lubricity additives resulting from the these sulfur standards will be similar to that for highway diesel fuel meeting the same sulfur standard. In the HD2007 rule, we conservatively estimated that all diesel fuel meeting a 15 ppm sulfur standard will use lubricity additives at a cost of 0.2 cents per gallon.[55] Consistent with the estimated cost from the increased use of lubricity additives in 15 ppm highway diesel fuel, we have included a charge of 0.2 cents per gallon in our cost calculation to account for the increased use of lubricity additives in 15 ppm NRLM diesel fuel. This lubricity additive cost applies to the affected NRLM diesel fuel pool beginning in 2010.

In estimating lubricity additive costs for 500 ppm diesel fuel, we conservatively assumed that if diesel fuel is required to have its lubricity improved through the use of additives, that the same additive concentration will be needed both for 15 ppm and for 500 ppm diesel fuel. However, the vast majority of 500 ppm diesel fuel does not require the use of lubricity additives. We assumed that 5 percent of all 500 ppm diesel fuel would need a lubricity additive. Based on these assumptions, we estimate that the cost of additional lubricity additives for the affected 500 ppm NRLM diesel fuel is 0.01 cents per gallon. The amount of lubricity additive needed increases substantially as diesel fuel is desulfurized to lower levels. Also, based on the industry input (see Section 5.9) it is likely that substantially less than 5 percent of 500 ppm diesel fuel outside of California requires a lubricity additive. We therefore believe 0.01 cents per gallon represents a conservatively high estimate of the cost of lubricity additives for affected volume of 500 ppm nonroad, locomotive, and marine diesel fuel. Although the actual cost will likely be considerably less, we have no information to better quantify the percentage of 500 ppm diesel fuel currently treated with a lubricity additive or the appropriate additive treatment rate. The 0.01 cents per gallon cost for a lubricity additive applies to the affected non-highway diesel pool (NRLM) until the 15 ppm sulfur standard takes effect in 2010.

EIA FOKS/AEO NRLM Fuel Demand Scenario:

As discussed in Section 5.9, lubricity costs vary primarily with sulfur level, as the sulfur level affects the degree of hydrotreating applied, which in turn results in changes to other fuel properties which affect lubricity. Thus, lubricity costs do not vary with implementation date or type of diesel fuel market (i.e., highway, nonroad, locomotive or marine). Thus, as the sulfur level of various diesel fuels change under the alternative control options, the lubricity costs vary accordingly. However, the cost per gallon for 500 ppm fuel will remain 0.01 cent per gallon and the cost for 15 ppm fuel will remain 0.2 cent per gallon.

7.4 Cost of Distributing Non-Highway Diesel Fuel

A summary of the distribution costs that we project will result from the implementation of the NRLM sulfur standards is contained in Table 7.4.-1. How we arrived at these cost estimates is described in the following sections.

TABLE 7.4.-1
SUMMARY OF DISTRIBUTION COSTS (CENTS PER GALLON) *

Cause of Increase in Distribution Costs	Time Period Over Which Costs Apply			
	2007-2010	2010-2012	2012-2014	After 2014
Distribution of Additional NRLM Volume to Compensate for Reduction in Volumetric Energy Content	0.08	0.1	0.1	0.1
Distillate Interface Handling	0	0.4	0.4	0.8
New Product Segregation as Bulk Plants	0.1	0.1	0.1	0.1
Heating Oil and L&M Fuel Marker	0.01	0.02	0.01	0.01
Total	0.2	0.6	0.6	1.0

* Costs have been rounded to one significant figure.

7.4.1 New Production Segregation at Bulk Plants

Section 5.4.1. evaluates the potential for additional product segregation in each segment of the distribution system. As discussed in Section 5.5.1.2., approximately 1,000 bulk plants could add an additional storage tank and demanifold their delivery truck(s) to handle an additional diesel product.

In its comments to the government/industry panel convened in accordance with the Small Business Regulatory Enforcement Act (SBREFA), the Petroleum Marketers Association of America (PMAA) stated that, depending on the location, the cost of installing a new diesel storage tank at a bulk plant ranges from $70,000 to $100,000. To provide a conservatively high estimate of the cost to bulk plant operators, we used an average cost of $90,000. This is consistent with the information we obtained from a contractor working for EPA (ICF Kaiser) on the installed cost of a 20,000-gallon storage tank, which is the typical tank size at bulk plant facilities. Demanifolding of the bulk plant operators delivery truck involves installing an internal bulkhead to make two tank compartments from a single compartment. To help control contamination concerns, we also estimated that an additional fuel delivery system will be installed on the tank truck (i.e., that there will be a separate delivery system for each fuel carried by the delivery truck). The cost of demanifolding a tank truck and installing an additional fuel delivery system is estimated at $10,000, of which $6,000 is the cost of installing a new fuel delivery system.[56]

In the NPRM, we estimated that each bulk plant that needed to install a new storage tank would need to demanifold a single tank truck. Thus, the NPRM estimated the cost per bulk plant would be $100,000. Fuel distributors stated that the assumptions and calculations made by EPA in characterizing costs for bulk plant operators seem reasonable. However, they also stated that our estimate that a single tank truck would service a bulk plant is probably not accurate. No suggestion was offered regarding what might be a more appropriate estimate other than the number is likely to be much greater. Part of the reason why we estimated that only a single tank truck would need to be demanifolded, is that we expected that due to the seasonal nature of the demand for heating oil versus nonroad fuel, it would primarily only be at the juncture of these two seasons that both fuels would need to be distributed in substantial quantities. We also expected that the small demand for heating oil in the summer and the small demand for nonroad fuel in the winter could be serviced using a single demanifolded truck. The primary fuel distributed during a given season would be distributed by single compartment tank trucks. During the crossover between seasons, bulk plant operators would switch the fuel to which such single compartment tank trucks are used from nonroad to heating oil and back again.[NN] Nevertheless, we agree that some of the subject bulk plant operators would likely be compelled to demanifold more that a single tank truck. Lacking additional specific information, we believe that assuming that each bulk plant operator demanifolds three tank trucks will provide a conservatively high estimate of the cost to bulk plant operators due to this rule.

If all 1,000 bulk plants were to install a new tank and demanifold three tank trucks, the cost for each bulk plant would be $120,000, and the total one-time capital cost would be $120,000,000. To provide a conservatively high estimate of the costs to bulk plant operators, we are assuming that all 1,000 bulk plants will do so. Amortizing the capital costs over 20 years, results in a estimated cost for tankage at such bulk plants of 0.1 cents per gallon of affected NRLM diesel fuel supplied. Although the impact on the overall cost of the program is small, the cost to those bulk plant operators who need to put in a separate storage tank may represent a substantial investment. Thus, we believe many of these bulk plants will search out other arrangements to continue servicing both heating oil and NRLM markets such as an exchange agreement between two bulk plants that serve a common area.

The need for additional storage tanks at terminals to handle products produced from pipeline interface is discussed in Section 7.4.1.2. of this RIA. Aside from the costs described above for bulk plant operators, and those discussed in Section 7.4.1.2, we project that there will be no substantial need for additional storage tanks or other facility changes to segregate additional products.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Using EIA nonroad fuel volumes rather than our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption does not affect our assessment of product distribution patterns on which the above estimate of the costs to bulk plant operators are based. Therefore, our estimate of the costs to bulk plant operators under the EIA nonroad fuel volume scenario is the same as that under our primary fuel volume scenario. However, the

[NN] To avoid sulfur contamination of NRLM fuel, the tank compartment would need to be flushed with some NRLM fuel prior to switching from carrying heating oil to NRLM fuel.

volume of affected NRLM to which these costs are attributed is reduced somewhat under the EIA nonroad volume scenario, and consequently the cost per gallon is directionally higher than under our primary fuel volume scenario. Nevertheless, because the costs are small, this does not result in a material change to our estimate of 0.1 cents per gallon of affected NRLM diesel fuel supplied.

Because our assessment of product distribution patterns is not different under the EIA nonroad volume scenario from that under our primary scenario, we also project that aside from the costs described above for bulk plant operators, and those discussed in Section 7.4.1.2, there will be no substantial need for additional storage tanks or other facility changes to segregate additional products.

7.4.2 Reduction in Fuel Volumetric Energy Content

We project that desulfurizing diesel fuel to 500 ppm will reduce volumetric energy content (VEC) by 0.7 percent. The cost of which is equivalent to 0.08 cent per gallon of affected NRLM fuel. We project that desulfurizing diesel fuel to 15 ppm will reduce volumetric energy content by an additional 0.5 percent. This will increase the cost of distributing fuel by an additional 0.05 cents per gallon, for a total cost of 0.13 cents per gallon of affected 15 ppm NRLM fuel. Following is a discussion of how we arrived at these estimated costs.

The reduction in VEC due to desulfurization of NRLM fuel to meet the standards in this rule depends on the desulfurization process used. We project that conventional hydrotreating will be the desulfurization process used to desulfurize NRLM to meet the 500 ppm sulfur standard. However, as discussed in Chapter 5, we project that new technology (Process Dynamics Isotherming) will be used as well to desulfurize NRLM to meet the 15 ppm standard. These processes have different projected impacts on VEC, as discussed in Chapter 5.2. and shown in Table 7.4-2.

Table 7.4-2
Impact of Desulfurization on the Volumetric Energy Content of Diesel Fuel

Process	NRLM Fuel Volume Processed		Reduction in VEC High Sulfur to 500 ppm	Reduction in VEC 500 ppm to 15 ppm
	500 ppm Standard	15 ppm Standard		
Hydrodesulfurization	100 %	40 %	0.7%	0.7%
Process Dynamics Isotherming	0 %	60 %	NA	0.4%
Overall for NRLM Pool	-	-	0.7%	0.5%

The difference between the price of non-highway diesel fuel to end-users and the price to resellers provides an appropriate estimate of the cost of distributing non-highway diesel fuel. The Energy Information Administration (EIA) publishes data regarding the price excluding taxes of high-sulfur No. 2 diesel fuel to end-users versus the price to resellers. We used the five-year average of the difference between these two prices to arrive at an estimated typical cost of distributing NRLM fuel to the end-user. In the NPRM, we used data from 1995 through 1999 to arrive at an estimated distribution cost of 10 cents per gallon. For this final rule, we used 1997 through 2001 data to update this analysis. The EIA data that we used to estimate the cost of distributing NRLM fuel is presented in Table 7.4-3.

Table 7.4-3
Cost of Distributing High-Sulfur No. 2 Diesel Fuel[a] (cents per gallon, excluding taxes)

Year	Sales to Resellers	Sales to End Users	Difference Between Sales to End Users and Sales to Resellers
1995	52.4	61.4	9.0
1996	63.9	73.2	9.3
1997	60.2	69.8	9.6
1998	43.7	55.5	11.8
1999	51.9	62.0	10.1
2000	87.5	98.1	10.6
2001	77.1	89.2	12.1
Average of 5 Most Recent Years	54.4	64.4	10.8

[a] Energy Information Administration, Annual Energy Review 2003

Based on the information in Table 7.4-3, we assumed a 10.8 cent per gallon cost of distributing diesel for the purposes of estimating the increased distribution costs due to reduced VEC. We derived our estimates of the increase in distribution costs under each step of the NRLM sulfur program by multiplying the applicable percent reduction in VEC by 10.8 cents per gallon.

Since the difference in price at the refiner rack versus that at retail also includes some profit for the distributor and retailer, its use provides a conservatively high estimate of distribution costs. The fact that a slightly less dense (lighter, less viscous) fuel requires slightly less energy to be distributed also indicates that this estimate is conservative.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Using EIA nonroad fuel volumes rather than our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption does not affect our estimate of the increased distribution costs related to the reduction in VEC. Thus, the 0.08 and 0.13 cent per gallon costs for 500 ppm and 15 ppm fuel do change.

7.4.3 Handling of Distillate Fuel Produced from Pipeline Interface

As discussed in Section 5.1, the shipment of 30 ppm gasoline, 15 ppm diesel fuel, jet fuel and, in some cases, 500 ppm locomotive and marine fuel and high sulfur heating oil, will produce commingled distillate fuel at the interfaces of each batch. In Section 5.1, we estimate the volumes of each interface and how the fuel distribution system could dispose of each interface in order to maximize profits (i.e., minimize costs). Basically, interfaces containing some gasoline are presumed to go to existing transmix facilities. The distillate fuel produced by these transmix processors will contain a mixture of heavy naphtha, jet fuel and 15 ppm diesel fuel. We project that this mixture will contain 500 ppm sulfur or less and can thus be sold as 500 ppm diesel fuel of high sulfur heating oil.

The other interface which will not be able to be blended into either of the adjacent batches is that between jet fuel and 15 ppm diesel fuel. In the Northeast and along the Colonial and Plantation pipelines, we assume that this distillate interface will be added to the heating oil tank, which will continue to be distributed throughout the distribution system. Elsewhere, we do not believe that heating oil will be distributed in pipelines. We assume the interface containing jet fuel and 15 ppm diesel fuel will not be shipped to transmix processors. Interface processors basically distill transmix into a lighter than average naphtha component and a lighter than average distillate component.[OO] This distillate contains all of the original jet fuel and No. 2 distillate (both highway and high sulfur) fuel. Adding an interface consisting of jet fuel and No. 2 distillate to the current transmix tank and running this through a distillation column would only result in all of this jet-distillate interface flowing to the bottoms of the column. The additional distillate would also affect the operation of the distillation column, as they are typically designed for a certain fraction of the feedstock going overhead. Thus, we believe that it would be more economical for terminals to segregate this No. 1/No. 2 distillate interface from transmix in a separate storage tank. As described in Section 7.1, we estimate that this interfacial material will likewise meet a 500 ppm sulfur cap. Thus, the terminal can ship this interface to consumers in either the 500 ppm diesel fuel or heating oil markets.

The disposition of this 500 ppm interface fuel is described in Section 5.1. Generally, we assumed that this material would be sold to the heating oil first, then into the 500 ppm highway fuel market (through 2010), to the 500 ppm NRLM market (the nonroad fuel market through 2014), and finally into the L&M diesel market (after 2014). An exception to this applies in the Northeast/Mid-Atlantic Area, where this interface cannot be sold into the nonroad fuel market after 2010, nor into the L&M fuel market after 2012. If the volume of this 500 ppm interface exceeds the demand for 500 ppm diesel fuel and heating oil, then we assumed that it would have to be shipped back to a refiner and reprocessed to meet the 15 ppm cap.

[OO] Normally, one thinks of transmix processing as separating transmix back into its original gasoline and distillate components. However, the lighter compounds in original distillate fuel inevitably mix with the heavier compounds in the original gasoline and lower the octane of this heavy gasoline dramatically. Due to the cost of making up for this octane loss, transmix processors typically send the heavier gasoline compounds to the distillate half of their product..

The cost of disposing of this 500 ppm distillate material will likely vary geographically, depending on the size of the heating oil market. In the Northeast, the only cost of disposing of this interface will be the value lost by selling former jet fuel and 15 ppm diesel fuel as heating oil. This cost is already included in our refining costs, as there, we increased the volume of 15 ppm diesel fuel which had to be processed due to losses during distribution. We estimate that about 80% of the diesel fuel shipped to PADD 1 is sold in areas with large heating oil markets. In the remainder of the country, the heating oil market is more limited. Matching any high sulfur heating oil and users of this fuel will be more difficult and costly in terms of transportation.

Prior to mid-2010, 500 ppm interface can simply be added to the 500 ppm NRLM fuel storage tank, which should exist at most terminals, or the 500 ppm highway fuel storage tank, if this fuel is being stored at that terminal. Thus, there should be essentially no cost related to disposing of this interface material.

From mid-2010 through 2012, 500 ppm fuel can no longer be sold to the highway fuel market. Also, we do not expect that small refiner 500 ppm nonroad fuel and 500 ppm L&M fuel will be widely distributed. Thus, this interface material will require its own storage tank. The 500 ppm interface can be sold to users of NRLM fuel, as well as heating oil. The only restriction is that it cannot be used in nonroad equipment equipped with emission controls requiring 15 ppm fuel, nor in nonroad engines in general within the Northeast/Mid-Atlantic Area. Most nonroad fuel users only have one fuel storage tank on-site. Or, if they have more than one tank, it is because their operations cover long distances (e.g., farms, quarries, etc.) and multiple tanks reduce the time it takes to move the equipment to the refueling station. Thus, nonroad equipment users which have purchased even one new piece of equipment requiring 15 ppm fuel will often desire to purchase 15 ppm fuel for all their equipment. Thus, the number of NRLM fuel users willing to accept 500 ppm fuel will gradually diminish from 2010 to 2014. This will increase the distance that the fuel will have to be shipped to find a purchaser.

We estimate that the cost to store this 500 ppm fuel at a terminal will vary by terminal. At those terminals able to receive jet fuel and 15 ppm diesel fuel from the heart of the pipeline batches passing by it, the only distillate-distillate interface will be from washing lines to protect jet fuel and diesel fuel quality. This material might be stored in a small tank, but will most likely simply be added to the existing transmix tank. Thus, incremental storage costs will likely be negligible, but transmix volume will increase. Terminals near the end of pipeline or pipeline branch will receive a relatively large volume of distillate-distillate interface. Some of these terminals will likely be able to use the tank that was previously used to hold heating oil or 500 ppm NRLM fuel or the tank used to hold 500 ppm L&M diesel fuel from 2010-2012. However, in other cases it may require some new tankage. Economics will likely encourage the off-loading at terminals with existing tankage. However, proximity to a large 500 ppm market (L&M fuel, heating oil) will also likely be a factor.

Depending on the size of the tank, storage costs vary substantially. Smaller tanks can cost $5 per gallon of capacity, while very large tanks might only cost $20 per barrel ($0.5 per gallon). Amortizing these costs over 15 years of weekly shipments of 60% of capacity at a 7% rate of return, storage costs range from 0.2-1.6 cents per gallon in those cases requiring a new tank. It is not possible to estimate a precise distribution of tank sizes and thus, costs. We assume that the availability of existing tankage will balance the need for smaller tanks on average and that the average storage cost will be near the lower end of this range, 0.4 cents per gallon. In addition, there is an inventory cost to have this stored fuel on hand. At a 7% rate of return, assuming that the tank is half full on average, for fuel at $1 per gallon, the carrying cost is 0.1 cent per gallon. Thus, the total storage cost is roughly 0.5 cent per gallon.

There is also the potential for increased storage costs at transmix processing facilities. The increased volume of distillate-distillate interface added to transmix will likely be very small relative to the total volume of gasoline-distillate interface. Thus, existing tankage should be sufficient. However, currently, transmix processors often ship their distillate production into tankage at terminals which are usually located adjacent to the processing facility. After 2010, the only 500 ppm fuel that would be stored at most of these terminals would be interface, and all terminals after 2012, as discussed above. These terminals may have to increase their storage capacity beyond that necessary to handle interface received directly from the pipeline and line washing. We project that the incremental cost to store this transmix interface will be the same 0.5 cent per gallon as that projected above for non-transmix interface. Since all the distillate-distillate interface will either be stored as a distinct fuel at the terminal or combined with transmix and processed, the overall storage cost for all distillate-distillate interface is 0.5 cent per gallon.

We expect that there will be an additional cost of shipping this 500 ppm fuel to those who can use it. Nonroad fuel markets will likely be served by truck, as is the case today. Locomotive and most marine markets will likely be served by rail. Shipping this 500 ppm fuel will not have the economies of scale of the current nonroad market or the future 15 ppm nonroad market. Trucks will have to spend more time driving between stops or a smaller compartment will have to be added to the tank. In either case, costs will increase. Rail shipments will also be smaller than today, increasing handling costs. We estimate that the additional cost of delivering 500 ppm interface to these NRLM users without 2011 and later nonroad equipment will cost 1.5 cents per gallon. This cost is equivalent to increasing the shipping distance by 45 miles by truck and 100 miles by rail.[PP] Combined with storage costs, distributing this fuel to NRLM users will cost 2.0 cents per gallon.

In those cases where the 500 ppm interface is sold to the heating oil markets outside of the Northeast, we expect that the costs will be larger. Heating oil users outside of the Northeast are not evenly distributed geographically. The interface will also not be evenly distributed geographically. Thus, the interface may not be removed from the pipeline near the users of heating oil. Also, we expect that this fuel will have to be transported by truck. We project that the additional mileage will be roughly 85 miles and cost 3.0 cents per gallon. Combined with storage costs, distributing this fuel to heating oil users outside of the Northeast will cost 3.5 cents per gallon.

[PP] Trucking and rail costs of 0.035 and 0.012-0.2 cent per gallon, respectively from: "Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel", Robert E. Cunningham, Thomas R. Hogan, Joseph A. Loftus, and Charles L. Miller, Turner and Mason and Co. Consulting Engineers, February 2000.

Finally, there are some PADDs where the NRLM and heating oil markers are not large enough to handle all of the 500 ppm interface generated. In these cases, the interface will have to be shipped back to a refinery by truck, reprocessed through the refiner's hydrotreater and shipped back to the fuel market with the rest of the refiner's production. The storage cost of 0.5 cent per gallon at terminals and transmix operators will still apply, since it will still likely to be less costly to keep this interface segregated from gasoline-distillate transmix. (Transmix will be sent to transmix processors, while the jet-distillate interface will have to be sent to refineries with excess hydrotreating capacity.) We estimate that most of this distillate will be shipped roughly 200 miles by rail and cost 3.0 cents per gallon. Desulfurizing this material to 15 ppm will be technically simple, since it will consist of heavy naphtha, jet fuel and 15 ppm diesel fuel. The two lighter fuels do not contain any stearically hindered molecules. However, refiners generally do not add material into the middle of their distillate production train. There will likely be a tank storing diesel fuel prior to desulfurization, where straight run, LCO and other cracked stocks are mixed. However, there might not be easy access to this tank from outside of the refinery. Thus, we expect that the handling costs will far exceed the desulfurization costs. We project a total cost for reprocessing of 4.5 cents per gallon. Finally, this re-processed fuel must be shipped out again, usually via pipeline. We project this last distribution cost to be 2 cents per gallon. Thus, the total cost for interface which must be reprocessed is 10 cents per gallon.

From mid-2012 through 2014, very little changes from 2010-2012. The only change is that downgraded distillate can no longer be sold to the L&M fuel market in the Northeast/Mid-Atlantic Area. Instead this fuel shifts to the heating oil market. As this is a minor change, we assume that all of the costs of distributing the downgraded distillate to the various markets from 2012-2014 remain the same as in 2010-2014.

In 2014, when 500 ppm fuel can no longer be sold to nonroad equipment users, we project that the transportation distance to L&M fuel users will nearly double, as will the transportation cost, to 2.5 cents per gallon. Outside of PADDs 1 and 3, we estimate that the downgraded material will comprise 70-100% of the L&M market, so, given the above methodology, the downgraded material will have to move to nearly every L&M refueling site. With storage costs of 0.5 cents per gallon, the total cost of distributing downgraded material to the L&M fuel market will be 3.0 cents per gallon.

Likewise, we project that the transportation distance to heating oil users will also increase. However, we do not believe that these distances will double, because the increase in downgraded material going to the heating oil market is smaller on a relative basis than for the L&M fuel market. Thus, we project that the transportation distance to heating oil users will increase to roughly 130 miles and cost 4.5 cents per gallon. With storage costs of 0.5 cents per gallon, the total cost of distributing downgraded material to the heating oil market will be 5.0 cents per gallon. The cost to reprocess distillate to meet a 15 ppm cap will remain at 10 cents per gallon.

In Section 7.1, we estimated the volume of downgraded jet fuel and diesel fuel which would be sold to the nonroad, L&M and heating oil markets prior to the NRLM rule (Table 7.1.3-9), from 2007-2010 (Table 7.1.3-14), from 2010-2012 (Table 7.1.3-17), from 2013-2014 (Table 7.1.3-18) and in 2014 and beyond (Table 7.1.3-19). We likewise estimate the volumes of fuel which must be reprocessed to meet a 15 ppm cap. These volumes are summarized in Table 7.4.4, along with the cost per gallon of storing and shipping this interface to the various fuel markets.

Table 7.4.4
Annual Costs Associated With Distribution of Distillate Interface

Jet-Distillate Interface Sent to:	Volume Affected (million gallons/yr)	Cost per Gallon	Annual Cost (million)
Baseline			
NRLM Market	247	2.0 cents	$5
Heating Oil Market	219	3.5 cents	$8
Reprocessed	0	10.0 cents	0
Total	---	---	$13
2010-2012			
NRLM Market	1,395	2.0 cents	$30
Heating Oil Market	1,045	3.5 cents	$32
Reprocessed	0	10.0 cents	0
Total	---	---	$63
2012-2014			
NRLM Market	1,395	2.0 cents	$28
Heating Oil Market	1,045	3.5 cents	$37
Reprocessed	0	10.0 cents	0
Total	---	---	$65
2014 and beyond			
NRLM Market	1,336	3.0 cents	$40
Heating Oil Market	885	5.0 cents	$44
Reprocessed	335	10.0 cents	$34
Total	---	---	$118

Table 7.4.4 also shows the annual cost associated with each fuel market, which is simply the product of the fuel volume and the cost per gallon (converted from cents to dollars). The annual cost due to the NRLM rule from 2007-2010 is $47 million, which is the total cost of $61 million less the $14 million cost occurring prior to the rule. Likewise, the cost due to the NRLM rule in

2010-2012, 2012-2014 and 2014 and beyond is $63, $65, and $102 million, respectively. The total affected NRLM fuel volume is 12.4 billion gallons in 2010, 12.8 billion gallons in 2012 and 13.4 billion gallons in 2014 (all three figures represent fuel production and demand grown to 2014). Thus, these annual costs represent incremental costs of 0.40, 0.41 and 0.79 cent per gallon from 2010-2012, 2012-2014, and 2014 and beyond, respectively.[QQ]

We anticipate that there will be no other significant distribution costs associated with the NRLM sulfur standards in this rule beyond those described in Sections 7.4.1, 7.4.2, and 7.4.3. We do not expect the need for additional storage tanks beyond that discussed in Sections 7.4.1., and 7.4.3., or a significant increase in pipeline downgrade or transmix volumes beyond the modest potential increase in tranmix volume discussed in Section 7.4.3. As discussed in Section 7.4.5., we are projecting costs associated with the need to install fuel marker injection equipment at a limited number of refineries, transmix processors, and terminals

Operators of bulk plants and tank trucks who previously handled only high-sulfur diesel fuel will need to begin observing practices to limit sulfur contamination during the distribution of 500 ppm and 15 ppm diesel fuel. However, these practices are either well established or will be for compliance with the 15 ppm highway standard in 2006. Furthermore, they are primarily associated with purging storage tanks and fuel delivery systems of high-sulfur diesel fuel before handling 500 ppm and 15 ppm diesel fuel. Training employees will be necessary to stress the importance of consistently and carefully observing practices to limit sulfur contamination. However, we estimate the associated costs will be minimal. In addition, we are estimating that most of the affected bulk plant operators will install dedicated storage tanks and truck delivery systems. This obviates the need for much of the cautionary actions necessary to limit sulfur contamination when both low and high-sulfur diesel fuel is carried by the same marketer.

As discussed in Section 5.6, the vast majority of the fuel distribution system (primarily pipeline and terminal facilities) will already have optimized their facilities and procedures to limit sulfur contamination for distributing 15 ppm sulfur fuel due to the need to comply with the highway diesel fuel program in 2006. The costs associated with this optimization process were accounted for in the HD2007 Regulatory Impact Analysis.[57] Highway diesel fuel and nonroad diesel fuel meeting a 15 ppm sulfur specification will share the same distribution system until nonroad diesel fuel is dyed to meet IRS requirements as it leaves the terminal. We therefore do not expect any additional actions or costs to optimize the distribution system to limit sulfur contamination during the distribution of 15 ppm nonroad diesel fuel.

EIA FOKS/AEO Nonroad Fuel Volume Scenario: We followed the same methodology for estimating downgrade-related distribution costs for this scenario as our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption. Using EIA nonroad fuel volumes, as described in Section 7.1 above, reduces the volume of NRLM fuel demanded in each PADD, except PADD 3. Consequently, the volumes of heating oil consumed

[QQ] The increase in cost in 2014 is due to the inability to use downgraded material in the nonroad market. If the $105 million cost in 2014 is spread only over the nonroad fuel market, the cost per gallon is 1.0 cents.

increase everywhere except PADD 3. This reduces the contribution of the volume of downgraded material to the NRLM and heating oil markets substantially. Particularly in PADD 2, instead of downgraded material comprising a major portion of the NRLM and heating oil markets, it comprises roughly 33%. We believe that this will make it easier for terminals to find heating oil consumers and reduce the transport distance to these users. Thus, for PADD 2, we reduced the cost of distributing interface to the heating oil market to that of the NRLM or L&M markets (depending on the time period), or 2 cents per gallon. However, the volume of NRLM fuel over which the increased transportion costs are spread also decreases. The net result is that the cost of distributing interface material from 2010-2014 remains unchanged at 0.4 cent per gallon. However, the cost after 2014 decreases from 0.79 to 0.56 cents per gallon.

7.4.4 Fuel Marker Costs

In the NPRM we estimated that the cost to blenders of the heating oil marker in bulk quantities would translate to 0.2 cents per gallon of fuel treated with the marker. This estimate was based on the fee charged by a major pipeline to inject red dye at the IRS concentration into its customers diesel fuel. Conversations with marker manufactures prior to the publication of the NRLM indicated that the cost to treat fuel with either of the markers considered in the NPRM would be lower than the costs to treat non-highway diesel fuel with red dye to meet IRS requirements. We used this estimate because we lacked specific cost information on the proposed marker, there was uncertainty regarding the specific marker that we would require, and we believed that it provided a conservatively high estimate of cost for any of the markers under consideration. Since the proposal, we received input from a major distributor of fuel markers and dyes, regarding the cost of bulk deliveries of the specified fuel marker (solvent yellow 124) to terminals which translates to a cost of 0.03 cents per gallon of fuel treated with the marker. The volume of heating oil that we expect will need to be marked has also decreased substantially from that estimated in the NPRM due to the provisions applicable in the Northeast/Mid-Atlantic Area and Alaska. We estimate that 1.4 billion gallons of heating oil will be marked annually, for an annual marker cost of $425,000.[RR] In the NPRM, this marker cost applied to heating oil for just three years, but then continued on for another four years for locomotive and marine diesel fuel. Under this final rule, the marker requirement for locomotive and marine diesel fuel is applicable only from 2010 though 2012, and only outside of the Northeast/Mid-Atlantic Area and Alaska. However, the marker requirements for heating oil continues indefinitely.

The NPRM projected that there would be no capital costs associated with the proposed marker requirement. We proposed that the marker would be added at the refinery gate, and that the current requirement that non-highway fuel be dyed red at the refinery gate be made voluntary. Thus, we believed that the refiner's additive injection equipment that is currently used to inject red dye into off-highway diesel fuel could instead be used to inject the fuel marker. As a result of the allowance provided in this final rule that the marker may be added at the terminal rather than the refinery gate, and our reevaluation of the conditions for dye injection at

[RR] The costs of the marker requirement for L&M diesel fuel are discussed at the end of this section.

the refinery, we are now assessing capital costs for terminals and refiners related to compliance with the marker requirements.

Except for fuel that is distributed directly from a refiner's rack, this final rule allows the marker to be added at the terminal rather than at the refinery (see Section IV.D. of the preamble for a discussion of the fuel marker requirements).[SS] We expect that except for fuel dispensed directly from the refinery rack, the fuel marker will be added to at the terminal to avoid the potential for marked fuel to contaminate jet fuel in during distribution by pipeline. Terminals that need to inject the fuel marker will need to purchase a new injection system, including a marker storage tank and a segregated line and injector for each truck loading station at which fuel that is required to contain the marker is dispensed. Terminals will still be subject to IRS red dye requirements, and thus will not be able to rededicate such injection equipment to inject the fuel marker. Due to concerns regarding the need to maintain a visible evidence of the presence of the fuel marker, this final rule also contains a requirement that any fuel which contains the fuel marker also contains visible evidence of red dye. Furthermore, there is little chance to adapt parts of the red dye injection system (such as the feed lines and injectors) for the alternate injection of red dye and the fuel marker due to concerns that fuel which must not contain the marker might become contaminated with the marker.

We received information from various sources to estimate the cost of installing new injection equipment to handle the heating oil marker. Our first source of information was the Independent Fuel Terminal Operators Association (IFTOA). IFTOA stated that the cost for new additive injection equipment would be $40,000 per loading arm used to deliver heating oil to tank trucks with the cost for some terminals being as much as $250,000 (for 6-7 loading arms).

We also sought information from manufacturers of additive injection equipment. Titan industries and Lubrizol, leading manufacturers of such equipment, provided information on the uninstalled cost of the necessary hardware which is summarized in the following Table 7.4.5.[58].

Table 7.4.5
Uninstalled Cost of Additive Injection Hardware

Item	Cost
500 gallon Skid Storage Tank	$3,700 - $8,000
Rack Mounted Pump Assembly	$5,000 - $9,000[1]
Chemical Injector	$2,500-$2,900
Total	$11,200-$19,900

1. Depending on whether a single or a double pump assembly is used. The second pump serves as a back-up.

[SS]A refinery rack functions similar to a terminal in that it distributes fuel by truck to wholesale purchaser consumers and retailers.

The lower end tank cost was more consistent with our previous experience regarding tank costs. Consequently we elected to use $4,000 as a reasonable estimate of the uninstalled cost of an additive storage tank. We elected to use the higher cost estimate of $9,000 for the pump assembly because we believe that many additive blenders would wish to have a double pump assembly to prevent their fueling arm from being shut down when maintenance must be performed on the primary pump. This also provides something of a conservatively high cost estimate. We also elected to use $3,000 as the estimated uninstalled cost of an injector unit for this same reason. This results in an total uninstalled cost of $16,000 for the equipment necessary to equip one injection loading arm: $13,000 for the tank and pump, and $3,000 for each injector.

We estimated the installed costs by two means. Our primary means was to apply the rule for such projects of multiplying the equipment costs by 2 to arrive at the installed cost and then by increasing this result by an additional 50 percent to ensure that the estimated cost would be sufficient to account for areas in the U.S. where labor costs are higher that the average (such as the Northeast). Since the Northeast/Mid-Atlantic Area was defined to exclude terminals in the Northeast from the marker requirement, this step might be expected to provide a conservatively high estimate of installation costs for those facilities that do need to install new injection equipment. Following this method results in an estimated installed cost of the equipment necessary to provide marker injection at one loading arm of $50,000 ($40,000 for the tank and pump assembly, and $10,000 for the injector assembly. Thus, for each additional loading arm at a terminal the cost would increase by $10,000. As a double check on these results we employed an in-house expert to estimate the time required of various skilled tradesmen at their respective hourly pay rates: e.g. instrumentation specialist, welder, welder's helper, concrete installer, engineer, and laborers. The estimate that we arrived at using this means supported the estimates described above. We believe that these estimates are more accurate than those provided by IFTOA, and therefore are using them to calculate the costs under this rule.

Terminal operators expressed concern regarding the potential burden of installing new additive injection equipment. In response to these comments, this rule includes provisions that exempt terminal operators from the fuel marker requirements in a geographic "Northeast/Mid-Atlantic Area" and Alaska.[TT] These provisions provide that any heating oil or 500 ppm sulfue L&M diesel fuel produced by a refiner or imported that is delivered to a retailer or wholesale-purchaser consumer inside the Northeast/Mid-Atlantic Area and Alaska does not need to contain the marker. The Northeast/Mid-Atlantic Area was defined to include the region where the majority of heating oil in the country is projected to continue to be supplied though the bulk distribution system (the Northeast and Mid-Atlantic). The vast majority of heating oil consumption in the U.S. will be within the Northeast/Mid-Atlantic Area. Outside of the

[TT]Small refiner and credit high sulfur NRLM will not be permitted to be sold in the area where terminals are not required to add the fuel marker to heating oil and 500 ppm sulfur L&M diesel fuel produced by refiners or imported (the "Northeast/Mid-Atlantic Area"). See Section IV.D. of the preamble. See Section 5.5.1.4 regarding our determination of the boundary of the Northeast/Mid-Atlantic Area to minimize the number of facilities that would need in to install new injection equipment for the fuel marker and to limit the volume of fuel that will need to be marked.

Northeast/Mid-Atlantic Area, we expect that only limited quantities of heating oil will be supplied, primarily from certain refiner's racks. Based on our analysis of the number of refineries that we expect will continue to produce heating oil and information from transmix processors on the number of such facilities, we estimate that 30 refineries and transmix processor facilities outside of the Northeast/Mid-Atlantic Area will distribute heating oil from their racks (in limited volumes) on a sufficiently frequent basis to warrant the installation of a marker injection system at a total one time cost of $1,500,000.

Terminals outside of the Northeast/Mid-Atlantic Area will mostly be located in areas without continued production and/or bulk shipment of heating oil. Consequently, any high sulfur diesel fuel they sell will typically be NRLM. Terminals located within the Northeast/Mid-Atlantic Area will not need to mark their heating oil, except for those few that choose to ship heating oil outside of the Northeast/Mid-Atlantic Area. The terminals most likely to install marker injection equipment will therefore be those in states outside the Northeast/Mid-Atlantic Area with modest markets for heating oil after the implementation of this program.

A few terminals inside the Northeast/Mid-Atlantic Area and near the border may choose to install marker injection equipment so that they can serve customers outside of the Northeast/Mid-Atlantic Area. However, based on our review of the proximity of terminals inside the Northeast/Mid-Atlantic Area to potential heating oil markets outside of the Northeast/Mid-Atlantic Area, we project that no more than 15 terminals will be induced to do so. Given the relatively low level of the potential demand for marked heating oil, we believe that the boundary area terminals that install marker injection equipment would provide for the loading of marked heating oil into trucks at only one loading bay (at $50,000 per terminal).

Some terminals outside of the Northeast/Mid-Atlantic Area that are supplied by the pipeline system which supplies the Northeast/Mid-Atlantic Area are likely to carry heating oil. Considering the relatively low volume of heating oil demand in the states in which these terminals are located, we estimate that only 15 terminals in this area will choose to install marker injection equipment so they can handle heating oil. We believe that such terminals would likely feel the need to have two loading bays at which marked heating oil could be delivered to a truck. Considering the added cost of a second injection station, the cost of new injection equipment would be $60,000 for each of these terminals. Except for heating oil distributed from these terminals, we project that the small quantities of fuel that are sold as heating oil outside of the Northeast/Mid-Atlantic Area will often meet a 500 ppm sulfur specification.[UU] Therefore, we expect that the other terminals outside of the Northeast/Mid-Atlantic Area will typically not need to distribute marked heating oil. For the infrequent instances in where terminals do receive >500 ppm fuel that they wish to distribute as heating oil (rather than blending it down to meet a 500 ppm standard using 15 ppm diesel fuel) we except that the terminal operator will elect to add the marker by hand, thereby avoiding the cost of installing new additive injection equipment. However, to provide a conservatively high estimated cost, we assumed that an additional 30

[UU] Fuel sold as heating oil outside of the Northeast/Mid-Atlantic Area will primarily be generated as a by-product of the distribution of 15 ppm diesel fuel by pipeline.

terminals outside of the Northeast/Mid-Atlantic Area will install new equipment to allow the injection of fuel marker at one truck loading bay (at $50,000 per terminal).

In analyzing the various situations as discussed above, we project that fewer than 60 terminals nationwide will choose to install injection equipment to add the marker to heating oil at a total cost of $4,150,000. The total capital cost to refiners and terminals to install injection equipment to add the marker to heating oil is estimated to be $5,650,000. Thus, the Northeast/Mid-Atlantic Area provisions in this rule minimize the number of terminals that will need to install additive injection equipment and its associated cost to comply with the fuel marker requirements.

Because heating oil is being marked to prevent its use in NRLM engines, for the purposes of estimating the impact of the marker requirement on the cost of the NRLM program we have spread the cost of adding the marker to heating oil over NRLM diesel fuel. Amortizing the capital costs of marker injection equipment over 20 years, results in an estimated cost of just 0.006 cents per gallon of affected NRLM diesel fuel supplied. Spreading the cost of the marker for heating oil over the volume of affected NRLM fuel results in an estimated cost of 0.003 cents per gallon of affected NRLM fuel. Adding the amortized cost of the injection equipment and the cost or the marker results in a total estimated cost of the marker requirement for heating oil in this rule of 0.01 cents per gallon of affected NRLM fuel.

In addition to heating oil, 500 ppm L&M fuel produced at refineries must also be marked from 2010 to 2012. As discussed in Section 7.2.2, we project that 6 refineries will produce this fuel. These refineries will have to install equipment to mark the fuel, unless they already have the equipment to mark heating oil. We assume that all 6 refineries will have to install new equipment. We do not expect that 500 ppm L&M fuel will be distributed by common carrier pipeline. Thus, it can be marked at the refinery and shipped to the final user by rail, truck or barge already marked. Therefore, we expect that very few terminals will add marking equipment exclusively for this fuel. To cover the few terminals that could do so, we have increased the number of new marking installations to 15. At $60,000, the total capital cost is $900,000. The cost of the marker is 0.03 cent per gallon of marked fuel. As described in Appendix 8B, we estimate that 2.975 billion gallons of 500 ppm L&M fuel will be produced in 2011. Thus, the cost of marking two years of 500 ppm L&M fuel production will be $1.875 million. Amortizing the $900,000 capital cost over 2 years of 15 and 500 ppm NRLM fuel production at 7 percent before taxes and adding in the marker costs yields a cost of 0.01 cents per gallon of NRLM fuel over this two year period for the marker requirement for L&M diesel fuel.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Since using EIA nonroad fuel volumes rather than our primary fuel volume scenario (which utilized the EPA NONROAD model for nonroad fuel consumption) does not affect our assessment of product distribution patterns, our projections of the number of facilities that will need to install new injection equipment is the same under both scenarios. However, there are two factors that do have the potential to affect our per gallon cost estimate. The heating oil volume under the EIA nonroad volume scenario is greater than that under our primary volume scenario and the NRLM volume is smaller than under our primary volume scenario. The greater volume of heating oil under the EIA volume scenario means that it is likely that the volume of heating oil marked would be larger relative to our primary scenario, and the volume of NRLM to which this cost (and the capitol cost of the injection equipment) would be attributed would be smaller. Both of these criteria directionally increase the per gallon marker costs under the EIA volume scenario relative to our primary volume scenario. Because of these changes, the cost of adding the marker increases to 0.02 cent per gallon of affected NRLM diesel fuel supplied. The cost of marking L&M fuel stays at 0.01 cent per gallon from 2010-2012.

7.4.5 Distribution and Marker Costs Under Alternative Sulfur Control Options

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

The distribution and marker costs assuming a reduced volume of nonroad fuel demand, resulting from deriving this demand from information in EIA's FOKS and AEO 2003 reports are summarized in Table 7.4-6 below. The derivation of each cost component was discussed in the previous sub-sections of Section 7.4.

TABLE 7.4-6
DISTRIBUTION COSTS FOR EIA FOKS/AEO FUEL DEMAND SCENARIO (CENTS PER GALLON) *

Cause of Increase in Distribution Costs	Time Period Over Which Costs Apply		
	2007-2010	2010-2014	After 2014
New Product Segregation as Bulk Plants	0.1	0.1	0.1
Distribution of Additional NRLM Volume to Compensate for Reduction in Volumetric Energy Content	0.08	0.1	0.1
Distillate Interface Handling	0	0.4	0.6
Heating Oil and L&M Fuel Marker	0.03	0.03	0.03
Total	0.2	0.6	0.8

* Costs have been rounded to one significant figure.

Other Fuel Control Options: The other fuel control options analyzed in this Final RIA are: 1) 500 ppm NRLM cap in 2007 with no subsequent control to 15 ppm, and 2) the proposed fuel program of 500 ppm NRLM in 2007 and 15 ppm nonroad fuel in 2010. The distribution costs for the 500 ppm NRLM only program are the same as those for the final NRLM fuel program in 2007.

Under the proposed fuel program, the distribution costs are essentially the same as those for the final rule when the costs are spread over all NRLM fuel. However, when the costs of distributing downgraded distillate are assigned to the only 15 ppm nonroad cap, as this is the incremental step in fuel control which causes these costs, the cost per gallon is of higher. In this case, the cost from 2010-2014 and in 2014 and beyond increase to 0.54 and 1.0 cent per gallon, respectively. In this case, the cost assigned to L&M fuel of distributing downgraded distillate is zero.

7.5 Total Cost of Supplying NRLM Fuel Under the Two-Step Program

The estimated refining, additive, and distribution costs from Sections 7.2 - 7.4 for the final NRLM fuel program and the other fuel control options considered are summarized in Table 7.5-1. Estimated costs during the various phases of these programs are also shown. Note that these fuel costs include the impacts of the small-refiner provisions. Also, in the case of the final NRLM fuel program, we spread the downgrade distribution costs across all NRLM fuel from 2010-2012, even though L&M fuel is still at 500 ppm. We did so to avoid a higher apparent cost of 15 ppm nonroad fuel from 2010-2012 than from 2012-2014. However, in the case of the proposed NRLM fuel program, we assigned all of the downgrade distribution cost to nonroad fuel, since the long term standard for L&M fuel is 500 ppm in this scenario. These cost estimates do not include the costs associated with testing, labeling, reporting, and recordkeeping to satisfy the compliance assurance provisions of the final rule, but these costs are small enought such that they would not change the values in Table 7.5-1 due to round-off.

Table 7.5-1
Summary of Fuel Costs for NRLM Fuel Control Options (cents per gallon, $2002)

Option	Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
Final Rule	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.7	0.6	3.3
	500 ppm NRLM	2012-14	2.9	0.6	3.5
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.8	1.2	7.0
Proposed NRLM Program: 500 ppm NRLM in 2007, 15 ppm Nonroad in 2010	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm L & M	2010-14	2.7	0.2	2.9
	500 ppm L & M	2014+	2.7	0.2	2.9
	15 ppm Nonroad	2010-14	5.0	1.0	6.0
	15 ppm Nonroad	2014+	5.2	1.4	6.6
500 ppm NRLM in 2007 only (no 15 ppm fuel control)	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010+	2.0	0.2	2.2
Final Rule with NRLM Volume Derived from EIA FOKS/AEO Reports	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.8	0.6	3.4
	500 ppm NRLM	2012-14	3.0	0.6	3.6
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.7	1.2	6.9

Our projected total cost for supplying 500 ppm fuel is slightly less than the historical price differential between 500 ppm highway diesel fuel and uncontrolled high-sulfur diesel fuel. This differential has averaged about 2.5 cents per gallon for the five-year period from 1995 to 1999. Market prices may be either higher or lower than the societal costs estimated here as discussed in the next section. Thus, such comparisons can only be considered approximate. The primary reason that our projected costs for 500 ppm NRLM fuel might be lower than those for highway fuel is the ability to use existing hydrotreaters which are no longer being used to produce 500 ppm highway fuel in the 2007-2010 timeframe.

7.6 Potential Fuel Price Impacts

Transportation fuel prices are dependent on a wide range of factors, such as world crude oil prices, economic activity at the national level, seasonal demand fluctuations, refinery capacity utilization levels, processing costs (including fuel-quality specifications), and the cost of alternative energy sources (e.g., coal, natural gas). Only a few of these factors, namely fuel processing costs and refinery capacity utilization, may be affected by the NRLM fuel program.

Fuel processing and distribution costs will clearly be affected due to the cost of desulfurizing NRLM diesel fuel to either the 500 or 15 ppm sulfur cap. Refinery utilization levels may be affected as the capacity to produce 500 ppm or 15 ppm NRLM diesel fuel will depend on refiners' investment in desulfurization capacity. The potential impact of increased fuel processing and distribution costs on the prices is assessed below. The impact of the NRLM fuel program on refinery utilization levels is beyond the scope of this analysis. In the long run, refiners will clearly invest to produce adequate volumes of NRLM diesel fuels, as well as other distillate fuels. In the shorter term, the issue of refiners' adequate investment in desulfurization capacity is addressed in Section 5.9.

Two approaches to projecting future price impacts are evaluated here. The most direct approach to estimating the impact of the NRLM fuel program on prices is to observe the price premiums commanded by similar products in the marketplace. This is feasible for 500 ppm NRLM diesel fuel, as both 500 ppm highway diesel fuel and high-sulfur diesel fuel are both marketed today. As discussed in Section 7.2.2 above, the historical price premium of 500 ppm highway diesel fuel is 2.5 cents per gallon over that of high-sulfur distillate. As this premium is almost identical to our projected average total cost of the supplying 500 ppm NRLM diesel fuel, it represents one reasonable estimate of the future price impact of the 500 ppm NRLM diesel fuel standard.

It is not possible to use this methodology to project the price impact of the 15 ppm nonroad diesel fuel cap. Only a very limited amount of diesel fuel meeting a 15 ppm sulfur cap is currently marketed in the United States. This fuel is designed to be used in vehicle fleets retrofitted with particulate traps. The fuel is produced in very limited quantities using equipment designed to meet the current EPA and California highway diesel fuel standards. It is also much more costly to distribute due to its extremely low volume. Thus, the current market prices for 15 ppm diesel fuel in the United States are not at all representative of what might be expected in 2010 and 2012 under the NRLM program.

A greater volume, though still not large quantities, of 10 ppm sulfur diesel fuel is currently being sold in Europe. The great majority of this fuel is Swedish Class 1 (so-called City) diesel fuel, which is effectively a number one diesel fuel with very low aromatic content. The low aromatic specification significantly affects the cost of producing this fuel. Also, this fuel is generally produced using equipment not originally designed to produce 10 to 15 ppm sulfur fuel. Thus, as in the United States, the prices paid for this fuel are not representative of what will occur in the United States in 2010 and 2012. We therefore did not attempt to use current fuels, which have sulfur levels similar to the standards in this final rule, to evaluate our cost estimate for meeting the 15 ppm standard.

The other approach to project potential price impacts utilizes the projected costs to meet the 500 ppm and 15 ppm NRLM fuel sulfur caps. Both sulfur caps will affect fuel processing and distribution costs across the nation. (The exception will be California, where we presume that sulfur caps at least as stringent as those in this final rule will already be in effect.) However, these costs appear to vary significantly from region to region. Because of the cost of fuel distribution and limited pipeline capacities (pipelines are the most efficient means of transporting fuel), the NRLM fuel markets (and those for other transportation fuels) are actually regional in nature. Price differences can and usually do exist between the various regions of the country. Because of this, we have performed our assessment of potential price impacts on a regional basis. For the regions in our analysis, we have chosen PADDs. Practically speaking, there are probably more than five fuel markets in the United States with distinct prices. However, analyzing five distinct refining regions appears to provide a reasonable range of price impacts without adding precision that significantly exceeds our ability to project costs.

We made one exception to the PADD structure. PADD 3 (the Gulf Coast) supplies more high-sulfur distillate to PADD 1, particularly the Northeast, than is produced by PADD 1 refineries. Two large pipelines connect PADD 3 refineries to the Northeast, the Colonial and the Plantation. Because of this low-cost transportation connection, prices between the two PADDs are closely linked. We therefore combined our price analysis for PADDs 1 and 3.

As mentioned above, it is very difficult to predict fuel prices, either in the short term or long term. Over the past three years, transportation fuel prices (before excise taxes) have varied by a factor of two. Therefore, we have avoided any attempt to project absolute fuel prices. Because of the wide swings in absolute fuel prices, it is very difficult to assess the impact of individual factors on fuel price. The one exception is the price of crude oil, for two reasons. One, the cost of crude oil is the dominant factor in the overall cost of producing transportation fuels. Two, the pricing of almost all crude oils is tied to the "world" market price of crude oil. While the cost of producing crude oil in each region of the world is independent of those of other crude oil, contract prices are tied to crude oils traded on the open market, such as West Texas Intermediate and North Sea Brent crude oils. Thus, as the price of world crude oil climbs, the price of gasoline and diesel fuel climb across the United States, and vice versa. There is also a very rough correlation between refinery capacity utilization levels and fuel price. However, an unusually high availability of imports can cause prices to be relatively low despite high refinery capacity utilization rates in the United States.

For example, fuel prices, as a function of crude oil price, have varied widely over the past decade. Refiner records supplied to EIA indicate that refiners' net refining margin has ranged from a low of $0.45 per barrel in 1992 to a high of 2.78 per barrel in 2001.[59] Thus, fuel prices have varied between being so low that refineries are barely covering their cash expenses to high enough to justify moderate cost increases in refining capacity (but not new refineries). The NRLM program will very unlikely have a major impact on factors such as these. Thus, projecting the likely price impact of the NRLM program is highly speculative. The best that can be done is to develop a wide range of potential price impacts indicative of the types of conditions that have existed in the past.

In order to do this, we developed three projections for the potential impact of the NRLM program on fuel prices. The lower end of the range assumes a very competitive NRLM fuel market with excess refining capacity. In this case, fuel prices within a PADD are generally low and reflect only incremental operating costs. Consistent with this assumption, we project that the price of NRLM diesel fuel within a PADD will increase by the operating cost of the refinery with the highest operating cost in that PADD. This assumes that the refinery facing the highest operating cost in producing NRLM diesel fuel is setting the price of NRLM diesel fuel before this rule. This may or may not be the case. If not, the price increase may be even lower than that projected below. Under this "low -cost" set of assumptions, the refiner with the highest operating cost will not recover any of his invested capital related to desulfurizing NRLM diesel fuel, but all other refiners will recover some of their investment.[VV] Note that this scenario is only viable in the short run, since refineries need to recover both operating and fixed costs in the long run.

The mid-range estimate of price impacts can be termed the "full-cost" scenario. It assumes that prices within a PADD increase by the average refining and distribution cost within that PADD, including full recovery of capital (at the societal rate of return of 7 percent per annum before taxes). This scenario represents a case where there is full cost pass through to consumers under a competitive market setting. It should be noted that there are instances when this full-cost scenario produces lower costs than the maximum operating cost scenario. This occurs when the bulk of the low sulfur fuel can be produced at a relatively low cost compared to a few refineries facing relatively high operating costs.

Under this full-cost price scenario, lower cost refiners will recover their capital investment plus economic profit, while those with higher than average costs will recover some of their invested capital, but not all of it (i.e., at a rate of return lower than 7 percent annually).

The high-end estimate of price impacts assumes a NRLM fuel market that is constrained with respect to fuel production capacity. Prices rise to the point necessary to encourage additional desulfurization capacity. Also, prices are assumed to remain at this level in the long term, meaning that any additional desulfurization capacity barely fulfills demand and does not create

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[VV] Theoretically, some refiners might recover all their invested capital if their operating costs were sufficiently lower than those of the high cost refiner. However, practically, in the case of desulfurizing NRLM diesel fuel, this is highly unlikely.

an excess in capacity that would tend to reduce prices. However, prices should not increase beyond this level in the long run, as this would encourage the construction of additional desulfurization capacity, lowering prices. Consistent with this, prices within a PADD increase by the maximum total refining and distribution cost of any refinery within that PADD, including full recovery of capital (at 7 percent per annum before taxes). All other refiners will recover more than their capital investment.

Table 7.6-1 presents the refining costs for the four phases of the NRLM fuel program under the three potential price scenarios.

Table 7.6-1
NRLM Fuel Refining Costs by Region (cents per gallon)

	Maximum Operating Cost	Average Total Cost	Maximum Total Cost
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.7	1.6	4.3
PADD 2	2.8	2.8	3.6
PADD 4	3.5	3.3	5.9
PADD 5	1.0	1.3	1.3
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2010-2012)			
PADDs 1 and 3	2.3	3.7	5.0
PADD 2	2.9	2.9	3.8
PADD 4	3.9	8.9	8.9
PADD 5	1.6	2.8	2.9
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2012-2014)			
PADDs 1 and 3	2.7	2.5	5.9
PADD 2	2.7	3.7	5.7
PADD 4	3.9	9.0	9.0
PADD 5	2.2	3.5	4.2
15 ppm Sulfur Cap: NRLM Fuel (2010-2012			
PADDs 1 and 3	4.7	4.6	8.5
PADD 2	5.0	7.1	8.5
PADD 4	7.1	11.6	12.7
PADD 5	3.6	4.3	4.3
15 ppm Sulfur Cap: NRLM Fuel (2012-2014)			
PADDs 1 and 3	4.8	4.8	8.6
PADD 2	6.4	7.8	10.0
PADD 4	7.0	11.7	12.7
PADD 5	3.6	4.3	4.3
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	6.5	5.1	8.6
PADD 2	6.4	7.8	10.0
PADD 4	7.0	11.8	12.7
PADD 5	3.9	5.6	6.0

Table 7.6-2 shows these same cost projections including distribution and lubricity additive costs. The wholesale price of high-sulfur distillate fuel has varied widely even over the past twelve months. The March 2003 heating oil futures price alone has ranged from 60-110 cents per gallon since early 2002. Assuming a base cost of NRLM fuel of one dollar per gallon, the increase in NRLM fuel prices will be equivalent to the price increase in terms of cents per gallon shown below.

Table 7.6-2
Range of Possible Total Diesel Fuel Price Increases (cents per gallon)[a]

	Maximum Operating Cost	Average Total Cost	Maximum Total Cost
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.9	1.8	4.5
PADD 2	3.0	2.5	3.8
PADD 4	3.7	3.5	6.1
PADD 5	1.2	1.5	1.5
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2010-2012)			
PADDs 1 and 3	2.9	4.3	5.6
PADD 2	3.5	3.5	4.4
PADD 4	4.5	9.5	9.5
PADD 5	2.2	3.4	3.5
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2012-2014)			
PADDs 1 and 3	3.3	3.1	6.5
PADD 2	3.3	4.3	6.3
PADD 4	4.5	9.6	9.6
PADD 5	2.8	4.1	4.8
15 ppm Sulfur Cap: NRLM Fuel (2010-2012			
PADDs 1 and 3	5.5	5.4	9.3
PADD 2	5.8	6.8	9.3
PADD 4	7.9	12.4	13.5
PADD 5	4.4	5.1	5.1
15 ppm Sulfur Cap: NRLM Fuel (2012-2014)			
PADDs 1 and 3	5.6	5.6	9.4
PADD 2	7.2	8.5	10.8
PADD 4	7.8	12.5	13.5
PADD 5	4.4	5.1	5.1
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	7.7	6.3	9.8
PADD 2	7.6	7.9	11.2
PADD 4	8.2	13.0	13.9
PADD 5	5.1	6.8	7.2

Notes: [a] At a wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

There are a number of assumptions inherent in these price projections. First, both the lower and upper limits of the projected price impacts described above assume that the refinery facing the highest compliance costs is currently the price setter in their market. If this is not the case, the price impacts would be lower than those shown in the previous tables. Many factors affect a refinery's total costs of fuel production. Most of these factors, such as crude oil cost, labor costs, age of equipment, etc., are not considered in projecting the incremental costs associated with lower NRLM diesel fuel sulfur levels. Thus, current prices may very well be set in any specific market by a refinery facing lower incremental compliance costs than other refineries. This point was highlighted in a study by the National Economic Research Associates (NERA) for AAM of the potential price impacts of EPA's 2007 highway diesel fuel program.[WW] In that study, NERA criticized the above referenced study performed by Charles River Associates, *et. al.* for API, which projected that prices will increase nationwide to reflect the total cost faced by the U.S. refinery with the maximum total compliance cost of all the refineries in the U.S. producing highway diesel fuel. To reflect the potential that the refinery with the highest projected compliance costs under the maximum price scenario is not the current price setter, we included the mid-point price impacts above. It is possible that even the lower limit price impacts are too high, if the conditions exist where prices are set based on operating costs alone. However, these price impacts are sufficiently low that considering even lower price impacts was not considered critical to estimating the potential economic impact of this rule.

Second, we assumed in some cases that a single refinery's costs could affect fuel prices throughout an entire PADD. While this is a definite improvement over analyses which assume that a single refinery's costs could affect fuel prices throughout the entire nation, it is still conservative, since one refinery's fuel can rarely have such a widespread influence. For example, Chicago and Detroit have experienced unusually high gasoline prices at times over the past 4 years, but prices in St. Louis, Cincinnati, Minneapolis, etc. were not similarly affected. High cost refineries are more likely to have a more limited geographical impact on market pricing than an entire PADD. In many cases, high cost refiners are able to operate profitably because they are in a niche location where transportation costs limit competition.

Third, by focusing solely on the cost of desulfurizing NRLM diesel fuel, we assume that the production of NRLM diesel fuel is independent of the production of other refining products, such as gasoline, jet fuel and highway diesel fuel. However, this is clearly not the case. Refiners have some flexibility to increase the production of one product without significantly affecting the others, but this flexibility is quite limited. It is possible that the relative economics of producing other products could influence a refiner's decision to increase or decrease the production of NRLM diesel fuel under the fuel program in this rule. It is this price response that causes fuel supply to match fuel demand. And, this response in turn could increase or decrease the price impact relative to those projected above.

[WW] "Potential Impacts of Environmental Regulations on Diesel Fuel Prices," NERA, for AAM, December 2000.

Fourth, all three of the above price projections are based on the projected cost for U.S. refineries of meeting the NRLM fuel sulfur caps. Thus, these price projections assume that imports of NRLM fuel, which are currently significant in the Northeast, are available at roughly the same cost as those for U.S. refineries in PADDs 1 and 3. We have not performed any analysis of the cost of lower sulfur caps on diesel fuel produced by foreign refiners. However, there are reasons to believe that imports of 500 and 15 ppm NRLM diesel fuel will be available at prices in the ranges of those projected for U.S. refiners.

One recent study analyzed the relative cost of lower sulfur caps for Asian refiners relative to those in the U.S., Europe and Japan.[XX] It concluded that costs for Asian refiners will be comparatively higher, due to the lack of current hydrotreating capacity at Asian refineries. This conclusion is certainly valid when evaluating lower sulfur levels for highway diesel fuels which are already at low levels in the U.S., Europe and Japan and for which refineries in these areas have already invested in hydrotreating capacity. It appears to be less valid when assessing the relative cost of meeting lower sulfur standards for NRLM fuels and heating oils which are currently at much higher sulfur levels in the U.S., Europe and Japan. All refineries face additional investments to remove sulfur from these fuels and so face roughly comparable control costs on a per gallon basis.

One factor arguing for competitively priced imports is the fact that refinery utilization rates are currently higher in the U.S. and Europe than in the rest of the world. The primary issue is whether overseas refiners will invest to meet tight sulfur standards for U.S., European and Japanese markets. Many overseas refiners will not invest, instead focusing on local, higher sulfur markets. However, many overseas refiners focus on exports. Both Europe and the U.S. are moving towards highway and nonroad diesel fuel sulfur caps in the 10-15 ppm range. Europe is currently and projected to continue to need to import large volumes of highway diesel fuel. Thus, it seems reasonable to expect that a number of overseas refiners will invest in the capacity to produce some or all of their diesel fuel at these levels. Many overseas refiners also have the flexibility to produce 10-15 ppm diesel fuel from their cleanest blendstocks, as most of their available markets have less stringent sulfur standards. Thus, there are reasons to believe that some capacity to produce 10-15 ppm diesel fuel will be available overseas at competitive prices. If these refineries were operating well below capacity, they might be willing to supply complying product at prices which only reflect incremental operating costs. This could hold prices down in areas where importing fuel is economical. However, it is unlikely that these refiners could supply sufficient volumes to hold prices down nationwide. Despite this expectation, to be conservative, in the refining cost analysis conducted earlier in this chapter, we assumed no imports of 500 ppm or 15 ppm NRLM diesel fuel. All 500 ppm and 15 ppm NRLM fuel was produced by domestic refineries. This raised the average and maximum costs of 500 ppm and 15 ppm NRLM diesel fuel and increased the potential price impacts projected above beyond what would have been projected had we projected that 5-10 percent of NRLM diesel fuel will be imported at competitive prices.

[XX] "Cost of Diesel Fuel Desulfurization In Asian Refineries," Estrada International Ltd., for the Asian Development Bank, December 17, 2002.

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CHAPTER 8: Estimated Aggregate Cost and Cost per Ton of Reduced Emissions

CHAPTER 8: Estimated Aggregate Cost and Cost per Ton of Reduced Emissions

This chapter aggregates the estimated incremental engine costs, operating costs, equipment costs, and fuel costs of the final rule. This chapter also presents detailed information on the calculation for the cost per ton of pollutant. Chapter 6 details the estimated fixed and variable costs for modifying new nonroad engines and equipment to meet new emission standards; Chapter 6 also discusses the effects of the new low-sulfur diesel fuels on operating costs for land-based nonroad diesel engines, locomotive engines, and marine diesel engines. Chapter 7 describes our estimates of the costs associated with the fuel requirements in this final rule.

We have calculated the cost per ton of emission reductions for this final rule based on the net present value of all costs incurred and all emission reductions generated over a 30-year time window after the program takes effect. This approach captures all the costs and emission reductions from the final rule, including those costs incurred and emission reductions generated by the existing fleet. The point of comparison for this evaluation is the existing set of fuel and engine standards (i.e., unregulated fuel and the Tier 2/Tier 3 program). The 30-year time window is meant to capture both the early period of the program when there are a small number of compliant engines in the fleet, and the later period when there is nearly complete turnover to compliant engines. Note that all costs and emission reductions presented here are 30-year numbers (the net present values in 2004 of the stream of costs/reductions occurring from 2007 through 2036, expressed in $2002).

While there is a broad consensus among economists that future benefits and costs of regulatory programs should be discounted, there is no consensus in the literature regarding the most appropriate discounting concept and rate to apply. In particular, the theoretical literature is divided between two alternative approaches. The first approach is referred to as the "demand-side approach" (see Arrow et al, 1996), which defines the appropriate discount rate as the rate at which society would collectively trade off current versus future consumption. This rate is difficult to establish empirically, but estimates in the literature commonly range from 1 to 4 percent. EPA's economic Guidelines suggest using a value of two to three percent.[1] The second approach is referred to as the "cost-side approach" (see Lind, 1982), and discount rates associated with this concept reflect trade-offs between current and future consumption derived by market rates driven by the marginal productivity of capital. This rate is also difficult to derive from empirical data, but estimates typically fall in the range of 4 to 10 percent. OMB's circular A-94 expresses a preference for the cost-side approach and specifies a seven percent rate.

Given both the lack of consensus in the literature on the most appropriate concept and the uncertainty surrounding the associated empirical estimates, EPA's Economic Guidelines and the two key outside expert groups which advise EPA on economic analytical issues all recommend evaluating benefits and costs using a range of discount rates. Consistent with this advice, we have analyzed the benefits and costs of the nonroad Tier 4 rule using both a three percent rate and a seven percent rate. We present the results based on a three percent discount rate as our primary estimates.

8.1 Projected Sales and Cost Allocations

Projected nonroad engine and equipment sales estimates are used in several portions of this analysis. We have used two sources for our projected sales numbers—the PSR database for the 2000 model year, and our Nonroad Model.[2, 3] The PSR database has been used as the basis for our current fleet mix; i.e., which equipment types were sold in 2000 and with engines from which power category. The sales estimates and growth rates used throughout this analysis are shown in Table 8.1-1.[4]

Table 8.1-1
Estimated 2000 Engine Sales and Future Sales Growth

Power range	2000 Model Year Sales	Annual Growth in Engines Sold	Linear Growth Rate
0<hp<25	119,159	4,116	3.5%
25≤hp<50	132,981	3,505	2.6%
50≤hp<75	93,914	2,046	2.2%
75≤hp<100	68,665	1,499	2.2%
100≤hp<175	112,340	2,321	2.1%
175≤hp<300	61,851	1,414	2.3%
300≤hp<600	34,095	436	1.3%
600≤hp≤750	2,752	50	1.8%
hp>750	2,785	51	1.8%
Total	628,542	15,438	2.5%

Because the new emission standards will reduce emissions of several different pollutants (i.e., NOx, PM, NMHC, and SOx), we have attempted to allocate the estimated costs to emission reductions of specific pollutants. This apportionment of costs by pollutant allows us to calculate the average cost per ton of emission reduction resulting from this rule. Table 8.1-2 summarizes the allocations we have used in the final rule. Deciding how to apportion costs can be difficult even in the case of technologies that, on the surface, seem to have an obvious split by which their costs should be attributed. For instance, we have apportioned 100 percent of the cost for CDPF technology to PM even though CDPFs are expected to reduce NMHC emissions significantly.[A] For fuel-related costs where no technology enablement occurs (i.e., fuel-derived emissions

[A] A CDPF is a catalyzed diesel particulate filter; a DOC is a diesel oxidation catalyst; CCV is a closed crankcase ventilation system; Regen is short for regeneration; EGR is exhaust gas recirculation; NRLM refers to nonroad, locomotive, and marine.

reductions where no new engine standards exist that rely on the new fuel), we have apportioned one-third of the costs to PM and two-thirds to SOx. This is different than how we allocated costs in the proposal where we allocated 100 percent of such costs to SOx control. We believe the allocation used here is more appropriate given that the lower sulfur fuel provides for substantial PM reductions even without new engine standards.[B] The estimated costs for 15 ppm fuel are apportioned one-half to technology enablement (i.e., engine-derived emissions reductions) and one-half to fuel-derived emissions reductions. Respectively, these halves are allocated 50%/50% to NOx+NMHC/PM and 33%/67% to PM/SOx. This latter split is consistent with the fuel-derived allocation described above. This is different than the proposal where we allocated 15 ppm costs entirely to technology enablement. We believe the allocations used here in the final rule are more appropriate given the substantial PM and SOx reductions that occur solely because the fuel sulfur level has been reduced. We note throughout the discussion to which pollutant we have attributed costs.

8.2 Aggregate Engine Costs

This section presents aggregate engine fixed costs (recovered costs) and variable costs. These costs are discussed in detail in Section 6.2.

8.2.1 Aggregate Engine Fixed Costs

Chapter 6 presents the aggregate engine fixed costs, along with our best estimate of how those costs might be recovered (i.e., on which engines), for engine R&D, tooling, and certification, respectively (see Tables 6.2-4, 6.2-6, and 6.2-8).[C] Table 8.2-1 presents the combined total of all engine fixed costs in the indicated years for each power category. Table 8.2-2 shows to what pollutant the total costs by year are allocated. Note that the cost allocations shown in Table 8.2-1 are not generated assuming any simple split of costs between NOx and PM control. Some engine fixed costs are solely attributed to PM control (for example, costs associated with the 2008 standards and costs associated with the 2013 standards for 50 to 75 hp engines). Therefore, the costs presented in Table 8.2-2 for PM do not represent the total fixed costs of the program if there were no new NOx standards; the same is true of NOx costs if there

[B] A 50/50 split between PM/SOx could be argued, but that seems inappropriate given that 98 percent of fuel borne sulfur is exhausted as SOx and only two percent is exhausted as PM. Given that, a 2/98 split between PM/SOx could be argued, but that seems inappropriate given the importance of PM reductions—which have much higher human health benefits—relative to SOx reductions. The 33/67 split between PM/SOx that we have chosen here seems to provide an appropriate balance.

[C] We have estimated a "recovered" cost for all engine and equipment fixed costs to present a per-production-unit analysis of the cost of the final rule (see Section 6.4.3 or Chapter 10 for our estimate of engine costs on a per-unit basis). In general, in environmental economics, it is more conventional to simply count the total costs of the program (i.e., opportunity costs) in the year they occur. However, this approach does not directly estimate a per-unit cost, since fixed costs occur before the standards take effect, resulting in costs that do not correspond to units certified to the new emission standards. As a result, we grow fixed costs until they can be "recovered" on complying units. Note that the approach used here results in a higher estimate of the total costs of the program, since the recovered costs include a seven percent interest rate to reflect the time value of money (i.e., the lost opportunity cost of that capital).

were no new PM standards. Refer to Section 6.2 for detail on how we have estimated engine fixed costs and their recovery, and to Table 8.1-2 for how they are allocated among each pollutant.

Table 8.1-2
Summary of How Cost are Allocated Among Pollutants under the NRT4 Final Program

Item		NOx+NMHC	PM	SOx
Fuel Costs – incremental cent/gallon	500 ppm Affected NRLM		33%	67%
	15 ppm Affected NR	50% of 50%	50% of 50% 33% of 50%	67% of 50%
	15 ppm Affected L&M		33%	67%
Operating Costs – Oil-Change Savings	500 ppm Affected NRLM		33%	67%
	15 ppm Affected NR	50% of 50%	50% of 50% 33% of 50%	67% of 50%
	15 ppm Affected L&M		33%	67%
Operating Costs – CDPF Maintenance	15 ppm NR in new CDPF engines		100%	
Operating Costs – CDPF Regen (FE impact)	15 ppm NR in new CDPF engines		100%	
Operating Costs – CCV Maintenance	All NR in new CCV engines	50%	50%	
Engine Variable Costs	CDPF System		100%	
	NOx Adsorber System	100%		
	DOC		100%	
	Fuel-Injection System	50%	50%	
	Regeneration System		100%	
	Cooled EGR	100%		
	Closed Crankcase Ventilation Sys	50%	50%	
Engine Fixed Costs – R&D	CDPF+NOx Adsorber	67%	33%	
	CDPF-only		100%	
	DOC-only		100%	
Engine Fixed Costs – Tooling	CDPF+NOx Adsorber	50%	50%	
	CDPF-only		100%	
	DOC-only		100%	
	Cooled EGR	100%		
Engine Fixed Costs – Certification	<75 hp 2008		100%	
	25-50 hp 2013	50%	50%	
	50-75 hp 2013		100%	
	75-750 hp at start of phase-in	50%	50%	
	75-750 hp at end of phase-in	100%		
	>750 hp	50%	50%	
Equipment Variable Costs	<25 hp; 25-75 hp 2008-2012		100%	
	25-50 hp 2013+	50%	50%	
	50-75 hp 2013+		100%	
	75-750 hp at start of phase-in[b]	25%	75%	
	75-750 hp at end of phase-in	50%	50%	
	>750 hp		100%	
Equipment Fixed Costs	<75 hp 2008 standards		100%	
	25-75 hp 2013 standards	50%	50%	
	75-750 hp at start of phase-in	50%	50%	
	75-750 hp at end of phase-in	100%		
	>750 hp 2011	100%		
	>750 hp 2015		100%	

[b] All engines meet the new PM standard and half meet the new NOx standard. For NOx phase-in engines, the allocation is 50/50 to PM/NOx. For PM-only engines, the allocation is 100% PM. The resultant allocation is 75/25 to PM/NOx.

8.2-1
Aggregate Engine Fixed Costs by Power Category
($Millions of 2002 dollars)

Year	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2008	$ 5.8	$ 8.0	$ 5.5	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.3
2009	$ 5.8	$ 8.0	$ 5.5	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.3
2010	$ 5.8	$ 8.0	$ 5.5	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.3
2011	$ 5.8	$ 8.0	$ 5.5	$ -	$ -	$ 17.4	$ 20.5	$ 3.8	$ 1.9	$ 62.9
2012	$ 5.8	$ 8.0	$ 5.5	$ 6.9	$ 10.9	$ 17.4	$	$ 3.8	$ 1.9	$ 80.7
2013	$ -	$ 13.3	$ 9.2	$ 6.9	$ 10.9	$ 17.4	$ 20.5	$ 3.8	$ 1.9	$ 83.8
2014	$ -	$ 13.3	$ 9.2	$ 9.6	$ 15.4	$ 23.7	$ 20.5	$ 5.6	$ 1.9	$ 108.2
2015	$ -	$ 13.3	$ 9.2	$ 9.6	$ 15.4	$ 23.7	$ 29.5	$ 5.6	$ 5.1	$ 111.4
2016	$ -	$ 13.3	$ 9.2	$ 9.6	$ 15.4	$ 6.3	$ 29.5	$ 1.8	$ 3.2	$ 67.8
2017	$ -	$ 13.3	$ 9.2	$ 2.7	$ 4.5	$ 6.3	$	$ 1.8	$ 3.2	$ 50.0
2018	$ -	$ -	$ -	$ 2.7	$ 4.5	$ 6.3	$ 9.0 9.0	$ 1.8	$ 3.2	$ 27.6
2019	$ -	$ -	$ -	$ -	$ -	$	$ 9.0 -	$ -	$ 3.2	$ 3.2
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 28.8	$ 106.1	$ 73.5	$ 48.2	$ 77.0	$ 118.3	$ 147.7	$ 28.1	$ 25.7	$ 653.4
30 Yr NPV at 3%	$ 24.2	$ 81.3	$ 56.3	$ 35.3	$ 56.4	$ 88.7	$ 110.3	$ 21.0	$ 18.3	$ 491.8
30 Yr NPV at 7%	$ 19.3	$ 58.3	$ 40.4	$ 23.7	$ 37.9	$ 61.5	$ 76.2	$ 14.5	$ 11.9	$ 343.6

Table 8.2-2
Aggregate Engine Fixed Costs by Pollutant
($Millions of 2002 dollars)

Year	Recovery of PM Costs	Recovery of NOx Costs	Recovery of Fixed Costs
2008	$ 19.3	$ -	$ 19.3
2009	$ 19.3	$ -	$ 19.3
2010	$ 19.3	$ -	$ 19.3
2011	$ 40.9	$ 22.0	$ 62.9
2012	$ 49.8	$ 30.9	$ 80.7
2013	$ 51.3	$ 32.5	$ 83.8
2014	$ 51.3	$ 56.9	$ 108.2
2015	$ 54.1	$ 57.3	$ 111.4
2016	$ 32.5	$ 35.3	$ 67.8
2017	$ 23.6	$ 26.4	$ 50.0
2018	$ 2.8	$ 24.8	$ 27.6
2019	$ 2.8	$ 0.4	$ 3.2
2020	$ -	$ -	$ -
Total	$ 366.9	$ 286.4	$ 653.4
30 Yr NPV at 3%	$ 281.6	$ 210.3	$ 491.8
30 Yr NPV at 7%	$ 201.8	$ 141.9	$ 343.6

We have assumed that all engine R&D expenditures occur over a five-year span preceding the first year any emission-control device is introduced into the market, with the exception of R&D for the 2008 standards which occurs over a four-year span preceding the standards as described in Chapter 6. Where a phase-in exists (for example, for NOx standards on engines between 75 and 750 hp), expenditures are assumed to occur over the five years preceding the first year that NOx adsorbers will be introduced, then continuing during the phase-in years; the expenditures will be incurred consistent with the phase-in of the standard. All R&D expenditures are then recovered by the engine manufacturer over an identical time span following the introduction of the technology. We include a cost of seven percent when amortizing engine R&D expenditures.

We have assumed that all tooling and certification costs are incurred one year in advance of the new standard and are recovered over a five-year period after the new standards take effect; we include a cost of seven percent when amortizing engine tooling costs.

We have calculated the net present value of the engine fixed costs over the 30-year period following implementation of the program as $492 million. This value assumes a three percent social discount rate.

8.2.2 Aggregate Engine Variable Costs

Engine variable costs are discussed in detail in Section 6.2.2. As explained there, we have generated cost estimation equations to calculate engine variable costs. These cost estimation equations are summarized in Table 6.4-2. Using these equations, we have calculated the engine variable costs during the years 2008 through 2036 as shown in Tables 8.2-3 and 8.2-4 (refer to Table 8.1-2 for how costs have been allocated to PM and NOx). Because of their nature, variable costs are proportional to engine sales and are projected to increase in the future as engine sales increase. We have calculated the net present value of the engine variable costs over the 30-year period following implementation of the program as $13.6 billion. This value assumes a three percent social discount rate.

Table 8.2-3
Aggregate Engine Variable Costs by Power Category ($Millions of 2002 dollars)

Year	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2008	$ 19.7	$ 23.7	$ 18.4	$ -	$ -	$ -	$	$ -	$ -	$ 61.8
2009	$ 20.2	$ 24.2	$ 18.8	$ -	$ -	$ -	$	$ -	$ -	$ 63.2
2010	$ 19.7	$ 23.4	$ 18.0	$ -	$ -	$ -	$ -	$ -	$ -	$ 61.1
2011	$ 20.2	$ 23.9	$ 18.4	$ -	$ -	$ 153.4	$ - 101.5	$ 16.3	$ 6.6	$ 340.2
2012	$ 20.7	$ 24.4	$ 18.7	$ 98.2	$ 192.8	$ 156.2	$ - 102.6	$	$ 6.7	$ 636.8
2013	$ 21.2	$ 158.4	$ 100.9	$ 99.9	$ 196.0	$ 123.2	$ 80.4	$	$ 5.3	$ 798.3
2014	$ 21.7	$ 161.5	$ 102.6	$ 100.6	$ 195.6	$ 158.1	$ 102.3	$ 16.6	$ 5.4	$ 864.4
2015	$ 22.2	$ 125.3	$ 79.3	$ 102.2	$ 198.8	$ 160.9	$ 103.4	$ 13.0	$ 29.6	$ 838.5
2016	$ 22.7	$ 127.7	$ 80.6	$ 103.9	$ 201.9	$ 163.6	$ 104.5	$ 16.6	$ 30.0	$ 852.0
2017	$ 23.2	$ 130.0	$ 81.9	$ 105.6	$ 205.0	$ 166.3	$ 105.6	$ 16.8	$ 24.6	$ 859.6
2018	$ 23.7	$ 132.4	$ 83.2	$ 107.3	$ 208.2	$ 169.1	$ 106.7	$ 17.1	$ 24.9	$ 873.1
2019	$ 24.2	$ 134.8	$ 84.5	$ 109.0	$ 211.3	$ 171.8	$ 107.8	$ 17.3	$ 25.3	$ 886.5
2020	$ 24.7	$ 137.1	$ 85.8	$ 110.7	$ 214.4	$ 174.6	$ 109.0	$ 17.6	$ 25.6	$ 899.9
2021	$ 25.2	$ 139.5	$ 87.1	$ 112.3	$ 217.6	$ 177.3	$ 110.1	$ 17.8	$ 26.0	$ 913.3
2022	$ 25.7	$ 141.9	$ 88.4	$ 114.0	$ 220.7	$ 180.0	$ 111.2	$ 18.0	$ 26.3	$ 926.8
2023	$ 26.2	$ 144.2	$ 89.7	$ 115.7	$ 223.8	$ 182.8	$ 112.3	$ 18.3	$ 26.7	$ 940.2
2024	$ 26.8	$ 146.6	$ 91.0	$ 117.4	$ 227.0	$ 185.5	$ 113.4	$ 18.5	$ 27.0	$ 953.6
2025	$ 27.3	$ 149.0	$ 92.3	$ 119.1	$ 230.1	$ 188.2	$ 114.5	$ 18.8	$ 27.3	$ 967.0
2026	$ 27.8	$ 151.3	$ 93.6	$ 120.7	$ 233.2	$ 191.0	$ 115.6	$ 19.0	$ 27.7	$ 980.4
2027	$ 28.3	$ 153.7	$ 94.9	$ 122.4	$ 236.4	$ 193.7	$ 116.7	$ 19.2	$ 28.0	$ 993.9
2028	$ 28.8	$ 156.1	$ 96.2	$ 124.1	$ 239.5	$ 196.5	$ 117.8	$ 19.5	$ 28.4	$ 1,007.3
2029	$ 29.3	$ 158.4	$ 97.5	$ 125.8	$ 242.6	$ 199.2	$ 118.9	$ 19.7	$ 28.7	$ 1,020.7
2030	$ 29.8	$ 160.8	$ 98.8	$ 127.5	$ 245.8	$ 201.9	$ 120.1	$ 20.0	$ 29.1	$ 1,034.1
2031	$ 30.3	$ 163.2	$ 100.1	$ 129.2	$ 248.9	$ 204.7	$ 121.2	$ 20.2	$ 29.4	$ 1,047.6
2032	$ 30.8	$ 165.5	$ 101.4	$ 130.8	$ 252.0	$ 207.4	$ 122.3	$ 20.4	$ 29.7	$ 1,061.0
2033	$ 31.3	$ 167.9	$ 102.7	$ 132.5	$ 255.2	$ 210.2	$ 123.4	$ 20.7	$ 30.1	$ 1,074.4
2034	$ 31.8	$ 170.3	$ 104.0	$ 134.2	$ 258.3	$ 212.9	$ 124.5	$ 20.9	$ 30.4	$ 1,087.8
2035	$ 32.3	$ 172.6	$ 105.3	$ 135.9	$ 261.5	$ 215.6	$ 125.6	$ 21.2	$ 30.8	$ 1,101.2
2036	$ 32.8	$ 175.0	$ 106.6	$ 137.6	$ 264.6	$ 218.4	$ 126.7	$ 21.4	$ 31.1	$ 1,114.7
30 Yr NPV at 3%	$ 435.7	$ 2,089.2	$ 1,315.1	$ 1,627.3	$ 3,151.4	$ 2,670.3	$ 1,650.1	$ 21.6 274.9	$ 348.3	$ 13,562.1
30 Yr NPV at 7%	$ 236.9	$ 1,057.6	$ 672.3	$ 812.0	$ 1,574.6	$ 1,359.6	$ 849.2	$ 21.9 140.6	$ 168.5	$ 6,871.3

Table 8.2-4
Aggregate Engine Variable Costs by Technology and by Pollutant ($Millions of 2002 dollars)

Year	Fuel System	Cooled EGR	CCV	DOC	CDPF System	CDPF Regen System	NOx Adsorber System	Total PM Costs	Total NOx+NMHC Costs	Total Costs
2008	$ -	$ -	$ 0.5	$ 61.2	$ -	$ -	$	$ 61.5	$ 0.3	$ 61.8
2009	$ -	$ -	$ 0.6	$ 62.6	$ -	$ -	$	$ 62.9	$ 0.3	$ 63.2
2010	$ -	$ -	$ 0.4	$ 60.7	$ -	$ -	$	$ 60.9	$ 0.2	$ 61.1
2011	$ -	$ 6.2	$ 7.1	$ 62.0	$ 168.8	$ 28.7	$ - 67.4	$ 263.1	$ 77.1	$ 340.2
2012	$ -	$ 6.3	$ 13.4	$ 63.3	$ 338.4	$ 73.2	$ - 142.1	$ 481.7	$ 155.1	$ 636.8
2013	$ 53.3	$ 29.2	$ 11.8	$ 21.2	$ 414.1	$ 137.4	$ - 131.2	$	$ 193.0	$ 798.3
2014	$ 54.3	$ 29.8	$ 10.3	$ 21.7	$ 380.3	$ 128.8	$ 239.3	$	$ 301.4	$ 864.4
2015	$ 41.6	$ 24.4	$ 10.4	$ 22.2	$ 381.3	$ 115.6	$ 243.0	$ 605.3	$ 293.4	$ 838.5
2016	$ 42.4	$ 24.8	$ 10.6	$ 22.7	$ 387.3	$ 117.5	$ 246.8	$ 563.1	$ 298.0	$ 852.0
2017	$ 43.1	$ 25.2	$ 10.8	$ 23.2	$ 388.0	$ 118.9	$ 250.5	$ 545.1	$ 302.6	$ 859.6
2018	$ 43.8	$ 25.7	$ 10.9	$ 23.7	$ 393.9	$ 120.8	$ 254.2	$ 554.0	$ 307.2	$ 873.1
2019	$ 44.6	$ 26.1	$ 11.1	$ 24.2	$ 399.8	$ 122.8	$ 257.9	$ 557.0	$ 311.9	$ 886.5
2020	$ 45.3	$ 26.5	$ 11.2	$ 24.7	$ 405.7	$ 124.7	$ 261.6	$ 565.8	$ 316.5	$ 899.9
2021	$ 46.1	$ 27.0	$ 11.4	$ 25.2	$ 411.7	$ 126.6	$ 265.4	$ 574.6	$ 321.1	$ 913.3
2022	$ 46.8	$ 27.4	$ 11.6	$ 25.7	$ 417.6	$ 128.5	$ 269.1	$ 583.4	$ 325.7	$ 926.8
2023	$ 47.6	$ 27.8	$ 11.7	$ 26.2	$ 423.5	$ 130.5	$ 272.8	$ 592.3	$ 330.3	$ 940.2
2024	$ 48.3	$ 28.3	$ 11.9	$ 26.8	$ 429.5	$ 132.4	$ 276.5	$ 601.1	$ 334.9	$ 953.6
2025	$ 49.1	$ 28.7	$ 12.0	$ 27.3	$ 435.4	$ 134.3	$ 280.2	$ 609.9	$ 339.5	$ 967.0
2026	$ 49.8	$ 29.2	$ 12.2	$ 27.8	$ 441.3	$ 136.2	$ 284.0	$ 618.7	$ 344.1	$ 980.4
2027	$ 50.5	$ 29.6	$ 12.4	$ 28.3	$ 447.3	$ 138.2	$ 287.7	$ 627.5	$ 348.7	$ 993.9
2028	$ 51.3	$ 30.0	$ 12.5	$ 28.8	$ 453.2	$ 140.1	$ 291.4	$ 636.3	$ 353.3	$ 1,007.3
2029	$ 52.0	$ 30.5	$ 12.7	$ 29.3	$ 459.1	$ 142.0	$ 295.1	$ 645.1	$ 358.0	$ 1,020.7
2030	$ 52.8	$ 30.9	$ 12.8	$ 29.8	$ 465.1	$ 143.9	$ 298.8	$ 653.9	$ 362.6	$ 1,034.1
2031	$ 53.5	$ 31.3	$ 13.0	$ 30.3	$ 471.0	$ 145.8	$ 302.6	$ 662.8	$ 367.2	$ 1,047.6
2032	$ 54.3	$ 31.8	$ 13.2	$ 30.8	$ 476.9	$ 147.8	$ 306.3	$ 671.6	$ 371.8	$ 1,061.0
2033	$ 55.0	$ 32.2	$ 13.3	$ 31.3	$ 482.8	$ 149.7	$ 310.0	$ 680.4	$ 376.4	$ 1,074.4
2034	$ 55.8	$ 32.7	$ 13.5	$ 31.8	$ 488.8	$ 151.6	$ 313.7	$ 689.2	$ 381.0	$ 1,087.8
2035	$ 56.5	$ 33.1	$ 13.6	$ 32.3	$ 494.7	$ 153.5	$ 317.5	$ 698.0	$ 385.6	$ 1,101.2
2036	$ 57.2	$ 33.5	$ 13.8	$ 32.8	$ 500.6	$ 155.5	$ 321.2	$ 706.8	$ 390.2	$ 1,114.7
30 Yr NPV at 3%	$ 657.0	$ 391.7	$ 175.8	$ 611.1	$ 6,127.5	$ 1,860.1	$ 3,738.8	$ 715.8 8,015.3	$ 4,546.9	$ 13,562.1
30 Yr NPV at 7%	$ 323.5	$ 194.8	$ 90.7	$ 377.0	$ 3,102.8	$ 933.3	$ 1,849.0	$ 724.4 4,620.3	$ 2,251.0	$ 6,871.3

8.3 Aggregate Equipment Costs

This section aggregates the amortized fixed and variable cost for equipment estimated in Section 6.3.

8.3.1 Aggregate Equipment Fixed Costs

In Table 6.3-4 we presented the aggregate equipment fixed costs, along with our best estimate of how those costs might be recovered, for equipment redesign and revisions to product literature. Table 8.3-1 presents aggregate equipment fixed costs and Table 8.3-2 shows to what pollutant these costs are attributed. Note that the cost allocations shown in Table 8.3-2 are not generated assuming any simple split of costs between NOx and PM control. Some equipment fixed costs are solely attributed to PM control (for example, costs associated with the 2008 standards and costs associated with the 2013 standards for 50 to 75 hp engines). The costs presented in Table 8.3-1 for PM therefore do not represent the total fixed costs of the program if there were no new NOx standards; the same is true of NOx costs if there were no new PM standards. Refer to Section 6.3 for detail on how we have estimated equipment fixed costs and their recovery, and to Table 8.1-2 for how they are allocated among each pollutant.

We have assumed that all equipment fixed costs (redesign and product literature) occur over a two-year span preceding the first year any emission-control device is introduced into the market. Where a phase-in exists (for example, for NOx standards on engines over 75 hp engines), expenditures are assumed to occur over the two years preceding the first year that NOx adsorbers will be introduced, then continuing during the phase-in years; the expenditures will be incurred consistent with the phase-in of the standard. All expenditures are then recovered by the equipment manufacturer over 10 years following the introduction of the technology. We include a cost of seven percent when amortizing equipment fixed costs.

We have calculated the net present value of the equipment fixed costs over the 30-year period following implementation of the program as $847 million. This value assumes a three percent social discount rate.

Table 8.3-1

Aggregate Equipment Fixed Costs by Power Range ($Millions of 2002 dollars)

Year Recovered	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2008	$ 2.3	$ 1.3	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.5
2009	$ 2.3	$ 1.3	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.5
2010	$ 2.3	$ 1.3	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.5
2011	$ 2.3	$ 1.3	$ 0.9	$ -	$ -	$ 23.4	$ 20.6	$ 4.0	$ 0.6	$ 53.1
2012	$ 2.3	$ 1.3	$ 0.9	$ 9.4	$ 23.9	$ 23.4	$	$ 4.0	$ 0.6	$ 86.4
2013	$ 2.3	$ 7.5	$ 5.3	$ 9.4	$ 23.9	$ 23.4	$	$ 4.0	$ 0.6	$ 97.0
2014	$ 2.3	$ 7.5	$ 5.3	$ 11.9	$ 30.0	$ 29.4	$ 20.6	$ 5.0	$ 0.6	$ 117.7
2015	$ 2.3	$ 7.5	$ 5.3	$ 11.9	$ 30.0	$ 29.4	$ 20.6	$ 5.0	$ 4.9	$ 122.0
2016	$ 2.3	$ 7.5	$ 5.3	$ 11.9	$ 30.0	$ 29.4	$ 25.8	$ 5.0	$ 4.9	$ 122.0
2017	$ 2.3	$ 7.5	$ 5.3	$ 11.9	$ 30.0	$ 29.4	$ 25.8	$ 5.0	$ 4.9	$ 122.0
2018	$ -	$ 6.2	$ 4.4	$ 11.9	$ 30.0	$ 29.4	$ 25.8	$ 5.0	$ 4.9	$ 117.5
2019	$ -	$ 6.2	$ 4.4	$ 11.9	$ 30.0	$ 29.4	$ 25.8	$ 5.0	$ 4.9	$ 117.5
2020	$ -	$ 6.2	$ 4.4	$ 11.9	$ 30.0	$ 29.4	$ 25.8	$ 5.0	$ 4.9	$ 117.5
2021	$ -	$ 6.2	$ 4.4	$ 11.9	$ 30.0	$ 6.0	$ 25.8	$ 1.0	$ 4.3	$ 68.9
2022	$ -	$ 6.2	$ 4.4	$ 2.4	$ 6.1	$ 6.0	$ 25.8 5.2	$ 1.0	$ 4.3	$ 35.6
2023	$ -	$ -	$ -	$ 2.4	$ 6.1	$ 6.0	$ 5.2	$ 1.0	$ 4.3	$ 25.0
2024	$ -	$ -	$ -	$ -	$ -	$	$ 5.2 -	$ -	$ 4.3	$ 4.3
Total	$ 23.0	$ 75.0	$ 52.9	$ 118.6	$ 299.7	$ 293.6	$ 258.0	$ 50.1	$ 48.9	$ 1,219.9
30 Yr NPV at 3%	$ 18.0	$ 51.9	$ 36.6	$ 81.3	$ 205.5	$ 206.1	$ 181.2	$ 35.2	$ 31.5	$ 847.2
30 Yr NPV at 7%	$ 13.2	$ 32.8	$ 23.1	$ 50.5	$ 127.7	$ 132.3	$ 116.3	$ 22.6	$ 18.1	$ 536.6

Table 8.3-2
Aggregate Equipment Fixed Costs by Pollutant
($Millions of 2002 dollars)

Year	Recovery of PM Costs	Recovery of NOx+NMHC Costs	Recovery of Fixed Costs
2008	$ 4.5	$ -	$ 4.5
2009	$ 4.5	$ -	$ 4.5
2010	$ 4.5	$ -	$ 4.5
2011	$ 28.5	$ 24.6	$ 53.1
2012	$ 45.1	$ 41.2	$ 86.4
2013	$ 50.4	$ 46.5	$ 97.0
2014	$ 50.4	$ 67.3	$ 117.7
2015	$ 54.7	$ 67.3	$ 122.0
2016	$ 54.7	$ 67.3	$ 122.0
2017	$ 54.7	$ 67.3	$ 122.0
2018	$ 50.2	$ 67.3	$ 117.5
2019	$ 50.2	$ 67.3	$ 117.5
2020	$ 50.2	$ 67.3	$ 117.5
2021	$ 26.2	$ 42.7	$ 68.9
2022	$ 9.6	$ 26.0	$ 35.6
2023	$ 4.3	$ 20.7	$ 25.0
2024	$ 4.3	$ -	$ 4.3
Total	$ 547.3	$ 672.5	$ 1,219.9
30 Yr NPV at 3%	$ 384.9	$ 462.2	$ 847.2
30 Yr NPV at 7%	$ 247.9	$ 288.7	$ 536.6

8.3.2 Aggregate Equipment Variable Costs

The equipment variable costs, such as sheet metal costs, mounting hardware, and labor, were estimated by power category in Section 6.3. The aggregate equipment variable costs through 2036 are presented in Table 8.3-3. Table 8.3-4 shows the total aggregate equipment variable costs allocated by pollutant (refer to Table 8.1-2 for how costs have been allocated to PM and NOx). We have calculated the net present value of the equipment variable costs over the 30-year period following implementation of the program as $434 million. This value assumes a three percent social discount rate.

Table 8.3-3

Aggregate Equipment Variable Costs by Power Category ($Millions of 2002 dollars)

Year	0<hp<25	25<=hp<50	50<=hp<75	75<=hp<100	100<=hp<175	175<=hp<300	300<=hp<600	600<=hp<=750	>750hp	Total
2008	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -	$ -	$ -
2010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ 4.5	$ -	$ 0.4	$ -	$ 9.1
2012	$ -	$ -	$ -	$ 3.9	$ 6.4	$ 4.6	$ - 4.3 4.3	$ 0.4	$ -	$ 19.6
2013	$ -	$ 3.6	$ 2.5	$ 4.0	$ 6.5	$ 3.7	$ 3.5	$ 0.3	$ -	$ 24.2
2014	$ -	$ 3.7	$ 2.6	$ 4.3	$ 7.1	$ 5.0	$ 4.7	$ 0.4	$ -	$ 27.9
2015	$ -	$ 3.0	$ 2.1	$ 4.4	$ 7.2	$ 5.1	$ 4.8	$ 0.4	$ 0.4	$ 27.5
2016	$ -	$ 3.1	$ 2.1	$ 4.5	$ 7.3	$ 5.2	$ 4.8	$ 0.4	$ 0.4	$ 27.9
2017	$ -	$ 3.1	$ 2.2	$ 4.5	$ 7.4	$ 5.3	$ 4.9	$ 0.4	$ 0.4	$ 28.2
2018	$ -	$ 3.2	$ 2.2	$ 4.6	$ 7.6	$ 5.4	$ 4.9	$ 0.5	$ 0.4	$ 28.7
2019	$ -	$ 3.3	$ 2.2	$ 4.7	$ 7.7	$ 5.5	$ 5.0	$ 0.5	$ 0.4	$ 29.1
2020	$ -	$ 3.3	$ 2.3	$ 4.7	$ 7.8	$ 5.6	$ 5.0	$ 0.5	$ 0.4	$ 29.5
2021	$ -	$ 3.4	$ 2.3	$ 4.8	$ 7.9	$ 5.6	$ 5.1	$ 0.5	$ 0.4	$ 29.9
2022	$ -	$ 3.4	$ 2.3	$ 4.9	$ 8.0	$ 5.7	$ 5.1	$ 0.5	$ 0.4	$ 30.4
2023	$ -	$ 3.5	$ 2.4	$ 5.0	$ 8.1	$ 5.8	$ 5.2	$ 0.5	$ 0.4	$ 30.8
2024	$ -	$ 3.5	$ 2.4	$ 5.0	$ 8.2	$ 5.9	$ 5.2	$ 0.5	$ 0.4	$ 31.2
2025	$ -	$ 3.6	$ 2.4	$ 5.1	$ 8.3	$ 6.0	$ 5.3	$ 0.5	$ 0.4	$ 31.6
2026	$ -	$ 3.7	$ 2.5	$ 5.2	$ 8.5	$ 6.1	$ 5.3	$ 0.5	$ 0.4	$ 32.1
2027	$ -	$ 3.7	$ 2.5	$ 5.3	$ 8.6	$ 6.2	$ 5.4	$ 0.5	$ 0.4	$ 32.5
2028	$ -	$ 3.8	$ 2.5	$ 5.3	$ 8.7	$ 6.3	$ 5.4	$ 0.5	$ 0.4	$ 32.9
2029	$ -	$ 3.8	$ 2.6	$ 5.4	$ 8.8	$ 6.3	$ 5.5	$ 0.5	$ 0.4	$ 33.4
2030	$ -	$ 3.9	$ 2.6	$ 5.5	$ 8.9	$ 6.4	$ 5.5	$ 0.5	$ 0.4	$ 33.8
2031	$ -	$ 3.9	$ 2.7	$ 5.5	$ 9.0	$ 6.5	$ 5.6	$ 0.5	$ 0.4	$ 34.2
2032	$ -	$ 4.0	$ 2.7	$ 5.6	$ 9.1	$ 6.6	$ 5.6	$ 0.5	$ 0.4	$ 34.6
2033	$ -	$ 4.1	$ 2.7	$ 5.7	$ 9.3	$ 6.7	$ 5.7	$ 0.5	$ 0.4	$ 35.1
2034	$ -	$ 4.1	$ 2.8	$ 5.8	$ 9.4	$ 6.8	$ 5.7	$ 0.5	$ 0.4	$ 35.5
2035	$ -	$ 4.2	$ 2.8	$ 5.8	$ 9.5	$ 6.9	$ 5.8	$ 0.6	$ 0.4	$ 35.9
2036	$ -	$ 4.2	$ 2.8	$ 5.9	$ 9.6	$ 7.0	$ 5.8	$ 0.6	$ 0.5	$ 36.3
30 Yr NPV at 3%	$ -	$ 47.8	$ 32.6	$ 69.3	$ 113.5	$ 84.2	$ 75.0	$ 7.0	$ 4.8	$ 434.2
30 YR NPV at 7%	$ -	$ 23.4	$ 16.0	$ 34.5	$ 56.5	$ 42.7	$ 38.4	$ 3.6	$ 2.3	$ 217.4

Table 8.3-4
Aggregate Equipment Variable Costs by Pollutant
($Millions of 2002 dollars)

Year	PM Costs	NOx Costs	Total Variable Costs
2008	$ -	$ -	$ -
2009	$ -	$ -	$ -
2010	$ -	$ -	$ -
2011	$ 6.8	$ 2.3	$ 9.1
2012	$ 14.7	$ 4.9	$ 19.6
2013	$ 19.7	$ 4.5	$ 24.2
2014	$ 17.1	$ 10.8	$ 27.9
2015	$ 16.5	$ 11.0	$ 27.5
2016	$ 16.8	$ 11.1	$ 27.9
2017	$ 17.0	$ 11.3	$ 28.2
2018	$ 17.2	$ 11.4	$ 28.7
2019	$ 17.5	$ 11.6	$ 29.1
2020	$ 17.7	$ 11.8	$ 29.5
2021	$ 18.0	$ 11.9	$ 29.9
2022	$ 18.3	$ 12.1	$ 30.4
2023	$ 18.5	$ 12.3	$ 30.8
2024	$ 18.8	$ 12.4	$ 31.2
2025	$ 19.0	$ 12.6	$ 31.6
2026	$ 19.3	$ 12.8	$ 32.1
2027	$ 19.6	$ 12.9	$ 32.5
2028	$ 19.8	$ 13.1	$ 32.9
2029	$ 20.1	$ 13.3	$ 33.4
2030	$ 20.4	$ 13.4	$ 33.8
2031	$ 20.6	$ 13.6	$ 34.2
2032	$ 20.9	$ 13.8	$ 34.6
2033	$ 21.1	$ 13.9	$ 35.1
2034	$ 21.4	$ 14.1	$ 35.5
2035	$ 21.7	$ 14.3	$ 35.9
2036	$ 21.9	$ 14.4	$ 36.3
30 Yr NPV at 3%	$ 268.9	$ 165.3	$ 434.2
30 Yr NPV at 7%	$ 136.3	$ 81.1	$ 217.4

8.4 Aggregate Fuel Costs and Other Operating Costs

Aggregate costs presented here are used in the calculation of costs per ton of emission reductions resulting from this final rule. This includes a two-step fuel sulfur control program consisting of a NRLM sulfur cap of 500 ppm beginning in 2007 to be followed by a nonroad (NR) sulfur cap of 15 ppm beginning in 2010 and a locomotive and marine (L&M) sulfur cap of 15 ppm beginning in 2012. Refer to Chapters 5 and 7 for more information about the fuel program and how the costs for that portion of the NRT4 final rule were estimated.

As noted, the second step in the fuel program limits NR sulfur levels to 15 ppm beginning in 2010. This fuel program enables the introduction of advanced emission-control technologies—CDPFs and NOx adsorbers—that will enable nonroad engines to meet the new Tier 4 standards, and it also achieves additional emissions reductions from the fuel control itself (i.e., independent of new engine standards). The combination of the two-step NRLM fuel program and the new diesel engine standards represents the full engine and fuel program (i.e., the NRT4 final rule). Section 8.4.1 presents our estimate of the aggregate fuel costs associated with the NRT4 final rule. Sections 8.4-2 through 8.4-4 present estimates of other operating costs—CDPF and CCV maintenance, fuel economy impacts, and oil change maintenance—associated with the NRT4 final rule. Section 8.4-5 presents the cost of the fuel program absent any new engine standards. These costs differ from the costs associated with the fuel program costs of the NRT4 final rule in that no CDPF and CCV maintenance costs, and no fuel economy impacts would be realized. We present these costs because they are used in calculations of $/ton associated with such a "fuel-only" scenario.

8.4.1 Aggregate Fuel Costs

Fuel costs, described in detail in Chapter 7, are developed on a cent-per-gallon basis. Table 8.4-1 summarizes cent-per-gallon fuel costs (see Table 7.5-1), estimated fuel volumes for NR, L&M, and the resultant annual fuel costs associated with the two-step NRT4 final rule fuel program. Table 8.4-1 shows that the 30-year net present value of the new lower sulfur requirements is estimated at $16.3 billion. This assumes a three percent social discount rate. Note that the affected fuel volumes presented in Table 8.4-1 are gallons consumed in both new and existing engines since both new and existing engines will have to pay for the higher cost fuel. We have not included spillover gallons or other such gallons that would have entered the NRLM fuel pool with a sulfur level below the new cap absent the new requirements since these gallons do not represent an incremental increase in costs associated with the NRT4 final rule.

Table 8.4-1
Aggregate Fuel Costs of the Two-Step Fuel Program ($2002)

Year	Affected NR		Affected L&M		Fuel Cost*		NR Fuel Costs			L&M Fuel Costs			NRLM Annual Fuel Costs (10^6 dollars)
	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm ($/gal)	15 ppm ($/gal)	500 ppm (10^6 dollars)	15 ppm (10^6 dollars)	Total (10^6 dollars)	500 ppm (10^6 dollars)	15 ppm (10^6 dollars)	Total (10^6 dollars)	
2007					$ 0.021	$ -	$ 101		$ 101	$ 42	$ -	$ 42	$ 142
2008					$ 0.021	$ -	$ 177		$ 177	$ 73	$ -	$ 73	$ 249
2009	4,790		1,990		$ 0.021	$ -	$ 181	-	$ 181	$ 73	$ -	$ 73	$ 254
2010	8,406	-	3,454	-	$ 0.028	$ 0.058	$ 112	- 359	$ 471	$ 89	$ 0	$ 89	$ 561
2011	8,599	-	3,498	-	$ 0.033	$ 0.058	$ 20	- 472	$ 493	$ 98	$ 0	$ 98	$ 591
2012	4,014	6,189	3,185	-	$ 0.034	$ 0.062	$ 18	518	$ 536	$ 48	$ 121	$ 169	$ 704
2013	614	8,145	2,975	0	$ 0.035	$ 0.064	$ 16	555	$ 571	$ 9	$ 217	$ 226	$ 797
2014	528	8,420	1,396	1,965 0	$ 0.035	$ 0.068	$ 7	656	$ 663	$ 4	$ 208	$ 212	$ 874
2015	468	8,671	247	3,397		$ 0.070	$ -		$ 738	$ -	$ 200	$ 200	$ 938
2016	199	9,713	104	3,081		$ 0.070	$ -		$ 752	$ -	$ 202	$ 202	$ 954
2017		10,539		2,860		$ 0.070	$ -		$ 767	$ -	$ 204	$ 204	$ 971
2018	-	10,747	-	2,888		$ 0.070	$ -	738	$ 781	$ -	$ 207	$ 207	$ 988
2019	-	10,955	-	2,918		$ 0.070	$ -	752	$ 796	$ -	$ 210	$ 210	$ 1,006
2020	-	11,162	-	2,953		$ 0.070	$ -	767	$ 810	$ -	$ 212	$ 212	$ 1,022
2021	-	11,370	-	2,995		$ 0.070	$ -	781	$ 825	$ -	$ 214	$ 214	$ 1,039
2022	-	11,578	-	3,024		$ 0.070	$ -	796	$ 840	$ -	$ 217	$ 217	$ 1,056
2023	-	11,786	-	3,052		$ 0.070	$ -	810	$ 854	$ -	$ 219	$ 219	$ 1,073
2024	-	11,994	-	3,093		$ 0.070	$ -	825	$ 869	$ -	$ 221	$ 221	$ 1,090
2025	-	12,201	-	3,125		$ 0.070	$ -	840	$ 883	$ -	$ 224	$ 224	$ 1,107
2026	-	12,409	-	3,161		$ 0.070	$ -	854	$ 898	$ -	$ 226	$ 226	$ 1,124
2027	-	12,617	-	3,195		$ 0.070	$ -	869	$ 912	$ -	$ 229	$ 229	$ 1,141
2028	-	12,823	-	3,230		$ 0.070	$ -	883	$ 927	$ -	$ 231	$ 231	$ 1,158
2029	-	13,030	-	3,265		$ 0.070	$ -	898	$ 941	$ -	$ 233	$ 233	$ 1,174
2030	-	13,236	-	3,301		$ 0.070	$ -	912	$ 955	$ -	$ 236	$ 236	$ 1,191
2031	-	13,442	-	3,336		$ 0.070	$ -	927	$ 970	$ -	$ 238	$ 238	$ 1,208
2032	-	13,649	-	3,371		$ 0.070	$ -	941	$ 984	$ -	$ 241	$ 241	$ 1,225
2033	-	13,855	-	3,406		$ 0.070	$ -	955	$ 999	$ -	$ 243	$ 243	$ 1,242
2034	-	14,061	-	3,441		$ 0.070	$ -	970	$	$ -	$ 246	$ 246	$ 1,259
2035	-	14,268	-	3,476		$ 0.070	$ -	984	$ 1,013	$ -	$ 248	$ 248	$ 1,276
2036	-	14,474	-	3,512		$ 0.070	$ -	999 1,013	$ 1,028	$ -	$ 251	$ 251	$ 1,293
30 Yr NPV at 3%	-	14,680	-	3,547			$ 547	$ 1,028 12,360	$ 1,042 12,907	$	$ 3,052	$ 3,419	$ 16,326
30 Yr NPV at 7%	24,054	14,887 180,224	- 14,363	3,582 44,087			$ 456	$ 1,042 6,261	$ 6,717	$ 368	$ 1,524	$ 1,821	$ 8,538

20,174 92,196 11,729 22,124 297

* Fuel costs are relative to uncontrolled fuel and assume that, during the transitional years of 2010, 2012, & 2014, the first 5 months are at the previous year's cost and the remaining 7 months are at the next year's cost.
See Appendix 8B for how these fuel volumes were developed.

8.4.2 Aggregate Oil-Change Maintenance Savings

Maintenance savings associated with extended oil-change intervals are developed on a cent-per-gallon basis, as described in Section 6.2.3.1. The cent-per-gallon savings for nonroad engines is the fleet weighted value for nonroad engines presented in Section 6.2.3.1. This fleet weighted value is derived using data presented in Table 6.2-28 as discussed in that section. The cent-per-gallon savings for locomotive and marine engines is taken directly from Table 6.2-28. Table 8.4-2 summarizes the annual maintenance savings and associated fuel volumes for nonroad, locomotive, and marine engines. Note that the fuel volumes used for oil change maintenance savings are the same affected volumes presented in Table 8.4-1. We have not included savings associated with unaffected gallons (i.e., low sulfur gallons that would have entered the NRLM fuel pool absent the new requirements) since we assume that engines consuming those gallons benefit from the low sulfur fuel absent the NRT4 final rule. As shown in Table 8.4-2, the net present value of the oil change maintenance savings is estimated at $7.1 billion. This assumes a three percent social discount rate.

Table 8.4-2
Oil-Change Maintenance Savings Associated with the Two-Step Fuel Program ($2002)

Year	Affected NR		Affected L&M		NR Savings		L&M Savings		NRLM
	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	savings=$0.029/gal ($10^6$ dollars)	savings=$0.032/gal ($10^6$ dollars)	savings=$0.010/gal ($10^6$ dollars)	savings=$0.011/gal ($10^6$ dollars)	Total Savings (10^6 dollars)
2007					$ 140	$	$ 21	$ -	$ 161
2008					$ 246	$	$ 36	$ -	$ 282
2009	4,790		1,990		$ 251	$ -	$ 37	$ -	$ 288
2010	8,406	-	3,454	-	$ 117	$ - 198	$ 33	$ 0	$ 349
2011	8,599	-	3,498	-	$ 18	$ 261	$ 31	$ 0	$ 310
2012	4,014	6,189	3,185	-	$ 15	$ 270	$ 15	$ 23	$ 322
2013		8,145	2,975	0	$ 14	$ 278	$ 3	$ 39	$ 333
2014	614	8,420	1,396	1,965	$ 6	$ 311	$ 1	$ 35	$ 353
2015	528	8,671		0 3,397	$ -	$	$ -	$ 33	$ 370
2016	468	9,713	247	3,081	$ -	$ 338	$ -	$ 33	$ 377
2017	199	10,539	104	2,860	$ -	$ 344	$ -	$ 33	$ 384
2018	-	10,747	-	2,888	$ -	$ 351	$ -	$ 34	$ 391
2019	-	10,955	-	2,918	$ -	$ 358	$ -	$ 34	$ 399
2020	-	11,162	-	2,953	$ -	$ 364	$ -	$ 35	$ 406
2021	-	11,370	-	2,995	$ -	$ 371	$ -	$ 35	$ 412
2022	-	11,578	-	3,024	$ -	$ 377	$ -	$ 35	$ 420
2023	-	11,786	-	3,052	$ -	$ 384	$ -	$ 36	$ 427
2024	-	11,994	-	3,093	$ -	$ 391	$ -	$ 36	$ 434
2025	-	12,201	-	3,125	$ -	$ 397	$ -	$ 37	$ 441
2026	-	12,409	-	3,161	$ -	$ 404	$ -	$ 37	$ 448
2027	-	12,617	-	3,195	$ -	$ 411	$ -	$ 37	$ 455
2028	-	12,823	-	3,230	$ -	$ 417	$ -	$ 38	$ 462
2029	-	13,030	-	3,265	$ -	$ 424	$ -	$ 38	$ 469
2030	-	13,236	-	3,301	$ -	$ 431	$ -	$ 39	$ 476
2031	-	13,442	-	3,336	$ -	$ 437	$ -	$ 39	$ 483
2032	-	13,649	-	3,371	$ -	$ 444	$ -	$ 39	$ 490
2033	-	13,855	-	3,406	$ -	$ 450	$ -	$ 40	$ 497
2034	-	14,061	-	3,441	$ -	$ 457	$ -	$ 40	$ 504
2035	-	14,268	-	3,476	$ -	$ 464	$ -	$ 41	$ 511
2036	-	14,474	-	3,512	$ -	$ 470	$ -	$ 41	$ 518
30 Yr NPV at 3%	-	14,680	-	3,547	$ 703	$ 477 5,772	$ 150	$ 506	$ 7,132
30 Yr NPV at 7%		14,887 180,224		3,582	$ 590	$ 2,953	$ 123	$ 254	$ 3,919
	24,054		14,363	44,087					
	20,174	92,196	11,729	22,124					

8.4.3 Aggregate CDPF Maintenance, CDPF Regeneration, and CCV Maintenance Costs

Costs associated with CDPF maintenance and CCV maintenance are developed on a cent-per-gallon basis as described in Section 6.2.3. Table 8.4-3 summarizes the CDPF maintenance and CDPF regeneration costs associated with the NRT4 fuel program. The fuel volumes shown in Table 8.4-3 differ from those shown in Tables 8.4-1 through 8.4-2 because here we want only those gallons consumed in new CDPF equipped engines. Therefore, fuel consumed in existing engines and fuel consumed in new engines not yet equipped with a CDPF are not included in Table 8.4-3.

The cent-per-gallon costs shown for CDPF maintenance are taken from data presented in Table 6.2-29. As engines in different power categories add CDPFs, the weighted $/gallon number changes until all new engines have added a CDPF and the fleet weighted average becomes the 0.6 cents/gallon value presented in Section 6.2.3.2. The cent-per-gallon costs shown for CDPF regeneration are taken from information presented in Section 6.2.3.3.2. The weighted value shown accounts for the 60 cent/gallon base fuel cost for diesel fuel and the NOx phase-in on different engines—engines equipped with a CDPF and no NOx adsorber incur a 2% fuel economy impact associated with regeneration while engines equipped with both a CDPF and a NOx adsorber incur a 1% fuel economy impact. This weighted number also accounts for the different 15 ppm fuel cost during the years 2010-2014 and then for 2015 and later.

As shown in Table 8.4-3, the 30-year net present value of these two CDPF-related operating costs is estimated at $2.3 billion. This assumes a three percent social discount rate.

Table 8.4-3
CDPF Maintenance and CDPF Regeneration Costs Associated with the Two-Step Fuel Program ($2002)

Year	Fuel Consumed in New CDPF Equipped Engines (10^6 gallons)	Weighted Maintenance Cost ($/gal)	Weighted Regeneration Cost ($/gal)	CDPF Maintenance Cost (10^6 dollars)	CDPF Regeneration Cost (10^6 dollars)	Total Costs (10^6 dollars)
2007	-	$ -	$ -	$ -	$ -	$ -
2008	-	$ -	$ -	$ -	$ -	$ -
2009	-	$ -	$ -	$ -	$ -	$ -
2010	-	$ -	$ -	$ -	$ -	$ -
2011	559	$ 0.002	$ 0.010	$ 1	$ 6	$ 6
2012	1,543	$ 0.003	$ 0.010	$ 5	$ 15	$ 20
2013	2,774	$ 0.005	$ 0.010	$ 14	$ 28	$ 42
2014	4,010	$ 0.006	$ 0.007	$ 23	$ 30	$ 53
2015	5,343	$ 0.006	$ 0.008	$ 31	$ 41	$ 73
2016	6,630	$ 0.006	$ 0.008	$ 40	$ 52	$ 92
2017	7,842	$ 0.006	$ 0.008	$ 47	$ 62	$ 110
2018	8,966	$ 0.006	$ 0.008	$ 55	$ 72	$ 127
2019	10,006	$ 0.006	$ 0.008	$ 61	$ 81	$ 142
2020	10,975	$ 0.006	$ 0.008	$ 67	$ 89	$ 156
2021	11,848	$ 0.006	$ 0.008	$ 72	$ 97	$ 169
2022	12,631	$ 0.006	$ 0.008	$ 77	$ 103	$ 180
2023	13,358	$ 0.006	$ 0.008	$ 82	$ 109	$ 191
2024	14,044	$ 0.006	$ 0.008	$ 86	$ 114	$ 200
2025	14,697	$ 0.006	$ 0.008	$ 90	$ 120	$ 210
2026	15,304	$ 0.006	$ 0.008	$ 94	$ 125	$ 218
2027	15,852	$ 0.006	$ 0.008	$ 97	$ 129	$ 226
2028	16,351	$ 0.006	$ 0.008	$ 100	$ 133	$ 234
2029	16,825	$ 0.006	$ 0.008	$ 103	$ 137	$ 240
2030	17,277	$ 0.006	$ 0.008	$ 106	$ 141	$ 247
2031	17,704	$ 0.006	$ 0.008	$ 109	$ 144	$ 253
2032	18,116	$ 0.006	$ 0.008	$ 111	$ 148	$ 259
2033	18,521	$ 0.006	$ 0.008	$ 113	$ 151	$ 264
2034	18,913	$ 0.006	$ 0.008	$ 116	$ 154	$ 270
2035	19,287	$ 0.006	$ 0.008	$ 118	$ 157	$ 275
2036	19,645	$ 0.006	$ 0.008	$ 120	$ 160	$ 280
30 Yr NPV at 3%	164,697			$ 997	$ 1,343	$ 2,340
30 Yr NPV at 7%	74,092			$ 445	$ 605	$ 1,050

* Note that fuel used in CDPF engines includes some highway spillover fuel.
**Weighted Regeneration Cost ($/gal) changes year-to-year due to different fuel economy impacts with a NOx adsorber (1 percent) and without a NOx adsorber (2 percent) matched with the phase-in schedules of the emission standards.

The cent-per-gallon costs for CCV maintenance are taken from data presented in Table 6.2-30. Table 8.4-4 presents the annual costs associated with CCV maintenance. The gallons shown in Table 8.4-4 are gallons of fuel consumed in engines in power ranges for which the new CCV requirements have gone into effect. However, these are not necessarily equal to the gallons consumed in new CCV equipped engines since only the turbocharged engines will be adding a CCV system. Therefore, the cent-per-gallon costs in early years is essentially zero since so few engines in the <75hp range are turbocharged and, hence, so few are adding a CCV system and incurring the associated maintenance costs. As shown in Table 8.4-4, the 30-year net present value of the CCV maintenance costs are estimated at $275 million. This assumes a three percent social discount rate.

Table 8.4-4
CCV Maintenance Costs Associated with the Two-Step Fuel Program
($2002)

Year	Fuel Consumed in Power Categories Adding CCV System (10^6 gallons)	Weighted Maintenance Cost ($/gal)	Total Costs (10^6 dollars)
2007	-	$ -	$ -
2008	242	$ 0.000	$ 0
2009	248	$ 0.000	$ 0
2010	254	$ 0.000	$ 0
2011	927	$ 0.001	$ 1
2012	2,023	$ 0.001	$ 3
2013	3,369	$ 0.002	$ 5
2014	4,716	$ 0.002	$ 7
2015	6,160	$ 0.002	$ 9
2016	7,552	$ 0.002	$ 11
2017	8,857	$ 0.002	$ 13
2018	10,042	$ 0.002	$ 15
2019	11,139	$ 0.002	$ 17
2020	12,161	$ 0.002	$ 18
2021	13,084	$ 0.002	$ 20
2022	13,913	$ 0.002	$ 21
2023	14,680	$ 0.002	$ 22
2024	15,402	$ 0.002	$ 23
2025	16,088	$ 0.002	$ 24
2026	16,724	$ 0.002	$ 25
2027	17,301	$ 0.002	$ 26
2028	17,827	$ 0.002	$ 27
2029	18,327	$ 0.002	$ 28
2030	18,805	$ 0.002	$ 28
2031	19,258	$ 0.002	$ 29
2032	19,695	$ 0.002	$ 30
2033	20,125	$ 0.002	$ 30
2034	20,543	$ 0.002	$ 31
2035	20,940	$ 0.002	$ 32
2036	21,323	$ 0.002	$ 32
30 Yr NPV at 3%	182,540		$ 275
30 Yr NPV at 7%	82,865		$ 124

* Weighted Maintenance Cost ($/gal) changes year-to-year due to the implementation schedule for engines adding the CCV system.

8.4.4 Summary of Aggregate Operating Costs

The net operating costs include the incremental costs for fuel (Table 8.4-1), cost savings from reduced oil changes (Table 8.4-2), costs for CDPF maintenance and regeneration (Table 8.4-3), and costs for CCV maintenance (Table 8.4-4). The results of this summation for the two-step NRT4 program are shown in Table 8.4-5. The oil-change maintenance savings, CDPF maintenance and regeneration costs, and the CCV maintenance costs are added together in Table 8.4-5 and presented as "Other Operating Costs." The other operating costs are presented as negative values because the oil change maintenance savings (negative costs) outweigh the other operating costs and, thus, their summation represents a net savings. The "Net Operating Cost" is the sum of the incremental fuel costs shown in Table 8.4-1 and the other operating costs shown in Tables 8.4-2 through 8.4-4. As shown in Table 8.4-5, the 30-year net present value of the net operating costs is estimated at $11.8 billion consisting of the $16.3 billion fuel cost and the $4.5 billion savings associated with other operating costs. These net present values assume a three percent social discount rate.

Also included in Table 8.4-5 are the costs by pollutant (refer to Table 8.1-2 for how these costs have been allocated). The sum of the SOx cost, the PM cost, and the NOx+NMHC cost is the value presented in the "Net Operating Cost" column.

Table 8.4-5
Aggregate Net Operating Costs and Costs by Pollutant
Associated with the NRT4 Program
($2002)

Year	Fuel Costs (10^6 dollars)	Other Operating Costs (10^6 dollars)	Net Operating Costs (10^6 dollars)	SOx Related Costs (10^6 dollars)	PM Related Costs (10^6 dollars)	NOx+HC Related Costs (10^6 dollars)
2007	$ 142	$ (161)	$ (18)	$ (12)	$ (6)	$ -
2008	$ 249	$ (282)	$ (33)	$ (22)	$ (11)	$ 0
2009	$ 254	$ (288)	$ (34)	$ (23)	$ (11)	$ 0
2010	$ 561	$ (349)	$ 212	$ 88	$ 84	$ 40
2011	$ 591	$ (302)	$ 289	$ 117	$ 118	$ 54
2012	$ 704	$ (299)	$ 406	$ 172	$ 170	$ 64
2013	$ 797	$ (286)	$ 512	$ 217	$ 223	$ 72
2014	$ 874	$ (294)	$ 581	$ 232	$ 259	$ 90
2015	$ 938	$ (288)	$ 650	$ 245	$ 300	$ 105
2016	$ 954	$ (274)	$ 680	$ 249	$ 324	$ 108
2017	$ 971	$ (261)	$ 710	$ 253	$ 347	$ 111
2018	$ 988	$ (250)	$ 738	$ 257	$ 368	$ 114
2019	$ 1,006	$ (240)	$ 766	$ 261	$ 389	$ 116
2020	$ 1,022	$ (231)	$ 791	$ 265	$ 408	$ 119
2021	$ 1,039	$ (224)	$ 815	$ 268	$ 425	$ 122
2022	$ 1,056	$ (219)	$ 838	$ 272	$ 441	$ 124
2023	$ 1,073	$ (214)	$ 859	$ 276	$ 456	$ 127
2024	$ 1,090	$ (210)	$ 880	$ 280	$ 470	$ 129
2025	$ 1,107	$ (207)	$ 900	$ 284	$ 484	$ 132
2026	$ 1,124	$ (204)	$ 920	$ 288	$ 497	$ 134
2027	$ 1,141	$ (202)	$ 938	$ 292	$ 509	$ 137
2028	$ 1,158	$ (201)	$ 956	$ 296	$ 521	$ 139
2029	$ 1,174	$ (201)	$ 974	$ 300	$ 532	$ 141
2030	$ 1,191	$ (201)	$ 991	$ 304	$ 543	$ 144
2031	$ 1,208	$ (201)	$ 1,007	$ 308	$ 553	$ 146
2032	$ 1,225	$ (201)	$ 1,024	$ 312	$ 563	$ 148
2033	$ 1,242	$ (202)	$ 1,040	$ 316	$ 573	$ 151
2034	$ 1,259	$ (203)	$ 1,056	$ 320	$ 583	$ 153
2035	$ 1,276	$ (204)	$ 1,072	$ 324	$ 593	$ 155
2036	$ 1,293	$ (205)	$ 1,088	$ 328	$ 602	$ 157
30 Yr NPV at 3%	$ 16,326	$ (4,517)	$ 11,809	$ 3,934	$ 6,091	$ 1,784
30 Yr NPV at 7%	$ 8,538	$ (2,745)	$ 5,793	$ 1,976	$ 2,928	$ 889

8.4.5 Summary of Aggregate Operating Costs Associated with a Fuel-only Scenario

The aggregate operating costs of a fuel-only scenario would be essentially the same as those presented above for the full NRT4 program with the exception of those operating costs associated with maintenance or regeneration of new engine hardware. These operating cost elements would not be incurred because without new engine standards the new engine hardware would not be added. However, the oil change maintenance savings would still be realized just as they would under the full NRT4 program.

As noted several times throughout this chapter, Table 8.1-2 shows how we allocated costs to each pollutant under the full engine and fuel program. However, the allocations shown in that table assume an engine program to which a portion of the fuel-related costs are allocated. Specifically, the 15 ppm NR fuel, which enables aftertreatment devices and, thus, new NR engine standards, is split evenly between engine derived benefits and fuel derived benefits. Subsequently, the costs allocated to fuel derived benefits were split one-third to PM and two-thirds to SOx.

Under the fuel-only scenario, there are no new engine standards. As a result, all the fuel costs are allocated to fuel-derived benefits. Consistent with the approach taken in the full engine and fuel program, we have allocated one-third of those costs to PM and two-thirds of those costs to SOx. Table 8.4-6 shows the cost allocations under the fuel-only scenario.

Table 8.4-6
Cost Allocations under the Fuel-only Scenario

<table>
<tr><th>Item</th><th></th><th>NOx+HC</th><th>PM</th><th>SOx</th></tr>
<tr><td rowspan="3">Fuel Costs – incremental cent/gallon</td><td>500 ppm Affected NRLM</td><td rowspan="6"></td><td rowspan="6">33%</td><td rowspan="6">67%</td></tr>
<tr><td>15 ppm Affected NR</td></tr>
<tr><td>15 ppm Affected L&M</td></tr>
<tr><td rowspan="3">Operating Costs – Oil-Change Savings</td><td>500 ppm Affected NRLM</td></tr>
<tr><td>15 ppm Affected NR</td></tr>
<tr><td>15 ppm Affected L&M</td></tr>
<tr><td>Operating Costs – CDPF Maintenance</td><td colspan="4" rowspan="3">None</td></tr>
<tr><td>Operating Costs – CDPF Regen (FE impact)</td></tr>
<tr><td>Operating Costs – CCV Maintenance</td></tr>
</table>

Note that there are no costs associated with CDPF and CCV maintenance or with CDPF regeneration since there would be no new engine standards under the fuel-only scenario. Note also that the oil change maintenance savings would still be realized absent any new engine standards.

Table 8.4-7 presents the net operating costs associated with a fuel-only scenario. The costs presented in Table 8.4-7 include the incremental costs for fuel (Table 8.4-1) and costs for oil-change maintenance savings (Table 8.4-2). The oil-change maintenance savings are presented in the table as "Other Operating Costs," and, thus represent a net savings. The "Net Operating

Cost" is the sum of the incremental fuel costs and the other operating costs. Table 8.4-7 also presents these costs by pollutant (refer to Table 8.4-6 for how these costs have been allocated). Since there are no new engine standards under a fuel-only scenario there are no costs associated with technology enablement and, hence, no costs allocated to NOx+NMHC. As shown in Table 8.4-7, the 30-year net present value of costs associated with a fuel-only scenario is estimated at \$9.2 billion consisting of the \$16.3 billion fuel cost and a \$7.1 billion savings associated with oil change maintenance. These values assume a three percent social discount rate.

Table 8.4-7
Aggregate Net Operating Costs and Costs by Pollutant
Associated with a Fuel-Only Scenario
(\$2002)

Year	Fuel Costs (10^6 dollars)	Other Operating Costs (10^6 dollars)	Net Operating Costs (10^6 dollars)	SOx Related Costs (10^6 dollars)	PM Related Costs (10^6 dollars)	NOx+HC Related Costs (10^6 dollars)
2007	$ 142	$ (161)	$ (18)	$ (12)	$ (6)	$ -
2008	$ 249	$ (282)	$ (33)	$ (22)	$ (11)	$ -
2009	$ 254	$ (288)	$ (34)	$ (23)	$ (11)	$ -
2010	$ 561	$ (349)	$ 212	$ 141	$ 71	$ -
2011	$ 591	$ (310)	$ 281	$ 187	$ 94	$ -
2012	$ 704	$ (322)	$ 382	$ 255	$ 127	$ -
2013	$ 797	$ (333)	$ 464	$ 310	$ 155	$ -
2014	$ 874	$ (353)	$ 521	$ 347	$ 174	$ -
2015	$ 938	$ (370)	$ 568	$ 378	$ 189	$ -
2016	$ 954	$ (377)	$ 577	$ 385	$ 192	$ -
2017	$ 971	$ (384)	$ 587	$ 391	$ 196	$ -
2018	$ 988	$ (391)	$ 597	$ 398	$ 199	$ -
2019	$ 1,006	$ (399)	$ 607	$ 405	$ 202	$ -
2020	$ 1,022	$ (406)	$ 617	$ 411	$ 206	$ -
2021	$ 1,039	$ (412)	$ 626	$ 417	$ 209	$ -
2022	$ 1,056	$ (420)	$ 636	$ 424	$ 212	$ -
2023	$ 1,073	$ (427)	$ 646	$ 431	$ 215	$ -
2024	$ 1,090	$ (434)	$ 656	$ 437	$ 219	$ -
2025	$ 1,107	$ (441)	$ 666	$ 444	$ 222	$ -
2026	$ 1,124	$ (448)	$ 676	$ 451	$ 225	$ -
2027	$ 1,141	$ (455)	$ 686	$ 457	$ 229	$ -
2028	$ 1,158	$ (462)	$ 696	$ 464	$ 232	$ -
2029	$ 1,174	$ (469)	$ 706	$ 470	$ 235	$ -
2030	$ 1,191	$ (476)	$ 716	$ 477	$ 239	$ -
2031	$ 1,208	$ (483)	$ 725	$ 484	$ 242	$ -
2032	$ 1,225	$ (490)	$ 735	$ 490	$ 245	$ -
2033	$ 1,242	$ (497)	$ 745	$ 497	$ 248	$ -
2034	$ 1,259	$ (504)	$ 755	$ 503	$ 252	$ -
2035	$ 1,276	$ (511)	$ 765	$ 510	$ 255	$ -
2036	$ 1,293	$ (518)	$ 775	$ 517	$ 258	$ -
30 Yr NPV at 3%	$ 16,326	$ (7,132)	$ 9,194	$ 6,130	$ 3,065	$ -
30 Yr NPV at 7%	$ 8,538	$ (3,919)	$ 4,618	$ 3,079	$ 1,539	$ -

8.5 Summary of Aggregate Costs of the Final Rule

Table 8.5-1 presents a summary of all the costs presented above for the NRT4 final rule engine and fuel program. Engine costs are the summation of costs presented in Tables 8.2-1 and 8.2-3, equipment costs are the summation of costs presented in Tables 8.3-1 and 8.3-3, and fuel costs, other operating costs, and net operating costs are presented in Table 8.4-5. The "Total Program Costs" are the summation of engine costs, equipment costs, and net operating costs. As shown, the 30-year net present value of the NRT4 program is estimated at $27.1 billion consisting of $14.1 billion in engine costs, $1.3 billion in equipment costs, $16.3 billion in fuel costs, and a savings of $4.5 billion in other operating costs. These values assume a three percent social discount rate.

Table 8.5-2 presents the summary of all the costs presented above by pollutant (refer to Table 8.1-2 for how we have allocated costs among the various pollutants).

Note that a similar summary of aggregate costs associated with a fuel-only scenario are presented in full in Table 8.4-6 since there are no new engine or equipment costs associated with that scenario.

Table 8.5-1
Summary of Aggregate Costs for the NRT4 Final Engine and Fuel Program
($Millions of 2002 dollars)

Year	Engine Costs	Equipment Costs	Fuel Costs	Other Operating Costs	Net Operating Costs	Total Annual Costs
2007	$ -	$ -	$ 142	$ (161)	$ (18)	$ (18)
2008	$ 81	$ 5	$ 249	$ (282)	$ (33)	$ 53
2009	$ 82	$ 5	$ 254	$ (288)	$ (34)	$ 53
2010	$ 80	$ 5	$ 561	$ (349)	$ 212	$ 297
2011	$ 403	$ 62	$ 591	$ (302)	$ 289	$ 754
2012	$ 718	$ 106	$ 704	$ (299)	$ 406	$ 1,229
2013	$ 882	$ 121	$ 797	$ (286)	$ 512	$ 1,515
2014	$ 973	$ 146	$ 874	$ (294)	$ 581	$ 1,699
2015	$ 950	$ 149	$ 938	$ (288)	$ 650	$ 1,749
2016	$ 920	$ 150	$ 954	$ (274)	$ 680	$ 1,750
2017	$ 910	$ 150	$ 971	$ (261)	$ 710	$ 1,770
2018	$ 901	$ 146	$ 988	$ (250)	$ 738	$ 1,785
2019	$ 890	$ 147	$ 1,006	$ (240)	$ 766	$ 1,802
2020	$ 900	$ 147	$ 1,022	$ (231)	$ 791	$ 1,838
2021	$ 913	$ 99	$ 1,039	$ (224)	$ 815	$ 1,827
2022	$ 927	$ 66	$ 1,056	$ (219)	$ 838	$ 1,830
2023	$ 940	$ 56	$ 1,073	$ (214)	$ 859	$ 1,855
2024	$ 954	$ 36	$ 1,090	$ (210)	$ 880	$ 1,869
2025	$ 967	$ 32	$ 1,107	$ (207)	$ 900	$ 1,899
2026	$ 980	$ 32	$ 1,124	$ (204)	$ 920	$ 1,932
2027	$ 994	$ 33	$ 1,141	$ (202)	$ 938	$ 1,965
2028	$ 1,007	$ 33	$ 1,158	$ (201)	$ 956	$ 1,997
2029	$ 1,021	$ 33	$ 1,174	$ (201)	$ 974	$ 2,028
2030	$ 1,034	$ 34	$ 1,191	$ (201)	$ 991	$ 2,059
2031	$ 1,048	$ 34	$ 1,208	$ (201)	$ 1,007	$ 2,089
2032	$ 1,061	$ 35	$ 1,225	$ (201)	$ 1,024	$ 2,119
2033	$ 1,074	$ 35	$ 1,242	$ (202)	$ 1,040	$ 2,149
2034	$ 1,088	$ 35	$ 1,259	$ (203)	$ 1,056	$ 2,179
2035	$ 1,101	$ 36	$ 1,276	$ (204)	$ 1,072	$ 2,209
2036	$ 1,115	$ 36	$ 1,293	$ (205)	$ 1,088	$ 2,239
30 Yr NPV at 3%	$ 14,054	$ 1,281	$ 16,326	$ (4,517)	$ 11,809	$ 27,144
30 Yr NPV at 7%	$ 7,215	$ 754	$ 8,538	$ (2,745)	$ 5,793	$ 13,762

Table 8.5-2
Summary of Aggregate Costs for the NRT4 Final Engine and Fuel Program by Pollutant
($Millions of 2002 dollars)

Year	PM Costs	NOx+NMHC Costs	SOx Costs	Total Costs
2007	$ (6)	$ -	$ (12)	$ (18)
2008	$ 74	$ 0	$ (22)	$ 53
2009	$ 75	$ 0	$ (23)	$ 53
2010	$ 169	$ 40	$ 88	$ 297
2011	$ 458	$ 179	$ 117	$ 754
2012	$ 761	$ 296	$ 172	$ 1,229
2013	$ 949	$ 348	$ 217	$ 1,515
2014	$ 940	$ 526	$ 232	$ 1,699
2015	$ 970	$ 534	$ 245	$ 1,749
2016	$ 982	$ 519	$ 249	$ 1,750
2017	$ 999	$ 518	$ 253	$ 1,770
2018	$ 1,004	$ 524	$ 257	$ 1,785
2019	$ 1,034	$ 507	$ 261	$ 1,802
2020	$ 1,059	$ 515	$ 265	$ 1,838
2021	$ 1,061	$ 497	$ 268	$ 1,827
2022	$ 1,070	$ 488	$ 272	$ 1,830
2023	$ 1,088	$ 490	$ 276	$ 1,855
2024	$ 1,112	$ 477	$ 280	$ 1,869
2025	$ 1,130	$ 484	$ 284	$ 1,899
2026	$ 1,153	$ 491	$ 288	$ 1,932
2027	$ 1,174	$ 498	$ 292	$ 1,965
2028	$ 1,195	$ 506	$ 296	$ 1,997
2029	$ 1,215	$ 513	$ 300	$ 2,028
2030	$ 1,235	$ 520	$ 304	$ 2,059
2031	$ 1,254	$ 527	$ 308	$ 2,089
2032	$ 1,273	$ 534	$ 312	$ 2,119
2033	$ 1,292	$ 541	$ 316	$ 2,149
2034	$ 1,311	$ 548	$ 320	$ 2,179
2035	$ 1,330	$ 555	$ 324	$ 2,209
2036	$ 1,348	$ 562	$ 328	$ 2,239
30 Yr NPV at 3%	$ 16,041	$ 7,169	$ 3,934	$ 27,144
30 Yr NPV at 7%	$ 8,134	$ 3,652	$ 1,976	$ 13,762

8.6 Emission Reductions

Table 8.6-1 presents the emission reductions estimated to result from the fuel program in conjunction with the new engine standards. Also presented are reductions associated with a fuel-only scenario. A complete discussion of these emission reductions and how they were generated can be found in Chapter 3.

Table 8.6-1
Emission Reductions Associated with the NRT4 Final Fuel and Engine Program
and the Fuel-only Scenario (tons)

Year	NRT4 Fuel and Engine Program			NRLM Fuel-only Program	
	PM	NOx+NMHC	SOx	PM	SOx
2007	10,700	0	133,000	10,700	133,000
2008	19,500	200	235,400	19,000	235,400
2009	20,400	400	240,100	19,400	240,100
2010	22,300	700	255,500	20,600	255,500
2011	25,900	19,100	268,600	21,600	268,600
2012	32,100	49,600	277,800	22,400	277,700
2013	39,200	84,400	285,700	23,000	285,500
2014	46,900	143,600	291,600	23,500	291,500
2015	54,900	203,000	297,400	24,000	297,300
2016	62,400	261,100	302,600	24,400	302,400
2017	69,600	316,900	307,700	24,800	307,500
2018	76,400	368,500	312,900	25,200	312,700
2019	82,800	417,300	318,300	25,600	318,000
2020	88,800	463,000	323,300	26,000	323,100
2021	94,400	504,400	328,300	26,400	328,000
2022	99,700	542,400	333,600	26,900	333,400
2023	104,600	578,100	338,800	27,300	338,500
2024	109,400	611,100	344,000	27,700	343,700
2025	113,900	642,300	349,200	28,100	348,900
2026	118,200	671,400	354,400	28,500	354,100
2027	122,300	698,200	359,600	28,900	359,300
2028	125,900	723,200	364,800	29,400	364,500
2029	129,500	746,900	370,000	29,800	369,700
2030	132,900	768,500	375,300	30,200	374,900
2031	136,000	788,800	380,500	30,600	380,100
2032	139,100	808,400	385,800	31,000	385,400
2033	142,100	827,300	391,000	31,500	390,600
2034	145,000	845,600	396,300	31,900	395,900
2035	147,800	863,100	401,600	32,300	401,200
2036	150,500	880,100	406,900	32,700	406,400
30 Yr NPV at 3%	1,430,500	7,077,900	5,725,900	461,000	5,722,100
30 Yr NPV at 7%	690,800	3,142,700	3,164,100	254,800	3,162,300

[b] Note that the SOx reductions for the Final program and the fuel-only scenario are nearly identical while the PM reductions are very different. This is a result of there being no new engine standards under the fuel-only scenario and, therefore, no CDPFs added to new engines.

8.7 Cost per Ton

We have calculated the cost per ton of the final rule based on the net present value of all costs incurred and all emission reductions generated over a 30-year time window following implementation of the program. This approach captures all the costs and emission reductions from the final rule, including costs incurred and emission reductions generated by both the new and the existing fleet.

The baseline (i.e., the point of comparison) for this evaluation is the existing set of engine standards (i.e., the Tier 2/Tier 3 program) and fuel standards (i.e., unregulated sulfur level). The 30-year time window is meant to capture both the early period of the program when there are a small number of compliant engines in the fleet, and the later period when there is nearly complete turnover to compliant engines. The final rule also requires reduced sulfur content in NRLM diesel fuel with a 500 ppm cap beginning in 2007, a 15 ppm NR cap beginning in 2010, and a 15 ppm L&M cap beginning in 2012.

In Section 8.7.1 we present the cost per ton for the NRT4 final engine and fuel program—this represents the cost per ton of this final rule including all costs and emissions reductions associated with the new fuel standards and the new engine standards. In Section 8.7.2 we present the cost per ton for the fuel-only scenario—this scenario would include the same fuel standards as the full engine and fuel program but no new engine standards. In Section 8.7.3 we present two different sets of cost per ton information—cost per ton of a 500 ppm fuel scenario should it remain in place forever with no new engine standards, and the incremental cost per ton of the 15 ppm L&M portion of the fuel program. In Section 8.7.4, we summarize all the cost per ton calculations presented in Sections 8.7.1 through 8.7.3. In Appendix 8A, we present the cost per ton of two sensitivity cases—the case 1 sensitivity shows the cost per ton using future projections of fuel demand developed by the Energy Information Administration; and, the case 2 sensitivity shows the cost per ton if we increase the percentage of mobile versus stationary generator sets (i.e., increase the number of generator sets that will meet the new standards) and increase the usage rates for some >750hp equipment. The rationale for choosing these two sensitivity cases is presented in section 8A.1.

8.7.1 Cost per Ton for the NRT4 Final Rule

The NRT4 final rule adopts fuel requirements in two steps—reducing NRLM sulfur levels from current uncontrolled levels to 500 ppm in 2007 and then controlling NR fuel and L&M fuel to 15 ppm in 2010 and 2012, respectively. Beginning June 1, 2007, refiners must produce NRLM diesel fuel that meets a maximum sulfur level of 500 ppm. Then, beginning in June 1, 2010, NR fuel must meet a maximum sulfur level of 15 ppm and, beginning in June 1, 2012, L&M fuel must meet a maximum sulfur level of 15 ppm. This program also adopts new Tier 4 engine standards for nonroad diesel engines that begin in different years for different power categories. See Table 1 in the Executive Summary for details on the new engine standards and when they are implemented. All nonroad diesel-fueled engines with a CDPF must be refueled with the new 15 ppm diesel fuel.

The costs of the final rule include costs associated with both steps in the fuel program (500 ppm and 15 ppm) and costs for the engine standards including equipment modifications. Maintenance costs and savings realized by both the existing fleet (nonroad, locomotive, and marine), future locomotive and marine engines, and the new fleet of nonroad engines complying with the new emissions standards are included. Figure 8.7-1 presents in graphic form the cost of the final rule. These costs are summarized in Table 8.5-1. The cost streams include the amortized capital (fixed) costs and variable costs.

Figure 8.7-1
Estimated Aggregate Cost of the NRT4 Final Rule

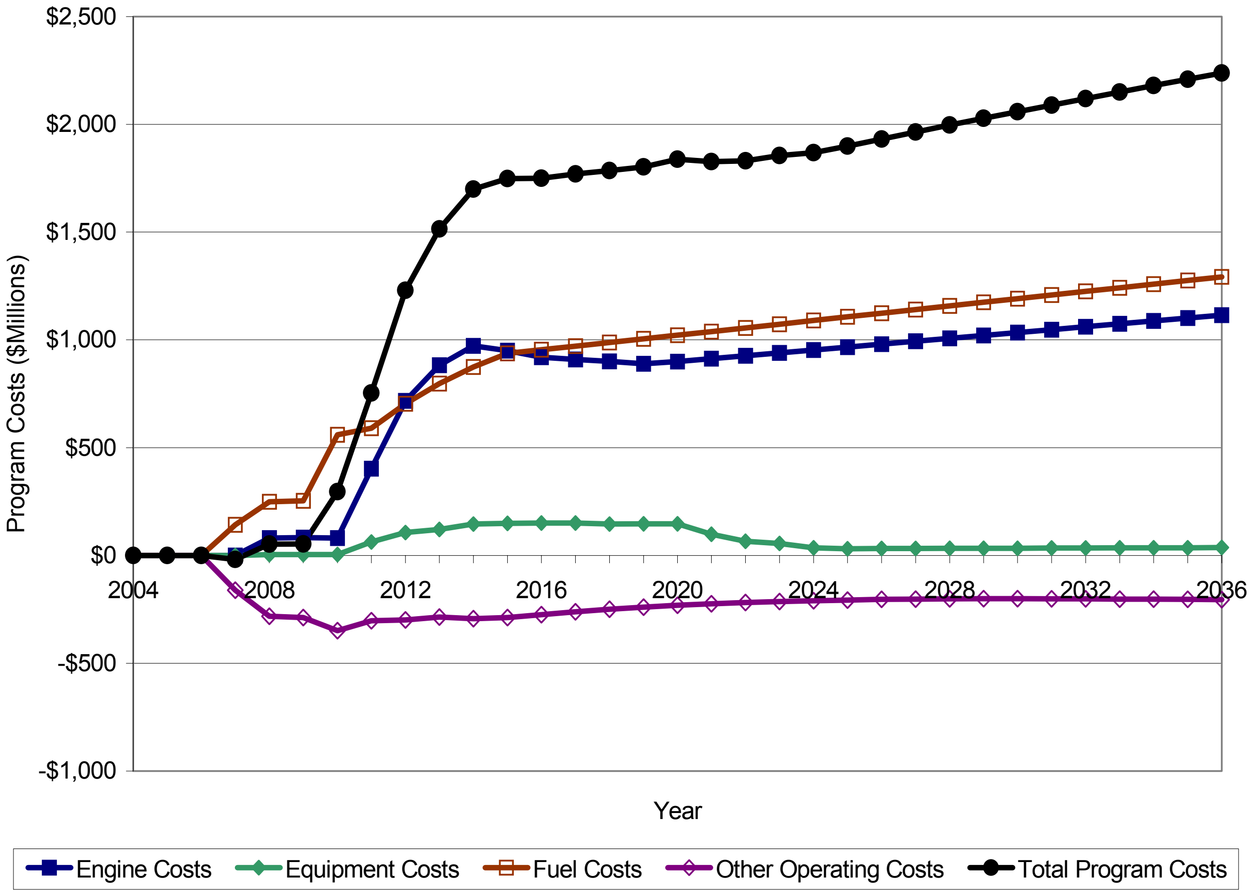

Figure 8.7-1 shows that total annual costs are estimated to be $50 million in the first year the new engine standards apply, increasing to $2.2 billion in 2036 as increasing numbers of engines become subject to the new standards and an ever increasing amount of fuel is consumed. As shown in Table 8.5-1, the 30-year net present value of the costs for this program is estimated as $27.1 billion using a three percent discount rate.

The calculations of cost per ton of each emission reduced under the final program divides the net present value of the annual costs assigned to each pollutant (see Table 8.5-2 for costs by pollutant and Table 8.1-2 for how we have allocated costs by pollutant) by the net present value of the total annual reductions of each pollutant – NOx+NMHC, PM and SOx (see Table 8.6-1).

The net present value of the costs associated with each pollutant, calculated with a three percent discount rate, are shown in Table 8.5-1 as $7.2 billion for NOx+NMHC, $16.0 billion for PM and $3.9 billion for SOx. The 30-year net present value, with a three percent discount rate, of emission reductions are 7.1 million tons for NOx+NMHC, 1.4 million tons for PM and 5.7 million tons for SOx (see Table 8.6-1). Our air quality analysis, emissions reduction analysis, and benefits analysis are found in Chapters 2, 3, and 9, respectively.

The cost per ton of emissions reduced for the NRT4 final rule is calculated by dividing the net present value of the annualized costs of the program through 2036 by the net present value of the annual emission reductions through 2036. These results are shown in Table 8.7-1.

Table 8.7-1
Aggregate Costs and Costs per Ton for the NRT4 Final Rule
30-year Net Present Values at a 3% and 7% Discount Rate ($2002)

Item	Units	3% discount rate	7% discount rate	Source
500ppm at $0.021/gal, 2007-2010	(10^6 gallons)	29,690	25,207	Table 8.4-1
500ppm at $0.033/gal, 2010-2012	(10^6 gallons)	7,068	5,500	Table 8.4-1
500ppm at $0.035/gal, 2012-2014	(10^6 gallons)	1,660	1,196	Table 8.4-1
15ppm at $0.058/gal, 2010-2012	(10^6 gallons)	15,223	11,715	Table 8.4-1
15ppm at $0.064/gal, 2012-2014	(10^6 gallons)	17,998	12,800	Table 8.4-1
15ppm at $0.070/gal, 2014+	(10^6 gallons)	191,091	89,805	Table 8.4-1
500ppm Fuel Cost	($million)	$915	$753	Table 8.4-1
15ppm Fuel Cost	($million)	$15,411	$7,785	Table 8.4-1
Other Operating Costs*	($million)	-$4,517	-$2,745	Table 8.4-5
Engine Costs	($million)	$14,054	$7,215	Table 8.5-1
Equipment Costs	($million)	$1,281	$754	Table 8.5-1
Total Program Costs	($million)	$27,144	$13,762	Table 8.5-1
NOx+NMHC Costs	($million)	$7,169	$3,652	Table 8.5-2
PM Costs	($million)	$16,041	$8,134	Table 8.5-2
SOx Costs	($million)	$3,934	$1,976	Table 8.5-2
NOx+NMHC Reduction	(10^6 tons)	7.1	3.1	Table 8.6-1
PM Reduction	(10^6 tons)	1.4	0.7	Table 8.6-1
SOx Reduction	(10^6 tons)	5.7	3.2	Table 8.6-1
Cost per Ton NOx+NMHC	($/ton)	$1,010	$1,160	Calculated
Cost per Ton PM	($/ton)	$11,200	$11,800	Calculated
Cost per Ton	($/ton)	$690	$620	Calculated

* Other operating costs include oil change maintenance savings, CDPF and CCV maintenance costs, and CDPF regeneration costs.

We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emission reductions in that year alone. This number, shown in Table 8.7-2, approaches the long-term cost per ton of emissions reduced after all fixed costs of the program have been recovered by industry leaving only the variable costs of control (and maintenance costs), and after most (though not all) of the pre-control fleet has been retired.

Table 8.7-3
Long-Term Cost per Ton of the NRT4 Final Rule
Annual Values without Discounting ($2002)

Pollutant	Long-Term Cost per Ton in 2030
NOx+NMHC	$680
PM	$9,300
SOx	$810

8.7.2 Cost per Ton for the NRLM Fuel-only Scenario

The costs of the fuel-only scenario include costs associated with both steps in the fuel program absent any new engine standards. Oil change maintenance savings would be realized by both the existing fleet and the new fleet of engines as these savings are not dependent on any new engine standards. Figure 8.7-2 presents in graphic form the cost of the fuel-only scenario. These costs are summarized in Table 8.4-7. The cost streams include the amortized capital (fixed) costs and variable costs.

Figure 8.7-2
Estimated Aggregate Cost of the NRLM Fuel-only Scenario

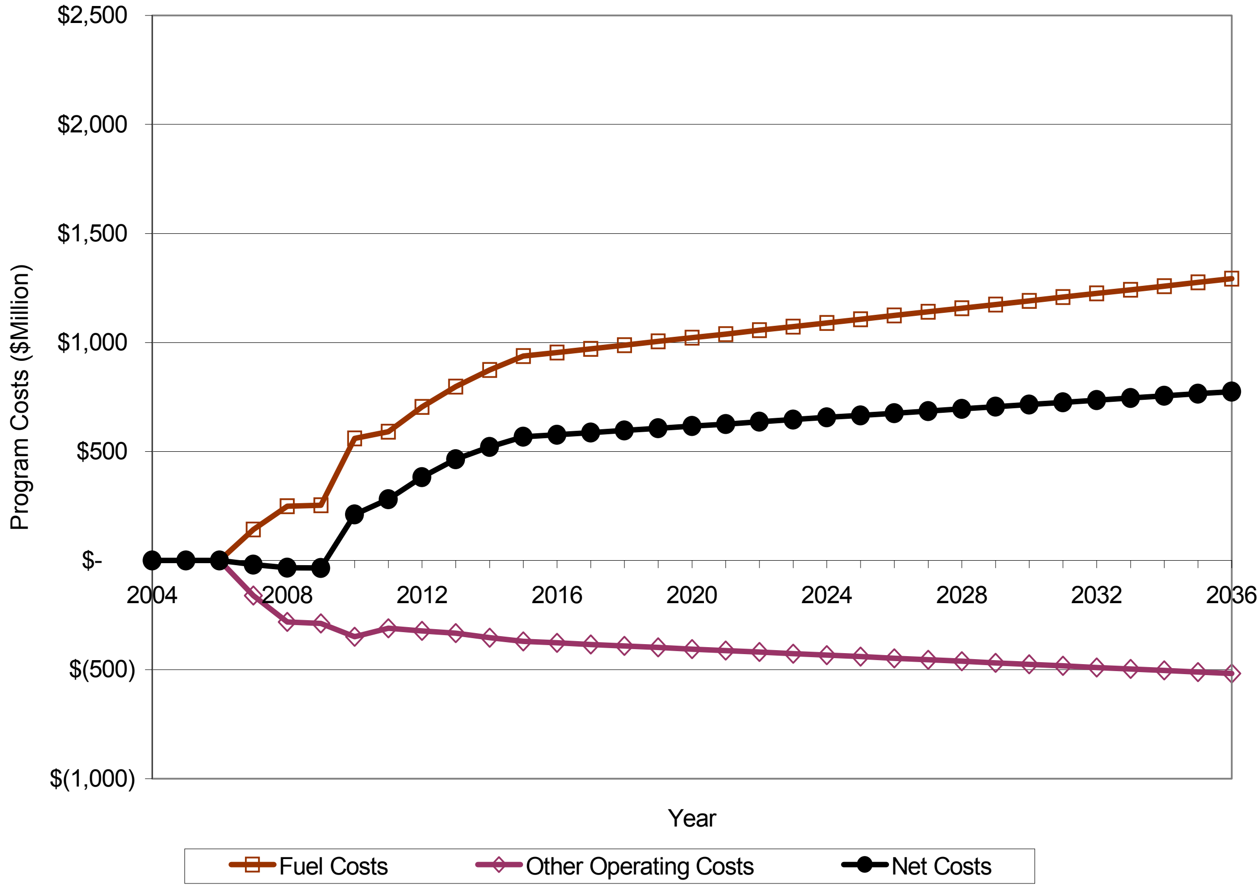

Figure 8.7-2 shows that total annual costs are estimated to be -$33 million in the first full year of the new fuel standards (i.e., a $33 million savings), increasing to $775 million in 2036 as an ever increasing amount of fuel is consumed. As shown in Table 8.4-7, the 30-year net present value of the fuel-only scenario is estimated as $9.2 billion using a three percent discount rate.

The calculations of cost per ton of each emission reduced under the fuel-only scenario divides the net present value of the annual costs assigned to each pollutant (see Table 8.4-7 for costs by pollutant and Table 8.4-6 for how we have allocated costs by pollutant) by the net present value of the total annual reductions of each pollutant. The 30-year net present value of the costs associated with each pollutant, calculated with a three percent discount rate, are shown in Table 8.4-7 as $3.1 billion for PM and $6.1 billion for SOx. If we exclude the oil change maintenance savings, the costs of the fuel-only scenario would be $5.4 billion for PM and $10.9 billion for SOx. The 30-year net present value, with a three percent discount rate, of emission reductions are 461 thousand tons for PM and 5.7 million tons for SOx. Our air quality analysis, emissions reduction analysis, and benefits analysis are found in Chapters 2, 3, and 9, respectively. Table 8.7-4 presents the cost per ton results for the fuel-only scenario including the oil change maintenance savings and excluding those savings.

Table 8.7-4
Aggregate Costs and Costs per Ton for the Fuel-only Scenario
30-year Net Present Values at a 3% and 7% Discount Rate ($2002)

Item	Units	3% discount rate	7% discount rate	Source
500ppm at $0.021/gal, 2007-2010	(10^6 gallons)	29,690	25,207	Table 8.4-1
500ppm at $0.033/gal, 2010-2012	(10^6 gallons)	7,068	5,500	Table 8.4-1
500ppm at $0.035/gal, 2012-2014	(10^6 gallons)	1,660	1,196	Table 8.4-1
15ppm at $0.058/gal, 2010-2012	(10^6 gallons)	15,223	11,715	Table 8.4-1
15ppm at $0.064/gal, 2012-2014	(10^6 gallons)	17,998	12,800	Table 8.4-1
15ppm at $0.070/gal, 2014+	(10^6 gallons)	191,091	89,805	Table 8.4-1
500ppm Fuel Cost	($million)	$915	$753	Table 8.4-1
15ppm Fuel Cost	($million)	$15,411	$7,785	Table 8.4-1
Other Operating Costs*	($million)	-$4,517	-$2,745	Table 8.4-7
Total Costs (w/ maintenance savings)	($million)	$9,194	$4,618	Table 8.4-7
Total Costs (w/o maintenance savings)	($million)	$16,326	$8,538	Table 8.4-7
PM Costs (w/ maintenance savings)	($million)	$3,065	$1,539	Table 8.4-7
PM Costs (w/o maintenance savings)	($million)	$5,442	$2,846	Calculated**
SOx Costs (w/ maintenance savings)	($million)	$6,130	$3,079	Table 8.4-7
SOx Costs (w/o maintenance savings)	($million)	$10,884	$5,692	Calculated**
PM Reduction	(10^6 tons)	0.46	0.26	Table 8.6-1
SOx Reduction	(10^6 tons)	5.7	3.2	Table 8.6-1
Cost per Ton PM (w/ maintenance savings)	($/ton)	$6,600	$6,000	Calculated
Cost per Ton PM (w/o maintenance savings)	($/ton)	$11,800	$11,200	Calculated
Cost per Ton SOx (w/ maintenance savings)	($/ton)	$1,070	$970	Calculated
Cost per Ton Sox (w/o maintenance savings)	($/ton)	$1,900	$1,800	Calculated

* Other operating costs include oil change maintenance savings.
** Calculated as one-third (PM) or two-thirds (SOx) of the Total Scenario Costs w/o maintenance savings.

We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emission reductions in that year alone. This number, shown in Table 8.7-5, approaches the long-term cost per ton of emissions reduced.

Table 8.7-5
Long-Term Cost per Ton of the NRT4 Fuel-only Scenario
Annual Values without Discounting ($2002)

Pollutant	Long-Term Cost per Ton in 2030
PM (with maintenance savings)	$7,900
PM (without maintenance savings)	$13,200
SOx (with maintenance savings)	$1,270
SOx (without maintenance savings)	$2,100

8.7.3 Costs and Costs per Ton for Other Control Scenarios

Here we look at the costs and costs per ton of other control scenarios. Specifically, we look at the cost per ton of the 500 ppm NRLM fuel scenario should it continue forever without any new engine standards. We also look at the incremental cost per ton of the 15 ppm L&M fuel scenario.

8.7.3.1 Costs and Costs per Ton of a 500 ppm NRLM Fuel-only Scenario

A 500 ppm NRLM fuel-only scenario would mirror the fuel-only scenario discussed above with the exception that no 15 ppm fuel step would occur. The incremental fuel cost would be $0.021 per gallon during the years 2007 through 2010 and then $0.022 per gallon thereafter (see Table 7.5-1). The oil change maintenance savings would be $0.029 per gallon for NR and $0.010 per gallon for L&M (see Table 8.4-2). Tables 8.7-6 and 8.7-7 present the fuel costs and oil change maintenance savings, respectively, associated with a 500 ppm NRLM fuel-only scenario.

Table 8.7-6
Aggregate Fuel Costs of a 500 ppm NRLM Fuel-only Scenario ($2002)

Year	Affected NR Fuel 500 ppm (10^6 gallons)	Affected L&M Fuel 500 ppm (10^6 gallons)	Fuel Cost* 500 ppm ($/gal)	NRLM Fuel Costs (10^6 dollars)
2007	4,790	1,990	$ 0.021	$ 142
2008	8,406	3,454	$ 0.021	$ 249
2009	8,599	3,498	$ 0.021	$ 254
2010	8,400	3,457	$ 0.022	$ 256
2011	8,300	3,450	$ 0.022	$ 258
2012	8,479	3,489	$ 0.022	$ 263
2013	8,659	3,518	$ 0.022	$ 268
2014	8,839	3,552	$ 0.022	$ 273
2015	9,018	3,586	$ 0.022	$ 277
2016	9,196	3,623	$ 0.022	$ 282
2017	9,374	3,659	$ 0.022	$ 287
2018	9,552	3,699	$ 0.022	$ 292
2019	9,730	3,747	$ 0.022	$ 296
2020	9,907	3,781	$ 0.022	$ 301
2021	10,085	3,812	$ 0.022	$ 306
2022	10,263	3,859	$ 0.022	$ 311
2023	10,441	3,897	$ 0.022	$ 315
2024	10,619	3,939	$ 0.022	$ 320
2025	10,797	3,980	$ 0.022	$ 325
2026	10,973	4,022	$ 0.022	$ 330
2027	11,150	4,064	$ 0.022	$ 335
2028	11,326	4,106	$ 0.022	$ 340
2029	11,503	4,148	$ 0.022	$ 344
2030	11,679	4,190	$ 0.022	$ 349
2031	11,856	4,232	$ 0.022	$ 354
2032	12,032	4,275	$ 0.022	$ 359
2033	12,209	4,318	$ 0.022	$ 364
2034	12,386	4,360	$ 0.022	$ 368
2035	12,562	4,403	$ 0.022	$ 373
2036	12,739	4,447	$ 0.022	$ 378
30 Yr NPV at 3%	179,520	68,639		$ 5,428
30 Yr NPV at 7%	99,928	38,879		$ 3,027

* Fuel costs are relative to uncontrolled fuel and assume that, during the transitional years of 2010 & 2014, the first 5 months are at the previous year's cost and the remaining 7 months are at the next year's cost.
See Appendix 8B for how these fuel volumes were developed.

Table 8.7-7
Oil-Change Maintenance Savings Associated with a 500 ppm NRLM Fuel-only Scenario
($2002)

Year	Affected NR Fuel 500 ppm (10^6 gallons)	Affected L&M Fuel 500 ppm (10^6 gallons)	NR Savings savings=$0.029/gal ($10^6$ dollars)	L&M Savings savings=$0.010/gal ($10^6$ dollars)	NRLM Total Savings (10^6 dollars)
2007	4,790	1,990	$ 140	$ 21	$ 161
2008	8,406	3,454	$ 246	$ 36	$ 282
2009	8,599	3,498	$ 251	$ 37	$ 288
2010	8,400	3,457	$ 246	$ 36	$ 282
2011	8,300	3,450	$ 243	$ 36	$ 279
2012	8,479	3,489	$ 248	$ 37	$ 284
2013	8,659	3,518	$ 253	$ 37	$ 290
2014	8,839	3,552	$ 258	$ 37	$ 296
2015	9,018	3,586	$ 264	$ 38	$ 301
2016	9,196	3,623	$ 269	$ 38	$ 307
2017	9,374	3,659	$ 274	$ 38	$ 312
2018	9,552	3,699	$ 279	$ 39	$ 318
2019	9,730	3,747	$ 284	$ 39	$ 324
2020	9,907	3,781	$ 290	$ 40	$ 329
2021	10,085	3,812	$ 295	$ 40	$ 335
2022	10,263	3,859	$ 300	$ 40	$ 340
2023	10,441	3,897	$ 305	$ 41	$ 346
2024	10,619	3,939	$ 310	$ 41	$ 352
2025	10,797	3,980	$ 316	$ 42	$ 357
2026	10,973	4,022	$ 321	$ 42	$ 363
2027	11,150	4,064	$ 326	$ 43	$ 369
2028	11,326	4,106	$ 331	$ 43	$ 374
2029	11,503	4,148	$ 336	$ 43	$ 380
2030	11,679	4,190	$ 341	$ 44	$ 385
2031	11,856	4,232	$ 347	$ 44	$ 391
2032	12,032	4,275	$ 352	$ 45	$ 397
2033	12,209	4,318	$ 357	$ 45	$ 402
2034	12,386	4,360	$ 362	$ 46	$ 408
2035	12,562	4,403	$ 367	$ 46	$ 413
2036	12,739	4,447	$ 372	$ 47	$ 419
30 Yr NPV at 3%	179,520	68,639	$ 5,248	$ 719	$ 5,967
30 Yr NPV at 7%	99,928	38,879	$ 2,921	$ 407	$ 3,328

Table 8.7-8 presents the annual net operating costs (Tables 8.7-6 and 8.7-7) along with the costs by pollutant associated with a 500 ppm NRLM fuel-only scenario. Because a 500 ppm NRLM fuel-only scenario is analogous to the NRT4 fuel-only scenario discussed above (i.e., no new engine standards and, thus, only fuel-derived benefits will occur), we would allocate costs to PM and SOx the same way as the NRT4 fuel-only scenario (see Table 8.4-6) except that costs for 15 ppm fuel would clearly be zero. Table 8.7-8 also presents the emission reductions that would result from a 500 ppm NRLM fuel-only scenario.

Table 8.7-8
Aggregate Net Operating Costs, Costs by Pollutant, and Emissions Reductions
Associated with a 500 ppm NRLM Fuel-only Scenario ($2002)

Year	Fuel Costs ($million)	Other Operating Costs ($million)	Net Operating Costs ($million)	SOx Costs ($million)	PM Costs ($million)	PM Reduction (tons)	SOx Reduction (tons)
2007	$ 142	$ (161)	$ (18)	$ (12)	$ (6)	10,700	133,000
2008	$ 249	$ (282)	$ (33)	$ (22)	$ (11)	19,000	235,400
2009	$ 254	$ (288)	$ (34)	$ (23)	$ (11)	19,400	240,100
2010	$ 256	$ (282)	$ (26)	$ (17)	$ (9)	19,700	244,000
2011	$ 258	$ (279)	$ (20)	$ (14)	$ (7)	20,000	248,500
2012	$ 263	$ (284)	$ (21)	$ (14)	$ (7)	20,400	253,100
2013	$ 268	$ (290)	$ (22)	$ (15)	$ (7)	20,800	257,600
2014	$ 273	$ (296)	$ (23)	$ (15)	$ (8)	21,100	262,200
2015	$ 277	$ (301)	$ (24)	$ (16)	$ (8)	21,500	266,700
2016	$ 282	$ (307)	$ (25)	$ (17)	$ (8)	21,900	271,300
2017	$ 287	$ (312)	$ (26)	$ (17)	$ (9)	22,200	275,800
2018	$ 292	$ (318)	$ (26)	$ (18)	$ (9)	22,600	280,400
2019	$ 296	$ (324)	$ (27)	$ (18)	$ (9)	23,000	285,200
2020	$ 301	$ (329)	$ (28)	$ (19)	$ (9)	23,300	289,700
2021	$ 306	$ (335)	$ (29)	$ (19)	$ (10)	23,700	294,200
2022	$ 311	$ (340)	$ (30)	$ (20)	$ (10)	24,100	299,000
2023	$ 315	$ (346)	$ (31)	$ (20)	$ (10)	24,500	303,600
2024	$ 320	$ (352)	$ (31)	$ (21)	$ (10)	24,800	308,200
2025	$ 325	$ (357)	$ (32)	$ (21)	$ (11)	25,200	312,900
2026	$ 330	$ (363)	$ (33)	$ (22)	$ (11)	25,600	317,500
2027	$ 335	$ (369)	$ (34)	$ (23)	$ (11)	25,900	322,200
2028	$ 340	$ (374)	$ (35)	$ (23)	$ (12)	26,300	326,800
2029	$ 344	$ (380)	$ (35)	$ (24)	$ (12)	26,700	331,500
2030	$ 349	$ (385)	$ (36)	$ (24)	$ (12)	27,100	336,200
2031	$ 354	$ (391)	$ (37)	$ (25)	$ (12)	27,400	340,800
2032	$ 359	$ (397)	$ (38)	$ (25)	$ (13)	27,800	345,500
2033	$ 364	$ (402)	$ (39)	$ (26)	$ (13)	28,200	350,200
2034	$ 368	$ (408)	$ (39)	$ (26)	$ (13)	28,600	354,900
2035	$ 373	$ (413)	$ (40)	$ (27)	$ (13)	29,000	359,700
2036	$ 378	$ (419)	$ (41)	$ (27)	$ (14)	29,300	364,400
30 Yr NPV at 3%	$ 5,428	$ (5,967)	$ (539)	$ (359)	$ (180)	419,800	5,210,600
30 Yr NPV at 7%	$ 3,027	$ (3,328)	$ (301)	$ (201)	$ (100)	233,800	2,901,700

The calculations of cost per ton of each emission reduced under the 500 ppm NRLM fuel-only scenario divides the net present value of the annual costs assigned to each pollutant (see Table 8.7-8) by the net present value of the total annual reductions of each pollutant (Table 8.7-8). The 30-year net present value of the costs (remember that negative costs are actually savings) associated with each pollutant, calculated with a three percent discount rate, are shown in Table 8.7-8 as -$107 million for PM and -$213 million for SOx. If we exclude the oil change maintenance savings, the costs of the fuel-only scenario would be $1.9 billion for PM and $3.8 billion for SOx. The 30-year net present value, with a three percent discount rate, of emission reductions are 420 thousand tons for PM and 5.2 million tons for SOx. Our air quality analysis, emissions reduction analysis, and benefits analysis are found in Chapters 2, 3, and 9, respectively. Table 8.7-9 presents the cost per ton results for the 500 ppm NRLM fuel-only scenario including the oil change maintenance savings and excluding those savings.

Table 8.7-9
Aggregate Cost per Ton for the 500 ppm NRLM Fuel-only Scenario
30-year Net Present Values at a 3% and 7% Discount Rate ($2002)

Item	Units	3% discount rate	7% discount rate	Source
500ppm at $0.021/gal, 2007-2010	(10^6 gallons)	31,316	26,500	Table 8.7-6
500ppm at $0.022/gal, 2010+	(10^6 gallons)	216,843	112,307	Table 8.7-6
500ppm Fuel Cost	($million)	$5,428	$3,027	Table 8.7-6
Other Operating Costs*	($million)	-$5,967	-$3,328	Table 8.7-7
Total Costs (w/ maintenance savings)	($million)	-$539	-$301	Table 8.7-7
Total Costs (w/o maintenance savings)	($million)	$5,428	$3,027	Table 8.7-7
PM Costs (w/ maintenance savings)	($million)	-$180	-$100	Table 8.7-8
PM Costs (w/o maintenance savings)	($million)	$1,809	$1,009	Calculated**
SOx Costs (w/ maintenance savings)	($million)	-$359	-$201	Table 8.7-8
SOx Costs (w/o maintenance savings)	($million)	$3,619	$2,018	Calculated**
PM Reduction	(10^6 tons)	0.42	0.23	Table 8.7-8
SOx Reduction	(10^6 tons)	5.2	2.9	Table 8.7-8
Cost per Ton PM (w/ maintenance savings)	($/ton)	-$400	-$400	Calculated
Cost per Ton PM (w/o maintenance savings)	($/ton)	$4,300	$4,400	Calculated
Cost per Ton SOx (w/ maintenance savings)	($/ton)	-$70	-$70	Calculated
Cost per Ton Sox (w/o maintenance savings)	($/ton)	$690	$700	Calculated

* Other operating costs include oil change maintenance savings.
** Calculated as one-third (PM) or two-thirds (SOx) of the Total Scenario Costs w/o maintenance savings.

We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emission reductions in that year alone. This number, shown in Table 8.7-10, approaches the long-term cost per ton of emissions reduced.

Table 8.7-10
Long-Term Cost per Ton of the 500 ppm NRLM Fuel-only Scenario
Annual Values without Discounting ($2002)

Pollutant	Long-Term Cost per Ton in 2030
PM (with maintenance savings)	-$400
PM (without maintenance savings)	$4,300
SOx (with maintenance savings)	-$70
SOx (without maintenance savings)	$690

8.7.3.2 Costs and Costs per Ton of the 15 ppm L&M Fuel Increment

In this section, we evaluate the incremental cost per ton of the 15 ppm L&M fuel cap in 2012 (final NRLM program) relative to retaining the 500 ppm cap on L&M fuel (the proposed NRLM program) indefinitely. Nonroad diesel fuel is assumed to be subject to a 15 ppm cap starting in 2010 in both cases. We assume that the emission standards applicable to nonroad engines are the same regardless of the sulfur cap applicable to L&M fuel. Therefore, the only differences between the 500 and 15 ppm cap on L&M fuel are in emissions of SO_2 and sulfate PM, fuel costs and engine maintenance savings. The cost of complying with emission standards for land-based nonroad equipment, as well as HC, NOx, and non-sulfate PM emissions from this equipment are unaffected.

The difference in costs between the two L&M fuel caps are primarily related to the production 15 ppm L&M fuel. The differences in sulfurous emissions arise from differences in the sulfur content of both L&M fuel and, in the Northeast/Middle Atlantic area, heating oil. While the difference in heating oil sulfur content is a direct result of the final NRLM fuel provisions for the Northeast/Middle Atlantic area, heating oil sulfur content is not directly regulated by this final rule. Therefore, we develop estimates of the incremental cost effectiveness of the 15 ppm L&M fuel cap both with and without the changes in heating oil sulfur. However, we believe that the most appropriate estimate of the incremental cost effectiveness of the 15 ppm L&M fuel cap is that including the change in heating oil sulfur content.

The key inputs to this sensitivity analysis are: 1) the volumes and sulfur contents of each type of distillate fuel being produced and consumed in the 2012-2036 timeframe, and 2) the cost of supplying these fuels over the same timeframe. The fuels produced prior to June 1, 2012 are identical under the two scenarios being evaluated here. Thus, we ignore all emissions and costs prior to June 1, 2012. This incremental analysis models the U.S. minus California., although it would also apply for the total U.S. as well since California's fuel quality is not expected to change with the requirement that L&M fuel meet a 15 ppm cap.

The process for estimating the annual production volumes of each fuel was described in Chapter 7. The first step in the process was to develop a comprehensive description of fuel production and demand in 2001 for non-highway and highway diesel fuel which accounted for the spillover of low sulfur, highway fuel into the non-highway markets. The analysis also considered the downgrade of jet fuel and highway diesel fuel, along with some gasoline, to lower quality fuels during pipeline distribution.

We then developed a set of analogous estimates for 2014, starting with demand. Fuel demand in 2014 was projected using the EPA draft NONROAD2004 model and EIA's AEO 2003. We also estimated the volume of highway diesel fuel demand considering the highway diesel fuel requirements being implemented in 2006 and 2010. Spillover of highway fuel into the non-highway markets was assumed to remain constant (in terms of the percentage of each non-highway market represented by spillover). The volume of gasoline, jet fuel and highway diesel fuel in 2014 downgraded to 500 ppm and high sulfur distillate was projected to increase in proportion to the growth in jet fuel demand and the supply of highway diesel fuel. This downgraded fuel was first distributed to the non-highway fuel markets assuming sulfur controls on highway fuel only, followed by the 500 ppm standard on NRLM fuel in 2007 and subsequent 15 ppm standards on nonroad fuel and L&M fuel in 2010 and 2012, respectively. NRLM fuel not already complying with the required sulfur limit prior to the NRLM rule from spillover of highway fuel or downgrade, had to be desulfurized at refineries.

We then used these 2014 estimates of fuel production, downgrade and spillover to develop similar estimates for individual calendar years starting with 2007 and going through 2040 consistent with the phase of NRLM program in place at the time. These individual, annual estimates were based on a slightly more approximate methodology which assumed that the fraction of each non-highway distillate fuel's market demand represented by spillover and downgrade remained constant at its 2014 level. Regarding spillover, this is the same assumption made in developing our estimate of spillover in 2014. However, with respect to downgrade, this assumption differs from that used in the more comprehensive 2014 analysis. Because the demand for jet fuel and highway diesel fuel is projected to grow faster than that for NRLM fuel and heating oil, the percentage of downgrade in the NRLM and heating oil markets is higher in 2014 than in 2001. Thus, the net effect of assuming that the percentage of downgrade remains constant at 2014 levels underestimates the percentage of downgrade in the non-highway fuel markets after 2014, and overestimates it prior to 2014.

The effect of assuming constant downgrade percentages in the non-highway markets on the estimated costs and benefits of the overall rule is very small, given that it affects only a small portion of the overall fuel demanded, that none of the benefits of the engine emission standards are involved and that the changes in costs and benefits are offsetting. However, it has a larger impact on this incremental analysis, as about half of the 30-year sulfur dioxide emission benefits of the 15 ppm L&M cap are due to a shift in downgrade from the L&M fuel market to the heating oil market in the Northeast/Middle Atlantic area. Thus, for this incremental analysis, we revised the assumption that the downgrade fraction of the demand for the various non-highway fuels for years other than 2014 will remain constant at their 2014 levels. Instead, we estimated the volume of downgrade generated each year, based on future highway diesel fuel supply and jet fuel demand. We made one simplifying assumption: that highway diesel fuel supply grew at the same rate as highway fuel demand. Highway fuel supply includes spillover to the non-highway fuel markets. While nonroad fuel demand is projected to grow at roughly the same rate as highway fuel, L&M fuel and heating oil demand are expected to grow much more slowly. Thus, this simplifying assumption overestimates highway fuel supply. However, the degree of overestimation is slight, since only about 10% of highway diesel fuel supply is spillover to the non-highway pool, and about 70% of that goes to the nonroad fuel market.

Estimates of the demand for highway and jet fuel through 2025 are taken from EIA's AEO 2003. After 2025 the yearly projected demand for both highway diesel fuel and jet fuel are estimated from the average projected growth from AEO 2003 between 2020 and 2025. The year-over-year growth rates for highway and jet fuel from 2020 to 2025 were 1.019 and 1.021, respectively. The annual demand for highway and jet fuel from 2012 to 2036 and the volume ratios to the projected 2014 volumes are summarized in Table 8.7-11. In last column of Table 8.7-11 an average set of volume ratios are shown which represents the combined growth for highway and jet-based downgrade in heating oil. The relative volume of highway and jet-based downgrade was similar in NRLM diesel fuel, so these volume ratios were used for estimating non-2014 downgrade volumes for NRLM diesel fuel as well.

Table 8.7-11
Projected Highway Diesel Fuel and Jet Fuel Demand - AEO 2003 (Trillion BTU)

Year	Highway		Jet Fuel		Avg Ratio to 2014
	Fuel Demand	Ratio to 2014	Fuel Demand	Ratio to 2014	
2012	7,500	0.957	4,140	0.945	0.954
2013	7,670	0.978	4,260	0.973	0.977
2014	7,840	1.000	4,380	1.000	1.000
2015	7,980	1.018	4,500	1.027	1.020
2016	8,110	1.034	4,620	1.055	1.039
2017	8,250	1.052	4,730	1.080	1.059
2018	8,390	1.070	4,860	1.110	1.079
2019	8,560	1.092	4,970	1.135	1.102
2020	8,700	1.110	5,090	1.162	1.122
2021	8,850	1.129	5,200	1.187	1.142
2022	9,020	1.151	5,310	1.212	1.165
2023	9,200	1.173	5,430	1.240	1.189
2024	9,400	1.199	5,540	1.265	1.214
2025	9,580	1.222	5,660	1.292	1.238
2026	9,762	1.245	5,780	1.319	1.262
2027	9,947	1.269	5,900	1.347	1.287
2028	10,140	1.293	6,020	1.375	1.312
2029	10,330	1.317	6,150	1.404	1.338
2030	10,530	1.343	6,280	1.434	1.364
2031	10,730	1.368	6,410	1.464	1.390
2032	10,930	1.394	6,550	1.495	1.417
2033	11,140	1.421	6,680	1.526	1.445
2034	11,350	1.447	6,820	1.558	1.473
2035	11,560	1.475	6,970	1.591	1.502
2036	11,780	1.503	7,110	1.624	1.531

The next step is to estimate the annual demand, spillover, downgrade and production volumes for NRLM fuel from 2012 to 2036 for both the proposed and final rule NRLM programs. Starting with the proposed NRLM fuel program, we estimated the jet and highway-based downgrade in the nonroad, locomotive and marine fuel markets from mid-2012 to mid-2014 by multiplying the 2014 highway and jet-based downgrade volumes shown in Table 7.1.4-1 by the ratio of highway and jet fuel demand in each year to 2014 from Table 8.7-11, respectively. For the years following 2014, we multiplied the 2014 highway and jet-based downgrade volumes shown in Table 7.1.4-2 by the ratio of highway and jet fuel demand in each year to 2014 from Table 8.7-11, respectively. Annual demand for NRLM fuel, and the contribution of spillover and small refiner fuel to these markets, were estimated by multiplying the 2014 estimates of these volumes in Tables 7.1.4-1 (for 2012-2014) and 7.1.4-2 (for 2015 and beyond) by the growth in NRLM fuel demand contained in Tables 7.1.5-1 (for nonroad and locomotive fuel) and 7.1.5-2 (for marine fuel). Annual production volumes of NRLM fuel were estimated by subtracting the downgrade, spillover and small refiner fuel volumes from total demand. The resulting estimates of downgrade, spillover, small refiner fuel, and 15 and 500 ppm production volumes for nonroad, locomotive and marine diesel fuel for the proposed rule program are summarized in Tables 8.7-12, 8.7-13 and 8.7-14, respectively. The highway-based and jet fuel-based downgrade volumes are combined together into one column.

Table 8.7-12
Nonroad Fuel Supply Under the Proposed NRLM Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	Small Refiner Fuel	Spillover	New 15 ppm Fuel	Total Volume
2012	1,061	627	2,760	8,327	12,774
2013	1,085	640	2,818	8,501	13,045
2014	463	272	2,940	9,641	13,316
2015	0	0	3,047	10,539	13,586
2016	0	0	3,107	10,747	13,854
2017	0	0	3,167	10,955	14,122
2018	0	0	3,227	11,162	14,390
2019	0	0	3,288	11,370	14,658
2020	0	0	3,352	11,578	14,926
2021	0	0	3,408	11,786	15,193
2022	0	0	3,468	11,993	15,461
2023	0	0	3,528	12,201	15,729
2024	0	0	3,588	12,409	15,997
2025	0	0	3,648	12,616	16,265
2026	0	0	3,708	12,823	16,531
2027	0	0	3,767	13,029	16,797
2028	0	0	3,827	13,236	17,063
2029	0	0	3,887	13,443	17,329
2030	0	0	3,946	13,649	17,595
2031	0	0	4,006	13,855	17,861
2032	0	0	4,066	14,062	18,127
2033	0	0	4,125	14,268	18,393
2034	0	0	4,185	14,474	18,659
2035	0	0	4,245	14,681	18,925
2036	0	0	4,304	14,887	19,191

* Excludes NRLM fuel demand in California

Table 8.7-13
Locomotive Volumes Under the Proposed NRLM Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	New 500 ppm Fuel	Spillover	Total Volume
2012	579	1,705	602	2,886
2013	593	1,710	607	2,909
2014	1,176	1,190	566	2,932
2015	1,614	804	539	2,956
2016	1,644	800	544	2,988
2017	1,675	791	549	3,015
2018	1,707	777	554	3,038
2019	1,743	766	559	3,067
2020	1,775	751	563	3,089
2021	1,807	731	566	3,104
2022	1,843	719	571	3,132
2023	1,881	703	576	3,160
2024	1,921	686	581	3,187
2025	1,959	673	586	3,218
2026	1,997	656	591	3,244
2027	2,036	638	596	3,270
2028	2,076	619	601	3,295
2029	2,116	600	605	3,321
2030	2,157	580	610	3,347
2031	2,199	559	615	3,373
2032	2,242	537	619	3,399
2033	2,286	515	624	3,425
2034	2,330	491	629	3,450
2035	2,376	467	634	3,476
2036	2,422	442	638	3,502

* Excludes NRLM fuel demand in California

Table 8.7-14
Marine Volumes Under the Proposed NRLM Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	New 500 ppm Fuel	Spillover	Total Volume
2012	446	1,333	280	2,059
2013	456	1,338	283	2,078
2014	451	1,369	281	2,103
2015	436	1,409	280	2,126
2016	445	1,419	283	2,146
2017	453	1,431	286	2,170
2018	462	1,451	290	2,203
2019	471	1,473	295	2,240
2020	480	1,488	299	2,266
2021	489	1,503	302	2,294
2022	498	1,526	307	2,331
2023	509	1,538	311	2,357
2024	519	1,555	315	2,389
2025	530	1,568	319	2,417
2026	540	1,585	323	2,448
2027	551	1,602	327	2,479
2028	561	1,618	331	2,510
2029	572	1,634	335	2,542
2030	583	1,650	339	2,573
2031	595	1,666	343	2,604
2032	606	1,682	347	2,635
2033	618	1,697	352	2,667
2034	630	1,712	356	2,698
2035	642	1,727	360	2,729
2036	655	1,742	364	2,760

* Excludes NRLM fuel demand in California

Annual estimates of downgrade, spillover, small refiner fuel, and 15 and 500 ppm production volumes under the final NRLM fuel program in years other than 2014 were estimated from the estimates for 2014 in the same manner. The only difference is a new set of 2014 estimates. The 2014 estimates of downgrade, spillover, small refiner fuel, and total demand for NRLM fuel for mid-2012 to mid-2014 were taken from Table 7.1.3-19. The 2014 estimates of downgrade, spillover, small refiner fuel, and total demand for NRLM fuel for 2015 and beyond were taken from Table 7.1.3-20. The resulting estimates of downgrade, spillover, small refiner fuel, and 15 and 500 ppm production volumes for nonroad, locomotive and marine diesel fuel for the proposed rule program are summarized in Tables 8.7-15, 8.7-16 and 8.7-17, respectively.

Table 8.7-15
Nonroad Fuel Supply Under the Final Rule Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	Small Refiner Fuel	Spillover	New 15 ppm Fuel	Total Volume
2012	1,061	528	2,760	8,426	12,774
2013	1,085	468	2,818	8,674	13,045
2014	463	199	2,941	9,713	13,316
2015	-	-	3,047	10,539	13,586
2016	-	-	3,107	10,747	13,854
2017	-	-	3,167	10,955	14,122
2018	-	-	3,227	11,162	14,390
2019	-	-	3,288	11,370	14,658
2020	-	-	3,352	11,578	14,926
2021	-	-	3,408	11,786	15,193
2022	-	-	3,468	11,993	15,461
2023	-	-	3,528	12,201	15,729
2024	-	-	3,588	12,409	15,997
2025	-	-	3,648	12,616	16,265
2026	-	-	3,708	12,823	16,531
2027	-	-	3,767	13,029	16,797
2028	-	-	3,827	13,236	17,063
2029	-	-	3,887	13,443	17,329
2030	-	-	3,946	13,649	17,595
2031	-	-	4,006	13,855	17,861
2032	-	-	4,066	14,062	18,127
2033	-	-	4,125	14,268	18,393
2034	-	-	4,185	14,474	18,659
2035	-	-	4,245	14,681	18,925
2036	-	-	4,304	14,887	19,191

* Excludes NRLM fuel demand in California

Table 8.7-16
Locomotive Fuel Supply Under the Final Rule Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	Small Refiner Fuel	Spillover	New 15 ppm Fuel	Total Volume
2012	397	761	602	1,127	2,841
2013	274	99	607	1,930	2,909
2014	849	42	589	1,476	2,932
2015	1,281	-	577	1,099	2,956
2016	1,304	-	583	1,100	2,988
2017	1,329	-	589	1,098	3,015
2018	1,355	-	593	1,090	3,038
2019	1,383	-	599	1,086	3,067
2020	1,408	-	603	1,069	3,089
2021	1,434	-	606	1,053	3,104
2022	1,462	-	611	1,058	3,132
2023	1,492	-	617	1,051	3,160
2024	1,524	-	622	1,041	3,187
2025	1,554	-	628	1,035	3,218
2026	1,585	-	633	1,026	3,244
2027	1,616	-	638	1,016	3,270
2028	1,647	-	643	1,005	3,295
2029	1,679	-	648	994	3,321
2030	1,712	-	653	982	3,347
2031	1,745	-	658	969	3,373
2032	1,779	-	663	956	3,399
2033	1,814	-	668	942	3,425
2034	1,849	-	674	928	3,450
2035	1,885	-	679	912	3,476
2036	1,922	-	684	897	3,502

* Excludes NRLM fuel demand in California

Table 8.7-17
Marine Fuel Supply Under the Final Rule Fuel Program With the Shift of Downgrade to the Heating Oil Market (million gallons) *

Year	Downgrade	Small Refiner Fuel	Spillover	New 15 ppm Fuel	Total Volume
2012	285	636	280	874	2,059
2013	173	148	283	1,474	2,078
2014	155	62	281	1,605	2,103
2015	141	-	280	1,705	2,126
2016	143	-	283	1,720	2,146
2017	146	-	286	1,738	2,170
2018	149	-	290	1,763	2,203
2019	152	-	295	1,793	2,240
2020	155	-	299	1,813	2,266
2021	158	-	302	1,834	2,294
2022	161	-	307	1,863	2,331
2023	164	-	311	1,883	2,357
2024	168	-	315	1,906	2,389
2025	171	-	319	1,927	2,417
2026	174	-	323	1,951	2,448
2027	178	-	327	1,975	2,479
2028	181	-	331	1,998	2,510
2029	185	-	335	2,022	2,542
2030	188	-	339	2,046	2,573
2031	192	-	343	2,069	2,604
2032	196	-	347	2,092	2,635
2033	199	-	352	2,116	2,667
2034	203	-	356	2,139	2,698
2035	207	-	360	2,162	2,729
2036	211	-	364	2,185	2,760

* Excludes NRLM fuel demand in California

The cost of supplying NRLM fuel under the final NRLM program and for the proposed NRLM program are developed in Chapter 7 and summarized in Table 7.5-1. The engine maintenance savings associated with reduced sulfur contents are developed in Chapter 6 and summarized in Table 6.2-29. We assume that the per gallon costs developed for 2014 apply through 2036. With the increase in downgrade volume, the cost of reprocessing downgrade which occurs in some regions would increase. However, this increase occurs both with and without the 15 ppm L&M fuel cap. Thus, we did not update the estimated cost of reprocessing downgrade. The per gallon costs and savings under both L&M fuel caps are summarized here in Table 8.7-18.

Table 8.7-18
Total Diesel Fuel Costs Under 500 and 15 ppm L&M Fuel Caps*

	Refining Cost	Additive and Distribution Cost	Maintenance Savings	Total w/o Maintenance Savings	Total with Maintenance Savings
Final NRLM Fuel Program					
2012-2014					
15 ppm Nonroad	5.6	0.8	-3.2	6.4	3.2
Small Refiner 500 ppm Nonroad	2.9	0.2	-2.9	3.1	0.2
Small Refiner 500 ppm L&M	2.9	0.2	-1	3.1	2.1
2014 +					
15 ppm Nonroad	5.8	1.2	-3.2	7	3.8
15 ppm L&M	5.8	1.2	-1.1	7	5.9
500 ppm NRLM Fuel Cap in 2007 and 15 ppm Nonroad Fuel Cap in 2010 (proposed rule program)					
2012-2014					
15 ppm Nonroad	5	0.8	-3.2	5.8	2.6
Small Refiner 500 ppm Nonroad	2.7	0.2	-2.9	2.9	0
500 ppm L&M	2.7	0.3	-1.0	3	2.0
2014 +					
15 ppm NR	5.2	1.2	-3.2	6.4	3.2
500 ppm L&M	2.7	0.2	-1.0	2.9	1.9

* Fuel costs are relative to uncontrolled fuel and assume that, during the transitional years of 2012 & 2014, the first 5 months are at the previous year's cost and the remaining 7 months are at the next year's cost.

We then multiplied the production volume of each fuel in a given calendar year by the net cost of using that fuel from Table 8.7-18. For this incremental analysis, we only present estimated annual costs including the maintenance savings because, on the increment, these maintenance savings are minor (0.1 c/gal) compared to the incremental cost of producing 15 ppm L&M fuel. Little information would be gained from presenting costs without the maintenance savings, as is done for the final rule analysis and the other sensitivity cases. We do present the final discounted costs without the maintenance savings, as well as the cost-effectiveness based on the costs without maintenance savings, in Table 8.7-24. The resulting annual costs are shown in Table 8.7-19.

Table 8.7-19
Annual Fuel Costs & Oil Change Maintenance Savings With the Shift of Downgrade to the Heating Oil Market ($2002 million)

Year	Final NRLM Fuel Program	15 ppm NR Cap and 500 ppm L&M Cap	15 ppm L&M Incremental Costs
2012	$ 268	$ 162	$ 107
2013	$ 472	$ 282	$ 190
2014	$ 524	$ 337	$ 187
2015	$ 566	$ 379	$ 187
2016	$ 575	$ 386	$ 189
2017	$ 583	$ 393	$ 191
2018	$ 592	$ 400	$ 193
2019	$ 602	$ 406	$ 195
2020	$ 610	$ 413	$ 197
2021	$ 618	$ 420	$ 198
2022	$ 628	$ 426	$ 202
2023	$ 637	$ 433	$ 203
2024	$ 645	$ 440	$ 206
2025	$ 654	$ 446	$ 208
2026	$ 663	$ 453	$ 210
2027	$ 671	$ 459	$ 212
2028	$ 680	$ 466	$ 214
2029	$ 688	$ 473	$ 216
2030	$ 697	$ 479	$ 218
2031	$ 705	$ 486	$ 220
2032	$ 714	$ 492	$ 222
2033	$ 722	$ 499	$ 224
2034	$ 731	$ 505	$ 226
2035	$ 739	$ 511	$ 227
2036	$ 747	$ 518	$ 229
Total 30-Year Costs (2007-2036)			
Undiscounted	$ 15,731	$ 10,664	$ 5,068
30 Yr NPV at 3%	$ 8,640	$ 5,829	$ 2,811
30 Yr NPV at 7%	$ 4,249	$ 2,847	$ 1,402

The absence of the shift of downgrade to the heating oil market in the Northeast/Middle Atlantic area has no impact on the supply of NRLM fuel under the proposed NRLM fuel program. Thus, the various volumes of NRLM fuel shown in Tables 8.7-12 through 8.7-14 still apply. Without the shift of downgrade to heating oil, the production volumes of NRLM fuel under the final NRLM fuel program become very similar to those for the proposed NRLM fuel program, except that L&M fuel produced after mid-2012 would have to meet a 15 ppm cap instead of a 500 ppm cap. The volumes of spillover, downgrade and demand are identical. The only difference is that the volume of 500 ppm, small refiner fuel is slightly greater with a long-term 500 ppm L&M fuel cap than with a 15 ppm cap. Thus, the incremental volume of 15 ppm fuel from mid-2012 to mid-2014 under the 15 ppm L&M fuel cap is slightly higher than simply the volume of 500 ppm L&M fuel which must be produced under the 500 ppm L&M cap. Table 8.7-20 shows the breakdown of nonroad, locomotive and marine fuel supply for the final NRLM fuel program without a shift in downgrade to heating oil.

Table 8.7-20
NRLM Fuel Supply Under the Final NRLM Fuel Program Without a Downgrade Shift to Heating Oil (million gallons) *

Year	Downgrade	Small Refiner Fuel	Spillover	New 15 ppm Fuel	Total Volume
	Nonroad Diesel Fuel				
2012	1,061	528	2,760	8,426	12,774
2013	1,085	468	2,818	8,674	13,045
2014	463	199	2,940	9,713	13,316
2015 +	Same as for Proposed NRLM Fuel Program				
	Locomotive Diesel Fuel				
2012	579	761	602	944	2,886
2013	593	99	607	1610	2,909
2014	1,176	42	566	1148	2,932
2015 +	Same as for Proposed NRLM Fuel Program				
	Marine Diesel Fuel				
2012	446	636	280	697	2,059
2013	456	148	283	1191	2,078
2014	451	62	280	1310	2,103
2015 +	Same as for Proposed NRLM Fuel Program				

* Excludes NRLM fuel demand in California

The per gallon costs shown in Table 8.7-19 are unaffected by the absence of a shift in downgrade to the heating oil market.[D] Thus, the annual costs with a 500 ppm L&M cap are the same as before. The annual costs under the final NRLM program decrease slightly, as 15 ppm L&M fuel does not need to replace downgrade shifted from the L&M market to the heating oil market in the Northeast/Middle Atlantic exclusion area. The annual costs under both programs are shown in Table 8.7-21.

[D] The reduced volume of 15 ppm L&M fuel under the final NRLM fuel program could reduce the per gallon cost of 15 ppm fuel, as those refiners facing the highest costs might be the first to avoid producing this fuel. However, as indicated by the sensitivity analysis of potentially lower nonroad fuel demand (Case 1 Sensitivity) discussed in Section 3 of Appendix 8A, significantly lowering the demand for 15 ppm NRLM fuel has little effect on the cost per gallon.

Table 8.7-21
Annual Fuel Costs & Oil Change Maintenance Savings Without Shift of Downgrade to the Heating Oil Market ($2002 million)

Year	Final NRLM Fuel Program	Proposed NRLM Fuel Program	Incremental Cost of 15 ppm L&M Cap
2012	$249	$162	$88
2013	$432	$282	$150
2014	$488	$337	$151
2015	$531	$379	$152
2016	$539	$386	$153
2017	$547	$393	$155
2018	$556	$400	$156
2019	$564	$406	$158
2020	$572	$413	$159
2021	$580	$420	$160
2022	$588	$427	$162
2023	$596	$433	$163
2024	$604	$440	$164
2025	$612	$446	$165
2026	$619	$453	$166
2027	$627	$460	$168
2028	$635	$466	$169
2029	$643	$473	$170
2030	$650	$479	$171
2031	$658	$486	$172
2032	$665	$492	$173
2033	$673	$499	$174
2034	$680	$505	$175
2035	$687	$512	$176
2036	$695	$518	$177
Total 30-Year Costs (2007 - 2036)			
Undiscounted	$14,690	$10,665	$4,025
30-Year NPV at 3%	$8,070	$5,830	$2,240
30-Year NPV at 7%	$3,969	$2,847	$1,121

Moving to emission reductions, we used the methodology used in the draft 2004 NONROAD model to estimate SO_2 and sulfate PM emissions from NRLM engines (Section 3.1 of the Final RIA). To calculate the emission reductions, we needed estimates for the sulfur levels for nonroad, locomotive and marine diesel fuel.

In Section 7.1.6 of the Final RIA, we present our estimate of the sulfur levels of on-purpose produced diesel fuel, spillover, and downgrade. These sulfur levels, spillover (11 ppm), small refiner fuel (340 ppm), and non-small refiner fuel (either 340 or 11 ppm), are unaffected by changing the volume of downgrade projected to be generated during fuel distribution. For downgrade, in Section 7.1, we estimated that jet-based downgrade contained 400-470 ppm sulfur and highway-based downgrade contained 25-35 ppm sulfur. The relative volumes of these downgrades varies by region. We calculated a national average sulfur content for combined highway-based and jet-based downgrade used in the L&M markets by weighting the sulfur contents of each downgrade type in each region. The result was an average downgrade sulfur content of 101 ppm for the proposed NRLM program and 172 ppm for the final NRLM program. These sulfur levels were used for downgrade volumes for all the years of the incremental analysis.[E] We also applied these downgrade sulfur contents to the small volume of downgrade used in the nonroad fuel market from mid-2012 to mid-2014. The resulting overall sulfur levels for NRLM fuel are summarized in Table 8.7-22.

[E] The downgrade comprised of highway diesel fuel and jet fuel likely changes in sulfur level throughout the period as the relative volume of highway and jet fuel varies relative to each other. However, the growth of highway diesel fuel and jet fuel is very similar so very little change is expected throughout the analysis period. Thus, this assumption seems reasonable.

Table 8.7-22
Sulfur Levels of NRLM Diesel Fuel Based on Revised Downgrade Estimates (million gallons)

	48 State Analysis				50 State Analysis			
Year	Proposed Rule		Final Rule		Proposed Rule		Final Rule	
	NR	L&M	NR	L&M	NR	L&M	NR	L&M
2012	36	236	32	122	36	237	33	125
2013	36	235	29	43	36	237	30	47
2014	21	215	19	49	22	214	19	51
2015	11	201	11	55	11	198	11	54
2016	11	200	11	55	11	197	11	54
2017	11	199	11	55	11	196	11	54
2018	11	198	11	56	11	195	11	55
2019	11	198	11	56	11	194	11	55
2020	11	197	11	56	11	194	11	55
2021	11	195	11	57	11	192	11	56
2022	11	193	11	57	11	190	11	56
2023	11	192	11	57	11	189	11	57
2024	11	191	11	58	11	188	11	57
2025	11	190	11	58	11	187	11	57
2026	11	189	11	59	11	186	11	58
2027	11	188	11	59	11	185	11	58
2028	11	187	11	59	11	184	11	59
2029	11	187	11	60	11	183	11	59
2030	11	186	11	60	11	182	11	59
2031	11	185	11	61	11	181	11	60
2032	11	184	11	61	11	180	11	60
2033	11	183	11	62	11	179	11	61
2034	11	181	11	62	11	178	11	61
2035	11	180	11	62	11	177	11	62
2036	11	179	11	63	11	176	11	62
2037	11	178	11	63	11	175	11	62
2038	11	177	11	64	11	174	11	63
2039	11	176	11	64	11	173	11	63
2040	11	175	11	65	11	171	11	64

We developed these for 50-state and 48-state regions, as this was done for the other alternatives evaluated in Chapter 3. We use the 50-state sulfur levels here, even though the volumes developed above are for the U.S. excluding California. Thus, the total sulfur dioxide and sulfate PM emissions resulting from combining the fuel volumes with the sulfur contents are not correct. However, as the 15 ppm L&M cap has no impact on sulfur levels in California, the difference in sulfurous emissions between the two L&M fuel caps is correct. To avoid any possible mis-use of the absolute emissions under either L&M cap, we only present the differential emission estimates below.

In Section 7.1.6, we also estimate the sulfur content of heating oil by assuming that heating oil has the same sulfur content as NRLM fuel prior to the final NRLM rule. That is acceptable for the analysis of the overall NRLM rule, since the emission reductions related to changes in the sulfur content of heating oil are minor relative to emission reductions related to changes in sulfur content of NRLM. However, in analyzing the incremental step of reducing L&M fuel sulfur from 500 to 15 ppm, heating oil related emission represent a significant portion of the emission reductions and therefore warrant closer scrutiny. The impacts on the sulfur content of heating oil occur in the overall program primarily as a result of changes in where spillover and downgrade are projected to be used. With the imposition of the 15 ppm limit, downgrade product in particular is forced from other markets into the heating oil market. When this downgraded distillate cannot be used in NR or in L&M fuel, it will shift to the heating oil market. The main impact of this is felt as the last increment of diesel fuel, the L&M portion, is required to meet a 15 ppm limit, and primarily in the Northeast and Mid-Atlantic area where the majority of heating oil is marketed, and when under the provisions of the final rule downgraded material cannot continue to be sold into the NRLM markets. The downgrade contains between 31 (highway-based) and 435 ppm (jet-based) sulfur, well below that of heating oil. Thus, the sulfur content of heating oil decreases significantly in the Northeast/Mid-Atlantic area with a 15 ppm cap on L&M fuel.

In the Northeast and Middle Atlantic area of the U.S., certain states regulate the sulfur content of heating oil, so some of the heating oil in this area contains much less sulfur than NRLM fuel. As a result, the sulfur level estimates based on high sulfur diesel fuel may not be entirely accurate for representing the sulfur level of heating oil, particularly in this area of the country. Given that the majority of the impact on emissions from heating oil for analyzing the L&M increment to 15 ppm are in this part of the country, we looked to see what other data might be available to better assess the sulfur levels. We obtained heating oil surveys from TRW [5,6]. TRW surveys covers heating oil produced in the U.S. TRW's districts A and B match the Northeast/Mid-Atlantic area area quite closely. In 2001 and 2002, heating oil produced by refineries for this market averaged 1385 ppm sulfur. (As was described in Section 7.1.6, we exclude sulfur measurements less than 500 ppm, as these likely represent spillover from the highway fuel supply.) This is less than half that of average NRLM fuel in PADD 1 (2925 ppm, see Table 7.1.6-3).

One difficulty in using the heating oil survey results directly is that the heating oil may be marketed as a single high sulfur distillate fuel to both the diesel fuel and heating oil markets. Thus, much of the intended sales for heating oil purposes could have been used as diesel fuel. The TRW surveys for both diesel fuel and heating oil cover only a small fraction of the total volume of fuel sold in the U.S. It is not clear whether the heating oil not covered by the data submitted by refiners to TRW resembles the high sulfur diesel fuel containing roughly 2900 ppm sulfur or the heating oil containing roughly 1400 ppm sulfur. Because of this uncertainty, we assume that the average heating oil in the Northeast/Mid-Atlantic Area contains 2155 ppm sulfur, the average of the TRW survey estimates for high sulfur diesel fuel and heating oil.

With the imposition of the 15 ppm L&M standard in 2012, and because of the Northeast/Mid-Atlantic area provisions of the final NRLM fuel program, 616 million gallons of downgrade is shifted from the NRLM market to the heating oil market in 2014. Of this, 143 million gallons is jet-based downgrade and 473 million gallons is highway-based downgrade. In PADD 1, jet-based downgrade is estimated to contain 470 ppm sulfur, while highway-based downgrade contains 35 ppm sulfur. Thus, the average sulfur content of both downgrades is 129 ppm. Shifting this downgrade from the NRLM fuel market to the heating oil market reduces the sulfur content of the 616 million gallons of heating oil by 2026 ppm (2155 ppm minus 129 ppm). The volume of downgrade used in heating oil is estimated for the years before and after 2014 using the overall downgrade growth rates shown in Table 8.7-11. The resulting incremental volume of downgrade estimated to be shifted over to heating oil from 2012 to 2036 due to the final NRLM program is summarized in Table 8.7-23. The same 2026 ppm sulfur reduction due to the shift of downgrade to the heating oil pool is used for all the years.

Table 8.7-23
Incremental Volume of Downgrade Forced into Heating Oil by the Final NRLM Program
(Million gallons)

Year	Volume
2012	343
2013	602
2014	616
2015	628
2016	640
2017	652
2018	665
2019	679
2020	691
2021	704
2022	718
2023	732
2024	748
2025	763
2026	778
2027	793
2028	808
2029	824
2030	840
2031	856
2032	873
2033	890
2034	907
2035	925
2036	943

We estimate that 99% of the sulfur in heating oil is emitted in the form of sulfur dioxide and 1% in the form of sulfate PM.[7] Otherwise, the reductions in sulfur dioxide and sulfate PM emissions due to this shift of downgrade to the PADD 1 heating oil market were estimated using the formula described in Chapter 3.[F] Table 8.7-16 presents the annual sulfur dioxide and sulfate PM emission reductions from NRLM fuel and heating oil. The reductions in NRLM emissions represent the difference in sulfur dioxide and sulfate PM emissions under the proposed and final NRLM fuel programs. These emissions under each fuel program are derived from combining the sulfur contents shown in Table 8.7-24 for the 50-state region with the NRLM fuel demands shown in Tables 8.7-12 through 8.7-17.

[F] As described in Chapter 3, sulfur dioxide has twice the mass of sulfur contained within it. Diesel fuel and heating oil are both assumed to have a density of 7.1 pounds per gallon. Thus, the formula for calculating the sulfur dioxide emission reduction from heating oil consumption in 2014 is: 616 million gallons * 7.1 lb/gal * 2026 parts sulfur per million parts heating oil by mass * 99% conversion of sulfur to SO_2 * 2 lbs SO_2 per lb sulfur / 2000 lb/ton. Sulfate PM in the atmosphere is estimated to have 7 times the mass of the sulfur contained within it. Thus, the formula for calculating the sulfate PM emission reduction from heating oil consumption in 2014 is: 616 million gallons * 7.1 lb/gal * 2026 parts sulfur per million parts heating oil by mass * 1% conversion of sulfur to sulfate PM * 7 lbs sulfate PM per lb sulfur / 2000 lb/ton.

Table 8.7-24
Annual Sulfur Dioxide and Sulfate PM Emission Reductions: 15 ppm Versus 500 ppm L&M Cap (tons per year)

Year	Sulfur Dioxide			Sulfate PM		
	NRLM Fuel	Heating Oil	Total	NRLM Fuel	Heating Oil	Total
2012	4,305	4,884	9,189	372	173	545
2013	7,450	8,572	16,022	709	303	1012
2014	6,264	8,772	15,036	580	310	890
2015	5,319	8,944	14,263	415	316	731
2016	5,332	9,108	14,440	416	322	738
2017	5,342	9,276	14,618	417	328	745
2018	5,353	9,453	14,806	418	334	752
2019	5,381	9,649	15,030	420	341	761
2020	5,385	9,822	15,207	420	347	767
2021	5,346	9,999	15,345	417	354	771
2022	5,327	10,195	15,522	416	360	776
2023	5,309	10,404	15,713	414	368	782
2024	5,310	10,627	15,937	414	376	790
2025	5,310	10,836	16,146	414	383	797
2026	5,309	11,046	16,355	414	391	805
2027	5,311	11,261	16,572	414	398	812
2028	5,305	11,479	16,784	414	406	820
2029	5,300	11,702	17,002	414	414	828
2030	5,294	11,929	17,223	413	422	835
2031	5,283	12,160	17,443	412	430	842
2032	5,274	12,396	17,670	412	438	850
2033	5,258	12,637	17,895	410	447	857
2034	5,245	12,882	18,127	409	455	864
2035	5,226	13,132	18,358	408	464	872
2036	5,209	13,387	18,596	407	473	880
30-Year (2007-2036) Emission Reduction						
Undiscounted	134,700	264,600	399,300	10,760	9,350	20,100
30 Yr NPV at 3%	76,800	144,600	221,400	6,180	5,110	11,300
30 Yr NPV at 7%	39,700	70,800	110,500	3,230	2,500	5,730

If no shift in downgrade to heating oil is assumed, the sulfur dioxide and sulfate PM emission reductions due to the 15 ppm L&M fuel cap are simply the differences in the emissions in the two columns of Table 8.7-24 labeled NRLM fuel.[G]

The 30-year cost effectiveness of the 15 ppm L&M cap is the ratio of the 30-year costs shown in Tables 8.7-19 and 8.7-21 divided by the 30-year emission reductions of sulfur dioxide and sulfate PM shown in Table 8.7-24. We have allocated 67 percent of the costs to sulfur dioxide emission control and 33 percent to sulfate PM control consistent with our allocation of

[G] We ignored the small change in L&M fuel sulfur content which would occur if the downgrade remained in the L&M market.

costs associated with fuel-derived benefits throughout our analysis. The results are presented in Table 8.7-25.

Table 8.7-25
Incremental Cost Effectiveness of the 15 ppm L&M Fuel Sulfur Cap
30-year Net Present Values at a 3% Discount Rate ($2002)

	3% Discount Rate		7% Discount Rate	
	SOx	PM	SOx	PM
With Shift of Downgrade to Heating Oil				
Cost ($ million)	$ 1,870	$ 940	$ 935	$ 467
Emissions Reduction (tons)	221,400	11,300	110,500	5,730
Cost per ton ($/ton)	$ 8,450	$ 83,200	$ 8,460	$ 81,500
Without Shift of Downgrade to Heating Oil				
Cost ($ million)	$1,493	$747	$747	$374
Emissions Reduction (tons)	76,800	6,180	39,700	3,230
Cost per ton ($/ton)	$ 19,400	$ 120,700	$ 18,800	$ 115,800

As can be seen, the incremental cost effectiveness of the 15 ppm L&M fuel cap worsens without the shift in downgrade to the heating oil market. This indicates that the cost effectiveness of shifting downgrade from the L&M market to the heating oil market and replacing it with 15 ppm L&M fuel is more cost effective than simply reducing L&M fuel sulfur from 500 ppm to 15 ppm. The shift in downgrade itself is environmentally neutral from sulfur perspective, since all of the sulfur is emitted regardless of whether it is burned in a locomotive or marine diesel engine or a furnace or stationary diesel engine. The conversion of sulfur to PM is less for heating oil, but as the majority of the sulfur is emitted as sulfur dioxide in either case, sulfur dioxide emissions are the same. The difference is that, with the downgrade shift to heating oil, the new 15 ppm L&M fuel replaces high sulfur heating oil. Without the shift, the new 15 ppm L&M fuel replaces 500 ppm L&M fuel. The cost of producing 15 ppm L&M fuel from high sulfur fuel are higher than from 500 ppm fuel, 8.3 cents per gallon versus 3.1 cents per gallon. However, the sulfur reduction is also higher and to a much greater degree. With heating oil at 2155 ppm, the in-use reduction is 2144 ppm, while that from 500 ppm L&M fuel is only 329 ppm. Thus, the sulfur benefits are a factor of seven time higher, while costs are less than a factor of three higher.

While we evaluate the incremental cost effectiveness of the 15 ppm L&M cap with and without the shift of downgrade to the heating oil market, we believe that the former is the most appropriate way to evaluate this fuel control step as it is consistent with the design of the program which reflects the characteristics of the distribution system. The prohibition on using downgrade in the NRLM markets in the Northeast/Middle Atlantic area eliminates the marking of the significant volume of heating oil in this area beginning in 2007. This is an important and valuable aspect of the final NRLM fuel program which was made regardless of any decision to control L&M fuel to 15 ppm. Thus, it is appropriate to include the effect of this provision on the cost effectiveness of 15 ppm L&M fuel control.

8.7.4 Costs per Ton Summary

Table 8.7-26 presents a summary of the cost per ton calculations presented in Sections 8.7.1 through 8.7.4.

As noted in section 8.1, we have allocated costs slightly differently in the final analysis than we did in the proposed analysis.[H] Table 8.7-27 presents the costs per ton using the allocations used in the proposal. To clarify, Table 8.7-27 does not present the costs per ton from the proposed analysis. Instead, the values presented in Table 8.7-27 are the costs per ton using the final rule's costs and emissions reductions but allocating the costs using the method used in the proposal. As such, Table 8.7-27 provides a comparison of how the new cost allocations affect the costs per ton and does not provide a comparison of the final costs per ton to the proposed costs per ton.

[H] The cost allocations used in the proposal differed slightly in that costs associated with fuel-derived benefits were allocated entirely to SOx (FRM allocations split them one-third to PM and two-thirds to SOx) and costs of 15 ppm fuel were allocated entirely to engine-derived benefits (FRM allocations split them one-half to fuel-derived benefits and one-half to engine-derived benefits).

Table 8.7-26
Summary of Costs and Cost per Ton Estimates based on 30 Year NPVs
($2002)

NRT4 Full Program	3% discount rate	7% discount rate
NPV of Total Cost ($millions)	$ 27,100	$ 13,800
$/ton PM	$ 11,200	$ 11,800
$/ton NOx+NMHC	$ 1,010	$ 1,160
$/ton SOx	$ 690	$ 620
15ppm NRLM Fuel-only Scenario		
NPV of Total Cost w/ Savings ($millions)	$ 9,200	$ 4,600
NPV of Total Cost w/o Savings ($millions)	$ 16,300	$ 8,500
$/ton PM w/ Savings	$ 6,600	$ 6,000
$/ton PM w/o Savings	$ 11,800	$ 11,200
$/ton SOx w/ Savings	$ 1,070	$ 970
$/ton SOx w/o Savings	$ 1,900	$ 1,800
500ppm NRLM Fuel-only Scenario		
NPV of Total Cost w/ Savings ($millions)	$ (500)	$ (300)
NPV of Total Cost w/o Savings ($millions)	$ 5,400	$ 3,000
$/ton PM w/ Savings	$ (400)	$ (400)
$/ton PM w/o Savings	$ 4,300	$ 4,300
$/ton SOx w/ Savings	$ (70)	$ (70)
$/ton SOx w/o Savings	$ 690	$ 700
15 ppm L&M Fuel-only Scenario (Increment) *		
NPV of Incremental Cost w/ Savings ($millions)	$ 2,810	$ 1,400
$/ton PM w/ Savings (incremental)	$ 83,200	$ 81,500
$/ton SOx w/ Savings (incremental)	$ 8,450	$ 8,460

* Includes shift of downgrade to heating oil in the Northeast/Middle Atlantic area

Table 8.7-27
Costs and Costs per Ton of the NRT4 Full Program
using the Proposal's Cost Allocations
30 Year NPVs using a 3% Discount Rate ($2002)

NRT4 Full Program	3% discount rate
NPV of Total Cost ($millions)	$ 27,100
$/ton PM	$ 11,000
$/ton NOx+NMHC	$ 1,250
$/ton SOx	$ 460

Appendix 8A: Estimated Aggregate Cost and Cost per Ton of Sensitivity Analyses

8A.1 What Sensitivity Analyses Have Been Performed?

This Appendix contains two sensitivity analyses EPA performed regarding the emissions inventory predictions from the NONROAD model, as well as cost and cost per ton analysis which correspond to these two NONROAD model sensitivities. In the NONROAD model sensitivity Case 1, we have adjusted the emissions predictions so that NONROAD's fuel consumption estimates match the predictions of fuel volume from the Energy Information Agency. In the NONROAD model sensitivity Case 2, we have increased the fraction of diesel generators sold in the U.S. which are considered "mobile" (and therefore decreased the percentage which are "stationary") and we have increased the annual hours of use for several categories of nonroad equipment in the >750 hp category.

In the remainder of section 8A.1, we describe why we have included these sensitivity analyses in the final rule. In section 8A.2, we describe what changes were made to the NONROAD model, how each of the sensitivities were performed, and the emission inventory impacts of Case 1 and Case 2. In section 8A.3, we describe how we have altered our engine and fuel program cost methodology to match Case 1 and Case 2, what the resulting program cost estimates are using Case 1 and Case 2, and finally what the cost-per-ton estimates are for Case 1 and Case 2. In section 8A.4, we summarize the results presented in sections 8A.1 through 8A.3.

8A.1.1 What is the Case 1 Sensitivity Analysis?

The Case 1 sensitivity analysis results from comments we received on the proposal which suggested that the NONROAD model over-predicts the growth rate of the nonroad fleet. The commenters suggested that the NONROAD model's growth rates should be adjusted downward so that overall fuel consumption matches the predictions made by the Department of Energy's Energy Information Agency (EIA). As described in detail in the Summary and Analysis of Comments for this rule, we disagree with these comments and we have not made a change to the NONROAD model as a result of these comments (see section 2.3.2.2.3 of the Summary and Analysis of Comments document for this final rule). However, we are performing a sensitivity analysis (Case 1) which estimates what the impact of such a change would have on our estimates of the emissions reduction of this rule, the costs of this rule, and our cost-per-ton estimates.

8A.1.2 What is the Case 2 Sensitivity Analysis?

The Case 2 sensitivity analysis results from information we received during the development of the rule on two issues which indicates NONROAD is under-predicting emissions from some nonroad engines. One of these issues is the partitioning of generator sets into mobile and stationary. The second issue is the annual hours of use estimates for large engines (those >750 hp).

8A.1.2.1 Information Regarding Mobile & Stationary Generator Sets

During our discussions with several engine manufacturers who produce the >750 hp diesel engines, three manufacturers (who together represent a majority of the market), provided EPA with recent year sales estimates of engines used in mobile machines in the >750 hp category (e.g., mining trucks, dozers, wheel loaders, etc.) and generator sets. These manufacturers produce engines for generator sets which are certified to the existing Tier 1 nonroad standards, as well as engines which are not certified to the nonroad standards because the engines are designed for stationary power generation and therefore are not subject to EPA's nonroad standards. Many of the >750 hp nonroad certified engines which are used in generator sets are used in applications such as the large portable power generators that are contained in a Class 8 truck trailer, where power generation ratings of 1, 1.5 and 2 megawatts are common. These products are designed to be portable and are used by rental companies and in other industries where large amounts of power are needed for a relatively short duration of time. The data from the engine manufacturers indicates that approximately 30 percent of the >750 hp diesel generator sets sold in the U.S. are portable and subject to EPA nonroad diesel standards. In addition, manufacturers build some stationary engines to nonroad certified configurations to simplify their product base and thus the nonroad engine standards yield an added indirect, yet real, emission benefit.

The data which is used to estimate the nonroad equipment population in NONROAD comes from the PSR database. This database does not distinguish between mobile and stationary diesel generator sets. As documented in EPA report EPA420-P-02-004, we estimate for all of the diesel generators what percent of the PSR database diesel generator sets are mobile (and therefore subject to the EPA's nonroad standards) and what percent is stationary. These estimates vary by power range, with the percent that are considered stationary increasing with increasing rated power. For example, for <25 hp engines we estimate 10 percent are stationary, and for >600 hp, we estimate that 100 percent are stationary. Once these percentages are applied to the PSR database data to remove the estimated stationary generator sets, the remaining generator set data is used to estimate the population of generator sets in NONROAD.

The recent information we received from the engine manufacturers (~ 30 percent of generator sets >750 hp are mobile/portable) is substantially different from the current assumptions which go into NONROAD (no generators >600 hp are mobile/portable). Because at this time we do not have reference-able industry-wide information on this issue, we have not performed a new analysis to update NONROAD. However, it is clear that the recent confidential information from the engine companies indicates NONROAD is underestimating the number of nonroad diesel generators. As discussed in Chapter 8A.2, we have performed a sensitivity analysis which includes a higher percentage of mobile diesel generator sets based on the information we received from the engine manufacturers.

8A.1.2.2 Information Regarding Usage Factors for >750hp Mobile Machines and Generators

As discussed in the preamble for this final rule, we have recognized some of the unique features of the >750 hp mobile machines. Most of the >750 hp engines used in the mobile machine category are used in mining applications, such as mining trucks, dozers, excavators and loaders. As part of our feasibility analysis, we spent a considerable amount of time with a number of engine manufacturers and equipment manufacturers to understand the applications these large engines are used in. In addition, several manufacturers provided EPA with data regarding the >750 hp mobile machine applications. One of the pieces of data which we noticed was the high annual hours of use for this equipment, which in some cases was greater than 4,000 hours per year. During our discussions with both engine and equipment manufacturers, companies made the point these large pieces of equipment are very expensive (in excess of $1 million), and that mining operations are often run 7 days a week, “around the clock”. Because of these two factors, the large mobile machines are operated at higher annual usage rates than most nonroad applications.

While we received this type of information from multiple companies, the most convincing data we received came from one of the industry’s larger equipment companies. This equipment company provided EPA with confidential data for mobile machines >750 hp which included sales and annual hours of use estimates. The equipment types covered by the data included applications such as off-highway trucks, dozers, wheel loaders, and off-highway tractors. The data was representative of 10 years worth of sales, and several thousand pieces of equipment. On average, the manufacturer estimated the annual hours of use for this equipment was > 3,500 hours per year. We also received information from several engine and equipment companies which indicates the annual hours of use for >750 portable generator sets are on the order of 1,000 hours per year.

The NONROAD model contains estimates of annual hours of use which are used in the process of estimating annual emissions. The annual hours of use values are documented in EPA report EPA420-P-02-014. The annual hours of use do not vary by power category, therefore the estimate for a 250 hp dozer is the same as the estimate for a 1,000 hp dozer. For the >750 hp applications on which we received new data, the highest annual hours of use value in NONROAD is 1,641 hours/year for off-highway trucks, and for generator sets the value is 338 hours/year. These values are substantially lower than the usage information we received from engine and equipment manufacturers. While we now believe NONROAD underestimates the emissions impact of the >750hp equipment based on the new information we have received, we have not changed NONROAD at this time. The information we received, though useful for this sensitivity analysis, is not adequately reference-able and may not be sufficiently representative. In addition, while we believe it is directionally correct, we have not had an opportunity to independently verify the information or collect additional data from other sources. As a result, though not reflected in the NONROAD model results for this final rule, the Case 2 sensitivity analysis does include higher annual hours of use values for several categories of mobile machines >750hp and for generator sets >750hp, which is based on the information we received from engine and equipment companies.

8A.2 What Emissions Modeling was Done?

8A.2.1 Case 1: Inventories Adjusted to Match Fuel Consumption Derived from EIA Sources

To represent the emissions inventory for Case 1, we did not perform additional NONROAD runs. Rather, we adjusted the NONROAD fuel consumption and emissions estimates so that estimated fuel consumption matched fuel consumption estimates derived from EIA sources. We performed the adjustment by applying ratios to the NONROAD fuel consumption and emissions outputs. Specifically,, we calculated an adjustment ratio *r* as

$$r_y = \frac{F_{\text{NONROAD},y}}{F_{\text{EIA},y}}$$

where $F_{\text{NONROAD},y}$ is a national fuel consumption estimate as generated by Draft NONROAD2004 for year *y*, and $F_{\text{EIA},y}$ is a corresponding estimate derived from EIA's *Annual Energy Outlook 2003* (AEO 2003). These reports provide distillate fuel consumption projections by economic sector.

The derivation of F_{EIA} is based on a linear projection of nonroad diesel fuel consumption from 2002 to 2040, as described below. To establish a basis for estimaton of a growth rate, we derived estimates for the years 2002 and 2014 from AEO 2003, the derivation of which is described in Chapter 7.1 of the RIA. These two estimates, along with corresponding estimates from Draft NONROAD2004, are shown in Table 8A.2-1.

Table 8A.2-1
Nonroad Fuel Consumption: Draft NONROAD2004 and Estimates derived from EIA Sources
(Million gallons per year)

Year	Draft NONROAD2004	Derived from EIA Sources
2002	10,625	8,428
2014	14,433	9,814

Using the following equation, we estimated a 1.4%/year average linear growth rate (without compounding) in fuel consumption g_{EIA} over this 12-year period:

$$g_{\text{EIA}} = \frac{F_{\text{EIA},2014} - F_{\text{EIA},2002}}{2014 - 2002}\left(\frac{1}{F_{\text{EIA},2002}}\right)$$

Using the resulting growth rate (0.014/year), we projected fuel consumption from 2002 to 2040, based on the expression

$$F_{\text{EIA},y} = F_{\text{EIA},2002}\left(1 + (y - 2002)g_{\text{EIA}}\right)$$

The resulting EIA-derived fuel consumption estimates are shown in Table 8A.2-2, along with fuel consumption estimates from Draft NONROAD2004. The ratio of the two fuel consumption estimates in each year are also shown.

Table 8A.2-3 shows projected land-based nonroad diesel fuel consumption and associated emissions inventories (NO_x, SO_2, PM_{10}) at the national level for selected years between 2001 and 2040, as estimated by NONROAD and from EIA sources. Results are shown for both the base and control cases. These results are also presented graphically in Figures 8A.2-1 - 8A.2-4.

Table 8A.2-2
2001-2040 Nonroad Fuel Consumption (Million gallons per year)

Calendar Year	Draft NONROAD2004 ($F_{NONROAD}$)	EIA FOKS/AEO Derived (F_{EIA})	Ratio (r)
2001	10,625	9,080	1.170
2002	10,919	8,428	1.296
2003	11,213	8,544	1.312
2004	11,507	8,659	1.329
2005	11,801	8,775	1.345
2006	12,092	8,890	1.360
2007	12,384	9,006	1.375
2008	12,676	9,121	1.390
2009	12,968	9,237	1.404
2010	13,259	9,352	1.418
2011	13,553	9,468	1.431
2012	13,846	9,583	1.445
2013	14,139	9,699	1.458
2014	14,433	9,814	1.471
2015	14,726	9,930	1.483
2016	15,016	10,045	1.495
2017	15,307	10,160	1.507
2018	15,597	10,276	1.518
2019	15,887	10,391	1.529
2020	16,178	10,507	1.540
2021	16,468	10,622	1.550
2022	16,759	10,738	1.561
2023	17,049	10,853	1.571
2024	17,339	10,969	1.581
2025	17,630	11,084	1.591
2026	17,918	11,200	1.600
2027	18,206	11,315	1.609
2028	18,495	11,431	1.618
2029	18,783	11,546	1.627
2030	19,071	11,662	1.635
2031	19,360	11,777	1.644
2032	19,648	11,892	1.652
2033	19,936	12,007	1.660
2034	20,225	12,123	1.668
2035	20,513	12,239	1.676
2036	20,801	12,354	1.684
2037	21,090	12,470	1.691
2038	21,378	12,585	1.699
2039	21,666	12,701	1.706
2040	21,955	12,816	1.713

Table 8A.2-3
Case 1: *Adjustment to Match EIA Projections*
Projected Nonroad Diesel Emissions Inventories

Year (*y*)	National Emissions Inventory (thousand tons)					
	NOx		SO_2		PM_{10}	
	Base	Control	Base	Control	Base	Control
2002	1,184	1,184	133	133	128	128
2005	1,096	1,096	139	139	111	111
2010	906	906	140	10.7	94.0	82.4
2015	781	650	145	0.673	87.9	55.4
2020	731	442	154	0.644	86.8	33.7
2025	722	334	162	0.644	88.1	21.2
2030	733	282	171	0.660	90.2	13.7
2035	754	259	179	0.684	92.8	9.5
2040	780	251	188	0.712	96.3	7.5

8A.2.2 Case 2: Large Equipment Population and Activity

To represent Case 2, we performed NONROAD runs with modified inputs for selected equipment types. Specifically, we used modified activity for large equipment (>750 hp) in five equipment types, as shown in Table 8A.2-4. This change represents the use of large equipment on a continuous shift basis. Additionally, we modified the fractions of generators assumed to be mobile, as opposed to stationary equipment, as shown in Table 8A.2-5. The modified fractions increased populations for generators of size 100 hp and greater, resulting in an increase in the total generator population of approximately 135,000 pieces. As in Case 1, we repeated the analysis for both the base and control cases.

Table 8A.3-6 shows projected land-based nonroad diesel fuel consumption and associated emissions inventories (NO_x, SO_2, PM_{10}) at the national level for selected years between 2001 and 2040, for both the base and control cases. These results are also presented graphically in Figures 8A.2-1 - 8A.2-4.

Table 8A.2-4
Case 2: *Large Equipment Population and Activity*
Annual Activity Estimates for Large Equipment (>750 hp)

Equipment Type	Activity (hours/year)	
	FRM Base	Sensitivity Case
Excavators	1,092	3,800
Off-Highway Trucks	1,641	3,800
Rubber Tire Loaders	761	3,800
Crawler Tractors/Dozers	936	3,800
Off-Highway Tractors	855	3,800
Generators	338	1,000

Table 8A.2-5
Case 2: *Large Equipment Population and Activity*
Modified Mobile-Equipment Population Fractions for Diesel Generators

Hp Class	FRM Base		Sensitivity Case	
	Mobile Fraction	Mobile Population	Mobile Fraction	Mobile Population
< 25	0.90	240,180	0.90	240,180
25-40	0.90	121,050	0.90	121,050
40-50	0.70	16,530	0.70	16,530
50-75	0.70	61,000	0.70	61,000
75-100	0.70	74,240	0.70	74,240
100-175	0.20	25,340	0.62	78,560
175-300	0.15	14,090	0.54	50,720
300-600	0.10	7,320	0.46	33,660
600-750	0.0	0	0.38	6,260
> 750	0.0	0	0.30	12,290
Total		559,750		694,490

Table 8A.2-6
Case 2: *Large Equipment Population and Activity*:
Projected Nonroad Diesel Fuel Consumption and Emissions Inventories

Year (y)	Fuel Consumption (million gal)		National Emissions Inventory (thousand tons)					
	NONROAD FRM 50-state Base	NONROAD Sensitivity-Case	NOx		SO_2		PM_{10}	
			Base	Control	Base	Control	Base	Control
2001	10,630	12,550	1,817	1,817	198	198	189	189
2005	11,800	13,960	1,759	1,759	220	220	165	165
2010	13,260	15,710	1,519	1,518	234	17.9	148	128
2015	14,730	17,470	1,409	1,132	256	1.15	145	89.3
2020	16,180	19,220	1,393	848	282	1.16	149	57.0
2025	17,630	20,970	1,434	692	307	1.21	156	38.2
2030	19,070	22,710	1,502	916	333	1.28	164	26.4
2035	20,510	24,440	1,585	595	358	1.37	173	19.3
2040	21,950	26,180	1,678	594	384	1.45	183	16.0

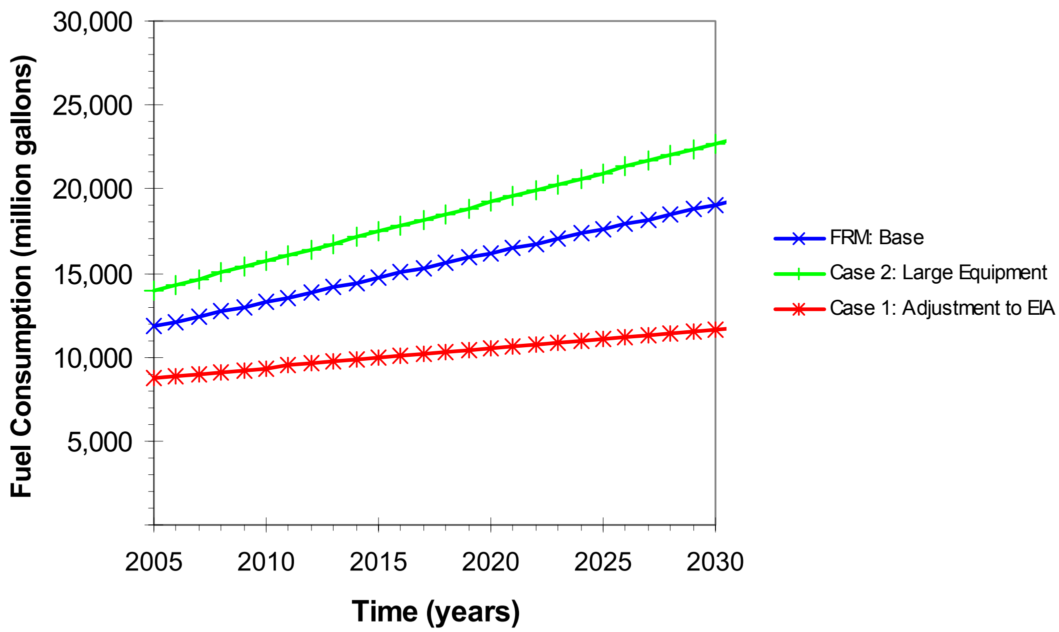

Figure 8A.2-1. Projected land-based nonroad diesel fuel consumption at the national level for the FRM base and two sensitivity cases. Case 1 represents Draft NONROAD2004 estimates adjusted to match EIA-based projections; Case 2 represents modified population and activity estimates for large equipment (>750 hp).

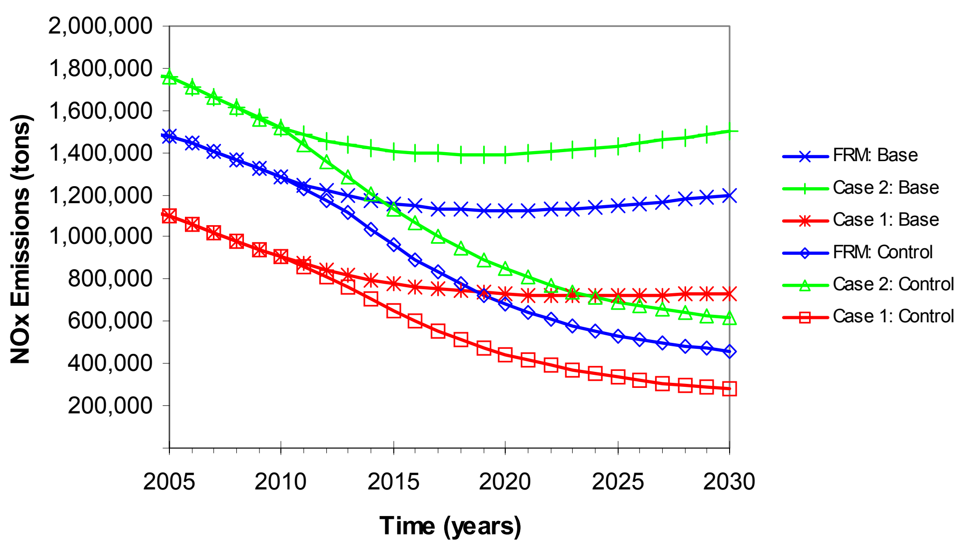

Figure 8A.2-2. Projected land-based nonroad NOx inventories at the national level for the FRM base and two sensitivity cases. Case 1 represents Draft NONROAD2004 estimates adjusted to match EIA-based projections; Case 2 represents modified population and activity estimates for large equipment (>750 hp).

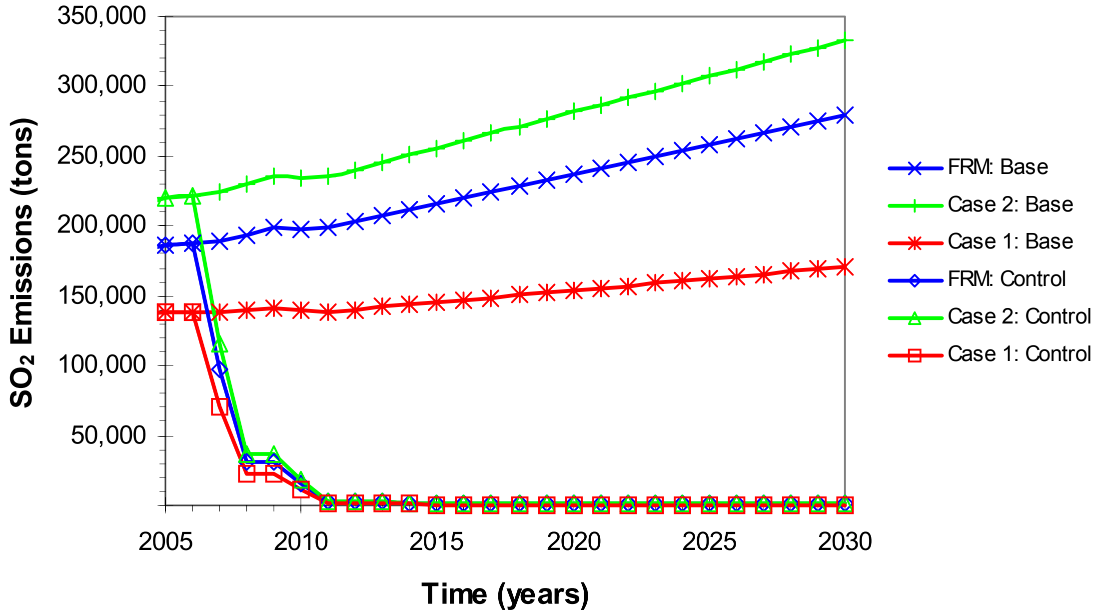

Figure 8A.2-3. Projected land-based nonroad SO_2 inventories at the national level for the FRM base and two sensitivity cases. Case 1 represents Draft NONROAD2004 estimates adjusted to match EIA-based projections; Case 2 represents modified population and activity estimates for large equipment (>750 hp).

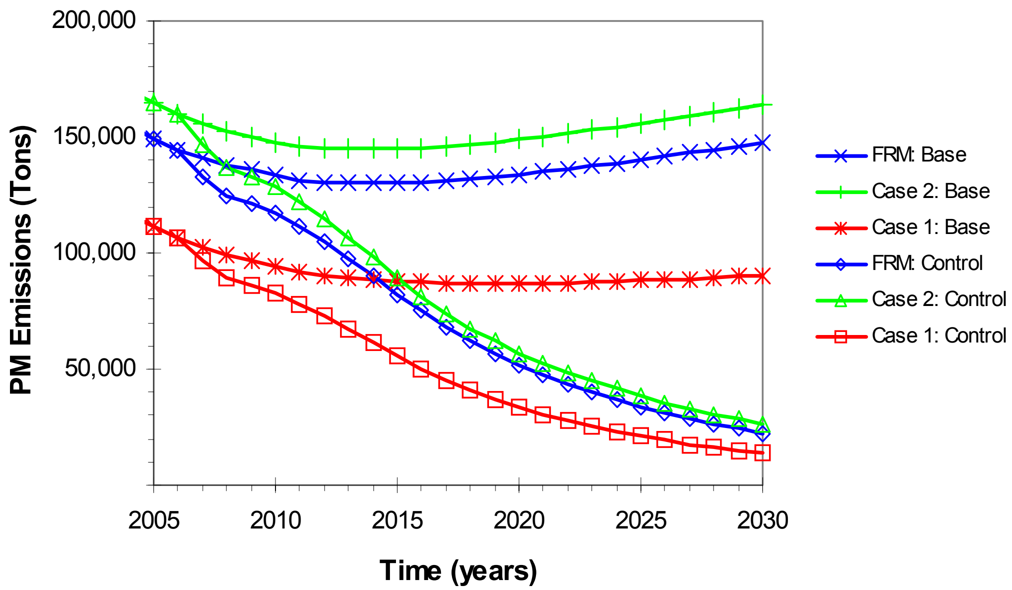

Figure 8A.2-4. Projected land-based nonroad PM_{10} inventories at the national level for the FRM base and two sensitivity cases. Case 1 represents Draft NONROAD2004 estimates adjusted to match EIA-based projections; Case 2 represents modified population and activity estimates for large equipment (>750 hp).

8A.3 What Are the Costs and Costs per Ton?

Here we look at the cost per ton of two sensitivity cases—a Case 1 sensitivity using future fuel consumption projections developed by the Energy Information Administration (EIA); and, a Case 2 sensitivity that incorporates more generator sets in both the costs and emissions reductions estimates than are incorporated under NRT4 full engine and fuel program (i.e., the NRT4 final rule estimates).

8A.3.1 Costs and Costs per Ton for the Case 1 Sensitivity

Under the Case 1 sensitivity we use future fuel projections developed by EIA rather than using the projections generated in our NONROAD model as discussed in Section 8A.1. Doing this results in lower fuel-related costs (including all operating costs expressed throughout this Regulatory Impact Analysis on a cent-per-gallon basis) since the EIA projections are lower than our model's projections. Doing this also results in lower emissions reductions as discussed in Section 8A.2. The engine and equipment costs under the Case 1 sensitivity would be identical to those under the full engine and fuel program since all engine standards would still be implemented. Tables 8A.3-1 though 8A.3-4 show all fuel-related costs associated with the Case 1 sensitivity. All these tables are analogous to Tables 8.4-1 through 8.4-4 presented above for the NRT4 final program. The cent per gallon fuel costs are presented in Table 7.5-1.

Table 8A.3-1
Aggregate Fuel Costs of the Case 1 Sensitivity ($2002)

Year	Affected NR Fuel		Affected L&M Fuel		Fuel Cost *		NR Fuel Costs			L&M Fuel Costs			NRLM Annual Fuel Costs (10^6 dollars)
	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm ($/gal)	15 ppm ($/gal)	500 ppm (10^6 dollars)	15 ppm (10^6 dollars)	Total (10^6 dollars)	500 ppm (10^6 dollars)	15 ppm (10^6 dollars)	Total (10^6 dollars)	
2007					$ 0.021	$ -	$ 77		$ 77	$ 42	$ -	$ 42	$ 119
2008					$ 0.021	$ -	$ 134		$ 134	$ 72	$ -	$ 72	$ 206
2009	3,671		1,981		$ 0.021	$ -	$ 136		$ 136	$ 73	$ -	$ 73	$ 209
2010	6,373	-	3,438	-	$ 0.029	$ 0.058	$ 88	-	$ 313	$ 88	$ -	$ 88	$ 401
2011	6,454	-	3,483	-	$ 0.034	$ 0.058	$ 21	- 225	$ 411	$ 95	$ -	$ 95	$ 506
2012	3,086	3,873	3,069	-	$ 0.035	$ 0.062	$ 18	- 390 404	$ 423	$ 43	$ 130	$ 173	$ 596
2013		6,721	2,785	-	$ 0.036	$ 0.064	$ 16	415	$ 431	$ 4	$ 234	$ 238	$ 670
2014	631	6,574	1,243	2,116	$ 0.036	$ 0.067	$ 7		$ 485	$ 2	$ 236	$ 238	$ 723
2015	531	6,488		3,657		$ 0.069	$ -	479	$	$ -	$ 237	$ 237	$ 766
2016	460	7,153	120	3,527		$ 0.069	$ -		$	$ -	$ 240	$ 240	$ 775
2017	194	7,662	50	3,441		$ 0.069	$ -		$ 529	$ -	$ 242	$ 242	$ 783
2018	-	7,751	-	3,476		$ 0.069	$ -	529	$ 535	$ -	$ 245	$ 245	$ 792
2019	-	7,840	-	3,511		$ 0.069	$ -	535	$ 541	$ -	$ 248	$ 248	$ 802
2020	-	7,929	-	3,551		$ 0.069	$ -	541	$ 547	$ -	$ 251	$ 251	$ 810
2021	-	8,018	-	3,598		$ 0.069	$ -	547	$ 553	$ -	$ 253	$ 253	$ 818
2022	-	8,107	-	3,632		$ 0.069	$ -	553	$ 559	$ -	$ 256	$ 256	$ 828
2023	-	8,196	-	3,663		$ 0.069	$ -	559	$ 566	$ -	$ 259	$ 259	$ 836
2024	-	8,285	-	3,709		$ 0.069	$ -	566	$ 572	$ -	$ 261	$ 261	$ 845
2025	-	8,374	-	3,747		$ 0.069	$ -	572	$ 578	$ -	$ 264	$ 264	$ 854
2026	-	8,464	-	3,788		$ 0.069	$ -	578	$ 584	$ -	$ 267	$ 267	$ 863
2027	-	8,553	-	3,828		$ 0.069	$ -	584	$ 590	$ -	$ 270	$ 270	$ 872
2028	-	8,642	-	3,868		$ 0.069	$ -	590	$ 596	$ -	$ 272	$ 272	$ 881
2029	-	8,731	-	3,909		$ 0.069	$ -	596	$ 602	$ -	$ 275	$ 275	$ 890
2030	-	8,820	-	3,949		$ 0.069	$ -	602	$ 609	$ -	$ 278	$ 278	$ 899
2031	-	8,909	-	3,989		$ 0.069	$ -	609	$ 615	$ -	$ 281	$ 281	$ 908
2032	-	8,998	-	4,029		$ 0.069	$ -	615	$ 621	$ -	$ 284	$ 284	$ 917
2033	-	9,087	-	4,070		$ 0.069	$ -	621	$ 627	$ -	$ 286	$ 286	$ 926
2034	-	9,176	-	4,110		$ 0.069	$ -	627	$ 633	$ -	$ 289	$ 289	$ 935
2035	-	9,265	-	4,150		$ 0.069	$ -	633	$ 639	$ -	$ 292	$ 292	$ 944
2036	-	9,354	-	4,190		$ 0.069	$ -	639	$ 645	$ -	$ 295	$ 295	$ 952
30 Yr NPV at 3%	-	9,444	-	4,231			$ 430	645 $ 8,447	$ 652 8,877	$	$ 3,570	$ 3,924	$ 12,801
30 Yr NPV at 7%	-	9,533	-	4,271			$ 357	652 $ 4,342	$ 658 4,698	$	$ 1,776	$ 2,063	$ 6,762
	18,002	124,895	13,818	52,292				658		354			
	15,567	64,783	11,317	26,078						287			

*Fuel costs are relative to uncontrolled fuel and assume that, during the transitional years of 2010, 2012, & 2014, the first 5 months are at the previous year's cost and the remaining 7 months are at the next year's cost.
See Appendix 8B for information on how these fuel volumes were developed.

Table 8A.3-2
Oil Change Maintenance Savings Associated with the Case 1 Sensitivity ($2002)

Year	Affected NR Fuel		Affected L&M Fuel		NR Savings		L&M Savings		NRLM
	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	500 ppm (10^6 gallons)	15 ppm (10^6 gallons)	savings=$0.029/gal ($10^6$ dollars)	savings=$0.032/gal ($10^6$ dollars)	savings=$0.010/gal ($10^6$ dollars)	savings=$0.011/gal ($10^6$ dollars)	Total Savings (10^6 dollars)
2007					$ 107	$	$ 21	$ -	$ 128
2008					$ 186	$	$ 36	$ -	$ 222
2009	3,671		1,981		$ 189	$ -	$ 36	$ -	$ 225
2010	6,373	-	3,438		$ 90	$ -	$ 32	$ -	$ 246
2011	6,454	-	3,483	-	$ 18	$ - 124	$ 29	$ -	$ 263
2012	3,086	3,873	3,069	-	$ 16	$ 215 211	$ 13	$ 24	$ 263
2013		6,721	2,785	-	$ 13	$ 208	$ 1	$ 42	$ 264
2014	631	6,574	1,243	- 2,116	$ 6	$	$ 1	$ 40	$ 276
2015	531	6,488		3,657	$ -	$ 229	$ -	$ 39	$ 285
2016	460	7,153	120	3,527	$ -	$	$ -	$ 40	$ 288
2017	194	7,662	50	3,441	$ -	$ 245	$ -	$ 40	$ 291
2018	-	7,751	-	3,476	$ -	$ 248	$ -	$ 41	$ 295
2019	-	7,840	-	3,511	$ -	$ 251	$ -	$ 41	$ 298
2020	-	7,929	-	3,551	$ -	$ 254	$ -	$ 42	$ 301
2021	-	8,018	-	3,598	$ -	$ 257	$ -	$ 42	$ 305
2022	-	8,107	-	3,632	$ -	$ 260	$ -	$ 43	$ 308
2023	-	8,196	-	3,663	$ -	$ 263	$ -	$ 43	$ 311
2024	-	8,285	-	3,709	$ -	$ 265	$ -	$ 43	$ 315
2025	-	8,374	-	3,747	$ -	$ 268	$ -	$ 44	$ 318
2026	-	8,464	-	3,788	$ -	$ 271	$ -	$ 44	$ 321
2027	-	8,553	-	3,828	$ -	$ 274	$ -	$ 45	$ 324
2028	-	8,642	-	3,868	$ -	$ 277	$ -	$ 45	$ 328
2029	-	8,731	-	3,909	$ -	$ 280	$ -	$ 46	$ 331
2030	-	8,820	-	3,949	$ -	$ 282	$ -	$ 46	$ 334
2031	-	8,909	-	3,989	$ -	$ 285	$ -	$ 47	$ 338
2032	-	8,998	-	4,029	$ -	$ 288	$ -	$ 47	$ 341
2033	-	9,087	-	4,070	$ -	$ 291	$ -	$ 48	$ 344
2034	-	9,176	-	4,110	$ -	$ 294	$ -	$ 48	$ 348
2035	-	9,265	-	4,150	$ -	$ 297	$ -	$ 49	$ 351
2036	-	9,354	-	4,190	$ -	$ 300	$ -	$ 49	$ 354
30 Yr NPV at 3%	-	9,444	-	4,231	$ 544	$ 302 4,000	$ 145	$ 599	$ 5,287
30 Yr NPV at 7%	-	9,533 124,895	-	4,271	$ 455	$ 305 2,675	$ 118	$ 299	$ 2,948
	18,602 15,567	64,783	13,818 11,317	52,202 26,078					

Table 8A.3-3
CDPF Maintenance and CDPF Regeneration Costs Associated with the Case 1 Sensitivity
($2002)

Year	Fuel Consumed in New CDPF Equipped Engines (10^6 gallons)	Weighted Maintenance Cost ($/gal)	Weighted Regeneration Cost ($/gal)	CDPF Maintenance Cost (10^6 dollars)	CDPF Regeneration Cost (10^6 dollars)	Total Costs (10^6 dollars)
2007	-	$ -	$ -	$ -	$ -	$ -
2008	-	$ -	$ -	$ -	$ -	$ -
2009	-	$ -	$ -	$ -	$ -	$ -
2010	-	$ -	$ -	$ -	$ -	$ -
2011	461	$ 0.002	$ 0.010	$ 1	$ 5	$ 5
2012	1,204	$ 0.003	$ 0.010	$ 4	$ 12	$ 16
2013	2,076	$ 0.005	$ 0.010	$ 10	$ 21	$ 32
2014	2,953	$ 0.006	$ 0.007	$ 17	$ 22	$ 39
2015	3,885	$ 0.006	$ 0.008	$ 23	$ 30	$ 53
2016	4,782	$ 0.006	$ 0.008	$ 29	$ 38	$ 66
2017	5,612	$ 0.006	$ 0.008	$ 34	$ 45	$ 79
2018	6,369	$ 0.006	$ 0.008	$ 39	$ 51	$ 90
2019	7,056	$ 0.006	$ 0.008	$ 43	$ 57	$ 100
2020	7,685	$ 0.006	$ 0.008	$ 47	$ 62	$ 110
2021	8,239	$ 0.006	$ 0.008	$ 50	$ 67	$ 118
2022	8,726	$ 0.006	$ 0.008	$ 53	$ 71	$ 124
2023	9,168	$ 0.006	$ 0.008	$ 56	$ 75	$ 131
2024	9,579	$ 0.006	$ 0.008	$ 59	$ 78	$ 137
2025	9,962	$ 0.006	$ 0.008	$ 61	$ 81	$ 142
2026	10,314	$ 0.006	$ 0.008	$ 63	$ 84	$ 147
2027	10,622	$ 0.006	$ 0.008	$ 65	$ 87	$ 152
2028	10,896	$ 0.006	$ 0.008	$ 67	$ 89	$ 156
2029	11,151	$ 0.006	$ 0.008	$ 68	$ 91	$ 159
2030	11,390	$ 0.006	$ 0.008	$ 70	$ 93	$ 163
2031	11,612	$ 0.006	$ 0.008	$ 71	$ 95	$ 166
2032	11,823	$ 0.006	$ 0.008	$ 72	$ 96	$ 169
2033	12,027	$ 0.006	$ 0.008	$ 74	$ 98	$ 172
2034	12,224	$ 0.006	$ 0.008	$ 75	$ 100	$ 174
2035	12,407	$ 0.006	$ 0.008	$ 76	$ 101	$ 177
2036	12,579	$ 0.006	$ 0.008	$ 77	$ 102	$ 180
30 Yr NPV at 3%	111,737			$ 675	$ 911	$ 1,587
30 Yr NPV at 7%	50,796			$ 305	$ 415	$ 720

* Note that fuel used in CDPF engines includes some highway spillover fuel.
**Weighted Regeneration Cost ($/gal) changes year-to-year due to different fuel economy impacts with a NOx adsorber (1 percent) and without a NOx adsorber (2 percent) matched with the phase-in schedules of the emission standards.

Table 8A.3-4
CCV Maintenance Costs Associated with the Case 1 Sensitivity
($2002)

Year	Fuel Consumed in Engines Adding CCV System (10^6 gallons)	Weighted Maintenance Cost ($/gal)	Total Costs (10^6 dollars)
2007	-	$ -	$ -
2008	183	$ 0.000	$ 0
2009	186	$ 0.000	$ 0
2010	173	$ 0.000	$ 0
2011	778	$ 0.001	$ 1
2012	1,606	$ 0.001	$ 2
2013	2,561	$ 0.002	$ 4
2014	3,496	$ 0.002	$ 5
2015	4,478	$ 0.002	$ 7
2016	5,447	$ 0.002	$ 8
2017	6,339	$ 0.002	$ 10
2018	7,133	$ 0.002	$ 11
2019	7,855	$ 0.002	$ 12
2020	8,516	$ 0.002	$ 13
2021	9,099	$ 0.002	$ 14
2022	9,612	$ 0.002	$ 14
2023	10,076	$ 0.002	$ 15
2024	10,505	$ 0.002	$ 16
2025	10,905	$ 0.002	$ 16
2026	11,271	$ 0.002	$ 17
2027	11,593	$ 0.002	$ 18
2028	11,879	$ 0.002	$ 18
2029	12,146	$ 0.002	$ 18
2030	12,398	$ 0.002	$ 19
2031	12,631	$ 0.002	$ 19
2032	12,853	$ 0.002	$ 19
2033	13,069	$ 0.002	$ 20
2034	13,277	$ 0.002	$ 20
2035	13,471	$ 0.002	$ 20
2036	13,654	$ 0.002	$ 21
30 Yr NPV at 3%	124,105		$ 187
30 Yr NPV at 7%	56,982		$ 86

* Weighted Maintenance Cost ($/gal) changes year-to-year due to the implementation schedule for engines adding the CCV system.

Using Tables 8A.3-1 through 8A.3-4 and Table 8.2-2 (engine fixed costs by pollutant), Table 8.2-4 (engine variable costs by pollutant), Table 8.3-2 (equipment fixed costs by pollutant), and Table 8.3-4 (equipment variable costs) we can generate the annual costs and costs by pollutant for the Case 1 sensitivity. Table 8A.3-5 shows these results (this table is analogous to Tables 8.5-1 and 8.5-2 for the NRT4 final program). Note that the pollutant allocations for the Case 1 sensitivity are identical to those used for the NRT4 final program (see Table 8.1-2). Also shown in Table 8A.3-5 are the emissions reductions associated with the Case 1 sensitivity (these values are analogous to Table 8.6-1 for the NRT4 final program).

Table 8A.3-5
Summary of Aggregate Costs, Costs by Pollutant, and Emissions Reductions Associated with the Case 1 Sensitivity ($2002)

Year	Engine Costs ($million)	Equipment Costs ($million)	Fuel Costs ($million)	Other Operating Costs ($million)	Net Operating Costs ($million)	Total Annual Costs ($million)	PM Costs ($million)	NOx+NMHC Costs ($million)	SOx Costs ($million)	PM Reduction (tons)	NOx+NMHC Reduction (tons)	SOx Reduction (tons)
2007	$ -	$ -	$ 119	$ (128)	$ (9)	$ (9)	$ (3)	$ -	$ (6)			
2008	$ 81	$ 5	$ 206	$ (222)	$ (16)	$ 69	$	$ 0	$ (11)			
2009	$ 82	$ 5	$ 209	$ (225)	$ (16)	$ 71	$	$ 0	$ (11)	7,100 12,700		87,600 153,200
2010	$ 80	$ 5	$ 401	$ (246)	$ 154	$ 239	$ 80	$ 25	$ 69	13,200	- 100	154,400
2011	$ 403	$ 62	$ 506	$ (256)	$ 250	$ 715	$ 81	$ 170	$ 104	15,800	200	186,500
2012	$ 718	$ 106	$ 596	$ (245)	$ 351	$ 1,174	$ 145 441	$ 282	$ 157	19,000	400	201,600
2013	$ 882	$ 121	$ 670	$ (229)	$ 440	$ 1,444	$ 735	$ 330	$ 201	23,200	19,200	209,500
2014	$ 973	$ 146	$ 723	$ (232)	$ 491	$ 1,610	$ 912	$ 501	$ 215	27,900	34,100	215,500
2015	$ 950	$ 149	$ 766	$ (225)	$ 541	$ 1,640	$ 893	$ 503	$ 226	32,800	57,500	218,500
2016	$ 920	$ 150	$ 775	$ (214)	$ 561	$ 1,631	$ 911	$ 487	$ 229	37,900	97,100 136,200	221,300
2017	$ 910	$ 150	$ 783	$ (203)	$ 580	$ 1,640	$ 914	$ 485	$ 231	42,500	173,800	223,400
2018	$ 901	$ 146	$ 792	$ (194)	$ 598	$ 1,645	$ 924	$ 489	$ 234	47,000	209,400	225,500
2019	$ 890	$ 147	$ 802	$ (186)	$ 615	$ 1,652	$ 922	$ 471	$ 237	51,100	241,700	227,700
2020	$ 900	$ 147	$ 810	$ (179)	$ 631	$ 1,678	$ 944	$ 477	$ 239	54,900	271,800	230,100
2021	$ 913	$ 99	$ 818	$ (173)	$ 645	$ 1,657	$ 962	$ 458	$ 241	58,500	299,400	232,200
2022	$ 927	$ 66	$ 828	$ (169)	$ 659	$ 1,651	$ 957	$ 448	$ 244	61,700	324,000	234,200
2023	$ 940	$ 56	$ 836	$ (165)	$ 671	$ 1,667	$ 959	$ 448	$ 247	64,700	346,100	236,600
2024	$ 954	$ 36	$ 845	$ (162)	$ 683	$ 1,672	$ 972	$ 433	$ 250	67,400	366,500	238,800
2025	$ 967	$ 32	$ 854	$ (159)	$ 695	$ 1,694	$ 989	$ 439	$ 252	70,000	385,000	241,100
2026	$ 980	$ 32	$ 863	$ (157)	$ 706	$ 1,719	$ 1,002	$ 445	$ 255	72,400	402,200	243,300
2027	$ 994	$ 33	$ 872	$ (155)	$ 717	$ 1,743	$ 1,019	$ 451	$ 258	74,700	417,900	245,600
2028	$ 1,007	$ 33	$ 881	$ (154)	$ 727	$ 1,767	$ 1,035	$ 457	$ 260	76,800	432,200	247,900
2029	$ 1,021	$ 33	$ 890	$ (153)	$ 737	$ 1,791	$ 1,050	$ 463	$ 263	78,600	445,200	250,100
2030	$ 1,034	$ 34	$ 899	$ (153)	$ 746	$ 1,814	$ 1,065	$ 469	$ 265	80,400	457,300	252,400
2031	$ 1,048	$ 34	$ 908	$ (153)	$ 755	$ 1,837	$ 1,080	$ 474	$ 268	82,100	468,000	254,700
2032	$ 1,061	$ 35	$ 917	$ (153)	$ 764	$ 1,860	$ 1,094	$ 480	$ 271	83,600	477,900	257,100
2033	$ 1,074	$ 35	$ 926	$ (153)	$ 773	$ 1,882	$ 1,109	$ 486	$ 273	85,000	487,400	259,400
2034	$ 1,088	$ 35	$ 935	$ (153)	$ 781	$ 1,905	$ 1,123	$ 492	$ 276	86,400	496,300	261,700
2035	$ 1,101	$ 36	$ 944	$ (154)	$ 790	$ 1,927	$ 1,137	$ 497	$ 279	87,800	504,900	264,100
2036	$ 1,115	$ 36	$ 952	$ (154)	$ 798	$ 1,949	$ 1,151	$ 503	$ 281	89,000	512,900	266,400
30 Yr NPV at 3%	$ 14,054	$ 1,281	$ 12,801	$ (3,514)	$ 9,286	$ 24,622	$ 1,165	$ 6,590	$ 3,527	90,200	520,600	268,800
30 Yr NPV at 7%	$ 7,215	$ 754	$ 6,762	$ (2,143)	$ 4,619	$ 12,588	$ 14,505	$ 3,372	$ 1,787	919,400	4,421,600	4,032,300
							7,429			450,100	1,981,700	2,240,800

The calculations of cost per ton of each emission reduced under the Case 1 sensitivity divides the net present value of the annual costs assigned to each pollutant (Table 8A.3-5) by the net present value of the total annual reductions of each pollutant (Table 8A.3-5). The 30-year net present value of the costs associated with each pollutant, calculated with a three percent discount rate, are shown in Table 8A.3-5 as $6.6 billion for NOx+NMHC, $14.5 billion for PM, and $3.5 billion for SOx with the total cost of the program estimated at $24.6 billion. The 30-year net present value, with a three percent discount rate, of emission reductions are estimated at 4.4 million tons of NOx+NMHC, 919 thousand tons of PM and 4.0 million tons of SOx (see Table 8A.3-5). How these emissions reductions were developed is described in Section 8A.2 (see Table 8A.2-3).[I] The results of the cost per ton calculations are shown in Table 8A.3-6.

Table 8A.3-6
Aggregate Cost per Ton for the Case 1 Sensitivity
30-year Net Present Values at a 3% and 7% Discount Rate ($2002)

Item	3% discount rate	7% discount rate	Source
Cost per Ton NOx+NMHC	$1,490	$1,700	Calculated
Cost per Ton PM	$15,800	$16,500	Calculated
Cost per Ton SOx	$870	$800	Calculated

We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emission reductions in that year alone. This number, shown in Table 8A.3-7, approaches the long-term cost per ton of emissions reduced.

[I] Note that the emissions reductions shown in Table 8A.3-5 are not identical to the reductions one would get using the inventories presented in Table 8A.2-3. The emissions inventories in Table 8A.2-3 are for land based nonroad engines only and do not include emissions associated with locomotive and marine engines. To make the comparison between the Case 1 $/ton and the NRT4 full program $/ton, the Case 1 locomotive and marine emissions reductions are included with the Case 1 nonroad land based emissions reductions. Because the emissions reductions associated with locomotive and marine engines are directly proportional to gallons of fuel consumed (because no new emission control hardware is being added to those engines), we have calculated the locomotive and marine emissions reductions by taking the ratio of the Case 1 locomotive and marine gallons consumed to the NRT4 full program locomotive and marine gallons consumed and multiplied that ratio by the NRT4 locomotive and marine emissions reductions to arrive at the Case 1 locomotive and marine emissions reductions. These Case 1 locomotive and marine emissions reductions were then added to the Case 1 nonroad land based emissions reductions to arrive at the Case 1 emissions reductions shown in Table 8A.3-5.

Table 8A.3-7
Long-Term Cost per Ton of the Case 1 Sensitivity
Annual Values without Discounting ($2002)

Pollutant	Long-Term Cost per Ton in 2030
NOx+NMHC	$1,000
PM	$13,200
SOx	$1,050

8A.3.2 Costs and Costs per Ton of the Case 2 Sensitivity

Under the Case 2 sensitivity, more generator sets are assumed to be mobile than are assumed under NRT4 full engine and fuel program, as described in Section 8A.1. This results in higher engine and equipment variable costs since more generator sets (gensets) add NOx adsorbers and CDPFs and more equipment fixed costs since more machines must undergo redesign and product support literature changes. Engine fixed costs would not change since we believe that the R&D work estimated for the NRT4 full program would cover these additional gensets. Fuel-related costs would also increase because more machines would incur CDPF and CCV maintenance costs and CDPF regeneration costs. Increased costs for the incrementally higher cost fuel and savings associated with that fuel should not change since our earlier calculations for the NRT4 full engine and fuel program would have included these costs (i.e., those costs and savings are included in the NRT4 final rule).

We have calculated the increased engine variable costs using the equations shown in Table 6.4-2 and have applied those costs to the same nonroad engine fleet with the exception that more gensets are included. Likewise, we followed the same process for developing equipment costs as described in Chapter 6 to generate the higher equipment fixed and variable costs.

Because more machines are adding the new engine hardware (CDPFs and NOx adsorbers), the emissions reductions associated with the Case 2 sensitivity would be higher than under the NRT4 final program. These higher emissions reductions were generated using our NONROAD model as discussed in section 8A.2.2. These emissions reductions are directly proportional to the increased amount of fuel that would be consumed in these additional engines and, likewise, to the increased fuel-related costs under this sensitivity. Using that direct relationship, we can estimate the incremental fuel-related costs by calculating the ratio of fuel-related costs under the full engine and fuel program to the emissions reductions under the full engine and fuel program and then applying that ratio to the emissions reductions under the Case 2 sensitivity. Table 8A.3-8 presents the annual costs, the costs by pollutant, and the emissions reductions of the Case 2 sensitivity. Note that costs have been allocated as done under the NRT4 full engine and fuel program (see Table 8.1-2). Note also that the emissions reductions shown in Table 8A.3-8 include the higher reductions from gensets and the nonroad, locomotive, and marine reductions that would occur under the full engine and fuel program.

Table 8A.3-8
Summary of Aggregate Costs, Costs by Pollutant, and Emissions Reductions Associated with the Case 2 Sensitivity ($2002)

Year	Engine Costs ($million)	Equipment Costs ($million)	Fuel Costs ($million)	Other Operating Costs ($million)	Net Operating Costs ($million)	Total Annual Costs ($million)	PM Costs ($million)	NOx+NMHC Costs ($million)	SOx Costs ($million)	PM Reduction (tons)	NOx+NMHC Reduction (tons)	SOx Reduction (tons)
2007	$ -	$ -	$ 161	$ (181)	$ (21)	$ (21)	$	$ -	$ (14)			
2008	$ 81	$ 5	$ 281	$ (318)	$ (37)	$ 49	$ (7)	$ 0	$ (25)	12,100		149,900
2009	$ 82	$ 5	$ 286	$ (324)	$ (38)	$ 49	$ 73	$ 0	$ (26)	21,900		265,500
2010	$ 80	$ 5	$ 602	$ (375)	$ 228	$ 312	$ 74 179	$ 34	$ 99	22,900	- 200	270,900
2011	$ 423	$ 67	$ 811	$ (415)	$ 396	$ 885	$ 486	$ 267	$ 133	25,000	300	289,300
2012	$ 745	$ 111	$ 902	$ (383)	$ 520	$ 1,376	$ 803	$ 377	$ 195	29,700	600 45,600	304,900
2013	$ 906	$ 126	$ 984	$ (352)	$ 631	$ 1,663	$ 996	$ 421	$ 246	37,000	100,500	315,000
2014	$ 1,000	$ 151	$ 1,041	$ (349)	$ 691	$ 1,842	$ 987	$ 591	$ 264	45,000	152,300	323,800
2015	$ 989	$ 157	$ 1,103	$ (339)	$ 764	$ 1,910	$ 1,037	$ 596	$ 278	53,100	215,900	330,700
2016	$ 959	$ 158	$ 1,113	$ (319)	$ 793	$ 1,911	$ 1,052	$ 576	$ 282	62,400	281,600	337,600
2017	$ 947	$ 158	$ 1,124	$ (302)	$ 822	$ 1,927	$ 1,070	$ 571	$ 287	70,900	345,100	343,500
2018	$ 939	$ 154	$ 1,136	$ (287)	$ 849	$ 1,941	$ 1,075	$ 574	$ 292	79,000	405,600	349,500
2019	$ 928	$ 155	$ 1,149	$ (274)	$ 875	$ 1,958	$ 1,105	$ 556	$ 296	86,100	461,200	355,600
2020	$ 939	$ 155	$ 1,162	$ (262)	$ 900	$ 1,994	$ 1,130	$ 563	$ 301	92,600	514,100	361,800
2021	$ 953	$ 103	$ 1,177	$ (254)	$ 923	$ 1,979	$ 1,132	$ 542	$ 305	98,800	563,900	367,700
2022	$ 967	$ 70	$ 1,193	$ (247)	$ 946	$ 1,984	$ 1,140	$ 533	$ 310	104,600	609,600	373,600
2023	$ 981	$ 60	$ 1,210	$ (241)	$ 969	$ 2,010	$ 1,160	$ 535	$ 315	110,100	652,200	379,800
2024	$ 995	$ 39	$ 1,227	$ (237)	$ 991	$ 2,025	$ 1,184	$ 522	$ 319	115,300	692,700	385,800
2025	$ 1,009	$ 33	$ 1,245	$ (233)	$ 1,012	$ 2,054	$ 1,201	$ 529	$ 324	120,200	730,500	391,900
2026	$ 1,023	$ 33	$ 1,263	$ (229)	$ 1,034	$ 2,090	$ 1,224	$ 537	$ 329	125,100	766,600	398,000
2027	$ 1,037	$ 34	$ 1,281	$ (227)	$ 1,054	$ 2,125	$ 1,247	$ 545	$ 333	129,600	800,400	404,000
2028	$ 1,051	$ 34	$ 1,300	$ (226)	$ 1,074	$ 2,159	$ 1,268	$ 552	$ 338	133,900	831,200	410,100
2029	$ 1,065	$ 34	$ 1,318	$ (225)	$ 1,093	$ 2,192	$ 1,290	$ 560	$ 343	137,900	860,200	416,100
2030	$ 1,079	$ 35	$ 1,337	$ (225)	$ 1,112	$ 2,226	$ 1,311	$ 568	$ 347	141,700	887,700	422,200
2031	$ 1,093	$ 35	$ 1,356	$ (225)	$ 1,130	$ 2,259	$ 1,331	$ 576	$ 352	145,400	913,100	428,300
2032	$ 1,107	$ 36	$ 1,374	$ (226)	$ 1,149	$ 2,291	$ 1,351	$ 583	$ 357	148,800	936,700	434,400
2033	$ 1,121	$ 36	$ 1,393	$ (227)	$ 1,167	$ 2,324	$ 1,372	$ 591	$ 361	152,100	959,800	440,500
2034	$ 1,135	$ 37	$ 1,412	$ (228)	$ 1,185	$ 2,356	$ 1,392	$ 599	$ 366	155,400	982,000 1,003,700	446,700
2035	$ 1,149	$ 37	$ 1,431	$ (229)	$ 1,202	$ 2,389	$ 1,412	$ 606	$ 371	158,500	1,024,500	452,800
2036	$ 1,163	$ 38	$ 1,450	$ (230)	$ 1,220	$ 2,421	$ 1,431	$ 614	$ 375	161,600	1,044,800	458,900
30 Yr NPV at 3%	$ 14,628	$ 1,344	$ 18,772	$ (5,236)	$ 13,535	$ 29,507	$ 17,040	$ 7,988	$ 4,479	164,500 1,584,300	8,662,500	465,100 6,511,100
30 Yr NPV at 7%	$ 7,502	$ 791	$ 9,891	$ (3,198)	$ 6,693	$ 14,986	$ 8,635	$ 4,102	$ 2,248		3,900,200	3,593,900

768,300

The calculations of cost per ton of each emission reduced under the Case 2 sensitivity divides the net present value of the annual costs assigned to each pollutant (Table 8A.3-8) by the net present value of the total annual reductions of each pollutant (Table 8A.3-8). The 30-year net present value of the costs associated with each pollutant, calculated with a three percent discount rate, are shown in Table 8A.3-8 as $8.0 billion for NOx+NMHC, $17.0 billion for PM, and $4.5 billion for SOx, with the total cost of the program estimated at $29.5 billion. The 30-year net present value, with a three percent discount rate, of emission reductions are estimated at 8.7 million tons of NOx+NMHC, 1.6 million tons of PM, and 6.5 million tons of SOx (see Table 8A.3-8). How these emissions reductions were developed is described in Section 8A.2 (see Table 8A.2-6).[J] The results of the cost per ton calculations are shown in Table 8A.3-9.

Table 8A.3-9
Aggregate Cost per Ton for the Case 2 Sensitivity
30-year Net Present Values at a 3% and 7% Discount Rate ($2002)

Item	3% discount rate	7% discount rate	Source
Cost per Ton NOx+NMHC	$920	$1,050	Calculated
Cost per Ton PM	$10,800	$11,200	Calculated
Cost per Ton SOx	$690	$630	Calculated

We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emission reductions in that year alone. This number, shown in Table 8A.3-10, approaches the long-term cost per ton of emissions reduced.

Table 8A.3-10
Long-Term Cost per Ton of the Case 2 Sensitivity
Annual Values without Discounting ($2002)

Pollutant	Long-Term Cost per Ton in 2030
NOx+NMHC	$620
PM	$9,000
SOx	$810

[J] Note that the emissions reductions shown in Table 8A.3-8 are not identical to the reductions one would get using the inventories presented in Table 8A.2-6. The emissions inventories in Table 8A.2-6 are for land based nonroad engines only and do not include emissions associated with locomotive and marine engines. To make the comparison between the Case 2 $/ton and the NRT4 full program $/ton, the Case 2 locomotive and marine emissions reductions are included with the Case 2 nonroad land based emissions reductions. The Case 2 locomotive and marine emissions reductions would be identical to those under the NRT4 full program since nothing about the Case 2 sensitivity would impact emissions reductions from locomotive and marine engines. Therefore, the NRT4 full program locomotive and marine emissions reductions have been added to the Case 2 nonroad land based emissions reductions to arrive at the Case 2 emissions reductions shown in Table 8A.3-8.

8A.4 Summary of the Sensitivity Analyses Results

We present here a summary of the results of the Case 1 and Case 2 sensitivity analyses, and we compare these results to the NRT4 full engine and fuel program (i.e., the NRT4 Final Rule).

Table 8A.4-1 shows the emission reduction comparison between the NRT4 full program and the sensitivity cases for PM and NOx. As can be seen, the Case 1 sensitivity results in a decrease in both PM and NOx emissions reductions on the order of 35 to 40 percent. The Case 2 sensitivity results in an increase in PM reductions on the order of 10 percent and an increase in NOx reductions on the order of 20 percent.

Table 8A.4-1
Emissions Reduction* Comparison for Case 1 and Case 2 Sensitivity Analyses
30 Year Net Present Values at a 3% Discount Rate

Baseline/Control Scenario	NOx+NMHC (tons)	Percent Relative to NRT4 FRM	PM (tons)	Percent Relative to NRT4 FRM
Nonroad Tier 4 Final Rule	7,077,900	-	1,430,500	-
Case 1 Sensitivity Analysis	4,421,600	-38%	919,400	-36%
Case 2 Sensitivity Analysis	8,662,500	22%	1,584,300	11%

* See Tables 8.6-1, 8A.3-5, and 8A.3-8, respectively.

Table 8A.4-2 summarizes the results of the two sensitivity cases with respect to cost-effectiveness for NMHC+NOx, PM, and SOx, and compares these values to the final NRT4 program. As can be seen, the Case 1 sensitivity analysis results in an increase in the $/ton estimates for all pollutants. However, in all cases, these estimates are still within the range of previous mobile source control programs for NMHC+NOx and PM, and for SOx on the same order as stationary control programs for acid rain (see Tables VI.D-3, -4, and -5 of the preamble for this final rule). For the Case 2 sensitivity analysis, Table 8A.4-2 shows that the cost-effectiveness for NOx+NMHC and for PM are lower than for the final Tier 4 program, and for SOx the cost-effectiveness is the same as for the final Tier 4 program.

Table 8A.4-2
Comparison of Aggregate Cost per Ton Estimates: NRT4 Final Rule, Case 1 Sensitivity Analysis, and Case 2 Sensitivity Analysis
30-year Net Present Values at a 3 percent Discount Rate ($2002)

Pollutant	Nonroad Tier 4 Final Rule	Case 1 Sensitivity Analysis	Case 2 Sensitivity Analysis
NOx+NMHC ($/ton)	$1,010	$1,490	$920
PM ($/ton)	$11,200	$15,800	$10,800
SOx ($/ton)	$690	$870	$690

Appendix 8B: Fuel Volumes used throughout Chapter 8

The volumes in this Appendix were developed from the information contained in Section 7.1 of Chapter 7 of the RIA. Demand volumes are estimated for each EPA use category, including nonroad, locomotive, marine, and highway diesel fuel, and heating oil, for 2014. The 2014 estimated volumes of pipeline downgrade and highway diesel fuel spillover are apportioned to various EPA use categories depending on the regulatory scenario. By default, this analysis estimates the volume of fuel which must be desulfurized for supplying the overall demand of each EPA use category. The regulatory scenarios modeled for their volumes for this Chapter include the Final Rule Program and several sensitivity cases which are summarized here. For each case, the table which summarizes the 2014 volumes is listed along with the case description.

Final Rule Program:

- Period from 2007 to 2010 - NRLM must meet a 500 ppm sulfur cap standard. Small refiners are exempted and are assumed to produce high sulfur distillate and sell that fuel into the NRLM diesel fuel pool (Table 7.1.3-14).

- Period from 2010 to 2012 - nonroad must meet a 15 ppm sulfur cap standard and locomotive and marine must meet a 500 ppm sulfur cap. Small refiners are exempted and can sell exempted fuel into the nonroad diesel fuel pool, except for most of PADD 1, providing that they produce 500 ppm fuel (Table 7.1.3-17).

- Period from 2012 to 2014 - NRLM must meet a 15 ppm sulfur cap standard. Small refiners are exempted and can sell exempted fuel into the NRLM diesel fuel pool, except for most of PADD 1, providing that they produce 500 ppm fuel (Table 7.1.3-19).

- Period from 2014 and thereafter - The small refiner provisions have expired (Table 7.1.3-20).

NRLM to 500 ppm only:

- Period from 2007 to 2010 - Same as Final Rule Program above for the period 2007 to 2010 (Table 7.1.3-14).

- Period after 2010 - NRLM fuel remains at 500 ppm (Table 7.1.4-1).

Final Rule Program, EIA nonroad volumes:

- Same as Final Rule Program except that the nonroad volumes were developed using EIA information instead of using NONROAD (Tables 7.1.4-10, 7.1.4-11, 7.1.4-12, and 7.1.4-13).

All the volume streams in each case were apportioned into specific families of similar fuels depending on the quality of the specific volume stream and whether it was regulated under the NRLM Program. These fuel families and the streams which comprise them are summarized in the following table.

Fuel Families and the Fuels They Represent*

Fuel Family						
High Sulfur	Old 500 ppm	New 500 ppm	Old 15 ppm	Reprocessed Downgrade	New 15 ppm	Total Volume
High Sulfur (3000 ppm) distillate fuel including NRLM and heating oil Small refiner fuel from 2007 to 2010	500 ppm diesel fuel meeting the Highway Diesel Fuel Program requirements	500 ppm diesel fuel meeting the Nonroad Diesel Fuel Program requirements Small refiner fuel from 2010 to 2014	15 ppm diesel fuel meeting the Highway Diesel Fuel Program requirements	Oversupply of downgrade into a market which must be reprocessed to 15 ppm	15 ppm diesel fuel meeting the Nonroad Diesel Fuel Program requirements	Total of these various volumes.

* California gallons are not included. "Affected" 500 ppm gallons are labeled here as "New 500 ppm" and "Affected" 15 ppm gallons are the summation of the columns labeled "Reprocessed Downgrade" and "New 15 ppm."

The 2014 volumes are adjusted to estimate the volumes in each year from 2007 to 2040 using growth ratios compared to 2014 based on the growth rate factors in Tables 7.1.5-1 and 7.1.5-2.

Analyzing and categorizing the volumes in this fashion resulted in the development of the input volumes used in this chapter. For a more complete summary of how the volumes were calculated consult Section 7.1 of Chapter 7 of the RIA. The following tables summarize this information.

Table 8B-1
Nationwide Nonroad Volumes Under the NRT4 Final Rule Fuel Program

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	4,027	239	4,790	2,369	-	-	11,426
2008	584	179	8,406	2,526	-	-	11,695
2009	597	183	8,599	2,585	-	-	11,964
2010	255	673	4,014	2,643	-	6,189	12,233
2011	-	1,043	614	2,701	-	8,145	12,504
2012	-	1,066	528	2,760	-	8,420	12,774
2013	-	1,088	468	2,818	-	8,671	13,045
2014	-	463	199	2,941	68	9,645	13,316
2015	-	-	-	3,047	118	10,421	13,586
2016	-	-	-	3,107	121	10,626	13,854
2017	-	-	-	3,167	123	10,832	14,122
2018	-	-	-	3,227	125	11,037	14,390
2019	-	-	-	3,288	127	11,243	14,658
2020	-	-	-	3,352	130	11,448	14,926
2021	-	-	-	3,408	132	11,654	15,193
2022	-	-	-	3,468	134	11,859	15,461
2023	-	-	-	3,528	137	12,064	15,729
2024	-	-	-	3,588	139	12,270	15,997
2025	-	-	-	3,648	141	12,475	16,265
2026	-	-	-	3,708	144	12,679	16,531
2027	-	-	-	3,767	146	12,883	16,797
2028	-	-	-	3,827	148	13,088	17,063
2029	-	-	-	3,887	151	13,292	17,329
2030	-	-	-	3,946	153	13,496	17,595
2031	-	-	-	4,006	155	13,700	17,861
2032	-	-	-	4,066	158	13,904	18,127
2033	-	-	-	4,125	160	14,108	18,393
2034	-	-	-	4,185	162	14,312	18,659
2035	-	-	-	4,245	165	14,516	18,925
2036	-	-	-	4,304	167	14,720	19,191

Table 8B-2
Nationwide Locomotive Volumes Under the NRT4 Final Rule Fuel Program

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	968	45	1,141	539	-	-	2,694
2008	138	40	1,978	568	-	-	2,724
2009	140	40	2,005	576	-	-	2,761
2010	59	356	1,805	585	-	-	2,805
2011	-	591	1,671	596	-	-	2,858
2012	-	410	761	602	-	1,114	2,841
2013	-	278	99	607	-	1,925	2,909
2014	-	849	42	589	-	1,476	2,932
2015	-	1,266	-	577	-	1,154	2,956
2016	-	1,279	-	583	-	1,166	2,988
2017	-	1,291	-	589	-	1,177	3,015
2018	-	1,301	-	593	-	1,186	3,038
2019	-	1,313	-	599	-	1,197	3,067
2020	-	1,322	-	603	-	1,205	3,089
2021	-	1,329	-	606	-	1,212	3,104
2022	-	1,341	-	611	-	1,222	3,132
2023	-	1,353	-	617	-	1,233	3,160
2024	-	1,365	-	622	-	1,244	3,187
2025	-	1,378	-	628	-	1,256	3,218
2026	-	1,389	-	633	-	1,266	3,244
2027	-	1,400	-	638	-	1,276	3,270
2028	-	1,411	-	643	-	1,286	3,295
2029	-	1,422	-	648	-	1,296	3,321
2030	-	1,433	-	653	-	1,306	3,347
2031	-	1,444	-	658	-	1,316	3,373
2032	-	1,455	-	663	-	1,327	3,399
2033	-	1,466	-	668	-	1,337	3,425
2034	-	1,477	-	674	-	1,347	3,450
2035	-	1,488	-	679	-	1,357	3,476
2036	-	1,500	-	684	-	1,367	3,502

Table 8B-3
Nationwide Marine Volumes Under the NRT4 Final Rule Fuel Program

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	806	21	849	252	-	-	1,929
2008	190	23	1,476	266	-	-	1,955
2009	192	23	1,494	269	-	-	1,979
2010	81	269	1,380	273	-	0	2,003
2011	-	452	1,304	277	-	0	2,033
2012	-	292	636	280	-	851	2,059
2013	-	175	148	283	-	1,472	2,078
2014	-	222	62	281	-	1,605	2,103
2015	-	257	-	280	-	1,706	2,126
2016	-	259	-	283	-	1,722	2,146
2017	-	262	-	286	-	1,741	2,170
2018	-	266	-	290	-	1,768	2,203
2019	-	271	-	295	-	1,798	2,240
2020	-	202	-	299	-	1,818	2,266
2021	-	152	-	302	-	1,841	2,294
2022	-	154	-	307	-	1,871	2,331
2023	-	156	-	311	-	1,892	2,357
2024	-	158	-	315	-	1,917	2,389
2025	-	160	-	319	-	1,939	2,417
2026	-	162	-	323	-	1,964	2,448
2027	-	164	-	327	-	1,989	2,479
2028	-	166	-	331	-	2,014	2,510
2029	-	168	-	335	-	2,039	2,542
2030	-	170	-	339	-	2,065	2,573
2031	-	172	-	343	-	2,090	2,604
2032	-	175	-	347	-	2,115	2,635
2033	-	177	-	352	-	2,140	2,667
2034	-	179	-	356	-	2,165	2,698
2035	-	181	-	360	-	2,190	2,729
2036	-	183	-	364	-	2,215	2,760

Table 8B-4
Nationwide Nonroad Volumes Under the 500ppm NRLM Scenario

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	4,027	239	4,790	2,369	-	-	11,426
2008	584	179	8,406	2,526	-	-	11,695
2009	597	183	8,599	2,585	-	-	11,964
2010	255	936	8,400	2,643	-	-	12,233
2011	-	1,503	8,300	2,701	-	-	12,504
2012	-	1,535	8,479	2,760	-	-	12,774
2013	-	1,568	8,659	2,818	-	-	13,045
2014	-	1,600	8,839	2,877	-	-	13,316
2015	-	1,633	9,018	2,935	-	-	13,586
2016	-	1,665	9,196	2,993	-	-	13,854
2017	-	1,697	9,374	3,051	-	-	14,122
2018	-	1,729	9,552	3,109	-	-	14,390
2019	-	1,762	9,730	3,166	-	-	14,658
2020	-	1,794	9,907	3,224	-	-	14,926
2021	-	1,826	10,085	3,282	-	-	15,193
2022	-	1,858	10,263	3,340	-	-	15,461
2023	-	1,890	10,441	3,398	-	-	15,729
2024	-	1,923	10,619	3,456	-	-	15,997
2025	-	1,955	10,797	3,514	-	-	16,265
2026	-	1,987	10,973	3,571	-	-	16,531
2027	-	2,019	11,150	3,629	-	-	16,797
2028	-	2,051	11,326	3,686	-	-	17,063
2029	-	2,083	11,503	3,744	-	-	17,329
2030	-	2,115	11,679	3,801	-	-	17,595
2031	-	2,147	11,856	3,859	-	-	17,861
2032	-	2,179	12,032	3,916	-	-	18,127
2033	-	2,210	12,209	3,973	-	-	18,393
2034	-	2,242	12,386	4,031	-	-	18,659
2035	-	2,274	12,562	4,088	-	-	18,925
2036	-	2,306	12,739	4,146	-	-	19,191

Table 8B-5
Nationwide Locomotive Volumes Under the 500ppm NRLM Scenario

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	968	45	1,141	539	-	-	2,694
2008	138	40	1,978	568	-	-	2,724
2009	140	40	2,005	576	-	-	2,761
2010	59	211	1,950	585	-	-	2,805
2011	-	339	1,923	596	-	-	2,858
2012	-	342	1,942	602	-	-	2,886
2013	-	345	1,958	607	-	-	2,909
2014	-	347	1,973	611	-	-	2,932
2015	-	350	1,990	616	-	-	2,956
2016	-	354	2,011	623	-	-	2,988
2017	-	357	2,029	629	-	-	3,015
2018	-	360	2,044	633	-	-	3,038
2019	-	364	2,064	640	-	-	3,067
2020	-	366	2,079	644	-	-	3,089
2021	-	368	2,089	647	-	-	3,104
2022	-	371	2,108	653	-	-	3,132
2023	-	374	2,127	659	-	-	3,160
2024	-	378	2,145	664	-	-	3,187
2025	-	381	2,166	671	-	-	3,218
2026	-	385	2,184	677	-	-	3,244
2027	-	388	2,202	682	-	-	3,270
2028	-	391	2,220	688	-	-	3,295
2029	-	394	2,239	694	-	-	3,321
2030	-	398	2,258	699	-	-	3,347
2031	-	401	2,277	705	-	-	3,373
2032	-	404	2,296	711	-	-	3,399
2033	-	408	2,315	717	-	-	3,425
2034	-	411	2,334	723	-	-	3,450
2035	-	415	2,354	729	-	-	3,476
2036	-	418	2,374	735	-	-	3,502

Table 8B-6
Nationwide Marine Volumes Under the 500ppm NRLM Scenario

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	806	21	849	252	-	-	1,929
2008	190	23	1,476	266	-	-	1,955
2009	192	23	1,494	269	-	-	1,979
2010	81	142	1,508	273	-	-	2,003
2011	-	229	1,527	277	-	-	2,033
2012	-	232	1,546	280	-	-	2,059
2013	-	234	1,560	283	-	-	2,078
2014	-	237	1,579	286	-	-	2,103
2015	-	240	1,597	289	-	-	2,126
2016	-	242	1,612	292	-	-	2,146
2017	-	245	1,630	295	-	-	2,170
2018	-	249	1,654	300	-	-	2,203
2019	-	253	1,682	305	-	-	2,240
2020	-	256	1,702	309	-	-	2,266
2021	-	259	1,723	312	-	-	2,294
2022	-	263	1,751	317	-	-	2,331
2023	-	266	1,770	321	-	-	2,357
2024	-	270	1,794	325	-	-	2,389
2025	-	273	1,815	329	-	-	2,417
2026	-	276	1,838	333	-	-	2,448
2027	-	280	1,862	337	-	-	2,479
2028	-	283	1,885	342	-	-	2,510
2029	-	287	1,909	346	-	-	2,542
2030	-	290	1,932	350	-	-	2,573
2031	-	294	1,956	355	-	-	2,604
2032	-	297	1,979	359	-	-	2,635
2033	-	301	2,003	363	-	-	2,667
2034	-	305	2,026	367	-	-	2,698
2035	-	308	2,050	372	-	-	2,729
2036	-	312	2,073	376	-	-	2,760

Table 8B-7
Nationwide Nonroad Volumes Under the Case 1 Sensitivity

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	2,996	444	3,671	1,959	-	-	9,070
2008	592	153	6,373	2,067	-	-	9,186
2009	600	155	6,454	2,093	-	-	9,302
2010	253	66	3,086	2,141	-	3,873	9,419
2011	-	-	631	2,183	-	6,721	9,535
2012	-	358	531	2,188	-	6,574	9,651
2013	-	621	460	2,198	-	6,488	9,767
2014	-	262	194	2,275	-	7,153	9,884
2015	-	-	-	2,338	-	7,662	10,000
2016	-	-	-	2,366	-	7,751	10,116
2017	-	-	-	2,393	-	7,840	10,233
2018	-	-	-	2,420	-	7,929	10,349
2019	-	-	-	2,447	-	8,018	10,465
2020	-	-	-	2,474	-	8,107	10,581
2021	-	-	-	2,502	-	8,196	10,698
2022	-	-	-	2,529	-	8,285	10,814
2023	-	-	-	2,556	-	8,374	10,930
2024	-	-	-	2,583	-	8,464	11,047
2025	-	-	-	2,610	-	8,553	11,163
2026	-	-	-	2,638	-	8,642	11,279
2027	-	-	-	2,665	-	8,731	11,395
2028	-	-	-	2,692	-	8,820	11,512
2029	-	-	-	2,719	-	8,909	11,628
2030	-	-	-	2,746	-	8,998	11,744
2031	-	-	-	2,774	-	9,087	11,861
2032	-	-	-	2,801	-	9,176	11,977
2033	-	-	-	2,828	-	9,265	12,093
2034	-	-	-	2,855	-	9,354	12,210
2035	-	-	-	2,882	-	9,444	12,326
2036	-	-	-	2,910	-	9,533	12,442

Table 8B-8
Nationwide Locomotive Volumes Under the Case 1 Sensitivity

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	910	116	1,129	539	-	-	2,694
2008	162	37	1,957	568	-	-	2,724
2009	164	38	1,983	576	-	-	2,761
2010	70	426	1,741	569	-	-	2,805
2011	-	715	1,575	568	-	-	2,858
2012	-	410	732	590	-	1,155	2,886
2013	-	188	120	607	-	1,995	2,909
2014	-	455	50	584	-	1,842	2,932
2015	-	651	-	570	-	1,735	2,956
2016	-	658	-	576	-	1,754	2,988
2017	-	664	-	581	-	1,770	3,015
2018	-	669	-	586	-	1,783	3,038
2019	-	675	-	591	-	1,801	3,067
2020	-	680	-	595	-	1,813	3,089
2021	-	684	-	599	-	1,822	3,104
2022	-	690	-	604	-	1,838	3,132
2023	-	696	-	609	-	1,855	3,160
2024	-	702	-	614	-	1,871	3,187
2025	-	709	-	620	-	1,889	3,218
2026	-	714	-	625	-	1,904	3,244
2027	-	720	-	630	-	1,919	3,270
2028	-	726	-	635	-	1,934	3,295
2029	-	731	-	640	-	1,950	3,321
2030	-	737	-	645	-	1,965	3,347
2031	-	743	-	650	-	1,980	3,373
2032	-	748	-	655	-	1,995	3,399
2033	-	754	-	660	-	2,010	3,425
2034	-	760	-	665	-	2,025	3,450
2035	-	766	-	670	-	2,041	3,476
2036	-	771	-	675	-	2,056	3,502

Table 8B-9
Nationwide Marine Volumes Under the Case 1 Sensitivity

Year	High Sulfur (million gallons)	Old 500 ppm (million gallons)	New 500 ppm (million gallons)	Old 15 ppm (million gallons)	Reprocessed Downgrade (million gallons)	New 15 ppm (million gallons)	Total Volume (million gallons)
2007	757	67	853	252	-	-	1,929
2008	186	22	1,482	266	-	-	1,955
2009	188	22	1,499	269	-	-	1,979
2010	79	326	1,328	269	-	-	2,003
2011	-	551	1,210	271	-	-	2,033
2012	-	309	511	278	-	961	2,059
2013	-	133	-	283	-	1,662	2,078
2014	-	136	-	281	-	1,685	2,103
2015	-	140	-	280	-	1,706	2,126
2016	-	141	-	283	-	1,722	2,146
2017	-	143	-	286	-	1,742	2,170
2018	-	145	-	290	-	1,768	2,203
2019	-	147	-	295	-	1,798	2,240
2020	-	149	-	299	-	1,819	2,266
2021	-	151	-	302	-	1,841	2,294
2022	-	153	-	307	-	1,871	2,331
2023	-	155	-	311	-	1,892	2,357
2024	-	157	-	315	-	1,917	2,389
2025	-	159	-	319	-	1,939	2,417
2026	-	161	-	323	-	1,964	2,448
2027	-	163	-	327	-	1,989	2,479
2028	-	165	-	331	-	2,015	2,510
2029	-	167	-	335	-	2,040	2,542
2030	-	169	-	339	-	2,065	2,573
2031	-	171	-	343	-	2,090	2,604
2032	-	173	-	347	-	2,115	2,635
2033	-	175	-	352	-	2,140	2,667
2034	-	177	-	356	-	2,165	2,698
2035	-	179	-	360	-	2,190	2,729
2036	-	181	-	364	-	2,215	2,760

Chapter 8 References

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2. Power Systems Research, OELink Sales Version, 2002.

3. Nonroad Engine Growth Estimate, Report No. NR-008b, Docket Item II-A-32.

4. “Engine Sales Used in Proposed Nonroad Tier 4 Cost Analysis,” memorandum from Todd Sherwood to Public Docket No. A-2001-28, Docket Item II-B-37.

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CHAPTER 9: Cost-Benefit Analysis

CHAPTER 9: Cost-Benefit Analysis

This chapter reports EPA's analysis of the public health and welfare impacts and associated monetized benefits to society of the final Nonroad Diesel Engines Tier 4 Standards. EPA is required by Executive Order 12866 to estimate the costs and benefits of major new pollution control regulations. Accordingly, the analysis presented here attempts to answer three questions: (1) what are the physical health and welfare effects of changes in ambient air quality resulting from reductions in nitrogen oxides (NOx), sulfur dioxide (SO_2), non-methane hydrocarbons (NMHC), carbon monoxide (CO) and direct diesel particulate matter ($PM_{2.5}$)[A] emissions?; (2) how much are the changes in these effects attributable to the final rule worth to U.S. citizens as a whole in monetary terms?; and (3) how do the monetized benefits compare to the costs over time? It constitutes one part of EPA's thorough examination of the relative merits of this regulation. In Chapter 12, of the Draft RIA, we provided an analysis of the benefits of several alternatives to the selected standards to examine their relative benefits and costs for public comment.

For the final rulemaking, we rely on the air quality modeling conducted for the proposed rule, documented in the Regulatory Impact Analysis (U.S. EPA, 2003a), available at http://www.epa.gov/nonroad.[B] To estimate the benefits of the final rule, we use a set of scaling factors which separately estimate a set of emission reduction profiles for NOx, SO_2, and directly emitted diesel $PM_{2.5}$. For this analysis of the final rule, we conduct a benefits transfer analysis using those same scaling factors, applied to the updated results of the modeled preliminary control option which accounts for changes in the health benefits methodology adopted during the recent proposed Interstate Air Quality Rule (IAQR) analysis.[C] These methodological changes are reflected both in the detailed estimates for 2020 and 2030 and in the time stream of total monetized benefits. The methodological changes are summarized in this chapter and described in detail in Appendix 9A.

EPA has used the best available information and tools of analysis to quantify the expected changes in public health, environmental and economic benefits for the modeled option. We

[A]Emissions from nonroad diesel engines include directly emitted fine particles (carbon and sulfates) as well as gaseous pollutants that react in the atmosphere to form fine particles. This final rule will results in reductions in ambient PM particle levels due to reductions in both directly emitted particles as well as reductions in PM precursor emissions, including NOx and SO_2.

[B]As discussed in Chapter 2, because of the long lead times to conduct complex photochemical air quality modeling at the national scale, decisions must be made early in the process about the scenarios to be modeled. Based on updated information and public comment, EPA has made changes to the final control program, which results in changes in emissions as detailed in Chapter 3, section 3.6.

[C]Note that the methodology for estimating visibility benefits is unchanged from proposal. The documents related to the IAQR can be found at OAR Docket number 2003-0053.

summarize the results of that analysis in section 9.3, and present details in Appendix 9A, directly following this chapter. The standards we are finalizing in this rulemaking are slightly different in the amount of emission reductions expected to be achieved in 2020 and 2030 relative to both the proposed standards and the preliminary modeled option. As such, we determined that benefits would need to be scaled to reflect the differences in emission reductions between the modeled and final standards. The results of that scaling analysis are the focus of this chapter.

In order to characterize the benefits attributable to the Nonroad Diesel Engines standards, given the constraints on time and resources available for the analysis, we use a benefits transfer method to scale the benefits of the modeled preliminary control options to reflect the differences in emission reductions. We also apply intertemporal scaling factors to examine the stream of benefits over the rule implementation period. The benefits transfer method used to estimate benefits for the final rule is similar to that used to estimate benefits in the recent analysis of the Large SI/Recreational Vehicles standards (see U.S. EPA 2002, Docket A-2000-01, Document V-B-4). A similar method has also been used in recent benefits analyses for the proposed Clean Air Act Section 112 Utility Mercury Emission Reduction rule, the proposed Industrial Boilers and Process Heaters National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards (Docket numbers OAR-2003-A-96-47) and the Reciprocating Internal Combustion Engines NESHAP standards (Docket numbers OAR-2002-0059 and A-95-35). One significant limitation to this method is the inability to scale ozone-related benefits. Because ozone is a homogeneous gaseous pollutant formed through complex atmospheric photochemical processes, it is not possible to apportion ozone benefits to the precursor emissions of NOx and VOC. Coupled with the potential for NOx reductions to either increase or decrease ambient ozone levels, this prevents us from scaling the benefits associated with a particular combination of VOC and NOx emissions reductions to another (a more detailed discussion is provided below). Because of our inability to scale ozone benefits, we provide the ozone benefits results for the modeled preliminary control options as a referent, but do not include ozone benefits as part of the monetized benefits of the standards. For the most part, quantifiable ozone benefits do not contribute significantly to the monetized benefits: thus, their omission will not materially affect the conclusions of the benefits analysis.

Table 9-1 lists the known quantifiable and unquantifiable effects considered for this analysis. We quantify benefits for the contiguous 48 states. Note that this table categorizes ozone-related benefits as unquantified effects. Furthermore, we quantify benefits for the contiguous 48 states. We have quantified ozone-related benefits in our modeling of the preliminary control option, summarized in Section 9.3 and detailed in Appendix 9A. However, as noted above, we are unable to quantify ozone-related benefits for the final standards. It is important to note that there are significant categories of benefits which can not be monetized (or in many cases even quantified), resulting in a significant limitation to this analysis. Also, EPA currently does not have appropriate tools for modeling changes in ambient concentrations of CO or air toxics input into a national benefits analysis. Although these pollutants have been linked to numerous adverse health effects, we are unable to quantify the CO- or air toxics-related health or welfare benefits of the final rule at this time. We also omitted the significant SO2 reductions from lower sulfur in home heating oil in the Northeast.

The benefit analysis that we performed for our rule can be thought of as having seven parts, each of which will be discussed separately in the Sections that follow. These seven steps include the following:

1. Identification of final standards and calculation of the impact that the standards will have on the nationwide inventories for NOx, non-methane hydrocarbons (NMHC), SO_2, and PM emissions throughout the rule implementation period;
2. Calculation of scaling factors relating emissions changes resulting from the final standards to emissions changes from a set of preliminary control options that were used to model air quality and benefits (see Appendix 9A for full details).
3. Apportionment of modeled benefits of preliminary control options to NOx, SO_2, and diesel PM emissions (see Appendix 9A for a complete discussion of the modeling of the benefits for the preliminary set of standards, including updates in the benefits methodology since the time of proposal).
4. Application of scaling factors to apportioned modeled benefits associated with NOx, $_{SO2}$, and PM in 2020 and 2030.
5. Development of intertemporal scaling factors based on 2020 and 2030 modeled air quality and benefits results.
6. Application of intertemporal scaling factors to the yearly emission changes expected to result from the standards from 2010 through 2030 to obtain yearly monetized benefits.
7. Calculation of present value of stream of benefits.

This analysis presents estimates of the potential benefits from the final Nonroad Diesel Engine rule occurring in future years. The predicted emissions reductions that will result from the rule have yet to occur, and therefore the actual changes in human health and welfare outcomes to which economic values are ascribed are predictions. These predictions are based on the best available scientific evidence and judgment, but there is unavoidable uncertainty associated with each step in the complex process between regulation and specific health and welfare outcomes. Uncertainties associated with projecting input and parameter values into the future may contribute significantly to the overall uncertainty in the benefits estimates. However, we make these projections to more completely examine the impact of the program as the equipment fleet turns over.

In general, the chapter is organized around the seven steps laid out above. In Section 1, we identify the potential standard to analyze, establish the timeframe over which benefits are estimated, and summarize emissions impacts. In Section 2, we summarize the changes in emissions that were used in the preliminary modeled benefits analysis and develop the ratios of the emissions reductions under the final standards to preliminary emissions reductions that are used to scale modeled benefits. In Section 3, we summarize the modeled benefits associated with the emissions changes for the preliminary control options and apportion those benefits to the individual emission species (NOx, SO_2, and $PM_{2.5}$). In Section 4, we estimate the benefits in 2020 and 2030 for the final standards, based on scaling of the modeled benefits of the preliminary control options. In Section 5, we develop intertermporal scaling factors based on the ratios of yearly emission changes to the emission changes in 2020 and 2030 and estimate yearly benefits of the final standards, based on scaling of the benefits in 2020 and 2030. Finally, in

Section 6, we compare the estimated streams of benefits and costs over the full implementation period, 2007 to 2030, to calculate the present value of net benefits for the final standards.

Table 9-1
Health and Welfare Effects of Pollutants Affected by the Final Nonroad Diesel Engine Rule

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
PM/Health	Premature mortality in adults Infant mortality Bronchitis - chronic and acute Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma Non-fatal heart attacks (myocardial infarction) Asthma exacerbations (asthmatic population) Lower and upper respiratory illness Respiratory symptoms (asthmatic population) Minor restricted activity days Work loss days		Low birth weight Changes in pulmonary function Chronic respiratory diseases other than chronic bronchitis Morphological changes Altered host defense mechanisms Non-asthma respiratory emergency room visits PM reductions associated with reductions in sulfur in home heating oil
PM/Welfare	Visibility in California, Southwestern, and Southeastern Class I areas		Visibility in Northeastern, Northwestern, and Midwestern Class I areas Visibility in residential and non-Class I areas Household soiling Sulfate PM reductions associated with reductions in sulfur in home heating oil

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
Ozone/Health			Increased airway responsiveness to stimuli Inflammation in the lung Chronic respiratory damage Premature aging of the lungs Acute inflammation and respiratory cell damage Increased susceptibility to respiratory infection Non-asthma respiratory emergency room visits Hospital admissions - respiratory Emergency room visits for asthma Minor restricted activity days School loss days Chronic Asthma[a] Asthma attacks Cardiovascular emergency room visits Premature mortality – acute exposures[b] Acute respiratory symptoms
Ozone/Welfare			Decreased commercial forest productivity Decreased yields for fruits and vegetables Decreased yields for commercial and non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Damage to ecosystem functions Decreased outdoor worker productivity
Nitrogen and Sulfate Deposition/ Welfare			Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries Impacts of acidic sulfate and nitrate deposition on commercial forests Impacts of acidic deposition on commercial freshwater fishing Impacts of acidic deposition on recreation in terrestrial ecosystems Impacts of nitrogen deposition on commercial fishing, agriculture, and forests Impacts of nitrogen deposition on recreation in estuarine ecosystems Reduced existence values for currently healthy ecosystems
SO_2/Health			Hospital admissions for respiratory and cardiac diseases Respiratory symptoms in asthmatics

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
NOx/Health			Lung irritation Lowered resistance to respiratory infection Hospital Admissions for respiratory and cardiac diseases
CO/Health			Premature mortality Behavioral effects Hospital admissions - respiratory, cardiovascular, and other Other cardiovascular effects Developmental effects Decreased time to onset of angina
NMHCs [c] Health			Cancer (diesel PM, benzene, 1,3-butadiene, formaldehyde, acetaldehyde) Anemia (benzene) Disruption of production of blood components (benzene) Reduction in the number of blood platelets (benzene) Excessive bone marrow formation (benzene) Depression of lymphocyte counts (benzene) Reproductive and developmental effects (1,3-butadiene) Irritation of eyes and mucous membranes (formaldehyde) Respiratory and respiratory tract Asthma attacks in asthmatics (formaldehyde) Asthma-like symptoms in non-asthmatics (formaldehyde) Irritation of the eyes, skin, and respiratory tract (acetaldehyde) Upper respiratory tract irritation & congestion (acrolein)
NMHCs [c] Welfare			Direct toxic effects to animals Bioaccumlation in the food chain Reduced odors

[a] While no causal mechanism has been identified linking new development of chronic asthma to ozone exposure, two epidemiological studies shows a statistical association between long-term exposure to ozone and development of chronic asthma in exercising children and some non-smoking men (McConnell, 2002; McDonnell, et al., 1999).

[b] Premature mortality associated with ozone is not separately included in the calculation of total monetized benefits.

[c] All non-methane hydrocarbons (NMHCs) listed in the table are also hazardous air pollutants listed in Section 112(b) of the Clean Air Act.

9.1 Time Path of Emission Changes for the Final Standards

The final standards have various cost and emission related components, as described earlier in this RIA. These components would begin at various times and in some cases would phase in over time. This means that during the early years of the program there would not be a consistent match between cost and benefits. This is especially true for the equipment control portions and initial fuel changes required by the program, where the full equipment cost would be incurred at the time of equipment purchase, while the fuel and maintenance costs, along with the emission reductions and benefits resulting from all these costs would occur throughout the lifetime of the equipment. Because of this inconsistency and our desire to more appropriately match the costs and emission reductions of our program, our analysis examines costs and benefits throughout the period of program implementation. This chapter focuses on estimating the stream of benefits over time and comparing streams of benefits and costs. Detailed information on cost estimates can be found in chapters 6, 7 and 8 of this RIA.

For the nonroad diesel engine standards, implementation will occur in stages: reductions in sulfur content of nonroad diesel fuel and then adoption of controls on most new nonroad engines. Because full turnover of the fleet of nonroad diesel engines will not occur for many years, the emission reduction benefits of the standards will not be fully realized until several decades after the reduction in fuel sulfur content. The timeframe for the analysis reflects this turnover, beginning in 2007 and extending through 2030.

Chapter 3 discussed the development of the 1996, 2020 and 2030 baseline emissions inventories for the nonroad sector and for the sectors not affected by this rule. The emission sources and the basis for current and future-year inventories are listed in Table 9-2. Using these modeled inventories, emissions with and without the standards are interpolated to provide streams of emissions from the rule implementation date through full implementation in 2030. These streams of emissions are presented in Chapter 3. NOx and VOC contribute to ambient ozone formation, while NOx, SO_2, NMHC/VOC, and directly emitted $PM_{2.5}$ emissions are precursors to ambient $PM_{2.5}$ and PM_{10} concentrations. Although the rule is expected to reduced CO and air toxics emissions as well, we do not include benefits related to these reductions in the benefits analysis due to a lack of appropriate air quality and exposure models.

Table 9-2
Emissions Sources and Basis for Current and Future-Year Inventories for Air Quality Modeling

Emissions Source	1996 Base year	Future-year Base Case Projections
Utilities	1996 NEI Version 3.12 (CEM data)	Integrated Planning Model (IPM)
Non-Utility Point and Area sources	1996 NEI Version 3.12 (point) Version 3.11 (area)	BEA growth projections
Highway vehicles	MOBILE5b model with MOBILE6 adjustment factors for VOC and NOx; PART5 model for PM	VMT projection data
Nonroad engines (except locomotives, commercial marine vessels, and aircraft)	NONROAD2002 model	BEA and Nonroad equipment growth projections

Note: Full description of data, models, and methods applied for emissions inventory development and modeling are provided in the Emissions Inventory TSD (U.S. EPA, 2003a).

Table 9-3 summarizes the expected changes in emissions of key species. SO_2 emissions are expected to be reduced by over 84 percent within the first two years of implementation. Emissions of $PM_{2.5}$, NOx, and NMHC are expected to be reduced significantly over the period of implementation from 2007 to 2030. Table 9-4 breaks out the expected changes in emissions of key species for the components the fuel portion of the program.

Table 9-3
Summary of Reduction in 48-State Emissions[a]
Attributable to Final Nonroad Diesel Engine Standards and Fuel Programs

	Tons Reduced (Percent of baseline from this category)[a]			
	Direct $PM_{2.5}$	NOx	SO_2	VOC
2010	21,692 13%	149 0%	256,447 91%	525 0%
2015	53,072 33%	193,431 17%	297,513 99%	8,318 8%
2020	85,808 52%	442,061 39%	323,378 99%	18,141 19%
2025	110,043 64%	613,629 54%	349,312 99%	25,002 26%
2030	128,350 72%	734,184 62%	375,354 99%	30,030 31%

[a] NOx, VOC, and CO inventories are for land-based diesel engines only; PM and SO_2 inventories include land-based, recreational marine, commercial marine, and locomotive diesel engines.

Table 9-4
Summary of Reduction in 48-State Emissions
Attributable to Final Fuel Programs of the Nonroad Diesel Standards

	Tons Direct $PM_{2.5}$ and SO_2 Reduced					
	Fuel Only Program		500 ppm NRLM Fuel Program		15 ppm LM Fuel Program (no home heating oil)	
	Direct $PM_{2.5}$	SO_2	Direct $PM_{2.5}$	SO_2	Direct $PM_{2.5}$	SO_2
2010	20,051	256,447	19,156	245,007	0	0
2015	23,241	297,389	20,876	267,118	428	5,318
2020	25,248	323,137	22,674	290,192	433	5,382
2025	27,265	348,994	24,482	313,367	427	5,308
2030	29,293	374,982	26,300	336,665	426	5,294

9.2 Development of Benefits Scaling Factors Based on Differences in Emission Impacts Between the Final Standards and Modeled Preliminary Control Options

Based on the projected time paths for emissions reductions, we focused our detailed emissions and air quality modeling on two future years, 2020 and 2030, which reflect partial and close to complete turnover of the fleet of nonroad diesel engines to rule compliant engines. The emissions changes modeled for these two years are similar to those in the final standards, differing in the treatment of smaller engines and fuel requirements.[D] Table 9-5 summarizes the reductions in emissions of NOx, SO_2, and $PM_{2.5}$ from baseline for the preliminary and final standards, the difference between the two, and the ratio of emissions reductions from the final standards to the preliminary control options. The ratios presented in the last column of Table 9-5 are the basis for the benefits scaling approach discussed below.

[D]As discussed in Chapter 2, emissions and air quality modeling decisions are made early in EPA's analytical process. Since the preliminary control scenario was developed, EPA has gathered more information regarding the technical feasibility of the standards and considered public comment. As a result, we have revised the control scenario as described in detail in previous chapters of this document. Section 3.6 describes the changes in the inputs and resulting emission inventories between the preliminary baseline and control scenarios used for the air quality modeling and the final baseline and control scenarios.

Table 9-5
Comparison of 48-state Emission Reductions[a, b]
in 2020 and 2030 Between Preliminary and Final Standards

Emissions Species	Reduction from Baseline		Difference in Reductions (Final minus Preliminary)	Ratio of Reductions (Final/ Preliminary)
	Preliminary	Final		
2020				
NOx	663,618	442,061	221,557	0.67
SO_2	414,692	323,378	91,314	0.78
$PM_{2.5}$	98,121	85,808	12,313	0.87
2030				
NOx	1,009,744	734,184	275,560	0.73
SO_2	483,401	375,354	108,047	0.78
$PM_{2.5}$	138,208	128,350	9,858	0.93

[a] Includes all affected nonroad sources: land-based, recreational marine, commercial marine, and locomotives.
[b] We note that the magnitude of NOx reductions determined in the final rule analysis is somewhat less than what was reported in the proposal's draft RIA, especially in the later years when the fleet has mostly turned over to Tier 4 designs. The greater part of this is due to the fact that we have deferred setting a long-term NOx standard for mobile machinery over 750 hp to a later action. When this future action is completed, we would expect roughly equivalent reductions between the proposal and the overall final program, though there are some other effects reflected in the differing NOx reductions as well, due to updated modeling assumptions and the adjusted NOx standards levels for engines over 750 hp. Preamble Section II.A.4 contains a detailed discussion of the NOx standards we are adopting for engines over 750 hp, and the basis for those standards.

9.3 Summary of Modeled Benefits and Apportionment Method

As a second step in the analysis, we calculated scaling factors relating emissions changes resulting from the final standards to emissions changes from a set of preliminary control options that were used to model air quality and benefits (see Appendix 9A for full details). Based on the emissions inventories developed at the time of the proposal for the preliminary control option, we conducted a benefits analysis to determine the air quality and associated human health and welfare benefits resulting from the reductions in emissions of NOx, SO_2, NMHC/VOC, and $PM_{2.5}$. Based on the availability of air quality and exposure models, this summary focuses on reporting the health and welfare benefits of reductions in ambient PM and ozone concentrations. However, health improvements may also come from reductions in exposure to CO and air toxics. The full analysis is available in Appendix 9A and the benefits Technical Support Document (TSD) (Abt Associates, 2003).

The reductions in emissions of NOx, SO_2, and $PM_{2.5}$ from nonroad engines in the United States are expected to result in wide-spread overall reductions in ambient concentrations of ozone and $PM_{2.5}$[E]. These improvements in air quality are expected to result in substantial health benefits, based on the body of epidemiological evidence linking PM and ozone with health effects such as premature mortality, chronic lung disease, hospital admissions, and acute respiratory symptoms. Based on modeled changes in ambient concentrations of $PM_{2.5}$ and ozone, we estimate changes in the incidence of each health effect using concentration-response (C-R) functions derived from the epidemiological literature with appropriate baseline populations and incidence rates. We then apply estimates of the dollar value of each health effect to obtain a monetary estimate of the total PM- and ozone-related health benefits of the rule. Welfare effects are estimated using economic models which link changes in physical damages (e.g., light extinction or agricultural yields) with economic values.

Since the publication of the RIA for the proposed rule, EPA has received new technical guidance and input regarding its methodology for conducting PM- and ozone-related benefits analysis from the Health Effects Subgroup (HES) of the Science Advisory Board (SAB) Council reviewing the 812 blueprint (SAB-HES, 2003) and the Office of Management and Budget (OMB) through ongoing discussions regarding methods used in conducting regulatory impact analyses (RIAs) (e.g., see OMB Circular A-4). The SAB HES recommendations include the following (SAB-HES, 2003):

- use of the updated ACS Pope et al. (2002) study rather than the ACS Krewski et al. study to estimate premature mortality for the primary analysis;

- dropping the alternative estimate used in earlier RIAs and instead including a primary estimate that incorporates consideration of uncertainly in key effects categories such as premature mortality directly into the estimates (e.g., use of the standard errors from the Pope et al. (2002) study in deriving confidence bounds for the adult mortality estimates);

- addition of infant mortality (children under the age of one) into the primary estimate, based on supporting evidence from the World Health Organization Global Burden of Disease study (World Health Organization, 2002) and other published studies that strengthen the evidence for a relationship between PM exposure and respiratory inflamation and infection in children leading to death;

- inclusion of asthma exacerbations for children in the primary estimate;

- expansion of the age groups evaluated for a range of morbidity effects beyond the narrow band of the studies to the broader (total) age group (e.g., expanding a study population for 7 to 11 year olds to cover the entire child age range of 6 to 18 years).

[E] Reductions in NOx are expected to result in some localized increases in ozone concentrations, especially in NOx-limited large urban areas, such as Los Angeles, New York, and Chicago. A fuller discussion of this phenomenon is provided in Chapter 2.3. While localized increases in ozone will result in some increases in health impacts from ozone exposure in these areas, on net, the reductions in NOx are expected to reduce national levels of health impacts associated with ozone.

- inclusion of new endpoints (school absences [ozone], nonfatal heart attacks in adults [PM], hospital admissions for children under two [ozone]), and suggestion of a new meta-analysis of hospital admissions (PM_{10}) rather than using a few $PM_{2.5}$ studies;[F] and

- updating of populations and baseline incidences.

Recommendations from the Office of Management and Budget (OMB) regarding EPA's methods have focused on the approach used to characterize uncertainty in the benefits estimates generated for RIAs, as well as the approach used to value premature mortality estimates. The EPA is currently in the process of developing a comprehensive, integrated strategy for characterizing the impact of uncertainty in key elements of the benefits modeling process (e.g., emissions modeling, air quality modeling, health effects incidence estimation, valuation) on the results that are generated. A subset of this effort involved an expert elicitation designed to characterize uncertainty in the estimation of PM-related mortality resulting from both short-term and longer-term exposure. In its 2002 report, the NAS provides a number of recommendations on how EPA might improve the characterization of uncertainty in its benefits analyses. One recommendation was that "EPA should begin to move the assessment of uncertainties from its ancillary analyses into its primary analyses by conducting probabalistic, multiple-source uncertainty analyses. This shift will require specification of probability distributions for major sources of uncertainty. These distributions should be based on available data and expert judgement." The NAS elaborated on this recommendation by suggesting a program of methodological development involving review and critique of existing protocols for selection and elicitation of experts by decision analysts, biostatisticians, and psychologists. They recommended the use of formally elicited expert judgements, but noted that a number of issues must be addressed, and that sensitivity analyses would be needed for distributions that are based on expert judgment. They also recommended that EPA clearly distinguish between data-derived components of an uncertainty assessment and those based on expert opinions. As a first step in addressing the NAS recommendations regarding expert elicitation, EPA, in collaboration with OMB, conducted a pilot expert elicitation to characterize uncertainties in the relationship between ambient $PM_{2.5}$ concentrations and premature mortality. While it is premature to include the results of the pilot in the primary analysis for this rulemaking, EPA and OMB believe this pilot moves toward the goal of incorporating additional uncertainty analyses in its future primary benefits analyses. The pilot expert elicitation is described in Appendix 9B and the full report is placed in the public docket.

We have also modified the analysis to reflect new information in the academic literature on the appropriate characterization of the value of reducing the risk of premature mortality (value of

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[F]Note that the SAB-HES comments were made in the context of a review of the methods for the Section 812 analysis of the costs and benefits of the Clean Air Act. This context is pertinent to our interpretation of the SAB-HES comments on the selection of effect estimates for hospital admissions associated with PM (SAB-HES, 2003). The Section 812 analysis is focused on a broad set of air quality changes, including both the coarse and fine fractions of PM_{10}. As such, impact functions that focus on the full impact of PM_{10} are appropriate. However, for the Nonroad Diesel Engines rule, which is expected to affect primarily the fine fraction ($PM_{2.5}$) of PM_{10}, impact functions that focus primarily on $PM_{2.5}$ are more appropriate.

statistical life (VSL)). In previous analyses, we used a distribution based on 26 VSL estimates from the economics literature. For this analysis, we are characterizing the VSL distribution in a more general fashion, based on two recent meta-analyses of the wage-risk-based VSL literature (Mrozek and Taylor, 2000 and Viscusi and Aldy, 2003). The new distribution is assumed to be normal, with a mean of $5.5 million and a 95 percent confidence interval between $1 and $10 million. The $1 million lower confidence limit represents the lower end of the interquartile range from the Mrozek and Taylor (2000) meta-analysis.[G] The $10 million upper confidence limit represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis.

The EPA has addressed many of the comments received from the SAB-HES and OMB in developing the analytical approach for the final rule. We use an approach consistent with the methods used in the benefits analysis of the recently proposed Interstate Air Quality rule (IAQR). We have also reflected advances in data and methods in air quality modeling, epidemiology, and economics in developing this analysis. Updates to the assumptions and methods used in estimating $PM_{2.5}$-related and ozone-related benefits since completion of the Proposed Nonroad Diesel Rule include the following:

<u>Health Endpoints</u>

- We incorporated updated impact functions to reflect updated time-series studies of hospital admissions to correct for errors in application of the generalized additive model (GAM) functions in S-plus. More information on this issue is available at http://www.healtheffects.org.
- The primary analysis used an all-cause mortality effect estimate based on the Pope et al. (2002) reanalysis of the ACS study data.
- Infant mortality was included in the primary analysis.
- Asthma exacerbations were incorporated into the primary analysis. Although the analysis of the proposed rule included asthma exacerbations as a separate endpoint outside of the base case analysis, for the final rule, we will include asthma exacerbations in children 6 to 18 years of age as part of the primary analysis.
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<u>Valuation</u>

- In generating the monetized benefits for premature mortality in the primary analysis, the VSL will be entered as a mean (best estimate) of $5.5 million. Unlike the analysis of the proposed rule, the final rule analysis will not include a value of

[G]An alternative rationale for the low end of the range could be found in some recent stated preference studies suggesting VSL of between $1 and $5 million (Alberini et al., forthcoming).

statistical life year (VSLY) estimate. This reflects the advice of the SAB-Council and concerns raised by commentors on the proposed rule.

The proposed Nonroad Diesel rule included an alternative estimate in addition to the primary estimate that was intended to evaluate the impact of several key assumptions on the estimated reductions in premature mortality and chronic bronchitis. However, reflecting comments from the SAB-HES, rather than including an alternative estimate in the analysis of the final rule, the EPA will investigate the impact of key assumptions on mortality and morbidity estimates through a series of sensitivity analyses. This advice is consistent with the NAS recommendations as well.

9.3.1 Overview of Analytical Approach

This section summarizes the three steps involved in our analysis of the modeled preliminary control options: 1) Calculation of the impact that a set of preliminary fuel and engine standards would have on the nationwide inventories for NOx, NMHC, SO_2, and direct PM emissions in 2020 and 2030; 2) Air quality modeling for 2020 and 2030 to determine changes in ambient concentrations of ozone and PM, reflecting baseline and post-control emissions inventories; and 3) A benefits analysis to determine the changes in human health and welfare, both in terms of physical effects and monetary value, that result from the projected changes in ambient concentrations of various pollutants for the modeled standards.

We follow a “damage-function” approach in calculating total benefits of the modeled changes in environmental quality. This approach estimates changes in individual health and welfare endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the individual values. Total benefits are calculated simply as the sum of the values for all non-overlapping health and welfare endpoints. This imposes no overall preference structure, and does not account for potential income or substitution effects, i.e. adding a new endpoint will not reduce the value of changes in other endpoints. The “damage-function” approach is the standard approach for most cost-benefit analyses of regulations affecting environmental quality, and it has been used in several recent published analyses (Banzhaf et al., 2002; Levy et al., 2001; Kunzli et al., 2000; Levy et al., 1999; Ostro and Chestnut, 1998). Time and resource constraints prevented us from performing extensive new research to measure either the health outcomes or their values for this analysis. Thus, similar to these studies, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary research from similar contexts to obtain the most accurate measure of benefits available for the environmental quality change under analysis.

There are significant categories of benefits that cannot be monetized (or in many cases even quantified), and thus they are not included in our accounting of health and welfare benefits. These unquantified effects include low birth weight, changes in pulmonary function, chronic respiratory diseases other than chronic bronchitis, morphological changes, altered host defense mechanisms, non-fatal cancers, and non-asthma respiratory emergency room visits. A complete discussion of PM -related health effects can be found in the PM Criteria Documents (U.S. EPA

1996a, U.S. EPA, 2004) and the EPA Diesel HAD (U.S. EPA 2002). A discussion of the state of the science as of the last NAAQS review of ozone-related effects can be found in the Ozone Criteria Document (U.S. EPA 1996b). Since many health effects overlap, such as minor restricted activity days and asthma symptoms, we made assumptions intended to reduce the chances of "double-counting" health benefits, which may result in an underestimate of the total health benefits of the pollution controls.

9.3.2 Air Quality Modeling

As described in Chapter 2 and the technical support documents (TSDs), we used a national-scale version of the REgional Modeling System for Aerosols and Deposition (REMSAD version 7) to estimate PM air quality in the contiguous United States. We used the Comprehensive Air Quality Model with Extensions (CAMx) to estimate ambient ozone concentrations,[H] using two domains representing the Eastern and Western U.S. These models are discussed in the air quality TSD for this rule.

9.3.2.1 PM Air Quality Modeling with REMSAD

REMSAD is appropriate for evaluating the impacts of emissions reductions from nonroad sources, because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions. The annual county level emission inventory data described in Chapter 3 was speciated, temporally allocated and gridded to the REMSAD modeling domain to simulate PM concentrations for the 1996 base year and the 2020 and 2030 base and control scenarios. Peer-reviewed for the EPA, REMSAD is a three-dimensional grid-based Eulerian air quality model designed to estimate annual particulate concentrations and deposition over large spatial scales (Seigneur et al., 1999). Each of the future scenarios was simulated using 1996 meteorological data to provide daily averages and annual mean PM concentrations required for input to the concentration-response functions of the benefits analysis. Details regarding the application of REMSAD Version 7 for this analysis are provided in the Air Quality Modeling TSD (U.S. EPA, 2003b). This version reflects updates in the following areas to improve performance and address comments from the 1999 peer-review:

1. Gas phase chemistry updates to "micro-CB4" mechanism including new treatment for the NO_3 and N_2O_5 species and the addition of several reactions to better account for the wide ranges in temperature, pressure, and concentrations that are encountered for regional and national applications.

2. PM chemistry updates to calculate particulate nitrate concentrations through use of the MARS-A equilibrium algorithm and internal calculation of secondary organic aerosols from both biogenic (terpene) and anthropogenic (estimated aromatic) VOC emissions.

[H]In the benefits analysis of the recent Heavy Duty Engine/Diesel Fuel rule, we used the Urban Airshed Model Variable-Grid (UAM-V) to estimate ozone concentrations in the Eastern U.S. CAMx has a number of improvements relative to UAM and has improved model performance in the Western U.S. Details on the performance of CAMx can be found in Chapter 2 as well as the Air Quality Modeling TSD (U.S. EPA, 2003b).

3. Aqueous phase chemistry updates to incorporate the oxidation of $_{SO2}$ by O_3 and O2 and to include the cloud and rain liquid water content from MM5 meteorological data directly in sulfate production and deposition calculations.

As discussed earlier in Chapter 2, the model tends to underestimate observed $PM_{2.5}$ concentrations nationwide, especially over the western U.S.[I]

9.3.2.2 Ozone Air Quality Modeling with CAMx

We use the emissions inputs described in Chapter 3 with a regional-scale version of CAMx to estimate ozone air quality in the Eastern and Western U.S. CAMx is an Eulerian three-dimensional photochemical grid air quality model designed to calculate the concentrations of both inert and chemically reactive pollutants by simulating the physical and chemical processes in the atmosphere that affect ozone formation. Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, the CAMx is useful for evaluating the impacts of the nonroad diesel engine rule on U.S. ozone concentrations. As discussed earlier in Chapter 2, although the model tends to underestimate observed ozone, especially over the western U.S., it exhibits less bias and error than any past regional ozone modeling application conducted by EPA (i.e., Ozone Transport Assessment Group (OTAG), On-highway Tier-2 Passenger Vehicles, and Heavy Duty Engine/Diesel Fuel 2007 program).

Our analysis applies the modeling system separately to the Eastern and Western U.S. for five emissions scenarios: a 1996 baseline projection, a 2020 baseline projection and a 2020 projection with nonroad controls, a 2030 baseline projection and a 2030 projection with nonroad controls. As discussed in detail in the technical support document, a 1996 base year assessment is necessary because the relative model predictions are used with ambient air quality observations from 1996 to determine the expected changes in 2020 and 2030 ozone concentrations due to the modeled emission changes (Abt Associates, 2003). These results are used solely in the benefits analysis.

[I] Comments from industry have stated that EPA's methodology form computing benefits over time is based on unsupportable assumptions related to air quality modeling. Specifically, they state that EPA assumes that there will be no interactions between precursors and directly emitted PM in the formation of secondary PM and that EPA excludes consideration of non-linearities in its air quality modeling. The commentor is partially incorrect in the statement that "EPA assumes no interactions between NOx, SO_2, and direct PM in the formation of $PM_{2.5}$." In order to estimate benefits in years other than 2020 and 2030, it was necessary to interpolate values from 2020 and 2030. We used sophisticated air quality modeling (using the REMSAD model) to predict changes in ambient $PM_{2.5}$ in 2020 and 2030. This air quality modeling for 2020 and 2030 does incorporate the nonlinear interactions between NOx, SO_2, and direct PM. However, in order to develop the intertemporal scaling factors, we had to make some simplifying assumptions. We assumed that the interactions between SO_2 and NOx were linear over time, rather than assuming that there was no interaction. In other words, we assumed that the rate of change in the sulfate to SO_2, nitrate to NOx, and primary PM to direct PM ratios was a linear function of time. The rate of change is driven by differences in the baseline emissions between 2020 and 2030 and by differences in the ratio of NOx to SO_2 reductions from the nonroad sector. We verified the interpolation approach by predicting 2020 benefits using scaling factors for sulfate, nitrate, and direct PM based on the modeled 2030 benefits. Scaled benefits were within 4 percent of the actual modeled benefits for 2020.

As discussed in more detail in Chapter 2.3, our ozone air quality modeling showed that the NOx emissions reductions from the preliminary modeled standards are projected to result in increases in ozone concentrations for certain hours during the year, especially in urban, NOx-limited areas. Most of these increases are expected to occur during hours where ozone levels are low (and often below the one-hour ozone standard). However, most of the country experiences decreases in ozone concentrations for most hours in the year.

9.3.3 Health Impact Functions

Health impact functions are derived from the epidemiology literature. A standard health impact function has four components: an effect estimate from a particular epidemiological study, a baseline incidence rate for the health effect (obtained from either the epidemiology study or a source of public health statistics like the Centers for Disease Control), the affected population, and the estimated change in the relevant PM or ozone summary measure.

A typical health impact function might look like:

$$\Delta y = y_0 \cdot (e^{\beta \cdot \Delta x} - 1) ,$$

where y_0 is the baseline incidence, equal to the baseline incidence rate times the potentially affected population, β is the effect estimate, and Δx is the estimated change in the summary $PM_{2.5}$ or ozone measure. There are other functional forms, but the basic elements remain the same.

Integral to the estimation of the impact functions are reasonable estimates of future population projections. The underlying data used to create county-level 2010 population projections is based on county level allocations of national population projections from the U.S. Census Bureau (Hollman, Mulder and Kallan, 2000). County-level allocations of populations by age, race, and sex are based on economic forecasting models developed by Woods and Poole, Inc (WP), which account for patterns of economic growth and migration.

The WP projections of county level population are based on historical population data from 1969-1999, and do not include the 2000 Census results. Given the availability of detailed 2000 Census data, we constructed adjusted county level population projections for each future year using a two stage process. First, we constructed ratios of the projected WP populations in a future year to the projected WP population in 2000 for each future year by age, sex, and race. Second, we multiplied the block level 2000 Census population data by the appropriate age, sex, and race specific WP ratio for the county containing the census block, for each future year. This results in a set of future population projections that is consistent with the most recent detailed census data.

Specific populations matching the study populations in each epidemiological study are constructed by accessing the appropriate age-specific projections from the overall population database. For some endpoints, such as asthma attacks, we further limit the population by applying prevalence rates to the overall population. We do not have sufficient information to quantitatively characterize uncertainty in the population estimates.

Fundamental to the estimation of health benefits was our utilization of the PM epidemiology literature. We rely upon effect estimates derived from published, peer reviewed epidemiological studies that relate health effects to ambient concentrations of PM. The specific studies from which effect estimates are drawn are listed in Table 9-5. While a broad range of serious health effects have been associated with exposure to elevated PM levels, we include only a subset of health effects in this benefit analysis due to limitations in available effect estimates and concerns about double-counting of overlapping effects (U.S. EPA, 1996). For the most part, we use the same set of effect estimates as we used in the analysis of the proposed Nonroad Diesel Engines rule. However, based on recent advice from the SAB, we use an updated effect estimate for premature mortality and include two additional health effects, infant mortality and asthma exacerbations. Because of their significance in the analysis, we provide a more detailed discussion of premature mortality and chronic illness endpoints below.

To generate health outcomes, projected changes in ambient PM concentrations were entered into BenMAP, a customized geographic information system based program. BenMAP aggregates populations to air quality model grids and calculates changes in air pollution metrics (e.g., daily averages) for input into health impact functions. BenMAP uses grid cell level population data and changes in pollutant concentrations to estimate changes in health outcomes for each grid cell. Details on the BenMAP program can be found in the BenMAP User's Manual (Abt Associates, 2003).

The baseline incidences for health outcomes used in our analyses are selected and adapted to match the specific populations studied. For example, we use age- and county-specific baseline total mortality rates in the estimation of PM-related premature mortality. County-level incidence rates are not available for other endpoints. We used national incidence rates whenever possible, because these data are most applicable to a national assessment of benefits. However, for some studies, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level. Sources of baseline incidence rates are reported in Table 9-6.

In this assessment we made analytical judgements affecting both the selection of effect estimates and the application of those estimates in formulating health impact functions. In general, we selected effect estimates that 1) most closely match the pollutants of interest, i.e. $PM_{2.5}$) cover the broadest potentially exposed population (i.e. all ages functions would be preferred to adults 27 to 35), 3) have appropriate model specification (e.g. control for confounding pollutants), 4) have been peer-reviewed, and 5) are biologically plausible. Other factors may also affect our selection of effect estimates for specific endpoints, such as premature mortality. Some of the more important of these relating to premature mortality and chronic illness are discussed below and are discussed in detail in Appendix 9A. Alternative assumptions about these judgements may lead to substantially different results and they are explored using appropriate sensitivity analyses provided in Appendix 9B.

While there is a consistent body of evidence supporting a relationship between a number of adverse health effects and ambient PM levels, there is often only a single study of a specific endpoint covering a specific age group. There may be multiple estimates examining subgroups (i.e. asthmatic children). However, for the purposes of assessing national population level benefits, we chose the most broadly applicable effect estimate to more completely capture health benefits in the general population. Estimates for subpopulations are provided in Appendix 9A.

There is no consensus on whether or not there is a threshold for the health effects of PM, and if so, what the possible threshold might be. Consistent with recent literature (Daniels et al., 2000; Pope et al., 2002; Rossi et al., 1999; Schwartz, 2000), we chose for the purposes of this analysis to assume that PM-related health effects occur down to natural background (i.e., there is no health effects threshold). We assume that all of the health impact functions are continuous and differentiable down to natural background levels. Our assumptions regarding thresholds are considered reasonable by the National Research Council in its recent review of methods for estimating the public health benefits of air pollution regulations. In their review, the National Research Council concluded that there is no evidence for any departure from linearity in the observed range of exposure to PM_{10} or $PM_{2.5}$, nor any indication of a threshold. (NRC, 2002). They cite the weight of evidence available from both short and long term exposure models and the similar effects found in cities with low and high ambient concentrations of PM. We explore this important assumption in a sensitivity analysis described in Appendix 9C.

Premature Mortality

As receommended by the NAS (2002) and the SAB-HES, and demonstrated in the Kunzli et al. (2000) health impact assessment, we focus on the prospective cohort long-term exposure studies in deriving the health impact function for our base estimate of premature mortality. Cohort analyses are better able to capture the full public health impact of exposure to air pollution over time (Kunzli, 2001; NRC, 2002). We selected an effect estimate from the extended analysis of the American Cancer Society (ACS) cohort (Pope et al., 2002) because it represents the most comprehensive cohort analysis with the longest period of followup. In addition, this study has been recommended for impact assessments by the SAB-HES (SAB-HES, 2003). This effect estimate quantifies the relationship between annual mean $PM_{2.5}$ levels and all-cause mortality in adults 30 and older. We selected the effect estimate estimated using the measure of PM representing average exposure over the follow-up period, calculated as the average of 1979-1984 and 1999-2000 $PM_{2.5}$ levels.

In previous analyses, infant mortality has not been evaluated as part of the primary analysis due to uncertainty in the strength of the association between exposure to PM and postneonatal mortality. Instead, benefits estimates related to reduced infant mortality have been included as part of the sensitivity analyses. However recently published studies have strengthened the case for an association between PM exposure and respiratory inflamation and infection leading to premature mortality in infants under five years of age. Specifically, the SAB's HES noted the release of the World Health Organization Global Burden of Disease Study focusing on ambient air which cites several recently-published time-series studies relating daily PM exposure to mortality in children. The HES also cites the study by Belanger et al., (2003) as corroborating findings linking PM exposure to increased respiratory inflamation and infections in children. With regard to the cohort study conducted by Woodruff et al. (1997), the HES notes several strengths of the study including the use of a larger cohort drawn from a large number of metropolitan areas and efforts to control for a variety of individual risk factors in children (e.g., maternal educational level, maternal ethnicity, parental marital status and maternal smoking status). We follow the HES recommendation to include infant mortality in the primary benefits estimate using the effect estimate from the Woodruff et al. (1997) study.

Chronic Illness

Although there are several studies examining the relationship between PM of different size fractions and incidence of chronic bronchitis, we use a study by Abbey et al. (1995) to obtain our estimate of avoided incidences of chronic bronchitis in adults aged 25 and older, because Abbey et al. (1995) is the only available estimate of the relationship between $PM_{2.5}$ and chronic bronchitis. Based on the Abbey et al. study, we estimate the number of new chronic bronchitis cases that will "reverse" over time and subtract these reversals from the estimate of avoided chronic bronchitis incidences. Reversals refer to those cases of chronic bronchitis that were reported at the start of the Abbey et al. survey, but were subsequently not reported at the end of the survey. Since we assume that chronic bronchitis is a permanent condition, we subtract these reversals. Given the relatively high value assigned to chronic bronchitis, this ensures that we do not overstate the economic value of this health effect.

Non-fatal heart attacks have been linked with short term exposures to $PM_{2.5}$ in the U.S. (Peters et al., 2001) and other countries (Poloniecki et al., 1997). We use a recent study by Peters et al. (2001) as the basis for the C-R function estimating the relationship between $PM_{2.5}$ and non-fatal heart attacks in adults. Peters et al. is the only available U.S. study to provide a specific estimate for heart attacks. Other studies, such as Samet et al. (2000) and Moolgavkar et al. (2000) show a consistent relationship between all cardiovascular hospital admissions, including for non-fatal heart attacks, and PM. Given the lasting impact of a heart attack on longer-term health costs and earnings, we choose to provide a separate estimate for non-fatal heart attacks based on the single available U.S. C-R function. The finding of a specific impact on heart attacks is consistent with hospital admission and other studies showing relationships between fine particles and cardiovascular effects both within and outside the U.S. These studies provide a weight of evidence for this type of effect. Several epidemiologic studies (Liao et al., 1999; Gold et al., 2000; Magari et al., 2001) have shown that heart rate variability (an indicator of how much the heart is able to speed up or slow down in response to momentary stresses) is negatively related to PM levels. Heart rate variability is a risk factor for heart attacks and other coronary heart diseases (Carthenon et al., 2002; Dekker et al., 2000; Liao et al., 1997, Tsuji et al. 1996). As such, significant impacts of PM on heart rate variability are consistent with an increased risk of heart attacks.

9.3.4 Economic Values for Health Outcomes

Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health affects by a fairly small amount for a large population. The appropriate economic measure is therefore willingness-to-pay (WTP) for changes in risk prior to the regulation (Freeman, 1993). For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as a primary estimate. These costs of illness (COI) estimates generally understate the true value of reductions in risk of a health effect, reflecting the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect (Harrington and Portney, 1987; Berger, 1987). Unit values for health endpoints are provided in Table 9-7. All values are in constant year 2000 dollars.

The length of the delay between reduction in chronic PM exposures and reduction in mortality rates is unknown and yet an important parameter in the benefits analysis. The size of such a time lag is important for the valuation of premature mortality incidences as economic theory suggests benefits occurring in the future should be discounted relative to benefits occurring today. Although there is no specific scientific evidence of the size of a PM effects lag, current scientific literature on adverse health effects associated with smoking and the difference in the effect size between chronic exposure studies and daily premature mortality studies suggest that all incidences of premature mortality reduction associated with a given incremental change in PM exposure would not occur in the same year as the exposure reduction. This literature implies that lags of a few years or longer are plausible. For our current analysis, based on previous advice from the SAB (EPA-SAB-COUNCIL-ADV-00-001, 1999), we have assumed a five-year distributed lag structure, with 25 percent of premature deaths occurring in the first year, another 25 percent in the second year, and 16.7 percent in each of the remaining three years. To account for the preferences of individuals for current risk reductions relative to future risk reductions, we discount the value of avoided premature mortalities occurring beyond the analytical year (2020 or 2030) using three and seven percent discount rates.

A more recent SAB-HES report confirmed the NAS (2002) conclusion that there is little justification for the 5-year time course used by EPA in its past assessments, and suggested that future assessments more fully and explicitly account for the uncertainty. The SAB-HES suggests that appropriate lag structures may be developed based on the distribution of cause specific deaths within the overall all-cause estimate. The SAB-HES specifically noted understanding mechanisms of damage and developing models for different cause of death categories may be the key to characterizing more appropriate cessation lag functions. They note that our current understanding of mechanisms suggests there are likely short-term (e.g., less than six months for some cardiovascular effects), medium term (e.g., 2-5 years for COPD), and longer term (e.g., 15 to 25 years for lung cancer). They noted that there is a current lack of direct data to specify a lag function and recommended that information on the lag function be considered in future expert elicitations and/or sensitivity analyses. While we are working to develop the underlying data to support a more appropriate segmented lag structure, for this analysis we maintain the 5-year lag structure used in the benefits analysis for the proposed rule. We have added an additional sensitivity analysis to Appendix 9C examining the impact of assuming a segmented lag of the type suggested by the SAB-HES. The overall impact of moving from the 5-year distributed lag to this version of a segmented lag is relatively modest, reducing benefits by approximately 8 percent when a three percent discount rate is used and 22 percent when a seven percent discount rate is used.

Our analysis accounts for expected growth in real income over time. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real incomes increase. The economics literature suggests that the severity of a health effect is a primary determinant of the strength of the relationship between changes in real income and WTP (Alberini, 1997; Miller, 2000; Evans and Viscusi, 1993). As such, we use different factors to adjust the WTP for minor health effects, severe and chronic health effects, and premature mortality. We also adjust WTP for improvements in recreational visibility. Adjustment factors used to account for projected growth in real income from 1990 to 2030 are 1.08 for minor health effects, 1.27 for severe and chronic health effects, 1.23 for premature mortality, and 1.61 for recreational visibility. Adjustment factors for 2020 are 1.07 for minor health effects, 1.23 for severe and chronic health effects, 1.20 for premature mortality, and 1.52 for recreational visibility. Note that due to a lack of reliable projections of income growth past 2024, we assume constant WTP from 2024 through 2030. This will result in an underestimate of benefits occurring between 2024 and 2030. Details of the calculation of the income adjustment factors are provided in Appendix 9A.

9.3.5 Welfare Effects

Our analysis of the preliminary control option examined two categories of welfare effects: visibility in a subset of national parks and changes in consumer and producer surplus associated with changes in agricultural yields. There are a number of other environmental effects which may affect human welfare, but due to a lack of appropriate physical effects or valuation methods, we are unable to quantify or monetize these effects for our analysis of the nonroad standards.

9.3.5.1 Visibility Benefits

Changes in the level of ambient particulate matter caused by the reduction in emissions from the preliminary control options will change the level of visibility in much of the U.S. as discussed in Chapter 2. Visibility directly affects people's enjoyment of a variety of daily activities. Individuals value visibility both in the places they live, work, and recreate, in the places they travel to for recreational purposes, and at sites of unique public value, such as the Grand Canyon.

For the purposes of this analysis, visibility improvements were valued only for a limited set of mandatory federal Class I areas. Benefits of improved visibility in the places people live, work, and recreate outside of these limited set of Class I areas were not included in our estimate of total benefits, although they are examined in a sensitivity analysis presented in Appendix 9B. All households in the U.S. are assumed to derive some benefit from improvements in Class I areas, given their national importance and high visitation rates from populations throughout the U.S. However, values are assumed to be higher if the Class I area is located close to their home.[J]

[J] For details of the visibility estimates discussed in this section, please refer to the benefits technical support document for this RIA (Abt Associates 2003).

We use the results of a 1988 contingent valuation survey on recreational visibility value (Chestnut and Rowe, 1990a; 1990b) to derive values for visibility improvements. The Chestnut and Rowe study measured the demand for visibility in Class I areas managed by the National Park Service (NPS) in three broad regions of the country: California, the Southwest, and the Southeast. The Chestnut and Rowe study did not measure values for visibility improvement in Class I areas outside the three regions. Their study covered 86 of the 156 Class I areas in the U.S. We can infer the value of visibility changes in the other Class I areas by transferring values of visibility changes at Class I areas in the study regions. However, these values are less certain and are thus presented only as an sensitivity estimate in Appendix 9B.

A general willingness to pay equation for improved visibility (measured in deciviews) was developed as a function of the baseline level of visibility, the magnitude of the visibility improvement, and household income. The behavioral parameters of this equation were taken from analysis of the Chestnut and Rowe data. These parameters were used to calibrate WTP for the visibility changes resulting from the Nonroad Diesel Engine rule. The method for developing calibrated WTP functions is based on the approach developed by Smith, et al. (2002), and is described in detail in the benefits technical support document for the proposed rule (Abt Associates, 2003). Major sources of uncertainty for the visibility benefit estimate include the quality of the underlying study and the benefits transfer process used. Judgments used to choose the functional form and key parameters of the estimating equation for willingness to pay for the affected population could have significant effects on the size of the estimates. Assumptions about how individuals respond to changes in visibility that are either very small, or outside the range covered in the Chestnut and Rowe study, could also affect the results. EPA is considering next steps in improving its visibility benefits estimates.

9.3.5.2 Agricultural Benefits

Laboratory and field experiments have shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The economic value associated with varying levels of yield loss for ozone-sensitive commodity crops is analyzed using the AGSIM© agricultural benefits model (Taylor, et al., 1993). AGSIM© is an econometric-simulation model that is based on a large set of statistically estimated demand and supply equations for agricultural commodities produced in the United States.

The model employs biological exposure-response information derived from controlled experiments conducted by the NCLAN (NCLAN, 1996). For the purpose of our analysis, we analyze changes for the six most economically significant crops for which C-R functions are available: corn, cotton, peanuts, sorghum, soybean, and winter wheat. For some crops there are multiple C-R functions, some more sensitive to ozone and some less. Our base estimate assumes that crops are evenly mixed between relatively sensitive and relatively insensitive varieties.

The measure of benefits calculated by the AGSIM© model is the net change in consumer and producer surplus from baseline ozone concentrations to the ozone concentrations resulting from emission reductions. Using the baseline and post-control equilibria, the model calculates the change in net consumer and producer surplus on a crop-by-crop basis. Dollar values are aggregated across crops for each standard. The total dollar value represents a measure of the change in social welfare associated with changes in ambient ozone.

9.3.5.3 Other Welfare Benefits

Ozone also has been shown conclusively to cause discernible injury to forest trees (US EPA, 1996; Fox and Mickler, 1996). In our previous analysis of the HD Engine/Diesel Fuel rule, we were able to quantify the effects of changes in ozone concentrations on tree growth for a limited set of species. Due to data limitations, we were not able to quantify such impacts for this analysis.

An additional welfare benefit expected to accrue as a result of reductions in ambient ozone concentrations in the U.S. is the economic value the public receives from reduced aesthetic injury to forests. There is sufficient scientific information available to reliably establish that ambient ozone levels cause visible injury to foliage and impair the growth of some sensitive plant species (US EPA, 1996c, p. 5-521). However, present analytic tools and resources preclude EPA from quantifying the benefits of improved forest aesthetics.

Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels and likely to impact large economic sectors. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative economic benefits analysis has been conducted.

The nonroad diesel standards, by reducing NO_X emissions, will also reduce nitrogen deposition on agricultural land and forests. There is some evidence that nitrogen deposition may have positive effects on agricultural output through passive fertilization. Holding all other factors constant, farmers' use of purchased fertilizers or manure may increase as deposited nitrogen is reduced. Estimates of the potential value of this possible increase in the use of purchased fertilizers are not available, but it is likely that the overall value is very small relative to other health and welfare effects.

The nonroad diesel standards are also expected to produce economic benefits in the form of reduced materials damage. There are two important categories of these benefits. Household soiling refers to the accumulation of dirt, dust, and ash on exposed surfaces. Criteria pollutants also have corrosive effects on commercial/industrial buildings and structures of cultural and historical significance. The effects on historic buildings and outdoor works of art are of particular concern because of the uniqueness and irreplaceability of many of these objects.

Previous EPA benefit analyses have been able to provide quantitative estimates of household soiling damage. Consistent with SAB advice, we determined that the existing data (based on consumer expenditures from the early 1970's) are too out of date to provide a reliable enough estimate of current household soiling damages (EPA-SAB-Council-ADV-003, 1998) to include in our base estimate. We calculate household soiling damages in a sensitivity estimate provided in Appendix 9C.

EPA is unable to estimate any benefits to commercial and industrial entities from reduced materials damage. Nor is EPA able to estimate the benefits of reductions in PM-related damage to historic buildings and outdoor works of art. Existing studies of damage to this latter category in Sweden (Grosclaude and Soguel, 1994) indicate that these benefits could be an order of magnitude larger than household soiling benefits.

Reductions in emissions of diesel hydrocarbons that result in unpleasant odors may also lead to improvements in public welfare. The magnitude of this benefit is very uncertain, however, Lareau and Rae (1989) found a significant and positive WTP to reduce the number of exposures to diesel odors. They found that households were on average willing to pay around $20 to $27 (2000$) per year for a reduction of one exposure to intense diesel odors per week (translating this to a national level, for the approximately 125 million households in 2020, the total WTP would be between $2.5 and $3.4 billion annually). Their results are not in a form that can be transferred to the context of this analysis, but the general magnitude of their results suggests this could be a significant welfare benefit of the rule.

The effects of air pollution on the health and stability of ecosystems are potentially very important, but are at present poorly understood and difficult to measure. The reductions in NO_X caused by the rule could produce significant benefits. Excess nutrient loads, especially of nitrogen, cause a variety of adverse consequences to the health of estuarine and coastal waters. These effects include toxic and/or noxious algal blooms such as brown and red tides, low (hypoxic) or zero (anoxic) concentrations of dissolved oxygen in bottom waters, the loss of submerged aquatic vegetation due to the light-filtering effect of thick algal mats, and fundamental shifts in phytoplankton community structure (Bricker et al., 1999).

Direct C-R functions relating changes in nitrogen loadings to changes in estuarine benefits are not available. The preferred WTP based measure of benefits depends on the availability of these C-R functions and on estimates of the value of environmental responses. Because neither appropriate C-R functions nor sufficient information to estimate the marginal value of changes in water quality exist at present, calculation of a WTP measure is not possible. Likewise, EPA is unable to quantify climate-change related impacts.

If better models of ecological effects can be defined, EPA believes that progress can be made in estimating WTP measures for ecosystem functions. For example, if nitrogen or sulfate loadings can be linked to measurable and definable changes in fish populations or definable indexes of biodiversity, then CV studies can be designed to elicit individuals' WTP for changes in these effects. This is an important area for further research and analysis, and will require close collaboration among air quality modelers, natural scientists, and economists.

9.3.6 Treatment of Uncertainty

In any complex analysis, there are likely to be many sources of uncertainty. This analysis is no exception. Many inputs are used to derive the final estimate of economic benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological estimates of C-R functions, estimates of values, population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). Some of the key uncertainties in the benefits analysis are presented in Table 9-8. For some parameters or inputs it may be possible to provide a statistical representation of the underlying uncertainty distribution. For other parameters or inputs, the necessary information is not available.

In addition to uncertainty, the annual benefit estimates presented in this analysis are also inherently variable due to the truly random processes that govern pollutant emissions and ambient air quality in a given year. Factors such as hours of equipment use and weather display constant variability regardless of our ability to accurately measure them. As such, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

We present a primary estimate of the total benefits, based on our interpretation of the best available scientific literature and methods and supported by the SAB-HES and the NAS (NRC, 2002). The benefits estimates generated for the final Nonroad Diesel Engine rule are subject to a number of assumptions and uncertainties, which are discussed throughout the document. For example, key assumptions underlying the primary estimate for the premature mortality which accounts for 90 percent of the total benefits we were able to quantify include the following:

(1) Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been definitively established, the weight of the available epidemiological evidence supports an assumption of causality.
(2) All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.
(3) The impact function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with fine particle standard and those that do not meet the standard.
(4) The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

In addition, we provide sensitivity analyses to illustrate the effects of uncertainty about key analytical assumptions. Our analysis of the preliminary control options did not include formal integrated probabilistic uncertainty analyses, although we have conducted several sensitivity tests based on changes to several key model parameters. The recent NAS report on estimating public health benefits of air pollution regulations recommended that EPA begin to move the assessment of uncertainties from its ancillary analyses into its primary analyses by conducting probabilistic, multiple-source uncertainty analyses. We are working to implement these recommendations.

In Appendix 9B, we present two types of probabilistic approaches designed to illustrate how some aspects of the uncertainty in the C-R function could be handled in a PM benefits analysis. The first approach generates a probabilistic estimate of statistical uncertainty based on standard errors reported in the underlying studies used in the benefit modeling framework. In the second illustrative approach, EPA, in collaboration with OMB, conducted a pilot expert elicitation to characterize uncertainties in the relationship between ambient $PM_{2.5}$ and premature mortality (IEc 2004). This pilot was designed to improve our understanding of the design and application of expert elicitation methods to economic benefits analysis. For instance, the pilot was designed to provide feedback on the efficacy of the protocol developed and the analytic challenges, as well as to provide insight regarding potential implications of the results on the degree of uncertainty surrounding the C-R function for $PM_{2.5}$ mortality. The scope of the pilot was limited in that we focused the elicitation on the C-R function of PM mass rather than on individual issues surrounding an estimate of the change in premature mortality due to PM exposure. In Appendix 9B we present sensitivity analyses for illustrative purposes.

9.3.7 Model Results

We summarize our preliminary control option modeling as background for calculating the scaling factors. The scaling factors are then used to estimate the PM-related benefits of the final rule. Insights into ozone impacts can also be discerned. As discussed in Table 9-5 above and Table 9A-4 below, full implementation of the modeled preliminary control options is projected in 2020 to reduce 48-state emissions of land-based nonroad NOx by 663,600 tons (58 percent of base case), SO_2 by 305,000 tons (98.9 percent), VOC by 23,200 tons (24 percent) and directly emitted $PM_{2.5}$ by 91,300 tons (71 percent). In 2030, the modeled preliminary control option is expected to reduce 48-state emissions of NOx by 1 million tons (82 percent), SO_2 by 359,800 tons (99.7 percent), VOC by 34,000 tons (35 percent) and direct PM by 138,000 tons (90 percent).

Based on these projected emission changes, REMSAD modeling results indicate the pollution controls generate greater absolute air quality improvements in more populated, urban areas. The rule will reduce average annual mean concentrations of $PM_{2.5}$ across the U.S. by roughly 2.5 percent (or 0.2 $\mu g/m^3$) and 3.4 percent (or 0.28 $\mu g/m^3$) in 2020 and 2030, respectively. The population-weighted average mean concentration declined by 3.3 percent (or 0.42 $\mu g/m^3$) in 2020 and 4.5 percent (or 0.59 $\mu g/m^3$) in 2030, which is much larger in absolute terms than the spatial average for both years. Table 9-9 presents information on the distribution of modeled reductions in ambient PM concentrations across populations in the U.S. By 2030, slightly over 50 percent of U.S. populations will live in areas with reductions of greater than 0.5 $\mu g/m^3$. This information indicates how widespread the improvements in PM air quality are expected to be.

Applying the health impact functions described in Table 9-5 to the estimated changes in $PM_{2.5}$ and ozone from the preliminary modeling yields estimates of the number of avoided incidences for each health outcome. These estimates are presented in Appendix A Table 9A-30 for the 2020 and 2030 model analysis years. To provide estimates of the monetized benefits of the reductions in PM-related health outcomes described in Table 9A-30, we multiply the point estimates of avoided incidences by unit values. Values for welfare effects are based on application of the economic models described above. The estimated total monetized health and welfare benefits for the preliminary modeled scenario are also presented in Appendix A in Table 9A-31.

The largest monetized health benefit is associated with reductions in the risk of premature mortality, which accounts for 90 percent of total monetized health benefits. The next largest benefit is for chronic illness reductions (chronic bronchitis and nonfatal heart attacks), although this value is more than an order of magnitude lower than for premature mortality. Minor restricted activity days, work loss days, and hospital admissions account for the majority of the remaining benefits. While the other categories account for less than $100 million each, they represent a large number of avoided incidences affecting many individuals.

Ozone benefits arising from this rule are in aggregate positive for the nation. However, due to ozone increases occurring during certain hours of the day in some urban areas, in 2020 the net effect is an increase in ozone-related minor restricted activity days (MRAD), which are related to changes in daily average ozone (which includes hours during which ozone levels are low, but are increased relative to the baseline based on the preliminary modeling). However, by 2030, there is a net decrease in ozone-related MRAD consistent with widespread reductions in ozone concentrations from the increased NOx emissions reductions. Note that in both years, the overall impact of changes in both PM and ozone is a large decrease in the number of MRAD. Overall, ozone benefits are low relative to PM benefits for similar endpoint categories because of the increases in ozone concentrations during some hours of some days in certain urban areas. For a more complete discussion of this issue, see Chapter 2.

Monetized and quantified welfare benefits are far outweighed by health benefits. However, we have not been able to quantify some important welfare categories, including the value of changes in ecosystems from reduced deposition of nitrogen and sulfur and climate impacts. The welfare benefits we are able to quantify are dominated by the value of improved visibility. Visibility benefits just in the limited set of parks included in the monetized total benefit estimate are over $1.6 billion in 2030. Agricultural benefits, while small relative to visibility benefits, are significant relative to ozone-related health benefits, representing the largest single benefit category for ozone.

Table 9-6
Endpoints and Studies Used to Calculate Total Monetized Health Benefits

Endpoint	Pollutant	Applied Population	Source of Effect Estimate(s)	Source of Baseline Incidence
Premature Mortality				
Adults – Long-term exposure	$PM_{2.5}$	>29 years	Pope, et al. (2002)	CDC Wonder (1996-1998)
Infants	$PM_{2.5}$	<1	Woodruff et al. (1997)	CDC Wonder (1996-1998)
Chronic Illness				
Chronic Bronchitis	$PM_{2.5}$	> 26 years	Abbey, et al. (1995)	1999 HIS (American Lung Association, 2002b, Table 4); Abbey et al. (1993, Table 3)
Non-fatal Heart Attacks	$PM_{2.5}$	Adults	Peters et al. (2001)	1999 NHDS public use data files; adjusted by 0.93 for prob. of surviving after 28 days (Rosamond et al., 1999)
Hospital Admissions				
Respiratory	O_3	> 64 years	Pooled estimate: Schwartz (1995) - ICD 460-519 (all resp) Schwartz (1994a, 1994b) - ICD 480-486 (pneumonia) Moolgavkar et al. (1997) - ICD 480-487 (pneumonia) Schwartz (1994b) - ICD 491-492, 494-496 (COPD) Moolgavkar et al. (1997) - ICD 490-496 (COPD)	1999 NHDS public use data files
	O_3	< 2 years	Burnett et al. (2001)	1999 NHDS public use data files
	$PM_{2.5}$	>64 years	Pooled estimate: Moolgavkar (2003) - ICD 490-496 (COPD) Ito (2003) - ICD 490-496 (COPD)	1999 NHDS public use data files
	$PM_{2.5}$	20-64 years	Moolgavkar (2000) - ICD 490-496 (COPD)	1999 NHDS public use data files
	$PM_{2.5}$	> 64 years	Ito (2003) - ICD 480-486 (pneumonia)	1999 NHDS public use data files
	$PM_{2.5}$	< 65 years	Sheppard, et al. (2003) - ICD 493 (asthma)	1999 NHDS public use data files
Cardiovascular	$PM_{2.5}$	> 64 years	Pooled estimate:	1999 NHDS public use

Table 9-6
Endpoints and Studies Used to Calculate Total Monetized Health Benefits

Endpoint	Pollutant	Applied Population	Source of Effect Estimate(s)	Source of Baseline Incidence
	$PM_{2.5}$	20-64 years	Moolgavkar (2000) - ICD 390-429 (all cardiovascular)	1999 NHDS public use data files
Asthma-Related ER Visits	O_3	All ages	Pooled estimate: Weisel et al. (1995), Cody et al. (1992), Stieb et al. (1996)	2000 NHAMCS public use data files[3]; 1999 NHDS public use data files
	$PM_{2.5}$	0-18 years	Norris et al. (1999)	2000 NHAMCS public use data files; 1999 NHDS public use data files
Other Health Endpoints				
Acute Bronchitis	$PM_{2.5}$	8-12 years	Dockery et al. (1996)	American Lung Association (2002a, Table 11)
Asthma Exacerbations	$PM_{2.5}$	6-18 years[A]	Pooled estimate: Ostro et al. (2001) Cough Ostro et al. (2001) Wheeze Ostro et al. (2001) Shortness of breath Vedal et al. (1998) Cough	Ostro et al. (2001) Vedal et al. (1998)
Upper Respiratory Symptoms	PM_{10}	Asthmatics, 9-11 years	Pope et al. (1991)	Pope et al. (1991, Table 2)
Lower Respiratory Symptoms	$PM_{2.5}$	7-14 years	Schwartz and Neas (2000)	Schwartz (1994, Table 2)
Work Loss Days	$PM_{2.5}$	18-65 years	Ostro (1987)	1996 HIS (Adams et al., 1999, Table 41); U.S. Bureau of the Census (2000)
School Absence Days	O_3	 9-10 years 6-11 years	Pooled estimate: Gilliland et al. (2001) Chen et al. (2000)	National Center for Education Statistics (1996)
Worker Productivity	O_3	Outdoor workers, 18-65	Crocker and Horst (1981) and U.S. EPA (1984)	NA
Minor Restricted Activity Days	$PM_{2.5}$, O_3	18-65 years	Ostro and Rothschild (1989)	Ostro and Rothschild (1989, p. 243)

[A] The original study populations were 8-13 for the Ostro et al. (2001) study and 6-13 for the Vedal et al. (1998) study. Based on advice from the SAB-HES and NRC, we have extended the applied population to 6-18, reflecting the common biological basis for the effect in children in the broader age group.

Table 9-7. Unit Values Used for Economic Valuation of Health Endpoints (2000$)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Premature Mortality (Value of a Statistical Life)	$5,500,000	$6,600,000	$6,800,000	Point estimate is the mean of a normal distribution with a 95 percent confidence interval between $1 and $10 million. Confidence interval is based on two meta-analyses of the wage-risk VSL literature. $1 million represents the lower end of the interquartile range from the Mrozek and Taylor (2000) meta-analysis. $10 million represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis. The VSL represents the value of a small change in mortality risk aggregated over the affected population.
Chronic Bronchitis (CB)	$340,000	$420,000	$430,000	Point estimate is the mean of a generated distribution of WTP to avoid a case of pollution-related CB. WTP to avoid a case of pollution-related CB is derived by adjusting WTP (as described in Viscusi et al., 1991) to avoid a severe case of CB for the difference in severity and taking into account the elasticity of WTP with respect to severity of CB.
Nonfatal Myocardial Infarction (heart attack)				Age specific cost-of-illness values reflecting lost earnings and direct medical costs over a 5 year period following a non-fatal MI. Lost earnings estimates based on Cropper and Krupnick (1990). Direct medical costs based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990).
3% discount rate				
Age 0-24	$66,902	$66,902	$66,902	
Age 25-44	$74,676	$74,676	$74,676	
Age 45-54	$78,834	$78,834	$78,834	Lost earnings:
Age 55-65	$140,649	$140,649	$140,649	Cropper and Krupnick (1990). Present discounted value of 5 yrs of lost
Age 66 and over	$66,902	$66,902	$66,902	earnings:
				age of onset: at 3% at 7%
7% discount rate				25-44 $8,774 $7,855
Age 0-24	$65,293	$65,293	$65,293	45-54 $12,932 $11,578
Age 25-44	$73,149	$73,149	$73,149	55-65 $74,746 $66,920
Age 45-54	$76,871	$76,871	$76,871	
Age 55-65	$132,214	$132,214	$132,214	Direct medical expenses: An average of:
Age 66 and over	$65,293	$65,293	$65,293	1. Wittels et al., 1990 ($102,658 – no discounting)
				2. Russell et al., 1998, 5-yr period. ($22,331 at 3% discount rate; $21,113 at 7% discount rate)

(continued)

Table 9-7. Unit Values Used for Economic Valuation of Health Endpoints (2000$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Hospital Admissions				
Chronic Obstructive Pulmonary Disease (COPD) (ICD codes 490-492, 494-496)	$12,378	$12,378	$12,378	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Pneumonia (ICD codes 480-487)	$14,693	$14,693	$14,693	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total pneumonia category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Asthma admissions	$6,634	$6,634	$6,634	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
All Cardiovascular (ICD codes 390-429)	$18,387	$18,387	$18,387	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Emergency room visits for asthma	$286	$286	$286	Simple average of two unit COI values: (1) $311.55, from Smith et al., 1997, and (2) $260.67, from Stanford et al., 1999.

(continued)

Table 9-7. Unit Values Used for Economic Valuation of Health Endpoints (2000$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Respiratory Ailments Not Requiring Hospitalization				
Upper Respiratory Symptoms (URS)	$25	$27	$27	Combinations of the 3 symptoms for which WTP estimates are available that closely match those listed by Pope, et al. result in 7 different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for URS is the average of the dollar values for the 7 different types of URS.
Lower Respiratory Symptoms (LRS)	$16	$17	$17	Combinations of the 4 symptoms for which WTP estimates are available that closely match those listed by Schwartz, et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS.
Asthma Exacerbations	$42	$45	$45	Asthma exacerbations are valued at $42 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma attack is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study.
Acute Bronchitis	$360	$380	$390	Assumes a 6 day episode, with daily value equal to the average of low and high values for related respiratory symptoms recommended in Neumann, et al. 1994.

(continued)

Table 9-7. Unit Values Used for Economic Valuation of Health Endpoints (2000$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Restricted Activity and Work/School Loss Days				
Work Loss Days (WLDs)	Variable	Variable	Variable	County-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5 – to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
School Absence Days	$75	$75	$75	Based on expected lost wages from parent staying home with child. Estimated daily lost wage (if a mother must stay at home with a sick child) is based on the median weekly wage among women age 25 and older in 2000 (U.S. Census Bureau, Statistical Abstract of the United States: 2001, Section 12: Labor Force, Employment, and Earnings, Table No. 621). This median wage is $551. Dividing by 5 gives an estimated median daily wage of $103. The expected loss in wages due to a day of school absence in which the mother would have to stay home with her child is estimated as the probability that the mother is in the workforce times the daily wage she would lose if she missed a day = 72.85% of $103, or $75.
Worker Productivity	$0.95 per worker per 10% change in ozone per day	$0.95 per worker per 10% change in ozone per day	$0.95 per worker per 10% change in ozone per day	Based on $68 – median daily earnings of workers in farming, forestry and fishing – from Table 621, Statistical Abstract of the United States ("Full-Time Wage and Salary Workers – Number and Earnings: 1985 to 2000") (Source of data in table: U.S. Bureau of Labor Statistics, Bulletin 2307 and Employment and Earnings, monthly).
Minor Restricted Activity Days (MRADs)	$51	$54	$55	Median WTP estimate to avoid one MRAD from Tolley, et al. (1986) .

Table 9-8
Primary Sources of Uncertainty in the Benefit Analysis

1. Uncertainties Associated With Health Impact Functions
– The value of the ozone or PM effect estimate in each health impact function. – Application of a single effect estimate to pollutant changes and populations in all locations. – Similarity of future year effect estimates to current effect estimates. – Correct functional form of each impact function. – Extrapolation of effect estimates beyond the range of ozone or PM concentrations observed in the study. – Application of effect estimates only to those subpopulations matching the original study population.
2. Uncertainties Associated With Ozone and PM Concentrations
– Responsiveness of the models to changes in precursor emissions resulting from the control policy. – Projections of future levels of precursor emissions, especially ammonia and crustal materials. – Model chemistry for the formation of ambient nitrate concentrations. – Lack of ozone monitors in rural areas requires extrapolation of observed ozone data from urban to rural areas. – Use of separate air quality models for ozone and PM does not allow for a fully integrated analysis of pollutants and their interactions. – Full ozone season air quality distributions are extrapolated from a limited number of simulation days. – Comparison of model predictions of particulate nitrate with observed rural monitored nitrate levels indicates that REMSAD overpredicts nitrate in some parts of the Eastern US and underpredicts nitrate in parts of the Western US.
3. Uncertainties Associated with PM Premature mortality Risk
– No scientific literature supporting a direct biological mechanism for observed epidemiological evidence. – Direct causal agents within the complex mixture of PM have not been identified. – The extent to which adverse health effects are associated with low level exposures that occur many times in the year versus peak exposures. – The extent to which effects reported in the long-term exposure studies are associated with historically higher levels of PM rather than the levels occurring during the period of study. – Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.
4. Uncertainties Associated With Possible Lagged Effects
– The portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels would occur in a single year is uncertain as well as the portion that might occur in subsequent years.
5. Uncertainties Associated With Baseline Incidence Rates
– Some baseline incidence rates are not location-specific (e.g., those taken from studies) and may therefore not accurately represent the actual location-specific rates. – Current baseline incidence rates may not approximate well baseline incidence rates in 2030. – Projected population and demographics may not represent well future-year population and demographics.
6. Uncertainties Associated With Economic Valuation
– Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them. – Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates due to differences in income or other factors. – Future markets for agricultural products are uncertain.
7. Uncertainties Associated With Aggregation of Monetized Benefits
– Health and welfare benefits estimates are limited to the available effect estimates. Thus, unquantified or unmonetized benefits are not included.

Table 9-9
Distribution of $PM_{2.5}$ Air Quality Improvements Over Population
Due to Nonroad Engine/Diesel Fuel Standards [a] in 2020 and 2030

Change in Annual Mean $PM_{2.5}$ Concentrations ($\mu g/m^3$)	*2020 Population*		*2030 Population*	
	Number (millions)	*Percent (%)*	*Number (millions)*	*Percent (%)*
$0 < \Delta PM_{2.5}$ Conc ≤ 0.25	65.11	19.75%	28.60	8.04%
$0.25 < \Delta PM_{2.5}$ Conc ≤ 0.5	184.52	55.97%	147.09	41.33%
$0.5 < \Delta PM_{2.5}$ Conc ≤ 0.75	56.66	17.19%	107.47	30.20%
$0.75 < \Delta PM_{2.5}$ Conc ≤ 1.0	14.60	4.43%	38.50	10.82%
$1.0 < \Delta PM_{2.5}$ Conc ≤ 1.25	5.29	1.60%	8.82	2.48%
$1.25 < \Delta PM_{2.5}$ Conc ≤ 1.5	3.51	1.06%	15.52	4.36%
$1.5 < \Delta PM_{2.5}$ Conc ≤ 1.75	0	0.00%	5.70	1.60%
$\Delta PM_{2.5}$ Conc > 1.75	0	0.00%	4.19	1.18%

[a] The change is defined as the control case value minus the base case value. The results reflect the modeling for the preliminary control option, not the final rule.

9.3.8 Apportionment of Benefits to NOx, SO_2, and Direct PM Emissions Reductions

As noted in the introduction to this chapter, the standards we are finalizing in this rule differ from those that we used in modeling air quality and economic benefits. As such, it is necessary for us to scale the modeled benefits to reflect the difference in emissions reductions between the final and preliminary modeled standards. In order to do so, however, we must first apportion total benefits to the NOx, SO_2, and direct PM reductions for the modeled preliminary control options. This apportionment is necessary due to the differential contribution of each emission species to the total change in ambient PM and total benefits. We do not attempt to develop scaling factors for ozone benefits because of the difficulty in separating the contribution of NOx and NMHC/VOC reductions to the change in ozone concentrations.

As discussed in detail in Chapter 2, PM is a complex mixture of particles of varying species, including nitrates, sulfates, and primary particles, including organic and elemental carbon. These particles are formed in complex chemical reactions from emissions of precursor pollutants, including NOx, $_{SO2}$, ammonia, hydrocarbons, and directly emitted particles. Different emissions species contribute to the formation of PM in different amounts, so that a ton of emissions of NOx contributes to total ambient PM mass differently than a ton of SO_2 or directly emitted PM. As such, it is inappropriate to scale benefits by simply scaling the sum of all precursor emissions. A more appropriate scaling method is to first apportion total PM benefits to the changes in underlying emission species and then scale the apportioned benefits.

PM formation relative to any particular reduction in an emission species is a highly nonlinear process, depending on meteorological conditions and baseline conditions, including the amount of available ammonia to form ammonium nitrate and ammonium sulfate. Given the limited air quality modeling conducted for this analysis, we make several simplifying assumptions about the contributions of emissions reductions for specific species to changes in particulate species. For this exercise, we assume that changes in sulfate particles are attributable to changes in SO_2 emissions, changes in nitrate particles are attributable to changes in NOx emissions, and changes in primary PM are attributable to changes in direct PM emissions. These assumptions essentially assume independence between SO_2, NOx, and direct PM in the formation of ambient PM. This is a reasonable assumption for direct PM, as it is generally not reactive in the atmosphere. However, SO_2 and NOx emissions interact with other compounds in the atmosphere to form $PM_{2.5}$. For example, ammonia reacts with SO_2 first to form ammonium sulfate. If there is remaining ammonia, it reacts with NOx to form ammonium nitrate. When $_{SO2}$ alone is reduced, ammonia is freed to react with any NOx that has not been used in forming ammonium nitrate. If NOx is also reduced, then there will be less available NOx to form ammonium nitrate from the newly available ammonia. Thus, reducing SO_2 can potentially lead to decreased ammonium sulfate and increased nitrate, so that overall ambient PM benefits are less than the reduction in sulfate particles. If NOx alone is reduced, there will be a direct reduction in ammonium nitrate, although the amount of reduction depends on whether an area is ammonia limited. If there is not enough ammonia in an area to use up all of the available NOx, then NOx reductions will only have an impact if they reduce emissions to the point where ammonium nitrate formation will be affected. NOx reductions will not result in any offsetting increases in ambient PM under most conditions. The implications of this for apportioning benefits between NOx, SO_2, and direct PM is that some of the sulfate-related benefits will be offset by reductions in nitrate benefits, so benefits from SO_2 reductions will be overstated, while NOx benefits will be understated. It is not immediately apparent the size of this bias.

The measure of change in ambient particulate mass that is most related to health benefits is the population-weighted change in $PM_{2.5}$ $\mu g/m^3$, because health benefits are driven both by the size of the change in $PM_{2.5}$ and the populations exposed to that change. We calculate the proportional share of total change in mass accounted for by nitrate, sulfate, and primary particles. Results of these calculations for the 2020 and 2030 REMSAD modeling analysis are presented in Table 9-10. The sulfate percentage of total change is used to represent the $_{SO2}$ contribution to health benefits, the nitrate percentage is used to represent the NOx contribution to health benefits, and the primary PM percentage is used to represent the direct PM contribution to health benefits. These percentages will be applied to the PM-related health benefits estimates in Appendix A in Tables 9A-30 and 9A-31 and combined with the emission scaling factors developed in section 9.2 to estimate benefits for the final set of standards.

Table 9-10. Apportionment of Modeled Preliminary Control Option Population-weighted Change in Ambient $PM_{2.5}$ to Nitrate, Sulfate, and Primary Particles

	2020		2030	
	Population-weighted Change (µg/m3)	Percent of Total Change	Population-weighted Change (µg/m3)	Percent of Total Change
Total $PM_{2.5}$	0.316	--	0.438	--
Sulfate	0.071	22.5%	0.090	20.5%
Nitrate	0.041	13.1%	0.073	16.8%
Primary PM	0.203	64.4%	0.274	62.7%

Visibility benefits are highly specific to the parks at which visibility improvement occur, rather than where populations live. As such, it is necessary to scale benefits at each individual park and then aggregate to total scaled visibility benefits. We apportion benefits at each park using the contribution of changes in sulfates, nitrates, and primary particles to changes in light extinction. The change in light extinction at each park is determined by the following equation (Sisler, 1996):

$$\Delta\beta_{EXT} = [3F(rh)*1.375*\Delta TSO4] + [3F(rh)*1.29*\Delta PNO3] + 10*\Delta PEC + 4*\Delta TOA + \Delta PMFINE + 0.6*\Delta PMCOARSE$$

where rh is relative humidity, ΔTSO4 is the change in particulate sulfate, ΔPNO3 is the change in particulate nitrate, ΔPEC is the change in primary elemental carbon, ΔTOA is the change in total organic aerosols, ΔPMFINE is the change in primary fine particles, and ΔPMCOARSE is the change in primary coarse particles.

The proportion of the total change in light extinction associated with changes in sulfate particles is $[3F(rh)*1.375*\Delta TSO4]/\Delta\beta_{EXT}$. The proportion of the total change in light extinction associated with changes in nitrate particles is $[3F(rh)*1.29*\Delta PNO3]/\Delta\beta_{EXT}$. Finally, the proportion of the total change in light extinction associated with the change in directly emitted particles is $[10*\Delta PEC + 4*\Delta TOA + \Delta PMFINE + 0.6*\Delta PMCOARSE]/\Delta\beta_{EXT}$.

We calculate these proportions for each park to apportion park specific benefits between $_{SO2}$, NOx, and PM. The apportioned benefits are then scaled using the emission ratios in Table 9-5. Park specific apportionment of benefits is detailed in Appendix 9D.

9.4 Estimated Benefits of Final Nonroad Diesel Engine Standards in 2020 and 2030

To estimate the benefits of the NOx, SO_2, and direct PM emission reductions from the nonroad diesel engine standards in 2020 and 2030, we apply the emissions scaling factors derived in section 9.2 and the apportionment factors described in section 9.3 to the benefits estimates for 2020 and 2030 listed in Tables 9A-30 and 9A-31. Note that we apply scaling and apportionment factors only to PM and visibility related endpoints. Ozone related health and welfare benefits are not estimated for the emissions reductions associated with the final standards for reasons noted in the introduction to this chapter.

The scaled avoided incidence estimate for any particular health endpoint is calculated using the following equation:

$$Scaled\ Incidence = \ Modeled\ Incidence * \sum_i R_i A_i\ ,$$

where Ri is the emissions ratio for emission species i from Table 9-4, and A_i is the health benefits apportionment factor for emission species i, from Table 9-10. Essentially, benefits are scaled using a weighted average of the species specific emissions ratios. For example, the calculation of the avoided incidence of premature mortality for the base estimate in 2020 is:

Scaled Premature Mortality Incidence = 7,821 * (0.759*0.131 + 0.800*0.225 + 0.869*0.644) = 6,562 (rounded to 6,600)

The monetized value for each endpoint is then obtained simply by multiplying the scaled incidence estimate by the appropriate unit value in Table 9-6. The estimated changes in incidence of health effects in 2020 and 2030 for the final rule based on application of the weighted scaling factors are presented in Table 9-11. The estimated monetized benefits for both PM health and visibility benefits are presented in Table 9-12. The visibility benefits are based on application of the weighted scaling factors for visibility at each Class I area in the Chestnut and Rowe study regions, aggregated to a national total for each year.

Table 9-11.
Reductions in Incidence of PM-related Adverse Health Effects Associated with the Final Full Program of Nonroad Diesel Engine and Fuel Standards

Endpoint	Avoided Incidence[A] (cases/year)	
	2020	2030
Premature mortality[B]: Long-term exposure (adults, 30 and over)	6,400	12,000
Infant mortality (infants under one year)	15	22
Chronic bronchitis (adults, 26 and over)	3,500	5,600
Non-fatal myocardial infarctions (adults, 18 and older)	8,700	15,000
Hospital admissions – Respiratory (adults, 20 and older)[C]	2,800	5,100
Hospital admissions – Cardiovascular (adults, 20 and older)[D]	2,300	3,800
Emergency Room Visits for Asthma (18 and younger)	3,800	6,000
Acute bronchitis (children, 8-12)	8,400	13,000
Asthma exacerbations (asthmatic children, 6-18)	120,000	200,000
Lower respiratory symptoms (children, 7-14)	99,000	160,000
Upper respiratory symptoms (asthmatic children, 9-11)	76,000	120,000
Work loss days (adults, 18-65)	670,000	1,000,000
Minor restricted activity days (adults, age 18-65)	3,900,000	5,900,000

[A] Incidences are rounded to two significant digits.
[B] Premature mortality associated with ozone is not separately included in this analysis
[C] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[D] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 9-12. Results of PM Human Health and Welfare Benefits Valuation for the Final Full Program of Nonroad Diesel Engine and Fuel Standards

Endpoint	Monetary Benefits[A,B] (millions 2000$, Adjusted for Income Growth)	
	2020	2030
Premature mortality[C]: (adults, 30 and over)		
3% discount rate	$40,000	$77,000
7% discount rate	$38,000	$72,000
Infant mortality (infants under one year)	$960	$150
Chronic bronchitis (adults, 26 and over)	$1,500	$2,400
Non-fatal myocardial infarctions[D]		
3% discount rate	$740	$1,200
7% discount rate	$720	$1,200
Hospital Admissions from Respiratory Causes[E]	$49	$92
Hospital Admissions from Cardiovascular Causes[F]	$50	$83
Emergency Room Visits for Asthma	$1.0	$1.7
Acute bronchitis (children, 8-12)	$3.2	$5.1
Asthma exacerbations (asthmatic children, 6-18)	$5.7	$9.2
Lower respiratory symptoms (children, 7-14)	$1.7	$2.7
Upper respiratory symptoms (asthmatic children, 9-11)	$2.0	$3.2
Work loss days (adults, 18-65)	$91	$130
Minor restricted activity days (adults, age 18-65)	$210	$320
Recreational visibility (86 Class I Areas)	$1,000	$1,700
Monetized Total[G]		
3% discount rate	$44,000+B	$83,000+B
7% discount rate	$42,000+B	$78,000+B

[A] Monetary benefits are rounded to two significant digits.
[B] Monetary benefits are adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2020 or 2030).
[C] Valuation of base estimate assumes discounting over the distributed lag structure described earlier. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).
[D] Estimates assume costs of illness and lost earnings in later life years are discounted using either 3 or 7 percent
[E] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[F] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[G] B represents the monetary value of the unmonetized health and welfare benefits. A detailed listing of unquantified PM, ozone, CO, and NMHC related health effects is provided in Table 9-1. These estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii.

We also evaluated the benefits of the NOx, SO_2, and direct PM emission reductions from the nonroad diesel engine standards in 2020 and 2030 of the fuel-only portions of the program. Accordingly, we applied the benefits transfer methods to calculate similar results for the fuel only portion of the program and the 500 ppm NRLM program. Because there would be no NOx or NMHC reductions for the fuel-only components of the rule, the benefits transfer technique may have more uncertainty in this application compared to the full program. As discussed above, we apply scaling and apportionment factors only to PM health and visibility related endpoints. Toxics and ozone-related health and welfare benefits are not estimated for the emissions reductions associated with the final standards for reasons noted in the introduction to this chapter.

The estimated changes in incidence of health effects in 2020 and 2030 for the fuel-only components of the final rule based on application of the weighted scaling factors are presented in Table 9-13. The estimated monetized benefits for both PM health and visibility benefits are presented in Table 9-14. As described above, the visibility benefits are based on application of the weighted scaling factors for visibility at each Class I area in the Chestnut and Rowe study regions, aggregated to a national total for each year.

Table 9-13.
Reductions in Incidence of PM-related Adverse Health Effects Associated with the Final Fuel-Related Components of Nonroad Diesel Standards

Endpoint	Avoided Incidence[A] (cases/year)			
	Fuel Only Program		500 ppm NRLM Fuel	
	2020	2030	2020	2030
Premature mortality[B]: Long-term exposure (adults, 30 and over)	2,700	4,000	2,400	3,600
Infant mortality (infants under one year)	<10	<10	<10	<10
Chronic bronchitis (adults, 26 and over)	1,500	1,900	1,300	1,700
Non-fatal myocardial infarctions (adults, 18 and older)	3,600	5,200	3,200	4,700
Hospital admissions – Respiratory (adults, 20 and older)[C]	1,200	1,700	1,000	1,600
Hospital admissions – Cardiovascular (adults, 20 and older)[D]	900	1,300	900	1,100
Emergency Room Visits for Asthma (18 and younger)	1,600	2,000	1,400	1,800
Acute bronchitis (children, 8-12)	3,500	4,600	3,100	4,100
Asthma exacerbations (asthmatic children, 6-18)	51,000	68,000	46,000	61,000
Lower respiratory symptoms (children, 7-14)	41,000	54,000	37,000	49,000
Upper respiratory symptoms (asthmatic children, 9-11)	31,000	41,000	28,000	37,000
Work loss days (adults, 18-65)	280,000	340,000	250,000	300,000
Minor restricted activity days (adults, age 18-65)	1,600,000	2,000,000	1,500,000	1,800,000

[A] Incidences are rounded to two significant digits or nearest ten. The estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii.
[B] Premature mortality associated with ozone is not separately included in this analysis
[C] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[D] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 9-14. Results of PM Human Health and Welfare Benefits Valuation for the Final Fuel-Related Components of the Nonroad Diesel Standards

Endpoint	Monetary Benefits[A,B] (millions 2000$, Adjusted for Income Growth)			
	Fuel Only Program		500 ppm NRLM Fuel	
	2020	2030	2020	2030
Premature mortality[C]: (adults, 30 and over)				
3% discount rate	$17,000	$26,000	$15,000	$23,000
7% discount rate	$16,000	$24,000	$14,000	$22,000
Infant mortality (infants under one year)	$40	$52	$36	$47
Chronic bronchitis (adults, 26 and over)	$610	$820	$550	$740
Non-fatal myocardial infarctions[D]				
3% discount rate	$310	$420	$280	$380
7% discount rate	$300	$410	$270	$370
Hospital Admissions from Respiratory Causes[E]	$20	$31	$18	$28
Hospital Admissions from Cardiovascular Causes[F]	$21	$28	$19	$25
Emergency Room Visits for Asthma	$0.4	$0.6	$0.4	$0.5
Acute bronchitis (children, 8-12)	$1.3	$1.7	$1.2	$1.6
Asthma exacerbations (asthmatic children, 6-18)	$2.3	$3.1	$2.1	$2.8
Lower respiratory symptoms (children, 7-14)	$0.7	$0.9	$0.6	$0.8
Upper respiratory symptoms (asthmatic children, 9-11)	$0.8	$1.1	$0.7	$1.0
Work loss days (adults, 18-65)	$38	$43	$34	$39
Minor restricted activity days (adults, age 18-65)	$90	$110	$80	$100
Recreational visibility (86 Class I Areas)	$400	$550	$360	$500
Monetized Total[G]				
3% discount rate	$18,000+B	$28,000+B	$16,000+B	$25,000+B
7% discount rate	$17,000+B	$26,000+B	$15,000+B	$24,000+B

[A] Monetary benefits are rounded to two significant digits
[B] Monetary benefits are adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2020 or 2030).
[C] Valuation of base estimate assumes discounting over the distributed lag structure described earlier. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).
[D] Estimates assume costs of illness and lost earnings in later life years are discounted using either 3 or 7 percent
[E] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[F] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[G] B represents the monetary value of the unmonetized health and welfare benefits. A detailed listing of unquantified PM, ozone, CO, and NMHC related health effects is provided in Table 9-1. The estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii.

9.5 Development of Intertemporal Scaling Factors and Calculation of Benefits Over Time

To estimate the health and visibility benefits of the NOx, SO_2, and direct PM emission reductions from the final standards occurring in years other than 2020 and 2030, it is necessary to develop factors to scale the modeled benefits in 2020 and 2030. In addition to scaling based on the relative reductions in NOx, SO_2, and direct PM, intertemporal scaling requires additional adjustments to reflect population growth, changes in the age composition of the population, and per capita income levels.

Two separate sets of scaling factors are required, one for PM related health benefits, and one for visibility benefits. For the first of these, PM health benefits, we need scaling factors based on ambient $PM_{2.5}$. Because of the nonproportional relationship between precursor emissions and ambient concentrations of $PM_{2.5}$, it is necessary to first develop estimates of the marginal contribution of reductions in each emission species to reductions in $PM_{2.5}$ in each year. Because we have only two points (2020 and 2030), we assume a very simple linear function for each species over time (assuming that the marginal contribution of each emission species to $PM_{2.5}$ is independent of the other emission species) again assuming that sulfate changes are primarily associated with SO_2 emission reductions, nitrate changes are primarily associated with NOx emission reductions, and primary PM changes are associated with direct PM emission reductions.

Using the linear relationship, we estimate the marginal contribution of SO_2 to sulfate, NOx to nitrate, and direct PM to primary PM in each year. These marginal contribution estimates are presented in Table 9-15. Note that these projections do not take into account differences in overall baseline proportions of NOx, SO_2, and PM. They assume that the change in the relative effectiveness of each emission species in reducing ambient PM that is observed between 2020 and 2030 can be extrapolated to other years. Because baseline emissions of NOx, SO_2, and PM, as well as ammonia and VOCs are changing between years, the relative effectiveness of NOx and $_{SO2}$ emission reductions may change in a non-linear fashion. It is not clear what overall biases these nonlinearities will introduce into the scaling exercise. However, without these assumptions, it is not possible to develop year by year benefits estimates.

Multiplying the year-specific marginal contribution estimates by the appropriate emissions reductions in each year yields estimates of the population-weighted changes in $PM_{2.5}$ constituent species, which are summed to obtain year specific population-weighted changes in total $PM_{2.5}$. Total benefits in each specific year are then developed by scaling total benefits in a base year using the ratio of the change in $PM_{2.5}$ in the target year to the base year, with additional scaling factors to account for growth in total population, age composition of the population, and growth in per capita income.

**Table 9-15.
Projected Marginal Contribution of Reductions
in Emission Species to Reductions in Ambient $PM_{2.5}$**

	Change in $PM_{2.5}$ species (population-weighted $\mu g/m^3$ per million tons reduced)		
Year	Sulfate/SO_2	Nitrate/NOx	Primary PM/direct PM
2007	0.153	0.049	2.130
2008	0.154	0.050	2.123
2009	0.156	0.051	2.117
2010	0.157	0.052	2.111
2011	0.159	0.053	2.105
2012	0.160	0.054	2.098
2013	0.161	0.055	2.092
2014	0.163	0.056	2.086
2015	0.164	0.057	2.080
2016	0.166	0.058	2.073
2017	0.167	0.059	2.067
2018	0.169	0.060	2.061
2019	0.170	0.061	2.054
2020	0.171	0.062	2.048
2021	0.173	0.063	2.042
2022	0.174	0.064	2.036
2023	0.176	0.065	2.029
2024	0.177	0.066	2.023
2025	0.179	0.067	2.017
2026	0.180	0.069	2.011
2027	0.181	0.070	2.004
2028	0.183	0.071	1.998
2029	0.184	0.072	1.992
2030	0.186	0.073	1.985

Growth in population and changes in age composition are accounted for by apportioning total benefits into benefits accruing to three different age groups, 0 to 18, 19 to 64, and 65 and older. Benefits for each age group are then adjusted by the ratio of the age group population in the target year to the age group population in the base year. Age composition adjusted estimates are then reaggregated to obtain total population and age composition adjusted benefits for each year. Growth in per capita income is accounted for by multiplying the target year estimate by the ratio of the income adjustment factors in the target year to those in the base year.

For example, for the target year of 2015, there are 193,431 tons of NOx reductions, 297,513 tons of SO_2 reductions, and 53,072 tons of direct $PM_{2.5}$ reductions. These are associated with a populated weighted change in total $PM_{2.5}$ of 0.17, calculated from Table 9-15. The ratio of this change to the change in the 2030 base year is 0.392. The age group apportionment factors (based on using a 3% discount rate for 2030) are 0.2% for 0 to 18, 19.2% for 19 to 64, and 80.6% for 65 and older. The age group population growth ratios for 2015 relative to 2030 are 0.891 for 0 to 18, 0.986 for 19 to 64, and 0.639 for 65 and older. The income growth adjustment ratios for 2015 are 0.936 for premature mortality endpoints and 0.928 for morbidity endpoints. Premature mortality accounts for 93 percent of total health benefits and morbidity accounts for 7 percent of health benefits. Combining these elements with the total estimate of PM health benefits in 2030 of $94.2 billion , total PM health benefits in 2015 for the final standards are calculated as:

Total PM health benefits (2015) =

[$94.2 billion * 0.392*(0.002*0.891+0.192*0.986+0.806*0.639)*(0.93*0.936+0.07*0.928)]

= $24.2 billion

In order to develop the time stream of visibility benefits, we need to develop scaling factors based on the contribution of each emission species to light extinction. Similar to ambient $PM_{2.5}$, because we have only two estimates of the change in light extinction (2020 and 2030), we assume a very simple linear function for each species over time (assuming that the marginal contribution of each emission species to light extinction is independent of the other emission species) assuming that changes in the sulfate component of light extinction are associated with $_{SO2}$ emission reductions, changes in the nitrate component of light extinction are primarily associated with NOx emission reductions, and changes in the primary PM components of light extinction are associated with direct PM emission reductions. Linear relationships (slope and intercept) are calculated for each Class I area.

Using the linear relationships, we estimate the marginal contribution of SO_2, NOx, and direct PM to the change in light extinction at each Class I area in each year. Again, note that these estimates assume that the change in the relative effectiveness of each emission species in reducing light extinction that is observed between 2020 and 2030 can be extrapolated to other years.

Multiplying the year specific marginal contribution estimates by the appropriate emissions reductions in each year yields estimates of the changes in light extinction components, which are summed to obtain year specific changes in total light extinction. Benefits for each park in each specific year are then developed by scaling total benefits in a base year using the ratio of the change in light extinction in the target year to the base year, with additional scaling factors to account for growth in total population, and growth in per capita income. Total national visibility benefits for each year are obtained by summing the scaled benefits across Class I areas.

Table 9-16 provides undiscounted estimates of the time stream of benefits for the final standards using 3 and 7 percent concurrent discount rates.[K] Figure 9-1 shows the undiscounted time stream of benefits using a 3 percent concurrent discount rate. Because of the assumptions we made about the linearity of benefits for each emission species, overall benefits are also linear, reflecting the relatively linear emissions reductions over time for each emission type. The exception is during the early years of the program, where there is little NOx emission reduction, so that benefits are dominated by SO_2 and direct $PM_{2.5}$ reductions.

Using a 3 percent intertemporal discount rate, the present value in 2004 of the benefits of the final standards is approximately $805 billion for the time period 2007 to 2036, using a matching 3 percent concurrent discount rate. Using a 7 percent intertemporal discount rate, the present value in 2004 of the benefits of the final standards for the base estimate is approximately $352 billion using a matching 7 percent concurrent discount rate.

Annualized benefits using 3 percent intertemporal and concurrent discount rates are approximately $39 billion. Annualized benefits using 7 percent intertemporal and concurrent discount rates are approximately $28 billion.

[K]We refer to discounting that occurs during the calculation of benefits for individual years as concurrent discounting. This is distinct from discounting that occurs over the time stream of benefits, which is referred to as intertemporal discounting.

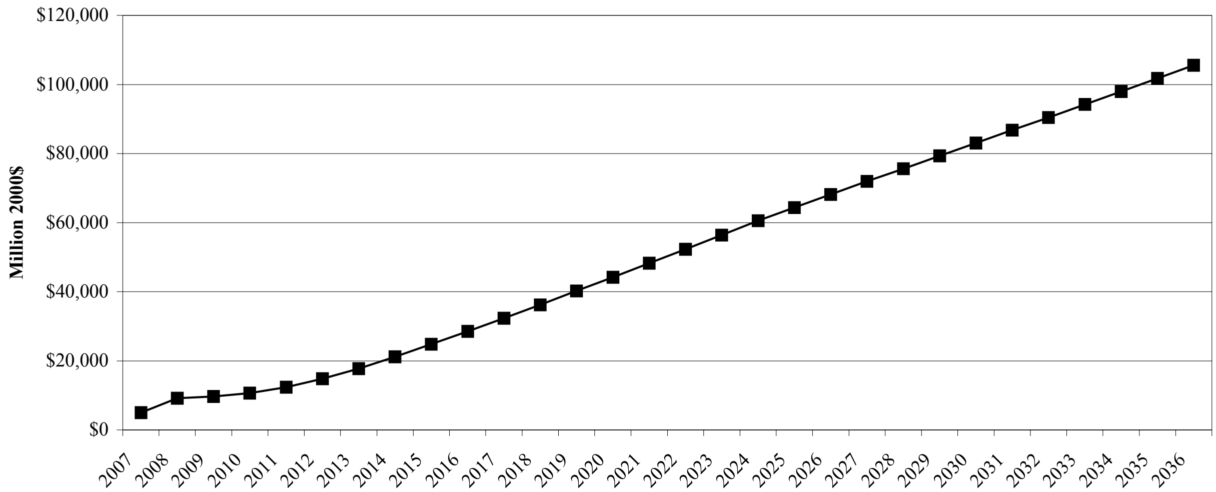
Table 9-16. Time Stream of Benefits for Final Nonroad Diesel Engine Standards[A,B]

Year	Monetized PM-Health and Visbility Benefits (Million 2000$)	
	3% Concurrent Discount Rate	7% Concurrent Discount Rate
2007	$5,000	$4,700
2008	$9,100	$8,600
2009	$9,700	$9,100
2010	$11,000	$10,000
2011	$12,000	$12,000
2012	$15,000	$14,000
2013	$18,000	$17,000
2014	$21,000	$20,000
2015	$25,000	$23,000
2016	$28,000	$27,000
2017	$32,000	$31,000
2018	$36,000	$34,000
2019	$40,000	$38,000
2020	$44,000	$42,000
2021	$48,000	$46,000
2022	$52,000	$49,000
2023	$56,000	$53,000
2024	$61,000	$57,000
2025	$64,000	$61,000
2026	$68,000	$64,000
2027	$72,000	$68,000
2028	$76,000	$71,000
2029	$79,000	$75,000
2030	$83,000	$78,000
2031	$87,000	$82,000
2032	$90,000	$85,000
2033	$94,000	$89,000
2034	$98,000	$92,000
2035	$100,000	$96,000
2036	$110,000	$100,000
Present Value in 2004		
3% Intertemporal Discount Rate	$805,000	--
7% Intertemporal Discount Rate	--	$350,000

[A] All dollar estimates rounded to two significant digits.

[B] Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).

Figure 9-1.
Base Estimate of the Stream of Annual Benefits for the Final Nonroad Diesel Engine Standards: 2007 to 2036



9.6 Comparison of Costs and Benefits

The estimated social cost (measured as changes in consumer and producer surplus) in 2030 to implement the final rule, as described in Chapter 8 is $2.0 billion (here, converted to 2000$). Thus, the net benefit (social benefits minus social costs) of the program at full implementation is approximately $81 + B billion, where B represents the sum of all unquantified benefits and disbenefits. In 2020, partial implementation of the program yields net benefits of $42 + B billion. Therefore, implementation of the final rule is expected, based purely on economic efficiency criteria, to provide society with a significant net gain in social welfare. Table 9-17 presents a summary of the benefits, costs, and net benefits of the final rule. Figure 9-2 displays the stream of benefits, costs, and net benefits of the Nonroad Diesel Engine and Fuel Standards from 2007 to 2036. In addition, Table 9-18 presents the present value of the stream of benefits, costs, and net benefits associated with the rule for this 30 year period. The total present value of the stream of monetized net benefits (benefits minus costs) is $750 billion (using a three percent discount rate).

**Table 9-17.
Summary of Monetized Benefits, Costs, and Net Benefits of the
Final Full Program Nonroad Diesel Engine and Fuel Standards[A]**

	Base Estimate[B]	
	2020 (Billions of 2000 dollars)	**2030** (Billions of 2000 dollars)
Social Costs[C]	$1.8	$2.0
Social Benefits[D, E]:		
CO, VOC, Air Toxic-related benefits	Not monetized	Not monetized
Ozone-related benefits	Not monetized	Not monetized
PM-related Welfare benefits	$1.0	$1.7
PM-related Health benefits (3% discount rate)	$43	$81
PM-related Health benefits (7% discount rate)	$41	$78
Net Benefits (Benefits-Costs)[D,E] (3% discount rate)	$42 +B	$81 +B
Net Benefits (Benefits-Costs)[D,E] (7% discount rate)	$41 +B	$78 +B

[A] All costs and benefits are rounded to two significant digits.
[B] Base Estimate reflects premature mortality based on application of concentration-response function derived from long-term exposure to $PM_{2.5}$, valuation using the value of statistical lives saved apporach, and a willingness-to-pay approach for valuing chronic bronchitis incidence.
[C] Note that costs are the total costs of reducing all pollutants, including CO, VOCs and air toxics, as well as NOx and PM. Benefits in this table are associated only with PM, NOx and $_{SO2}$ reductions. These estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii. Costs are converted from 2002$ to 2000$ in this table using the PPI for Total Manufacturing Industries.
[D] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 9-1. These estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii. B is the sum of all unquantified benefits and disbenefits.
[E] Monetized benefits are presented using two different discount rates. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).

Figure 9-2.
Stream of Benefits, Costs, and Net Benefits of the
Final Nonroad Diesel Engine and Fuel Standards

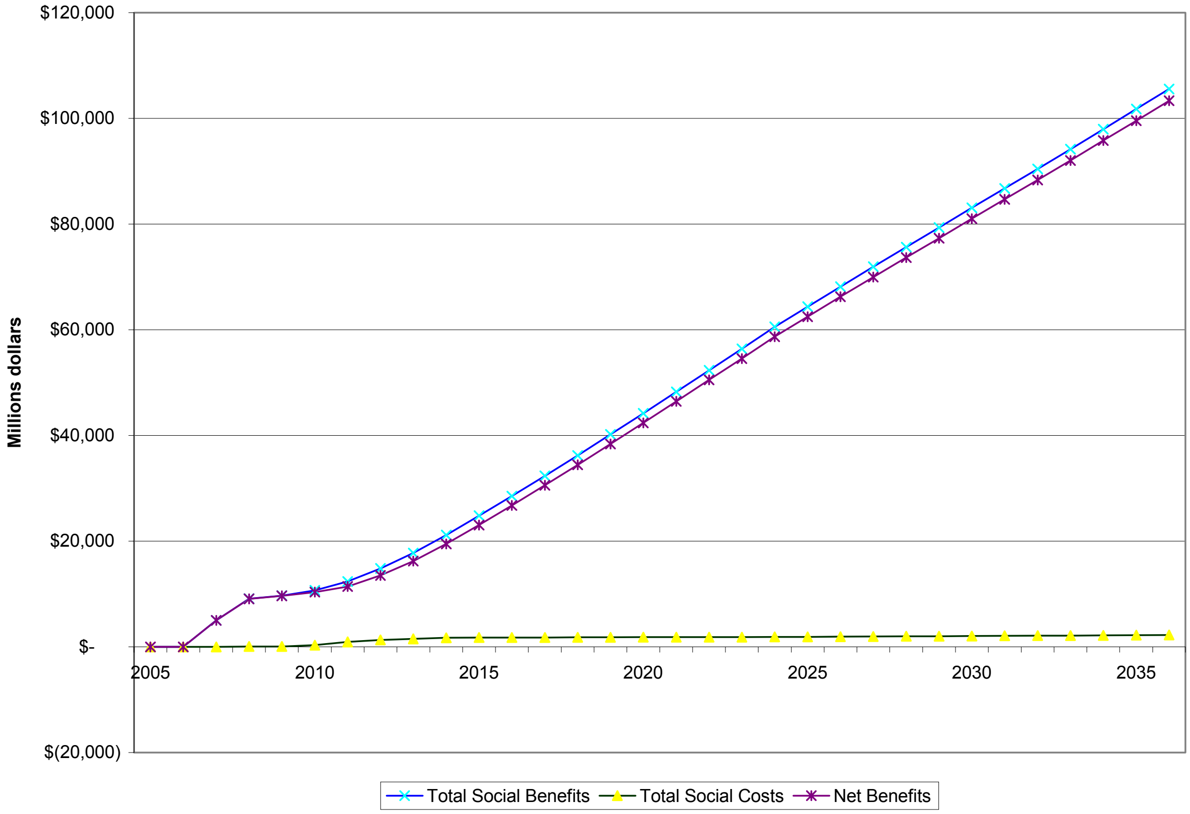


Table 9-18.
Present Value in 2004 of the Stream of 30 Years of Benefits, Costs, and Net Benefits for the Final Full Program Nonroad Diesel Engine and Fuel Standards (Billions of 2000$)[a, b]

	Billions of 2000$ 3% Discount Rate	**Billions of 2000$** 7% Discount Rate
Social Costs	$ 27	$ 14
Social Benefits	$805	$352
Net Benefits [a]	$780	$340

[a] Rounded to two significant digits
b Benefits represent 48-state benefits and exclude home heating oil sulfur reduction benefits, whereas costs include 50-state estimates. Costs were converted from 2002$ to 2000$ using the PPI for Total Manufacturing Industries.

Table 9-19.
Summary of Monetized Benefits, Costs, and Net Benefits of the Final Fuel Only Components of the Nonroad Diesel Standards (Billions of 2000 dollars) [A]

	Fuel Only Program		500 ppm NRLM Fuel	
	2020	**2030**	**2020**	**2030**
Costs [B, C]	$0.62	$0.72	($0.28)	($0.36)
Social Benefits[C, D, E]:				
CO, VOC, Air Toxic-related benefits	Not monetized	Not monetized	Not monetized	Not monetized
Ozone-related benefits	Not monetized	Not monetized	Not monetized	Not monetized
PM-related Welfare benefits	$0.4	$0.6	$0.4	$0.5
PM-related Health benefits (3 % discount rate)	$18	$28	$16	$25
PM-related Health benefits (7% discount rate)	$17	$26	$15	$23
Net Benefits (3% discount rate) = (Benefits-Costs)[C, D, E]	$ 18 + B	$ 28 + B	$ 16 + B	$ 25 + B
Net Benefits (7% discount rate) = (Benefits-Costs)[C, D, E]	$ 17 + B	$ 26 + B	$ 16 + B	$ 24 + B

[A] All costs and benefits are rounded to two significant digits.
[B] Engineering costs are presented instead of social costs. As discussed in previous chapters, total engineering costs include fuel costs (refining, distribution, lubricity) and other operating costs (oil change maintenance savings). All engine and equipment fixed cost expenditures are amortized using a seven percent capital cost to reflect the time value of money. The annual costs presented here are the costs in the indicated year and are not the net present values.
[C] Note that costs are the total costs of reducing all pollutants, including CO, VOCs and air toxics, as well as NOx and PM. Benefits in this table are associated only with PM, NOx and SO_2 reductions. The estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii. Costs were converted from 2002$ to 2000$ using the PPI for Total Manufacturing Industries.
[D] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 9-1. B is the sum of all unquantified benefits and disbenefits.
[E] Monetized costs and benefits are presented using two different discount rates. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).

Table 9-20.
Present Value in 2004 of the Stream of 30 Years of Benefits, Costs, and Net Benefits for the Final Fuel Only Components of the Nonroad Diesel Standards (Billions of 2000$)[A, B, C, D]

	Fuel Only Program	500 ppm NRLM Fuel
3 % discount rate		
Costs	$9.2	($0.54)
Social Benefits	$340	$310
Net Benefits	**$330**	**$310**
7 % discount rate		
Costs	$4.6	($0.3)
Social Benefits	$160	$140
Net Benefits	**$160**	**$140**

[A] Results are rounded to two significant digits. Sums may differ because of rounding.
[B] Engineering costs are presented instead of social costs. As discussed in previous chapters, total engineering costs include fuel costs (refining, distribution, lubricity) and other operating costs (oil change maintenance savings).
[C] Note that costs are the total costs of reducing all pollutants, including CO, VOCs and air toxics, as well as NOx and PM. Benefits in this table are associated only with PM, NOx and SO_2 reductions. The estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii.
[D] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 9-1. B is the sum of all unquantified benefits and disbenefits.
[E] Monetized costs and benefits are presented using two different discount rates. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).

A key input to our benefit-cost analysis is the social costs and emission reductions associated with the final program. Each of these elements also has associated uncertainty which contributes to the overall uncertainty in our analysis of benefit-cost.

EPA engineering cost estimates are based upon considerable expertise and experience within the Agency. At the same time, any estimate of the future cost of control technology for engines or the cost of removing sulfur from diesel fuel is inherently uncertain to some degree. At the start is the question of what technology will actually be used to meet future standards, and what such technology will cost at the time of implementation. Our estimates of control costs are based upon current technology plus newer technology already "in the pipeline." New technology not currently anticipated is by its nature not specifically included. Potential new production techniques which might lower costs are also not included in these estimates (although they are partially included among factors contributing to learning curve effects). On the other side of the equation are unforseen technical hurdles that may act to increase control system costs.

There is also uncertainty in our social cost estimates. Our Economic Impact Assessment presented in Chapter 10 includes sensitivity analyses examining the effect of varying assumptions surrounding the following key factors (Chapter 10, Appendix 10-I):

- market supply and demand elasticity parameters
- alternative assumptions about the fuel market supply shifts and fuel maintenance savings
- alternative assumptions about the engine and equipment market supply shifts

For all of these factors, the change in social cost was estimated to be very small, with a maximum impact of less than one percent. These results are not surprising given the small share of total production costs of diesel engines, equipment, and fuel affected by the rule. See Chapter 10 for a more detailed discussion.

Overall, we have limited means available to develop quantitative estimates of total uncertainty in costs. Some of the factors identified above can act to either increase or decrease actual cost compared to our estimates. Some, such as new technology developments and new production techniques, will act to lower costs compared to our estimates.

One source of a useful information about the overall uncertainty we might expect to see in cost is literature comparing historical rulemaking cost estimates with actual price increases when new standards went into effect.[L] Perhaps the most relevant of such studies is the paper by Anderson and Sherwood analyzing these effects for those mobile source rules adopted since the Clean Air Act Amendments of 1990. That paper reviewed six fuel quality rules and ten light-duty vehicle control rules that had been required by those amendments. It found that EPA estimates of the costs for future standards tended to be similar to or higher than actual price changes observed in the market place. Table 9-21 presents the results for some of the fuel and vehicle rules reviewed in the paper.

Table 9-21.
Comparison of Historical EPA Cost Estimates with Actual Price Changes

EPA Rule	EPA Mid-point Estimate	Actual Price Change	Percent Difference for Price vs EPA
Phase 2 RVP control	1.1 c/gal	0.5 c/gal	-54%
Reformulated Gasoline Phase 1	4.1 c/gal	2.2 c/gal	-46%
Reformulated Gasoline Phase 2	5.7 c/gal	5.1 c/gal	-10%
500ppm Sulfur Highway Diesel Fuel	2.2 c/gal	2.2 c/gal	0%
1994-2001 LDV Regulations	$446/vehicle	$347	-22%

The data in Table 9-21 would lead us to believe that cost uncertainty is largely a risk of overestimation by EPA. However, given the uncertainty in estimating costs, we believe it is appropriate to consider the potential for both overestimation and underestimation. As a sensitivity factor for social cost variability we have chosen to evaluate a range of possible errors in social cost of from twenty percent higher to twenty percent lower than the EPA estimate. The resulting social cost range is shown in Table 9 -22. This uncertainty has virtually no impact on

[L]For this analysis, we based our cost estimates on information received from industry and technical reports relevant to the US market. We are also aware of two studies done to support nonroad standards development in Europe, namely the VTT report and the EMA/Euromot report (Euromot 2002, Docket A-2001-28 Document number II-B-12). We are not utilizing the cost information in these reports because neither one has sufficient information to allow us to understand or derive the relevant cost figures and therefore provide us insufficient information that could be used in trying to estimate cost uncertainty for nonroad diesel engine technologies.

our estimates of the net benefits of the final rule, given the large magnitude by which benefits exceed costs.

Table 9-22.
Estimated Uncertainty for Cost of Final Full Program

Year	Engineering Cost Estimate	Uncertainty Range (-20 to +20 percent)
2010	$0.30 billion	$0.24 - $0.36 billion
2020	$1.8 billion	$1.5 - $2.2 billion
2030	$2.1 billion	$1.7 - $2.6 billion

Turning to the question of emissions uncertainty, the Agency does not at this time have useful quantitative information to bring to bear on this question. For our estimates, we rely on the best information that is available to us. However, there is uncertainty involved in many aspects of emissions estimations. Uncertainty exists in the estimates of emissions from the nonroad sources affected by this final rule, as well as in the universe of other sources included in the emission inventories used for our air quality modeling. To the extent that these other sources are unchanged between our baseline and control case, the impact of uncertainty in those estimates is lessened. Similarly, since the key driver of the benefits of our final rule is the changes produced by the new standards, the effect of uncertainty in the overall estimates of nonroad emissions on our benefits estimates may be lessened.

As discussed in Chapter 3 and our summary and analysis of comments, the main sources of uncertainty in our estimates of nonroad emissions fall in the three areas of population size estimates, equipment usage rates (activity) and engine emission factors. Since nonroad equipment is not subject to state registration and licensing requirements like those applying to highway vehicles, it is difficult to develop precise equipment counts for in-use nonroad equipment. Our modeled equipment populations are derived from related data about sales and scrappage rates. Similarly, annual amount of usage and related load factor information is estimated with some degree of uncertainty. We have access to extensive bodies of data on these areas, but are also aware of the need for improvement. Finally, the emission rates of engines in actual field operation cannot readily be measured at the present time, but are estimated from laboratory testing under a variety of typical operating cycles. While laboratory estimates are a reliable source of emissions data, they cannot fully capture all of the impacts of real in-use operation on emissions, leading to some uncertainty about the results. For further details on our modeling of nonroad emissions, please refer to the discussions in Chapters 3 and Appendix 8A of this RIA.

We have ongoing efforts in all three of these areas designed to improve their accuracy. Since the opportunity to gather better data exists, we have chosen to focus our main efforts on developing improved estimates rather than on developing elaborate techniques to estimate the uncertainty of current estimates. In the long run, better estimates are the most desired outcome.

One of the most important new tools we are developing is the use of portable emission measurement devices to gather detailed data on actual engines and equipment in daily use. These devices have recently become practical due to advances in computing and sensor technology, and will allow us to generate intensive data defining both activity-related factors (e.g., hours of use, load factors, patterns of use) and in-use emissions data specific to the measured activity and including effects from such things as age and emissions related deterioration. The Agency is pursuing this equipment for improving both its highway and nonroad engine emissions models. Because of the multiplicity of factors involved, we cannot make a quantitative estimate of the uncertainty in our emissions estimates.

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APPENDIX 9A: Benefits Analysis of Modeled Preliminary Control Option

This appendix details the models and methods used to generate the benefits estimates from which the benefits of the final standards presented in Chapter IX are derived. This analysis uses a methodology generally consistent with benefits analyses performed for the recent analysis of the Heavy Duty Engines/Diesel Fuel rulemaking (U.S. EPA, 2000a) and the proposed Interstate Air Quality Rule (U.S. EPA, 2004). The benefits analysis relies on three major modeling components:

1) Calculation of the impact that a set of preliminary fuel and engine standards would have on the nationwide inventories for NOx, non-methane hydrocarbons (NMHC), SO_2, and PM emissions in 2020 and 2030;

2) Air quality modeling for 2020 and 2030 to determine changes in ambient concentrations of ozone and particulate matter, reflecting baseline and post-control emissions inventories.

3) A benefits analysis to determine the changes in human health and welfare, both in terms of physical effects and monetary value, that result from the projected changes in ambient concentrations of various pollutants for the modeled standards.

Potential human health effects linked to $PM_{2.5}$ range from premature mortality linked to long-term exposure to PM, to a range of morbidity effects linked to long-term (chronic) and shorter-term (acute) exposures (e.g., respiratory and cardiovascular symptoms resulting in hospital admissions, asthma exacerbations, and acute and chronic bronchitis). Exposure to ozone has also been linked to a variety of respiratory effects including hospital admissions and illnesses resulting in school absences.[a] Welfare effects potentially linked to PM include materials damage and visibility impacts, while ozone can adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. Although methods exist for quantifying the benefits associated with many of these human health and welfare categories, not all can be evaluated at this time due to limitations in methods and/or data. Table 4-1 lists the full complement of human health and welfare effects associated with PM and ozone and identifies those effects that are quantified for the primary estimate, are quantified as part of the sensitivity analysis (to be completed for the supplemental analysis), and remain unquantified because of to current limitations in methods or available data.

[A]Short-term exposure to ambient ozone has also been linked to premature death. The EPA is currently evaluating the epidemiological literature examining the relationship between ozone and premature mortality, sponsoring three independent meta-analyses of the literature. Once this evaluation has been completed and peer-reviewed, the EPA will consider including ozone-related premature mortality in the primary benefits analysis for future rules.

Figure 9A.1 illustrates the major steps in the analysis. Given baseline and post-control emissions inventories for the emission species expected to impact ambient air quality, we use sophisticated photochemical air quality models to estimate baseline and post-control ambient concentrations of ozone and PM, and deposition of nitrogen and sulfur for each year. The estimated changes in ambient concentrations are then combined with monitoring data to estimate population level exposures to changes in ambient concentrations for use in estimating health effects. Modeled changes in ambient data are also used to estimate changes in visibility, and changes in other air quality statistics that are necessary to estimate welfare effects. Changes in population exposure to ambient air pollution are then input to concentration-response functions to generate changes in incidence of health effects, or, changes in other exposure metrics are input to dose-response functions to generate changes in welfare effects. The resulting effects changes are then assigned monetary values, taking into account adjustments to values for growth in real income out to the year of analysis (values for health and welfare effects are in general positively related to real income levels). Finally, values for individual health and welfare effects are summed to obtain an estimate of the total monetary value of the changes in emissions.

On September 26, 2002, the National Academy of Sciences (NAS) released a report on its review of the Agency's methodology for analyzing the health benefits of measures taken to reduce air pollution. The report focused on the EPA's approach for estimating the health benefits of regulations designed to reduce concentrations of airborne PM.

In its report, the NAS said that the EPA has generally used a reasonable framework for analyzing the health benefits of PM-control measures. It recommended, however, that the Agency take a number of steps to improve its benefits analysis. In particular, the NAS stated that the Agency should

- include benefits estimates for a range of regulatory options;
- estimate benefits for intervals, such as every 5 years, rather than a single year;
- clearly state the projected baseline statistics used in estimating health benefits, including those for air emissions, air quality, and health outcomes;
- examine whether implementation of regulations might cause unintended impacts on human health or the environment;
- when appropriate, use data from non-U.S. studies to broaden age ranges to which current estimates apply and to include more types of relevant health outcomes; and
- begin to move the assessment of uncertainties from its ancillary analyses into its base analyses by conducting probabilistic, multiple-source uncertainty analyses. This assessment should be based on available data and expert judgment.

Although the NAS made a number of recommendations for improvement in the EPA's approach, it found that the studies selected by the Agency for use in its benefits analysis were generally reasonable choices. In particular, the NAS agreed with the EPA's decision to use cohort studies to derive benefits estimates. It also concluded that the Agency's selection of the American Cancer Society (ACS) study for the evaluation of PM-related premature mortality was reasonable, although it noted the publication of new cohort studies that the Agency should evaluate. Since the publication of the NAS report, the EPA has reviewed new cohort studies, including reanalyses of the ACS study data and has carefully considered these new study data in developing the analytical approach for the final rule (see below).

In addition to the NAS report, the EPA has also received technical guidance and input regarding its methodology for conducting PM- and ozone-related benefits analysis from two additional sources, including the Health Effects Subgroup (HES) of the SAB Council reviewing the 812 blueprint (SAB-HES, 2003) and the Office of Management and Budget (OMB) through ongoing discussions regarding methods used in conducting regulatory impact analyses (RIAs) (e.g., see OMB Circular A-4). The SAB HES recommendations include the following (SAB-HES, 2003):

- use of the updated ACS Pope et al. (2002) study rather than the ACS Krewski et al. study to estimate premature mortality for the primary analysis;
- dropping the alternative estimate used in the proposal RIA and instead including a primary estimate that incorporates consideration of uncertainly in key effects categories such as premature mortality directly into the estimates (e.g., use of the standard errors from the Pope et al. [2002] study in deriving confidence bounds for the adult mortality estimates);
- addition of infant mortality (children under the age of one) into the primary estimate, based on supporting evidence from the World Health Organization Global Burden of Disease study and other published studies that strengthen the evidence for a relationship between PM exposure and respiratory inflamation and infection in children leading to death;
- inclusion of asthma exacerbations for children in the primary estimate;
- expansion of the age groups evaluated for a range of morbidity effects beyond the narrow band of the studies to the broader (total) age group (e.g., expanding a study population for 7 to 11 year olds to cover the entire child age range of 6 to 18 years).
- inclusion of new endpoints (school absences [ozone], nonfatal heart attacks in adults [PM], hospital admissions for children under two [ozone]), and suggestion of a new

meta-analysis of hospital admissions (PM_{10}) rather than using a few $PM_{2.5}$ studies;[b] and

- updating of populations and baseline incidences.

Recommendations from OMB regarding RIA methods have focused on the approach used to characterize uncertainty in the benefits estimates generated for RIAs, as well as the approach used to value premature mortality estimates. The EPA is currently in the process of developing a comprehensive integrated strategy for characterizing the impact of uncertainty in key elements of the benefits modeling process (e.g., emissions modeling, air quality modeling, health effects incidence estimation, valuation) on the results that are generated.

We are also altering the value of a statistical life (VSL) used in the analysis to reflect new information in the ongoing academic debate over the appropriate characterization of the value of reducing the risk of premature mortality. In previous analyses, we used a distribution of VSL based on 26 VSL estimates from the economics literature. For this analysis, we are characterizing the VSL distribution in a more general fashion, based on two recent meta-analyses of the wage-risk-based VSL literature. The new distribution is assumed to be normal, with a mean of $5.5 million and a 95 percent confidence interval between $1 and $10 million. The EPA welcomes public comment on the appropriate methodology for valuing reductions in the risk of premature death.

The EPA has addressed the comments received from the public, the NAS, the SAB-HES, and OMB in developing the analytical approach for the final rule. We have also reflected advances in data and methods in air quality modeling, epidemiology, and economics that have occurred since the proposal analysis. Updates to the assumptions and methods used in estimating $PM_{2.5}$-related and ozone-related benefits since completion of the Proposed Nonroad Diesel Rule include the following:

Health Endpoints

- The primary analysis incorporates updated impact functions to reflect updated time-series studies of hospital admissions to correct for errors in application of the

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[B]Note that the SAB-HES comments were made in the context of a review of the methods for the Section 812 analysis of the costs and benefits of the Clean Air Act. This context is pertinent to our interpretation of the SAB-HES comments on the selection of effect estimates for hospital admissions associated with PM (SAB-HES, 2003). The Section 812 analysis is focused on a broad set of air quality changes, including both the coarse and fine fractions of PM_{10}. As such, impact functions that focus on the full impact of PM_{10} are appropriate. However, for the Nonroad Diesel Engines rule, which is expected to affect primarily the fine fraction ($PM_{2.5}$) of PM_{10}, impact functions that focus primarily on $PM_{2.5}$ are more appropriate.

generalized additive model (GAM) functions in S-plus. More information on this issue is available at http://www.healtheffects.org.

- The primary analysis uses an all cause mortality effect estimate based on the Pope et al. (2002) reanalysis of the ACS study data. In addition, we provide a breakout for two major cause of death categories—cardiopulmonary and lung cancer.

- Infant mortality is included in the primary analysis (infants age 0-1 years).

- Asthma exacerbations are incorporated into the primary analysis. Although the analysis of the proposed rule included asthma exacerbations as a separate endpoint outside of the base case analysis, for the final rule, we will include asthma exacerbations in children 6 to 18 years of age as part of the primary analysis.

Valuation

- In generating the monetized benefits for premature mortality in the primary analysis, the VSL is entered as a mean (best estimate) of 5.5 million. Unlike the analysis of the proposed rule, the analysis of the final rule does not include a value of statistical life year (VSLY) estimate.

The analysis of the proposed rule included an alternative estimate in addition to the primary estimate that was intended to evaluate the impact of several key assumptions on the estimated reductions in premature premature mortality and chronic bronchitis. However, reflecting comments from the public, the SAB-HES as well as the NAS panel, rather than including an alternative estimate in the analysis, the EPA will investigate the impact of key assumptions on mortality and morbidity estimates through a series of sensitivity analyses.

The benefits estimates generated for the final Nonroad Diesel Engine rule are subject to a number of assumptions and uncertainties, which are discussed throughout the document. For example, key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been definitively established, the weight of the available epidemiological evidence supports an assumption of causality.
(2) All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) The impact function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with fine particle standard and those that do not meet the standard.
(4) The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

In addition to the quantified and monetized benefits summarized above, a number of additional categories are not currently amenable to quantification or valuation. These include reduced acid and particulate deposition damage to cultural monuments and other materials, reduced odor, reduced ozone effects on forested ecosystems, and environmental benefits due to reductions of impacts of acidification in lakes and streams and eutrophication in coastal areas. Additionally, we have not quantified a number of known or suspected health effects linked with PM and ozone for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in forced expiratory volume [FEV1]). As a result, monetized benefits generated for the primary estimate may underestimate the total benefits attributable to the final regulatory option.

Benefits estimates for the final Nonroad Diesel Engines rule were generated using BenMAP, which is a computer program developed by the EPA that integrates a number of the modeling elements used in previous RIAs (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates. BenMAP provides estimates of both the mean impacts and the distribution of impacts.

In general, the chapter is organized around the steps illustrated in Figure 9A.1. In section A, we describe and summarize the emissions inventories and modeled reductions in emissions of NOx, VOC, SO_2, and directly emitted diesel PM for the set of preliminary control options. In section B, we describe and summarize the air quality models and results, including both baseline and post-control conditions, and discuss the way modeled air quality changes are used in the benefits analysis. In Section C, we provide and overview of the data and methods that are used to quantify and value health and welfare endpoints, and provide a discussion of how we incorporate uncertainty into our analysis. In Section D, we report the results of the analysis for human health and welfare effects. Additional sensitivity analyses are provided in Appendix 9B and 9C.

Table 9A.1. Summary of Results: Estimated Benefits of the Modeled Preliminary Control Option

Discount Rate	Total Benefits[A, B] (Billions 2000$)	
	2020	2030
3% discount rate	$52+B	$92+B
7% discount rate	$49+B	$87+B

[A] Benefits of CO and HAP emission reductions are not quantified in this analysis and, therefore, are not presented in this table. The quantifiable benefits are from emission reductions of NOX, NMHC, SO_2 and PM only. For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. A detailed listing of unquantified health and welfare effects is provided in Table 9A-2.

[B] Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4). Results are rounded to two significant digits.

Figure 9A.1. Key Steps in Air Quality Modeling Based Benefits Analysis

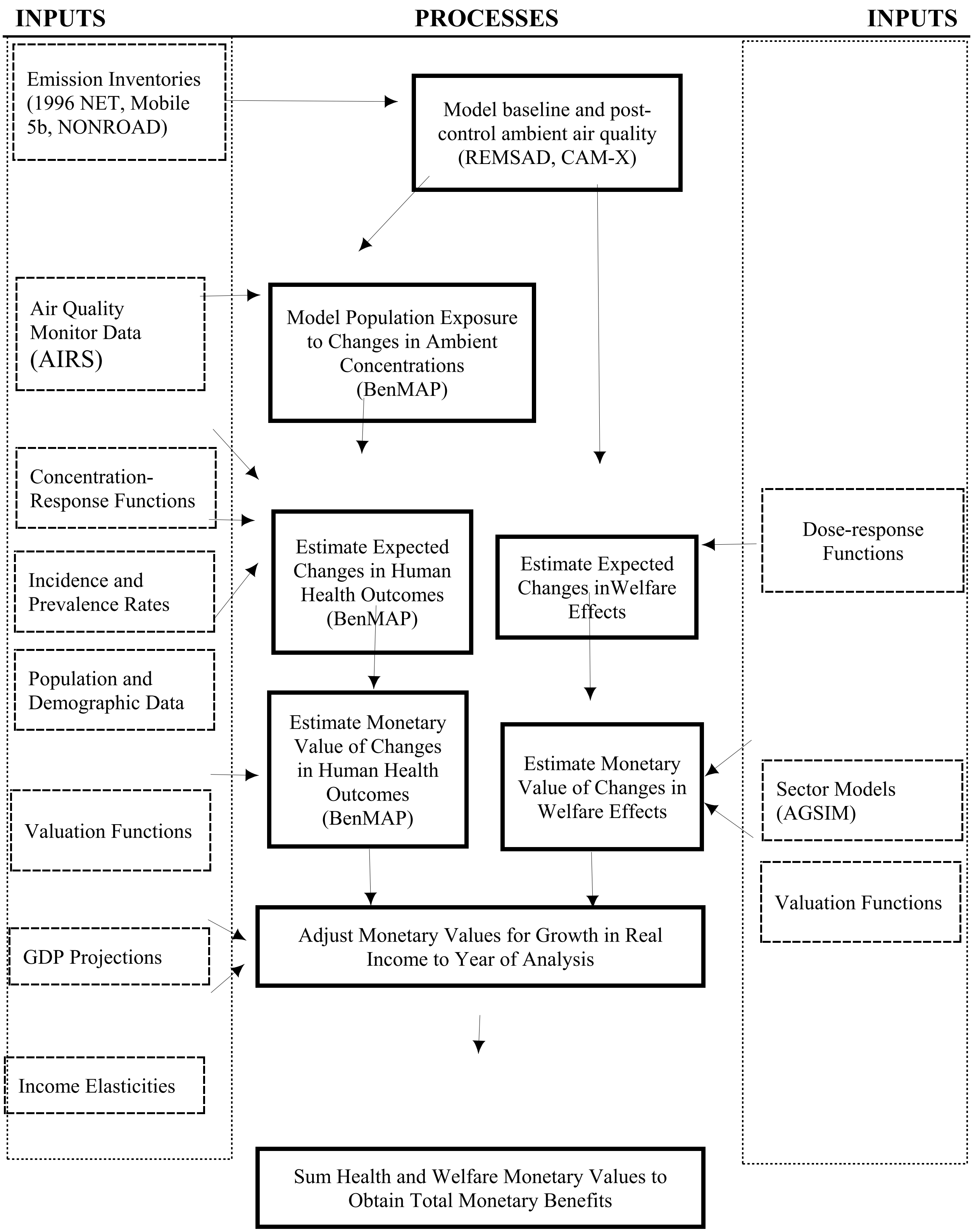


Table 9A.2.
Human Health and Welfare Effects of Pollutants Affected by the Final Nonroad Diesel Engine Rule

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
PM/Health	Premature mortality in adults – long term exposures Infant mortality Bronchitis - chronic and acute Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma Non-fatal heart attacks (myocardial infarction) Asthma exacerbations Lower and upper respiratory illness Minor restricted activity days Work loss days		Low birth weight Changes in pulmonary function Chronic respiratory diseases other than chronic bronchitis Morphological changes Altered host defense mechanisms Cancer Non-asthma respiratory emergency room visits Changes in cardiac function (e.g. heart rate variability) Allergic responses (to diesel exhaust)
PM/Welfare	Visibility in California, Southwestern, and Southeastern Class I areas	Visibility in Northeastern, Northwestern, and Midwestern Class I areas Visibility in residential and non-Class I areas Household soiling	

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
Ozone/Health			Increased airway responsiveness to stimuli Inflammation in the lung Chronic respiratory damage Premature aging of the lungs Acute inflammation and respiratory cell damage Increased susceptibility to respiratory infection Non-asthma respiratory emergency room visits Hospital admissions - respiratory Emergency room visits for asthma Minor restricted activity days School loss days Chronic Asthma[a] Asthma attacks Cardiovascular emergency room visits Premature mortality – acute exposures[b] Acute respiratory symptoms
Ozone/Welfare			Decreased commercial forest productivity Decreased yields for fruits and vegetables Decreased yields for commercial and non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Damage to ecosystem functions Decreased outdoor worker productivity
Nitrogen and Sulfate Deposition/ Welfare		Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries	Impacts of acidic sulfate and nitrate deposition on commercial forests Impacts of acidic deposition on commercial freshwater fishing Impacts of acidic deposition on recreation in terrestrial ecosystems Impacts of nitrogen deposition on commercial fishing, agriculture, and forests Impacts of nitrogen deposition on recreation in estuarine ecosystems Reduced existence values for currently healthy ecosystems

Pollutant/Effect	Quantified and Monetized Effects in Primary Analysis	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
SO_2/Health			Hospital admissions for respiratory and cardiac diseases Respiratory symptoms in asthmatics
NOx/Health			Lung irritation Lowered resistance to respiratory infection Hospital Admissions for respiratory and cardiac diseases
CO/Health			Premature mortality Behavioral effects Hospital admissions - respiratory, cardiovascular, and other Other cardiovascular effects Developmental effects Decreased time to onset of angina
NMHCs [c] Health			Cancer (diesel PM, benzene, 1,3-butadiene, formaldehyde, acetaldehyde) Anemia (benzene) Disruption of production of blood components (benzene) Reduction in the number of blood platelets (benzene) Excessive bone marrow formation (benzene) Depression of lymphocyte counts (benzene) Reproductive and developmental effects (1,3-butadiene) Irritation of eyes and mucous membranes (formaldehyde) Respiratory and respiratory tract Asthma attacks in asthmatics (formaldehyde) Asthma-like symptoms in non-asthmatics (formaldehyde) Irritation of the eyes, skin, and respiratory tract (acetaldehyde) Upper respiratory tract irritation & congestion (acrolein)
NMHCs [c] Welfare			Direct toxic effects to animals Bioaccumlation in the food chain Reduced odors

[a] While no causal mechanism has been identified linking new incidences of chronic asthma to ozone exposure, two epidemiological studies shows a statistical association between long-term exposure to ozone and incidences of chronic asthma in exercising children and some non-smoking men (McConnell, 2002; McDonnell, et al., 1999).

[b] Premature mortality associated with ozone is not separately included in the calculation of total monetized benefits.

[c] All non-methane hydrocarbons (NMHCs) listed in the table are also hazardous air pollutants listed in Section 112(b) of the Clean Air Act.

9A.1 Summary of Emissions Inventories and Modeled Changes in Emissions from Nonroad Engines

For the preliminary control options we modeled, implementation will occur in two ways: reduction in sulfur content of nonroad diesel fuel and adoption of controls on new engines. Because full turnover of the fleet of nonroad diesel engines will not occur for many years, the emission reduction benefits of the final standards will not be fully realized until decades after the initial reduction in fuel sulfur content. Based on the projected time paths for emissions reductions, EPA chose to focus detailed emissions and air quality modeling on two future years, 2020 and 2030, which reflect partial and close to complete turnover of the fleet of nonroad diesel engines to models meeting the preliminary control options. Tables 9A-3 and 9A-4 summarize the baseline emissions of NO_X, SO_2, VOC, and direct diesel $PM_{2.5}$ and the change in the emissions from nonroad engines used in modeling air quality changes.

Emissions and air quality modeling decisions are made early in the analytical process. Since the preliminary control scenario was developed, EPA has gathered more information and received public comment regarding the technical feasibility of the standards, and EPA has revised the control scenario accordingly. Section 3.6 of the RIA describes the changes in the inputs and resulting emission inventories between the preliminary baseline and control scenarios used for the air quality modeling and the baseline and control scenarios.

Chapter 3 discussed the development of the 1996, 2020 and 2030 baseline emissions inventories for the nonroad sector and for the sectors not affected by this rule. The emission sources and the basis for current and future-year inventories are listed in Table 9A-5.

Table 9A-3
Summary of Baseline Emissions for Preliminary Nonroad Engine Control Options

	Pollutant Emissions (tons)			
Source	**NO_X**	**SO_2**	**VOC**	**$PM_{2.5}$**
1996 Baseline				
Nonroad Engines	1,583,641	172,175	221,398	178,500
All Other Sources	22,974,945	18,251,679	18,377,795	2,038,726
Total, All Sources	24,558,586	18,423,854	18,599,193	2,217,226
2020 Base Case				
Nonroad Engines	1,144,686	308,075	97,113	127,755
All Other Sources	14,394,399	14,882,962	13,812,619	1,940,307
Total, All Sources	15,539,085	15,191,037	13,909,732	2,068,062
2030 Base Case				
Nonroad Engines	1,231,981	360,933	97,345	143,185
All Other Sources	14,316,841	15,190,439	15,310,670	2,066,918
Total, All Sources	15,548,822	15,551,372	15,408,015	2,210,103

Table 9A-4
Summary of Emissions Changes for the Preliminary Nonroad Control Options*

	Pollutant			
Item	**NO_X**	**SO_2**	**VOC**	**$PM_{2.5}$**
2020 Nationwide Emission Changes				
Absolute Tons	663,618	304,735	23,172	91,278
Percent Reduction from Landbased Nonroad Emissions	58.0%	98.9%	23.9%	71.4%
Percentage Reduction from All Manmade Sources	4.5%	2.1%	0.2%	4.6%
2030 Emission Changes				
Absolute Tons	1,009,744	359,774	34,060	129,073
Percent Reduction from Landbased Nonroad Emissions	82.0%	99.7%	35.0%	90.0%
Percentage Reduction from All Manmade Sources	6.3%	2.1%	0.2%	5.5%

* Does not include SO_2 and $PM_{2.5}$ reductions from recreational marine diesel engines, commercial marine diesel engines, and locomotives due to control of diesel fuel sulfur levels.

Table 9A-5
Emissions Sources and Basis for Current and Future-Year Inventories

Emissions Source	1996 Base year	Future-year Base Case Projections
Utilities	1996 NEI Version 3.12 (CEM data)	Integrated Planning Model (IPM)
Non-Utility Point and Area sources	1996 NEI Version 3.12 (point) Version 3.11 (area)	BEA growth projections
Highway vehicles	MOBILE5b model with MOBILE6 adjustment factors for VOC and NOX; PART5 model for PM	VMT projection data
Nonroad engines (except locomotives, commercial marine vessels, and aircraft)	NONROAD2002 model	BEA and Nonroad equipment growth projections

Note: Full description of data, models, and methods applied for emissions inventory development and modeling are provided in Emissions Inventory TSD (EPA, 2003a).

9A.2 Air Quality Impacts

This section summarizes the methods for and results of estimating air quality for the 2020 and 2030 base cases and control scenarios for the purposes of benefit-cost analyses. EPA has focused on the health, welfare, and ecological effects that have been linked to air quality changes. These air quality changes include the following:

– Ambient particulate matter (PM_{10} and $PM_{2.5}$)–as estimated using a national-scale version of the REgional Modeling System for Aerosols and Deposition (REMSAD);

– Ambient ozone–as estimated using regional-scale applications of the Comprehensive Air Quality Model with Extensions (CAMx); and

– Visibility degradation (i.e., regional haze), as developed using empirical estimates of light extinction coefficients and efficiencies in combination with REMSAD modeled reductions in pollutant concentrations.

Although we expect reductions in airborne sulfur and nitrogen deposition, these air quality impacts have not been quantified for this rule nor have the associated benefits been estimated.

The air quality estimates in this section are based on the emission changes for the modeled preliminary control program discussed in Chapter 3. These air quality results are in turn associated with human populations and ecosystems to estimate changes in health and welfare effects. In Section B-1, we describe the estimation of PM air quality using REMSAD, and in Section B-2, we cover the estimation of ozone air quality using CAMx. Lastly, in Section B-3, we discuss the estimation of visibility degradation.

9A.2.1 PM Air Quality Estimates

We use the emissions inputs summarized above with a national-scale version of the REgional Model System for Aerosols and Deposition (REMSAD) to estimate PM air quality in the contiguous U.S. REMSAD is a three-dimensional grid-based Eulerian air quality model designed to estimate annual particulate concentrations and deposition over large spatial scales (e.g., over the contiguous U.S.). Consideration of the different processes that affect primary (directly emitted) and secondary (formed by atmospheric processes) PM at the regional scale in different locations is fundamental to understanding and assessing the effects of pollution control measures that affect ozone, PM and deposition of pollutants to the surface.[c] Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, REMSAD is useful for evaluating the impacts of the rule on U.S. PM concentrations.

REMSAD was peer-reviewed in 1999 for EPA as reported in *"Scientific Peer-Review of the Regulatory Modeling System for Aerosols and Deposition*" (Seigneur et al., 1999). Earlier versions of REMSAD have been employed for the EPA's Prospective 812 Report to Congress, EPA's HD Engine/Diesel Fuel rule, and EPA's air quality assessment of the Clear Skies Initiative. Version 7 of REMSAD was employed for this analysis and is fully described in the air quality modeling technical support document (US EPA, 2003b). This version reflects updates in the following areas to improve performance and address comments from the 1999 peer-review:

– Gas phase chemistry updates to "micro-CB4" mechanism including new treatment for the NO3 and N2O5 species and the addition of several reactions to better account for the

[C] Given the potential impact of the Nonroad Engine/Diesel Fuel rule on secondarily formed particles it is important to employ a Eulerian model such as REMSAD. The impact of secondarily formed pollutants typically involves primary precursor emissions from a multitude of widely dispersed sources, and chemical and physical processes of pollutants that are best addressed using an air quality model that employs an Eulerian grid model design.

wide ranges in temperature, pressure, and concentrations that are encountered for regional and national applications.

- PM chemistry updates to calculate particulate nitrate concentrations through use of the MARS-A equilibrium algorithm and internal calculation of secondary organic aerosols from both biogenic (terpene) and anthropogenic (estimated aromatic) VOC emissions.

- Aqueous phase chemistry updates to incorporate the oxidation of SO_2 by O_3 and O_2 and to include the cloud and rain liquid water content from MM5 meteorological data directly in sulfate production and deposition calculations.

As discussed earlier in Chapter 2, the model tends to underestimate observed $PM_{2.5}$ concentrations nationwide, especially over the western U.S.

Our analysis applies the modeling system to the entire U.S. for the five emissions scenarios: a 1996 baseline projection, a 2020 baseline projection and a 2020 projection with nonroad controls, a 2030 baseline projection and a 2030 projection with nonroad controls. As discussed in the Benefits Analysis TSD, we use the relative predictions from the model by combining the 1996 base-year and each future-year scenario with ambient air quality observations to determine the expected change in 2020 or 2030 ozone concentrations due to the rule (Abt Associates, 2003). These results are used solely in the benefits analysis.

REMSAD simulates every hour of every day of the year and, thus, requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, 1-hour average emissions estimates and meteorological fields, initial and boundary conditions, and land-use information. As applied to the contiguous U.S., the model segments the area within the region into square blocks called grids (roughly equal in size to counties), each of which has several layers of air conditions. Using this data, REMSAD generates predictions of 1-hour average PM concentrations for every grid. We then calibrate the modeling results to develop 2020 and 2030 PM estimates at monitor sites by normalizing the observations to the observed 1996 concentrations at each monitor site. For areas (grids) without PM monitoring data, we interpolated concentration values using data from monitors surrounding the area. After completing this process, we then calculated daily and seasonal PM air quality metrics as inputs to the health and welfare C-R functions of the benefits analysis. The following sections provide a more detailed discussion of each of the steps in this evaluation and a summary of the results.

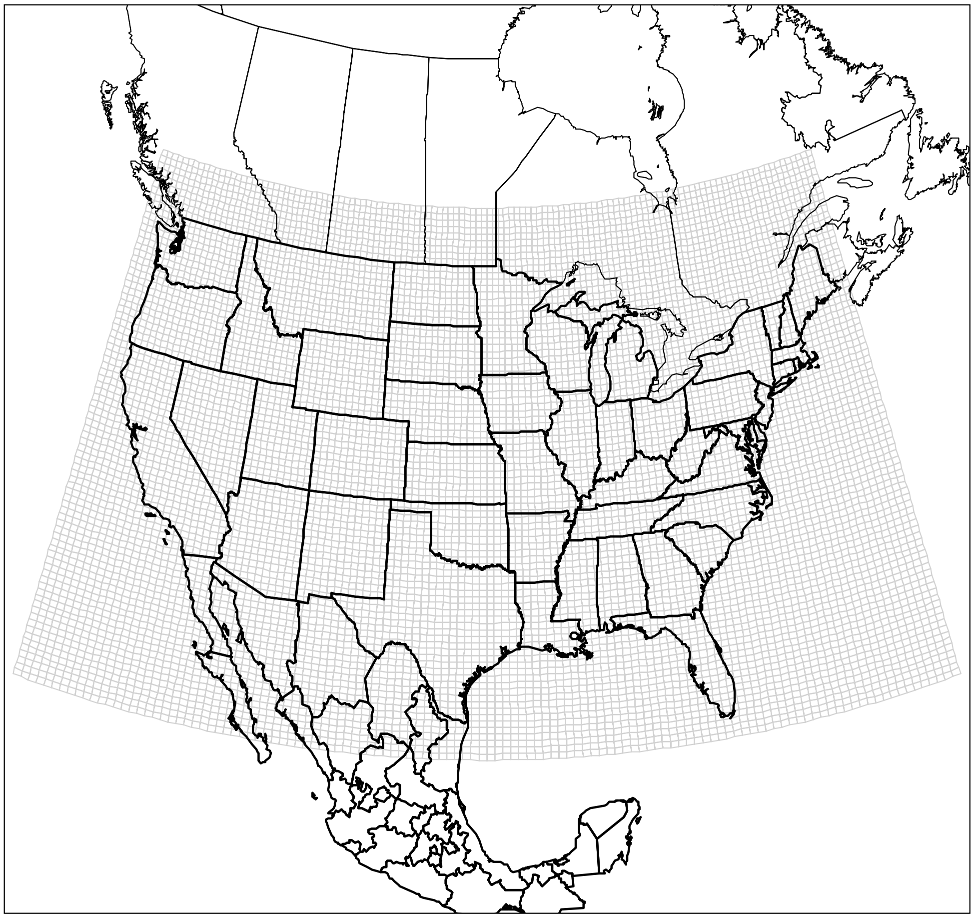
9A.2.1.1 Modeling Domain

The PM air quality analyses employed the modeling domain used previously in support of Clear Skies air quality assessment. As shown in Figure 9A-2, the modeling domain encompasses the lower 48 States and extends from 126 degrees to 66 degrees west longitude and from 24 degrees north latitude to 52 degrees north latitude. The model contains horizontal grid-cells across the model domain of roughly 36 km by 36 km. There are 12 vertical layers of atmospheric conditions with the top of the modeling domain at 16,200 meters. The 36 by 36 km horizontal grid results in a 120 by 84 grid (or 10,080 grid-cells) for each vertical layer. Figure 9A-3 illustrates the horizontal grid-cells for Maryland and surrounding areas.

9A.2.1.2 Simulation Periods

For use in this benefits analysis, the simulation periods modeled by REMSAD included separate full-year application for each of the five emissions scenarios as described in Chapter 3, i.e., 1996 baseline and the 2020 and 2030 base cases and control scenarios.

Figure 9A-2
REMSAD Modeling Domain for Continental United States



Note: Gray markings define individual grid-cells in the REMSAD model.

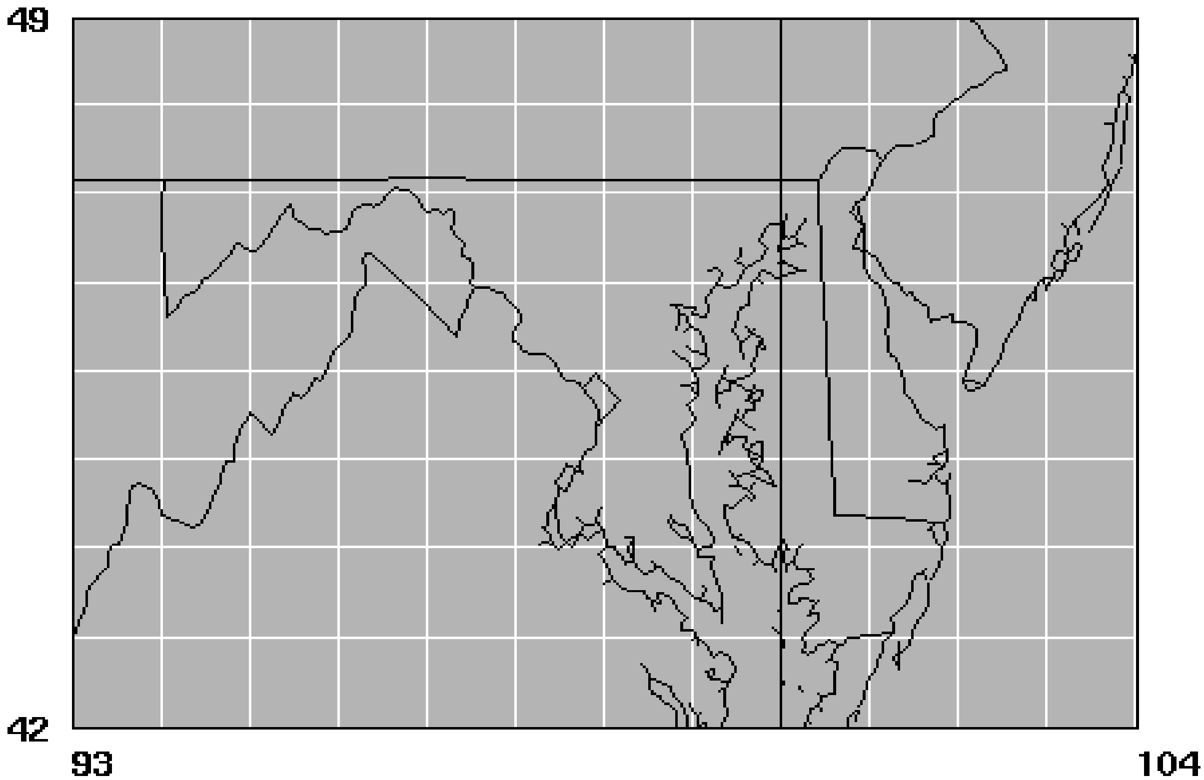


Figure 9A-3. Example of REMSAD 36 x 36km Grid-cells for Maryland Area

9A.2.1.3 Model Inputs

REMSAD requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, 1-hour average emissions estimates and meteorological fields, initial and boundary conditions, and land-use information. Separate emissions inventories were prepared for the 1996 baseline and each of the future-year base cases and control scenarios. All other inputs were specified for the 1996 baseline model application and remained unchanged for each future-year modeling scenario.

Similar to CAMx, REMSAD requires detailed emissions inventories containing temporally allocated emissions for each grid-cell in the modeling domain for each species being simulated. The previously described annual emission inventories were preprocessed into model-ready inputs through the SMOKE emissions preprocessing system. Details of the preprocessing of emissions through SMOKE as provided in the emissions modeling TSD. Meteorological inputs reflecting 1996 conditions across the contiguous U.S. were derived from Version 5 of the Mesoscale Model (MM5). These inputs included horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer. Details of the annual 1996 MM5 modeling are provided in Olerud (2000).

Initial species concentrations and lateral boundary conditions were specified to approximate background concentrations of the species; for the lateral boundaries the concentrations varied (decreased parabolically) with height. These background concentrations are provided in the air quality modeling TSD (U.S. EPA, 2003b). Land use information was obtained from the U.S. Geological Survey database at 10 km resolution and aggregated to the ~36 KM horizontal resolution used for this REMSAD application.

9A.2.1.4 Converting REMSAD Outputs to Benefits Inputs

REMSAD generates predictions of hourly PM concentrations for every grid. The particulate matter species modeled by REMSAD include a primary coarse fraction (corresponding to PM in the 2.5 to 10 micron size range), a primary fine fraction (corresponding to PM less than 2.5 microns in diameter), and several secondary particles (e.g., sulfates, nitrates, and organics). $PM_{2.5}$ is calculated as the sum of the primary fine fraction and all of the secondarily-formed particles. These hourly predictions for each REMSAD grid-cell are aggregated to daily averages and used in conjunction with observed PM concentrations from AIRS to generate the predicted changes in the daily and annual PM air quality metrics (i.e., annual mean PM concentration) from the future-year base case to future-year control scenario as inputs to the health and welfare

C-R functions of the benefits analysis.[d] In addition, the speciated predictions from REMSAD are employed as inputs to a post-processing module that estimates atmospheric visibility, as discussed later in Section 9A.3.

In order to estimate PM-related health and welfare effects for the contiguous U.S., daily and annual average PM concentrations are required for every location. Given available PM monitoring data, we generated an annual profile for each location in the contiguous 48 States in two steps: (1) we combine monitored observations and modeled PM predictions to interpolate forecasted daily PM concentrations for each REMSAD grid-cell, and (2) we compute the daily and annual PM measures of interest based on the annual PM profiles. [e] These methods are described in detail in the benefits analysis technical support document (Abt Associates, 2003).

9A.2.1.5 PM Air Quality Results

Table 9A-5 provides a summary of the predicted ambient $PM_{2.5}$ concentrations for the 2020 and 2030 base cases and changes associated with Nonroad Engine/Diesel Fuel control scenarios. The REMSAD results indicate that the predicted change in PM concentrations is composed almost entirely of reductions in fine particulates ($PM_{2.5}$) with little or no reduction in coarse particles (PM_{10} less $PM_{2.5}$). Therefore, the observed changes in PM_{10} are composed primarily of changes in $PM_{2.5}$. In addition to the standard frequency statistics (e.g., minimum, maximum, average, median), Table 9A-5 provides the population-weighted average which better reflects the baseline levels and predicted changes for more populated areas of the nation. This measure, therefore, will better reflect the potential benefits of these predicted changes through exposure changes to these populations. As shown, the average annual mean concentrations of $PM_{2.5}$ across all U.S. grid-cells declines by roughly 2.5 percent (or 0.2 $\mu g/m^3$) and 3.4 percent (or 0.28 $\mu g/m^3$) in 2020 and 2030, respectively. The population-weighted average mean concentration declined by 3.3 percent (or 0.42 $\mu g/m^3$) in 2020 and 4.5 percent (or 0.59 $\mu g/m^3$) in 2030, which is much larger in absolute terms than the spatial average for both years. This indicates the rule may generate greater absolute air quality improvements in more populated, urban areas.

[D]Based on AIRS, there were 1,071 FRM PM monitors with valid data as defined as more than 11 observations per season.

[E]This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (EVNA) spatial interpolation (See Abt Associates (2003) for a more detailed description).

Table 9A-6.
Summary of Base Case PM Air Quality
and Changes Due to Preliminary Control Option for Nonroad Diesel Standards: 2020 and 2030

Statistic	2020 Base Case	2020 Change[a]	2020 Percent Change	2030 Base Case	2030 Change[a]	2030 Percent Change
$PM_{2.5}$ (µg/m^3)						
Minimum Annual Mean [b]	2.18	-0.02	-0.78%	2.33	-0.02	-1.01%
Maximum Annual Mean [b]	29.85	-1.36	-4.56%	32.85	-2.03	-6.18%
Average Annual Mean	8.10	-0.20	-2.49%	8.37	-0.28	-3.38%
Median Annual Mean	7.50	-0.18	-2.68%	7.71	-0.22	-2.80%
Pop-Weighted Average Annual Mean [c]	12.42	-0.42	-3.34%	13.07	-0.59	-4.48%

[a] The change is defined as the control case value minus the base case value.

[b] The base case minimum (maximum) is the value for the populated grid-cell with the lowest (highest) annual average. The change relative to the base case is the observed change for the populated grid-cell with the lowest (highest) annual average in the base case.

[c] Calculated by summing the product of the projected REMSAD grid-cell population and the estimated PM concentration, for that grid-cell and then dividing by the total population in the 48 contiguous States.

Table 9A-6 provides information on the populations in 2020 and 2030 that will experience improved PM air quality. There are significant populations that live in areas with meaningful potential reductions in annual mean $PM_{2.5}$ concentrations resulting from the rule. As shown, almost 10 percent of the 2030 U.S. population are predicted to experience reductions of greater than 1 µg/m^3. This is an increase from the 2.7 percent of the U.S. population that are expected to experience such reductions in 2020. Furthermore, just over 20 percent of the 2030 U.S. population will benefit from reductions in annual mean $PM_{2.5}$ concentrations of greater than 0.75 µg/m^3 and slightly over 50 percent will live in areas with reductions of greater than 0.5 µg/m^3. This information indicates how widespread the improvements in PM air quality are expected to be and the large populations that will benefit from these improvements.

Table 9A-7
Distribution of $PM_{2.5}$ Air Quality Improvements Over Population Due to Preliminary Control Option for Nonroad Engine/Diesel Fuel Standards: 2020 and 2030

Change in Annual Mean $PM_{2.5}$ Concentrations ($\mu g/m^3$)	*2020 Population*		*2030 Population*	
	Number (millions)	*Percent (%)*	*Number (millions)*	*Percent (%)*
$0 < \Delta$ $PM_{2.5}$ Conc ≤ 0.25	65.11	19.75%	28.60	8.04%
$0.25 < \Delta$ $PM_{2.5}$ Conc ≤ 0.5	184.52	55.97%	147.09	41.33%
$0.5 < \Delta$ $PM_{2.5}$ Conc ≤ 0.75	56.66	17.19%	107.47	30.20%
$0.75 < \Delta$ $PM_{2.5}$ Conc ≤ 1.0	14.60	4.43%	38.50	10.82%
$1.0 < \Delta$ $PM_{2.5}$ Conc ≤ 1.25	5.29	1.60%	88.22	2.48%
$1.25 < \Delta$ $PM_{2.5}$ Conc ≤ 1.5	3.51	1.06%	15.52	4.36%
$1.5 < \Delta$ $PM_{2.5}$ Conc ≤ 1.75	0	0.00%	5.70	1.60%
Δ $PM_{2.5}$ Conc > 1.75	0	0.00%	4.19	1.18%

[a] The change is defined as the control case value minus the base case value.

Table 9A-7 provides additional insights on the potential changes in PM air quality resulting from the standards. The information presented previously in Table 9A-5 illustrated the absolute and relative changes for different points along the distribution of baseline 2020 and 2030 $PM_{2.5}$ concentration levels, e.g., the change reflects the lowering of the minimum predicted baseline concentration rather than the minimum predicted change for 2020 and 2030. The latter is the focus of Table 9A-7 as it presents the distribution of predicted changes in both absolute terms (i.e., $\mu g/m^3$) and relative terms (i.e., percent) across individual REMSAD grid-cells. Therefore, it provide more information on the range of predicted changes associated with the rule. As shown for 2020, the absolute reduction in annual mean $PM_{2.5}$ concentration ranged from a low of 0.02 $\mu g/m^3$ to a high of 1.36 $\mu g/m^3$, while the relative reduction ranged from a low of 0.3 percent to a high of 12.2 percent. Alternatively, for 2030, the absolute reduction ranged from 0.02 to 2.03 $\mu g/m^3$, while the relative reduction ranged from 0.4 to 15.5 percent.

Table 9A-8.
Summary of Absolute and Relative Changes in PM Air Quality Due to Preliminary Control Option for Nonroad Engine/Diesel Fuel Standards: 2020 and 2030

Statistic	2020 PM$_{2.5}$ Annual Mean	2030 PM$_{2.5}$ Annual Mean
Absolute Change from Base Case (µg/m^3)[a]		
Minimum	-0.02	-0.02
Maximum	-1.36	-2.03
Average	-0.20	-0.28
Median	-0.19	-0.26
Population-Weighted Average [c]	-0.42	-0.59
Relative Change from Base Case (%)[b]		
Minimum	-0.33%	-0.44%
Maximum	-12.24%	-15.52%
Average	-2.44%	-3.32%
Median	-2.33%	-3.13%
Population-Weighted Average [c]	-3.28%	-4.38%

[a] The absolute change is defined as the control case value minus the base case value for each REMSAD grid-cell.

[b] The relative change is defined as the absolute change divided by the base case value, or the percentage change, for each gridcell. The information reported in this section does not necessarily reflect the same gridcell as is portrayed in the absolute change section.

[c] Calculated by summing the product of the projected gridcell population and the estimated gridcell PM absolute/relative measure of change, and then dividing by the total population in the 48 contiguous states.

9A.2.2 Ozone Air Quality Estimates

We use the emissions inputs summarized in Section 9A.1 with a regional-scale version of CAMx to estimate ozone air quality in the Eastern and Western U.S. CAMx is an Eulerian three-dimensional photochemical grid air quality model designed to calculate the concentrations of both inert and chemically reactive pollutants by simulating the physical and chemical processes in the atmosphere that affect ozone formation. Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, the CAMx is useful for evaluating the impacts of the rule on U.S. ozone concentrations. As discussed earlier in Chapter 2, although the model tends to underestimate observed ozone, especially over the western U.S., it exhibits less bias and error than any past regional ozone modeling application conducted by EPA (i.e., Ozone Transport Assessment Group (OTAG), On-highway Tier-2, and HD Engine/Diesel Fuel).

Our analysis applies the modeling system separately to the Eastern and Western U.S. for five emissions scenarios: a 1996 baseline projection, a 2020 baseline projection and a 2020 projection with preliminary nonroad controls, a 2030 baseline projection and a 2030 projection with preliminary nonroad controls. As discussed in the Benefits Analysis TSD, we use the relative predictions from the model by combining the 1996 base-year and each future-year scenario with ambient air quality observations to determine the expected change in 2020 or 2030 ozone concentrations due to the rule (Abt Associates, 2003). These results are used solely in the benefits analysis.

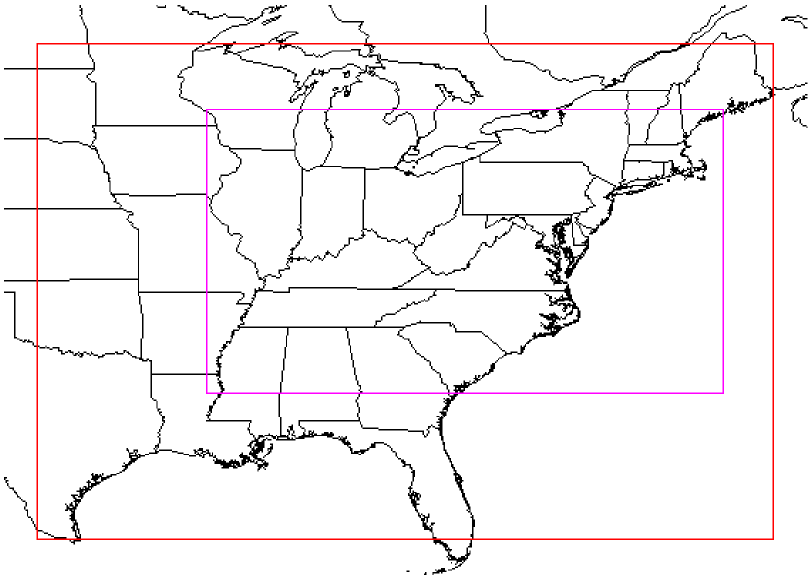
The CAMx modeling system requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, day-specific emissions estimates and meteorological fields, initial and boundary conditions, and land-use information. The model divides the continental United States into two regions: East and West. As applied to each region, the model segments the area within the subject region into square blocks called grids (roughly equal in size to counties), each of which has several layers of air conditions that are considered in the analysis. Using this data, the CAMx model generates predictions of hourly ozone concentrations for every grid. We then calibrate the results of this process to develop 2020 and 2030 ozone profiles at monitor sites by normalizing the observations to the observed ozone concentrations at each monitor site. For areas (grids) without ozone monitoring data, we interpolated ozone values using data from monitors surrounding the area. After completing this process, we calculated daily and seasonal ozone metrics to be used as inputs to the health and welfare C-R functions of the benefits analysis. The following sections provide a more detailed discussion of each of the steps in this evaluation and a summary of the results.

9A.2.2.1 Modeling Domain

The modeling domain representing the Eastern U.S. is the same as that used previously for OTAG and the On-highway Tier-2 rulemaking. As shown in Figure 9A-4, this domain encompasses most of the Eastern U.S. from the East coast to mid-Texas and consists of two grids with differing resolutions. The modeling domain extends from 99 degrees to 67 degrees west longitude and from 26 degrees to 47 degrees north latitude. The inner portion of the modeling domain shown in Figure 9A-4 uses a relatively fine grid of 12 km consisting of nine vertical layers. The outer area has less horizontal resolution, as it uses a 36 km grid with the same nine vertical layers. The vertical height of the modeling domain is 4,000 meters above ground level for both areas.

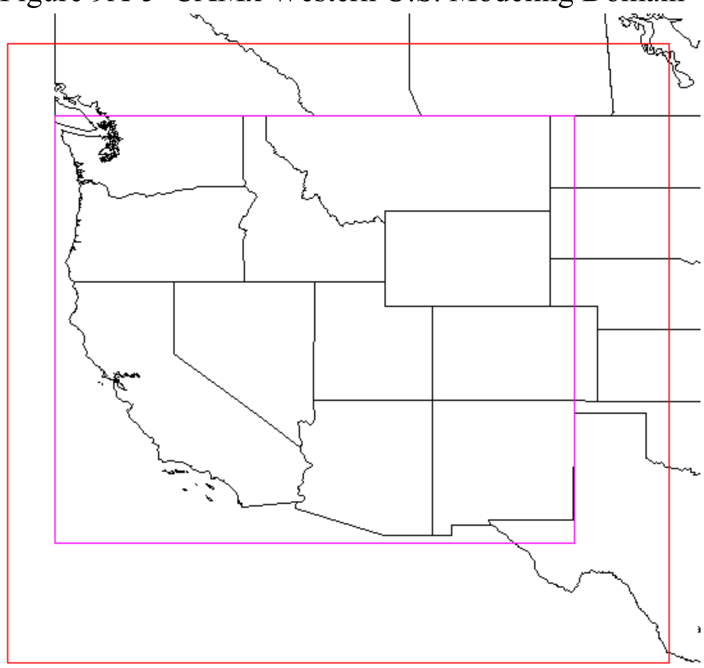
The modeling domain representing the Western U.S. is the same as that used previously for the On-highway Tier-2 rulemaking. As shown in Figure 9A-5, this domain encompasses the area west of the 99th degree longitude (which runs through North and South Dakota, Nebraska, Kansas, Oklahoma, and Texas) and consists of two grids with differing resolutions. The domain extends from 127 degrees to 99 degrees west longitude and from 26 degrees to 52 degrees north latitude. The inner portion of the modeling domain shown in Figure 9A-5 uses a relatively fine grid of 12 km consisting of eleven vertical layers. The outer area has less horizontal resolution, as it uses a 36 km grid with the same eleven vertical layers. The vertical height of the modeling domain is 4,800 meters above ground level.

Figure 9A-4 CAMx Eastern U.S. Modeling Domain



Note: The inner area represents fine grid modeling at 12 km resolution, while the outer area represents the coarse grid modeling at 36 km resolution.

Figure 9A-5 CAMx Western U.S. Modeling Domain



Note: The inner area represents fine grid modeling at 12 km resolution, while the outer area represents the coarse grid modeling at 36 km resolution.

9A.2.2.2 Simulation Periods

For use in this benefits analysis, the simulation periods modeled by CAMx included several multi-day periods when ambient measurements recorded high ozone concentrations. A simulation period, or episode, consists of meteorological data characterized over a block of days that are used as inputs to the air quality model. A simulation period is selected to characterize a variety of ozone conditions including some days with high ozone concentrations in one or more portions of the U.S. and observed exceedances of the 1-hour NAAQS for ozone being recorded at monitors. We focused on the summer of 1995 for selecting the episodes to model in the East and the summer of 1996 for selecting the episodes to model in the West because each is a recent time period for which we had model-ready meteorological inputs and this timeframe contained several periods of elevated ozone over the Eastern and Western U.S., respectively. As detailed in the air quality modeling TSD, this analysis used three multi-day meteorological scenarios during the summer of 1995 for the model simulations over the eastern U.S.: June 12-24, July 5-15, and August 7-21. Two multi-day meteorological scenarios during the summer of 1996 were used in the model simulations over the western U.S.: July 5-15 and July 18-31. Each of the five emissions scenarios (1996 base year, 2020 base, 2020 control, 2030 baseline, 2030 control) were simulated for the selected episodes. These episodes include a three day "ramp-up" period to initialize the model, but the results for these days are not used in this analysis.

9A.2.2.3 Converting CAMx Outputs to Full-Season Profiles for Benefits Analysis

This study extracted hourly, surface-layer ozone concentrations for each grid-cell from the standard CAMx output file containing hourly average ozone values. These model predictions are used in conjunction with the observed concentrations obtained from the Aerometric Information Retrieval System (AIRS) to generate ozone concentrations for the entire ozone season.[f,g] The predicted changes in ozone concentrations from the future-year base case to future-year control scenario serve as inputs to the health and welfare C-R functions of the benefits analysis, i.e., BENMAP.

In order to estimate ozone-related health and welfare effects for the contiguous U.S., full-season ozone data are required for every CAPMS grid-cell. Given available ozone monitoring data, we generated full-season ozone profiles for each location in the contiguous 48 States in two steps: (1) we combine monitored observations and modeled ozone predictions to interpolate

[F] The ozone season for this analysis is defined as the 5-month period from May to September; however, to estimate certain crop yield benefits, the modeling results were extended to include months outside the 5-month ozone season.

[G] Based on AIRS, there were 961 ozone monitors with sufficient data, i.e., 50 percent or more days reporting at least 9 hourly observations per day (8 am to 8 pm) during the ozone season.

hourly ozone concentrations to a grid of 8 km by 8 km population grid-cells, and (2) we converted these full-season hourly ozone profiles to an ozone measure of interest, such as the daily average. [h,i] For the analysis of ozone impacts on agriculture and commercial forestry, we use a similar approach except air quality is interpolated to county centroids as opposed to population grid-cells. We report ozone concentrations as a cumulative index called the SUM06. The SUM06 is the sum of the ozone concentrations for every hour that exceeds 0.06 parts per million (ppm) within a 12-hour period from 8 am to 8 pm in the months of May to September. These methods are described in detail in the benefits analysis technical support document (Abt Associates, 2003).

9A.2.2.4 Ozone Air Quality Results

This section provides a summary the predicted ambient ozone concentrations from the CAMx model for the 2020 and 2030 base cases and changes associated with the Nonroad Engine/Diesel Fuel control scenario. In Tables 9A-8 and 9A-9, we provide those ozone metrics for grid-cells in the Eastern and Western U.S. respectively, that enter the concentration response functions for health benefits endpoints. In addition to the standard frequency statistics (e.g., minimum, maximum, average, median), we provide the population-weighted average which better reflects the baseline levels and predicted changes for more populated areas of the nation. This measure, therefore, will better reflect the potential benefits of these predicted changes through exposure changes to these populations.

As shown in Table 9A-8, for the 2020 ozone season, the rule results in average reductions of roughly 2 percent, or between 0.57 to 0.85 ppb, in the daily average ozone concentration metrics across the Eastern U.S. population grid-cells. For the 2030 ozone season, the average reductions in the daily average ozone concentration are between 3 and 3.5 percent, or between 0.91 to 1.35 ppb. A slightly lower relative decline is predicted for the population-weighted average, which reflects the observed increases in ozone concentrations for certain hours during the year in highly populated urban areas associated with NOx emissions reductions (see more detailed discussion in Chapter 2). Additionally, the daily 1-hour maximum ozone concentrations are predicted to decline between 2.3 and 3.6 percent in 2020 and 2030 respectively, i.e., between 1.05 and 1.66 ppb.

As shown in Table 9A-9, for the 2020 ozone season, the rule results in average reductions of roughly 1.5 percent, or between 0.57 to 0.52 ppb, in the daily average ozone concentration

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[H]The 8 km grid squares contain the population data used in the health benefits analysis model, CAPMS. See Section C of this appendix for a discussion of this model.

[I]This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (EVNA) spatial interpolation (See Abt Associates (2003) for a more detailed description).

metrics across the Western U.S. population grid-cells. For the 2030 ozone season, the average reductions in the daily average ozone concentration are roughly 2 percent, or between 0.61 to 0.82 ppb. Additionally, the daily 1-hour maximum ozone concentrations are predicted to decline between 1.3 and 2.1 percent in 2020 and 2030 respectively, i.e., between 0.62 and 0.97 ppb.

As discussed in more detail in Chapter 2, our ozone air quality modeling showed that the NOx emissions reductions from the preliminary modeled standards are projected to result in increases in ozone concentrations for certain hours during the year, especially in urban, NOx limited areas. These increases are often observed within the highly populated urban areas in California. As a result, the population-weighted metrics for ozone shown in Table 9A-9 indicate increases in concentrations. Most of these increases are expected to occur during hours where ozone levels are low (and often below the one-hour ozone standard). These increase are accounted for in the benefits analysis because it relies on the changes in ozone concentrations across the entire distribution of baseline levels. However, as detailed in Chapter 2 and illustrated by the results from Tables 9A-8 and 9A-9, most of the country experiences decreases in ozone concentrations for most hours in the year.

In Table 9A-10, we provide the seasonal SUM06 ozone metric for counties in the Eastern and Western U.S. that enters the concentration response function for agriculture benefit end-points. This metric is a cumulative threshold measure so that the increase in baseline NOx emissions from Tier 2 post-control to this rulemaking have resulted in a larger number of rural counties exceeding the hourly 0.06 ppm threshold. As a result, changes in ozone concentrations for these counties are contributing to greater impacts of the Nonroad Diesel Engine rule on the seasonal SUM06 ozone metric. As shown, the average across all Eastern U.S. counties declined by 78 percent, or almost 17 ppb. Similarly high percentage reductions are observed across the other points on the distribution with the maximum declining by almost 30 ppb, or 55 percent, and the median declining by almost 20 ppb, or 83 percent.

Table 9A-9.
Summary of CAMx Derived Ozone Air Quality Metrics Due to Preliminary Control Option for Nonroad Engine/Diesel Fuel Standards for Health Benefits EndPoints: Eastern U.S.

Statistic [a]	2020			2030		
	Base Case	Change [b]	Percent Change [b]	Base Case	Change [b]	Percent Change [b]
Daily 1-Hour Maximum Concentration (ppb)						
Minimum [c]	28.85	-0.81	-2.80%	28.81	-1.24	-4.31%
Maximum [c]	93.94	-0.85	-0.90%	94.70	-1.61	-1.70%
Average	45.54	-1.05	-2.30%	45.65	-1.66	-3.64%
Median	45.45	-1.23	-2.71%	45.52	-1.73	-3.80%
Population-Weighted Average [d]	51.34	-0.67	-1.31%	51.47	-1.16	-2.25%
Daily 5-Hour Average Concentration (ppb)						
Minimum [c]	24.90	-0.67	-2.68%	24.87	-1.03	-4.13%
Maximum [c]	68.69	-0.20	-0.29%	69.11	-0.44	-0.64%
Average	38.99	-0.85	-2.17%	39.08	-1.35	-3.45%
Median	38.94	-0.92	-2.39%	39.00	-1.40	-3.58%
Population-Weighted Average [d]	42.77	-0.47	-1.10%	42.90	-0.84	-1.96%
Daily 8-Hour Average Concentration (ppb)						
Minimum [c]	24.15	-0.64	-2.64%	24.12	-0.98	-4.07%
Maximum [c]	68.30	-0.21	-0.31%	68.72	-0.46	-0.67%
Average	38.46	-0.83	-2.16%	38.55	-1.33	-3.44%
Median	38.44	-0.89	-2.33%	38.50	-1.45	-3.76%
Population-Weighted Average [d]	42.07	-0.46	-1.08%	42.19	-0.82	-1.93%
Daily 12-Hour Average Concentration (ppb)						
Minimum [c]	22.42	-0.58	-2.57%	22.40	-0.89	-3.96%
Maximum [c]	66.06	-0.17	-0.25%	66.46	-0.38	-0.58%
Average	36.59	-0.78	-2.13%	36.66	-1.25	-3.40%
Median	36.61	-0.84	-2.30%	36.66	-1.43	-3.89%
Population-Weighted Average [d]	39.65	-0.40	-1.00	39.75	-0.72	-1.80%
Daily 24-Hour Average Concentration (ppb)						
Minimum [c]	15.20	-0.35	-2.28%	15.19	-0.54	-3.52%
Maximum [c]	55.95	0.10	0.18%	56.23	0.04	0.07%
Average	28.93	-0.57	-1.96%	28.98	-0.91	-3.14%
Median	28.92	-0.63	-2.15%	28.98	-1.01	-3.48%
Population-Weighted Average [d]	30.24	-0.18	-0.60%	30.29	-0.37	-1.23%

[a] These ozone metrics are calculated at the CAMX grid-cell level for use in health effects estimates based on the results of spatial and temporal Voronoi Neighbor Averaging. Except for the daily 24-hour average, these ozone metrics are calculated over relevant time periods during the daylight hours of the "ozone season," i.e., May through September. For the 5-hour average, the relevant time period is 10 am to 3 pm; for the 8-hr average, it is 9 am to 5 pm; and, for the 12-hr average it is 8 am to 8 pm.

[b] The change is defined as the control case value minus the base case value. The percent change is the "Change" divided by the "Base Case," and then multiplied by 100 to convert the value to a percentage.

[c] The base case minimum (maximum) is the value for the CAMX grid cell with the lowest (highest) value.

[d] Calculated by summing the product of the projected CAMX grid-cell population and the estimated CAMX grid-cell seasonal ozone concentration, and then dividing by the total population.

Table 9A-10.
Summary of CAMx Derived Ozone Air Quality Metrics Due to Preliminary Control Option for Nonroad Engine/Diesel Fuel Standards for Health Benefits EndPoints: Western U.S.

Statistic [a]	2020 Base Case	2020 Change [b]	2020 Percent Change [b]	2030 Base Case	2030 Change [b]	2030 Percent Change [b]
Daily 1-Hour Maximum Concentration (ppb)						
Minimum [c]	27.48	-0.01	-0.03%	27.48	-0.01	-0.05%
Maximum [c]	201.28	4.87	2.42%	208.02	6.26	3.01%
Average	47.02	-0.62	-1.31%	47.04	-0.97	-2.07%
Median	46.10	-0.56	-1.19%	46.06	-0.66	-1.43%
Population-Weighted Average [d]	63.80	0.34	0.54%	64.23	0.38	0.58%
Daily 5-Hour Average Concentration (ppb)						
Minimum [c]	24.20	-0.01	-0.04%	24.21	-0.01	-0.05%
Maximum [c]	163.41	2.55	1.56%	168.89	6.04	3.57%
Average	41.11	-0.52	-1.26%	41.13	-0.82	-2.00%
Median	40.48	-0.40	-1.04%	40.46	-0.69	-1.70%
Population-Weighted Average [d]	53.56	0.45	0.84%	53.89	0.55	1.03%
Daily 8-Hour Average Concentration (ppb)						
Minimum [c]	23.77	-0.01	-0.04%	23.77	-0.01	-0.05%
Maximum [c]	157.49	1.33	0.84%	161.92	5.94	3.67%
Average	40.68	-0.51	-1.25%	40.69	-0.81	-1.99%
Median	40.11	-0.36	-1.03%	40.09	-0.72	-1.79%
Population-Weighted Average [d]	51.96	0.46	0.88%	52.29	0.57	1.10%
Daily 12-Hour Average Concentration (ppb)						
Minimum [c]	22.13	0.31	1.39%	22.09	0.44	2.01%
Maximum [c]	140.48	1.65	1.18%	143.59	1.78	1.24%
Average	39.30	-0.48	-1.23%	39.31	-0.77	-1.95%
Median	38.85	-0.38	-0.97%	38.82	-0.58	-1.50%
Population-Weighted Average [d]	47.68	0.49	1.02%	47.99	0.63	1.32%
Daily 24-Hour Average Concentration (ppb)						
Minimum [c]	14.08	0.22	1.60%	14.03	0.32	2.30%
Maximum [c]	95.27	0.41	0.43%	96.59	0.29	0.30%
Average	33.42	-0.38	-1.14%	33.42	-0.61	-1.82%
Median	32.97	-0.30	-0.89%	32.95	-0.61	-1.85%
Population-Weighted Average [d]	35.53	0.47	1.31%	35.74	0.63	1.77%

[a] These ozone metrics are calculated at the CAMX grid-cell level for use in health effects estimates based on the results of spatial and temporal Voronoi Neighbor Averaging. Except for the daily 24-hour average, these ozone metrics are calculated over relevant time periods during the daylight hours of the "ozone season," i.e., May through September. For the 5-hour average, the relevant time period is 10 am to 3 pm; for the 8-hr average, it is 9 am to 5 pm; and, for the 12-hr average it is 8 am to 8 pm.

[b] The change is defined as the control case value minus the base case value. The percent change is the "Change" divided by the "Base Case," and then multiplied by 100 to convert the value to a percentage.

[c] The base case minimum (maximum) is the value for the CAMX grid cell with the lowest (highest) value.

[d] Calculated by summing the product of the projected CAMX grid-cell population and the estimated CAMX grid-cell seasonal ozone concentration, and then dividing by the total population.

Table 9A-11.
Summary of CAMx Derived Ozone Air Quality Metrics Due to Preliminary Control Option for Nonroad Engine/Diesel Fuel Standards for Welfare Benefits Endpoints: 2020 and 2030

Statistic [a]	2020			2030		
	Base Case	Change [b]	Percent Change [b]	Base Case	Change [b]	Percent Change [b]
Eastern U.S.						
Sum06 (ppm)						
Minimum [c]	0.00	0.00	-	0.00	0.00	-
Maximum [c]	67.24	-3.30	-4.91	68.63	-5.54	-8.07%
Average	4.74	-0.72	-15.10	4.88	-1.09	-22.43%
Median	2.18	-0.76	-35.02	2.21	-0.77	-34.84%
Western U.S.						
Sum06 (ppm)						
Minimum [c]	0.00	0.00	-	0.00	0.00	-
Maximum [c]	132.73	6.09	4.59	137.71	8.45	6.14%
Average	2.78	-0.22	-7.85	2.83	-0.33	-11.72%
Median	0.00	0.00	-	0.00	0.00	-

[a] SUM06 is defined as the cumulative sum of hourly ozone concentrations over 0.06 ppm (or 60 ppb) that occur during daylight hours (from 8am to 8pm) in the months of May through September. It is calculated at the county level for use in agricultural benefits based on the results of temporal and spatial Voronoi Neighbor Averaging.

[b] The change is defined as the control case value minus the base case value. The percent change is the "Change" divided by the "Base Case," which is then multiplied by 100 to convert the value to a percentage.

[c] The base case minimum (maximum) is the value for the county level observation with the lowest (highest) concentration.

9A.2.3 Visibility Degradation Estimates

Visibility degradation is often directly proportional to decreases in light transmittal in the atmosphere. Scattering and absorption by both gases and particles decrease light transmittance. To quantify changes in visibility, our analysis computes a light-extinction coefficient, based on the work of Sisler (1996), which shows the total fraction of light that is decreased per unit distance. This coefficient accounts for the scattering and absorption of light by both particles and gases, and accounts for the higher extinction efficiency of fine particles compared to coarse particles. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon (soot), and soil (Sisler, 1996).

Based upon the light-extinction coefficient, we also calculated a unitless visibility index, called a "deciview," which is used in the valuation of visibility. The deciview metric provides a linear scale for perceived visual changes over the entire range of conditions, from clear to hazy. Under many scenic conditions, the average person can generally perceive a change of one deciview. The higher the deciview value, the worse the visibility. Thus, an improvement in visibility is a decrease in deciview value.

Table 9A-11 provides the distribution of visibility improvements across 2020 and 2030 populations resulting from the Nonroad Engine/Diesel Fuel rule. The majority of the 2030 U.S. population live in areas with predicted improvement in annual average visibility of between 0.4 to 0.6 deciviews resulting from the rule. As shown, almost 20 percent of the 2030 U.S. population are predicted to experience improved annual average visibility of greater than 0.6 deciviews. Furthermore, roughly 70 percent of the 2030 U.S. population will benefit from reductions in annual average visibility of greater than 0.4 deciviews. The information provided in Table 9A-11 indicates how widespread the improvements in visibility are expected to be and the share of populations that will benefit from these improvements.

Because the visibility benefits analysis distinguishes between general regional visibility degradation and that particular to Federally-designated Class I areas (i.e., national parks, forests, recreation areas, wilderness areas, etc.), we separated estimates of visibility degradation into “residential” and “recreational” categories. The estimates of visibility degradation for the “recreational” category apply to Federally-designated Class I areas, while estimates for the “residential” category apply to non-Class I areas. Deciview estimates are estimated using outputs from REMSAD for the 2020 and 2030 base cases and control scenarios.

Table 9A-12.
Distribution of Populations Experiencing Visibility Improvements Due to Preliminary Control Option for Nonroad Diesel Engine Standards: 2020 and 2030

Improvements in Visibility [a] *(annual average deciviews)*	*2020 Population*		*2030 Population*	
	Number (millions)	*Percent (%)*	*Number (millions)*	*Percent (%)*
0 < Δ Deciview ≤ 0.2	52.0	15.8%	11.6	3.3%
0.2 < Δ Deciview ≤ 0.4	115.5	35.0%	179.7	50.5%
0.4 < Δ Deciview ≤ 0.6	81.3	24.7%	90.5	25.4%
0.6 < Δ Deciview ≤ 0.8	62.0	18.8%	49.1	13.8%
0.8 < Δ Deciview ≤ 1.0	13.2	4.0%	16.4	4.6%
Δ Deciview > 1.0	5.6	1.7%	8.5	2.4%

[a] The change is defined as the control case deciview level minus the base case deciview level.

9A.2.3.1 Residential Visibility Improvements

Air quality modeling results predict that the Nonroad Engine/Diesel Fuel rule will create improvements in visibility through the country. In Table 9A-12, we summarize residential visibility improvements across the Eastern and Western U.S. in 2020 and 2030. The baseline annual average visibility for all U.S. counties is 14.8 deciviews. The mean improvement across all U.S. counties is 0.28 deciviews, or almost 2 percent. In urban areas with a population of 250,000 or more (i.e., 1,209 out of 5,147 counties), the mean improvement in annual visibility was 0.39 deciviews and ranged from 0.05 to 1.08 deciviews. In rural areas (i.e., 3,938 counties), the mean improvement in visibility was 0.25 deciviews in 2030 and ranged from 0.02 to 0.94 deciviews.

On average, the Eastern U.S. experienced slightly larger absolute but smaller relative improvements in visibility than the Western U.S. from the Nonroad Engine/Diesel Fuel reductions. In Eastern U.S., the mean improvement was 0.34 deciviews from an average baseline of 19.32 deciviews. Western counties experienced a mean improvement of 0.21 deciviews from an average baseline of 9.75 deciviews projected in 2030. Overall, the data suggest that the Nonroad Engine/Diesel Fuel rule has the potential to provide widespread improvements in visibility for 2020 and 2030.

Table 9A-13.
Summary of Baseline Residential Visibility and Changes by Region: 2020 and 2030
(Annual Average Deciviews)

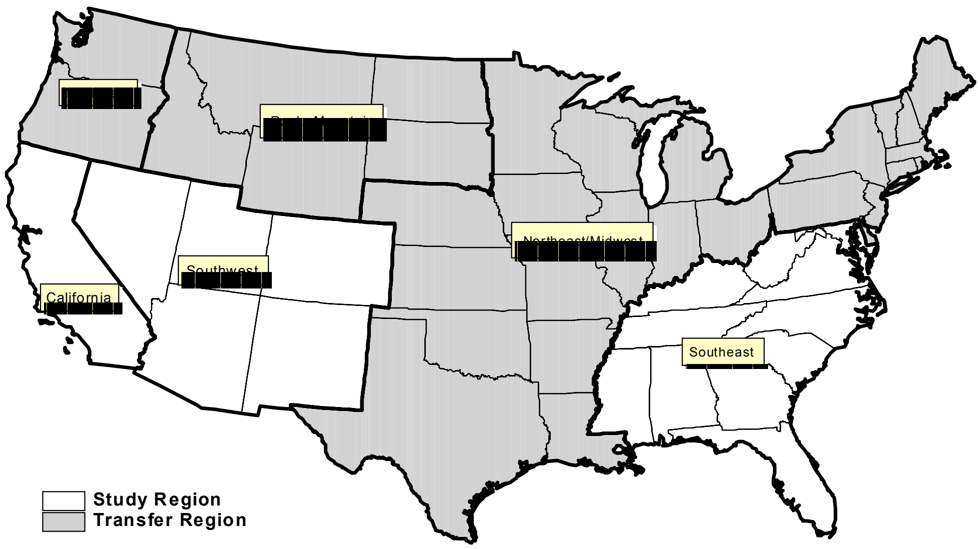
	2020			*2030*		
Regions[a]	*Base Case*	*Change*[b]	*Percent Change*	*Base Case*	*Change*[b]	*Percent Change*
Eastern U.S.	20.27	0.24	1.3%	20.54	0.33	1.7%
Urban	21.61	0.24	1.2%	21.94	0.33	1.6%
Rural	19.73	0.24	1.3%	19.98	0.33	1.8%
Western U.S.	8.69	0.18	2.1%	8.83	0.25	2.8%
Urban	9.55	0.25	2.7%	9.78	0.35	3.6%
Rural	8.50	0.17	2.0%	8.61	0.23	2.7%
National, all counties	14.77	0.21	1.7%	14.98	0.29	2.3%
Urban	17.21	0.24	1.7%	17.51	0.34	2.3%
Rural	14.02	0.20	1.6%	14.20	0.28	2.2%

[a] Eastern and Western regions are separated by 100 degrees north longitude. Background visibility conditions differ by region.
[b] An improvement in visibility is a decrease in deciview value. The change is defined as the Nonroad Engine/Diesel Fuel control case deciview level minus the basecase deciview level.

9A.2.3.2 Recreational Visibility Improvements

In Table 9A-13, we summarize recreational visibility improvements by region in 2020 and 2030 in Federal Class I areas. These recreational visibility regions are shown in Figure 9A-6. As shown, the national improvement in visibility for these areas increases from 1.5 percent, or 0.18 deciviews, in 2020 to 2.1 percent, or 0.24 deciviews, in 2030. Predicted relative visibility improvements are the largest in the Western U.S. as shown for California (3.2% in 2030), and the Southwest (2.9%) and the Rocky Mountain (2.5%). Federal Class I areas in the Eastern U.S. are predicted to have an absolute improvement of 0.24 deciviews in 2030, which reflects a 1.1 to 1.3 percent change from 2030 baseline visibility of 20.01 deciviews.

Figure 9A-6. Recreational Visibility Regions for Continental U.S.



Note: Study regions were represented in the Chestnut and Rowe (1990a, 1990b) studies used in evaluating the benefits of visibility improvements, while transfer regions used extrapolated study results.

Table 9A-14.
Summary of Baseline Recreational Visibility and Changes by Region: 2020 and 2030
(Annual Average Deciviews)

Class I Visibility Regions[a]	*2020*			*2030*		
	Base Case	*Change*[b]	*Percent Change*	*Base Case*	*Change*[b]	*Percent Change*
Eastern U.S.	19.72	0.18	0.9%	20.01	0.24	1.2%
Southeast	21.31	0.18	0.9%	21.62	0.24	1.1%
Northeast/Midwest	18.30	0.18	1.0%	18.56	0.24	1.3%
Western U.S.	8.80	0.17	2.0%	8.96	0.24	2.7%
California	9.33	0.21	2.3%	9.56	0.30	3.2%
Southwest	6.87	0.16	2.3%	7.03	0.21	2.9%
Rocky Mountain	8.46	0.15	1.8%	8.55	0.21	2.5%
Northwest	12.05	0.18	1.5%	12.18	0.24	2.0%
National Average (unweighted)	11.61	0.18	1.5%	11.80	0.24	2.1%

[a] Regions are pictured in Figure VI-5 and are defined in the technical support document (see Abt Associates, 2003).
[b] An improvement in visibility is a decrease in deciview value. The change is defined as the Nonroad Engine/Diesel Fuel control case deciview level minus the basecase deciview level.

9A.3 Benefit Analysis- Data and Methods

Environmental and health economists have a number of methods for estimating the economic value of improvements in (or deterioration of) environmental quality. The method used in any given situation depends on the nature of the effect and the kinds of data, time, and resources that are available for investigation and analysis. This section provides an overview of the methods we selected to quantify and monetize the benefits included in this RIA.

Given changes in environmental quality (ambient air quality, visibility, nitrogen and sulfate deposition, odor), the next step is to determine the economic value of those changes. We follow a "damage-function" approach in calculating total benefits of the modeled changes in environmental quality. This approach estimates changes in individual health and welfare endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the individual values. Total benefits are calculated simply as the sum of the values for all non-overlapping health and welfare endpoints. This imposes no overall preference structure, and does not account for potential income or substitution effects, i.e. adding a new endpoint will not reduce the value of changes in other endpoints. The "damage-function" approach is the standard approach for most cost-benefit analyses of environmental quality programs, and has been used in several recent published analyses (Banzhaf et al., 2002; Levy et al., 2001; Levy et al., 1999; Ostro and Chestnut, 1998).

In order to assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued, as is the case for changes in visibility. In other cases, such as for changes in ozone and PM, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

For the purposes of this RIA, the health impacts analysis is limited to those health effects that are directly linked to ambient levels of air pollution, and specifically to those linked to ozone and particulate matter. There are known health effects associated with other emissions expected to be reduced by these standards, however, due to limitations in air quality models, we are unable to quantify the changes in the ambient levels of CO, SO_2, and air toxics such as benzene.[j] There may be other, indirect health impacts associated with implementation of controls to meet the preliminary control options, such as occupational health impacts for equipment operators. These impacts may be positive or negative, but in general, for this set of preliminary control options, are expected to be small relative to the direct air pollution related impacts.

The welfare impacts analysis is limited to changes in the environment that have a direct impact on human welfare. For this analysis, we are limited by the available data to examining impacts of changes in visibility and agricultural yields. We also provide qualitative discussions of the impact of changes in other environmental and ecological effects, for example, changes in deposition of nitrogen and sulfur to terrestrial and aquatic ecosystems and odor, but we are unable to place an economic value on these changes.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure either the health outcomes or their values for this analysis. Thus, similar to Kunzli et al. (2000) and other recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Where appropriate, adjustments are made for the level of environmental quality change, the sociodemographic and economic characteristics of the

[J] Several commentators from the public and from public interest groups noted that occupational studies have shown diesel exhaust, as a mixture, to be carcinogenic. In addition, several of these commentors also noted that diesel exhaust contains carcinogenic hazardous air pollutants (HAPs). For these reasons, it was suggested that EPA should include modeling of cancer incidence associated with exposure to the carcinogenic components of diesel exhaust. Diesel particles producing lung cancer mortality may be included in the lung cancer mortality estimates for $PM_{2.5}$. We also acknowledge both that diesel exhaust as a mixture is likely to be carcinogenic and that it contains specific carcinogenic HAPs which represent a cancer risk. However, at this time, as discussed in Chapter 2, we do not believe that the data support the determination of a unit risk for diesel exhaust as a mixture and therefore, lifetime mortality attributable to diesel exhaust exposure cannot be quantified for purposes of benefits analysis.

affected population, and other factors in order to improve the accuracy and robustness of benefits estimates.

9A.3.1 Valuation Concepts

In valuing health impacts, we note that reductions in ambient concentrations of air pollution generally lower the risk of future adverse health affects by a fairly small amount for a large population. The appropriate economic measure is therefore willingness-to-pay for changes in risk prior to the regulation (Freeman, 1993). In general, economists tend to view an individual's willingness-to-pay (WTP) for a improvement in environmental quality as the appropriate measure of the value of a risk reduction. An individual's willingness-to-accept (WTA) compensation for not receiving the improvement is also a valid measure. However, WTP is generally considered to be a more readily available and conservative measure of benefits. Adoption of WTP as the measure of value implies that the value of environmental quality improvements is dependent on the individual preferences of the affected population and that the existing distribution of income (ability to pay) is appropriate. For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as a primary estimate. These costs of illness (COI) estimates generally understate the true value of reductions in risk of a health effect, reflecting the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect (Harrrington and Portnoy, 1987; Berger, 1987).

For many goods, WTP can be observed by examining actual market transactions. For example, if a gallon of bottled drinking water sells for one dollar, it can be observed that at least some persons are willing to pay one dollar for such water. For goods not exchanged in the market, such as most environmental "goods," valuation is not as straightforward. Nevertheless, a value may be inferred from observed behavior, such as sales and prices of products that result in similar effects or risk reductions, (e.g., non-toxic cleaners or bike helmets). Alternatively, surveys may be used in an attempt to directly elicit WTP for an environmental improvement.

One distinction in environmental benefits estimation is between use values and non-use values. Although no general agreement exists among economists on a precise distinction between the two (see Freeman, 1993), the general nature of the difference is clear. Use values are those aspects of environmental quality that affect an individual's welfare more or less directly. These effects include changes in product prices, quality, and availability, changes in the quality of outdoor recreation and outdoor aesthetics, changes in health or life expectancy, and the costs of actions taken to avoid negative effects of environmental quality changes.

Non-use values are those for which an individual is willing to pay for reasons that do not relate to the direct use or enjoyment of any environmental benefit, but might relate to existence values and bequest values. Non-use values are not traded, directly or indirectly, in markets. For this reason, the measurement of non-use values has proved to be significantly more difficult than the measurement of use values. The air quality changes produced by the Nonroad Diesel Engine rule cause changes in both use and non-use values, but the monetary benefit estimates are almost exclusively for use values.

More frequently than not, the economic benefits from environmental quality changes are not traded in markets, so direct measurement techniques can not be used. There are three main non-market valuation methods used to develop values for endpoints considered in this analysis. These include stated preference (or contingent valuation), indirect market (e.g. hedonic wage), and avoided cost methods.

The stated preference or CV method values endpoints by using carefully structured surveys to ask a sample of people what amount of compensation is equivalent to a given change in environmental quality. There is an extensive scientific literature and body of practice on both the theory and technique of stated preference based valuation. EPA believes that well-designed and well-executed stated preference studies are valid for estimating the benefits of air quality regulation.[k] Stated preference valuation studies form the basis for valuing a number of health and welfare endpoints, including the value of premature mortality risk reductions, chronic bronchitis risk reductions, minor illness risk reductions, and visibility improvements.

Indirect market methods can also be used to infer the benefits of pollution reduction. The most important application of this technique for our analysis is the calculation of the value of a statistical life for use in the estimate of benefits from premature mortality risk reductions. There exists no market where changes in the probability of death are directly exchanged. However, people make decisions about occupation, precautionary behavior, and other activities associated with changes in the risk of death. By examining these risk changes and the other characteristics of people's choices, it is possible to infer information about the monetary values associated with changes in premature mortality risk (see Section 9A.3.5.5.1).

Avoided cost methods are ways to estimate the costs of pollution by using the expenditures made necessary by pollution damage. For example, if buildings must be cleaned or painted more

[K]Concerns about the reliability of value estimates from CV studies arose because research has shown that bias can be introduced easily into these studies if they are not carefully conducted. Accurately measuring WTP for avoided health and welfare losses depends on the reliability and validity of the data collected. There are several issues to consider when evaluating study quality, including but not limited to 1) whether the sample estimates of WTP are representative of the population WTP; 2) whether the good to be valued is comprehended and accepted by the respondent; 3) whether the WTP elicitation format is designed to minimize strategic responses; 4) whether WTP is sensitive to respondent familiarity with the good, to the size of the change in the good, and to income; 5) whether the estimates of WTP are broadly consistent with other estimates of WTP for similar goods; and 6) the extent to which WTP responses are consistent with established economic principles.

frequently as levels of PM increase, then the appropriately calculated increment of these costs is a reasonable lower bound estimate (under most conditions) of true economic benefits when PM levels are reduced. Avoided costs methods are also used to estimate some of the health-related benefits related to morbidity, such as hospital admissions (see section 9A.3.5).

The most direct way to measure the economic value of air quality changes is in cases where the endpoints have market prices. For the final rule, this can only be done for effects on commercial agriculture. Well-established economic modeling approaches are used to predict price changes that result from predicted changes in agricultural outputs. Consumer and producer surplus measures can then be developed to give reliable indications of the benefits of changes in ambient air quality for this category (see Section 9A.3.6.2).

9A.3.2 Growth in WTP Reflecting National Income Growth Over Time

Our analysis accounts for expected growth in real income over time. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real incomes increase. There is substantial empirical evidence that the income elasticity[l] of WTP for health risk reductions is positive, although there is uncertainty about its exact value. Thus, as real income increases the WTP for environmental improvements also increases. While many analyses assume that the income elasticity of WTP is unit elastic (i.e., ten percent higher real income level implies a ten percent higher WTP to reduce risk changes), empirical evidence suggests that income elasticity is substantially less than one and thus relatively inelastic. As real income rises, the WTP value also rises but at a slower rate than real income.

The effects of real income changes on WTP estimates can influence benefit estimates in two different ways: (1) through real income growth between the year a WTP study was conducted and the year for which benefits are estimated, and (2) through differences in income between study populations and the affected populations at a particular time. Empirical evidence of the effect of real income on WTP gathered to date is based on studies examining the former. The Environmental Economics Advisory Committee (EEAC) of the SAB advised EPA to adjust WTP for increases in real income over time, but not to adjust WTP to account for cross-sectional income differences "because of the sensitivity of making such distinctions, and because of insufficient evidence available at present" (EPA-SAB-EEAC-00-013).

Based on a review of the available income elasticity literature, we adjust the valuation of human health benefits upward to account for projected growth in real U.S. income. Faced with a dearth of estimates of income elasticities derived from time-series studies, we applied estimates

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[L]Income elasticity is a common economic measure equal to the percentage change in WTP for a one percent change in income.

derived from cross-sectional studies in our analysis. Details of the procedure can be found in Kleckner and Neumann (1999). An abbreviated description of the procedure we used to account for WTP for real income growth between 1990 and 2030 is presented below.[m]

Reported income elasticities suggest that the severity of a health effect is a primary determinant of the strength of the relationship between changes in real income and WTP. As such, we use different elasticity estimates to adjust the WTP for minor health effects, severe and chronic health effects, and premature mortality. We also expect that the WTP for improved visibility in Class I areas would increase with growth in real income. The elasticity values used to adjust estimates of benefits in 2020 and 2030 are presented in Table 9A-11.

Table 9A-15. Elasticity Values Used to Account for Projected Real Income Growth[A]

Benefit Category	Central Elasticity Estimate
Minor Health Effect	0.14
Severe and Chronic Health Effects	0.45
Premature Mortality	0.40
Visibility[B]	0.90

[A] Derivation of estimates can be found in Kleckner and Neumann (1999) and Chestnut (1997). Cost of Illness (COI) estimates are assigned an adjustment factor of 1.0.
[B] No range was applied for visibility because no ranges were available in the current published literature.

In addition to elasticity estimates, projections of real GDP and populations from 1990 to 2020 and 2030 are needed to adjust benefits to reflect real per capita income growth. For consistency with the emissions and benefits modeling, we use national population estimates for the years 1990 to 1999 based on U.S. Census Bureau estimates (Hollman, Mulder and Kallan, 2000). These population estimates are based on application of a cohort-component model applied to 1990 U.S. Census data projections[n]. For the years between 2000 and 2030, we applied growth rates based on the U.S. Census Bureau projections to the U.S. Census estimate of national population in 2000. We use projections of real GDP provided in Kleckner and

[M] Industry commentors suggest that the income elasticity values used to adjust willingness to pay (WTP) values for avoidance of adverse health effects are based on incorrect methodology. Specifically, they assert that EPA values are based on cross-sectional data when they should be based on time series data. The method we used to derive income adjustment factors, which is detailed here, is consistent with advice from the SAB-EEAC and reflect modest increases in WTP over time. Some recent evidence from published meta-analyses (see Viscusi and Aldy, 2003) suggest that we should be using a larger income adjustment factor for premature mortality.

[N]U.S. Bureau of Census. Annual Projections of the Total Resident Population, Middle Series, 1999-2100. (Available on the internet at http://www.census.gov/population/www/projections/natsum-T1.html)

Neumann (1999) for the years 1990 to 2010[o]. We use projections of real GDP (in chained 1996 dollars) provided by Standard and Poor's[p] for the years 2010 to 2024[q]. The Standard and Poor's database only provides estimates of real GDP between 1990 and 2024. We were unable to find reliable projections of GDP past 2024. As such, we assume that per capita GDP remains constant between 2024 and 2030.

Using the method outlined in Kleckner and Neumann (1999), and the population and income data described above, we calculate WTP adjustment factors for each of the elasticity estimates listed in Table 1. Benefits for each of the categories (minor health effects, severe and chronic health effects, premature mortality, and visibility) will be adjusted by multiplying the unadjusted benefits by the appropriate adjustment factor. Table 2 lists the estimated adjustment factors. Note that for premature mortality, we apply the income adjustment factor ex post to the present discounted value of the stream of avoided mortalities occurring over the lag period. Also note that no adjustments will be made to benefits based on the cost-of-illness approach or to work loss days and worker productivity. This assumption will also lead us to under predict benefits in future years since it is likely that increases in real U.S. income would also result in increased cost-of-illness (due, for example, to increases in wages paid to medical workers) and increased cost of work loss days and lost worker productivity (reflecting that if worker incomes are higher, the losses resulting from reduced worker production would also be higher). No adjustments are needed for agricultural benefits, as the model is based on projections of supply and demand in future years and should already incorporate future changes in real income.

[O]U.S. Bureau of Economic Analysis, Table 2A (1992$). (Available on the internet at http://www.bea.doc.gov/bea/dn/0897nip2/tab2a.htm) and U.S. Bureau of Economic Analysis, Economics and Budget Outlook. Note that projections for 2007 to 2010 are based on average GDP growth rates between 1999 and 2007.

[P]Standard and Poor's. 2000. "The U.S. Economy: The 25 Year Focus." Winter.

[Q]In previous analyses, we used the Standard and Poor's projections of GDP directly. This led to an apparent discontinuity in the adjustment factors between 2010 and 2011. We refined the method by applying the relative growth rates for GDP derived from the Standard and Poor's projections to the 2010 projected GDP based on the Bureau of Economic Analysis projections.

Table 9A-16. Adjustment Factors Used to Account for Projected Real Income Growth[A,B]

Benefit Category	2020	2030[C]
Minor Health Effect	1.066	1.076
Severe and Chronic Health Effects	1.229	1.266
Premature Mortality	1.201	1.233
Visibility	1.516	1.613

[A] Based on elasticity values reported in Table 9A-11, US Census population projections, and projections of real gross domestic product per capita.
[B] Note that these factors have been modified from the proposal analysis to refelect relative growth rates for GDP derived from the Standard and Poor's projections rather than absolute growth rates.
[C] Income growth adjustment factor for 2030 is based on an assumption that there is no growth in per capita income between 2024 and 2030, based on a lack of available GDP projections beyond 2024.

9A.3.3 Methods for Describing Uncertainty

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty.[r] This analysis is no exception. As outlined both in this and preceding chapters, many inputs are used to derive the final estimate of benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological health effect estimates, estimates of values (both from WTP and cost-of-illness studies), population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain, and depending on their location in the benefits analysis, may have a disproportionately large impact on final estimates of total benefits. For example, emissions estimates are used in the first stage of the analysis. As such, any uncertainty in emissions estimates will be propagated through the entire analysis. When compounded with uncertainty in later stages, small uncertainties in emission levels can lead to much larger impacts on total benefits. A more thorough discussion of uncertainty can be found in the benefits technical support document (TSD) (Abt Associates, 2003).

Some key sources of uncertainty in each stage of the benefits analysis are:

- Gaps in scientific data and inquiry;

[R] It should be recognized that in addition to uncertainty, the annual benefit estimates for the Nonroad Diesel Engines rulemaking presented in this analysis are also inherently variable, due to the truly random processes that govern pollutant emissions and ambient air quality in a given year. Factors such as engine hours and weather display constant variability regardless of our ability to accurately measure them. As such, the estimates of annual benefits should be viewed as representative of the types of benefits that will be realized, rather than the actual benefits that would occur every year.

- Variability in estimated relationships, such as epidemiological effect estimates, introduced through differences in study design and statistical modeling;
- Errors in measurement and projection for variables such as population growth rates;
- Errors due to misspecification of model structures, including the use of surrogate variables, such as using PM_{10} when $PM_{2.5}$ is not available, excluded variables, and simplification of complex functions; and
- Biases due to omissions or other research limitations.

Some of the key uncertainties in the benefits analysis are presented in Table 9A-13. Given the wide variety of sources for uncertainty and the potentially large degree of uncertainty about any primary estimate, it is necessary for us to address this issue in several ways, based on the following types of uncertainty:

a. *Quantifiable uncertainty in benefits estimates.* For some parameters or inputs it may be possible to provide a statistical representation of the underlying uncertainty distribution. Quantitative uncertainty may include measurement uncertainty or variation in estimates across or within studies. For example, the variation in VSL results across available meta-analyses provides a quantifiable basis for representing some uncertainty that can be calculated for monetized benefits. Methods typically used to evaluate the impact of these quantifiable sources of uncertainty on benefits and incidence estimates center on Monte Carlo-based probabilistic simulation. This technique allows uncertainty in key inputs to be propagated through the model to generate a single distribution of results reflecting the combined impact of multiple sources of uncertainty. Variability can also be considered along with uncertainty using nested two-stage Monte Carlo simulation.

b. *Uncertainty in the basis for quantified estimates*. Often it is possible to identify a source of uncertainty (for example, an ongoing debate over the proper method to estimate premature mortality) that is not readily addressed through traditional uncertainty analysis. In these cases, it is possible to characterize the potential impact of this uncertainty on the overall benefits estimates through sensitivity analyses.

c. *Nonquantifiable uncertainty.* Uncertainties may also result from omissions of known effects from the benefits calculation, perhaps owing to a lack of data or modeling capability. For example, in this analysis we were unable to quantify the benefits of avoided airborne nitrogen deposition on aquatic and terrestrial ecosystems, diesel odor, or avoided health and environmental effects associated with reductions in CO emissions.

It should be noted that, even for individual endpoints, there is usually more than one source of uncertainty. This makes it difficult to provide an overall quantified uncertainty estimate for individual endpoints or for total benefits, without conducting a comprehensive uncertainty analysis that considers the aggregate impact of multiple sources of uncertainty on benefits estimates.

The NAS report on the EPA's benefits analysis methodology highlighted the need for the EPA to conduct rigorous quantitative analysis of uncertainty in its benefits estimates. In response to these comments, the EPA has initiated the development of a comprehensive methodology for characterizing the aggregate impact of uncertainty in key modeling elements on both health incidence and benefits estimates. This methodology will begin by identifying those modeling elements that have a significant impact on benefits due to either the magnitude of their uncertainty or other factors such as nonlinearity within the modeling framework. A combination of influence analysis and sensitivity analysis methods may be used to focus the analysis of uncertainty on these key sources of uncertainty. A probabilistic simulation approach based on Monte Carlo methods will be developed for propagating the impact of these sources of uncertainty through the modeling framework. Issues such as correlation between input parameters and the identification of reasonable upper and lower bounds for input distributions characterizing uncertainty will be addressed in developing the approach.

For this analysis of the final rule, EPA has addressed key sources of uncertainty through a series of sensitivity analyses examining the impact of alternate assumptions on the benefits estimates that are generated. Sensitivity estimates are presented in Appendix 9C. We also present information related to an expert elicitation pilot in Appendix 9B.

Our estimate of total benefits should be viewed as an approximate result because of the sources of uncertainty discussed above (see Table 9A-13). Uncertainty about specific aspects of the health and welfare estimation models are discussed in greater detail in the following sections and in the benefits TSD (Abt Associates, 2003). The total benefits estimate may understate or overstate actual benefits of the rule.

In considering the monetized benefits estimates, the reader should remain aware of the many limitations of conducting these analyses mentioned throughout this RIA. One significant limitation of both the health and welfare benefits analyses is the inability to quantify many of the serious effects listed in Table 9A-1. For many health and welfare effects, such as changes in ecosystem functions and PM-related materials damage, reliable C-R functions and/or valuation functions are not currently available. In general, if it were possible to monetize these benefits categories, the benefits estimates presented in this analysis would increase. Unquantified benefits are qualitatively discussed in the health and welfare effects sections. In addition to unquantified benefits, there may also be environmental costs that we are unable to quantify. Several of these environmental cost categories are related to nitrogen deposition, while one category is related to the issue of ultraviolet light. These endpoints are qualitatively discussed in the health and welfare effects sections as well. The net effect of excluding benefit and disbenefit categories from the estimate of total benefits depends on the relative magnitude of the effects.

Table 9A-17. Primary Sources of Uncertainty in the Benefit Analysis

1. Uncertainties Associated With Health Impact Functions
– The value of the ozone or PM effect estimate in each health impact function. – Application of a single effect estimate to pollutant changes and populations in all locations. – Similarity of future year effect estimates to current effect estimates. – Correct functional form of each impact function. – Extrapolation of effect estimates beyond the range of ozone or PM concentrations observed in the study. – Application of effect estimates only to those subpopulations matching the original study population.
2. Uncertainties Associated With Ozone and PM Concentrations
– Responsiveness of the models to changes in precursor emissions resulting from the control policy. – Projections of future levels of precursor emissions, especially ammonia and crustal materials. – Model chemistry for the formation of ambient nitrate concentrations. – Lack of ozone monitors in rural areas requires extrapolation of observed ozone data from urban to rural areas. – Use of separate air quality models for ozone and PM does not allow for a fully integrated analysis of pollutants and their interactions. – Full ozone season air quality distributions are extrapolated from a limited number of simulation days. – Comparison of model predictions of particulate nitrate with observed rural monitored nitrate levels indicates that REMSAD overpredicts nitrate in some parts of the Eastern US and underpredicts nitrate in parts of the Western US.
3. Uncertainties Associated with PM Premature mortality Risk
– No scientific literature supporting a direct biological mechanism for observed epidemiological evidence. – Direct causal agents within the complex mixture of PM have not been identified. – The extent to which adverse health effects are associated with low level exposures that occur many times in the year versus peak exposures. – The extent to which effects reported in the long-term exposure studies are associated with historically higher levels of PM rather than the levels occurring during the period of study. – Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.
4. Uncertainties Associated With Possible Lagged Effects
– The portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels would occur in a single year is uncertain as well as the portion that might occur in subsequent years.
5. Uncertainties Associated With Baseline Incidence Rates
– Some baseline incidence rates are not location-specific (e.g., those taken from studies) and may therefore not accurately represent the actual location-specific rates. – Current baseline incidence rates may not approximate well baseline incidence rates in 2030. – Projected population and demographics may not represent well future-year population and demographics.
6. Uncertainties Associated With Economic Valuation
– Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them. – Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates due to differences in income or other factors. – Future markets for agricultural products are uncertain.
7. Uncertainties Associated With Aggregation of Monetized Benefits
– Health and welfare benefits estimates are limited to the available effect estimates. Thus, unquantified or unmonetized benefits are not included.

9A.3.4 Demographic Projections

Quantified and monetized human health impacts depend critically on the demographic characteristics of the population, including age, location, and income. In previous analyses, we have used simple projections of total population that did not take into account changes in demographic composition over time. In the current analysis, we use more sophisticated projections based on economic forecasting models developed by Woods and Poole, Inc. The Woods and Poole (WP) database contains county level projections of population by age, sex, and race out to 2025. Projections in each county are determined simultaneously with every other county in the U.S. to take into account patterns of economic growth and migration. The sum of growth in county level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollman, Mulder and Kallan, 2000). According to WP, linking county level growth projections together and constraining to a national level total growth avoids potential errors introduced by forecasting each county independently. County projections are developed in a four stage process. First, national level variables such as income, employment, populations, etc. are forecasted. Second, employment projections are made for 172 economic areas defined by the Bureau of Economic Analysis, using an "export-base" approach, which relies on linking industrial sector production of non-locally consumed production items, such as outputs from mining, agriculture, and manufacturing with the national economy. The export-base approach requires estimation of demand equations or calculation of historical growth rates for output and employment by sector. Third, population is projected for each economic area based on net migration rates derived from employment opportunities, and following a cohort-component method based on fertility and mortality in each area. Fourth, employment and population projections are repeated for counties, using the economic region totals as bounds. The age, sex, and race distributions for each region or county are determined by aging the population by single year of age by sex and race for each year through 2025 based on historical rates of mortality, fertility, and migration.

The WP projections of county level population are based on historical population data from 1969-1999, and do not include the 2000 Census results. Given the availability of detailed 2000 Census data, we constructed adjusted county level population projections for each future year using a two stage process. First, we constructed ratios of the projected WP populations in a future year to the projected WP population in 2000 for each future year by age, sex, and race. Second, we multiplied the block level 2000 Census population data by the appropriate age, sex, and race specific WP ratio for the county containing the census block, for each future year. This results in a set of future population projections that is consistent with the most recent detailed census data. The WP projections extend only through 2025. To calculate populations for 2030, we applied the growth rate from 2024 to 2025 to each year between 2025 and 2030.

Figure 9A-7 shows the projected trends in total U.S. population and the percentage of total population aged zero to eighteen and over 65. This figure illustrates that total populations are projected increase from 281 million in 2000 to 345 million in 2025. The percent of the population 18 and under is expected to decrease slightly, from 27 to 25 percent, and the percent of the population over 65 is expected to increase from 12 percent to 18 percent.

populations. For consistency with the emissions and benefits modeling, we use national population estimates based on the U.S. Census Bureau projections. We use projections of real GDP provided in Kleckner and Neumann (1999) for the years 1990 to 2010.[s] We use projections of real GDP (in chained 1996 dollars) provided by Standard and Poor's for the years 2010 to 2024.[t] The Standard and Poor's database only provides estimates of real GDP between 1990 and 2024. We were unable to find reliable projections of GDP beyond 2024. As such, we assume that per capita GDP remains constant between 2024 and 2030. This assumption will lead us to under-predict benefits because at least some level of income growth would be projected to occur between the years 2024 and 2030.

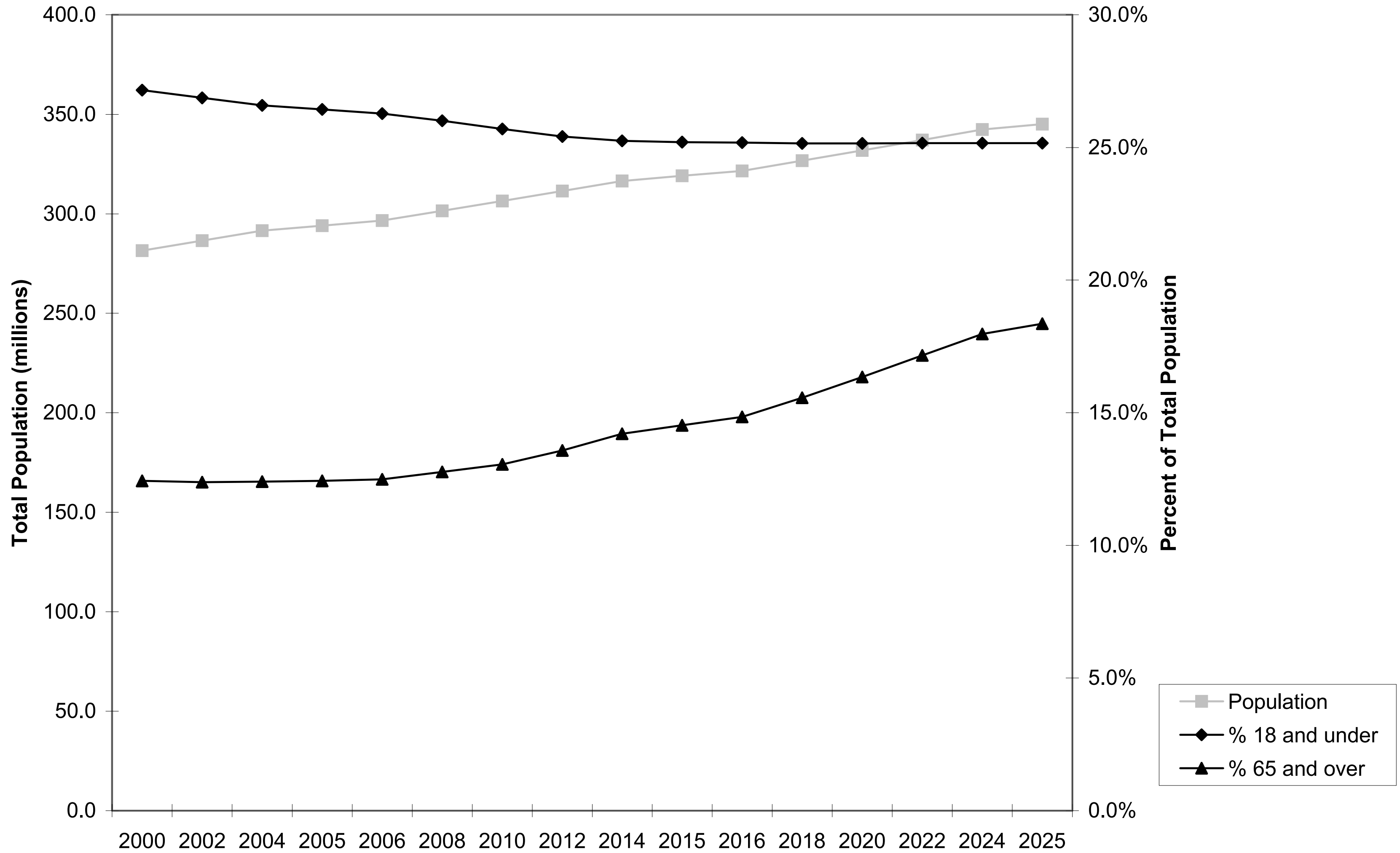
9A.3.5 Health Benefits Assessment Methods

The most significant monetized benefits of reducing ambient concentrations of PM and ozone are attributable to reductions in health risks associated with air pollution. The EPA's Criteria Documents for ozone and PM list numerous health effects known to be linked to ambient concentrations of these pollutants (EPA, 1996a and 1996b). As illustrated in Figure 9A-1, quantification of health impacts requires several inputs, including epidemiological effect estimates, baseline incidence and prevalence rates, potentially affected populations, and estimates of changes in ambient concentrations of air pollution. Previous sections have described the population and air quality inputs. This section describes the effect estimates and baseline incidence and prevalence inputs and the methods used to quantify and monetize changes in the expected number of incidences of various health effects.

[S] US Bureau of Economic Analysis, Table 2A (1992$). (Available on the internet at http://www.bea.doc.gov/bea/dn/0897nip2/tab2a.htm) and US Bureau of Economic Analysis, Economics and Budget Outlook. Note that projections for 2007 to 2010 are based on average GDP growth rates between 1999 and 2007.

[T] Standard and Poor's. 2000. "The U.S. Economy: The 25 Year Focus." Winter 2000.

Figure 9A-7.
Projections of U.S. Population, 2000-2025



As noted above, values for environmental quality improvements are expected to increase with growth in real per capita income. Accounting for real income growth over time requires projections of both real gross domestic product (GDP) and total U.S.

9A.3.5.1 Selecting Health Endpoints and Epidemiological Effect Estimates

Quantifiable health benefits of the rule may be related to ozone only, PM only, or both pollutants. Decreased worker productivity, respiratory hospital admissions for children under two, and school absences are related to ozone but not PM. PM-only health effects include premature mortality, nonfatal heart attacks, chronic bronchitis, acute bronchitis, upper and lower respiratory symptoms, asthma exacerbations, and work loss days.[u] Health effects related to both PM and ozone include hospital admissions, emergency room visits for asthma, and minor restricted activity days.

We relied on the available published scientific literature to ascertain the relationship between PM and ozone exposure and adverse human health effects. We evaluated studies using the selection criteria summarized in Table 9A-18. These criteria include consideration of whether the study was peer reviewed, the match between the pollutant studied and the pollutant of interest, the study design and location, and characteristics of the study population, among other considerations. The selection of C-R functions for the benefits analysis is guided by the goal of achieving a balance between comprehensiveness and scientific defensibility.

The Health Effects Institute (HEI) reported findings by health researchers at Johns Hopkins University and others that have raised concerns about aspects of the statistical methods used in a number of recent time-series studies of short-term exposures to air pollution and health effects (Greenbaum, 2002). The estimates derived from the long-term exposure studies, which account for a major share of the economic benefits described in this chapter, are not affected. Similarly, the time-series studies employing generalized linear models (GLMs) or other parametric methods, as well as case-crossover studies, are not affected. As discussed in HEI materials provided to the EPA and to CASAC (Greenbaum, 2002), researchers working on the National Morbidity, Mortality, and Air Pollution Study (NMMAPS) found problems in the default

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[U] Evidence has been found linking ozone exposures with premature mortality independent of PM exposures. A recent analysis by Thurston and Ito (2001) reviewed previously published time-series studies of the effect of daily ozone levels on daily mortality and found that previous EPA estimates of the short-term exposure mortality benefits of the ozone NAAQS (EPA, 1997) may have been underestimated by up to a factor of two, even when PM is controlled for in the models. In its September 2001 advisory on the draft analytical blueprint for the second Section 812 prospective analysis, the SAB cited the Thurston and Ito study as a significant advance in understanding the effects of ozone on daily mortality and recommended re-evaluation of the ozone mortality endpoint for inclusion in the next prospective study (EPA-SAB-COUNCIL-ADV-01-004, 2001). In addition, a recent World Health Organization (WHO) report found that "recent epidemiological studies have strengthened the evidence that there are short-term O3 effects on premature mortality and respiratory morbidity and provided further information on exposure-response relationships and effect modification." (WHO, 2003). Based on these new analyses and recommendations, the EPA is currently reevaluating ozone-related mortality for inclusion in the primary benefits analysis. The EPA is sponsoring three independent meta-analyses of the ozone-mortality epidemiology literature to inform a determination on inclusion of this important health endpoint. Upon completion and peer review of the meta-analyses, the EPA will make its determination on whether benefits of reductions in ozone-related mortality will be included in the future benefits analyses.

"convergence criteria" used in Generalized Additive Models (GAM) and a separate issue first identified by Canadian investigators about the potential to underestimate standard errors in the same statistical package. Following identification of the GAM issue, a number of time-series studies were reanalyzed using alternative methods, typically GAM with more stringent convergence criteria and an alternative model such as generalized linear models (GLM) with natural smoothing splines, and the results of the reanalyses have been compiled and reviewed in a recent HEI publication (HEI, 2003a). In most, but not all, of the reanalyzed studies, it was found that risk estimates were reduced and confidence intervals increased with the use of GAM with more stringent convergence criteria or GLM analyses; however, the reanalyses generally did not substantially change the findings of the original studies, and the changes in risk estimates with alternative analysis methods were much smaller than the variation in effects across studies. The HEI review committee concluded the following:

- Although the number of studies showing an association of PM with premature mortality was slightly smaller, the PM association persisted in the majority of studies.
- In some of the large number of studies in which the PM association persisted, the estimates of PM effect were substantially smaller.
- In the few studies in which investigators performed further sensitivity analyses, some showed marked sensitivity of the PM effect estimate to the degree of smoothing and/or the specification of weather (HEI, 2003b, p. 269)

Examination of the original studies used in our benefits analysis found that the health endpoints that are potentially affected by the GAM issues include reduced hospital admissions and reduced lower respiratory symptoms. For the analysis of the final rule, we have incorporated a number of studies that have been updated to correct for the GAM issue, including Ito et al. (2003) for respiratory-related hospital admissions (COPD and pneumonia), Shepard et al. (2003) for respiratory-related hospital admissions (asthma), Moolgavkar (2003) for cardiovascular-related hospital admissions (ICD codes 390-429), and Ito et al. (2003) for cardiovascular-related hospital admissions (ischemic heart disease, dysrhythmia, and heart failure). Several additional hospital admissions-related studies have not yet been formally updated to correct for the GAM issue. These include the lower respiratory symptoms study and hospital admissions for respiratory and cardiovascular causes in populations aged 20 to 64. However, as discussed above, available evidence suggests that the errors introduced into effect estimates due to the GAM issue should not significantly affect incidence results.

Table 9A-18. Summary of Considerations Used in Selecting C-R Functions

Consideration	Comments
Peer reviewed research	Peer reviewed research is preferred to research that has not undergone the peer review process.
Study type	Among studies that consider chronic exposure (e.g., over a year or longer) prospective cohort studies are preferred over cross-sectional studies because they control for important individual-level confounding variables that cannot be controlled for in cross-sectional studies.
Study period	Studies examining a relatively longer period of time (and therefore having more data) are preferred, because they have greater statistical power to detect effects. More recent studies are also preferred because of possible changes in pollution mixes, medical care, and life style over time. However, when there are only a few studies available, studies from all years will be included.
Population attributes	The most technically appropriate measures of benefits would be based on impact functions that cover the entire sensitive population, but allow for heterogeneity across age or other relevant demographic factors. In the absence of effect estimates specific to age, sex, preexisting condition status, or other relevant factors, it may be appropriate to select effect estimates that cover the broadest population, to match with the desired outcome of the analysis, which is total national-level health impacts.
Study size	Studies examining a relatively large sample are preferred because they generally have more power to detect small magnitude effects. A large sample can be obtained in several ways, either through a large population, or through repeated observations on a smaller population, i.e. through a symptom diary recorded for a panel of asthmatic children.
Study location	U.S. studies are more desirable than non-U.S. studies because of potential differences in pollution characteristics, exposure patterns, medical care system, population behavior and life style.
Pollutants included in model	When modeling the effects of ozone and PM (or other pollutant combinations) jointly, it is important to use properly specified impact functions that include both pollutants. Use of single pollutant models in cases where both pollutants are expected to affect a health outcome can lead to double-counting when pollutants are correlated.
Measure of pollutant	For this analysis for PM-related effects, impact functions based on $PM_{2.5}$ are preferred to PM_{10} because the Nonroad Diesel Engine rule will regulate emissions of $PM_{2.5}$ precursors and air quality modeling was conducted for this size fraction of PM. Where $PM_{2.5}$ functions are not available, PM_{10} functions are used as surrogates, recognizing that there will be potential downward (upward) biases if the fine fraction of PM_{10} is more (less) toxic than the coarse fraction. Adequacy of ozone exposure metrics in studies was also considered.
Economically valuable health effects	Some health effects, such as forced expiratory volume and other technical measurements of lung function, are difficult to value in monetary terms. These health effects are not quantified in this analysis.
Non-overlapping endpoints	Although the benefits associated with each individual health endpoint may be analyzed separately, care must be exercised in selecting health endpoints to include in the overall benefits analysis because of the possibility of double counting of benefits.

It is important to reiterate that the estimates derived from the long-term exposure studies, which account for a major share of the economic benefits described in this chapter, are not affected by the GAM issue. Similarly, the time-series studies employing GLMs or other parametric methods, as well as case-crossover studies, are not affected.

Although a broad range of serious health effects has been associated with exposure to elevated ozone and PM levels (as noted for example in Table 9A-1 and described more fully in the ozone and PM Criteria Documents (EPA, 1996a, 1996b)), we include only a subset of health effects in this quantified benefit analysis. Health effects are excluded from this analysis for three reasons: the possibility of double counting (such as hospital admissions for specific respiratory diseases); uncertainties in applying effect relationships based on clinical studies to the affected population; or a lack of an established relationship between the health effect and pollutant in the published epidemiological literature.

In general, the use of results from more than a single study can provide a more robust estimate of the relationship between a pollutant and a given health effect. However, there are often differences between studies examining the same endpoint, making it difficult to pool the results in a consistent manner. For example, studies may examine different pollutants or different age groups. For this reason, we consider very carefully the set of studies available examining each endpoint and select a consistent subset that provides a good balance of population coverage and match with the pollutant of interest. In many cases, either because of a lack of multiple studies, consistency problems, or clear superiority in the quality or comprehensiveness of one study over others, a single published study is selected as the basis of the effect estimate.

When several effect estimates for a pollutant and a given health endpoint have been selected, they are quantitatively combined or pooled to derive a more robust estimate of the relationship. The benefits Technical Support Document (TSD) completed for the nonroad diesel rulemaking provides details of the procedures used to combine multiple impact functions (Abt Associates, 2003). In general, we use fixed or random effects models to pool estimates from different studies of the same endpoint. Fixed effects pooling simply weights each study's estimate by the inverse variance, giving more weight to studies with greater statistical power (lower variance). Random effects pooling accounts for both within-study variance and between-study variability, due, for example, to differences in population susceptibility. We use the fixed effects model as our null hypothesis and then determine whether the data suggest that we should reject this null hypothesis, in which case we would use the random effects model.[v] Pooled impact functions are

[V]The fixed effects model assumes that there is only one pollutant coefficient for the entire modeled area. The random effects model assumes that different studies are estimating different parameters; therefore, there may be a number of different underlying pollutant coefficients.

used to estimate hospital admissions (PM), school absence days (ozone), lower respiratory symptoms (PM), asthma exacerbations (PM), and asthma-related emergency room visits (ozone). For more details on methods used to pool incidence estimates, see the benefits TSD for the nonroad diesel rulemaking (Abt Associates, 2003).

Effect estimates for a pollutant and a given health endpoint are applied consistently across all locations nationwide. This applies to both impact functions defined by a single effect estimate and those defined by a pooling of multiple effect estimates. Although the effect estimate may, in fact, vary from one location to another (e.g., due to differences in population susceptibilities or differences in the composition of PM), location-specific effect estimates are generally not available.

The specific studies from which effect estimates for the primary analysis are drawn are included in Table 9A-19.

Premature Mortality. Both long- and short-term exposures to ambient levels of air pollution have been associated with increased risk of premature mortality. The size of the premature mortality risk estimates from these epidemiological studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make premature mortality risk reduction the most important health endpoint quantified in this analysis.

Epidemiological analyses have consistently linked air pollution, especially PM, with excess mortality. Although a number of uncertainties remain to be addressed by continued research (NRC, 1998), a substantial body of published scientific literature documents the correlation between elevated PM concentrations and increased mortality rates. Community epidemiological studies that have used both short-term and long-term exposures and response have been used to estimate PM/ mortality relationships. Short-term studies use a time-series approach to relate short-term (often day-to-day) changes in PM concentrations and changes in daily mortality rates up to several days after a period of elevated PM concentrations. Long-term studies examine the potential relationship between community-level PM exposures over multiple years and community-level annual mortality rates.

Researchers have found statistically significant associations between PM and premature mortality using both types of studies. In general, the risk estimates based on the long-term exposure studies are larger than those derived from short-term studies. Cohort analyses are better able to capture the full public health impact of exposure to air pollution over time (Kunzli, 2001; NRC, 2002). This section discusses some of the issues surrounding the estimation of premature mortality.

Over a dozen studies have found significant associations between various measures of long-term exposure to PM and elevated rates of annual mortality, beginning with Lave and Seskin (1977). Most of the published studies found positive (but not always statistically significant) associations with available PM indices such as total suspended particles (TSP). Particles of different fine particles components (i.e., sulfates), and fine particles, as well as exploration of alternative model specifications sometimes found inconsistencies (e.g., Lipfert, [1989]). These early "cross-sectional" studies (e.g., Lave and Seskin [1977]; Ozkaynak and Thurston [1987]) were criticized for a number of methodological limitations, particularly for inadequate control at the individual level for variables that are potentially important in causing mortality, such as wealth, smoking, and diet.

More recently, several long-term studies have been published that use improved approaches and appear to be consistent with the earlier body of literature. These new "prospective cohort" studies reflect a significant improvement over the earlier work because they include individual-level information with respect to health status and residence. The most extensive study and analyses has been based on data from two prospective cohort groups, often referred to as the Harvard "Six-City Study" (Dockery et al., 1993) and the "American Cancer Society or ACS study" (Pope et al., 1995 and Pope et al., 2002); these studies have found consistent relationships between fine particle indicators and premature mortality across multiple locations in the United States. A third major data set comes from the California based 7th Day Adventist Study (e.g., Abbey et al., 1999), which reported associations between long-term PM exposure and premature mortality in men. Results from this cohort, however, have been inconsistent and the air quality results are not geographically representative of most of the United States. The Veterans Study was originally designed as a means of assessing the efficacy of anti-hypertensive drugs in reducing morbidity and mortality in a population with pre-existing high blood pressure (in this case, male veterans) (Lipfert et al., 2000). Unlike previous long-term analyses, this study found some associations between premature mortality and ozone but found inconsistent results for PM indicators. A variety of issues associated with the study design, including sample representativeness and loss to follow up, make this cohort a poor choice for extrapolating to the general public. Furthermore, because of the selective nature of the population in the veteran's cohort and methodological weaknesses, which may have resulted in estimates of relative risk that are biased relative to a relative risk for the general population, we have chosen not to include any effect estimates from the Lipfert et al. (2000) study in our benefits assessment. We note that, while the PM analyses considering segmented (shorter) time periods such as Lipfert et al. gave differing results (including significantly negative mortality coefficients for some PM metrics), when methods consistent with the past studies were used (i.e., many- year average PM concentrations), similar results were reported: the authors found that "(t)he single-mortality-period responses without ecological variables are qualitatively similar to what has been reported before ($SO_4 > PM_{2.5} > PM_{15}$)."

Table 9A-19. Endpoints and Studies Used to Calculate Total Monetized Health Benefits

Endpoint	Pollutant	Study	Study Population
Premature Mortality			
Premature Mortality— Long-term exposure, all-cause	$PM_{2.5}$	Pope et al. (2002)	>29 years
Premature Mortality— Long-term exposure, all-cause	$PM_{2.5}$	Woodruff et al., 1997	Infant (<1 yr)
Chronic Illness			
Chronic Bronchitis	$PM_{2.5}$	Abbey, et al. (1995)	> 26 years
Non-fatal Heart Attacks	$PM_{2.5}$	Peters et al. (2001)	Adults
Hospital Admissions			
Respiratory	Ozone	Pooled estimate: Schwartz (1995) - ICD 460-519 (all resp) Schwartz (1994a, 1994b) - ICD 480-486 (pneumonia) Moolgavkar et al. (1997) - ICD 480-487 (pneumonia) Schwartz (1994b) - ICD 491-492, 494-496 (COPD) Moolgavkar et al. (1997) - ICD 490-496 (COPD)	> 64 years
	Ozone	Burnett et al. (2001)	< 2 years
	$PM_{2.5}$	Pooled estimate: Moolgavkar (2003) - ICD 490-496 (COPD) Ito (2003) - ICD 490-496 (COPD)	> 64 years
	$PM_{2.5}$	Moolgavkar (2000) - ICD 490-496 (COPD)	20-64 years
	$PM_{2.5}$	Ito (2003) - ICD 480-486 (pneumonia)	> 64 years
	$PM_{2.5}$	Sheppard, et al. (2003) - ICD 493 (asthma)	< 65 years
Cardiovascular	$PM_{2.5}$	Pooled estimate: Moolgavkar (2003) - ICD 390-429 (all cardiovascular) Ito (2003) - ICD 410-414, 427-428 (ischemic heart disease, dysrhythmia, heart failure)	> 64 years
	$PM_{2.5}$	Moolgavkar (2000) - ICD 390-429 (all cardiovascular)	20-64 years
Asthma-Related ER Visits	Ozone	Pooled estimate: Weisel et al. (1995), Cody et al. (1992), Stieb et al. (1996)	All ages
	$PM_{2.5}$	Norris et al. (1999)	0-18 years

(continued)

Table 9A-19. Endpoints and Studies Used to Calculate Total Monetized Health Benefits (continued)

Endpoint	Pollutant	Study	Study Population
Other Health Endpoints			
Acute Bronchitis	$PM_{2.5}$	Dockery et al. (1996)	8-12 years
Upper Respiratory Symptoms	PM_{10}	Pope et al. (1991)	Asthmatics, 9-11 years
Lower Respiratory Symptoms	$PM_{2.5}$	Schwartz and Neas (2000)	7-14 years
Asthma Exacerbations	$PM_{2.5}$	Pooled estimate: Ostro et al. (2001) (cough, wheeze and shortness of breath) Vedal et al. (1998) Cough	6-18 years[a]
Work Loss Days	$PM_{2.5}$	Ostro (1987)	18-65 years
School Absence Days	Ozone	Pooled estimate: Gilliland et al. (2001) Chen et al. (2000)	 9-10 years 6-11 years
Worker Productivity	Ozone	Crocker and Horst (1981)	Outdoor workers, 18-65
Minor Restricted Activity Days	$PM_{2.5}$, Ozone	Ostro and Rothschild (1989)	18-65 years

[a] The original study populations were 8 to 13 for the Ostro et al. (2001) study and 6 to 13 for the Vedal et al. (1998) study. Based on advice from the SAB-HES, we have extended the applied population to 6 to 18, reflecting the common biological basis for the effect in children in the broader age group.

Given their consistent results and broad geographic coverage, the Six-City and ACS data have been particularly important in benefits analyses. The credibility of these two studies is further enhanced by the fact that they were subject to extensive reexamination and reanalysis by an independent team of scientific experts commissioned by HEI (Krewski et al., 2000). The final results of the reanalysis were then independently peer reviewed by a Special Panel of the HEI Health Review Committee. The results of these reanalyses confirmed and expanded those of the original investigators. This intensive independent reanalysis effort was occasioned both by the importance of the original findings as well as concerns that the underlying individual health effects information has never been made publicly available.

The HEI re-examination lends credibility to the original studies and highlights sensitivities concerning the relative impact of various pollutants, the potential role of education in mediating the association between pollution and premature mortality, and the influence of spatial correlation modeling.[w] Further confirmation and extension of the overall findings using more recent air quality and a longer follow-up period for the ACS cohort was recently published in the *Journal of the American Medical Association* (Pope et al., 2002).

In developing and improving the methods for estimating and valuing the potential reductions in premature mortality risk over the years, the EPA has consulted with the SAB-HES. That panel recommended use of long-term prospective cohort studies in estimating premature mortality risk reduction (EPA-SAB-COUNCIL-ADV-99-005, 1999). This recommendation has been confirmed by a recent report from the National Research Council, which stated that "it is essential to use the cohort studies in benefits analysis to capture all important effects from air pollution exposure" (NAS, 2002, p. 108). In the NRC's view, compared with the time-series studies, cohort studies give a more complete assessment of the long-term, cumulative effects of air pollution. The overall effect estimates may be a combination of effects from long-term exposure plus some fraction from short-term exposure, but the amount of overlap is unknown. Additionally, the SAB recommended emphasis on the ACS study because it includes a much larger sample size and longer exposure interval and covers more locations (e.g., 50 cities compared to the Six Cities Study) than other studies of its kind. As explained in the regulatory impact analysis for the Heavy-Duty Engine/Diesel Fuel rule (EPA, 2000a), more recent EPA benefits analyses have relied on an improved specification of the ACS cohort data that was developed in the HEI reanalysis (Krewski et al., 2000). The latest reanalysis of the ACS cohort data (Pope et al., 2002), provides additional refinements to the analysis of PM-related mortality by (a) extending the follow-up period for the ACS study subjects to 16 years, which triples the size of the mortality data set; (b) substantially increasing exposure data, including consideration

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[W] Regarding potential confounding by copollutants, commentors noted that the HEI reanalysis of the ACS study data for long-term exposure mortality found an association between SO_2 and premature mortality and did not find a strong association between $PM_{2.5}$ and premature mortality. These commentors suggest that these findings regarding potential confounding compromise the accuracy of the ACS study. While recognizing the need for research into the issue of copollutants, including SO_2, we disagree with the commentor's interpretation of the HEI reanalysis. While this study did find an association between premature mortality and SO_2, such an association was also reported for fine particles and sulfate. In addition, the HEI reanalysis, as well as other studies examining the copollutant issue (Samet et al., 2000, 2001) have suggested that SO_2 might represent a surrogate for ambient $PM_{2.5}$ concentrations and is likely associated with sulfate concentrations since it is a precursor. This could partially explain the association between SO_2 and premature mortality found in the HEI reanalysis. Finally, we have updated our methods for characterizing premature mortality and are now using the Pope et al. 2002 reanalysis of the ACS study data. While this study continues to find and association between SO_2 and cardiovascular mortality, it also finds the strongest association yet between long term $PM_{2.5}$ exposure and premature mortality.

Commentors have also suggested that both the ACS and Six Cities studies provide evidence for confounding by socio-economic factors in the chronic exposure mortality endpoint. Following recommendations by the SAB-HES, we have updated our analytical framework to use the Pope et al. 2002 reanalysis of the ACS study data in estimating long-term exposure mortality. This study incorporates consideration for a variety of potential risk factors including smoking, educational status and age. With the exception of smoking status, none of the socio-economic factors examined in the Pope et al. 2002 reanalysis had a significant effect on the association between premature mortality and $PM_{2.5}$ exposure. Rather than representing confounders, several of these socio-economic factors, including educational status, were identified as potential effects modifiers.

for cohort exposure to $PM_{2.5}$ following implementation of $PM_{2.5}$ standard in 1999; (c) controlling for a variety of personal risk factors including occupational exposure and diet; and (d) using advanced statistical methods to evaluate specific issues that can adversely affect risk estimates including the possibility of spatial autocorrelation of survival times in communities located near each other. Because of these refinements, the SAB- HES recommends using the Pope et al. (2002) study as the basis for the primary mortality estimate for adults and suggests that alternate estimates of premature mortality generated using other cohort and time series studies could be included as part of the sensitivity analysis (SAB-HES, 2003).

The SAB-HES also recommended using the estimated relative risks from the Pope et al. (2002) study based on the average exposure to $PM_{2.5}$, measured by the average of two $PM_{2.5}$ measurements, over the periods 1979-1983, and 1999-2000. In addition to relative risks for all-cause mortality, the Pope et al. (2002) study provides relative risks for cardiopulmonary, lung cancer, and all other cause mortality.[x] Because of concerns regarding the statistical reliability of the all-other cause mortality relative risk estimates, we calculate premature mortality impacts for the primary analysis based on the all-cause relative risk. However, we provide separate estimates of cardiopulmonary and lung cancer deaths to show how these important causes of death are affected by reductions in $PM_{2.5}$.

In previous RIAs, infant mortality has not been evaluated as part of the primary analysis because of uncertainty in the strength of the association between exposure to PM and postneonatal mortality. Instead, benefits estimates related to reduced infant mortality have been included as part of the sensitivity analysis for RIAs. However, recently published studies have strengthened the case for an association between PM exposure and respiratory inflamation and infection leading to premature mortality in children under 5 years of age. Specifically, the SAB-HES noted the release of the World Health Organization Global Burden of Disease Study focusing on ambient air, which cites several recently published time-series studies relating daily PM exposure to mortality in children (SAB-HES, 2003). The SAB-HES also cites the study by Belanger et al. (2003) as corroborating findings linking PM exposure to increased respiratory

[X] Commentors pointed out that both cardiovascular disease and cancer have latency periods of from 15 to 20 years. Therefore, given that PM concentrations were four times higher in the 1960's compared with the 1980's, we may be overestimating mortality incidence by using effects estimates, based on the original ACS study data, that do not sufficiently correct for these higher PM concentrations during earlier segments of the exposure period for target populations. We recognize that uncertainty is introduced into benefits estimates as a result of both latency and lag issues. As the SAB-HES pointed out, the lack of detailed temporal exposure data for long term prospective cohort studies makes it difficult to characterize latency and lag periods and evaluate the importance of temporal variation in exposure levels. The Pope et al. 2002 reanalysis of the ACS study data, which includes additional years of follow-up data for the original study population, does suggest that lung cancer may have a longer latency period. However, inclusion of additional years of exposure data, in the case of lung cancer has served to strengthen, rather than weaken the association between $PM_{2.5}$ and premature mortality. By contrast, inclusion of additional follow-on data for cardiovascular effects has suggested that this endpoint may have a shorter latency/lag period in that the effects estimate has been reduced and not strengthened with the inclusion of the additional data.

inflamation and infections in children. Recently, a study by Chay and Greenstone (2003) found that reductions in TSP caused by the recession of 1981-1982 were related to reductions in infant mortality at the county level. With regard to the cohort study conducted by Woodruff et al. (1997), the SAB- HES notes several strengths of the study, including the use of a larger cohort drawn from a large number of metropolitan areas and efforts to control for a variety of individual risk factors in infants (e.g., maternal educational level, maternal ethnicity, parental marital status, and maternal smoking status). Based on these findings, the SAB-HES recommends that the EPA incorporate infant mortality into the primary benefits estimate and that infant mortality be evaluated using a impact function developed from the Woodruff et al. (1997) study (SAB-HES, 2003).

Chronic Bronchitis. Chronic bronchitis is characterized by mucus in the lungs and a persistent wet cough for at least 3 months a year for several years in a row. Chronic bronchitis affects an estimated 5 percent of the U.S. population (American Lung Association, 1999). A limited number of studies have estimated the impact of air pollution on new incidences of chronic bronchitis. Schwartz (1993) and Abbey et al.(1995) provide evidence that long-term PM exposure gives rise to the development of chronic bronchitis in the United States. Because the Nonroad Diesel regulations are expected to reduce primarily $PM_{2.5}$, this analysis uses only the Abbey et al. (1995) study, because it is the only study focusing on the relationship between $PM_{2.5}$ and new incidences of chronic bronchitis.

Nonfatal Myocardial Infarctions (heart attacks). Nonfatal heart attacks have been linked with short-term exposures to $PM_{2.5}$ in the United States (Peters et al., 2001) and other countries (Poloniecki et al. ,1997). We use a recent study by Peters et al. (2001) as the basis for the impact function estimating the relationship between $PM_{2.5}$ and nonfatal heart attacks. Peters et al. is the only available U.S. study to provide a specific estimate for heart attacks. Other studies, such as Samet et al. (2000) and Moolgavkar et al. (2000), show a consistent relationship between all cardiovascular hospital admissions, including for nonfatal heart attacks, and PM. Given the lasting impact of a heart attack on longer-term health costs and earnings, we choose to provide a separate estimate for nonfatal heart attacks based on the single available U.S. effect estimate. The finding of a specific impact on heart attacks is consistent with hospital admission and other studies showing relationships between fine particles and cardiovascular effects both within and outside the United States. These studies provide a weight of evidence for this type of effect, as discussed in the Criteria Document. Several epidemiologic studies (Liao et al., 1999; Gold et al., 2000; Magari et al., 2001) have shown that heart rate variability (an indicator of how much the heart is able to speed up or slow down in response to momentary stresses) is negatively related to PM levels. Heart rate variability is a risk factor for heart attacks and other coronary heart diseases (Carthenon et a.l, 2002; Dekker et al., 2000; Liao et al., 1997, Tsuji et al., 1996). As such, significant impacts of PM on heart rate variability are consistent with an increased risk of heart attacks.

Hospital and Emergency Room Admissions. Because of the availability of detailed hospital admission and discharge records, there is an extensive body of literature examining the relationship between hospital admissions and air pollution. Because of this, many of the hospital admission endpoints use pooled impact functions based on the results of a number of studies. In addition, some studies have examined the relationship between air pollution and emergency room (ER) visits. Because most ER visits do not result in an admission to the hospital (the majority of people going to the ER are treated and return home), we treat hospital admissions and ER visits separately, taking account of the fraction of ER visits that are admitted to the hospital.

Hospital admissions require the patient to be examined by a physician and, on average, may represent more serious incidents than ER visits. The two main groups of hospital admissions estimated in this analysis are respiratory admissions and cardiovascular admissions. There is not much evidence linking ozone or PM with other types of hospital admissions. The only type of ER visits that have been consistently linked to ozone and PM in the United States are asthma-related visits.

To estimate avoided incidences of cardiovascular hospital admissions associated with $PM_{2.5}$, we use studies by Moolgavkar (2003) and Ito et al. (2003). There are additional published studies showing a statistically significant relationship between PM_{10} and cardiovascular hospital admissions. However, given that the preliminary control options we are analyzing are expected to reduce primarily $PM_{2.5}$, we have chosen to focus on the two studies focusing on $PM_{2.5}$. Both of these studies provide an effect estimate for populations over 65, allowing us to pool the impact functions for this age group. Only Moolgavkar (2000) provided a separate effect estimate for populations 20 to 64.[y] Total cardiovascular hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Cardiovascular hospital admissions include admissions for myocardial infarctions. To avoid double counting benefits from reductions in myocardial infarctions when applying the impact function for cardiovascular hospital admissions, we first adjusted the baseline cardiovascular hospital admissions to remove admissions for myocardial infarctions.

To estimate total avoided incidences of respiratory hospital admissions, we use impact functions for several respiratory causes, including chronic obstructive pulmonary disease (COPD), pneumonia, and asthma. As with cardiovascular admissions, there are additional published studies showing a statistically significant relationship between PM_{10} and respiratory

[Y]Note that the Moolgavkar (2000) study has not been updated to reflect the more stringent GAM convergence criteria. However, given that no other estimates are available for this age group, we have chosen to use the existing study. Given the very small (<5 percent) difference in the effect estimates for 65 and older cardiovascular hospital admissions between the original and reanalyzed results, we do not expect there to be much bias introduced by this choice.

hospital admissions. We use only those focusing on $PM_{2.5}$. Both Moolgavkar (2000) and Ito et al. (2003) provide effect estimates for COPD in populations over 65, allowing us to pool the impact functions for this group. Only Moolgavkar (2000) provided a separate effect estimate for populations 20 to 64.[z] Total COPD hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Only Ito et al. (2003) estimated pneumonia, and only for the population 65 and older. In addition, Sheppard et al. (2003) provided an effect estimate for asthma hospital admissions for populations under age 65. Total avoided incidences of PM-related respiratory-related hospital admissions is the sum of COPD, pneumonia, and asthma admissions.

To estimate the effects of PM air pollution reductions on asthma-related ER visits, we use the effect estimate from a study of children 18 and under by Norris et al. (1999). As noted earlier, there is another study by Schwartz examining a broader age group (less than 65), but the Schwartz study focused on PM_{10} rather than $PM_{2.5}$. We selected the Norris et al. (1999) effect estimate because it better matched the pollutant of interest. Because children tend to have higher rates of hospitalization for asthma relative to adults under 65, we will likely capture the majority of the impact of $PM_{2.5}$ on asthma ER visits in populations under 65, although there may still be significant impacts in the adult population under 65.

To estimate avoided incidences of respiratory hospital admissions associated with ozone, we use a number of studies examining hospital admissions for a range of respiratory illnesses, including pneumonia and COPD. Two age groups, adults over 65 and children under 2, are examined. For adults over 65, Schwartz (1995) provides effect estimates for two different cities relating ozone and hospital admissions for all respiratory causes (defined as ICD codes 460-519). Impact functions based on these studies are pooled first before being pooled with other studies. Two studies (Moolgavkar et al., 1997; Schwartz, 1994a) examined ozone and pneumonia hospital admissions in Minneapolis. One additional study (Schwartz, 1994b) examined ozone and pneumonia hospital admissions in Detroit. The impact functions for Minneapolis are pooled together first, and the resulting impact function is then pooled with the impact function for Detroit. This avoids assigning too much weight to the information coming from one city. For COPD hospital admissions, there are two available studies, Moolgavkar et al. (1997), conducted in Minneapolis, and Schwartz (1994b), conducted in Detroit. These two studies are pooled together. To estimate total respiratory hospital admissions for adults over 65, COPD admissions are added to pneumonia admissions, and the result is pooled with the Schwartz (1995) estimate of total respiratory admissions. Burnett et al. (2001) is the only study providing an effect estimate for respiratory hospital admissions in children under 2.

[Z]Again, given the very small (<10 percent) difference in the effect estimates for 65 and older COPD hospital admissions between the original and reanalyzed results, we do not expect there to be much bias introduced by this choice.

Acute Health Events and School/Work Loss Days. As indicated in Table 9A-1, in addition to mortality, chronic illness, and hospital admissions, a number of acute health effects not requiring hospitalization are associated with exposure to ambient levels of ozone and PM. The sources for the effect estimates used to quantify these effects are described below.

Around 4 percent of U.S. children between ages 5 and 17 experience episodes of acute bronchitis annually (American Lung Association, 2002). Acute bronchitis is characterized by coughing, chest discomfort, slight fever, and extreme tiredness, lasting for a number of days. According to the MedlinePlus medical encyclopedia,[aa] with the exception of cough, most acute bronchitis symptoms abate within 7 to 10 days. Incidence of episodes of acute bronchitis in children between the ages of 5 and 17 are estimated using an effect estimate developed from Dockery et al. (1996).

Incidences of lower respiratory symptoms (e.g., wheezing, deep cough) in children aged 7 to 14 are estimated using an effect estimate from Schwartz and Neas (2000).

Because asthmatics have greater sensitivity to stimuli (including air pollution), children with asthma can be more susceptible to a variety of upper respiratory symptoms (e.g., runny or stuffy nose; wet cough; and burning, aching, or red eyes). Research on the effects of air pollution on upper respiratory symptoms has thus focused on effects in asthmatics. Incidences of upper respiratory symptoms in asthmatic children aged 9 to 11 are estimated using an effect estimate developed from Pope et al. (1991).

Health effects from air pollution can also result in missed days of work (either from personal symptoms or from caring for a sick family member). Work loss days due to $PM_{2.5}$ are estimated using an effect estimate developed from Ostro (1987). Children may also be absent from school due to respiratory or other diseases caused by exposure to air pollution. Most studies examining school absence rates have found little or no association with $PM_{2.5}$, but several studies have found a significant association between ozone levels and school absence rates. We use two recent studies, Gilliland et al. (2001) and Chen et al. (2000), to estimate changes in absences (school loss days) due to changes in ozone levels. The Gilliland et al. study estimated the incidence of new periods of absence, while the Chen et al. study examined absence on a given day. We convert the Gilliland estimate to days of absence by multiplying the absence periods by the average duration of an absence. We estimate an average duration of school absence of 1.6 days by dividing the average daily school absence rate from Chen et al. (2000) and Ransom and Pope (1992) by the episodic absence rate from Gilliland et al. (2001). This provides estimates from Chen et al. (2000) and Gilliland et al. (2000), which can be pooled to provide an overall estimate.

[AA]See http://www.nlm.nih.gov/medlineplus/ency/article/000124.htm, accessed January 2002.

Minor restricted activity days (MRAD) result when individuals reduce most usual daily activities and replace them with less strenuous activities or rest, yet not to the point of missing work or school. For example, a mechanic who would usually be doing physical work most of the day will instead spend the day at a desk doing paper and phone work due to difficulty breathing or chest pain. The effect of $PM_{2.5}$ and ozone on MRAD is estimated using an effect estimate derived from Ostro and Rothschild (1989).

In previous RIAs, we have not included estimates of asthma exacerbations in the asthmatic population in the primary analysis because of concerns over double counting of benefits and difficulties in differentiating asthma symptoms for purposes of first developing impact functions that cover distinct endpoints and then establishing the baseline incidence estimates required for predicting incidence reductions. Concerns over double counting stem from the fact that studies of the general population also include asthmatics, so estimates based solely on the asthmatic population cannot be directly added to the general population numbers without double counting. In one specific case (upper respiratory symptoms in children), the only study available was limited to asthmatic children, so this endpoint can be readily included in the calculation of total benefits. However, other endpoints, such as lower respiratory symptoms and MRADs, are estimated for the total population that includes asthmatics. Therefore, to simply add predictions of asthma-related symptoms generated for the population of asthmatics to these total population-based estimates could result in double counting, especially if they evaluate similar endpoints.

The SAB-HES, in commenting on the analytical blueprint for 812 acknowledged these challenges in evaluating asthmatic symptoms and appropriately adding them into the primary analysis (SAB-HES, 2003). However, despite these challenges, the SAB-HES recommends the addition of asthma-related symptoms (i.e., asthma exacerbations) to the primary analysis, provided that the studies use the panel study approach and that they have comparable design and baseline frequencies in both asthma prevalence and exacerbation rates. Note also, that the SAB-HES, while supporting the incorporation of asthma exacerbation estimates, does not believe that the association between ambient air pollution, including ozone and PM, and the new onset of asthma is sufficiently strong to support inclusion of this asthma-related endpoint in the primary estimate. For this analysis, we have followed the SAB-HES recommendations regarding asthma exacerbations in developing the primary estimate. To prevent double counting, we are focusing the estimation on asthma exacerbations occurring in children and are excluding adults from the calculation. Asthma exacerbations occurring in adults are assumed to be captured in the general population endpoints such as work loss days and MRADs. Consequently, if we had included an adult-specific asthma exacerbation estimate, we would likely double count incidence for this endpoint. However, because the general population endpoints do not cover children (with regard to asthmatic effects), an analysis focused specifically on asthma exacerbations for children (6 to 18 years of age) could be conducted without concern for double counting.

To characterize asthma exacerbations in children, we selected two studies (Ostro et al., 2001 and Vedal et al., 1998) that followed panels of asthmatic children. Ostro et al. (2001) followed a group of 138 African-American children in Los Angeles for 13 weeks, recording daily occurrences of respiratory symptoms associated with asthma exacerbations (e.g., shortness of breath, wheeze, and cough). This study found a statistically significant association between $PM_{2.5}$, measured as a 12-hour average, and the daily prevalence of shortness of breath and wheeze endpoints. Although the association was not statistically significant for cough, the results were still positive and close to significance; consequently, we decided to include this endpoint, along with shortness of breath and wheeze, in generating incidence estimates (see below). Vedal et al. (1998) followed a group of elementary school children, including 74 asthmatics, located on the west coast of Vancouver Island for 18 months including measurements of daily peak expiratory flow (PEF) and the tracking of respiratory symptoms (e.g., cough, phlegm, wheeze, chest tightness) through the use of daily diaries. Association between PM_{10} and respiratory symptoms for the asthmatic population was only reported for two endpoints: cough and PEF. Because it is difficult to translate PEF measures into clearly defined health endpoints that can be monetized, we only included the cough-related effect estimate from this study in quantifying asthma exacerbations. We employed the following pooling approach in combining estimates generated using effect estimates from the two studies to produce a single asthma exacerbation incidence estimate. First, we pooled the separate incidence estimates for shortness of breath, wheeze, and cough generated using effect estimates from the Ostro et al. study, because each of these endpoints is aimed at capturing the same overall endpoint (asthma exacerbations) and there could be overlap in their predictions. The pooled estimate from the Ostro et al. study is then pooled with the cough-related estimate generated using the Vedal study. The rationale for this second pooling step is similar to the first; both studies are attempting to quantify the same overall endpoint (asthma exacerbations).

Additional epidemiological studies are available for characterizing asthma-related health endpoints (the full list of epidemiological studies considered for modeling asthma-related incidence are presented in Table 9A-20). However, based on recommendations from the SAB-HES, we decided not to use these additional studies in generating the primary estimate. In particular, the Yu et al. (2000) estimates show a much higher baseline incidence rate than other studies, which may lead to an overstatement of the expected impacts in the overall asthmatic population. The Whittemore and Korn (1980) study did not use a well-defined endpoint, instead focusing on a respondent-defined "asthma attack." Other studies looked at respiratory symptoms in asthmatics but did not focus on specific exacerbations of asthma.

9A.3.5.2 Uncertainties Associated with Health Impact Functions

Within-Study Variation. Within-study variation refers to the precision with which a given study estimates the relationship between air quality changes and health effects. Health effects studies provide both a "best estimate" of this relationship plus a measure of the statistical uncertainty of the relationship. This size of this uncertainty depends on factors such as the number of subjects studied and the size of the effect being measured. The results of even the most well-designed epidemiological studies are characterized by this type of uncertainty, though well-designed studies typically report narrower uncertainty bounds around the best estimate than do studies of lesser quality. In selecting health endpoints, we generally focus on endpoints where a statistically significant relationship has been observed in at least some studies, although we may pool together results from studies with both statistically significant and insignificant estimates to avoid selection bias.

Across-Study Variation. Across-study variation refers to the fact that different published studies of the same pollutant/health effect relationship typically do not report identical findings; in some instances the differences are substantial. These differences can exist even between equally reputable studies and may result in health effect estimates that vary considerably. Across-study variation can result from two possible causes. One possibility is that studies report different estimates of the single true relationship between a given pollutant and a health effect due to differences in study design, random chance, or other factors. For example, a hypothetical study conducted in New York and one conducted in Seattle may report different C-R functions for the relationship between PM and mortality, in part because of differences between these two study populations (e.g., demographics, activity patterns). Alternatively, study results may differ because these two studies are in fact estimating different relationships; that is, the same reduction in PM in New York and Seattle may result in different reductions in premature mortality. This may result from a number of factors, such as differences in the relative sensitivity of these two populations to PM pollution and differences in the composition of PM in these two locations. In either case, where we identified multiple studies that are appropriate for estimating a given health effect, we generated a pooled estimate of results from each of those studies.

Table 9A-20. Studies Examining Health Impacts in the Asthmatic Population Evaluated for Use in the Benefits Analysis

Endpoint	Definition	Pollutant	Study	Study Population
Asthma Attack Indicators[1]				
Shortness of breath	Prevalence of shortness of breath; incidence of shortness of breath	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8-13
Cough	Prevalence of cough; incidence of cough	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8-13
Wheeze	Prevalence of wheeze; incidence of wheeze	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8-13
Asthma exacerbation	≥1 mild asthma symptom: wheeze, cough, chest tightness, shortness of breath)	PM_{10}, $PM_{1.0}$	Yu et al. (2000)	Asthmatics, 5-13
Cough	Prevalence of cough	PM_{10}	Vedal et al. (1998)	Asthmatics, 6-13
Other symptoms/illness endpoints				
Upper respiratory symptoms	≥1 of the following: runny or stuffy nose; wet cough; burning, aching, or red eyes	PM_{10}	Pope et al. (1991)	Asthmatics 9-11
Moderate or worse asthma	Probability of moderate (or worse) rating of overall asthma status	$PM_{2.5}$	Ostro et al. (1991)	Asthmatics, all ages
Acute bronchitis	≥1 episodes of bronchitis in the past 12 months	$PM_{2.5}$	McConnell et al. (1999)	Asthmatics, 9-15*
Phlegm	"Other than with colds, does this child usually seem congested in the chest or bring up phlegm?"	$PM_{2.5}$	McConnell et al. (1999)	Asthmatics, 9-15*
Asthma attacks	Respondent-defined asthma attack	$PM_{2.5}$, ozone	Whittemore and Korn (1980)	Asthmatics, all ages

Application of C-R Relationship Nationwide. Regardless of the use of impact functions based on effect estimates from a single epidemiological study or multiple studies, each impact function was applied uniformly throughout the United States to generate health benefit estimates. However, to the extent that pollutant/health effect relationships are region-specific, applying a location-specific impact function at all locations in the United States may result in overestimates of health effect changes in some locations and underestimates of health effect changes in other locations. It is not possible, however, to know the extent or direction of the overall effect on health benefit estimates introduced by application of a single impact function to the entire United States. This may be a significant uncertainty in the analysis, but the current state of the scientific literature does not allow for a region-specific estimation of health benefits.[bb]

Extrapolation of Impact Functions Across Populations. Epidemiological studies often focus on specific age ranges, either due to data availability limitations (e.g., most hospital admission data come from Medicare records, which are limited to populations 65 and older), or to simplify data collection (e.g., some asthma symptom studies focus on children at summer camps, which usually have a limited age range). We have assumed for the primary analysis that most impact functions should be applied only to those populations with ages that strictly match the populations in the underlying epidemiological studies. However, in many cases, there is no biological reason why the observed health effect would not also occur in other populations within a reasonable range of the studied population. For example, Dockery et al. (1996) examined acute bronchitis in children aged 8 to 12. There is no biological reason to expect a very different response in children aged 6 or 14. By excluding populations outside the range in the studies, we may be underestimating the health impact in the overall population. In response to recommendations from the SAB-HES, where there appears to be a reasonable physiological basis for expanding the age group associated with a specific effect estimate beyond the study population to cover the full age group (e.g., expanding from a study population of 7 to 11 year olds to the full 6to 18 year child age group), we have done so and used those expanded incidence estimates in the primary analysis.

Uncertainties in the PM Mortality Relationship. Health researchers have consistently linked air pollution, especially PM, with excess mortality. A substantial body of published scientific literature recognizes a correlation between elevated PM concentrations and increased premature mortality rates. However, much about this relationship is still uncertain. These uncertainties include the following:

[BB]Although we are not able to use region-specific effect estimates, we use region-specific baseline incidence rates where available. This allows us to take into account regional differences in health status, which can have a significant impact on estimated health benefits.

- Causality: A substantial number of published epidemiological studies recognize an association between elevated PM concentrations and increased premature mortality rates; however, these epidemiological studies are not designed to and cannot definitively prove causation. For the analysis of the final Nonroad Diesel Engines rulemaking, we assumed a causal relationship between exposure to elevated PM and premature mortality, based on the consistent evidence of a correlation between PM and premature mortality reported in the substantial body of published scientific literature.

- Other Pollutants: PM concentrations are correlated with the concentrations of other criteria pollutants, such as ozone and CO, and it is unclear how much each of these pollutants may influence mortality rates. Recent studies (see Thurston and Ito [2001]) have explored whether ozone may have premature mortality effects independent of PM, but we do not view the evidence as conclusive at this time. The EPA is currently evaluating the epidemiological literature on the relationship between ozone and premature mortality and in future regulatory analyses may include ozone mortality as a separate impact in the primary analysis. To the extent that the effect estimates we use to evaluate the preliminary control options in fact capture premature mortality effects of other criteria pollutants besides PM, we may be overestimating the benefits of reductions in PM. However, we are not providing separate estimates of the premature mortality benefits from the ozone and CO reductions likely to occur due to the preliminary control options.

- Shape of the C-R Function: The shape of the true PM premature mortality C-R function is uncertain, but this analysis assumes the C-R function to have a log-linear form (as derived from the literature) throughout the relevant range of exposures. If this is not the correct form of the C-R function, or if certain scenarios predict concentrations well above the range of values for which the C-R function was fitted, avoided premature mortality may be mis-estimated.

- Regional Differences: As discussed above, significant variability exists in the results of different PM/mortality studies. This variability may reflect regionally specific C-R functions resulting from regional differences in factors such as the physical and chemical composition of PM. If true regional differences exist, applying the PM/mortality C-R function to regions outside the study location could result in mis-estimation of effects in these regions.

- Exposure/Mortality Lags: There is a potential time lag between changes in PM exposures and changes in premature mortality rates. For the chronic PM/mortality relationship, the length of the lag is unknown and may be dependent on the kind of exposure. The existence of such a lag is important for the valuation of premature mortality incidence because economic theory suggests that benefits occurring in the future should be discounted. There is no specific scientific evidence of the existence or structure of a PM effects lag. However, current scientific literature on adverse health effects similar to those associated with PM (e.g., smoking-related disease) and the difference in the effect size between chronic exposure studies and daily mortality studies suggests that all incidences of premature mortality reduction associated with a given incremental change in PM exposure probably would not occur in the same year as the exposure reduction. The smoking-related literature also implies that lags of up to a few years or longer are plausible. Adopting the lag structure used in the Tier 2/Gasoline Sulfur and Heavy-Duty Engine/Diesel Fuel RIAs and endorsed by the SAB (EPA-SAB-COUNCIL-ADV-00-001, 1999), we assume a 5-year lag structure. This approach assumes that 25 percent of PM-related premature deaths occur in each of the first 2 years after the exposure and the rest occur in equal parts (approximately 17 percent) in each of the ensuing 3 years.

- Cumulative Effects: As a general point, we attribute the PM/mortality relationship in the underlying epidemiological studies to cumulative exposure to PM. However, the relative roles of PM exposure duration and PM exposure level in inducing premature mortality remain unknown at this time.

9A.3.5.3 Baseline Health Effect Incidence Rates

The epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than an estimate of the absolute number of avoided cases. For example, a typical result might be that a 10 $\mu g/m^3$ decrease in daily $PM_{2.5}$ levels might decrease hospital admissions by 3 percent. The baseline incidence of the health effect is necessary to convert this relative change into a number of cases. The baseline incidence rate provides an estimate of the incidence rate (number of cases of the health effect per year, usually per 10,000 or 100,000 general population) in the assessment location corresponding to baseline pollutant levels in that location. To derive the total baseline incidence per year, this rate must be multiplied by the corresponding population number (e.g., if the baseline incidence rate is number of cases per year per 100,000 population, it must be multiplied by the number of 100,000s in the population).

Some epidemiological studies examine the association between pollution levels and adverse health effects in a specific subpopulation, such as asthmatics or diabetics. In these cases, it is necessary to develop not only baseline incidence rates, but also prevalence rates for the defining condition (e.g., asthma). For both baseline incidence and prevalence data, we use age-specific rates where available. Impact functions are applied to individual age groups and then summed over the relevant age range to provide an estimate of total population benefits.

In most cases, because of a lack of data or methods, we have not attempted to project incidence rates to future years, instead assuming that the most recent data on incidence rates are the best prediction of future incidence rates. In recent years, better data on trends in incidence and prevalence rates for some endpoints, such as asthma, have become available. We are working to develop methods to use these data to project future incidence rates. However, for our primary benefits analysis of the final rule, we will continue to use current incidence rates.

Table 9A-21 summarizes the baseline incidence data and sources used in the benefits analysis. In most cases, a single national incidence rate is used, due to a lack of more spatially disaggregated data. We used national incidence rates whenever possible, because these data are most applicable to a national assessment of benefits. However, for some studies, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level. However, for hospital admissions, regional rates are available, and for premature mortality, county-level data are available.

Age-, cause-, and county-specific mortality rates were obtained from the U.S. Centers for Disease Control (CDC) for the years 1996 through 1998. CDC maintains an online data repository of health statistics, CDC Wonder, accessible at http://wonder.cdc.gov/. The mortality rates provided are derived from U.S. death records and U.S. Census Bureau postcensal population estimates. Mortality rates were averaged across 3 years (1996 through 1998) to provide more stable estimates. When estimating rates for age groups that differed from the CDC Wonder groupings, we assumed that rates were uniform across all ages in the reported age group. For example, to estimate mortality rates for individuals ages 30 and up, we scaled the 25- to 34-year old death count and population by one-half and then generated a population-weighted mortality rate using data for the older age groups. Note that we have not projected any changes in mortality rates over time. We are aware that the U.S. Census projections of total and age-specific mortality rates used in our population projections are based on projections of declines in national level mortality rates for younger populations and increases in mortality rates for older populations over time. We are evaluating the most appropriate way to incorporate these projections of changes in overall national mortality rates into our database of county-level cause-specific mortality rates. In the interim, we have not attempted to adjust future mortality rates. This will lead to an overestimate of premature mortality benefits in future years, with the overestimation bias increasing the further benefits are projected into the future. We do not at this time have a quantified estimate of the magnitude of the potential bias in the years analyzed for this rule (2010 and 2015).

Table 9A-21. Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population

Endpoint	Parameter	Rates	
		Value	Source[a]
Premature mortality	Daily or annual mortality rate	Age, cause, and county-specific rate	CDC Wonder (1996-1998)
Hospitalizations	Daily hospitalization rate	Age, region, cause-specific rate	1999 NHDS public use data files[b]
Asthma ER visits	Daily asthma ER visit rate	Age, Region specific visit rate	2000 NHAMCS public use data files[c]; 1999 NHDS public use data files[b]
Chronic Bronchitis	Annual prevalence rate per person Age 18-44 Age 45-64 Age 65 and older	 0.0367 0.0505 0.0587	1999 HIS (American Lung Association, 2002b, Table 4)
	Annual incidence rate per person	0.00378	Abbey et al. (1993, Table 3)
Nonfatal MI (heart attacks)	Daily nonfatal myocardial infarction incidence rate per person, 18+ Northeast Midwest South West	 0.0000159 0.0000135 0.0000111 0.0000100	1999 NHDS public use data files[b]; adjusted by 0.93 for prob. of surviving after 28 days (Rosamond et al., 1999)
Asthma Exacerbations	Incidence (and prevalence) among asthmatic African American children - daily wheeze - daily cough - daily dyspnea	 0.076 (0.173) 0.067 (0.145) 0.037 (0.074)	Ostro et al. (2001)
	Prevalence among asthmatic children - daily wheeze - daily cough - daily dyspnea	 0.038 0.086 0.045	Vedal et al. (1998)
Acute Bronchitis	Annual bronchitis incidence rate, children	0.043	American Lung Association (2002a, Table 11)

(continued)

Table 9A-21. Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population (continued)

Endpoint	Parameter	Rates	
		Value	Source[a]
Lower Respiratory Symptoms	Daily lower respiratory symptom incidence among children[d]	0.0012	Schwartz (1994, Table 2)
Upper Respiratory Symptoms	Daily upper respiratory symptom incidence among asthmatic children	0.3419	Pope et al. (1991, Table 2)
Work Loss Days	Daily WLD incidence rate per person (18-65) Age 18-24 Age 25-44 Age 45-64	 0.00540 0.00678 0.00492	1996 HIS (Adams et al., 1999, Table 41); U.S. Bureau of the Census (2000)
Minor Restricted Activity Days	Daily MRAD incidence rate per person	0.02137	Ostro and Rothschild (1989, p. 243)
School Loss Days[e]	Daily school absence rate per person	0.055	National Center for Education Statistics (1996)
	Daily illness-related school absence rate per person[e] Northeast Midwest South Southwest	 0.0136 0.0146 0.0142 0.0206	1996 HIS (Adams et al., 1999, Table 47); estimate of 180 school days per year
	Daily *respiratory* illness-related school absence rate per person Northeast Midwest South West	 0.0073 0.0092 0.0061 0.0124	1996 HIS (Adams et al., 1999, Table 47); estimate of 180 school days per year

[a] The following abbreviations are used to describe the national surveys conducted by the National Center for Health Statistics: HIS refers to the National Health Interview Survey; NHDS—National Hospital Discharge Survey; NHAMCS—National Hospital Ambulatory Medical Care Survey.

[b] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHDS/

[c] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHAMCS/

[d] Lower Respiratory Symptoms are defined as ≥2 of the following: cough, chest pain, phlegm, wheeze

[e] The estimate of daily illness-related school absences excludes school loss days associated with injuries to match the definition in the Gilliland et al. (2001) study.

For the set of endpoints affecting the asthmatic population, in addition to baseline incidence rates, prevalence rates of asthma in the population are needed to define the applicable population. Table 9A-22 lists the prevalence rates used to determine the applicable population for asthma symptom endpoints. Note that these reflect current asthma prevalence and assume no change in prevalence rates in future years. As noted above, we are investigating methods for projecting asthma prevalence rates in future years.

9A.3.5.4 Accounting for Potential Health Effect Thresholds

When conducting clinical (chamber) and epidemiological studies, functions may be estimated with or without explicit thresholds. Air pollution levels below the threshold are assumed to have no associated adverse health effects. When a threshold is not assumed, as is often the case in epidemiological studies, any exposure level is assumed to pose a nonzero risk of response to at least one segment of the population.

The possible existence of an effect threshold is a very important scientific question and issue for policy analyses such as this one. The EPA SAB Advisory Council for Clean Air Compliance, which provides advice and review of the EPA's methods for assessing the benefits and costs of the Clean Air Act under Section 812 of the Clean Air Act, has advised the EPA that there is currently no scientific basis for selecting a threshold of 15 $\mu g/m^3$ or any other specific threshold for the PM-related health effects considered in typical benefits analyses (EPA-SAB-Council-ADV-99-012, 1999). This is supported by the recent literature on health effects of PM exposure (Daniels et al., 2000; Pope, 2000; Rossi et al., 1999; Schwartz, 2000) that finds in most cases no evidence of a nonlinear relationship between PM and health effects and certainly does not find a distinct threshold. The most recent draft of the EPA Air Quality Criteria for Particulate Matter (EPA, 2004) reports only one study, analyzing data from Phoenix, AZ, that reported even limited evidence suggestive of a possible threshold for $PM_{2.5}$ (Smith et al., 2000).

Table 9A-22. Asthma Prevalence Rates Used to Estimate Asthmatic Populations in Impact Functions

Population Group	Asthma Prevalence Rates	
	Value	Source
All Ages	0.0386	American Lung Association (2002c, Table 7)—based on 1999 HIS
<18	0.0527	American Lung Association (2002c, Table 7)—based on 1999 HIS
5-17	0.0567	American Lung Association (2002c, Table 7)—based on 1999 HIS
18-44	0.0371	American Lung Association (2002c, Table 7)—based on 1999 HIS
45-64	0.0333	American Lung Association (2002c, Table 7)—based on 1999 HIS
65+	0.0221	American Lung Association (2002c, Table 7)—based on 1999 HIS
Male, 27+	0.021	2000 HIS public use data files[a]
African-American, 5 to 17	0.0726	American Lung Association (2002c, Table 9)—based on 1999 HIS
African-American, <18	0.0735	American Lung Association (2002c, Table 9)—based on 1999 HIS

[a] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/HIS/2000/

Recent cohort analyses by HEI (Krewski et al., 2000) and Pope et al. (2002) provide additional evidence of a quasi-linear relationship between long-term exposures to $PM_{2.5}$ and premature mortality. According to the latest draft PM criteria document, Krewski et al. (2000) found a "visually near-linear relationship between all-cause and cardiopulmonary mortality residuals and mean sulfate concentrations, near-linear between cardiopulmonary mortality and mean $PM_{2.5}$, but a somewhat nonlinear relationship between all-cause mortality residuals and mean $PM_{2.5}$ concentrations that flattens above about 20 μg/m^3. The confidence bands around the fitted curves are very wide, however, neither requiring a linear relationship nor precluding a nonlinear relationship if suggested by reanalyses."

The Pope et al. (2002) analysis, which represented an extension to the Krewski et al. analysis, found that the functions relating $PM_{2.5}$ and premature mortality "were not significantly different from linear associations."

Daniels et al. (2000) examined the presence of thresholds in PM_{10} C-R relationships for daily mortality using the largest 20 U.S. cities for 1987-1994. The results of their models suggest that the linear model was preferred over spline and threshold models. Thus, these results suggest that linear models without a threshold may well be appropriate for estimating the effects of PM_{10} on the types of premature mortality of main interest. Schwartz and Zanobetti (2000) investigated the presence of threshold by simulation and actual data analysis of 10 U.S. cities. In the analysis of data from 10 cities, the combined C-R curve did not show evidence of a threshold in the PM_{10}-mortality associations. Schwartz, Laden, and Zanobetti (2002) investigated thresholds by combining data on the $PM_{2.5}$-mortality relationships for six cities and found an essentially linear relationship down to 2 $\mu g/m^3$, which is at or below anthropogenic background in most areas. They also examined just traffic-related particles and again found no evidence of a threshold. The Smith et al. (2000) study of associations between daily total mortality and $PM_{2.5}$ and $PM_{10-2.5}$ in Phoenix, AZ, (during 1995-1997) also investigated the possibility of a threshold using a piecewise linear model and a cubic spline model. For both the piecewise linear and cubic spline models, the analysis suggested a threshold of around 20 to 25 $\mu g/m^3$. However, the C-R curve for $PM_{2.5}$ presented in this publication suggests more of a U- or V-shaped relationship than the usual "hockey stick" threshold relationship.

Based on the recent literature and advice from the SAB, we assume there are no thresholds for modeling health effects. Although not included in the primary analysis, the potential impact of a health effects threshold on avoided incidences of PM-related premature mortality is explored as a key sensitivity analysis and is presented in Appendix 9-B.

Our assumptions regarding thresholds are supported by the National Research Council in its recent review of methods for estimating the public health benefits of air pollution regulations. In their review, the National Research Council concluded that there is no evidence for any departure from linearity in the observed range of exposure to PM_{10} or $PM_{2.5}$, nor any indication of a threshold. They cite the weight of evidence available from both short- and long-term exposure models and the similar effects found in cities with low and high ambient concentrations of PM.

9A.3.5.5 Selecting Unit Values for Monetizing Health Endpoints

The appropriate economic value of a change in a health effect depends on whether the health effect is viewed *ex ante* (before the effect has occurred) or *ex post* (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health affects by a fairly small amount for a large population. The appropriate economic measure is therefore *ex ante* WTP for changes in risk. However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use this data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a measure is able to reduce the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $100, then the WTP for an avoided statistical premature mortality amounts to $1 million ($100/0.0001 change in risk). Using this approach, the size of the affected population is automatically taken into account by the number of incidences predicted by epidemiological studies applied to the relevant population. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as a primary estimate. For example, for the valuation of hospital admissions we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These COI estimates generally understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. Table 9A-23 summarizes the value estimates per health effect that we used in this analysis. Values are presented both for a 1990 base income level and adjusted for income growth in the two future analysis years, 2010 and 2015. Note that the unit values for hospital admissions are the weighted averages of the ICD-9 code-specific values for the group of ICD-9 codes included in the hospital admission categories. A discussion of the valuation methods for premature mortality and chronic bronchitis is provided here because of the relative importance of these effects. Discussions of the methods used to value nonfatal myocardial infarctions (heart attacks) and school absence days are provided because these endpoints have only recently been added to the analysis and the valuation methods are still under development. In the following discussions, unit values are presented at 1990 levels of income for consistency with previous analyses. Equivalent future year values can be obtained from Table 9A-23.

Table 9A-23. Unit Values Used for Economic Valuation of Health Endpoints (1999$)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Premature Mortality (Value of a Statistical Life)	$5,500,000	$6,600,000	$6,800,000	Point estimate is the mean of a normal distribution with a 95 percent confidence interval between $1 and $10 million. Confidence interval is based on two meta-analyses of the wage-risk VSL literature. $1 million represents the lower end of the interquartile range from the Mrozek and Taylor (2000) meta-analysis. $10 million represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis. The VSL represents the value of a small change in mortality risk aggregated over the affected population.
Chronic Bronchitis (CB)	$340,000	$420,000	$430,000	Point estimate is the mean of a generated distribution of WTP to avoid a case of pollution-related CB. WTP to avoid a case of pollution-related CB is derived by adjusting WTP (as described in Viscusi et al., 1991) to avoid a severe case of CB for the difference in severity and taking into account the elasticity of WTP with respect to severity of CB.
Nonfatal Myocardial Infarction (heart attack)				Age specific cost-of-illness values reflecting lost earnings and direct medical costs over a 5 year period following a non-fatal MI. Lost earnings estimates based on Cropper and Krupnick (1990). Direct medical costs based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990).
3% discount rate				
Age 0-24	$66,902	$66,902	$66,902	
Age 25-44	$74,676	$74,676	$74,676	
Age 45-54	$78,834	$78,834	$78,834	Lost earnings:
Age 55-65	$140,649	$140,649	$140,649	Cropper and Krupnick (1990). Present discounted value of 5 yrs of lost
Age 66 and over	$66,902	$66,902	$66,902	earnings:
				age of onset: at 3% at 7%
7% discount rate				25-44 $8,774 $7,855
Age 0-24	$65,293	$65,293	$65,293	45-54 $12,932 $11,578
Age 25-44	$73,149	$73,149	$73,149	55-65 $74,746 $66,920
Age 45-54	$76,871	$76,871	$76,871	
Age 55-65	$132,214	$132,214	$132,214	Direct medical expenses: An average of:
Age 66 and over	$65,293	$65,293	$65,293	1. Wittels et al., 1990 ($102,658 – no discounting)
				2. Russell et al., 1998, 5-yr period. ($22,331 at 3% discount rate; $21,113 at 7% discount rate)

(continued)

Table 9A-23. Unit Values Used for Economic Valuation of Health Endpoints (1999$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Hospital Admissions				
Chronic Obstructive Pulmonary Disease (COPD) (ICD codes 490-492, 494-496)	$12,378	$12,378	$12,378	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Pneumonia (ICD codes 480-487)	$14,693	$14,693	$14,693	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total pneumonia category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Asthma admissions	$6,634	$6,634	$6,634	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
All Cardiovascular (ICD codes 390-429)	$18,387	$18,387	$18,387	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Emergency room visits for asthma	$286	$286	$286	Simple average of two unit COI values: (1) $311.55, from Smith et al., 1997, and (2) $260.67, from Stanford et al., 1999.

(continued)

Table 9A-23. Unit Values Used for Economic Valuation of Health Endpoints (1999$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Respiratory Ailments Not Requiring Hospitalization				
Upper Respiratory Symptoms (URS)	$25	$27	$27	Combinations of the 3 symptoms for which WTP estimates are available that closely match those listed by Pope, et al. result in 7 different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for URS is the average of the dollar values for the 7 different types of URS.
Lower Respiratory Symptoms (LRS)	$16	$17	$17	Combinations of the 4 symptoms for which WTP estimates are available that closely match those listed by Schwartz, et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS.
Asthma Exacerbations	$42	$45	$45	Asthma exacerbations are valued at $42 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma attack is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study.
Acute Bronchitis	$360	$380	$390	Assumes a 6 day episode, with daily value equal to the average of low and high values for related respiratory symptoms recommended in Neumann, et al. 1994.

(continued)

Table 9A-23. Unit Values Used for Economic Valuation of Health Endpoints (1999$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence			Derivation of Estimates
	1990 Income Level	2020 Income Level	2030 Income Level	
Restricted Activity and Work/School Loss Days				
Work Loss Days (WLDs)	Variable	Variable	Variable	County-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5 – to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
School Absence Days	$75	$75	$75	Based on expected lost wages from parent staying home with child. Estimated daily lost wage (if a mother must stay at home with a sick child) is based on the median weekly wage among women age 25 and older in 2000 (U.S. Census Bureau, Statistical Abstract of the United States: 2001, Section 12: Labor Force, Employment, and Earnings, Table No. 621). This median wage is $551. Dividing by 5 gives an estimated median daily wage of $103. The expected loss in wages due to a day of school absence in which the mother would have to stay home with her child is estimated as the probability that the mother is in the workforce times the daily wage she would lose if she missed a day = 72.85% of $103, or $75.
Worker Productivity	$0.95 per worker per 10% change in ozone per day	$0.95 per worker per 10% change in ozone per day	$0.95 per worker per 10% change in ozone per day	Based on $68 – median daily earnings of workers in farming, forestry and fishing – from Table 621, Statistical Abstract of the United States ("Full-Time Wage and Salary Workers – Number and Earnings: 1985 to 2000") (Source of data in table: U.S. Bureau of Labor Statistics, Bulletin 2307 and Employment and Earnings, monthly).
Minor Restricted Activity Days (MRADs)	$51	$54	$55	Median WTP estimate to avoid one MRAD from Tolley, et al. (1986) .

9A.3.5.5.1 Valuing Reductions in Premature Mortality Risk.

We estimate the monetary benefit of reducing premature mortality risk using the "value of statistical lives saved" (VSL) approach, which is a summary measure for the value of small changes in premature mortality risk experienced by a large number of people. The VSL approach applies information from several published value-of-life studies to determine a reasonable benefit of preventing premature mortality. The mean value of avoiding one statistical death is assumed to be $5.5 million in 1999 dollars. This represents a central value consistent with the range of values suggested by recent meta-analyses of the wage-risk VSL literature. The distribution of VSL is characterized by a confidence interval from $1 to $10 million, based on two meta-analyses of the wage-risk VSL literature. The $1 million lower confidence limit represents the lower end of the interquartile range from the Mrozek and Taylor (2000) meta-analysis. The $10 million upper confidence limit represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis.

In previous analyses, we used an estimate of mean VSL equal to $6.3 million, based on a distribution fitted to the estimates from 26 value-of-life studies identified in the Section 812 reports as "applicable to policy analysis." [cc]

As indicated in the previous section on quantification of premature mortality benefits, we assume for this analysis that some of the incidences of premature mortality related to PM exposures occur in a distributed fashion over the 5 years following exposure. To take this into account in the valuation of reductions in premature mortality, we apply 3 percent and 7 percent discount rates to the value of premature mortality occurring in future years.[dd]

[CC] Commentors have suggested that the VSL used in the Draft RIA may not be appropriate for populations impacted by the rule in that it may not reflect the risk preference of the of the target population. We recognize the large amount of uncertainty in the VSL for application to environmental policy. Following SAB-EEAC guidance, we used a wage-risk-based VSL in valuing premature mortality for the primary estimate in the final rule. In response to concerns about the range of estimates included in the VSL distribution, we modified the value of life distribution used for the final rule. As described above, the new mean value of avoiding one statistical death ($5.5 million in 1999 dollars) represents a central value consistent with the range of values suggested by recent meta-analyses of the wage-risk VSL literature. The distribution of VSL used in this RIA is characterized by a confidence interval from $1 to $10 million, based on two meta-analyses of the wage-risk VSL literature. Following SAB-EEAC guidance, we discount over the lag period between exposure and premature mortality in valuing reductions in mortality incidence (see Section 9.A.3.5.2).

[DD]The choice of a discount rate, and its associated conceptual basis, is a topic of ongoing discussion within the federal government. The EPA adopted a 3 percent discount rate for its base estimate in this case to reflect reliance on a "social rate of time preference" discounting concept. We have also calculated benefits and costs using a 7 percent rate consistent with an "opportunity cost of capital" concept to reflect the time value of resources directed to meet regulatory requirements. In this case, the benefit and cost estimates were not significantly affected by the choice of discount rate. Further discussion of this topic appears in the EPA's *Guidelines for Preparing Economic Analyses* (EPA 2000c).

The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Regardless of the theoretical economic considerations, the EPA prefers not to draw distinctions in the monetary value assigned to the lives saved even if they differ in age, health status, socioeconomic status, gender, or other characteristic of the adult population.

Following the advice of the EEAC of the SAB, the EPA currently uses the VSL approach in calculating the primary estimate of premature mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for reductions in premature mortality risk (EPA-SAB-EEAC-00-013). Although there are several differences between the labor market studies the EPA uses to derive a VSL estimate and the PM air pollution context addressed here, those differences in the affected populations and the nature of the risks imply both upward and downward adjustments. Table 9A-24 lists some of these differences and the expected effect on the VSL estimate for air pollution-related premature mortality. In the absence of a comprehensive and balanced set of adjustment factors, the EPA believes it is reasonable to continue to use the $5.5 million value while acknowledging the significant limitations and uncertainties in the available literature.

Table 9A-24. Expected Impact on Estimated Benefits of Premature Mortality Reductions of Differences Between Factors Used in Developing Applied VSL and Theoretically Appropriate VSL

Attribute	Expected Direction of Bias
Age	Uncertain, perhaps overestimate
Life expectancy/health status	Uncertain, perhaps overestimate
Attitudes toward risk	Underestimate
Income	Uncertain
Voluntary vs. Involuntary	Uncertain, perhaps underestimate
Catastrophic vs. protracted death	Uncertain, perhaps underestimate

Some economists emphasize that the VSL is not a single number relevant for all situations. Indeed, the VSL estimate of $5.5 million (1999 dollars) is itself the central tendency of a number of estimates of the VSL for some rather narrowly defined populations. When there are significant differences between the population affected by a particular health risk and the populations used in the labor market studies, as is the case here, some economists prefer to adjust the VSL estimate to reflect those differences.

The SAB-EEAC has advised that the EPA "continue to use a wage-risk-based VSL as its primary estimate, including appropriate sensitivity analyses to reflect the uncertainty of these estimates," and that "the only risk characteristic for which adjustments to the VSL can be made is the timing of the risk" (EPA-SAB-EEAC-00-013, EPA, 2000b). In developing our primary estimate of the benefits of premature mortality reductions, we have followed this advice and discounted over the lag period between exposure and premature mortality.

Uncertainties Specific to Premature Mortality Valuation. The economic benefits associated with premature mortality are the largest category of monetized benefits of this rule. In addition, in prior analyses, the EPA has identified valuation of premature mortality benefits as the largest contributor to the range of uncertainty in monetized benefits (see EPA [1999]). Because of the uncertainty in estimates of the value of premature mortality avoidance, it is important to adequately characterize and understand the various types of economic approaches available for premature mortality valuation. Such an assessment also requires an understanding of how alternative valuation approaches reflect that some individuals may be more susceptible to air pollution-induced premature mortality or reflect differences in the nature of the risk presented by air pollution relative to the risks studied in the relevant economics literature.

The health science literature on air pollution indicates that several human characteristics affect the degree to which mortality risk affects an individual. For example, some age groups appear to be more susceptible to air pollution than others (e.g., the elderly and children). Health status prior to exposure also affects susceptibility. An ideal benefits estimate of mortality risk reduction would reflect these human characteristics, in addition to an individual's WTP to improve one's own chances of survival plus WTP to improve other individuals' survival rates. The ideal measure would also take into account the specific nature of the risk reduction commodity that is provided to individuals, as well as the context in which risk is reduced. To measure this value, it is important to assess how reductions in air pollution reduce the risk of dying from the time that reductions take effect onward, and how individuals value these changes. Each individual's survival curve, or the probability of surviving beyond a given age, should shift as a result of an environmental quality improvement. For example, changing the current probability of survival for an individual also shifts future probabilities of that individual's survival. This probability shift will differ across individuals because survival curves depend on such characteristics as age, health state, and the current age to which the individual is likely to survive.

Although a survival curve approach provides a theoretically preferred method for valuing the benefits of reduced risk of premature mortality associated with reducing air pollution, the approach requires a great deal of data to implement. The economic valuation literature does not yet include good estimates of the value of this risk reduction commodity. As a result, in this study we value avoided premature mortality risk using the VSL approach.

Other uncertainties specific to premature mortality valuation include the following:

- Across-study variation: There is considerable uncertainty as to whether the available literature on VSL provides adequate estimates of the VSL saved by air pollution reduction. Although there is considerable variation in the analytical designs and data used in the existing literature, the majority of the studies involve the value of risks to a middle-aged working population. Most of the studies examine differences in wages of risky occupations, using a wage-hedonic approach. Certain characteristics of both the population affected and the mortality risk facing that population are believed to affect the average WTP to reduce the risk. The appropriateness of a distribution of WTP based on the current VSL literature for valuing the premature mortality-related benefits of reductions in air pollution concentrations therefore depends not only on the quality of the studies (i.e., how well they measure what they are trying to measure), but also on the extent to which the risks being valued are similar and the extent to which the subjects in the studies are similar to the population affected by changes in pollution concentrations.

- Level of risk reduction: The transferability of estimates of the VSL from the wage-risk studies to the context of the this rulemaking analysis rests on the assumption that, within a reasonable range, WTP for reductions in mortality risk is linear in risk reduction. For example, suppose a study estimates that the average WTP for a reduction in mortality risk of 1/100,000 is $50, but that the actual mortality risk reduction resulting from a given pollutant reduction is 1/10,000. If WTP for reductions in mortality risk is linear in risk reduction, then a WTP of $50 for a reduction of 1/100,000 implies a WTP of $500 for a risk reduction of 1/10,000 (which is 10 times the risk reduction valued in the study). Under the assumption of linearity, the estimate of the VSL does not depend on the particular amount of risk reduction being valued. This assumption has been shown to be reasonable provided the change in the risk being valued is within the range of risks evaluated in the underlying studies (Rowlatt et al., 1998).

- Voluntariness of risks evaluated: Although job-related mortality risks may differ in several ways from air pollution-related mortality risks, the most important difference may be that job-related risks are incurred voluntarily, or generally assumed to be, whereas air pollution-related risks are incurred involuntarily. Some evidence suggests that people will pay more to reduce involuntarily incurred risks than risks incurred voluntarily. If this is the case, WTP estimates based on wage-risk studies may understate WTP to reduce involuntarily incurred air pollution-related mortality risks.

- Sudden versus protracted death: A final important difference related to the nature of the risk may be that some workplace mortality risks tend to involve sudden, catastrophic events, whereas air pollution-related risks tend to involve longer periods of disease and suffering prior to death. Some evidence suggests that WTP to avoid a risk of a protracted death involving prolonged suffering and loss of dignity and personal control is greater than the WTP to avoid a risk (of identical magnitude) of sudden death. To the extent that the mortality risks addressed in this assessment are associated with longer periods of illness or greater pain and suffering than are the risks addressed in the valuation literature, the WTP measurements employed in the present analysis would reflect a downward bias.

- Self-selection and skill in avoiding risk. Recent research (Shogren et al., 2002) suggests that VSL estimates based on hedonic wage studies may overstate the average value of a risk reduction. This is based on the fact that the risk-wage tradeoff revealed in hedonic studies reflects the preferences of the marginal worker (i.e., that worker who demands the highest compensation for his risk reduction). This worker must have either higher risk, lower risk tolerance, or both. However, the risk estimate used in hedonic studies is generally based on average risk, so the VSL may be upwardly biased because the wage differential and risk measures do not match.

For more discussion, see Appendix 9B.

9A.3.5.5.2 Valuing Reductions in the Risk of Chronic Bronchitis.

The best available estimate of WTP to avoid a case of chronic bronchitis comes from Viscusi et al. (1991). The Viscusi et al. study, however, describes a severe case of chronic bronchitis to the survey respondents. We therefore employ an estimate of WTP to avoid a pollution-related case of chronic bronchitis, based on adjusting the Viscusi et al. (1991) estimate of the WTP to avoid a severe case. This is done to account for the likelihood that an average case of pollution-related chronic bronchitis is not as severe. The adjustment is made by applying the elasticity of WTP with respect to severity reported in the Krupnick and Cropper (1992) study. Details of this adjustment procedure are provided in the benefits TSD for the nonroad diesel rulemaking (Abt Associates, 2003).

We use the mean of a distribution of WTP estimates as the central tendency estimate of WTP to avoid a pollution-related case of chronic bronchitis in this analysis. The distribution incorporates uncertainty from three sources: the WTP to avoid a case of severe chronic bronchitis, as described by Viscusi et al.; the severity level of an average pollution-related case of chronic bronchitis (relative to that of the case described by Viscusi et al.); and the elasticity of WTP with respect to severity of the illness. Based on assumptions about the distributions of each of these three uncertain components, we derive a distribution of WTP to avoid a pollution-related case of chronic bronchitis by statistical uncertainty analysis techniques. The expected value (i.e., mean) of this distribution, which is about $331,000 (2000$), is taken as the central tendency estimate of WTP to avoid a PM-related case of chronic bronchitis.

9A.3.5.5.3 Valuing Reductions in Non-Fatal Myocardial Infarctions (Heart Attacks).

The Agency has recently incorporated into its analyses the impact of air pollution on the expected number of nonfatal heart attacks, although it has examined the impact of reductions in other related cardiovascular endpoints. We were not able to identify a suitable WTP value for reductions in the risk of nonfatal heart attacks. Instead, we propose a COI unit value with two components: the direct medical costs and the opportunity cost (lost earnings) associated with the illness event. Because the costs associated with an myocardial infarction extend beyond the initial event itself, we consider costs incurred over several years. Using age-specific annual lost earnings estimated by Cropper and Krupnick (1990) and a 3 percent discount rate, we estimated a present discounted value in lost earnings (in 2000$) over 5 years due to an myocardial infarction of $8,774 for someone between the ages of 25 and 44, $12,932 for someone between the ages of 45 and 54, and $74,746 for someone between the ages of 55 and 65. The corresponding age-specific estimates of lost earnings (in 2000$) using a 7 percent discount rate are $7,855, $11,578, and $66,920, respectively. Cropper and Krupnick (1990) do not provide lost earnings estimates for populations under 25 or over 65. As such, we do not include lost earnings in the cost estimates for these age groups.

We found three possible sources in the literature of estimates of the direct medical costs of myocardial infarction:

- Wittels et al. (1990) estimated expected total medical costs of myocardial infarction over 5 years to be $51,211 (in 1986$) for people who were admitted to the hospital and survived hospitalization. (There does not appear to be any discounting used.) Wittels et al. was used to value coronary heart disease in the 812 Retrospective Analysis of the Clean Air Act. Using the CPI-U for medical care, the Wittels estimate is $109,474 in year 2000$. This estimated cost is based on a medical cost model, which incorporated therapeutic options, projected outcomes, and prices (using “knowledgeable cardiologists” as consultants). The model used medical data and medical decision algorithms to estimate the probabilities of certain events and/or medical procedures being used. The authors note that the average length of hospitalization for acute myocardial infarction has decreased over time (from an average of 12.9 days in 1980 to an average of 11 days in 1983). Wittels et al. used 10 days as the average in their study. It is unclear how much further the length of stay for myocardial infarction may have decreased from 1983 to the present. The average length of stay for ICD code 410 (myocardial infarction) in the year-2000 AHQR HCUP database is 5.5 days. However, this may include patients who died in the hospital (not included among our nonfatal myocardial infarction cases), whose length of stay was therefore substantially shorter than it would be if they had not died.

- Eisenstein et al. (2001) estimated 10-year costs of $44,663 in 1997$, or $49,651 in 2000$ for myocardial infarction patients, using statistical prediction (regression) models to estimate inpatient costs. Only inpatient costs (physician fees and hospital costs) were included.

- Russell et al. (1998) estimated first-year direct medical costs of treating nonfatal myocardial infarction of $15,540 (in 1995$) and $1,051 annually thereafter. Converting to year 2000$, that would be $23,353 for a 5-year period (without discounting) or $29,568 for a 10-year period.

In summary, the three different studies provided significantly different values (see Table 9A-25).

As noted above, the estimates from these three studies are substantially different, and we have not adequately resolved the sources of differences in the estimates. Because the wage-related opportunity cost estimates from Cropper and Krupnick (1990) cover a 5-year period, we use estimates for medical costs that similarly cover a 5-year period (i.e., estimates from Wittels et al. (1990) and Russell et al. (1998). We use a simple average of the two 5-year estimates, or $65,902, and add it to the 5-year opportunity cost estimate. The resulting estimates are given in Table 9A-26.

Table 9A-25. Alternative Direct Medical Cost of Illness Estimates for Nonfatal Heart Attacks

Study	Direct Medical Costs (2000$)	Over an x-Year Period, for x =
Wittels et al. (1990)	$109,474[a]	5
Russell et al. (1998)	$22,331[b]	5
Eisenstein et al. (2001)	$49,651[b]	10
Russell et al. (1998)	$27,242[b]	10

[a] Wittels et al. did not appear to discount costs incurred in future years.
[b] Using a 3 percent discount rate.

Table 9A-26. Estimated Costs Over a 5-Year Period (in 2000$) of a Nonfatal Myocardial Infarction

Age Group	Opportunity Cost	Medical Cost[a]	Total Cost
0 - 24	$0	$65,902	$65,902
25-44	$8,774[b]	$65,902	$74,676
45 - 54	$12,253[b]	$65,902	$78,834
55 - 65	$70,619[b]	$65,902	$140,649
> 65	$0	$65,902	$65,902

[a] An average of the 5-year costs estimated by Wittels et al., 1990, and Russell et al., 1998.
[b] From Cropper and Krupnick, 1990, using a 3 percent discount rate.

9A.3.5.5.4 Valuing Reductions in School Absence Days.

School absences associated with exposure to ozone are likely to be due to respiratory-related symptoms and illnesses. Because the respiratory symptom and illness endpoints we are including are all PM-related rather than ozone-related, we do not have to be concerned about double counting of benefits if we aggregate the benefits of avoiding ozone-related school absences with the benefits of avoiding PM-related respiratory symptoms and illnesses.

One possible approach to valuing a school absence is using a parental opportunity cost approach. This method requires two steps: estimate the probability that, if a school child stays home from school, a parent will have to stay home from work to care for the child, and value the lost productivity at the person's wage. Using this method, we would estimate the proportion of families with school-age children in which both parents work, and value a school loss day as the probability of a work loss day resulting from a school loss day (i.e., the proportion of households with school-age children in which both parents work) times some measure of lost wages (whatever measure we use to value work loss days). There are three significant problems with this method, however. First, it omits WTP to avoid the symptoms/illness that resulted in the school absence. Second, it effectively gives zero value to school absences which do not result in a work loss day (unless we derive an alternative estimate of the value of the parent's time for those cases in which the parent is not in the labor force). Third, it makes an assumption about the gender of the parent that would miss work. We are investigating approaches using WTP for avoid the symptoms/illnesses causing the absence. In the interim, we will use the parental opportunity cost approach.

For the parental opportunity cost approach, we make an explicit, lower assumption that in married households with two working parents, the female parent will stay home with a sick child. From the U.S. Census Bureau, Statistical Abstract of the United States: 2001, we obtained (1) the numbers of single, married, and "other" (i.e., widowed, divorced, or separated) women with children in the workforce, and (2) the rates of participation in the workforce of single, married, and "other" women with children. From these two sets of statistics, we inferred the numbers of single, married, and "other" women with children, and the corresponding percentages. These percentages were used to calculate a weighted average participation rate, as shown in Table 9A-27. We do not take into account that many single and "other" women with children may lose their jobs if they are repeatedly absent due to their children's illnesses.

Our estimated daily lost wage (if a mother must stay at home with a sick child) is based on the median weekly wage among women age 25 and older in 2000 (U.S. Census Bureau, Statistical Abstract of the United States: 2001, Section 12: Labor Force, Employment, and Earnings, Table No. 621). This median wage is $551. Dividing by 5 gives an estimated median daily wage of $103.

Table 9A-27. Women with Children: Number and Percent in the Labor Force, 2000, and Weighted Average Participation Rate[a]

	Number (in millions) in Labor Force (1)	Participation Rate (2)	Implied Total Number in Population (in millions) (3) = (1)/(2)	Implied Percent in Population (4)	Weighted Average Participation Rate [=sum (2)*(4) over rows]
Single	3.1	73.9%	4.19	11.84%	
Married	18.2	70.6%	25.78	72.79%	
Other[b]	4.5	82.7%	5.44	15.36%	
Total:			35.42		
					72.85%

[a] Data in columns (1) and (2) are from U.S. Census Bureau, Statistical Abstract of the United States: 2001, Section 12: Labor Force, Employment, and Earnings, Table No. 577.
[b] Widowed, divorced, or separated.

The expected loss in wages due to a day of school absence in which the mother would have to stay home with her child is estimated as the probability that the mother is in the workforce times the daily wage she would lose if she missed a day = 72.85% of $103, or $75.[ee]

9A.3.5.6 Unquantified Health Effects

In addition to the health effects discussed above, there is emerging evidence that human exposure to ozone may be associated with premature mortality (Ito and Thurston, 1996; Samet, et al. 1997, Ito and Thurston, 2001), PM and ozone with increased emergency room visits for non-asthma respiratory causes (US EPA, 1996a; 1996b), ozone with impaired airway responsiveness (US EPA, 1996a), ozone with increased susceptibility to respiratory infection (US EPA, 1996a), ozone with acute inflammation and respiratory cell damage (US EPA, 1996a), ozone and PM with premature aging of the lungs and chronic respiratory damage (US EPA, 1996a; 1996b), ozone with onset of asthma in exercising children (McConnell et al. 2002), and PM with reduced heart rate variability and other changes in cardiac function. An improvement in ambient PM and ozone air quality may reduce the number of incidences within each effect category that the U.S. population would experience. Although these health effects are believed

[EE] In a very recent article, Hall, Brajer, and Lurmann (2003) use a similar methodology to derive a mid-estimate value per school absence day for California of between $70 and $81, depending on differences in incomes between three counties in California. Our national average estimate of $75 per absence is consistent with these published values.

to be PM or ozone-induced, effect estimates are not available for quantifying the benefits associated with reducing these effects. The inability to quantify these effects lends a downward bias to the monetized benefits presented in this analysis.

9A.3.6 Human Welfare Impact Assessment

PM and ozone have numerous documented effects on environmental quality that affect human welfare. These welfare effects include direct damages to property, either through impacts on material structures or by soiling of surfaces, direct economic damages in the form of lost productivity of crops and trees, indirect damages through alteration of ecosystem functions, and indirect economic damages through the loss in value of recreational experiences or the existence value of important resources. EPA's Criteria Documents for PM and ozone list numerous physical and ecological effects known to be linked to ambient concentrations of these pollutants (US EPA, 1996a; 1996b). This section describes individual effects and how we quantify and monetize them. These effects include changes in commercial crop and forest yields, visibility, and nitrogen deposition to estuaries.

9A.3.6.1 Visibility Benefits

Changes in the level of ambient particulate matter caused by the reduction in emissions from the preliminary control options will change the level of visibility in much of the U.S. Visibility directly affects people's enjoyment of a variety of daily activities. Individuals value visibility both in the places they live and work, in the places they travel to for recreational purposes, and at sites of unique public value, such as the Grand Canyon. This section discusses the measurement of the economic benefits of visibility.

It is difficult to quantitatively define a visibility endpoint that can be used for valuation. Increases in PM concentrations cause increases in light extinction. Light extinction is a measure of how much the components of the atmosphere absorb light. More light absorption means that the clarity of visual images and visual range is reduced, *ceteris paribus.* Light absorption is a variable that can be accurately measured. Sisler (1996) created a unitless measure of visibility based directly on the degree of measured light absorption called the *deciview*. Deciviews are standardized for a reference distance in such a way that one deciview corresponds to a change of about 10 percent in available light. Sisler characterized a change in light extinction of one deciview as "a small but perceptible scenic change under many circumstances." Air quality models were used to predict the change in visibility, measured in deciviews, of the areas affected by the preliminary control options.[ff]

EPA considers benefits from two categories of visibility changes: residential visibility and recreational visibility. In both cases economic benefits are believed to consist of both use values and non-use values. Use values include the aesthetic benefits of better visibility, improved road and air safety, and enhanced recreation in activities like hunting and birdwatching. Non-use values are based on people's beliefs that the environment ought to exist free of human-induced haze. Non-use values may be a more important component of value for recreational areas, particularly national parks and monuments.

Residential visibility benefits are those that occur from visibility changes in urban, suburban, and rural areas, and also in recreational areas not listed as federal Class I areas.[gg] For the purposes of this analysis, recreational visibility improvements are defined as those that occur specifically in federal Class I areas. A key distinction between recreational and residential benefits is that only those people living in residential areas are assumed to receive benefits from residential visibility, while all households in the U.S. are assumed to derive some benefit from improvements in Class I areas. Values are assumed to be higher if the Class I area is located close to their home.[hh]

Only two existing studies provide defensible monetary estimates of the value of visibility changes. One is a study on residential visibility conducted in 1990 (McClelland, et. al., 1993) and the other is a 1988 survey on recreational visibility value (Chestnut and Rowe, 1990a; 1990b). Both utilize the contingent valuation method. There has been a great deal of controversy and significant development of both theoretical and empirical knowledge about how to conduct CV surveys in the past decade. In EPA's judgment, the Chestnut and Rowe study contains many of the elements of a valid CV study and is sufficiently reliable to serve as the

[FF] A change of less than 10 percent in the light extinction budget represents a measurable improvement in visibility, but may not be perceptible to the eye in many cases. Some of the average regional changes in visibility are less than one deciview (i.e. less than 10 percent of the light extinction budget), and thus less than perceptible. However, this does not mean that these changes are not real or significant. Our assumption is then that individuals can place values on changes in visibility that may not be perceptible. This is quite plausible if individuals are aware that many regulations lead to small improvements in visibility which when considered together amount to perceptible changes in visibility.

[GG] The Clean Air Act designates 156 national parks and wilderness areas as Class I areas for visibility protection.

[HH] For details of the visibility estimates discussed in this chapter, please refer to the benefits technical support document for this RIA (Abt Associates 2003).

basis for monetary estimates of the benefits of visibility changes in recreational areas.[ii] This study serves as an essential input to our estimates of the benefits of recreational visibility improvements in the primary benefits estimates. Consistent with SAB advice, EPA has designated the McClelland, et al. study as significantly less reliable for regulatory benefit-cost analysis, although it does provide useful estimates on the order of magnitude of residential visibility benefits (EPA-SAB-COUNCIL-ADV-00-002, 1999). Residential visibility benefits are therefore only included as a sensitivity estimate in Appendix 9-B.

The Chestnut and Rowe study measured the demand for visibility in Class I areas managed by the National Park Service (NPS) in three broad regions of the country: California, the Southwest, and the Southeast. Respondents in five states were asked about their willingness to pay to protect national parks or NPS-managed wilderness areas within a particular region. The survey used photographs reflecting different visibility levels in the specified recreational areas. The visibility levels in these photographs were later converted to deciviews for the current analysis. The survey data collected were used to estimate a WTP equation for improved visibility. In addition to the visibility change variable, the estimating equation also included household income as an explanatory variable.

The Chestnut and Rowe study did not measure values for visibility improvement in Class I areas outside the three regions. Their study covered 86 of the 156 Class I areas in the U.S. We can infer the value of visibility changes in the other Class I areas by transferring values of visibility changes at Class I areas in the study regions. However, these values are not as defensible and are thus presented only as an alternative calculation in Table 9A-25. A complete description of the benefits transfer method used to infer values for visibility changes in Class I areas outside the study regions is provided in the benefits TSD for this RIA (Abt Associates, 2003).

The estimated relationship from the Chestnut and Rowe study is only directly applicable to the populations represented by survey respondents. EPA used benefits transfer methodology to extrapolate these results to the population affected by the Nonroad Diesel Engines rule. A general willingness to pay equation for improved visibility (measured in deciviews) was developed as a function of the baseline level of visibility, the magnitude of the visibility improvement, and household income. The behavioral parameters of this equation were taken from analysis of the Chestnut and Rowe data. These parameters were used to calibrate WTP for the visibility changes resulting from the Nonroad Diesel Engines rule. The method for

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[II] An SAB advisory letter indicates that"many members of the Council believe that the Chestnut and Rowe study is the best available." (EPA-SAB-COUNCIL-ADV-00-002, 1999) However, the committee did not formally approve use of these estimates because of concerns about the peer-reviewed status of the study. EPA believes the study has received adequate review and has been cited in numerous peer-reviewed publications (Chestnut and Dennis, 1997).

developing calibrated WTP functions is based on the approach developed by Smith, et al. (2002). Available evidence indicates that households are willing to pay more for a given visibility improvement as their income increases (Chestnut, 1997). The benefits estimates here incorporate Chestnut's estimate that a 1 percent increase in income is associated with a 0.9 percent increase in WTP for a given change in visibility.

Using the methodology outlined above, EPA estimates that the total WTP for the visibility improvements in California, Southwestern, and Southeastern Class I areas brought about by the Nonroad Diesel Engines rule is $2.2 billion. This value includes the value to households living in the same state as the Class I area as well as values for all households in the U.S. living outside the state containing the Class I area, and the value accounts for growth in real income. We examine the impact of expanding the visibility benefits analysis to other areas of the country in a sensitivity analysis presented in Appendix 9-B.

One major source of uncertainty for the visibility benefit estimate is the benefits transfer process used. Judgments used to choose the functional form and key parameters of the estimating equation for willingness to pay for the affected population could have significant effects on the size of the estimates. Assumptions about how individuals respond to changes in visibility that are either very small, or outside the range covered in the Chestnut and Rowe study, could also affect the results.

9A.3.6.2 Agricultural, Forestry and other Vegetation Related Benefits

The Ozone Criteria Document notes that "ozone affects vegetation throughout the United States, impairing crops, native vegetation, and ecosystems more than any other air pollutant" (US EPA, 1996). Changes in ground level ozone resulting from the preliminary control options are expected to impact crop and forest yields throughout the affected area.

Well-developed techniques exist to provide monetary estimates of these benefits to agricultural producers and to consumers. These techniques use models of planting decisions, yield response functions, and agricultural products supply and demand. The resulting welfare measures are based on predicted changes in market prices and production costs. Models also exist to measure benefits to silvicultural producers and consumers. However, these models have not been adapted for use in analyzing ozone related forest impacts. As such, our analysis provides monetized estimates of agricultural benefits, and a discussion of the impact of ozone changes on forest productivity, but does not monetize commercial forest related benefits.

9A.3.6.2.1 Agricultural Benefits

Laboratory and field experiments have shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN) examined 15 species and numerous cultivars. The NCLAN results show that "several economically important crop species are sensitive to ozone levels typical of those found in the U.S." (US EPA, 1996). In addition, economic studies have shown a relationship between observed ozone levels and crop yields (Garcia, et al., 1986). The economic value associated with varying levels of yield loss for ozone-sensitive commodity crops is analyzed using the AGSIM© agricultural benefits model (Taylor, et al., 1993). AGSIM© is an econometric-simulation model that is based on a large set of statistically estimated demand and supply equations for agricultural commodities produced in the United States. The model is capable of analyzing the effects of changes in policies (in this case, the implementation of the Nonroad Diesel Engines rule) that affect commodity crop yields or production costs.[jj]

The measure of benefits calculated by the model is the net change in consumer and producer surplus from baseline ozone concentrations to the ozone concentrations resulting from attainment of particular standards. Using the baseline and post-control equilibria, the model calculates the change in net consumer and producer surplus on a crop-by-crop basis.[kk] Dollar values are aggregated across crops for each standard. The total dollar value represents a measure of the change in social welfare associated with the Nonroad Diesel Engines rule.

The model employs biological exposure-response information derived from controlled experiments conducted by the NCLAN (NCLAN, 1996). For the purpose of our analysis, we analyze changes for the six most economically significant crops for which C-R functions are available: corn, cotton, peanuts, sorghum, soybean, and winter wheat.[ll] For some crops there are multiple C-R functions, some more sensitive to ozone and some less. Our base estimate assumes that crops are evenly mixed between relatively sensitive and relatively insensitive varieties. Sensitivity to this assumption is tested in Appendix 9-B.

[JJ]AGSIM© is designed to forecast agricultural supply and demand out to 2010. We were not able to adapt the model to forecast out to 2030. Instead, we apply percentage increases in yields from decreased ambient ozone levels in 2030 to 2010 yield levels, and input these into an agricultural sector model held at 2010 levels of demand and supply. It is uncertain what impact this assumption will have on net changes in surplus.

[KK] Agricultural benefits differ from other health and welfare endpoints in the length of the assumed ozone season. For agriculture, the ozone season is assumed to extend from April to September. This assumption is made to ensure proper calculation of the ozone statistic used in the exposure-response functions. The only crop affected by changes in ozone during April is winter wheat.

[LL] The total value for these crops in 1998 was $47 billion.

9A.3.6.2.2 Forestry Benefits

Ozone also has been shown conclusively to cause discernible injury to forest trees (US EPA, 1996; Fox and Mickler, 1996). In our previous analysis of the HD Engine/Diesel Fuel rule, we were able to quantify the effects of changes in ozone concentrations on tree growth for a limited set of species. Due to data limitations, we were not able to quantify such impacts for this analysis. We plan to assess both physical impacts on tree growth and the economic value of those phyisical impacts in our analysis of the final rule. We will use econometric models of forest product supply and demand to estimate changes in prices, producer profits and consumer surplus.

9A.3.6.2.3 Other Vegetation Effects

An additional welfare benefit expected to accrue as a result of reductions in ambient ozone concentrations in the U.S. is the economic value the public receives from reduced aesthetic injury to forests. There is sufficient scientific information available to reliably establish that ambient ozone levels cause visible injury to foliage and impair the growth of some sensitive plant species (US EPA, 1996c, p. 5-521). However, present analytic tools and resources preclude EPA from quantifying the benefits of improved forest aesthetics.

Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels and likely to impact large economic sectors. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative economic benefits analysis has been conducted. It is estimated that more than $20 billion (1990 dollars) are spent annually on landscaping using ornamentals (Abt Associates, 1995), both by private property owners/tenants and by governmental units responsible for public areas. This is therefore a potentially important welfare effects category. However, information and valuation methods are not available to allow for plausible estimates of the percentage of these expenditures that may be related to impacts associated with ozone exposure.

The nonroad diesel standards, by reducing NO_X emissions, will also reduce nitrogen deposition on agricultural land and forests. There is some evidence that nitrogen deposition may have positive effects on agricultural output through passive fertilization. Holding all other factors constant, farmers' use of purchased fertilizers or manure may increase as deposited nitrogen is reduced. Estimates of the potential value of this possible increase in the use of purchased fertilizers are not available, but it is likely that the overall value is very small relative to other health and welfare effects. The share of nitrogen requirements provided by this deposition is small, and the marginal cost of providing this nitrogen from alternative sources is quite low. In some areas, agricultural lands suffer from nitrogen over-saturation due to an abundance of on-farm nitrogen production, primarily from animal manure. In these areas, reductions in atmospheric deposition of nitrogen from PM represent additional agricultural benefits.

Information on the effects of changes in passive nitrogen deposition on forests and other terrestrial ecosystems is very limited. The multiplicity of factors affecting forests, including other potential stressors such as ozone, and limiting factors such as moisture and other nutrients, confound assessments of marginal changes in any one stressor or nutrient in forest ecosystems. However, reductions in deposition of nitrogen could have negative effects on forest and vegetation growth in ecosystems where nitrogen is a limiting factor (US EPA, 1993).

On the other hand, there is evidence that forest ecosystems in some areas of the United States are nitrogen saturated (US EPA, 1993). Once saturation is reached, adverse effects of additional nitrogen begin to occur such as soil acidification which can lead to leaching of nutrients needed for plant growth and mobilization of harmful elements such as aluminum. Increased soil acidification is also linked to higher amounts of acidic runoff to streams and lakes and leaching of harmful elements into aquatic ecosystems.

9A.3.6.3 Benefits from Reductions in Materials Damage and Odor

The preliminary control options that we modeled are expected to produce economic benefits in the form of reduced materials damage. There are two important categories of these benefits. Household soiling refers to the accumulation of dirt, dust, and ash on exposed surfaces. Criteria pollutants also have corrosive effects on commercial/industrial buildings and structures of cultural and historical significance. The effects on historic buildings and outdoor works of art are of particular concern because of the uniqueness and irreplaceability of many of these objects.

Previous EPA benefit analyses have been able to provide quantitative estimates of household soiling damage. Consistent with SAB advice, we determined that the existing data (based on consumer expenditures from the early 1970's) are too out of date to provide a reliable enough estimate of current household soiling damages (EPA-SAB-Council-ADV-003, 1998) to include in our base estimate. We calculate household soiling damages in a sensitivity estimate provided in Appendix 9C.

EPA is unable to estimate any benefits to commercial and industrial entities from reduced materials damage. Nor is EPA able to estimate the benefits of reductions in PM-related damage to historic buildings and outdoor works of art. Existing studies of damage to this latter category in Sweden (Grosclaude and Soguel, 1994) indicate that these benefits could be an order of magnitude larger than household soiling benefits.

Reductions in emissions of diesel hydrocarbons that result in unpleasant odors may also lead to improvements in public welfare. The magnitude of this benefit is very uncertain, however, Lareau and Rae (1989) found a significant and positive WTP to reduce the number of exposures to diesel odors. They found that households were on average willing to pay around $20 to $27 (2000$) per year for a reduction of one exposure to intense diesel odors per week (translating this to a national level, for the approximately 125 million households in 2020, the total WTP would be between $2.5 and $3.4 billion annually). Their results are not in a form that can be transferred to the context of this analysis, but the general magnitude of their results suggests this could be a significant welfare benefit of the rule.

9A.3.6.4 Benefits from Reduced Ecosystem Damage

The effects of air pollution on the health and stability of ecosystems are potentially very important, but are at present poorly understood and difficult to measure. The reductions in NO_X caused by the final rule could produce significant benefits. Excess nutrient loads, especially of nitrogen, cause a variety of adverse consequences to the health of estuarine and coastal waters. These effects include toxic and/or noxious algal blooms such as brown and red tides, low (hypoxic) or zero (anoxic) concentrations of dissolved oxygen in bottom waters, the loss of submerged aquatic vegetation due to the light-filtering effect of thick algal mats, and fundamental shifts in phytoplankton community structure (Bricker et al., 1999).

Direct C-R functions relating changes in nitrogen loadings to changes in estuarine benefits are not available. The preferred WTP based measure of benefits depends on the availability of these C-R functions and on estimates of the value of environmental responses. Because neither appropriate C-R functions nor sufficient information to estimate the marginal value of changes in water quality exist at present, calculation of a WTP measure is not possible.

If better models of ecological effects can be defined, EPA believes that progress can be made in estimating WTP measures for ecosystem functions. These estimates would be superior to avoided cost estimates in placing economic values on the welfare changes associated with air pollution damage to ecosystem health. For example, if nitrogen or sulfate loadings can be linked to measurable and definable changes in fish populations or definable indexes of biodiversity, then CV studies can be designed to elicit individuals' WTP for changes in these effects. This is an important area for further research and analysis, and will require close collaboration among air quality modelers, natural scientists, and economists.

9A.4 Benefits Analysis—Results

Applying the C-R and valuation functions described in Section C to the estimated changes in ozone and PM described in Section B yields estimates of the changes in physical damages (i.e.

premature mortalities, cases, admissions, change in deciviews, increased crop yields, etc.) and the associated monetary values for those changes. Estimates of physical health impacts are presented in Table 9A.9. Monetized values for both health and welfare endpoints are presented in Table 9A.10, along with total aggregate monetized benefits. All of the monetary benefits are in constant year 2000 dollars.

Not all known PM- and ozone-related health and welfare effects could be quantified or monetized. The monetized value of these unquantified effects is represented by adding an unknown "B" to the aggregate total. The estimate of total monetized health benefits is thus equal to the subset of monetized PM- and ozone-related health and welfare benefits plus B, the sum of the unmonetized health and welfare benefits.

The total monetized estimates are dominated by benefits of premature mortality risk reductions. Our benefits analysis projects that the modeled preliminary control options will result in 7,800 avoided premature deaths in 2020 and 14,000 avoided premature deaths in 2030. The increase in benefits from 2020 to 2030 reflects additional emission reductions from the standards, as well as increases in total population and the average age (and thus baseline mortality risk) of the population.

Our primary estimate of total monetized benefits (including PM health, ozone health and welfare, and visibility) in 2030 for the modeled nonroad preliminary control options is $96 billion using a 3 percent discount rate and $91 billion using a 7 percent discount rate. In 2020, the monetized benefits are estimated at $54 billion using a 3 percent discount rate and $51 billion using a 7 percent discount rate. Health benefits account for 97 percent of total benefits. The monetized benefit associated with reductions in the risk of premature mortality, which accounts for $89 billion in 2030 and $49 billion in 2020, is over 90 percent of total monetized health benefits. The next largest benefit is for reductions in chronic illness (chronic bronchitis and non-fatal heart attacks), although this value is more than an order of magnitude lower than for premature mortality. Visibility, minor restricted activity days, work loss days, school absence days, and worker productivity account for the majority of the remaining benefits. The remaining categories account for less than $10 million each, however, they represent a large number of avoided incidences affecting many individuals.

A comparison of the incidence table to the monetary benefits table reveals that there is not always a close correspondence between the number of incidences avoided for a given endpoint and the monetary value associated with that endpoint. For example, there are 100 times more work loss days than premature mortalities, yet work loss days account for only a very small fraction of total monetized benefits. This reflects the fact that many of the less severe health effects, while more common, are valued at a lower level than the more severe health effects. Also, some effects, such as hospital admissions, are valued using a proxy measure known to underestimate WTP. As such the true value of these effects may be higher than that reported in Table 9A.9.

Ozone benefits are in aggregate positive for the nation. However, due to ozone increases occurring during certain hours of the day in some urban areas, in 2020 the net effect is an increase in minor restricted activity days, which are related to changes in daily average ozone (which includes hours during which ozone levels are low, but are increased relative to the baseline). However, by 2030, there is a net decrease in MRAD consistent with widespread reductions in ozone concentrations from the increased NOX emissions reductions. Overall, ozone benefits are low relative to PM benefits for similar endpoint categories because of the increases in ozone concentrations during some hours of some days in certain urban areas. For a more complete discussion of this issue, see Chapter 3.

Table 9A.30.
Reductions in Incidence of Adverse Health Effects Associated with Reductions in Particulate Matter and Ozone Associated with the Modeled Preliminary Control Option

Endpoint	Avoided Incidence[A] (cases/year)	
	2020	2030
PM-related Endpoints		
Premature mortality: Long-term exposure (adults, 30 and over)[B]	7,800	13,800
Infant mortality (infants under one year)	18	26
Chronic bronchitis (adults, 26 and over)	4,300	6,500
Non-fatal myocardial infarctions (adults, 18 and older)	10,600	17,700
Hospital admissions — Respiratory (adults, 20 and older)[C]	3,400	6,000
Hospital admissions — Cardiovascular (adults, 20 and older)[D]	2,800	4,400
Emergency Room Visits for Asthma (18 and younger)	4,600	6,900
Acute bronchitis (children, 8-12)	10,000	16,000
Asthma exacerbations (asthmatic children, 6-18)	150,000	230,000
Lower respiratory symptoms (children, 7-14)	120,000	190,000
Upper respiratory symptoms (asthmatic children, 9-11)	92,000	141,000
Work loss days (adults, 18-65)	810,000	1,160,000
Minor restricted activity days (adults, age 18-65)	4,800,000	6,800,000
Ozone-related Endpoints		
Hospital Admissions – Respiratory Causes (adults, 65 and older)[E]	370	1,100
Hospital Admissions - Respiratory Causes (children, under 2 years)	150	280
Emergency Room Visits for Asthma (all ages)	93	200
Minor restricted activity days (adults, age 18-65)	(2,400)	96,000
School absence days (children, age 6-11)	65,000	96,000

[A] Incidences are rounded to two significant digits.
[B] Premature mortality associated with ozone is not separately included in this analysis
[C] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[D] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[E] Respiratory hospital admissions for ozone includes admissions for all respiratory causes and subcategories for COPD and pneumonia.

Table 9A.31
Results of Human Health and Welfare Benefits Valuation for the Modeled Preliminary Nonroad Diesel Engine Standards

Endpoint	Pollutant	Monetary Benefits[A,B] (millions 2000$, Adjusted for Income Growth)	
		2020	2030
Premature mortality[C]: (adults, 30 and over)	PM		
3% discount rate		$49,000	$89,000
7% discount rate		$46,000	$84,000
Infant mortality (infants under one year)	PM	$120	$180
Chronic bronchitis (adults, 26 and over)	PM	$1,800	$2,800
Non-fatal myocardial infarctions	PM		
3% discount rate		$910	$1,440
7% discount rate		$880	$1,400
Hospital Admissions from Respiratory Causes[D,F]	O_3	$7.4	$21
	PM	$60	$110
Hospital Admissions from Cardiovascular Causes[E]	PM	$61	$96
Emergency Room Visits for Asthma	O_3	$0.03	$0.06
	PM	$1.3	$2.0
Acute bronchitis (children, 8-12)	PM	$3.9	$6.0
Asthma exacerbations (asthmatic children, 6-18)	PM	$6.9	$10.7
Lower respiratory symptoms (children, 7-14)	PM	$2.0	$3.1
Upper respiratory symptoms (asthmatic children, 9-11)	PM	$2.4	$3.7
Work loss days (adults, 18-65)	PM	$110	$150
Minor restricted activity days (adults, age 18-65)	O_3	($0.1)	$4.9
	PM	$260	$370
School absence days (children, age 6-11)	O_3	$4.8	$10
Worker productivity (outdoor workers, age 18-65)	O_3	$4.2	$6.9
Recreational visibility (86 Class I Areas)	PM	$1,300	$2,100
Agricultural crop damage (6 crops)	O_3	$88	$137
Monetized Total[H]	O_3 and PM		
3% discount rate		$54,000+B	$96,000+B
7% discount rate		$51,000+B	$91,000+B

[A] Monetary benefits are rounded to two significant digits.
[B] Monetary benefits are adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2020 or 2030).
[C] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants. Also note that the valuation assumes the 5 year distributed lag structure described earlier. Results reflect the use 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).

[D] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[E] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[F] Respiratory hospital admissions for ozone includes admissions for all respiratory causes and subcategories for COPD and pneumonia.
[G] B represents the monetary value of the unmonetized health and welfare benefits. A detailed listing of unquantified PM, ozone, CO, and NMHC related health effects is provided in Table XI-B.1.

9A.5 Discussion

This analysis has estimated the health and welfare benefits of reductions in ambient concentrations of particulate matter resulting from reduced emissions of NOx, SO_2, VOC, and diesel PM from nonroad diesel engines. The result suggests there will be significant health and welfare benefits arising from the regulation of emissions from nonroad engines in the U.S. Our estimate that 14,000 premature mortalities would be avoided in 2030, when emission reductions from the regulation are fully realized, provides additional evidence of the important role that pollution from the nonroad sector plays in the public health impacts of air pollution.

We provide sensitivity analyses in Appendix 9C to examine key modeling assumptions. In addition, there are other uncertainties that we could not quantify, such as the importance of unquantified effects and uncertainties in the modeling of ambient air quality. Inherent in any analysis of future regulatory programs are uncertainties in projecting atmospheric conditions, source-level emissions, and engine use hours, as well as population, health baselines, incomes, technology, and other factors. The assumptions used to capture these elements are reasonable based on the available evidence. However, data limitations prevent an overall quantitative estimate of the uncertainty associated with estimates of total economic benefits. If one is mindful of these limitations, the magnitude of the benefit estimates presented here can be useful information in expanding the understanding of the public health impacts of reducing air pollution from nonroad engines.

The U.S. EPA will continue to evaluate new methods and models and select those most appropriate for the estimation the health benefits of reductions in air pollution. It is important to continue improving benefits transfer methods in terms of transferring economic values and transferring estimated C-R functions. The development of both better models of current health outcomes and new models for additional health effects such as asthma and high blood pressure will be essential to future improvements in the accuracy and reliability of benefits analyses (Guo et al., 1999; Ibald-Mulli et al., 2001). Enhanced collaboration between air quality modelers, epidemiologists, and economists should result in a more tightly integrated analytical framework for measuring health benefits of air pollution policies. The Agency welcomes comments on how we can improve the quantification and monetization of health and welfare effects and on methods for characterizing uncertainty in our estimates.

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APPENDIX 9B: Supplemental Analyses Addressing Uncertainties in the Concentration-Response and Valuation Functions for Particulate Matter Health Effects

9B.1 Introduction

In this appendix, we describe our progress toward improving our approach to characterizing the uncertainties in our economic benefits estimates, with particular emphasis on the concentration-response (C-R) function. We present two types of probabilistic approaches designed to illustrate how some aspects of the uncertainty in the C-R function might be handled in a PM benefits analysis. The first approach generates a probabilistic estimate of statistical uncertainty based on standard errors reported in the underlying studies used in the benefit modeling framework. The second approach uses the results from a pilot expert elicitation designed to characterize certain aspects of uncertainty in the ambient PM2.5/mortality relationship. For the reasons discussed earlier in Chapter 9, neither the primary benefit estimate nor these approaches have been used to inform any regulatory decisions in this rulemaking.

In any benefit analyses of air pollution regulations, estimation of pre-mature mortality accounts for 85 to 95 percent of total benefits. Therefore, it is an endpoint that will be an important focus for characterizing the uncertainty related to the estimates of total benefits. As part of a collaboration with the EPA's Office of Air and Radiation (OAR) and the Office of Management and Budget (OMB) on the Non-Road Diesel Rule, EPA extended it's collaboration with OMB in 2003 to conduct a pilot expert elicitation intended to more fully characterize uncertainty in the effect estimates used to estimate mortality resulting from exposure to PM.

It should be recognized that in addition to uncertainty, the annual benefit estimates for the Final Non-Road Diesel Rule also are inherently variable, due to the truly random processes that govern pollutant emissions and ambient air quality in a given year. Factors such as hourly use of engines and daily weather display constant variability regardless of our ability to accurately measure them. As such, the primary estimates of annual benefits presented in this chapter and the sensitivity analysis estimates presented in this and other appendices should be viewed as representative of the types of benefits that will be realized, rather than the actual benefits that would occur every year. As such, the distributions of the estimate of annual benefits should be viewed as representative of the types of benefits that will be realized, rather than the actual benefits that would occur every year.

9B.2 Monte Carlo Based Uncertainty Analysis Using Classical Statistical Sources of Uncertainty

The recent NAS report on estimating public health benefits of air pollution regulations recommended that EPA begin to move the assessment of uncertainties from its ancillary analyses into its primary analyses by conducting probabilistic, multiple-source uncertainty analyses.

However, for this proposal we did not attempt to assign probabilities to all of the uncertain parameters in the model due to a lack of resources and reliable methods. At this time, we simply generate estimates of the distributions of dollar benefits for PM health effects and for total dollar benefits including visibility. We provide a likelihood distribution for the total benefits estimate, based solely on the statistical uncertainty surrounding the estimated C-R functions and the assumed distributions around the unit values.

Our estimate of the likelihood distribution for total benefits should be viewed as an approximate result because of the wide range of sources of uncertainty that we have not incorporated. The 5th and 95th percentile points of our estimate are based on statistical error and cross-study variability provides some insight into how uncertain our estimate is with regards to those sources of uncertainty. However, it does not capture other sources of uncertainty regarding other inputs to the model, including emissions, air quality, and aspects of the health science not captured in the studies, such as the likelihood that PM is causally related to premature mortality and other serious health effects..

Although there are several sources of uncertainty affecting estimates of endpoint-specific benefits, the sources of uncertainty that are most readily quantifiable in this analysis are the C-R relationships and uncertainty about unit dollar values. The total dollar benefit associated with a given endpoint depends on how much reducing risk of the endpoint will change due to the final standard (e.g., how many premature deaths will be avoided) and how much each unit of change is worth (e.g., how much a premature death avoided is worth).[mm] However, as we have noted, this omits important sources of uncertainty, such as the contribution of air quality changes, baseline population incidences, projected populations exposed, transferability of the C-R function to diverse locations, and uncertainty about the C-R relationship for premature mortality. Thus, a likelihood description based on the standard error would provide a misleading picture about the overall uncertainty in the estimates. The empirical evidence about uncertainty is presented where it is available.

Both the uncertainty about the incidence changes and uncertainty about unit dollar values can be characterized by *distributions*. Each " likelihood distribution" characterizes our beliefs about what the true value of an unknown variable (e.g., the true change in incidence of a given health effect in relation to PM exposure) is likely to be, based on the available information from relevant studies.[nn] Unlike a sampling distribution (which describes the possible values that an

[MM] Because this is a national analysis in which, for each endpoint, a single C-R function is applied everywhere, there are two sources of uncertainty about incidence: (1) statistical uncertainty (due to sampling error) about the true value of the pollutant coefficient in the location where the C-R function was estimated, and (2) uncertainty about how well any given pollutant coefficient approximates β^*.

[NN] Although such a "likelihood distribution" is not formally a Bayesian posterior distribution, it is very similar in concept and function (see, for example, the discussion of the Bayesian approach in Kennedy 1990, pp. 168-172).

estimator of an unknown variable might take on), this likelihood distribution describes our beliefs about what values the unknown variable itself might be. Such likelihood distributions can be constructed for each underlying unknown variable (such as a particular pollutant coefficient for a particular location) or for a function of several underlying unknown variables (such as the total dollar benefit of a regulation). In either case, a likelihood distribution is a characterization of our beliefs about what the unknown variable (or the function of unknown variables) is likely to be, based on all the available relevant information. A likelihood description based on such distributions are typically expressed as the interval from the fifth percentile point of the likelihood distribution to the ninety-fifth percentile point. If all uncertainty had been included, this range would be the "credible range" within which we believe the true value is likely to lie with 90 percent probability.

The uncertainty about the total dollar benefit associated with any single endpoint combines the uncertainties from these two sources (the C-R relationship and the valuation), and is estimated with a Monte Carlo method. In each iteration of the Monte Carlo procedure, a value is randomly drawn from the incidence distribution and a value is randomly drawn from the unit dollar value distribution, and the total dollar benefit for that iteration is the product of the two.[oo] If this is repeated for many (e.g., thousands of) iterations, the distribution of total dollar benefits associated with the endpoint is generated.

Using this Monte Carlo procedure, a distribution of dollar benefits may be generated for each endpoint. As the number of Monte Carlo draws gets larger and larger, the Monte Carlo-generated distribution becomes a better and better approximation of a joint likelihood distribution for the considered likelihood distributions making up the overall model of total monetary benefits for the endpoint.

After endpoint-specific distributions are generated, the same Monte Carlo procedure can then be used to combine the dollar benefits from different (non-overlapping) endpoints to generate a distribution of total dollar benefits.

The estimate of total benefits may be thought of as the end result of a sequential process in which, at each step, the estimate of benefits from an additional source is added. Each time an estimate of dollar benefits from a new source (e.g., a new health endpoint) is added to the previous estimate of total dollar benefits, the estimated total dollar benefits increases. However, our bounding or likelihood description of where the true total value lies also increases as we add more sources.

[oo] This method assumes that the incidence change and the unit dollar value for an endpoint are stochastically independent.

As an example, consider the benefits from reductions in PM-related hospital admissions for cardiovascular disease. Because the actual dollar value is unknown, it may be described using a variable, with a distribution describing the possible values it might have. If this variable is denoted as X_1 , then the mean of the distribution, $E(X_1)$ and the variance of X_1, denoted $Var(X_1)$, and the 5th and 95th percentile points of the distribution (related to $Var(X_1)$), are ways to describe the likelihood for the true but unknown value for the benefits reduction.

Now suppose the benefits from reductions in PM-related hospital admissions for respiratory diseases are added. Like the benefits from reductions in PM-related hospital admissions for cardiovascular disease, the likelihood distribution for where we expect the true value to be may be considered a variable, with a distribution. Denoting this variable as X_2, the benefits from reductions in the incidence of *both* types of hospital admissions is $X_1 + X_2$. This variable has a distribution with mean $E(X_1 + X_2) = E(X_1) + E(X_2)$, and a variance of $Var(X_1 + X_2) = Var(X_1) + Var(X_2) + 2Cov(X_1,X_2)$; if X_1 and X_2 are stochastically independent, then it has a variance of $Var(X_1 + X_2) = Var(X_1) + Var(X_2)$, and the covariance term is zero.

The benefits from reductions in all non-overlapping PM-related health and welfare endpoints $(X_{m+1}, ..., X_n)$ is $X = X_1 + ... + X_n$. The mean of the distribution of total benefits, X, is:

$$E(X) = E(X_1) + E(X_2) + \ldots + E(X_n) \tag{1}$$

and the variance of the distribution of total benefits -- assuming that the components are stochastically independent of each other (i.e., no covariance between variables) -- is:

$$Var(X) = Var(X_1) + Var(X_2) + \ldots + Var(X_n) \quad . \tag{2}$$

If all the means are positive, then each additional source of benefits increases the point estimate (mean) of total benefits. However, with the addition of each new source of benefits, the

$$E(X_1) < E(X_1 + X_2) < E(X_1 + X_2 + X_3) < \ldots < E(X_1 + \ldots + X_n) = E(X) \tag{3}$$

variance of the estimate of total benefits also increases. That is,
but:

$$Var(X_1) < Var(X_1 + X_2) < Var(X_1 + X_2 + X_3) < \ldots < Var(X_1 + \ldots + X_n) = Var(X) \; .$$

That is, the addition of each new source of benefits results in a larger mean estimate of total benefits (as more and more sources of benefits are included in the total) about which there is less certainty. This phenomenon occurs whenever estimates of benefits are added.

Calculated with a Monte Carlo procedure, the distribution of X is composed of random draws from the components of X. In the first draw, a value is drawn from each of the distributions, X_1, X_2, through X_n, these values are summed, and the procedure is repeated again, with the number of repetitions set at a high enough value (e.g., 5,000) to reasonably trace out the distribution of X. The fifth percentile point of the distribution of X will be composed of points pulled from all points along the distributions of the individual components, and not simply from the fifth percentile. While the sum of the fifth percentiles of the components would be represented in the distribution of X generated by the Monte Carlo, it is likely that this value would occur at a significantly lower percentile. For a similar reason, the 95th percentile of X will be *less* than the sum of the 95th percentiles of the components, and instead the 95th percentile of X will be composed of component values that are significantly lower than the 95th percentiles.

The physical effects estimated in this analysis are assumed to occur independently. It is possible that, for any given pollution level, there is some correlation between the occurrence of physical effects, due to say avoidance behavior or common causal pathways and treatments (e.g., stroke, some kidney disease, and heart attack are related to treatable blood pressure). Estimating accurately any such correlation, however, is beyond the scope of this analysis, and instead it is simply assumed that the physical effects occur independently.

We conduct two different Monte Carlo analyses, one based on the distribution of reductions in premature mortality characterized by the mean effect estimate and standard error from the epidemiology study of PM-associated mortality associated with long-term exposure used in the primary estimate in Chapter 9 (Pope et al., 2002), and one based on the results from a pilot expert elicitation project (Industrial Economics, 2004). In both analyses, the distributions of all other health endpoints are characterized by the reported mean and standard deviations from the epidemiology literature. Distributions for unit dollar values are based on reported ranges or distributions of values in the economic literature and are summarized in Table 9B-1. We are unable at this time to characterize the uncertainty in the estimate of benefits of improvements in visibility at Class I areas. As such, we treat the visibility benefits as fixed and add them to all percentiles of the PM health benefits distribution. Results of the Monte Carlo analysis based on the Pope et al. (2002) distribution are presented in the next section. Results of the Monte Carlo analysis based on the pilot expert elicitation are presented in section 9B.3.

9B.2.1 Monte Carlo Analysis Using Pope et al. (2002) to Characterize the Distribution of Reductions in Premature Mortality

Based on the Monte Carlo techniques described earlier, we generated likelihood distributions for the dollar value of reductions in PM-related health endpoints and a similar distribution for total annual PM-related benefits including PM health and visibility benefits for the nonroad diesel modeled preliminary control option. For this analysis, the likelihood descriptions for the true value for each of the PM health endpoint incidence measures, including premature mortality, were based on classical statistical uncertainty measures, including the mean and standard deviation for the C-R relationships in the epidemiological literature, and assumption of particular likelihood distribution shapes for the valuation for each health endpoint values based on reported values in the economic literature. Table 9B-1 summarizes the chosen parameters for likelihood distributions for unit values for each of the PM health effects included in the Monte Carlo simulation. The distributions for the value used to represent incidence of a health effect in the total benefits valuation represent both the simple statistical uncertainty surrounding individual effect estimates and, for those health endpoints with multiple effects from different epidemiology studies, interstudy variability. Visibility benefits are also included in the distribution of total benefits, however, we were unable to characterize a distribution for visibility benefits. As such, they are simply added to each percentile of the distribution of PM health benefits.

Table 9B-1. Distributions for Unit Values of Health Endpoints

Health Endpoint	Mean Value, Adjusted for Income Growth to 2030	Derivation of Distribution
Premature Mortality (Value of a Statistical Life)	$5,500,000	Normal distribution anchored at 2.5th and 97.5th percentiles of $1 and $10 million, respectively. Confidence interval is based on two meta-analyses of the wage-risk VSL literature. $1 million represents the lower end of the interquartile range from the Mrozek and Taylor (2000) meta-analysis. $10 million represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis. The VSL represents the value of a small change in mortality risk aggregated over the affected population. Normal distribution chosen through best professional judgment.
Chronic Bronchitis (CB)	$430,000	The distribution of WTP to avoid a case of pollution-related CB was generated by Monte Carlo methods, drawing from each of three distributions: (1) WTP to avoid a severe case of CB is assigned a 1/9 probability of being each of the first nine deciles of the distribution of WTP responses in Viscusi et al., 1991; (2) the severity of a pollution related case of CB (relative to the case described in the Viscusi study) is assumed to have a triangular distribution, centered at severity level 6.5 with endpoints at 1.0 and 12.0 (see text for further explanation); and (3) the constant in the elasticity of WTP with respect to severity is normally distributed with mean = 0.18 and standard deviation = 0.0669 (from Krupnick and Cropper, 1992). This process and the rationale for choosing it is described in detail in the Costs and Benefits of the Clean Air Act, 1990 to 2010 (U.S. EPA, 1999)
Nonfatal Myocardial Infarction (heart attack) <u>3% discount rate</u> Age 0-24 Age 25-44 Age 45-54 Age 55-65 Age 66 and over <u>7% discount rate</u> Age 0-24 Age 25-44 Age 45-54 Age 55-65 Age 66 and over	 $66,902 $74,676 $78,834 $140,649 $66,902 $65,293 $73,149 $76,871 $132,214 $65,293	No distribution available. Age specific cost-of-illness values reflecting lost earnings and direct medical costs over a 5 year period following a non-fatal MI. Lost earnings estimates based on Cropper and Krupnick (1990). Direct medical costs based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990). <u>Lost earnings</u>: Cropper and Krupnick (1990). Present discounted value of 5 yrs of lost earnings: <u>age of onset</u>: <u>at 3%</u> <u>at 7%</u> 25-44 $8,774 $7,855 45-54 $12,932 $11,578 55-65 $74,746 $66,920 <u>Direct medical expenses</u>: An average of: 1. Wittels et al., 1990 ($102,658 – no discounting) 2. Russell et al., 1998, 5-yr period. ($22,331 at 3% discount rate; $21,113 at 7% discount rate)
Hospital Admissions		
Chronic Obstructive Pulmonary Disease (COPD) (ICD codes 490-492, 494-496)	$12,378	No distribution available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).

Health Endpoint	Mean Value, Adjusted for Income Growth to 2030	Derivation of Distribution
Pneumonia (ICD codes 480-487)	$14,693	No distribution available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total pneumonia category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Asthma admissions	$6,634	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
All Cardiovascular (ICD codes 390-429)	$18,387	No distribution available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Emergency room visits for asthma	$286	No distribution available. The COI point estimate is the simple average of two unit COI values: (1) $311.55, from Smith et al., 1997, and (2) $260.67, from Stanford et al., 1999.
Respiratory Ailments Not Requiring Hospitalization		
Upper Respiratory Symptoms (URS)	$27	Combinations of the 3 symptoms for which WTP estimates are available that closely match those listed by Pope, et al. result in 7 different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. In the absence of information surrounding the frequency with which each of the seven types of URS occurs within the URS symptom complex, we assume a uniform distribution between $10 and $45.
Lower Respiratory Symptoms (LRS)	$17	Combinations of the 4 symptoms for which WTP estimates are available that closely match those listed by Schwartz, et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS. In the absence of information surrounding the frequency with which each of the eleven types of LRS occurs within the LRS symptom complex, we assume a uniform distribution between $8 and $25.
Asthma Exacerbations	$45	Asthma exacerbations are valued at $45 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma exacerbation is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. The value is assumed have a uniform distribution between $17 and $73.

Health Endpoint	Mean Value, Adjusted for Income Growth to 2030	Derivation of Distribution
Acute Bronchitis	$390	Assumes a 6 day episode, with the distribution of the daily value specified as uniform with the low and high values based on those recommended for related respiratory symptoms in Neumann, et al. 1994. The low estimate is the sum of the midrange values recommended by IEc (1994) for two symptoms believed to be associated with acute bronchitis: coughing and chest tightness. The high estimate was taken to be twice the value of a minor respiratory restricted activity day.
Restricted Activity and Work Loss Days		
Work Loss Days (WLDs)	Variable	No distribution available. Point estimate is based on county-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5 – to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
Minor Restricted Activity Days (MRADs)	$55	Median WTP estimate to avoid one MRAD from Tolley, et al. (1986) . Distribution is assumed to be triangular with a minimum of $22 and a maximum of $83. Range is based on assumption that value should exceed WTP for a single mild symptom (the highest estimate for a single symptom--for eye irritation--is $16.00) and be less than that for a WLD. The triangular distribution acknowledges that the actual value is likely to be closer to the point estimate than either extreme.

Results of the Monte Carlo simulations are presented in Table 9B-2. The table provides the estimated means of the distributions and the estimated 5th and 95th percentiles of the distributions. The contribution of mortality to the mean benefits and to both the 5th and 95th percentiles of total benefits is substantial, with mortality accounting for over 90 percent of the mean estimate, and even the 5th percentile of mortality benefits dominating the 95th percentile of all other benefit categories. Thus, the choice of value and the shape for likelihood distribution for VSL should be examined closely and is key information to provide to decision makers for any decision involving this variable. The 95th percentile of total benefits is approximately twice the mean, while the 5th percentile is approximately one fourth of the mean. The overall range from 5th to 95th represents about one order of magnitude.

Table 9B-2.
Distribution of Value of Annual Human Health and Welfare Benefits in 2030 for the Modeled Preliminary Control Option of the Non-Road Diesel Rule[A]

Endpoint	Monetary Benefits[B, C] (Millions 2000$, Adjusted for Income Growth)		
	5th Percentile	Mean	95th Percentile
Premature mortality[D]			
Long-term exposure, (adults, >30yrs)	$20,000	$89,000	$180,000
Long-term exposure (child <1yr)	$40	$180	$350
Chronic bronchitis (adults, 26 and over)	$200	$2,800	$9,400
Non-fatal myocardial infarctions (adults, 18 and over)	$300	$1,400	$3,300
Hospital Admissions from Respiratory Causes[E]	$17	$36	$54
Hospital Admissions from Cardiovascular Causes[F]	$59	$96	$130
Emergency Room Visits for Asthma (children, <18)	$1.3	$2.2	$3.4
Acute bronchitis (children, 8-12)	($0.2)	$5.9	$15
Lower respiratory symptoms (children, 7-14)	$1.1	$2.9	$5.4
Upper respiratory symptoms (asthmatic children, 9-11)	$0.9	$3.7	$7.7
Work loss days (adults, 18-65)	$140	$160	$180
Asthma exacerbations (asthmatic children, 6-18)	$0.2	$11	$29
Minor restricted activity days (adults, age 18-65)	$200	$340	$500
Recreational visibility (86 Class I Areas)	$1,700	$1,700	$1,700
Unquantified Benefits	B	B	B
Monetized Total[G]	$23,000+B	$96,000+B	$200,000+B

[A] The benefit estimates provided in this table are based on the modeled air quality data for the preliminary control option used in the Non-Road Diesel proposal analysis and do not reflect the predicted emission reductions of the final rule's stringency levels. In the primary estimate in Chapter 9, the modeled benefits were scaled to the level necessary to reflect the predicted emission reductions of the final rule. The estimates provided in this table have not been scaled to the rule's stringency level, as the scaling methodology adds a new element of uncertainty that cannot be appropriately characterized here. These estimates should not be compared with the primary estimate provided in the chapter, but could be compared to results presented in Apprendix 9A.
[B] Monetary benefits are rounded to two significant digits.
[C] Monetary benefits are adjusted to account for growth in real GDP per capita between 1990 and 2030.
[D] The valuation of mortality assumes the 5 year distributed lag structure described earlier. Impacts of alternative lag structures are provided in a sensitivity analysis in Appendix 9C. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB's guidelines for preparing economic analyses (US EPA, 2000c, OMB Circular A-4).
[E] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma.
[F] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[G] B represents the monetary value of the unmonetized health and welfare benefits. A detailed listing of unquantified PM, ozone, CO, and NMHC related health effects is provided in Table 9-1.

9B.3 Expert Elicitation of PM Mortality

In its 2002 report, the NAS provides a number of recommendations on how EPA might improve the characterization of uncertainty in its benefits analyses. One recommendation was that "EPA should begin to move the assessment of uncertainties from its ancillary analyses into its primary analyses by conducting probabilistic, multiple-source uncertainty analyses. This shift will require specification of probability distributions for major sources of uncertainty. These distributions should be based on available data and expert judgment."(NAS, 2002: 14) The NAS elaborated on this recommendation by saying "although the specific methods for selection and elicitation of experts may need to be modified somewhat, the protocols that have been developed and tested by OAQPS [in prior EPA projects -- see below] provide a solid foundation for future work in the area. EPA may also consider having its approaches reviewed and critiqued by decision analysts, biostatisticians, and psychologists from other fields where expert judgment is applied." (NAS, 2002: 140). They recommended the use of formally elicited expert judgments, but noted that a number of issues must be addressed, and that sensitivity analyses would be needed for distributions that are based on expert judgment. They also recommended that EPA clearly distinguish between data-derived components of an uncertainty assessment and those based on expert opinions. As a first step in addressing the NAS recommendations regarding expert elicitation, EPA, in collaboration with OMB, conducted a pilot expert elicitation to characterize uncertainties in the relationship between ambient PM2.5 and mortality. While it is premature to include the results of the pilot in the primary analysis for this rulemaking, EPA and OMB believe this pilot is an important step in moving toward the goal of incorporating additional uncertainty analyses in its future primary benefits analyses.

This pilot was designed to provide EPA with an opportunity to improve its understanding of the design and application of expert elicitation methods to economic benefits analysis and lay the groundwork for a more comprehensive elicitation. For instance, the pilot was designed to provide feedback on the efficacy of the protocol developed and the analytic challenges, as well as to provide insight regarding potential implications of the results on the degree of uncertainty surrounding the C-R function for $PM_{2.5}$ mortality. The scope of the pilot was limited in that we focused the elicitation on the C-R function of PM mass rather than on individual issues surrounding an estimate of the change in mortality due to PM exposure. Also, to meet time constraints placed on the pilot, we selected expert s for participation from two previously established expert panels of the NAS, and chose not to conduct a workshop with the experts prior to the elicitation. The limited scope of the pilot meant that a full expert elicitation process was truncated and many aspects of the uncertainty surrounding the $PM_{2.5}$-mortality relationship could not be quantitatively characterized. Recognizing this, the results of the pilot are only used in this benefits estimation for illustrative purposes. A full description of the pilot is contained in a report titled, "An Expert Judgment Assessment of the Concentration-Response Relationship between PM2.5 Exposure and Mortality," (IEc, 2004) available in the public docket for this rule.

The analytic plan for the pilot was developed based on established elicitation methods as suggestedby the NAS and published in the peer-reviewed literature. The plan was internally reviewed by EPA and OMB scientists with experience using expert elicitation methods. The Health Effect Subcommittee (HES) of the Council on Clean Air Compliance Analysis (the "Council") then provided additional suggestions, which led to further changes in the elicitation protocol. However, it should be noted that the Council did not provide a complete peer review of the elicitation methods or interpretation of results. Finally, the protocol was tested on PM scientists from within EPA and external to the Agency, who would not be part of the final elicitation process. The project team that implemented the pilot consisted of individuals with experience in expert elicitation and individuals with expertise in PM health effects and health benefits.

As a final step in this carefully designed pilot, the EPA and OMB will sponsor an external peer review of the methods used in this pilot expert elicitation as well as the approaches to presenting the results (particularly with respect to combining results across experts), in accordance with EPA's peer review guidelines. Until the peer review is complete andthe comments of the reviewers addressed, we do not recommend use of these results for other regulatory analysis.

9B.3.1 Elicitation Method

Expert elicitation is a formal, highly structured and well documented process whereby expert judgments, usually of multiple experts, are obtained (U.S. NRC, 1996). Formal expert elicitation usually involves experts with training and expertise in statistics, decision analysis, and probability encoding who work with subject matter experts to structure questions about uncertain relationships or parameters and who design and implement the process used to obtain probability and other judgments from subject matter experts. Several academic traditions – judgment and decision-making, human factors, cognitive sciences, expert systems, management science, to name a few – have sought to understand how to successfully elicit probabilistic judgments from both lay people and experts (Morgan and Henrion 1990, Cooke 1991,; Wright and Ayton *1994,* Ayyub 2002). Over the past two decades, there has been an increasing number of studies that have used expert judgment techniques to characterize uncertainty in quantities of interest to environmental risk analysis and decision-making. North and Merkhofer (1976) considered the use of expert judgment in evaluating emission control strategies. As referred to by the NAS, the EPA's Office of Air Quality Planning and Standards (OAQPS) successfully used expert judgment to characterize uncertainty in the health effects of exposure to lead (McCurdy and Richmond, 1983; Whitfield and Wallsten, 1989) and to ozone (Whitfield et al. 1991; Winkler et al., 1995). Amaral (1983) and Morgan et al. (1984) used expert judgment in the evaluation of the transport and impacts of sulfur air pollution. Several studies have been done in the area of climate change (Manne and Richels, 1994; Nordhaus, 1994; Morgan and

Keith, 1995; Reilly et al, 2001). Hawkins and Evans (1989) used industrial hygienists to predict toluene exposures to workers involved in a batch chemical process. In a more recent use of expert judgment in exposure analysis, Walker et al. (2001, 2003) asked experts to estimate ambient, indoor and personal air concentrations of benzene. A few studies have used expert judgment to characterize uncertainty in chemical dose response: Hawkins and Graham (1988) and Evans et al. (1994) for formaldehyde and Evans et al. (1994b) for risk of exposure to chloroform in drinking water. Expert judgment has also been used in the characterization of residential radon risks (Krewski et al., 1999).

The literature (Granger and Morgan, 1990) suggest there are several steps involved in the design and implementation of an expert elicitation, including:

- developing a protocol that contains the specific content of the elicitation and the questions that will be asked of the experts,
- selection of experts,
- compiling a briefing book of materials that can be used by the experts as background information to respond to the elicitation,
- pilot testing the protocol,
- conducting the elicitation and summarizing the findings.

The pilot expert elicitation consisted of a series of structured questions, both quantitative and qualitative, about the nature of the $PM_{2.5}$/mortality relationship. The objective was to obtain experts' quantitative, probabilistic judgments about the average expected decrease in mortality rates associated with decreases in $PM_{2.5}$ exposures in the United States. These judgments were expressed in terms of median estimates and associated percentile values of an uncertainty distribution. The quantitative questions in the protocol asked experts to provide judgments about changes in mortality due exposure to $PM_{2.5}$. Specifically, they were asked to estimate:1) the percent change in annual non-accidental mortality associated with a 1 $\mu g/m^3$ change in annual average $PM_{2.5}$ (long-term exposure); and 2) the percent change in daily non-accidental mortality associated with a 10 $\mu g/m^3$ change in daily 24-hour average $PM_{2.5}$ (short-term exposure). For each type of exposure, each expert provided minimum, maximum, and median estimates, plus 5^{th}, 25^{th}, 75^{th}, and 95^{th} percentile values for the distribution describing his uncertainty in the mortality effect of the specified change in $PM_{2.5}$.

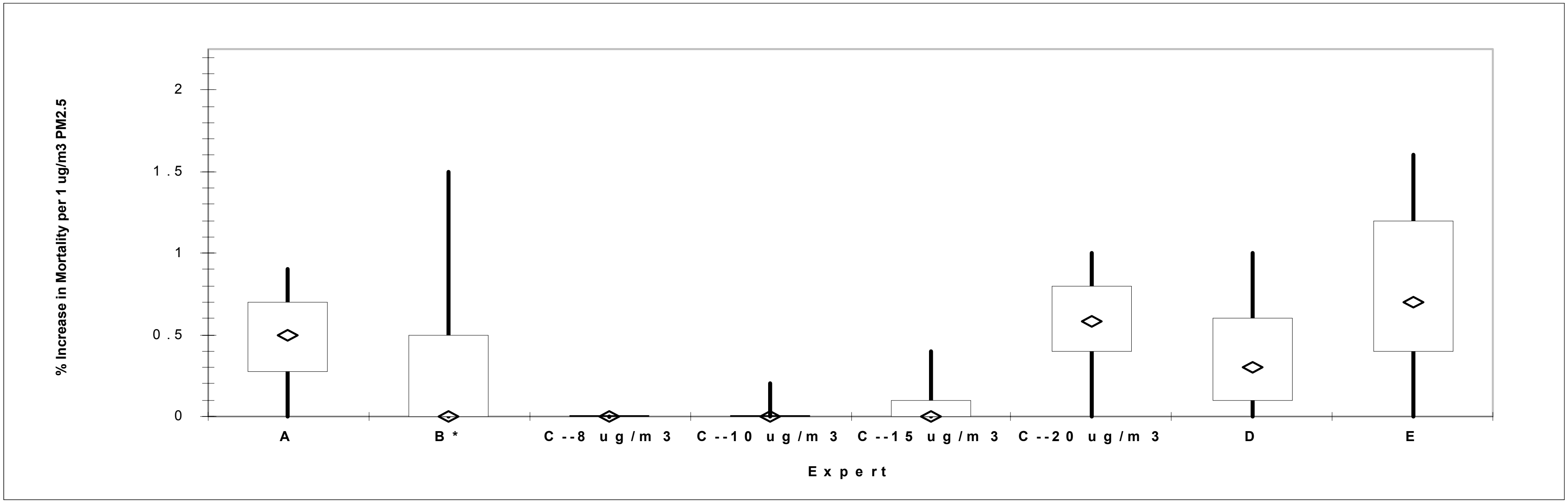
The pilot focused on eliciting judgments about the C-R function for PM2.5 mass (without regard to source) and their solicited opinions about the key factors influencing the uncertainty in estimating the PM2.5/mortality relationship. As a warm-up to answering the quantitative question, experts were asked their views on several key issues including: cause of death, mechanisms, thresholds, lag/cessation period, the relative effect of PM components and their sources, confounding, and effect modification. This discussion allowed the experts to articulate the way they interpreted the underlying issues, thus what would form the conceptual framework of their quantitative judgments. Their responses also provided EPA with information that would be useful for designing a more comprehensive and disaggregated elicitation assessment in the future.

The pilot elicitation consisted of personal interviews with five experts. The five experts were selected from an initial pool defined by the membership on two PM-related NAS committees. The rosters of both NRC committees included recognized experts in pertinent fields such as epidemiology and toxicology who had already undergone extensive review of their qualifications by the NRC, producing a reasonable initial list of experts likely to meet our expert selection criteria. The five experts selected for participation in the elicitation include: Dr. Roger McClellan, Dr. Bart Ostro, Dr. Jonathan Samet, Dr. Mark Utell, and Dr. Scott Zeger. The specific process used to select experts is detailed in the technical report of the elicitation (IEc, 2004) along with additional information about the experts' affiliations and fields of expertise. The size of the final expert panel was dictated by time and resource constraints, and the decision to restrict the initial expert pool to the NRC committees was made to help expedite the expert selection process. The experts were provided a briefing book of reference materials and a copy of the elicitation protocol prior to the interviews. Each interview lasts 6-8 hours.

9.B.3.2 Elicitation Results

Figure 9B-1 displays the responses of the experts to the quantitative elicitation question for the mortality effects of changes in long-term $PM_{2.5}$ exposures. The distributions provided by each expert, identified by the letters A through E, are depicted as box plots with the diamond symbol showing the median (50th percentile), a circle symbol showing the mean estimate, the box defining the interquartile range (bounded by the 25th and 75th percentiles), and the whiskers defining each expert's 90 percent confidence interval (bounded by the 5th and 95th percentiles of the distribution).

Figure 9B-1. Summary of Experts' Judgments About the Percent Increase in Annual Average Non-Accidental Mortality Associated with a 1 μg/m3 Increase in Annual Average Exposures to PM2.5



*Expert B specified this distribution for the PM/mortality coefficient above an uncertain threshold which he characterized as ranging between 4 and 15 with a modal value of 12 μg/m^3.As illustrated here, considerable variation exists in both the median values and the spread of uncertainty provided by the experts. The median value of the percent change in annual non-accidental mortality per unit change in annual $PM_{2.5}$ concentration (within a range of $PM_{2.5}$ concentrations from 8 to 20 μg/m^3) ranged from values at or near zero to a value of 0.7 percent. The variation in the responses largely reflects differences in the amount of uncertainty each expert considered inherent in the key epidemiological results from long-term cohort studies, the likelihood of a causal relationship, and the shape of the C-R function. The technical report (IEc, 2004) provides detailed descriptions of the experts' judgments about these factors, but we present a few brief observations relative to their responses below.

** Expert C specified a non-linear model and provided distributions for the slope of the curve at four discrete concentrations within the range.

As illustrated by the figure, the experts exhibited considerable variation in both the median values they reported and in the spread of uncertainty about the median. In response to the question concerning the effects of changes in long-term exposures to $PM_{2.5}$, the median value ranged from values at or near zero to a 0.7 percent increase in annual non-accidental mortality per 1 $\mu g/m^3$ increase in annual mean $PM_{2.5}$ concentration (within a range of $PM_{2.5}$ concentrations from 8 to 20 $\mu g/m^3$). The variation in the responses for the effects of long-term exposures largely reflects differences of opinion among the experts on a number of factors such as key epidemiological results from long-term cohort studies, the likelihood of a causal relationship, and the shape of the C-R function. Some observations concerning the outcome of the individual expert judgments are provided below:

Key Cohort Studies. The experts' non-zero responses for the percent change in annual mortality were mostly influenced by the Krewski et al., (2000) reanalysis of the original American Cancer Society (ACS) cohort study and by the later Pope et al. (2002) update of the ACS study that included additional years of follow-up. None of the experts placed substantial weight on the mortality estimates from the Six-Cities study (Dockery et al., 1993) in composing their quantitative responses, despite citing numerous strengths of that analysis. Concern about sample size and representativeness of the Six Cities study for the entire U.S. appeared to be a major reason for de-emphasizing those results.

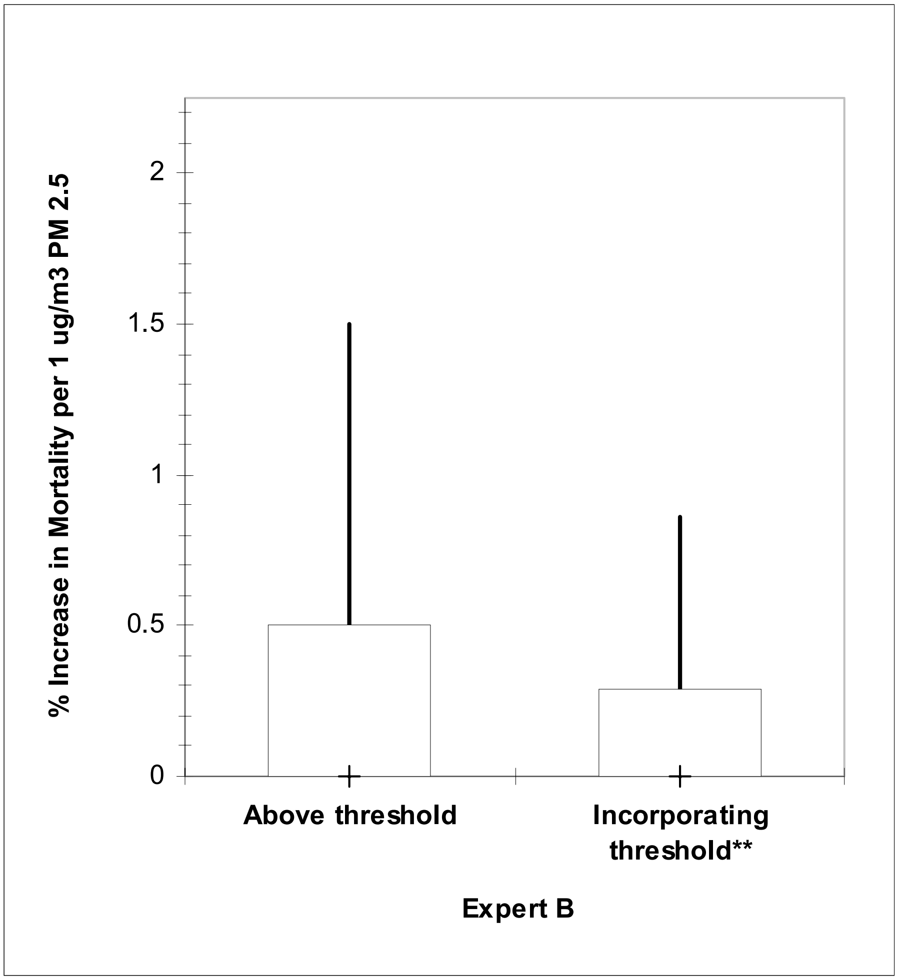
Causality for Long-Term Effects. Three of the five experts gave distributions more heavily weighted towards zero. Those experts were also the ones who gave the lowest probability of a causal effect of long-term exposure to $PM_{2.5}$ in the preliminary questions. All of the experts placed at least a 5 percent probability on the possibility that there is no causal relationship between fine PM exposure and mortality; as a result, all experts gave a fifth percentile value for the C-R coefficient of zero. For most of the experts, this was based primarily on residual concerns about the strength of the mechanistic link between the exposures and mortality.

Shape of the C-R Function for Long-Term Effects. The other key determinant of each expert's responses for long-term effects was his assumption about the nature of the C-R function across the range of baseline annual average $PM_{2.5}$ concentrations assumed in the pilot (8 to 20 $\mu g/m^3$). Three experts (A, D, and E) assumed that the function relating mortality with PM concentrations would be log-linear with constant slope over the specified range. They therefore gave a single estimate of the distribution of the slope describing that log-linear function. The other two experts provided more complex responses.

Expert B assumed a population threshold in his model, below which there would be no effect of increased $PM_{2.5}$ exposure and above which the relationship would be log-linear. He characterized his estimate of a possible threshold as uncertain, ranging between 4 $\mu g/m^3$ and 15 $\mu g/m^3$, with a modal value of 12 $\mu g/m^3$. He then described a distribution for the slope for the log-linear function that might exist above the threshold; this distribution is depicted in Figure 9B-2. The effect of incorporating the uncertain threshold is essentially to shift his entire distribution downward.

Expert C believed that the increased relative risks for mortality observed in the cohort studies were likely to be the result of exposures at the higher end of the exposure range, and he expected there to be a declining effect on mortality with decreasing levels of $PM_{2.5}$. He also argued that some practical concentration threshold was likely to exist below which we would not observe any increase in mortality. He reflected these beliefs by developing a non-linear model within the range from 8 to 20 $\mu g/m^3$; he described the model by providing distributions for the slope of the curve at four discrete concentrations within the range.

Figure 9B-2.
Expert B's Distributions for the Percent Increase in Annual Non-Accidental Mortality Associated with a 1 μg/m3 Increase in Long-term Exposures to PM2.5: Comparison of His Distribution Above a Threshold to His Expected Distribution* for the Range 8-20 μg/m3



* Expert B specified the threshold as uncertain between 4 and 15 μg/m^3 with a modal value at 12 μg/m3. He assumed the percent increase in mortality to increase linearly with concentration above the threshold. His effective distribution was simulated using Monte Carlo techniques assuming an underlying distribution of population-weighted annual average $PM_{2.5}$ concentrations for the U.S. generated from the BenMAP model (see the technical report (IEc, 2004) for details).

9B.3.3 Experts' Views of Sources of Uncertainty

The experts were asked at several points during the interview to discuss the key sources of potential bias and uncertainty in current evidence on which they relied for their judgments. In the context of the quantitative discussion they were asked to list the top five issues. They were encouraged to think about how these issues would affect the uncertainty surrounding their best estimate of the potential impact on total mortality of a small change in long-term exposure to $PM_{2.5}$. The tables summarizing the factors identified by each expert may be found in Appendix E of the technical report (IEc, 2004).

Many of the same factors appeared in the list of the five experts. However, the experts often differed on whether a particular factor was a source of potential bias or uncertainty. Some of the common concerns raised as either sources of bias or uncertainty, include:

- Residual confounding by smoking,
- Residual confounding by "life-style" or other personal factors or "stressors,"
- Exposure errors/misclassification,
- The role of co-pollutants as confounders or effect modifiers,
- Impact of the relative toxicity of PM components,
- Representativeness of the cohort populations with respect to the general U.S. population, and
- Investigator/publication biases.

Despite the many qualitative discussions about sources of uncertainty, because the pilot study did not elicit quantitative judgments about the size and nature of impacts of each source of uncertainty and bias, we were unable to systematically evaluate the nature of the influence of these factors on the quantitative results provided by each expert unless an expert explicitly adjusted his estimates by a particular factor.

9B.3.4 Advisory Council Comments on the Preliminary Design of the Elicitation

As part of a review of the analytical blueprint of the EPA's Second Prospective Analysis of the Costs and Benefits of the Clean Air Act under section 812 of the Act, a panel of outside experts - the Health Effects Subcommittee (HES) of the Advisory Council on Clean Air Compliance Analysis (Council)[pp] - provided a limited[qq] and preliminary review of the

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[PP] The Council is an advisory committee with an independent statutory charter that is organized and supported under the EPA's Science Advisory Board.

[QQ] Council/HES report: "**...**in view of the fact that the pilot project is well-underway, the experts have already been selected, and many (if not all) of the interviews have been conducted, the HES sees little potential benefit in providing detailed suggestions about the design or conduct of the pilot study." (EPA-SAB-COUNCIL-ADV-04-002, methodology and design of the expert elicitation. In an Advisory issued by the Council to the EPA (EPA-SAB-COUNCIL-ADV-04-002, March 2004), the Council-HES provided the following comments with regard to the elicitation:

- "We applaud the Agency's interest in exploring the use of formal expert judgment as a tool for improving uncertainty analysis and believe that the proposed pilot study has great potential to yield important insights. The pilot is well designed to inform subsequent and more comprehensive expert elicitation projects, but relies on the opinions of a relatively small group of experts. It may provide preliminary information about the general magnitude of the mortality effects, and may yield a sense of both the uncertainty inherent in these estimates and the factors largely responsible for such uncertainty. However, until the pilot study methods and results have been subjected to peer review, it may be unwise for the Agency to rely directly on these preliminary results in key policy decisions."

- In presenting results of the pilot elicitation, "the HES advises the EPA to present the entire collection of individual judgments; to carefully examine the collection of individual judgments noting the extent of agreement or disagreement; to thoughtfully assess the reasons for any disagreement; and to consider formal combinations of judgments only after such deliberation and with full awareness of the context ..."

- "The HES recognizes that in order to make the pilot tractable it was necessary to limit participation, and is aware of the many factors which must be balanced in the selections of expert panels (Hawkins and Graham, 1988), but is concerned about whether the judgments of such a limited group can reasonably be interpreted as representing a fair and balanced view of the current state of knowledge."

9B.3.5 Limitations in Pilot Elicitation Design

The pilot elicitation has afforded many opportunities for learning about expert elicitation in the context of economic benefits analysis. However, because this was an initial assessment that was limited in scope (as is discussed in section 9B.1), this section briefly discusses some of the limitations in the design of the pilot. Additional detail on the strengths and weaknesses of the pilot are provided in the technical report (IEc, 2004).

- Short time-period to design and conduct the elicitation - The scope of the pilot was limited in order to complete the assessment and present our findings as part of the Final Nonroad Diesel Rule. Thus, there was a one-year time period in which were

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designed the elicitation, conducted the interviews, and provided an interpretation of the results in this RIA and the technical report (IEc, 2004). In addition to designing the elicitation with specific limitations as are discussed below, the experts we given short notice of the elicitation (some experts were interested but not available in our time frame), and we were required to process the results rapidly to meet the rulemaking schedule.

- The design and implementation of the elicitation has not undergone a complete external peer review. While EPA is planning to conduct a peer review of the elicitation process, we were not able to complete the review prior to the promulgation of the final rule. The results of the pilot should be viewed tentatively until the full peer review is complete.

- Small panel of experts - Due to resource constraints we limited the pilot to a panel of five experts. As noted above, the SAB-HES expressed their concern "about whether the judgements of such a limited group can reasonably be interpreted as representing a fair and balanced view of the current state of knowledge." They point to the many factors which must be balanced in the selection of expert panels (Hawkins and Graham, 1988) and there are numerous opinions among a large set of experts.

  Little analytical research has been conducted on the more difficult question of how to determine the ideal number of experts for a particular application. We have not found any analyses of the effect of expert panel size based on comparisons of empirical results of expert judgment studies. A theoretical analysis by Clemen and Winkler (1985) suggests that where data sources are moderately positively dependent there are diminishing marginal returns to the value of information associated with each additional data source. In the context of expert judgment studies, such a result implies that when dealing with experts of similar backgrounds who rely on the same models and studies, a larger expert panel may not provide significantly higher quality results than a smaller one. However, the addition of an expert expected to provide a more independent assessment, such as an expert from a different, but pertinent field, would be expected to exhibit a much greater value of information. Clemen and Winkler (1999) note that "heterogeneity among experts is highly desirable." These findings would appear to support addressing complex issues using a panel comprised of relatively small subgroups (perhaps three to five experts each) from multiple disciplines. Although the decision analysis field tends to use relatively small sample sizes (i.e., typically 5-10 experts), some are not comfortable with obtaining a combined distribution from such small numbers in the absence of an apriori assessment of the degree to which the expert panel is likely to be representative of the overall population of relevant experts on the question of interest. The panel we used may not have captured the full range of reasonable opinions.

- Use of an aggregate elicitation question - The expert judgment literature discusses two broad approaches to elicitation of judgments; an aggregated and a disaggregated approach. As the term implies, an aggregated approach asks the expert to estimate the quantity of interest directly; for example, the numbers of newspapers sold in the U.S. in a particular year. In a disaggregated approach, the expert (or group of experts) would be asked to construct a model for estimating the quantity of interest and would be asked directly about the inputs to that model (e.g. population in each state, percentage of the population that reads newspapers, etc.) The intuition is that it is easier for experts to answer questions about the intermediate quantities than about the total quantity.

  The project team carefully considered the relative advantages and disadvantages of the two approaches. A major advantage of the disaggregated approach is a more structured and transparent characterization of the key inputs and sources of uncertainty in the final quantity of interest. However, the method does require additional time and resources to develop a model structure (or in some cases, multiple models) and set of inputs on which the experts can agree prior to the individual elicitations.

  The limited time frame available to complete this assessment drove the decision to undertake an aggregate approach to elicit the C-R coefficient for the $PM_{2.5}$/mortality relationship.[rr] Nonetheless, a major goal of the preliminary and follow-up questions in the protocol was to identify critical issues that could be addressed through the development of a more disaggregated approach in a future assessment.

  Thus, the design of the pilot limits our ability to determine the influence of any one key factor over others in a large list of issues that the experts were to consider prior to answering the quantitative question. It also limited the ability of the experts to express their views about the difference in the C-R function based on the location in the U.S. (i.e., the demographics of the exposed population, the air concentration of PM and/or PM mixture).

[RR] While the Project Team initially considered using a highly aggregated approach that would have asked experts to characterize a single overall PM / mortality effect due to both short- and long-term exposures to PM2.5. However, based on advice from the SAB-HES, we opted to disaggregate effects due to long- and short-term exposures. The Project Team felt that separate questions to address effects of long- and short-term exposures, though still at a high level of aggregation, would prove to be easier for experts to address than a question that "rolled up" all the effects into a single estimate. This level of disaggregation also enabled the elicitation team to explore with experts possible overlap in reported mortality effects detected using long-term and short-term epidemiological studies.

- No workshop was conducted - It is customary to conduct a workshop prior to the elicitation interview with the experts. This allows the experts to become familiar with the protocol, the background materials contained in the briefing book, and to discuss methods to limit bias during the interview. Due to time constraints for the pilot, we did not conduct a pre-elicitation workshop.

- No calibration of experts - We do not have calibration measures that could be used to assess the results of this pilot. At this point, we can only assess the process – did the pilot assessment employ a structure, supporting materials, and a process that enabled experts to make judgments that would be likely to be well calibrated? The peer review for this aspect is still underway. Nevertheless, without calibration measures, we cannot weight experts based on their performance on calibration tasks.

- Full-day elicitation - The elicitation interview with each expert took a full-day to complete. Again, experts were given short notice of the elicitation and found time in their schedules to participate, yet not all of the experts were available for the full-day interview. The length of the interview could lead to response fatigue that could affect the outcome of the experts' response.

9B.3.6 Combining the Expert Judgments for Application to Economic Benefit Analyses

Analysts must give careful thought to whether and how to combine the results individual expert judgments into a single distribution. When dealing with a small sample number of experts, the analyst must be particularly careful to identify the influence of each expert's response on the combined distribution. Therefore, we considered four alternative methods for combining the pilot results. However, the Project Team identified significant issues associated with each of the methods. In this section, we discuss the issues we considered in combining the results of the pilot and how we came to the conclusion that for the illustrative benefits analysis presented in Section 9B.5 below, we would present both the individual quantitative distributions of the C-R coefficient elicited from the five experts interviewed as well as results based on a probabilistic estimate that represents the combined results of the pilot based on an equal weighting of the calculated change in mortality incidence based on the individual judgments.

9B.3.6.1 Background

Combination of expert judgments is not strictly necessary; some investigators (e.g., Hawkins and Graham, 1990; Winkler and Wallsten, 1995; and Morgan et al., 1984) have preferred to keep expert opinions separate in order to preserve the diversity of opinion on the issues of interest. In such situations, the range of values expressed by the experts can help decision-makers to understand the sensitivity of their analyses to the analytical model chosen, thereby bounding possible outcomes. Individual judgments can also illustrate varying opinions arising from different disciplinary perspectives or from the rational selection of alternative theoretical models or data sets (Morgan and Henrion, 1990). Nonetheless, analysts are often interested in developing a single distribution of values that reflects a synthesis of the judgments elicited from a group of experts.

There are also some advantages to combining the results across experts. An extensive literature exists concerning methods for combining expert judgments. These methods can be broadly classified as either mathematical or behavioral (Clemen and Winkler, 1999). Mathematical approaches range from simple averaging of responses to much more complex models incorporating information about the quality of expert responses, potential dependence among expert judgments, or (in the case of Bayesian methods) prior probability distributions about the variable of interest. Behavioral approaches require the interaction of experts in an effort to encourage them to achieve consensus, either through face-to-face meetings or through the exchange of information about judgments among experts. As noted in the technical report (IEc, 2004) , there are both methodological and practical issues arguing against a behavioral approach. Therefore, we used a mathematical combination process to derive a single distribution.

One advantage of mathematical combination over behavioral approaches is the ability to be completely transparent about how weights have been assigned to the judgments of specific experts and about what assumptions have been made concerning the degree of correlation between experts. Several approaches can be used to assign weights to individual experts. Weights can be assigned based on the analyst's opinion of the relative expertise of each expert; on a quantitative assessment of the calibration and informativeness (i.e., precision) of each expert based on their responses to a set of calibration questions (as described in Cooke, 1991); or on weights assigned by each expert, either to him or herself or to the other experts on the panel (see Evans et al., 1994 for an example of this approach). Ideally, such a weighting system would address problems of uneven calibration and informativeness across experts, as well as potential motivational biases (Cooke, 1991).[a] In practice, appropriate weights can be difficult to determine, though Cooke and others have conducted considerable research on this issue.

At the design stages of the pilot, we decided that the resulting expert judgments would be combined using equal weights, essentially calculating the arithmetic mean of the expert responses, for simplicity and transparency. The reasons for choosing equal weights were both practical and

[A] "Motivational bias" refers to the willful distortion of an expert's true judgments. The origins of this bias can vary, but could include, for example, a reluctance to contradict views expressed by one's employer or a deliberate attempt to skew the outcome of the study for political gain.

methodological. Development of defensible differential weights was not possible given the expedited schedule for this project. Although we did conduct a sample calibration exercise with each expert, the purpose of the exercise was to train the experts in providing quantitative responses, not to develop calibration scores that would be used to weight experts. Some empirical evidence suggests that the simple combination rules, like equal weighting, perform equally well when compared to more complex methods in terms of calibration scores for the combined results (Clemen and Winkler, 1999). The methods to combine the expert judgments will be explicitly addressed during the peer review of the pilot assessment.

9B.3.6.2 Alternative Combination Methods

While a combination method using equal weights for the results of each expert is straightforward in principle, applying it in this context of the results of the pilot was complicated by the fact that the elicitation protocol gave the experts freedom to specify different forms for the C-R function. If all the experts had chosen the same form of the C-R function,(e.g., if each expert had specified a log-linear C-R function with a constant, but uncertain, C-R coefficient (i.e., slope) over the PM range specified in the protocol) the combination of their distributions for the C-R coefficient would require a simple averaging across experts at each elicited percentile. However, in this assessment, three experts specified log-linear functions with constant C-R coefficients over the specified range of $PM_{2.5}$ concentrations, and two of the experts specified the C-R coefficient as likely to vary over the range of specified $PM_{2.5}$ concentrations (as discussed in Section 9B.4.2 above). These more complex C-R functions necessitated some additional steps in the calculation of the combined results.

As discussed in the technical report for the pilot (IEc, 2004), individual response either can be combined before application of the benefits model or during the application of the model, allowing each expert's C-R function to be estimated in the benefits model independently. Specifically, we derive the total mortality incidence for each expert, and combine (or pool) the estimates into an aggregate value before taking an average of the mortality incidence. This is referred to as a "pooled" approach and is used in our modeling framework for other benefit endpoints that have multiple C-R function (due to multiple studies). We prefer the pooled approach because it seems to reduce the amount of alteration of the actual step-function responses provided by Experts B and C (although some adjustments must still be made)[b]. Details of the illustration are provided in Section 9B.6.

[B] Expert B specified a distribution for the C-R coefficient for $PM_{2.5}$ concentrations above a threshold and assigned the coefficient a value of zero for all PM concentrations below the threshold. He then specified a probability distribution to describe the uncertainty about the threshold value. Expert C specified separate distributions for the C-R coefficient at four discrete points within the concentration ranges defined in the protocol, to represent a continuous C-R function whose slope varied with the $PM_{2.5}$ concentration. Expert C indicated that the coefficient value between these points was best modeled as a continuous function, rather than a step function. Both experts assumed the same functional forms in responding to elicitation question.

The alternative would be to combine the individual expert judgments into a single C-R function before applying the results to the benefits model. Below, we present three approaches we considered for combining the expert judgments before applying the benefits model. Among the three approaches to combining expert judgments before the benefits analysis, the primary difference is how they account for the underlying particulate air pollution levels. The first option assumes a uniform distribution and equal weighting, which involves taking a simple average of responses across experts for each percentile. In a second combination method, we combined the results using a normal distribution describing population-weighted annual average $PM_{2.5}$ concentration data generated from EPA's Environmental Benefits and Mapping Analysis Program (BenMAP), the model EPA currently uses for economic benefit analyses of air quality regulations affecting PM and other criteria pollutants.[c]

As discussed above, for the two of the experts that specified a C-R function that varied over the range of PM concentrations., their estimated C-R function necessitated some additional steps in the calculation of the combined results. To derive a single distribution across all experts for a particular range of exposures (e.g. 8-20 $\mu g/m^3$ annual average $PM_{2.5}$), we first needed to estimate an "effective" distribution of uncertainty about the C-R coefficient for both Experts B and C across that range by using Monte Carlo simulation (Crystal Ball® software) to estimate the expected value of each percentile elicited across the full $PM_{2.5}$ range specified. Specifically, the additional steps we took for this combination method are as follows:

- Expert B specified a distribution for the C-R coefficient fo rPM2.5 concentrations above a stated threshold and assigned the coefficient a value of zero for all PM concentrations below the threshold. He then specified a probability distribution to describe the uncertainty about the threshold value. Thus, we conducted Monte Carlo sampling using two distributions: his uncertainty distribution for the threshold, and an assumed distribution of baseline $PM_{2.5}$ concentrations for the $PM_{2.5}$ range specified in the elicitation protocol. On each iteration, we selected a value from each of these two distributions and compared them. If the selected baseline concentration was less than or equal to the selected threshold value, each of the percentiles of Expert B's uncertainty distribution was assigned a zero value (no mortality effect); if the concentration was greater than the threshold, we assigned each percentile the "above-the-threshold" value specified by Expert B in his interview.[d] We repeated this

[C] To facilitate Monte Carlo sampling, we evaluated the fit of the BENMAP data to several distributional forms, ultimately selecting a normal distribution, truncated at zero, with a mean of 11.04 $\mu g/m^3$ and a standard deviation of 2.32 $\mu g/m^3$.

[D] An example for mortality effects from long-term exposures helps illustrate this approach. Expert B estimated that he was 75 percent sure (i.e., his 75th percentile) that the percent increase in mortality would be less than or equal to 0.5 percent per 1 $\mu g/m^3$ change in $PM_{2.5}$ concentration if the baseline concentration were above the threshold, but zero process for thousands of iterations and then took the average value for each of the percentiles to obtain Expert B's "effective" distribution of uncertainty about the C-R coefficient across each range of exposures.

- Expert C specified separate distributions for the C-R coefficient at four discrete points within the concentration ranges defined in the protocol, to represent an continuous function whose slope varied with the PM concentration. Thus, we first randomly sampled from the assumed distribution of baseline PM concentrations. We then linearly interpolated between Expert C's responses at the two points nearest to the sampled PM concentration, to estimate his uncertainty distribution for the C-R coefficient at the sampled concentration. For example, Expert C provided slope values at $PM_{2.5}$ concentrations of 8, 10, 15 and 20 for mortality effects of long-term exposure. If, on a given iteration we selected a $PM_{2.5}$ concentration of 12 μg/m^3, we would generate a slope at each percentile of his uncertainty distribution by interpolating between Expert C's responses at 10 and 15 μg/m^3. We repeated this process for thousands of iterations and then took the average value for each of the percentiles to obtain the "effective" distribution of the average slope of Expert C's C-R function.

While the uniform distribution is the simplest method of combining the expert judgments, it required us to alter the true responses of Experts B and C. It is also based on a uniform distribution, which does not match the observed $PM_{2.5}$ concentrations that tend to be skewed toward the lower concentration values. The estimates of Expert B and C's "effective" distributions, and thus the combined expert distribution, are all sensitive to the probability density function chosen to describe the U.S. baseline $PM_{2.5}$ concentrations in the simulations. This sensitivity arises because both Experts B and C assume that the effect of an increase in $PM_{2.5}$ concentration on mortality depends on the initial $PM_{2.5}$ concentration. Table 9B-3 presents the resulting values of the distribution for these two methods of combining the results of the pilot.

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percent if it were below the threshold. If on a given iteration, the program selects a baseline concentration of 12 μg/m^3 and a threshold level of 10 μg/m^3, we assign his 75th percentile the value of 0.5. If the threshold level selected were 15 μg/m^3, the 75th percentile would be assigned a value of zero.

Table 9B-3. Methods for Combining Expert Judgments: Combined C-R function with Uniform Distribution and a Population-Weighted Distribution

Percentiles	**Combined Expert Judgments using a Uniform Distribution of Baseline Annual Mean $PM_{2.5}$ Concentrations**	**Combined Expert Judgments Based on Population-Weighted Distribution of Baseline Annual Mean $PM_{2.5}$ Concentrations in U.S.**
95th %ile	1.05	0.93
75th %ile	0.65	0.59
50th %ile	0.33	0.3
25th %ile	0.17	0.16
5th %ile	0.00	0
Minimum	0.00	0
Maximum	1.71	1.5

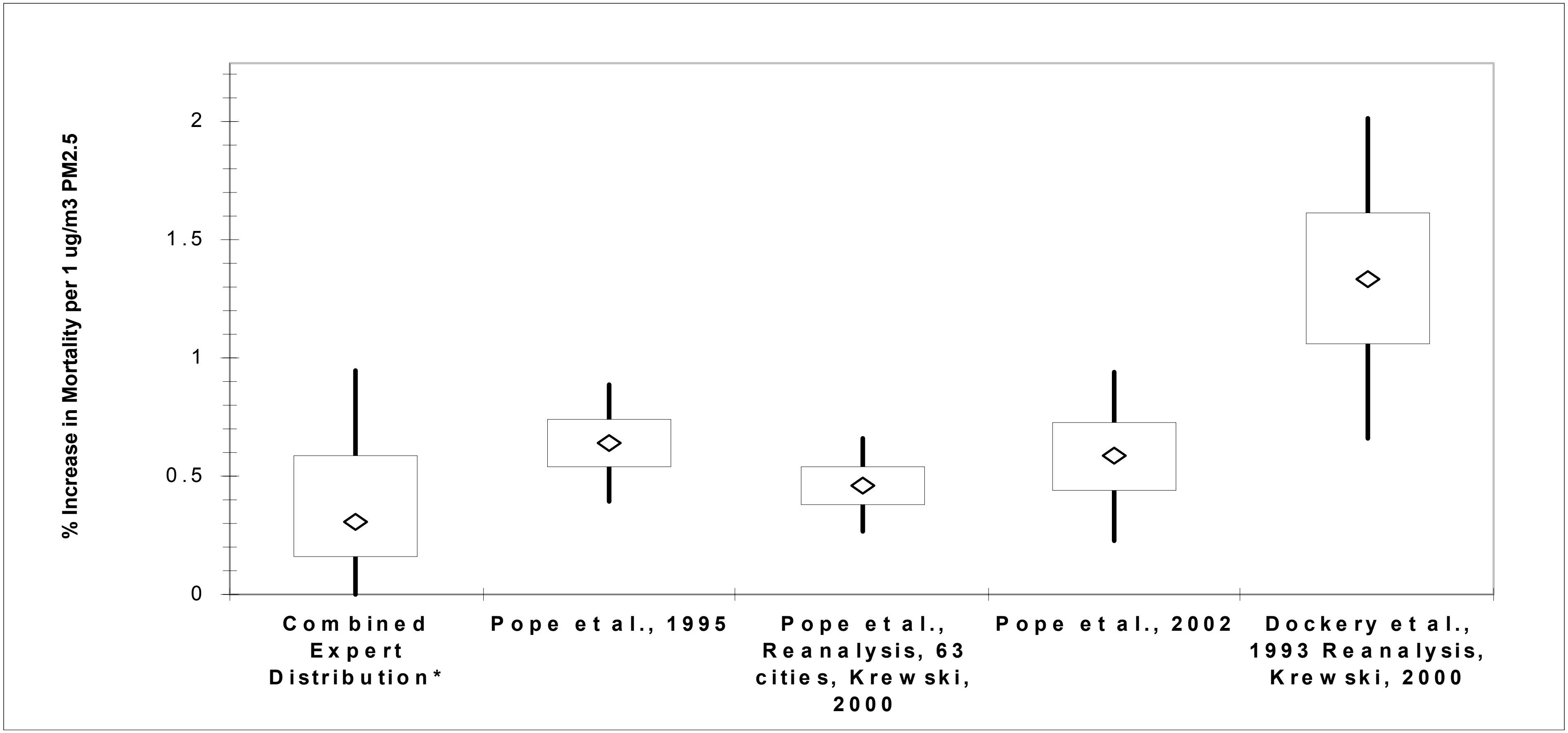
Given the differences in the responses given by Experts B and C at various levels of PM concentrations (i.e., a conditional C-R function), we considered a third combination method in which we calculate combined expert distributions at four different $PM_{2.5}$ baseline concentrations. Using the methods described above, we first calculated Expert B's and C's distributions at the four concentration points and then averaged them with the distributions of the other three experts (which remain constant over the concentration range) using equal weights. This method reduces the level of adjustments that are made to Expert B's and C's response function in that we estimate four C-R function for each individual, rather than one smoothed function. The functions for the three other experts remain log-linear. Results of this combination method are provided in Table 9B-4.

Table 9B-4. Combined Concentration-Response Function Conditional to PM Concentrations

Percentiles	8 ug/m3	12 ug/m3	15 ug/m3	20 ug/m3
95th percentile	0.82	0.99	1.08	1.20
75th percentile	0.56	0.61	0.64	0.76
50th percentile	**0.30**	**0.30**	**0.30**	**0.42**
25th percentile	0.16	0.16	0.16	0.24
5th percentile	0	0	0	0

Overall, the combination methods considered result in fairly similar results at the median and mean relative risk estimate. However, slight differences occur in the tails of the distribution in their characterization of uncertainty. In figure 9B-2, the C-R function for the population-weighted combination method was compared to the existing cohort epidemiological studies of the long-term $PM_{2.5}$/mortality relationship. We observe that the results of the pilot elicitation are generally within the range of findings from these epidemiological studies. However, as expected, the elicitation results in a larger spread of uncertainty than is given by the standard errors of the individual studies.

Figure 9B-2. Comparison of Combined Expert Judgment Distribution to Selected Published Studies



9B.3.5 Limitations of Combining Expert Judgments

Although we present several methods for combining the results of the pilot, there are several limitations in interpreting the pilot results that should be considered.

- The conditional functions of Experts B and C required us to estimate some values on the C-R function between the points that were elicited, which requires an extrapolation from the response provided in the pilot to create continuous distributions.

- There are many methods available to combine the responses from the experts. Each method has advantages and disadvantages from a statistical viewpoint. The project team is not aware of any rule-of-thumb in statistics that would provide guidance for combining linear and non-linear functions. Therefore, we present four alternative methods for combining the results as an illustration of potential combinations of the results, and have asked for a peer review of these methods.

- In designing the pilot, there was a decision to combine the results of the individual experts using an equal weighting. In some elicitation studies, the authors use a calibration measure to weight the experts appropriately. Because we did not conduct a calibration exercise, we present only an equal weighting of the responses.

- We have used a normal distribution to characterize the pilot results, but the distribution could potentially be skewed due to the bounding at zero. The C-R functions are bounded by zero, and anchored to one data source. There is a concern that the upper-end of the distribution resulting from the pilot may not fully reflect the available data and knowledge on the PM/mortality relationship. There may have been some anchoring to the study results from the ACS cohort, and less use of the Six-Cities study in the characterization of uncertainty upper-bounds. However, the experts were provided the Six Cities results in their briefing books as background material.

9B.4. Illustrative Application of Pilot Expert Elicitation Results

In this section, we apply the pilot expert elicitation results, using the pooled approach discussed above for combining results across participants to the VSL distribution discussed in Chapter 9 (section 9.3.4), thereby providing an illustrative example of how one might translate the results from the pilot elicitation into quantified estimates of economic benefits. The analysis is based on the modeled air quality changes conducted for the preliminary nonroad diesel control option in 2030. As such, the results are comparable to the point estimates provided in Appendix

9A, but not to those in Chapter 9. The values generated below do not reflect the Agency's estimates of the benefits of the emissions reductions expected from the Final Non-Road Diesel rule and are included solely as an illustration of the impacts of using expert elicitation based distributions for premature mortality associated with long-term exposure to $PM_{2.5}$ rather than a data-derived distribution.

9B.5.1 Method

9B.5.1.1 Concentration-Response Distribution Based on Combined Results Across Experts

As discussed in Section 9B.4.5, we converted each expert's percentile responses about mortality associated with long-term exposure into a custom distribution such that each percentile is correctly represented and percentiles in between are represented as continuous functions (custom distributions were generated using Crystal Ball and are represented as 15,000 equally probable points).

For experts A, D, and E, we used a standard log-linear functional form:

$$\Delta y = y_0 \cdot (e^{\beta \cdot \Delta x} - 1)\,, \qquad \textbf{(4)}$$

where we set β equal to ln(1+B/100), where B is the percent change in all cause mortality associated with a one µg reduction in $PM_{2.5}$. BenMAP then represents the distribution of Δy based on the custom distribution of β.

Expert C provided a set of conditional C-R functions for different baseline levels of $PM_{2.5}$. Expert C provided four conditional responses, one for 8 µg/m3, one for 10 µg/m3, one for 15 µg/m3, and one for 20 µg/m3. In order to "fill-in" the C-R function for intermediate baseline $PM_{2.5}$ values, we linearly interpolated between the responses for each pair of points, e.g. 10 to 15 or 15 to 20. We calculated interpolated values for 13 points, ranging from 8 µg to 20 µg. For baseline values less than 8 µg, we assigned a value of zero (essentially assuming a threshold at 8 µg). For baseline values greater than 20, we assigned the values provided by Expert C for 20 µg. This may result in an underestimate of the incidence of mortality for Expert C. For each of the conditional functions, we used a log-linear specification, similar to A, D, and E. Total incidence of mortality for Expert C is the sum of the conditional estimates over the range of baseline air concentrations.

Expert B provided a log-linear C-R function, conditional on an unknown threshold characterized by a triangular distribution bounded by 4 µg and 15 µg, with a mode at 12 µg. We discretized the triangular distribution into 12 ranges of unit length (e.g. 4 to 5, 5 to 6, etc.) and calculated the expected value of the response at each population gridcell based on the observed baseline $PM_{2.5}$ and the probability of that baseline value exceeding the potential threshold. We assume that if a grid cell has a baseline value above the threshold, then the full value of the reduction in $PM_{2.5}$ at that grid cell is associated with a reduction in mortality. This may result in an overestimate of the mortality impact for Expert B because for grid cells where the baseline level is only marginally above the threshold, a benefit might only accrue to the change in $PM_{2.5}$ down to the threshold. The rest of the change would not result in any mortality reduction. Because most of the changes in air quality are relatively small (population weighted change in annual mean $PM_{2.5}$ is -0.59 µg), this should not be a large issue.

To put these estimates in perspective, it is useful to summarize the projected baseline (pre-nonroad diesel regulations) air quality in 2030. Table 9B-5 lists the population distribution of baseline concentrations of $PM_{2.5}$ in 2030:

Table 9B-5. Population Distribution of Baseline Ambient $PM_{2.5}$

Baseline $PM_{2.5}$ ($\mu g/m^3$)	**2030 Population (millions)**	**Percent of Total 2030 Population**
$PM_{2.5}$<5	3.5	1.0%
5≤$PM_{2.5}$<10	68.8	19.5%
10≤$PM_{2.5}$<15	198.1	56.2%
15≤$PM_{2.5}$<20	66.1	18.8%
20≤$PM_{2.5}$<25	12.1	3.4%
25≤$PM_{2.5}$<30	4	1.1%

9B.5.1.2 Estimated Reduction in Premature Morality and Valuation

Based on the air quality modeling conducted for the Nonroad Diesel preliminary control option, we calculated the reduction in incidence of premature mortality associated with $PM_{2.5}$ and the value of that reduction. We used Monte Carlo simulations to derive the distributions of the dollar values of estimated reductions in premature mortality. For each expert, the Monte Carlo simulation generates a dollar value by randomly sampling from the distribution of the reduction in mortality incidence and the distribution of VSL (normally distributed with a mean of \$5.5 and a 95 percent confidence interval between \$1 and \$10 million) and multiplying the values together. This yields an estimate of the dollar value of the mortality reductions. This process is repeated 5,000 times to generate a distribution of dollar values. The Monte Carlo process was conducted using the estimated distribution for each expert individually and for the combined (pooled) distribution, as well as for the distribution derived from the Pope et al. (2002) study.

9B.5.2 Results

Figure 9B-4 presents box plots that display the distribution of the reduction in $PM_{2.5}$ related premature mortality based on the concentration response distributions provided by each expert, as well as that based on the pooled response.[a] For comparison, the figure also displays the distribution derived from the statistical error associated with Pope et al (2002). The figure shows that the average annual number of premature deaths avoided for the "modeled preliminarily control option" ranges from approximately 4000 to 19,000, depending on the concentration response function used. The medians span zero to 16,000, with the zero value due to the low threshold associated with one of the expert's distributions. Specifically, because less than a quarter of the population is expected to live in areas with PM2.5 levels above the threshold specified by expert C, and much of the decrease in PM2.5 predicted by the preliminary control option occurs below that threshold, a much smaller decrease in premature morality is predicted for expert C than those experts who provided continuos C-R functions down to zero (PM2.5) as well as for expert B who provided an uncertain threshold. Furthermore, note that at the 50th and 75th percentiles, the C-R functions provided by all of the experts predict positive benefits from the modeled control option.

The boxplots displayed in Figure 9B-4 are derived by applying the C-R distributions specified by each expert (as presented in Figure 9B-1) to the change in air quality predicted by the preliminary non-road diesel control option. Although the figures 9B-3 and 9B-1 show similar patterns, there are important differences. Specifically, the ratio of 75th percentiles of the C-R functions specified by experts A and B (as denoted in Figure 9B-1) is 0.4, whereas the ratio of the predicted change in incidence of premature mortality associated with the modeled preliminary control option is 0.5. This 25% increase in the ratio suggests a larger effective difference in the distributions between the experts than was evident before applying the expert's C-R functions to a predicted change in air quality and highlights the impact of the air quality change predicted on the choice of C-R function used in the benefits analysis.

The combined expert distribution depicted in Figure 9B-4 provides additional insights. The combined (average) distribution has a 90 percent credible interval between zero and 24,000. When compared with results derived from the Pope et al. (2002) study, it is clear that the combined expert distribution reflects greater uncertainty about the estimated reduction in

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[A] As discussed above, the elicitation results were combined assuming equal weight for each expert's distribution. We assumed complete dependence of the expert's distributions for this illustrative analysis, so that each percentile of the pooled distribution is simply the average of the corresponding percentiles of the 5 experts.

premature mortality, as well as placing more weight on the lower end of the distribution. The mean estimate from the combined expert distribution is almost 30 percent lower than the mean derived from the Pope et al. (2002) distribution. However, the 90 percent confidence interval based on the standard error from Pope et al. (2002) is completely contained within the 90 percent credible interval of the combined expert distribution.

Figure 9B-5 shows the same data using cumulative distribution functions (CDFs). This figure is valuable for demonstrating differences in degree of certainty in achieving specific reductions in premature mortality. For instance, the Pope et al. 2002 concentration response distribution predicts a 20% chance that there will be at least 10,000 fewer premature deaths, whereas the pooled distribution predicts a 60% chance of the same reduction in premature deaths. The probabilities associated with the individual experts for avoiding 10,000 premature deaths range from about 28% to 98%, demonstrating once again the sensitivity of the estimate to assumptions regarding the concentration response function. The CDFs of the estimated reductions in premature mortality shows that for several experts, there is a small probability of a substantially higher estimate. For example, the 75th percentile of the distribution based on Expert B's responses is at 8,800, while the 99th percentile for that distribution is almost 4 times higher, at 34,000. The CDF also shows that while most of the experts provided fairly wide distributions, reflecting a lack of confidence in the precision of the empirical data, the CDF based on Expert C's responses is much narrower, reflecting the high degree of confidence he placed on the existence of a threshold below 15 μg.

Figures 9B-6 and 9B-7 use box plots and CDFs to display the estimated dollar value of these annual reductions in premature mortality. Whereas the average based on the Pope et al 2002 distribution is $94 billion, the average based on the pooled estimate is $67 billion, a difference of approximately one-third. Once the concentration response distributions are combined with the VSL distributions, not only are the mean values closer to one another, but the distributions show considerably more overlap.

Because these distributions are the result of a Monte Carlo simulation combining the non-normal distributions for reductions in mortality with a normal distribution for VSL, the resulting distributions will also be non-normal, but the shape depends on the skewness of the input distribution of mortality reductions. For example, the ratio of the 95th to 75th percentile of mortality reductions for Expert B is 3.1, while the same ratio for the value of mortality reductions is 4.2, indicating the value distribution is more skewed than the reductions distribution. In general, combining normal or left skewed distributions in a mulitplicative fashion will result in left skewed distributions with greater skewness than the input distributions. So even for the normally distributed estimates based on Pope et al. (2002), the value distribution is somewhat skewed, because it is the result of multiplying two normally distributed random variables.

The shapes of the two distributions are more similar in this case because both reflect the same additional information in the VSL distribution. This demonstrates that as additional sources of uncertainty are added to the analysis, the influence of any one source of uncertainty will fall. Because VSL is a large source of uncertainty, the influence on overall uncertainty relative to the distribution of the mortality reduction is also large. All of the distributions of the value of mortality reductions have a small negative tail, this time due to propagation of the normally distributed VSL, which has a small amount of the distribution below zero. Again, we interpret this as a statistical artifact rather than a true probability that the value of a statistical life is negative (implying that individuals would pay to increase the risk of death).

We used additional Monte Carlo simulations to combine the expert-based distributions for the dollar benefits of mortality with the distributions of dollar benefits for the remaining health and welfare endpoints to derive estimates of the overall distribution of total dollar benefits[b]. The box plots for these distributions of overall dollar benefits associated with the modeled nonroad diesel preliminary control options are presented in Figure B-8. Because mortality accounts for over 90 percent of the benefits, the addition of other endpoints has little impact on the overall distributions. The overall mean annual total dollar benefits in 2030 for the distribution incorporating the combined expert distribution for reductions in premature mortality is $70 billion, compared to $96 billion for the results derived from the Pope et al. (2002) study for the nonroad diesel modeled preliminary control option.

For clarity of presentation, in Figure 9B-9, we present CDFs for total dollar benefits only for the combined expert distribution and results derived from the Pope et al. (2002) study. These again suggest that the use of the expert elicitation based representation of uncertainty in the relationship between $PM_{2.5}$ and premature mortality has a large impact on the shape and range of the distribution of total benefits. The Pope et al. (2002) derived results have an approximately Weibull shaped distribution with a range from 5th to 95th percentiles of $23 billion to $190 billion, or about one order of magnitude. The distribution of total dollar benefits incorporating the combined expert distribution for reductions in premature mortality has a much more skewed shape with an elongated positive tail above the 75th percentile with a range from 5th to 95th percentiles of $3 billion to $240 billion, or about two orders of magnitude.

[B]Note that visibility benefits are treated as fixed for this illustrative analysis. We are working on methods to characterize the uncertainty in visibility and other non-health benefits.

Figure 9B-4 Results of Illustrative Application of Pilot Expert Elicitation: Annual Reductions in Premature Mortality in 2030 Associated with the Modeled Preliminary Control Option for the Nonroad Diesel Rule

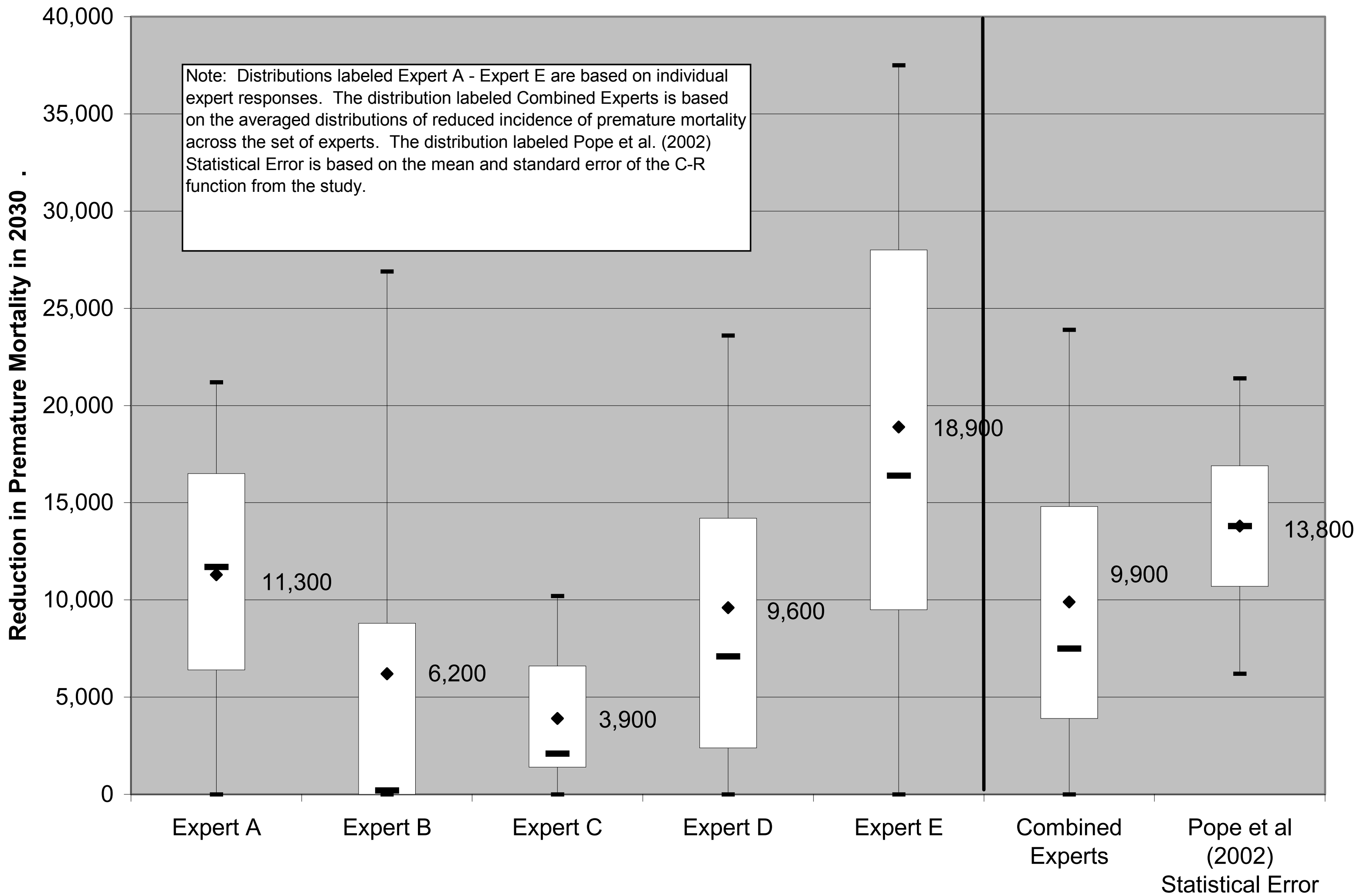


Figure 9B-5. Cumulative Distribution Functions for Annual Reductions in Premature Mortality in 2030 Associated with the Nonroad Diesel Modeled Preliminary Control Option

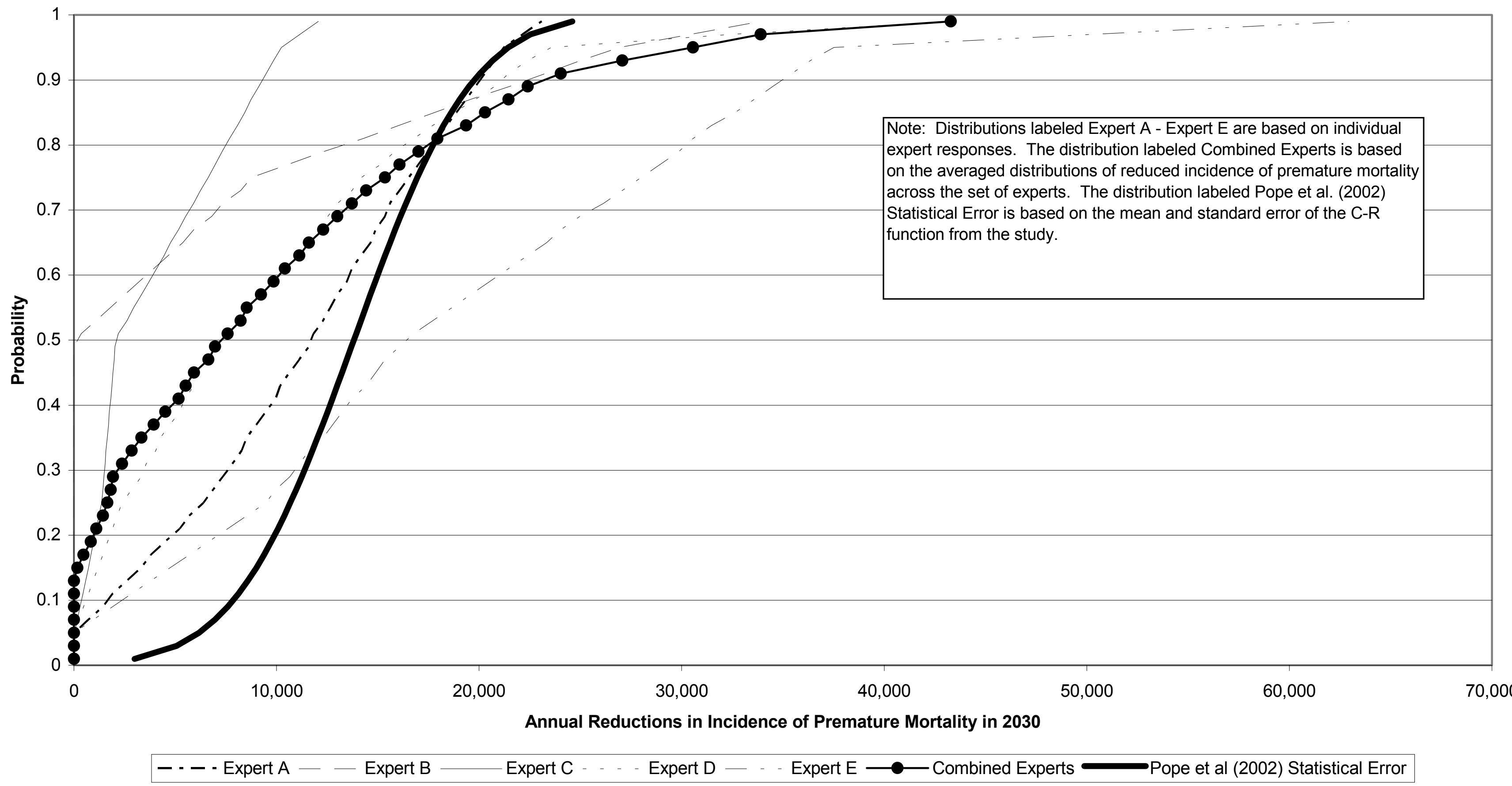


Figure 9B-6. Results of Illustrative Application of Pilot Expert Elicitation: Dollar Value of Annual Reductions in Premature Mortality in 2030 Associated with the Modeled Preliminary Control Option for the Nonroad Diesel Rule

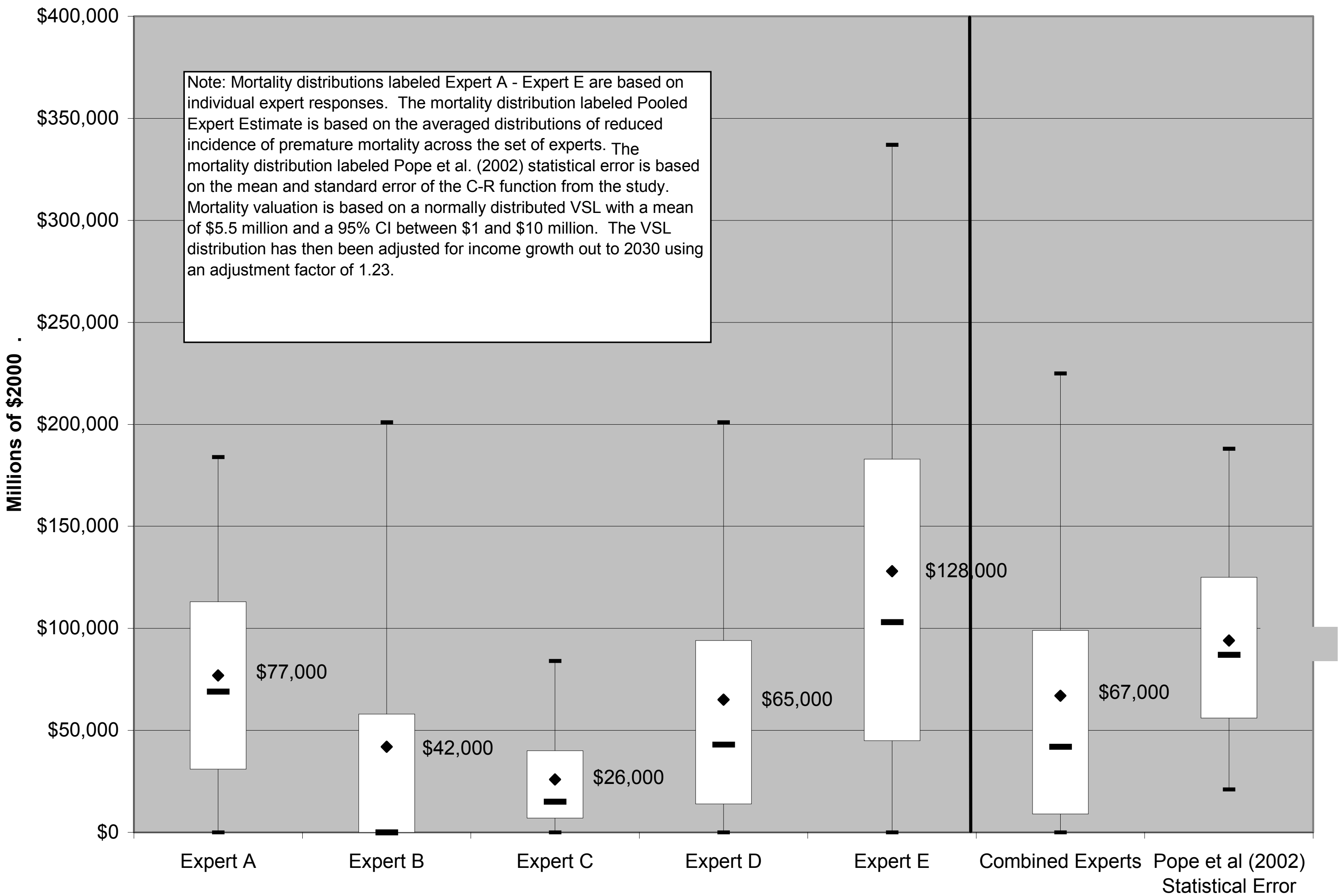


Figure 9B-7. Cumulative Distribution Functions for Dollar Value of Annual Reductions in Premature Mortality in 2030 Associated with the Nonroad Diesel Modeled Preliminary Control Option

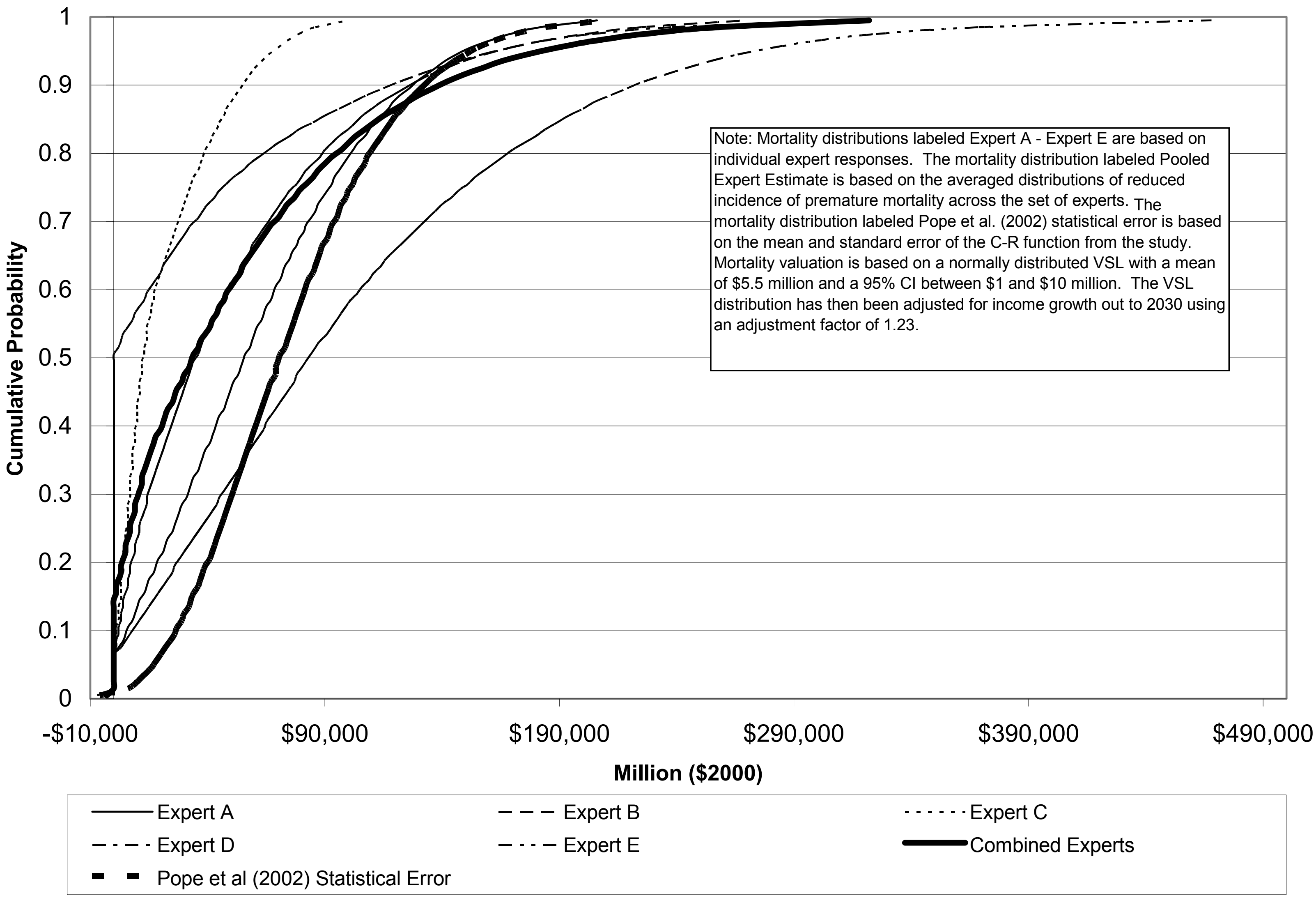


Figure 9B-8. Results of Illustrative Application of Pilot Expert Elicitation: Dollar Value of Total Annual PM-related Health and Visibility Benefits in 2030 Associated with the Modeled Preliminary Control Option for the Tier 4 Rule

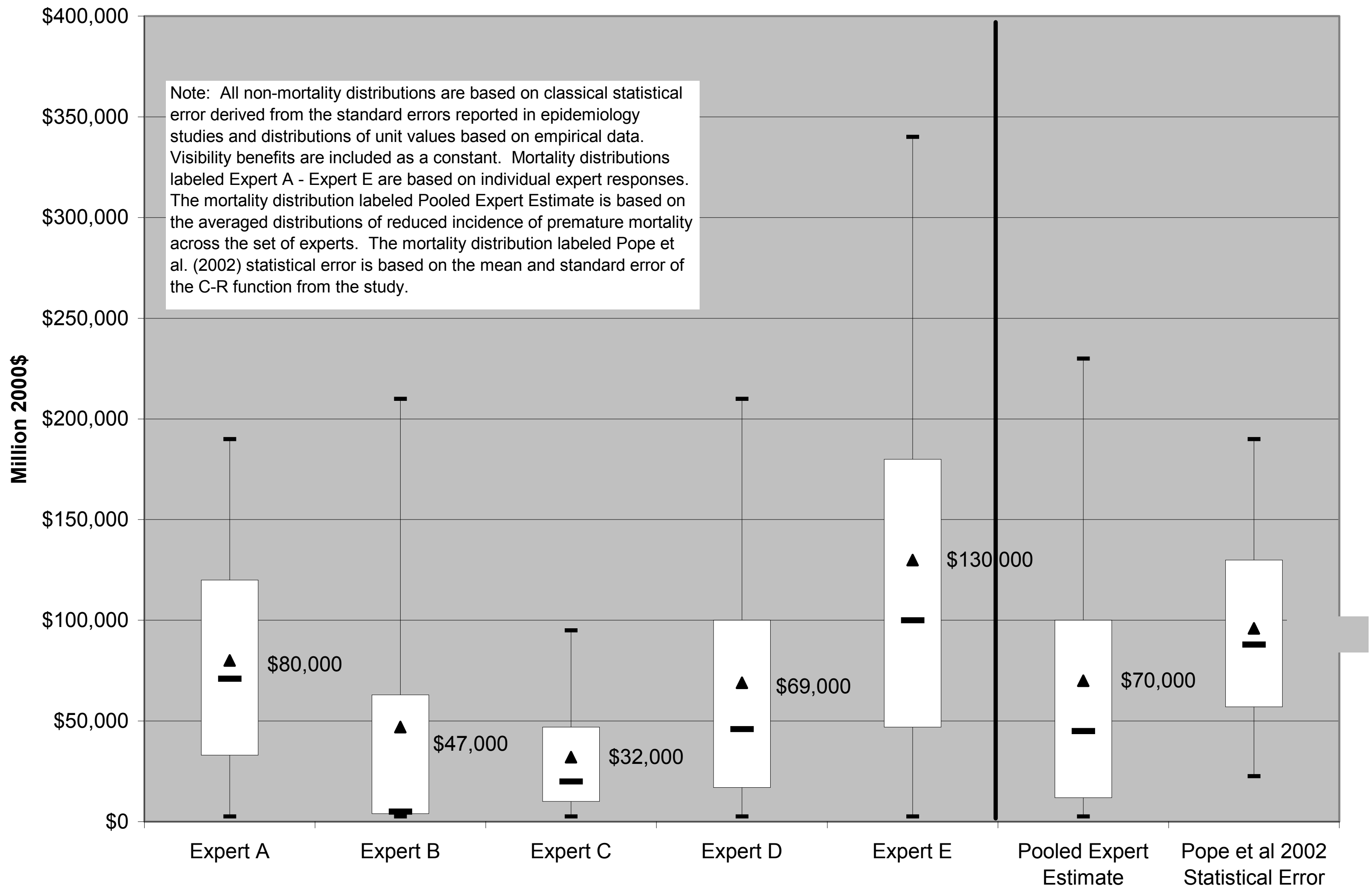
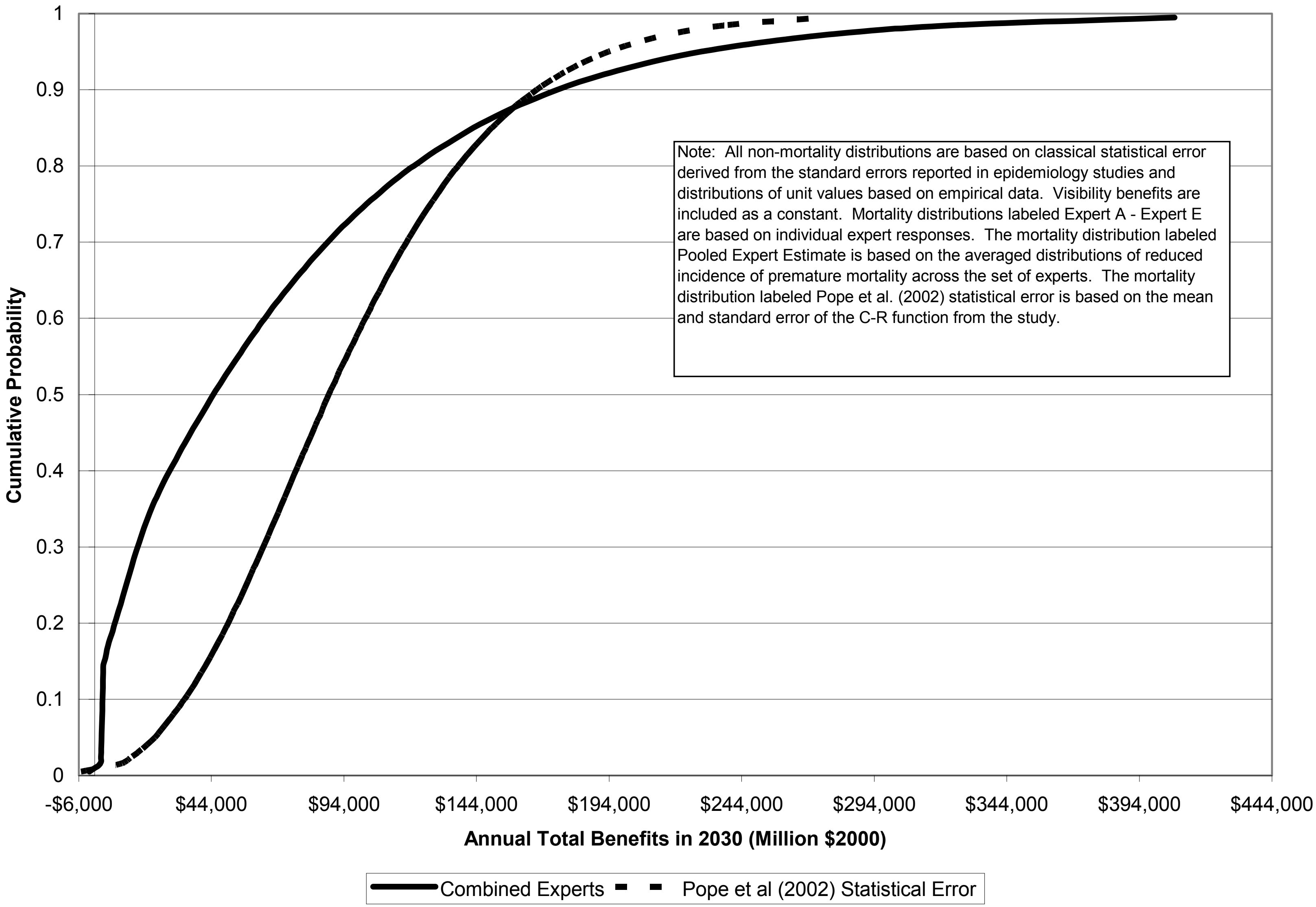


Figure 9B-9. Cumulative Distribution Functions of Dollar Value of Total Annual PM-related Health and Visibility Benefits in 2030 Associated with the Nonroad Diesel Modeled Preliminary Control Option



9B.5.3 Limitations of the Application of the Pilot Elicitation Results to the Nonroad Scenario

The results presented in this section should be viewed cautiously given the limited scope of the pilot, and the limitations of the elicitation design and methods used to combine the expert judgments discussed above. Therefore, the results presented above should be considered “illustrative” until both the peer review of the pilot is complete and the methods used to interpret and apply the results of the pilot have been peer-reviewed and accepted. Until this occurs, we do not recommend applying this method in other regulatory analyses.

Specific limitations of the illustrative application include:

- Extrapolation of percentile responses provided by individual experts. Each expert provided minimum and maximum values, as well as the 5^{th}, 25^{th}, 50^{th}, 75^{th}, and 95^{th} percentiles. In order to generate the continuous distributions of mortality impacts, we had to make assumptions about the continuity of the distributions between the reported percentiles. This adds uncertainty to the results.

- Interpolation of C-R relationship across $PM_{2.5}$ levels. Expert C provided a set of conditional distributions of the C-R relationship conditioned on the baseline level of $PM_{2.5}$. Because he only provided functions for a limited number of baseline levels, we had to interpolate the values between levels, introducing additional uncertainty. In addition, Expert C provided no information on the C-R function for baseline $PM_{2.5}$ levels below 8 µg/m3 or above 20 µg/m3. We assumed no mortality impacts for baseline levels lower than 8 and no increase in the C-R function above 20. This likely biased our results downward.

- Interpretation of Expert B results. Expert B provided a conditional distribution for the C-R function, conditioned on an uncertain threshold. Expert B provided additional information about the shape of the distribution for the threshold. To develop an applied function, we assumed that the uncertain threshold could be incorporated into the C-R function through the construction of an expected value function. The specific functions may lead to a slight overestimate of mortality impacts.

- Use of simple averaging of expert results. To develop the combined expert distribution, we used equal weights for each expert. Given the lack of calibration questions in the pilot elicitation, this is the most defensible approach. However, many expert elicitation applications have use more complex weighting schemes based on how well experts are calibrated.

- Ranges based on individual experts should be viewed with caution as they represent only a single individual's interpretation of the state of knowledge about PM and mortality. Results for individual experts should not be extracted and presented without reference to the full range of results across the five experts.

- Any range of results presented based on this application should be presented along with their relative likelihood (i.e., the percentile represented in the distribution).

References for Appendix 9B

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APPENDIX 9C: Sensitivity Analyses of Key Parameters in the Benefits Analysis

The primary analysis is based on our current interpretation of the scientific and economic literature. That interpretation requires judgments regarding the best available data, models, and modeling methodologies; and assumptions we consider most appropriate to adopt in the face of important uncertainties. The majority of the analytical assumptions used to develop the Base Estimate have been reviewed and approved by EPA's Science Advisory Board (SAB). However, we recognize that data and modeling limitations as well as simplifying assumptions can introduce significant uncertainty into the benefit results and that alternative choices exist for some inputs to the analysis, such as the mortality C-R functions.

We supplement our primary estimates of benefits with a series of sensitivity calculations that make use of other sources of health effect estimates and valuation data for key benefits categories. These estimates examine sensitivity to both valuation issues (e.g. the appropriate income elasticity) and for physical effects issues (e.g., possible recovery from chronic illnesses). These estimates are not meant to be comprehensive. Rather, they reflect some of the key issues identified by EPA or commentors as likely to have a significant impact on total benefits. Individual adjustments in the tables should not be added together without addressing potential issues of overlap and low joint probability among the endpoints.

9C.1 Premature Mortality—Long term exposure

Given current evidence regarding their value, reduction in the risk of premature mortality is the most important PM-related health outcome in terms of contribution to dollar benefits. There are at least three important analytical assumptions that may significantly impact the estimates of the number and valuation of avoided premature mortalities. These include selection of the C-R function, structure of the lag between reduced exposure and reduced mortality risk, and effect thresholds. Results of this set of sensitivity analyses are presented in Table 9C.1.

9C.1.1 Alternative C-R Functions

Following the advice of the EPA Science Advisory Board Health Effects Subcommittee (SAB-HES), we used the Pope, et al. (2002) all-cause mortality model exclusively to derive our primary estimate of avoided premature mortality. While the SAB-HES "recommends that the base case rely on the Pope et al. (2002) study and that EPA use total mortality concentration-response functions (C-R), rather than separate cause-specific C-R functions, to calculate total PM mortality cases," they also suggested that "the cause-specific estimates can be used to communicate the relative contribution of the main air pollution related causes of death." As such, we provide the estimates of cardiopulmonary and lung cancer deaths based on the Pope et al. (2002).

In addition, the SAB-HES has noted that the American Cancer Society cohort used in Pope et al. (2002) "has some inherent deficiencies, in particular the imprecise exposure data, and the non-representative (albeit very large) population. Thus, ACS is not necessarily "the better study," but, at this point in time, is a prudent choice for the base case estimates in the Second Prospective Analysis. The Harvard Six-Cities C-R functions are valid estimates on a more representative, although geographically selected, population, and its updated analysis has not yet been published. The Six Cities estimates may be used in a sensitivity analysis to demonstrate that with different but also plausible selection criteria for C-R functions, benefits may be considerably larger than suggested by the ACS study." (EPA-SAB-COUNCIL-ADV-04-002). In previous advice, the SAB has noted that "the [Harvard Six Cities] study had better monitoring with less measurement error than did most other studies" (EPA-SAB-COUNCIL-ADV-99-012, 1999). The demographics of the ACS study population, i.e., largely white and middle-class, may also produce a downward bias in the estimated PM mortality coefficient, because short-term studies indicate that the effects of PM tend to be significantly greater among groups of lower socioeconomic status. The Harvard Six Cities study also covered a broader age category (25 and older compared to 30 and older in the ACS study) and followed the cohort for a longer period (15 years compared to 8 years in the ACS study). We emphasize, that based on our understanding of the relative merits of the two datasets, the Pope, et al. (2002) ACS model based on mean $PM_{2.5}$ levels in 63 cities is the most appropriate model for analyzing the premature mortality impacts of the nonroad standards. It is thus used for our base estimate of this important health effect.

9C.1.2 Alternative Lag Structures

As noted by the SAB (EPA-SAB-COUNCIL-ADV-00-001, 1999), "some of the mortality effects of cumulative exposures will occur over short periods of time in individuals with compromised health status, but other effects are likely to occur among individuals who, at baseline, have reasonably good health that will deteriorate because of continued exposure. No animal models have yet been developed to quantify these cumulative effects, nor are there epidemiologic studies bearing on this question." However, they also note that "Although there is substantial evidence that a portion of the mortality effect of PM is manifest within a short period of time, i.e., less than one year, it can be argued that, if no lag assumption is made, the entire mortality excess observed in the cohort studies will be analyzed as immediate effects, and this will result in an overestimate of the health benefits of improved air quality. Thus some time lag is appropriate for distributing the cumulative mortality effect of PM in the population." In the primary analysis, based on previous SAB advice, we assume that mortality occurs over a five year period, with 25 percent of the deaths occurring in the first year, 25 percent in the second year, and 16.7 percent in each of the third, fourth, and fifth years. Readers should note that the selection of a 5 year lag is not supported by any scientific literature on PM-related mortality (NRC 2002). Rather it is intended to be a reasonable guess at the appropriate distribution of avoided incidences of PM-related mortality. The SAB-HES has recently noted that "empirical evidence is lacking to inform the choice of the lag distribution directly and agrees with the NAS report that there is little empirical justification for the 5-year cessation lag structure used in the previous analyses." The SAB-HES suggests that appropriate lag structures may be developed based on the distribution of cause specific deaths within the overall all-cause estimate. Diseases with longer progressions should be characterized by longer term lag structures, while air pollution impacts occurring in populations with existing disease may be characterized by shorter term lags.

A key question is the distribution of causes of death within the relatively broad categories analyzed in the long-term cohort studies. While we may be more certain about the appropriate length of cessation lag for lung cancer deaths, it is not at all clear what the appropriate lag structure should be for cardiopulmonary deaths, which include both respiratory and cardiovascular causes. Some respiratory diseases may have a long period of progression, while others, such as pneumonia, have a very short duration. In the case of cardiovascular disease, there is an important question of whether air pollution is causing the disease, which would imply a relatively long cessation lag, or whether air pollution is causing premature death in individuals with preexisting heart disease, which would imply very short cessation lags. The SAB-HES provides several recommendations for future research that could support the development of defensible lag structures, including the use of disease specific lag models, and the construction of a segmented lag distribution to combine differential lags across causes of death. The SAB-HES indicated support for using "a Weibull distribution or a simpler distributional form made up of several segments to cover the response mechanisms outlined above, given our lack of knowledge on the specific form of the distributions." However, they noted that "an important question to be resolved is what the relative magnitudes of these segments should be, and how many of the acute effects are assumed to be included in the cohort effect estimate." They conclude their discussion of cessation lags by stating that "given the current lack of direct data upon which to specify the lag function, the HES recommends that this question be considered for inclusion in future expert elicitation efforts and/or sensitivity analyses." (EPA-SAB-COUNCIL-ADV-04-002) EPA will continue to investigate this important issue for future benefits analyses and in the upcoming 2nd Prospective Analysis of the Costs and Benefits of the Clean Air Act. For this RIA, we investigate alternative cessation lag structures as senstivity analyses, noting that these might be as likely as the previous 5-year distributed lag in the base analysis.

Although the prior SAB recommended the five-year distributed lag be used for the primary analysis, the SAB has also recommended that alternative lag structures be explored as a sensitivity analysis (EPA-SAB-COUNCIL-ADV-00-001, 1999). Specifically, they recommended an analysis of 0, 8, and 15 year lags. The 0 year lag is representative of EPA's assumption in previous RIAs. The 8 and 15 year lags are based on the study periods from the Pope, et al. (1995) and Dockery, et al. (1993) studies, respectively[c]. However, neither the Pope, et al. or Dockery, et al. studies assumed any lag structure when estimating the relative risks from PM exposure. In fact, the Pope, et al. and Dockery, et al. studies do not contain any data either supporting or refuting the existence of a lag. Therefore, any lag structure applied to the avoided incidences estimated from either of these studies will be an assumed structure. The 8 and 15 year lags implicitly assume that all premature mortalities occur at the end of the study periods, i.e. at 8 and 15 years.

In addition to the simple 8 and 15 year lags, we have added an additional senstivity analysis examining the impact of assuming a segmented lag of the type suggested by the SAB-

[C]Although these studies were conducted for 8 and 15 years, respectively, the choice of the duration of the study by the authors was not likely due to observations of a lag in effects, but is more likely due to the expense of conducting long-term exposure studies or the amount of satisfactory data that could be collected during this time period.

HES. This illustrative lag structure is characterized by 20 percent of mortality reductions occuring in the first year, 50 percent occuring evenly over years 2 to 5 after the reduction in $PM_{2.5}$, and 30 percent occurring evenly over the years 6 to 20 after the reduction in $PM_{2.5}$. The distribution of deaths over the latency period is intended to reflect the contribution of short term exposures in the first year, cardiopulmonary deaths in the 2 to 5 year period, and longer term lung disease and lung cancer in the 6 to 20 year period. For future analyses, the specific distribution of deaths over time will need to be determined through research on causes of death and progression of diseases associated with air pollution. It is important to keep in mind that changes in the lag assumptions do not change the total number of estimated deaths, but rather the timing of those deaths.

The estimated impacts of alternative lag structures on the monetary benefits associated with reductions in PM-related premature mortality (estimated with the Pope et al. ACS impact function) are presented in Table 9C.2. These estimates are based on the value of statistical lives saved approach, i.e. $5.5 million per incidence, and are presented for both a 3 and 7 percent discount rate over the lag period.

9C.1.3 Thresholds

Although the consistent advice from EPA's Science Advisory Board has been to model premature mortality associated with PM exposure as a non-threshold effect, that is, with harmful effects to exposed populations regardless of the absolute level of ambient PM concentrations, some analysts have hypothesized the presence of a threshold relationship[d]. The nature of the hypothesized relationship is that there might exist a PM concentration level below which further reductions no longer yield premature mortality reduction benefits.[e] EPA does not necessarily endorse any particular threshold and, as discussed in Appendix 9A, virtually every study to consider the issue indicates absence of a threshold.

We construct a senstivity analysis by assigning different cutpoints below which changes in $PM_{2.5}$ are assumed to have no impact on premature mortality. The sensitivity analysis illustrates how our estimates of the number of premature mortalities in the Base Estimate might change under a range of alternative assumptions for a PM mortality threshold. If, for example, there were no benefits of reducing PM concentrations below the $PM_{2.5}$ standard of 15 μg/m3, our estimate of the total number of avoided PM-related premature mortalities in 2030 from the preliminary modeling would be reduced by approximately 70 percent, from approximately

[D]The most recent advice from the SAB-HES is characterized by the following: “For the studies of long-term exposure, the HES notes that Krewski et al. (2000) have conducted the most careful work on this issue. They report that the associations between PM2.5 and both all-cause and cardiopulmonary mortality were near linear within the relevant ranges, with no apparent threshold. Graphical analyses of these studies (Dockery et al., 1993, Figure 3 and Krewski et al., 2000, page 162) also suggest a continuum of effects down to lower levels. Therefore, it is reasonable for EPA to assume a no threshold model down to, at least, the low end of the concentrations reported in the studies.”

[E]The illustrative example in Appendix 9B presents the potential implications of assuming some probability of a threshold on the benefits estimate.

14,000 annually to approximately 4,000 annually. However, this type of cutoff is unlikely, as supported by the recent NRC report, which stated that "for pollutants such as PM_{10} and $PM_{2.5}$, there is no evidence for any departure of linearity in the observed range of exposure, nor any indiciation of a threshold. (NRC, 2002)" Another possible senstivity analysis which we have not conducted at this time might examine the potential for a nonlinear relationship at lower exposure levels.[f]

One important assumption that we adopted for the threshold sensitivity analysis is that no adjustments are made to the shape of the C-R function above the assumed threshold. Instead, thresholds were applied by simply assuming that any changes in ambient concentrations below the assumed threshold have no impacts on the incidence of premature mortality. If there were actually a threshold, then the shape of the C-R function would likely change and there would be no health benefits to reductions in PM below the threshold. However, as noted by the NRC, "the assumption of a zero slope over a portion of the curve will force the slope in the remaining segment of the positively sloped concentration-response function to be greater than was indicated in the original study" and that "the generation of the steeper slope in the remaining portion of the concentration-response function may fully offset the effect of assuming a threshold." The NRC suggested that the treatment of thresholds should be evaluated in a formal uncertainty analysis.

The results of these sensitivity analyses demonstrate that choice of effect estimate can have a large impact on benefits, potentially doubling benefits if the effect estimate is derived from the HEI reanalysis of the Harvard Six-cities data (Krewski et al., 2000). Due to discounting of delayed benefits, the lag structure may also have a large impact on monetized benefits, reducing benefits by 30 percent if an extreme assumption that no effects occur until after 15 years is applied. The overall impact of moving from the 5-year distributed lag to a segmented lag is relatively modest, reducing benefits by approximately 8 percent when a three percent discount rate is used and 22 percent when a seven percent discount rate is used. If no lag is assumed, benefits are increased by around five percent. The threshold analysis indicates that approximately 85 percent of the premature mortality related benefits are due to changes in $PM_{2.5}$ concentrations occurring above 10 $\mu g/m^3$, and around 30 percent are due to changes above 15 $\mu g/m^3$, the current $PM_{2.5}$ standard.

[F]The pilot expert elicitation discussed in Appendix 9B provides some information on the impact of applying nonlinear and threshold based C-R functions.

Table 9C-1.
Sensitivity of Benefits of Premature Mortality Reductions to Alternative Assumptions (Relative to Base Case Benefits of Modeled Preliminary Control Option)

Description of Sensitivity Analysis		**Avoided Incidences[A]**		**Value (million 2000$)[B]**	
		2020	**2030**	**2020**	**2030**
Alternative Concentration-Response Functions for PM-related Premature Mortality					
Pope/ACS Study (2002)[C]					
Lung Cancer		*1,200*	*2,100*	*$7,700*	*$13,000*
Cardiopulmonary		*6,000*	*11,000*	*$37,000*	*$67,000*
Krewski/Harvard Six-city Study		17,000	30,000	$110,000	$190,000
Alternative Lag Structures for PM-related Premature Mortality					
None	Incidences all occur in the first year	7,800	14,000	$52,000	$94,000
8-year	Incidences all occur in the 8th year				
	3% Discount Rate	7,800	14,000	$42,000	$76,000
	7% Discount Rate	7,800	14,000	$32,000	$62,000
15-year	Incidences all occur in the 15th year				
	3% Discount Rate	7,800	14,000	$34,000	$62,000
	7% Discount Rate	7,800	14,000	$20,000	$36,000
Segmented	20 percent of incidences occur in 1st year, 50 percent in years 2 to 5, and 30 percent in years 6 to 20				
	3% Discount Rate	7,800	14,000	$45,000	$82,000
	7% Discount Rate	7,	14	$3	$6

Alternative Thresholds				
No Threshold (base estimate)	7,800	14,000	$49,000	$89,000
5	7,800	14,000	$49,000	$89,000
10	6,300	12,000	$40,000	$77,000
15	1,700	4,000	$11,000	$26,000
20	630	1,300	$4,000	$8,400
25	190	520	$1,200	$3,400

[A] Incidences rounded to two significant digits.
[B] Dollar values rounded to two significant digits.
[C] Note that the sum of lung cancer and cardiopulmonary deaths will not be equal to the total all cause death estimate. There is some residual mortality associated with long term exposures to $PM_{2.5}$ that is not captured by the caridopulmonary and lung cancer categories.

9C.2 Other Health Endpoint Sensitivity Analyses

9C.2.1 Overlapping Endpoints

In Appendix 9A, we estimated the benefits of the modeled preliminary control options using the most comprehensive set of endpoints available. For some health endpoints, this meant using a health impact function that linked a larger set of effects to a change in pollution, rather than using health impact functions for individual effects. For example, for premature mortality, we selected an impact function that captured reductions in incidences due to long-term exposures to ambient concentrations of particulate matter, assuming that most incidences of mortality associated with short-term exposures would be captured. In addition, the long-term exposure premature mortality impact function for $PM_{2.5}$ is expected to capture at least some of the mortality effects associated with exposure to ozone.

In order to provide the reader with a fuller understanding of the health effects associated with reductions in air pollution associated with the preliminary control options, this set of sensitivity estimates examines those health effects which, if included in the primary estimate, could result in double-counting of benefits. For some endpoints, such as ozone mortality, additional research is needed to provide separate estimates of the effects for different pollutants, i.e. PM and ozone. These supplemental estimates should not be considered as additive to the total estimate of benefits, but illustrative of these issues and uncertainties. Sensitivity estimates included in this appendix include premature mortality associated with short-term exposures to ozone, and acute respiratory symptoms in adults. Results of this set of sensitivity analyses are presented in Table 9.C-3.

There has been a great deal of research recently on the potential effect of ozone on premature mortality. While the air pollutant most clearly associated with premature mortality is particulate matter, with dozens of studies reporting such an association, repeated ozone exposure is a likely contributing factor for premature mortality, causing an inflammatory response in the lungs which may predispose elderly and other sensitive individuals to become more susceptible. The findings of three recent analyses provide consistent data suggesting that ozone exposure is associated with increased mortality. Although the National Morbidity, Mortality, and Air Pollution Study (NMMAPS) did not find an effect of ozone on total mortality across the full year, Samet et al. (2000), who conducted the NMMAPS study, did observe an effect after limiting the analysis to summer when ozone levels are highest. Similarly, Thurston and Ito (1999) have shown associations between ozone and mortality. Toulomi et al. (1997) found that 1-hour maximum ozone levels were associated with daily numbers of deaths in 4 cities (London, Athens, Barcelona, and Paris), and a quantitatively similar effect was found in a group of 4 additional cities (Amsterdam, Basel, Geneva, and Zurich). Fairly et al. (2003) also found a relatively strong association between maximum 8-hour average ozone concentrations and mortality in Santa Clara County, CA, even after controlling for $PM_{2.5}$ exposure.

While not as extensive as the data base for particulate matter, these recent studies provide supporting evidence for inclusion of mortality in the ozone health benefits analysis. A recent analysis by Thurston and Ito (2001) reviewed previously published time series studies of the effect of daily ozone levels on daily mortality and found that previous EPA estimates of the short-term mortality benefits of the ozone NAAQS (U.S. EPA, 1997) may have been underestimated by up to a factor of two. Thurston and Ito hypothesized that much of the variability in published estimates of the ozone/mortality effect could be explained by how well each model controlled for the influence of weather, an important confounder of the ozone/mortality effect, and that earlier studies using less sophisticated approaches to controlling for weather consistently under-predicted the ozone/mortality effect.

Thurston and Ito (2001) found that models incorporating a non-linear temperature specification appropriate for the "U-shaped" nature of the temperature/mortality relationship (i.e., increased deaths at both very low and very high temperatures) produced ozone/mortality effect estimates that were both more strongly positive (a two percent increase in relative risk over the pooled estimate for all studies evaluated) and consistently statistically significant. Further accounting for the interaction effects between temperature and relative humidity produced even more strongly positive results. Inclusion of a PM index to control for PM/mortality effects had little effect on these results, suggesting an ozone/mortality relationship independent of that for PM. However, most of the studies examined by Thurston and Ito only controlled for PM_{10} or broader measures of particles and did not directly control for $PM_{2.5}$. As such, there may still be potential for confounding of $PM_{2.5}$ and ozone mortality effects, as ozone and $PM_{2.5}$ are highly correlated during summer months in some areas.

A recent World Health Organization (WHO) report found that "recent epidemiological studies have strengthened the evidence that there are short-term O_3 effects on mortality and respiratory morbidity and provided further information on exposure-response relationships and effect modification." (WHO, 2003). Based on a preliminary meta-analysis, the WHO report suggests an effect estimate of between 0.2 and 0.4 percent increase in premature death per 10 $\mu g/m^3$ increase in 1 hour maximum ozone and between 0.4 and 0.6 percent increase in premature death per 10 $\mu g/m^3$ increase in daily average. This is equivalent to a relative risk of between 1.04 and 1.08 per 100 ppb increase in 1 hour maximum and between 1.08 and 1.12 per 100 ppb increase in daily average. The WHO report provides effect estimates for both all seasons and summer seasons. Because our analysis is limited to the summer ozone season, the most appropriate effect estimate is for the summer season. The WHO summer season relative risk estimate is 1.08 per 100 ppb increase in 1 hour maximum ozone and 1.12 per 100 ppb increase in daily average ozone.

Levy et al. (2001) assessed the epidemiological evidence examining the link between short term exposures to ozone and premature mortality. Based on four U.S. studies (Kellsall et al., 1997; Moolgavkar et al., 1995; Ito and Thurston, 1996; and Moolgavkar, 2000), they conclude that an appropriate pooled effect estimate is a 0.5 percent increase in premature deaths per 10 $\mu g/m^3$ increase in 24-hour average ozone concentrations, with a 95 percent confidence interval between 0.3 percent and 0.7 percent. This is equivalent to a relative risk of 1.10 per 100 ppb increase in daily average, which falls in the middle of the range of relative risks from the WHO report. Levy et al. also note that there are a number of studies which did not report a quantitative effect estimate but did indicate that ozone was insignificant. They suggest that the uncertainty surrounding the ozone-mortality effect estimate is greater than that reflected in the confidence interval around their pooled estimate.

In its September 2001 advisory on the draft analytical blueprint for the second Section 812 prospective analysis, the SAB Health Effects Subcommittee (HES) cited the Thurston and Ito study as a significant advance in understanding the effects of ozone on daily mortality and recommended re-evaluation of the ozone mortality endpoint for inclusion in the next prospective study (EPA-SAB-COUNCIL-ADV-01-004, 2001). Based on these new analyses and recommendations, EPA is sponsoring three independent meta-analyses of the ozone-mortality epidemiology literature to inform a determination on inclusion of this important health endpoint. Publication of these meta-analyses will significantly enhance the scientific defensibility of benefits estimates for ozone which include the benefits of premature mortality reductions. In its 2003 review of the analysis plans for the second Prospective Analysis, the HES indicated support for EPAs new meta-analyses of the ozone mortality literature and EPA's plans to consider adding ozone mortality to the base case analysis, subsequent to review of the results of the meta-analyses. Thus, recent evidence suggests that by not including an estimate of reductions in short-term mortality due to changes in ambient ozone, the Base Estimate may underestimate the benefits of implementation of the Nonroad Diesel Engine rule.

The ozone mortality sensitivity estimate is calculated using results from four U.S. studies (Ito and Thurston, 1996; Kinney et al., 1995; Moolgavkar et al., 1995; and Samet et al., 1997), based on the assumption that demographic and environmental conditions on average would be more similar between these studies and the conditions prevailing when the nonroad standards are implemented. We include the Kinney et al., 1995 estimate for completeness, even though Levy et al. (2001) reject the results because the study only included a linear term for temperature. Because the Kinney et al. (1995) study found no significant effect of ozone, this has the effect of reducing the estimated mortality impacts and increasing the uncertainty surrounding the estimated mortality reductions. We combined these studies using probabilistic sampling methods to estimate the impact of ozone on mortality incidence. The technical support document for this analysis provides additional details of this approach (Abt Associates, 2003). The estimated incidences of short-term premature mortality are valued using the value of statistical lives saved method, as described in Appendix 9A.

Table 9C-2.
Sensitivity Estimates for Potentially Overlapping Endpoints[A]

Description of Sensitivity Analysis	**Avoided Incidences**		**Monetized Value (Million 2000$)**	
	2020	**2030**	**2020**	**2030**
Mortality from Short-term Ozone Exposure[B]				
Ito and Thurston (1996)	440	1,000	$2,900	$6,800
Kinney et al. (1995)	0	0	$0	$0
Moolgavkar et al. (1995)	77	240	$510	$1,600
Samet et al. (1997)	120	360	$790	$2,400
Pooled estimate (random effects weights)	**94**	**280**	**$620**	**$1,900**
Any of 19 Acute Respiratory Symptoms, Adults 18-64 (Krupnick et al. 1990)				
Ozone	1,500,000	2,800,000	$38	$71
PM	14,000,000	19,000,000	$340	$490

[A] All estimates rounded to two significant digits.

[B] Mortality valued using Base estimate of $5.5 million per premature statistical death, adjusted for income growth.

9C.2.2 Alternative and Supplementary Estimates

We also examine how the value for individual endpoints or total benefits would change if we were to make a different assumption about specific elements of the benefits analysis. Specifically, in Table 9C.3, we show the impact of alternative assumptions about other parameters, including treatment of reversals in chronic bronchitis as lowest severity cases, alternative impact functions for PM hospital and ER admissions, valuation of residential visibility, valuation of recreational visibility at Class I areas outside of the study regions examined in the Chestnut and Rowe (1990a, 1990b) study, and valuation of household soiling damages.

Table 9C-3.
Additional Parameter Sensitivity Analyses

Alternative Calculation		Description of Estimate	Impact on Base Benefit Estimate (million 2000$)	
			2020	2030
1	Reversals in chronic bronchitis treated as lowest severity cases	Instead of omitting cases of chronic bronchitis that reverse after a period of time, they are treated as being cases with the lowest severity rating. The number of avoided chronic bronchitis incidences in 2020 increases from 4,300 to 8,000 (87%). The increase in 2030 is from 6,500 to 12,000 (87%).	+$730 (+1.4%)	+$1,100 (+1.2%)
2	Value of visibility changes in all Class I areas	Values of visibility changes at Class I areas in California, the Southwest, and the Southeast are transferred to visibility changes in Class I areas in other regions of the country.	+$640 (+1.2%)	+$970 (+1.1%)
3	Value of visibility changes in Eastern U.S. residential areas	Value of visibility changes outside of Class I areas are estimated for the Eastern U.S. based on the reported values for Chicago and Atlanta from McClelland et al. (1990).	+$700 (+1.3%)	+$1,100 (+1.1%)
4	Value of visibility changes in Western U.S. residential areas	Value of visibility changes outside of Class I areas are estimated for the Western U.S. based on the reported values for Chicago and Atlanta from McClelland et al. (1990).	+$530 (+1.0%)	+$830 (+0.9%)
5	Household soiling damage	Value of decreases in expenditures on cleaning are estimated using values derived from Manuel, et al. (1983).	+$170 (+0.3%)	+$260 (+0.3%)

An important issue related to chronic conditions is the possible reversal in chronic bronchitis incidences (row 1 of Table 9C-3). Reversals are defined as those cases where an individual reported having chronic bronchitis at the beginning of the study period but reported not having chronic bronchitis in follow-up interviews at a later point in the study period. Since, by definition, chronic diseases are long-lasting or permanent, if the disease goes away it is not chronic. However, we have not captured the benefits of reducing incidences of bronchitis that are somewhere in-between acute and chronic. One way to address this is to treat reversals as cases of chronic bronchitis that are at the lowest severity level. These cases thus get the lowest value for chronic bronchitis.

The alternative calculation for recreational visibility (row 2 of Table 9C-3) is an estimate of the full value of visibility in the entire region affected by the nonroad emission reductions. The Chestnut and Rowe study from which the primary valuation estimates are derived only examined WTP for visibility changes in the southeastern portion of the affected region. In order to obtain estimates of WTP for visibility changes in the northeastern and central portion of the affected region, we have to transfer the southeastern WTP values. This introduces additional uncertainty into the estimates. However, we have taken steps to adjust the WTP values to account for the possibility that a visibility improvement in parks in one region, is not necessarily the same environmental quality good as the same visibility improvement at parks in a different region. This may be due to differences in the scenic vistas at different parks, uniqueness of the parks, or other factors, such as public familiarity with the park resource. To take this potential difference into account, we adjusted the WTP being transferred by the ratio of visitor days in the two regions.

The alternative calculations for residential visibility (rows 3 and 4 of Table 9C-3) are based on the McClelland, et al. study of WTP for visibility changes in Chicago and Atlanta. As discussed in Appendix 9A, SAB advised EPA that the residential visibility estimates from the available literature are inadequate for use in a primary estimate in a benefit-cost analysis. However, EPA recognizes that residential visibility is likely to have some value and the McClelland, et al. estimates are the most useful in providing an estimate of the likely magnitude of the benefits of residential visibility improvements.

The alternative calculation for household soiling (row 5 of Table 9C-3) is based on the Manuel, et al. study of consumer expenditures on cleaning and household maintenance. This study has been cited as being “the only study that measures welfare benefits in a manner consistent with economic principals (Desvouges et al., 1998).” However, the data used to estimate household soiling damages in the Manuel, et al. study are from a 1972 consumer expenditure survey and as such may not accurately represent consumer preferences in 2030. EPA recognizes this limitation, but believes the Manuel, et al. estimates are still useful in providing an estimate of the likely magnitude of the benefits of reduced PM household soiling.

9C.3 Income Elasticity of Willingness to Pay

As discussed in Appendix 9A, our estimate of monetized benefits accounts for growth in real GDP per capita by adjusting the WTP for individual endpoints based on the central estimate of the adjustment factor for each of the categories (minor health effects, severe and chronic health effects, premature mortality, and visibility). We examine how sensitive the estimate of total benefits is to alternative estimates of the income elasticities. Table 9C-4 lists the ranges elasticity values used to calculate the income adjustement factors, while Table 9C-5 lists the ranges of corresponding adjustement factors. The results of this sensitivity analysis, giving the monetized benefit subtotals for the four benefit categories, are presented in Table 9C-6.

Consistent with the impact of mortality on total benefits, the adjustment factor for mortality has the largest impact on total benefits. The value of mortality ranges from 81 percent to 150 percent of the primary estimate based on the lower and upper sensitivity bounds on the income adjustment factor. The effect on the value of minor and chronic health effects is much less pronounced, ranging from 93 percent to 111 percent of the primary estimate for minor effects and from 88 percent to 110 percent for chronic effects.

Table 9C-4.
Ranges of Elasticity Values Used to Account for Projected Real Income Growth[A]

Benefit Category	Lower Sensitivity Bound	Upper Sensitivity Bound
Minor Health Effect	0.04	0.30
Severe and Chronic Health Effects	0.25	0.60
Premature Mortality	0.08	1.00
Visibility[B]	--	--

[A] Derivation of these ranges can be found in Kleckner and Neumann (1999) and Chestnut (1997). Cost of Illness (COI) estimates are assigned an adjustment factor of 1.0.
[B] No range was applied for visibility because no ranges were available in the current published literature.

Table 9C-5.
Ranges of Adjustment Factors Used to Account for Projected Real Income Growth[A]

Benefit Category	Lower Sensitivity Bound		Upper Sensitivity Bound	
	2020	2030	2020	2030
Minor Health Effect	1.018	1.021	1.147	1.170
Severe and Chronic Health Effects	1.121	1.139	1.317	1.371
Premature Mortality	1.037	1.043	1.591	1.705
Visibility[B]	--	--	--	--

[A] Based on elasticity values reported in Table 9A-11, US Census population projections, and projections of real gross domestic product per capita.
[B] No range was applied for visibility because no ranges were available in the current published literature.

Table 9C-6.
Sensitivity Analysis of Alternative Income Elasticities[A]

Benefit Category	Lower Sensitivity Bound		Upper Sensitivity Bound	
	2020	2030	2020	2030
Minor Health Effect	$510	$760	$540	$810
Severe and Chronic Health Effects	$2,500	$3,900	$2,800	$4,400
Premature Mortality	$42,000	$75,000	$65,000	$123,000
Visibility and Other Welfare Effects[A]	$1,400	$2,200	$1,400	$2,200
Total Benefits	$47,000	$82,000	$70,000	$131,000

[A] All estimates rounded to two significant digits.
[B] No range was applied for visibility because no ranges were available in the current published literature.

Appendix 9C References

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APPENDIX 9D: Visibility Benefits Estimates for Individual Class I Areas

Table 9D-1
Apportionment Factors for 2020 Park Specific Visibility Benefits

PARK	COUNTY	STATE	Percent of 2020 Visibility Benefit Due to Changes in: SO_2	NOx	direct PM
Shenandoah	Lawrence	AL	0.428	0.234	0.338
Anaconda-Pintlar W	Cochise Co	AZ	0.337	0.061	0.602
Boundary Waters	Gila Co	AZ	0.396	0.054	0.550
Breton W	Gila Co	AZ	0.396	0.054	0.550
Isle Royale	Coconino	AZ	0.336	0.053	0.612
Jarbidge W	Apache Co	AZ	0.469	0.049	0.481
Medicine Lake W	Apache Co	AZ	0.469	0.049	0.481
Red Rock Lakes W	Graham Co	AZ	0.302	0.038	0.660
Roosevelt Campobello	Pima Co	AZ	0.224	0.061	0.715
Selway-Bitterroot W	Maricopa	AZ	0.061	0.014	0.924
Seney W	Coconino	AZ	0.336	0.053	0.612
Wolf Island W	Yavapai Co	AZ	0.216	0.140	0.644
Agua Tibia W	Tuolumne	CA	0.090	0.580	0.330
Black Canyon of the	San	CA	0.074	0.158	0.768
Caribou W	Calaveras	CA	0.049	0.520	0.432
Chiricahua	Trinity Co	CA	0.367	0.239	0.394
Cucamonga W	Fresno Co	CA	0.051	0.101	0.848
Dome Land W	Mono Co	CA	0.195	0.302	0.504
Flat Tops W	Inyo Co	CA	0.145	0.098	0.757
Grand Canyon	Marin Co	CA	0.060	0.577	0.363
Hoover W	Los	CA	0.099	0.143	0.758
John Muir W	Monterey	CA	0.071	0.563	0.366
Kaiser W	San Benito	CA	0.057	0.633	0.310
La Garita W	Riverside	CA	0.040	0.314	0.646
Mazatzal W	Siskiyou	CA	0.469	0.220	0.311
Mesa Verde	San	CA	0.074	0.158	0.768
Petrified Forest	Del Norte	CA	0.518	0.097	0.385
Pine Mountain W	Shasta Co	CA	0.146	0.469	0.385
Pinnacles	Fresno Co	CA	0.051	0.101	0.848
Point Reyes	Lassen Co	CA	0.285	0.347	0.368
Rawah W	Riverside	CA	0.040	0.314	0.646
Rocky Mountain	San Diego	CA	0.068	0.497	0.435
Saguaro	Shasta Co	CA	0.146	0.469	0.385
San Gabriel W	El Dorado	CA	0.050	0.487	0.463
San Gorgino W	Mariposa	CA	0.085	0.374	0.541
San Jacinto W	Fresno Co	CA	0.051	0.101	0.848
San Rafael W	Tuolumne	CA	0.090	0.580	0.330
Sequoia-Kings	Tulare Co	CA	0.052	0.478	0.470
Sycamore Canyon W	Siskiyou	CA	0.469	0.220	0.311
Ventana W	Santa	CA	0.111	0.156	0.733
Yolla-Bolly-Middle-	Tulare Co	CA	0.052	0.478	0.470

PARK	COUNTY	STATE	Percent of 2020 Visibility Benefit Due to Changes in: SO$_2$	NOx	direct PM
Yosemite	Modoc Co	CA	0.277	0.407	0.316
Carlsbad Caverns	San Juan	CO	0.522	0.114	0.364
Gila W	Garfield Co	CO	0.335	0.246	0.420
Joyce Kilmer-Slickrock	Routt Co	CO	0.420	0.140	0.440
Kalmiopsis W	Larimer Co	CO	0.449	0.120	0.431
Linville Gorge W	Pitkin Co	CO	0.425	0.098	0.477
Lostwood W	Alamosa	CO	0.458	0.097	0.445
Pecos W	Gunnison	CO	0.437	0.152	0.411
Presidential Range-Dry	Montezuma	CO	0.353	0.077	0.570
Salt Creek W	Montrose	CO	0.355	0.175	0.470
Shining Rock W	Summit Co	CO	0.525	0.042	0.433
Wheeler Peak W	Mineral Co	CO	0.589	0.048	0.364
Wichita Mountains W	Larimer Co	CO	0.449	0.120	0.431
Fitzpatrick W	Monroe Co	FL	0.546	0.020	0.434
Glacier Peak W	Wakulla Co	FL	0.535	0.048	0.417
Mount Adams W	Citrus Co	FL	0.416	0.148	0.436
Dolly Sods W	Charlton	GA	0.543	0.058	0.399
North Absaroka W	McIntosh	GA	0.500	0.052	0.448
Olympic	Edmonson	KY	0.415	0.246	0.338
Lye Brook W	Stone Co	MS	0.539	0.112	0.349
Bridger W	Hyde Co	NC	0.344	0.327	0.329
Goat Rocks W	Haywood	NC	0.476	0.191	0.333
Otter Creek W	Avery Co	NC	0.516	0.184	0.300
Pasayten W	Graham Co	NC	0.564	0.138	0.298
Bandelier	Sandoval	NM	0.426	0.034	0.540
Bosque del Apache W	Rio Arriba	NM	0.512	0.047	0.441
Brigantine W	Grant Co	NM	0.414	0.017	0.569
Crater Lake	Chaves Co	NM	0.471	0.094	0.434
Mount Hood W	Mora Co	NM	0.568	0.081	0.352
Mount Washington W	Eddy Co	NM	0.417	0.052	0.531
San Pedro Parks W	Socorro Co	NM	0.409	0.025	0.565
Swanguarter W	Taos Co	NM	0.538	0.057	0.405
Theodore Roosevelt	Lincoln Co	NM	0.603	0.056	0.341
Maroon Bells-	Elko Co	NV	0.311	0.301	0.388
Mount Rainier	Polk Co	TN	0.405	0.237	0.358
North Cascades	Blount Co	TN	0.384	0.184	0.432
Bob Marshall W	San Juan	UT	0.373	0.048	0.579
Gates of the Mountain	Grand Co	UT	0.354	0.038	0.608
Glacier	San Juan	UT	0.373	0.048	0.579
St. Marks W	Washington	UT	0.219	0.096	0.685
Voyageurs	Garfield Co	UT	0.295	0.052	0.652
Teton W	Botetourt	VA	0.485	0.151	0.364
Yellowstone	Madison	VA	0.385	0.316	0.300
Grand Teton NP	Grant Co	WV	0.533	0.190	0.278
Washakie W	Tucker Co	WV	0.568	0.118	0.314

Table 9D-2
Apportionment Factors for 2030 Park Specific Visibility Benefits

PARK	COUNTY	STATE	Percent of 2030 Visibility Benefit Due to Changes in: SO_2	NOx	direct PM
Shenandoah	Lawrence	AL	0.376	0.297	0.327
Anaconda-Pintlar W	Cochise	AZ	0.313	0.075	0.612
Boundary Waters	Gila Co	AZ	0.277	0.048	0.675
Breton W	Gila Co	AZ	0.293	0.089	0.619
Isle Royale	Coconino	AZ	0.342	0.107	0.551
Jarbidge W	Apache	AZ	0.429	0.069	0.503
Medicine Lake W	Apache	AZ	0.429	0.069	0.503
Red Rock Lakes W	Graham	AZ	0.188	0.173	0.639
Roosevelt Campobello	Pima Co	AZ	0.207	0.072	0.721
Selway-Bitterroot W	Maricopa	AZ	0.342	0.107	0.551
Seney W	Coconino	AZ	0.057	0.019	0.924
Wolf Island W	Yavapai	AZ	0.293	0.089	0.619
Agua Tibia W	Tuolumne	CA	0.055	0.571	0.375
Black Canyon of the	San	CA	0.226	0.407	0.368
Caribou W	Calaveras	CA	0.065	0.191	0.745
Chiricahua	Trinity Co	CA	0.129	0.111	0.759
Cucamonga W	Fresno Co	CA	0.039	0.520	0.441
Dome Land W	Mono Co	CA	0.046	0.493	0.461
Flat Tops W	Inyo Co	CA	0.070	0.616	0.314
Grand Canyon	Marin Co	CA	0.070	0.616	0.314
Hoover W	Los	CA	0.049	0.109	0.842
John Muir W	Monterey	CA	0.033	0.376	0.591
Kaiser W	San Benito	CA	0.049	0.109	0.842
La Garita W	Riverside	CA	0.049	0.109	0.842
Mazatzal W	Siskiyou	CA	0.116	0.518	0.366
Mesa Verde	San	CA	0.411	0.270	0.320
Petrified Forest	Del Norte	CA	0.411	0.270	0.320
Pine Mountain W	Shasta Co	CA	0.158	0.344	0.498
Pinnacles	Fresno Co	CA	0.043	0.535	0.422
Point Reyes	Lassen Co	CA	0.047	0.663	0.289
Rawah W	Riverside	CA	0.053	0.588	0.360
Rocky Mountain	San Diego	CA	0.468	0.133	0.399
Saguaro	Shasta Co	CA	0.090	0.175	0.735
San Gabriel W	El Dorado	CA	0.065	0.191	0.745
San Gorgino W	Mariposa	CA	0.033	0.376	0.591
San Jacinto W	Fresno Co	CA	0.099	0.179	0.722
San Rafael W	Tuolumne	CA	0.046	0.493	0.461
Sequoia-Kings	Tulare Co	CA	0.225	0.452	0.323
Sycamore Canyon W	Siskiyou	CA	0.116	0.518	0.366
Ventana W	Santa	CA	0.059	0.593	0.348
Yolla-Bolly-Middle-	Tulare Co	CA	0.321	0.292	0.386
Yosemite	Modoc Co	CA	0.073	0.400	0.527
Carlsbad Caverns	San Juan	CO	0.312	0.203	0.485
Gila W	Garfield	CO	0.464	0.087	0.449

PARK	COUNTY	STATE	Percent of 2030 Visibility Benefit Due to Changes in: SO_2	NOx	direct PM
Joyce Kilmer-Slickrock	Routt Co	CO	0.289	0.286	0.425
Kalmiopsis W	Larimer	CO	0.407	0.123	0.470
Linville Gorge W	Pitkin Co	CO	0.537	0.074	0.389
Lostwood W	Alamosa	CO	0.391	0.103	0.505
Pecos W	Gunnison	CO	0.320	0.091	0.589
Presidential Range-Dry	Montezum	CO	0.367	0.180	0.452
Salt Creek W	Montrose	CO	0.397	0.156	0.447
Shining Rock W	Summit	CO	0.397	0.156	0.447
Wheeler Peak W	Mineral	CO	0.471	0.140	0.389
Wichita Mountains W	Larimer	CO	0.385	0.188	0.428
Fitzpatrick W	Monroe	FL	0.365	0.204	0.431
Glacier Peak W	Wakulla	FL	0.503	0.033	0.464
Mount Adams W	Citrus Co	FL	0.497	0.070	0.433
Dolly Sods W	Charlton	GA	0.503	0.085	0.412
North Absaroka W	McIntosh	GA	0.463	0.082	0.456
Olympic	Edmonson	KY	0.365	0.304	0.332
Lye Brook W	Stone Co	MS	0.486	0.166	0.348
Bridger W	Hyde Co	NC	0.515	0.183	0.302
Goat Rocks W	Haywood	NC	0.455	0.252	0.293
Otter Creek W	Avery Co	NC	0.436	0.232	0.332
Pasayten W	Graham	NC	0.309	0.371	0.320
Bandelier	Sandoval	NM	0.389	0.051	0.560
Bosque del Apache W	Rio Arriba	NM	0.374	0.037	0.589
Brigantine W	Grant Co	NM	0.378	0.069	0.553
Crater Lake	Chaves Co	NM	0.387	0.021	0.592
Mount Hood W	Mora Co	NM	0.525	0.100	0.375
Mount Washington W	Eddy Co	NM	0.421	0.124	0.455
San Pedro Parks W	Socorro	NM	0.472	0.059	0.469
Swanguarter W	Taos Co	NM	0.481	0.092	0.427
Theodore Roosevelt	Lincoln	NM	0.553	0.078	0.369
Maroon Bells-	Elko Co	NV	0.261	0.345	0.394
Mount Rainier	Polk Co	TN	0.359	0.295	0.346
North Cascades	Blount Co	TN	0.345	0.232	0.423
Bob Marshall W	San Juan	UT	0.322	0.046	0.632
Gates of the Mountain	Grand Co	UT	0.265	0.065	0.671
Glacier	San Juan	UT	0.337	0.064	0.600
St. Marks W	Washingto	UT	0.337	0.064	0.600
Voyageurs	Garfield	UT	0.190	0.129	0.680
Teton W	Botetourt	VA	0.445	0.193	0.361
Yellowstone	Madison	VA	0.331	0.387	0.282
Grand Teton NP	Grant Co	WV	0.455	0.275	0.270
Washakie W	Tucker Co	WV	0.487	0.200	0.313

CHAPTER 10: Economic Impact Analysis

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This chapter contains the Economic Impact Analysis (EIA) prepared to estimate the economic impacts of this rule on producers and consumers of nonroad engines, equipment, fuel and related industries. This EIA relies on the Nonroad Diesel Economic Impact Model (NDEIM), developed for this analysis, to estimate market-level changes in prices and outputs for affected engine, equipment, fuel, and application markets as well as the social costs and their distribution across economic sectors affected by the program. The basis for this analysis is provided in the Economic Impact Analysis technical support document prepared for the proposal for this rule, as updated by a technical memoranda (RTI, 2003a, RTI 2004).

This analysis is based on an earlier version of the engineering costs developed for this rule. The final cost estimates for the engine program are slightly higher ($142 million) and the final fuel costs are slightly lower ($246 million), resulting in a 30-year net present value of $27.1 billion (30 year net present values in the year 2004, using a 3% Discount Rate, $2002) or $104 million less than the engineering costs used in this analysis. We do not expect that the revised engineering costs would change the overall results of this economic impact analysis given the small portion of engine, equipment, and fuel costs to total production costs for goods and services using these inputs and given the inelastic value of the estimated demand elasticities for the application markets.

The first section of this chapter briefly describes the methodology we used to estimate the economic impacts of this rule and presents an overview of the results. According to this analysis, this rule would be highly beneficial to society, with a net present value of social costs of about $27.2 billion, compared to net present value benefits through 2036 of $780 billion (30 year net present values in the year 2004 using 3% discount rate, $2002). The impact of these costs on society should be minimal, with the average price of goods and services produced using equipment and fuel affected by the final rule expected to increase by about 0.1 percent. The second section of this chapter presents a more detailed description of the economic methodology behind the NDEIM and certain modeling assumptions. The third section describes the markets included in the model and data inputs as well as the solution algorithm. Finally, the appendices to this chapter contain detailed results, additional information on the model, and a sensitivity analysis.

10.1 Overview and Results

10.1.1 What is an Economic Impact Analysis?

An Economic Impact Analysis is prepared to inform decision makers within the Agency about the potential economic consequences of a regulatory action. The analysis contains estimates of the social costs of a regulatory program and explores the distribution of these costs across stakeholders. These estimated social costs can then be compared with estimated social benefits (as presented in Chapter 9). As defined in EPA's *Guidelines for Preparing Economic*

Analyses (EPA 2000, p. 113), *social costs* are the value of the goods and services lost by society resulting from a) the use of resources to comply with and implement a regulation and b) reductions in output. In this analysis, social costs are explored in two steps. In the first step, called the *market analysis*, we estimate how prices and quantities of good directly and indirectly affected by the emission control program can be expected to change once the emission control program goes into effect. The estimated price and quantity changes for engines, equipment, fuel, and goods produced using these inputs are examined separately. In the second step, called the *economic welfare analysis*, we look at the total social costs associated with the program and their distribution across stakeholders.

10.1.2 What Methodology Did EPA Use in this Economic Impact Assessment?

The Nonroad Diesel Economic Impact Model (NDEIM) developed for this EIA estimates how producers and consumers can be expected to respond to the regulatory compliance costs associated with this rule. The NDEIM uses a multi-market analysis framework that considers interactions between regulated markets and other markets to estimate how compliance costs can be expected to ripple through these markets. The analysis provides an estimate of the average increase in price and decrease in quantity of output produced for the markets examined. It also allows us to estimate the social costs of the rule and identify how the various groups of affected stakeholders will bear them. The economic theory on which the NDEIM is based is described in Section 10.2. Market characteristics, compliance costs, and other data used in the NDEIM are described in Section 10.3.

The NDEIM tracks average price and quantity changes for 62 integrated product markets. Figure 10.1-1 illustrates the connections between the industry segments included in the model and the flow of regulatory compliance costs through the economic system. The rule will increase the cost of producing nonroad diesel engines. Engine manufacturers are expected to attempt to pass some or all of their direct compliance costs on to equipment manufacturers in the form of higher diesel engine prices. Similarly, equipment manufacturers are expected to attempt to pass some or all of their direct compliance costs (in the form of equipment redesign costs) and indirect compliance costs (in the form of increased engine costs) to application market producers through higher diesel equipment prices. Petroleum refiners are also expected to attempt to pass some or all of their direct compliance costs on to application market producers and to the locomotive and marine transportation service sectors through higher prices for diesel fuel. Finally, application market producers are expected to pass on some or all of their increased equipment and diesel fuel costs to consumers of final application market products and services. It is the interaction of suppliers and purchasers in each of the markets that determines the extent to which prices and quantities of goods produced change in response to the compliance costs associated with the rule. The amount of the compliance costs that can be passed on is affected by the price sensitivity of purchasers in the relevant market. The NDEIM explicitly models market linkages and behavioral responses and estimates new equilibrium prices and output and the resulting distribution of social costs across affected stakeholders.

Diesel engines, equipment, and fuel represent only a small portion of the total production costs for each of the three application market sectors (the final users of the engines, equipment and fuel affected by this rule). Other more significant production costs include land, labor, other capital, raw materials, insurance, profits, etc. These other production costs are not affected by

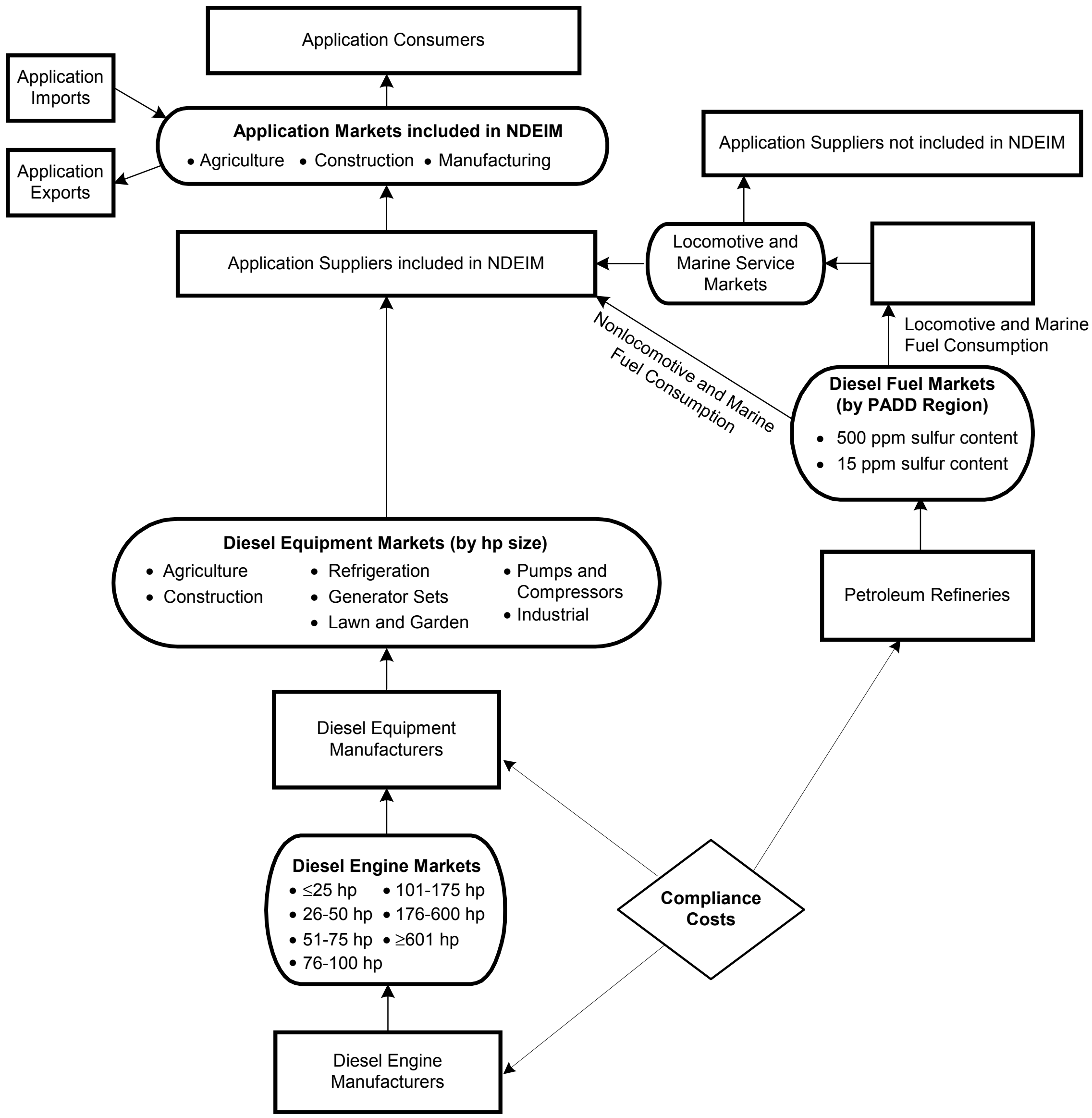

Figure 10.1-1. Market Linkages Included in the Economic Model

this emission control program. This is important because it means that this rule directly affects only a small part of total inputs for the relevant markets. Therefore, rule is not expected to have a large adverse impact on output and prices of goods produced in the three application sectors.

10.1.3 What are the key features of the NDEIM?

10.1.3.1 Brief Description of the NDEIM

The NDEIM is a computer model comprised of a series of spreadsheet modules that define the baseline characteristics of supply and demand for the relevant markets and the relationships between them. The basis for this analysis is provided in the EIA technical support document, as updated by a technical memo (RTI, 2003a, RTI 2004). The model methodology, as explained in Section 10.2.2, is firmly rooted in applied microeconomic theory and was developed following the *OAQPS Economic Analysis Resource Document* (EPA, 1999). The NDEIM uses a multi-market partial equilibrium approach to track changes in price and quantity for the modeled product markets. As explained in the *EPA Guidelines for Preparing Economic Analyses* (EPA 2000, 125-6; see also Section 10.2.2, below), 'partial' equilibrium refers to the fact that the supply and demand functions are modeled for just one or a few isolated markets and that conditions in other markets are assumed either to be unaffected by a policy or unimportant for social cost estimation. Multi-market models go beyond partial equilibrium analysis by extending the inquiry to more than just a single market. Multi-market analysis attempts to capture at least some of the interactions between markets.

The NDEIM uses an intermediate run time frame and assumes perfect competition in the market sectors. These model features are explained in Sections 10.2.3.1 and 10.2.3.2. The use of the intermediate run means that some factors of production are fixed and some are variable. This modeling period allows analysis of the economic effects of the rule's compliance costs on current producers. The short run, in contrast, imposes all compliance costs on the manufacturers (no pass-through to consumers), while the long run imposes all costs on consumers (full cost pass-through to consumers). The perfect competition assumption is appropriate given the number of firms and other key characteristics for each market (no indications of barriers to entry; the firms are not price setters; there is no evidence of high levels of strategic behavior in the price and quantity decisions of the firms; the products produced within each market are somewhat homogeneous in that engines from one firm can be purchased instead of engines from another firm; see Section 10.2.3.1, below). The use of the intermediate run time frame and the assumption of perfect competition are based on widely accepted economic practice for this type of analysis (see for example EPA, 2000, p. 126).

The NDEIM is constructed based on the market characteristics and inter-connections described in this chapter. The model is shocked by applying the engineering compliance cost estimates to the appropriate market suppliers, and then numerically solved using an iterative auctioneer approach by "calling out" new prices until a new equilibrium is reached in all markets simultaneously. The output of the model is new equilibrium prices and quantities for all affected markets. This information is used to estimate the social costs of the model and how those costs are shared among affected markets.

10.1.3.2 Product Markets Included in the Model

There are 62 integrated product markets included in the model, as follows:

- 7 diesel engine markets: less than 25 hp, 26 to 50 hp, 51 to 75 hp, 76 to 100 hp, 101 to 175 hp, 176 to 600 hp, and greater than 600 hp. The EIA includes more horsepower categories than the standards to allow more efficient use of the engine compliance costs estimates. The additional categories also allow estimating economic impacts for a more diverse set of markets.
- 42 diesel equipment markets: 7 horsepower categories within 7 application categories: agricultural, construction, general industrial, pumps and compressors, generator and welder sets, refrigeration and air conditioning, and lawn and garden. There are 7 horsepower/application categories that did not have sales in 2000 and are not included in the model, so the total number of diesel equipment markets is 42 rather than 49.
- 3 application markets: agricultural, construction, and manufacturing.
- 8 nonroad diesel fuel markets: 2 sulfur content levels (15 ppm and 500 ppm) for each of 4 PADDs. PADDs 1 and 3 are combined for the purpose of this analysis. It should be noted that PADD 5 includes Alaska and Hawaii. Also, California fuel volumes that are not affected by the program (because they are covered by separate California nonroad diesel fuel standards) are not included in the analysis.
- 2 transportation service markets: locomotive and marine.

Table 10.1-1 summarizes the characteristics of each of these five groups of markets. More detailed information on NDEIM model inputs in provided in Section 10.3.

Table 10.1-1
Summary of Markets in Nonroad Diesel Economic Impact Model (NDEIM)

Model Dimension	Markets (number)				
	Diesel Engines (7)	Diesel Equipment (42)	Diesel Fuel (8)	Application (3)	Locomotive and Marine Transportation Sectors (2)
Geographic scope	National	National	Regional by PADDs	National	National
Product groupings	7 horsepower categories consistent with emission standards[a]	7 horsepower categories within seven application categories[b,c]	2 diesel fuels by sulfur content (500, 15 ppm) for 4 regional markets[d]	Three broad commodity categories[e]	2: rail and marine transportation services
Market structure	Perfectly competitive	Perfectly competitive	Perfectly competitive	Perfectly competitive	Perfectly competitive
Baseline population	Power Systems Research (PSR) database for 2000 as modified by EPA	Assume one-to-one relationship with engine population[f]	Based on Energy Information Administration (EIA) 2000 fuel consumption data	Value of shipments for 2000 from U.S. Census Bureau	Service expenditures, BEA. 1997 Benchmark I-O Supplementary Make, Use and Direct Requirements Tables at the Detailed Level, Table 4
Growth projections	Growth rates used in cost analysis; see Section 8.1	Growth rates used in cost analysis; see Section 8.1	Based on nonroad model and EIA	Average of equipment growth rates consumed by these markets	EPA's SO_2 inventory projections for marine engines that use diesel distillate fuel (50-state annual inventory, 1999-2003)
Supply elasticity	Econometric estimate (elastic)	Econometric estimate (elastic)	Published econometric estimate (inelastic)	Published econometric estimate (inelastic)	Published econometric estimate (elastic)
Demand elasticity	Derived demand	Derived demand	Derived demand	Econometric estimate (inelastic)	Derived demand
Regulatory shock	Direct compliance costs cause shift in supply function	Direct compliance costs and higher diesel engine prices cause shift in supply function	Direct compliance costs cause shift in supply function	No direct compliance costs but higher prices for diesel equipment and fuel cause shift in supply function	No direct compliance costs but higher prices for diesel fuel cause shift in supply function

[a] Horsepower categories are 0-25, 26-50, 51-75, 76-100, 101-175, 176-600, and 601 hp and greater; the EIA includes more horsepower categories than the standards, allowing more efficient use of the engine compliance cost estimates.

[b] Engine categories are agricultural, construction, pumps and compressors, generator and welder sets, refrigeration and air conditioning, general industrial, and lawn and garden.

[c] There are seven horsepower/application categories that do not have sales in 2000 and are not included in the model. These are: agricultural equipment >600 hp; gensets & welders > 600 hp; refrigeration & A/C > 71 hp (4 hp categories); and lawn & garden >600 hp. Therefore, the total number of diesel equipment markets is 42 rather than 49.

[d] PADDs 1 and 3 are combined for the purpose of this analysis). Note that PADD 5 includes Alaska and Hawaii. Also, California fuel volumes that are not affected by the program (because they are covered by separate California nonroad diesel fuel standards) are not included in the analysis.

[e] Application market categories are construction, agriculture, and manufacturing.

[f] See Section 10.3.1 for an explanation of how the engines were allocated to the seven categories.

Analysis of the three application markets is limited to market output. The economic impacts on particular groups of application market suppliers (e.g., the profitability of farm production units or manufacturing or construction firms) or particular groups of consumers (e.g., households and companies that consume agricultural goods, buildings, or durable or consumer goods) are not estimated. In other words, while we estimate that the application markets will bear most of the burden of the regulatory program and we apportion the decrease in application market surplus between application market producers and application market consumers, we do not estimate how those social costs will be shared among specific application market producers and consumers (e.g., farmers and households). In some cases, application market producers may be able to pass most if not all of their increased costs to the ultimate consumers of their products; in other cases, they may be obliged to absorb a portion of these costs. The focus on market-level impacts in this analysis is appropriate because the standards in this emission control program are technical standards that apply to nonroad engines, equipment, and fuel regardless of how they are used and the structure of the program does not suggest that different sectors will be affected differently by the requirements.

10.1.3.3 Supply and Demand Elasticities

The estimated social costs of this emission control program are a function of the ways in which producers and consumers of the engines, equipment, and fuels affected by the standards change their behavior in response to the costs incurred in complying with the standards. As the compliance costs ripple through the markets, producers and consumers change their production and purchasing decisions in response to changes in prices. In the NDEIM, these behavioral changes are modeled by the demand and supply elasticities (behavioral-response parameters), which measure the price sensitivity of consumers and producers.

The supply elasticities for the equipment, engine, diesel fuel, and transportation service markets and the demand and supply elasticities for the application markets used in the NDEIM were obtained from peer-reviewed literature sources or were estimated using econometric methods. These econometric methods are well-documented and are consistent with generally accepted econometric practice. Details on sources and estimation method are provided in Section 10.3 and Appendix 10H.

The equipment and engine supply elasticities are elastic, meaning that quantities supplied are expected to be fairly sensitive to price changes. This means that manufacturers are more likely (better able) to change production levels in response to price changes.

The supply elasticities for the fuel, transportation service, and the supply and demand elasticities for the three application markets are inelastic or unit elastic, meaning that the quantity supplied/demanded is expected to be fairly insensitive to price changes or will vary one-to-one with price changes. For the agricultural application market, the inelastic supply and demand elasticities reflect the relatively constant demand for food products and the high fixed cost nature of food production. For the construction and manufacturing application markets, the estimated demand and supply elasticities are less inelastic, because consumers have more flexibility to substitute away from construction and manufactured products and producers have more flexibility to adjust production levels. The estimated supply elasticity for the diesel fuel market is inelastic, reflecting the fact that most refineries operate near capacity and are therefore less responsive to fluctuations in market prices. Note that these elasticities reflect intermediate run behavioral changes. In the long run, supply and demand are expected to be more elastic since more substitutes may become available.

The inelastic values for the demand elasticities for the application markets are consistent with the Hicks-Allen derived demand relationship, according to which a low cost-share in production combined with limited substitution yields inelastic demand.[A] As noted above, diesel engines, equipment, and fuel represent only a small portion of the total production costs for each of the three application sectors. The limited ability to substitute for these inputs is discussed in Section 10.2.3.4.

Because the elasticity estimates are a key input to the model, a sensitivity analysis for supply and demand elasticity parameters was performed as part of this EIA. The results are presented in Appendix 10I. In general, varying the elasticity values across the range of values reported in the literature or using the upper and lower bounds of a 90 percent confidence interval around estimated elasticities has no impact on the magnitude of the total social costs and only a minimal impact on the distribution of costs across stakeholders. This is not surprising because equipment and diesel fuel costs are a relatively small share of total production costs in the construction, agriculture, and manufacturing industries.

In contrast to the above, the demand elasticities for the engine, equipment, fuel, and transportation markets are internally derived as part of the process of running the model. This is an important feature of the NDEIM, which allows it to link the separate market components of the model and simulate how compliance costs can be expected to ripple through the affected economic sectors. In the real world, for example, the quantity of nonroad equipment units produced in a particular period depends on the price of engines (the engine market) and the demand for equipment (the application markets). Similarly, the number of engines produced depends on the demand for engines (the equipment market) which depends on the demand for equipment (the application markets). Changes in conditions in one of these markets will affect the others. By designing the model to derive the engine, equipment, transportation market, and fuel demand elasticities, the NDEIM simulates these connections between supply and demand among all the product markets and replicates the economic interactions between producers and consumers.

10.1.3.4 Fixed and Variable Costs

Engines and Equipment. The EIA treats the fixed costs expected to be incurred by engine and equipment manufacturers differently in the market and social costs analyses. This feature of

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[A] If the elasticity of demand for a final product is less than the elasticity of substitution between an input and other inputs to the final product, then the demand for the input is less elastic the smaller its cost share. Hicks, J.R., 1961, 1963.

the model is described in greater detail in Section 10.2.3.3. In the market analysis, estimated engine and equipment market impacts (changes in prices and quantities) are based solely on the expected increase in variable costs associated with the standards. Fixed costs are not included in the market analysis reported in Table 10.1-2 because in an analysis of competitive markets the industry supply curve is based on its marginal cost curve and fixed costs are not reflected in changes in the marginal cost curve. In addition, the fixed costs associated with the rule are primarily R&D costs for design and engineering changes. Firms in the affected industries currently allocate funds for R&D programs and this rule is not expected to lead firms to change the size of their R&D budget. Therefore, changes in fixed costs for engine and equipment redesign associated with this rule are not likely to affect the prices of engines or equipment. These fixed costs are reported in the social cost analysis reported in Table 10.1-4, however, as an additional cost to producers. This is appropriate because even though firms currently allocated funds to R&D those resources are intended for other purposes such as increasing engine power, ease of use, or comfort. These improvements will therefore be postponed for the length of the rule-related R&D program. This is a cost to society.

It may be the case, however, that some firms will maintain their current R&D budget and allocate additional funds to comply with the this rule. Therefore, a sensitivity analysis was performed as part of this EIA in which fixed costs are included in intermediate-run decision-making. The results of this sensitivity analysis are presented in Appendix 10.I. In this scenario, including fixed costs in the model results in a transfer of economic welfare losses from engine and equipment markets to the application markets (engine and equipment producer surplus losses decrease; consumer surplus losses increase), but does not change the overall social costs associated with the rule.

Fuels. Unlike for engines and equipment, most of the petroleum refinery fixed costs are for production hardware. Refiners are expected to have to make physical changes to their refineries and purchase additional equipment to produce 500 ppm and then 15 ppm fuel. Therefore, fixed costs are included in the market analysis for fuel price and quantity impacts.

10.1.3.5 Compliance Costs

Engine and Equipment Compliance Costs. The NDEIM uses the engine and equipment compliance costs described in Chapter 6. Engine and equipment costs vary over time because fixed costs are recovered over five to ten year periods while total variable costs, despite learning effects that serve to reduce costs on a per unit basis, continue to increase at a rate consistent with new sales increases. Similarly, engine operating costs also vary over time because oil change maintenance savings, PM filter maintenance, and fuel economy effects, all of which are calculated on the basis of gallons of fuel consumed, change over time consistent with the growth in nationwide fuel consumption.

The relative magnitude of engine and equipment compliance costs is expected to have a predictable relationship on market prices and quantities. Generally, the estimated price increases and quantity reductions for engines and equipment are expected to vary depending on the magnitude of compliance costs relative to total engine or equipment costs. In general, higher (lower) price increases are expected as a result of a high (low) relative level of compliance costs to market price. The change in price is also expected to be highest when compliance costs are highest.

Fuel Compliance Costs. The NDEIM uses the fuel compliance costs described in Chapter 7. Fuel-related compliance costs (costs for refining and distributing regulated fuels) also change over time. These changes are more subtle than the engine costs, however, as the fuel provisions are largely implemented in discrete steps instead of phasing in over time. Compliance costs were developed on a ¢/gallon basis; total compliance costs are determined by multiplying the ¢/gallon costs by the relevant fuel volumes. Therefore, total fuel costs increase as the demand for fuel increases. The variable operating costs are based on the natural gas cost of producing hydrogen and for heating diesel fuel for the new desulfurization equipment, and thus would fluctuate along with the price of natural gas.

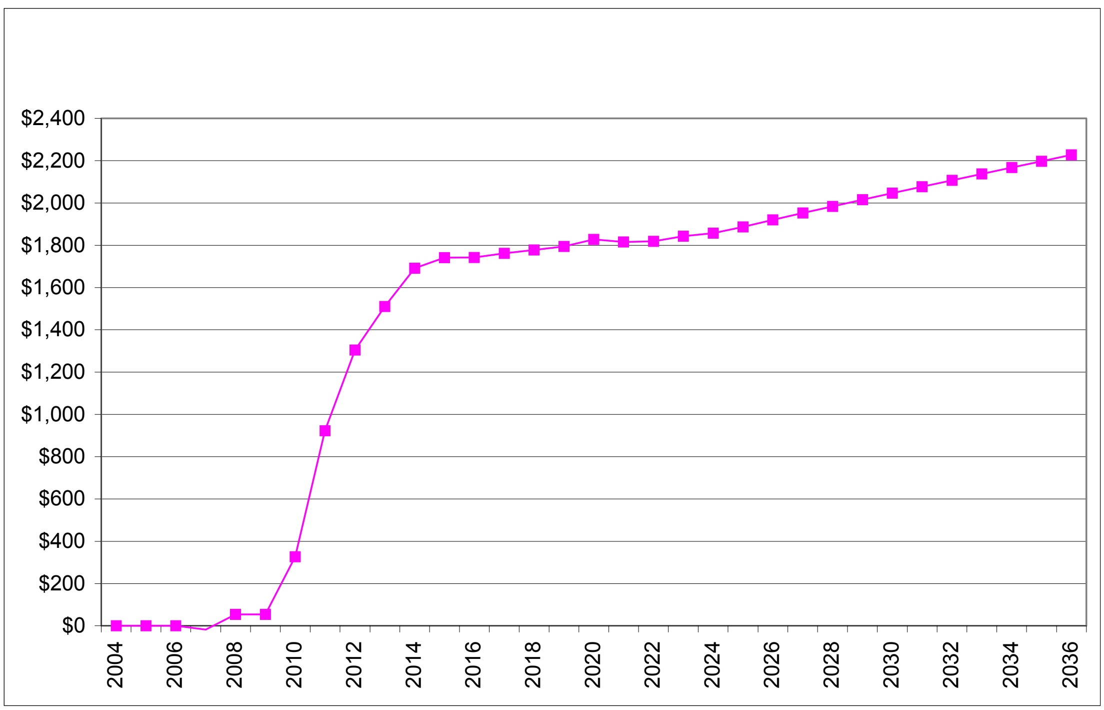
10.1.3.6 Other NDEIM Features

Substitution. In modeling the market impacts and social costs of this rule, the NDEIM considers only diesel equipment and fuel inputs to the production of goods in the applications markets. It does not explicitly model alternate production inputs that would serve as substitutes for new nonroad equipment or nonroad diesel fuel. In the model, market changes in the final demand for application market goods and services directly correspond to changes in the demand for nonroad equipment and fuel (i.e., in normalized terms there is a one-to-one correspondence between the quantity of the final goods produced and the quantity of nonroad diesel equipment and fuel used as inputs to that production). We believe modeling the market in this manner is economically sound and reflects the general experience for the nonroad market. Section 10.2.3.4 describes several alternative means of production that could serve as substitutes for new nonroad equipment and fuel and explains why they are not included in the NDEIM.

Operating Savings. Operating savings refers to changes in operating costs that are expected to be realized by users of both existing and new nonroad diesel equipment as a result of the reduced sulfur content of nonroad diesel fuel. These include operating savings (cost reductions) due to fewer oil changes, which accrue to nonroad, marine and locomotive engines that are already in use as well as new nonroad engines that will comply with the standards (see Section 6.2.3). These also include any extra operating costs associated with the new PM emission control technology which may accrue to certain new engines that use this technology. Operating savings are not included in the market analysis because some of the savings accrue to existing engines and because, as explained in Chapter 6, these savings are not expected to affect consumer decisions with respect to new engines. Operating savings are included in the social cost analysis, however, because they accrue to society. They are added into the estimated social costs as an additional savings to the application and transportation service markets, since it is the users of these engines and fuels who will see these savings. A sensitivity analysis was performed as part of this EIA that includes the operating savings in the market analysis. The results of this sensitivity analysis are presented in Appendix 10.I.

Fuel Marker Costs. Fuel marker costs refers to costs associated with marking high sulfur heating oil to distinguish it from high sulfur diesel fuel produced after 2007 through the use of early sulfur credits or small refiner provisions. Only heating oil sold outside of the Northeast is affected. The higher sulfur NRLM fuel is not allowed to be sold in most of the Northeast, so the marker need not be added in this large heating oil market. These costs are expected to be about \$810,000 in 2007, increasing to \$1.38 million in 2008, but steadily decreasing thereafter to about \$940,000 in 2040 (see Chapter 10 of the RIA). Because these costs are relatively small, they are incorporated into the estimated compliance costs for the fuel program (see discussion of fuel costs, above). They are therefore not counted separately in this economic impact analysis. This means that the costs of marking heating fuel are allocated to all users of the fuel affected by this rule (nonroad, locomotive, and marine) instead of uniquely to heating oil users. This is a reasonable approach since it is likely that refiners will pass the marker costs along their complete nonroad diesel product line and not just to heating oil.

Figure 10.1-2
Heating Oil Marker Costs (\$Million, \$2002)



Fuel Spillover. Spillover fuel is highway grade diesel fuel consumed by nonroad equipment, stationary diesel engines, boilers, and furnaces. As described in 7.1, refiners are expected to produce more 15 ppm fuel than is required for the highway diesel market. This excess 15 ppm fuel will be sold into markets that allow fuel with a higher sulfur level (i.e., nonroad for a limited period of time, locomotive, marine diesel and heating oil). This spillover fuel is affected by the diesel highway rule and is not affected by this regulation. Therefore, it is important to differentiate between spillover and nonspillover fuel to ensure that the compliance costs for that fuel pool are not counted twice. In the NDEIM, this is done by incorporating the impact of increased fuel costs associated with the highway rule prior to analysis of the final nonroad rule (see Section 10.3.8).

Compliance Flexibility Provisions. Consistent with the engine and equipment cost discussion in Chapter 6, the EIA does not include any cost savings associated with the equipment transition flexibility program or the nonroad engine ABT program. As a result, the results of this EIA can be viewed as somewhat conservative.

Locomotive and Marine Fuel Costs. The locomotive and marine transportation sectors are affected by this rule through the sulfur limits on the diesel fuel used by these engines. These sectors provide transportation to the three application markets as well as to other markets not considered in the NDEIM (e.g., public utilities, nonmanufacturing service industries, government). As explained in Section 10.3.1.5, the NDEIM applies only a portion of the locomotive and marine fuel costs to the three application markets. The rest of the locomotive and marine fuel costs are added as a separate item to the total social cost estimates (as Application Markets Not Included in NDEIM).

10.1.4 Summary of Economic Analysis

Economic impact results for 2013, 2020, 2030, and 2036 are presented in this section. The first of these years, 2013, corresponds to the first year in which the standards affect all engines, equipment, and fuels. It should be noted that, as illustrated in Table 10.1-3, aggregate program costs peak in 2014; increases in costs after that year are due to increases in the population of engines over time. The other years, 2020, 2030 and 2036, correspond to years analyzed in our benefits analysis. Detailed results for all years are included in the appendices for this chapter.

In the following discussion, social costs are computed as the sum of market surplus offset by operating savings. Market surplus is equal to the aggregate change in consumer and producer surplus based on the estimated market impacts associated with the rule. As explained above, operating savings are not included in the market analysis but instead are listed as a separate category in the social cost results tables.

In considering the results of this analysis, it should be noted that the estimated output quantities for diesel engines, equipment, and fuel are not identical to those estimated in the engineering cost discussions in Chapters 6 and 7. The difference is due to the different methodologies used to estimate these costs. As noted above, social costs are the value of goods and services lost by society resulting from a) the use of resources to comply with and implement a regulation (i.e., compliance costs) and b) reductions in output. Thus, the social cost analysis considers both price and output (quantity) effects associated with consumer and producer reaction to increased prices associated with the regulatory compliance costs. The engineering cost analysis, on the other hand, is based on applying additional technology to comply with the new regulations. The engine population in the engineering cost analysis does not adjust to reflect consumer and producer reactions to the compliance costs. Consequently, the estimated output quantities from the cost analysis are slightly larger than the estimated output quantities from the social cost analysis.

10.1.4.1 What are the Rule's Expected Market Impacts?

The estimated market impacts for 2015, 2020, 2030, and 2036 are presented in Table 10.1-2. The market-level impacts presented in this table represent production-weighted averages of the individual market-level impact estimates generated by the model: the average expected price increase and quantity decrease across all of the units in each of the engine, equipment, fuel, and final application markets. For example, the model includes seven individual engine markets that reflect the seven different horsepower size categories. The 21.4 percent price change for engines shown in Table 10.1-2 for 2013 is an average price change across all engine markets weighted by the number of production units. Similarly, the equipment impacts presented in Table 10.1-2 are the weighted averages of 42 equipment-application markets, such as small (< 25hp) agricultural equipment and large (>600hp) industrial equipment. Note that price increases and quantity decreases for specific types of engines, equipment, application sectors, or diesel fuel markets are likely to be different. The aggregated data presented in this table provide a broad overview of the expected market impacts that is useful when considering the impacts of the rule on the economy as a whole. Individual market-level impacts are presented in Appendix 10A through Appendix 10D.[B]

The market impacts of this rule suggest that the overall economic impact on society is expected be small, on average. With regard to the market analysis, the average price of goods and services produced using affected equipment and fuel is expected to increase by less than 0.1 percent despite the high level of cost pass-through to those markets.

Engine Market Results: This analysis suggests that most of the variable costs associated with the rule will be passed along in the form of higher prices. The average price increase in 2013 for engines is estimated to be about 21.4 percent. This percentage is expected to decrease to about 18.3 percent by 2020. In 2036, the last year considered, the average price increase is expected to be about 18.2 percent. This expected price increase varies by engine size because compliance costs are a larger share of total production costs for smaller engines. In 2013, the largest expected percent price increase is for engines between 25 and 50 hp: 29 percent or $850; the average price for an engine in this category is about $2,900. However, this price increase is expected to drop to 22 percent, or about $645, for 2015 and later. The smallest expected percent

[B]The NDEIM distinguishes between "merchant" engines and "captive" engines. "Merchant" engines are produced for sale to another company and are sold on the open market to anyone who wants to buy them. "Captive" engines are produced by a manufacturer for use in its own nonroad equipment line (this equipment is said to be produced by "integrated" manufacturers). The market analysis for engines includes compliance costs for merchant engines only. The market analysis for equipment includes equipment compliance costs plus a portion of the engine compliance costs attributable to captive engines.

price increase in 2013 is for engines in the greater than 600 hp category. These engines are expected to see price increases of about 3 percent increase in 2013, increasing to about 7.6 percent in 2015 and then decreasing to about 6.6 percent in 2017 beyond. The expected price increase for these engines is about $2,240 in 2013, increasing to about $6,150 in 2015 and then decreasing to $5,340 in 2017 and later, for engines that cost on average about $80,500.

The market impact analysis predicts that even with these increased in engine prices, total demand is not expected to change very much. The expected average change in quantity is less than 150 engines per year, out of total sales of more than 500,000 engines. The estimated change in market quantity is small because as compliance costs are passed along the supply chain they become a smaller share of total production costs. In other words, firms that use these engines and equipment will continue to purchase them even at the higher cost because the increase in costs will not have a large impact on their total production costs (diesel equipment is only one factor of production for their output of construction, agricultural, or manufactured goods).

Equipment Market Results: Estimated price changes for the equipment markets reflect both the direct costs of the new standards on equipment production and the indirect cost through increased engine prices. In general, the estimated percentage price changes for the equipment are less than that for engines because the engine is only one input in the production of equipment. In 2013, the average price increase for nonroad diesel equipment is estimated to be about 2.9 percent. This percentage is expected to decrease to about 2.5 percent for 2020 and beyond. The range of estimated price increases across equipment types parallels the share of engine costs relative to total equipment price, so the estimated percentage price increase among equipment types also varies. For example, the market price in 2013 for agricultural equipment between 175 and 600 hp is estimated to increase about 1.2 percent, or $1,740 for equipment with an average cost of $143,700. This compares with an estimated engine price increase of about $1,700 for engines of that size. The largest expected price increase in 2013 for equipment is $2,290, or 2.6 percent, for pumps and compressors over 600 hp. This compares with an estimated engine price increase of about $2,240 for engines of that size. The smallest expected price increase in 2013 for equipment is $120, or 0.7 percent, for construction equipment less than 25 hp. This compares with an estimated engine price increase of about $120 for engines of that size.

Again, the market analysis predicts that even with these increased equipment prices total demand is not expected to change very much. The expected average change in quantity is less than 250 pieces of equipment per year, out of a total sales of more than 500,000 units. The average decrease in the quantity of nonroad diesel equipment produced as a result of the regulation is estimated to be about 0.02 percent for all years. The largest expected decrease in quantity in 2013 is 18 units of construction equipment per year for construction equipment between 100 and 175 hp, out of about 63,000 units. The smallest expected decrease in quantity in 2013 is less than one unit per year in all hp categories of pumps and compressors.

It should be noted that the absolute change in the number of engines and equipment does not match. This is because the absolute change in the quantity of engines represents only engines sold on the market. Reductions in engines consumed internally by integrated engine/equipment manufacturers are not reflected in this number but are captured in the cost analysis.

Table 10.1-2
Summary of Market Impacts ($2002)

Market	Engineering Cost	Change in Price		Change in Quantity	
	Per Unit	Absolute ($million)	Percent	Absolute	Percent
2013					
Engines	$1,052	$821	21.4	–79[a]	–0.014
Equipment	$1,198	$975	2.9	–139	–0.017
Loco/Marine Transp[b]			0.009		–0.007
Application Markets[b]			0.097		–0.015
No. 2 Distillate Nonroad	$0.06	$0.07	6.0	–2.75[c]	–0.019
2020					
Engines	$950	$761	18.3	–98[a]	–0.016
Equipment	$1,107	$976	2.5	–172	–0.018
Loco/Marine Transp[b]			0.01		–0.008
Application Markets[b]			0.105		–0.017
No. 2 Distillate Nonroad	$0.07	$0.07	7.0	–3.00[c]	–0.021
2030					
Engines	$937	$751	18.2	–114[a]	–0.016
Equipment	$968	$963	2.5	–200	–0.018
Loco/Marine Transp[b]			0.010		–0.008
Application Markets[b]			0.102		–0.016
No. 2 Distillate Nonroad	$0.07	$0.07	7.0	–3.53[c]	–0.022
2036					
Engines	$931	$746	18.2	–124[a]	–0.016
Equipment	$962	$956	2.5	–216	–0.018
Loco/Marine Transp[b]			0.010		–0.008
Application Markets[b]			0.101		–0.016
No. 2 Distillate Nonroad	$0.07	$0.07	7.0	–3.85[c]	–0.022

[a] The absolute change in the quantity of engines represents only engines sold on the market. Reductions in engines consumed internally by integrated engine/equipment manufacturers are not reflected in this number but are captured in the cost analysis. For this reason, the absolute change in the number of engines and equipment does not match.
[b] The model uses normalized commodities in the application markets because of the great heterogeneity of products. Thus, only percentage changes are presented.
[c] Units are in million of gallons.

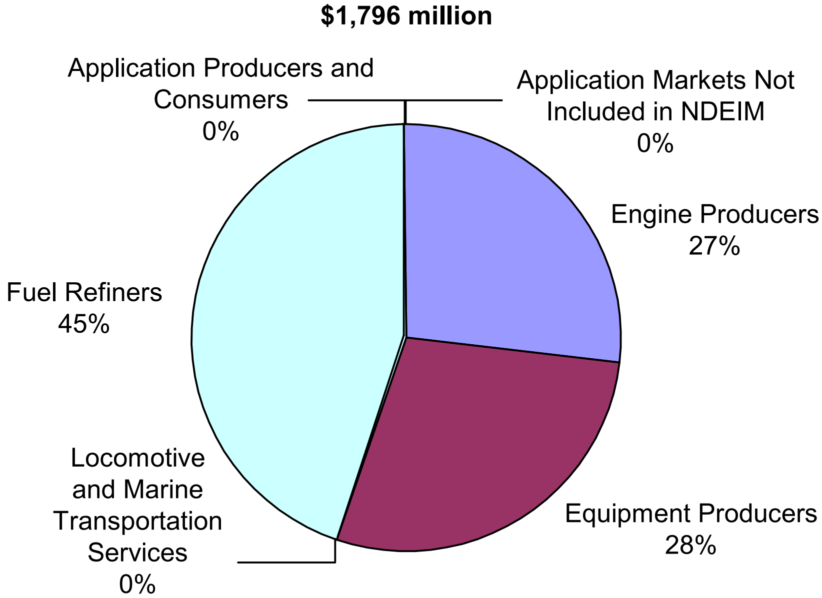
Transportation Market Results: The estimated price increase associated with the proposed standards in the locomotive and marine transportation markets is negligible, at 0.01 percent for all years. This means that these transportation service providers are expected to pass along nearly all of their increased costs to the agriculture, construction, and manufacturing application markets, as well as other application markets not explicitly modeled in the NDEIM. This price increases represent a small share of total application market production costs, and therefore are not expected to affect demand for these services.

Application Market Results: The estimated price increase associated with the new standards in all three application markets is very small and averages about 0.1 percent for all years. In other words, on average, the prices of goods and services produced using the affected engines, equipment, and fuel are expected to increase negligibly. This results from the observation that compliance costs passed on through price increases represent a very small share of total production costs in all the application markets. For example, the construction industry realizes an increase in production costs of approximately $580 million in 2013 because of the price increases for diesel equipment and fuel. However, this represents less than 0.001 percent of the $820 billion value of shipments in the construction industry in 2000. The estimated average commodity price increase in 2013 ranges from 0.08 percent in the manufacturing application market to about 0.5 percent in the construction application market. The percentage change in output is also estimated to be very small and averages less than 0.02 percent for all years. Note that these estimated price increases and quantity decreases are average for these sectors and may vary for specific subsectors. Also, note that absolute changes in price and quantity are not provided for the application markets in Table 10.1-2 because normalized commodity values are used in the market model. Because of the great heterogeneity of manufactured or agriculture products, a normalized commodity ($1 unit) is used in the application markets. This has no impact on the estimated percentage change impacts but makes interpretation of the absolute changes less informative.

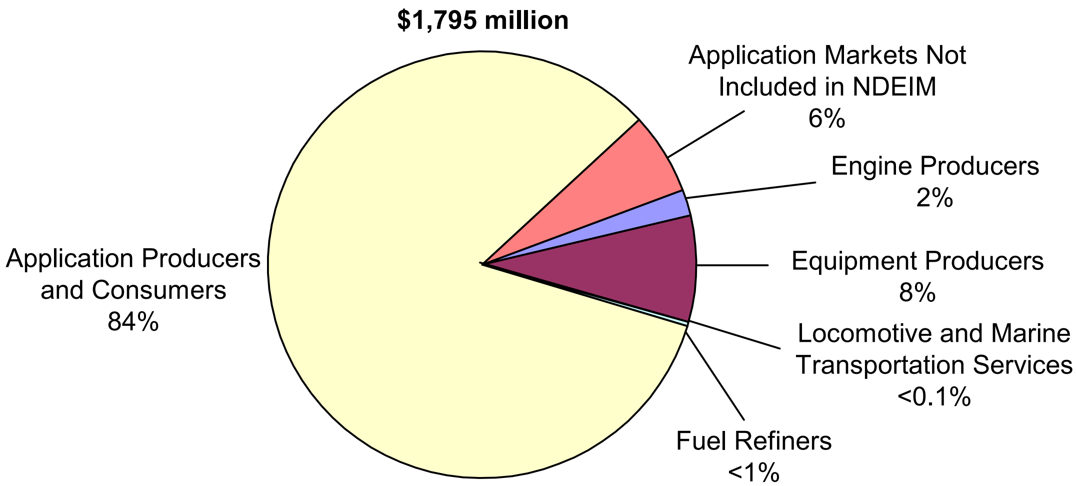
Fuel Markets Results: The estimated average price increase across all nonroad diesel fuel is about 7 percent for all years. For 15 ppm fuel, the estimated price increase for 2013 ranges from 5.6 percent in the East Coast region (PADD 1&3) to 9.1 percent in the mountain region (PADD 4). The average national output decrease for all fuel is estimated to be about 0.02 percent for all years, and is relatively constant across all four regional fuel markets.

10.1.4.2 What are the Rule's Expected Social Costs?

Social costs include the changes in market surplus estimated by the NDEIM and changes in operating costs associated with the regulation. Table 10.1-3 shows the time series of engineering compliance costs and social cost estimates for 2004 through 2036. As shown, these estimates for engineering and social costs are of similar magnitude for each year of the analysis. However, the compliance costs are distributed differently than the social costs. As illustrated in Figure 10.1-3a, engineering compliance costs are distributed evenly across engine, equipment, and fuel producers. However, as illustrated in Figure 10.1-3b, the social costs that result from those compliance costs are borne mostly by producers and consumers in the application markets (about 84 percent when the operating savings are not considered) due to the increased prices for diesel engines, equipment, and fuel. This means that engine, equipment, and fuel producers are expected to be able to pass on most of their compliance costs. Specifically, engine producers are expected to be able to pass on about 91.3 percent their compliance costs through higher prices. The remaining 8.7 percent are primarily fixed R&D costs that are internalized by engine manufacturers and not passed into the market. Equipment manufacturers are expected to retain a slightly higher share of compliance costs (28.5 percent) because they have greater fixed costs. Diesel fuel refiners are expected to pass about 99 percent of their compliance costs on to the application producers and consumers because, as discussed in Chapter 6, refiners pass both fixed and variable costs into the market.



a) Engineering Cost Distribution[a]



b) Social Cost Distribution[a]

Figure 10.1-3. Comparing the Distribution of Engineering Compliance Costs with Social Cost Estimates by Industry (2013)

[a] Costs do not include operating cost savings, which represent negative $285 million in costs (i.e., benefits).

Table 10.1-3
National Engineering Compliance Costs and
Social Costs Estimates for the Rule (2004 - 2036)($2002; $Million)

Year	Engineering Compliance Costs	Total Social Costs
2004	$0	$0
2005	$0	$0
2006	$0	$0
2007	($17)	($18)
2008	$54	$54
2009	$54	$54
2010	$328	$327
2011	$923	$922
2012	$1,305	$1,304
2013	$1,511	$1,510
2014	$1,691	$1,690
2015	$1,742	$1,741
2016	$1,743	$1,743
2017	$1,763	$1,762
2018	$1,778	$1,778
2019	$1,795	$1,795
2020	$1,829	$1,828
2021	$1,816	$1,815
2022	$1,819	$1,818
2023	$1,844	$1,843
2024	$1,858	$1,857
2025	$1,888	$1,887
2026	$1,921	$1,920
2027	$1,954	$1,952
2028	$1,985	$1,984
2029	$2,017	$2,016
2030	$2,047	$2,046
2031	$2,078	$2,077
2032	$2,108	$2,107
2033	$2,139	$2,137
2034	$2,169	$2,167
2035	$2,198	$2,197
2036	$2,228	$2,227
NPV at 3%	$27,247	$27,232
NPV at 7%	$13,876	$13,868

Figure 10.1-4 shows the time series of total social costs from 2004 through 2036. Social costs increase rapidly between 2007 and 2014 as engine, equipment and fuel costs are phased into the regulation. Estimated net annual social costs (including operating savings) in 2014 are about $1,690 million. After 2014, per unit compliance costs decrease as fixed costs are depreciated. However, due to growth in engine and equipment sales and related fuel consumption, net social costs are expected continue to increase, but at a slower rate, from 2015 to 2036. The estimated net present value of social costs over the time period 2004 through 2036 based on a social discount rate of 3 percent is reported in Table 10.1-3 and is about $27.2 billion. The present value over this same period based on a social discount rate of 7 percent is about $13.9 billion. As shown in Table 10.1-3, these results suggest that total engineering costs exceed compliance costs by a small amount. This is due primarily to the fact that the estimated output quantities for diesel engines, equipment, and fuel are not identical to those estimated in the engineering cost analysis, which is due to the different methodologies used to estimate these costs (see previous discussion in this Section 10.1.4).

Estimated social costs are disaggregated by market in Table 10.1-4, for 2015, 2020, 2030, and 2036. A more detailed time series from 2007 to 2030 provided is in Appendix 10E. The data in Table 10.1-4 shows that in 2013, social costs are expected to be about $1,510 million ($2002). About 83 percent of the total social costs is expected to be borne by producers and consumers in the application markets in 2013, indicating that the majority of the compliance costs associated with the rule are expected to be passed on in the form of higher prices. When these estimated impacts are broken down, about 58.5 percent of the social costs are expected to be borne by consumers in the application markets and about 41.5 percent are expected to be borne by producers in the application markets. Equipment manufacturers are expected to bear about 9.5 percent of the total social costs. Engine manufacturers and diesel fuel refineries are expected to bear 2.8 percent and 0.5 percent, respectively. The remaining 4.2 percent of the social costs is expected to be borne by the locomotive and marine transportation service sector. In this last sector, about 97 percent of the gross decrease in market surplus is expected to be borne by the application markets that are not included in the NDEIM but that use these services (e.g., public utilities, nonmanufacturing service industries, government) while about 3 percent is expected to be borne by locomotive and marine service providers. Because of the way the NDEIM is structured, with the fuel savings added separately, the results imply that locomotive and marine service provides would see net benefits from the rule due to the operating savings associated with low sulfur fuel. In fact, they are likely to pass along some or all of those operating savings to the users of their services, reducing the size of the welfare losses for those users.

Total social costs continue to increase over time and are projected to be about $2,046 million by 2030 and $2,227 million in 2036 ($2002). The increase is due to the projected annual growth in the engine and equipment populations. Producers and consumers in the application markets are expected to bear an even larger portion of the costs, approximately 96 percent. This is consistent with economic theory, which states that, in the long run, all costs are passed on to the consumers of goods and services.

Table 10.1-4

Summary of Social Costs Estimates Associated with Primary Program
2015, 2020, 2030, and 2036 ($2002, $Million)[a,b]

	Market Surplus ($10^6)	Operating Savings ($10^6)	Total	Percent
2013				
Engine Producers Total	**$42.0**		**$42.0**	**2.8%**
Equipment Producers Total	**$143.1**		**$143.1**	**9.5%**
Construction Equipment	$64.0		$64.0	
Agricultural Equipment	$51.8		$51.8	
Industrial Equipment	$27.2		$27.2	
Application Producers & Consumers Total	**$1,496.7**	**($243.2)**	**$1,253.5**	**83.0%**
Total Producer	*$620.9*			*41.5%*
Total Consumer	*$875.7*			*58.5%*
Construction	$584.3	($115.2)	$469.2	
Agriculture	$430.0	($78.2)	$351.8	
Manufacturing	$482.4	($49.8)	$432.5	
Fuel Producers Total	**$8.0**		**$8.0**	**0.5%**
PADD I&III	$4.1		$4.1	
PADD II	$3.3		$3.3	
PADD IV	$0.0		$0.0	
PADD V	$0.6		$6.0	
Transportation Services, Total	**$104.9**	**($41.5)**	**$63.4**	**4.2%**
Locomotive	$1.6	($12.4)	($10.8)	
Marine	$0.9	($9.9)	($9.0)	
Application markets not included in NDEIM	$102.4	($19.2)	$83.2	
Total	**$1,794.7**	**($284.7)**	**$1,510.0**	**100.0%**
2020				
	Market Surplus ($10^6)	Operating Savings ($10^6)	Total	Percent
Engine Producers Total	**$0.1**		**$0.1**	**0.0%**
Equipment Producers Total	**$122.7**		**$122.7**	**6.7%**
Construction Equipment	$57.8		$57.8	
Agricultural Equipment	$39.7		$39.7	
Industrial Equipment	$25.2		$25.2	
Application Producers & Consumers Total	**$1,826.1**	**($192.3)**	**$1,633.8**	**89.4%**
Total Producer	*$762.2*			*41.7%*
Total Consumer	*$1,063.8*			*58.3%*
Construction	$744.0	($91.1)	$653.0	
Agriculture	$524.3	($61.8)	$462.5	
Manufacturing	$557.8	($39.4)	$518.3	
Fuel Producers Total	**$11.2**		**$11.2**	**0.6%**
PADD I&III	$5.6		$5.6	
PADD II	$4.6		$4.6	

PADD IV	$0.2		$0.2	
PADD V	$0.8		$0.8	
Transportation Services, Total	**$95.7**	**($35.1)**	**$60.6**	**3.3%**
Locomotive	$2.0	($7.2)	($5.2)	
Marine	$1.1	($11.6)	($10.5)	
Application markets not included in NDEIM	$92.6	($16.3)	$76.3	
Total	**$2,055.7**	**($227.4)**	**$1,828.3**	**100.0%**
2030				
Engine Producers Total	**$0.1**		**$0.1**	**0.0%**
Equipment Producers Total	**$5.9**		**$5.9**	**0.3%**
Construction Equipment	$4.0		$4.0	
Agricultural Equipment	$1.9		$1.9	
Industrial Equipment	$0.1		$0.1	
Application Producers & Consumers Total	**$2,112.3**	**($154.2)**	**$1,958.1**	**95.7%**
Total Producer	*$882.2*			*41.7%*
Total Consumer	*$1,230.1*			*58.3%*
Construction	$863.8	($73.0)	$790.8	
Agriculture	$606.8	($49.6)	$557.2	
Manufacturing	$641.6	($31.6)	$610.0	
Fuel Producers Total	**$13.2**		**$13.2**	**0.6%**
PADD I&III	$6.7		$6.7	
PADD II	$5.2		$5.2	
PADD IV	$0.3		$0.3	
PADD V	$1.0		$1.0	
Transportation Services, Total	**$109.1**	**($39.9)**	**$69.2**	**3.4%**
Locomotive	$2.5	($7.8)	($5.3)	
Marine	$1.4	($13.6)	($12.2)	
Application markets not included in NDEIM	$105.2	($18.5)	$86.7	
Total	**$2,240.6**	**($194.1)**	**$2,046.4**	**100.0%**
2036				
	Market Surplus ($\$10^6$)	Operating Savings ($\$10^6$)	Total	Percent
Engine Producers Total	**$0.2**		**$0.2**	**0.0%**
Equipment Producers Total	**$6.4**		**$6.4**	**0.3%**
Construction Equipment	$4.3		$4.3	
Agricultural Equipment	$2.0		$2.0	
Industrial Equipment	$0.1		$0.1	
Application Producers & Consumers Total	**$2,287.4**	**($155.7)**	**$2,131.7**	**95.7%**
Total Producer	*$955.5*			*41.7%*

Total Consumer	*$1,331.9*			*58.3%*
Construction	$936.4	($50.0)	$862.7	
Agriculture	$657.8	($73.7)	$607.8	
Manufacturing	$693.2	($31.9)	$661.3	
Fuel Producers Total	**$14.5**		**$14.5**	**0.7%**
PADD I&III	$7.3		$7.3	
PADD II	$5.8		$5.8	
PADD IV	$0.3		$0.3	
PADD V	$1.0		$1.0	
Transportation Services, Total	**$116.9**	**($42.6)**	**$74.3**	**3.3%**
Locomotive	$2.8	($8.2)	($5.4)	
Marine	$1.6	($14.6)	($13.0)	
Application markets not included in NDEIM	$112.5	($19.8)	$92.7	
Total	**$2,425.3**	**($198.4)**	**$2,227.0**	**100.0%**

[a] Figures are in 2002 dollars.

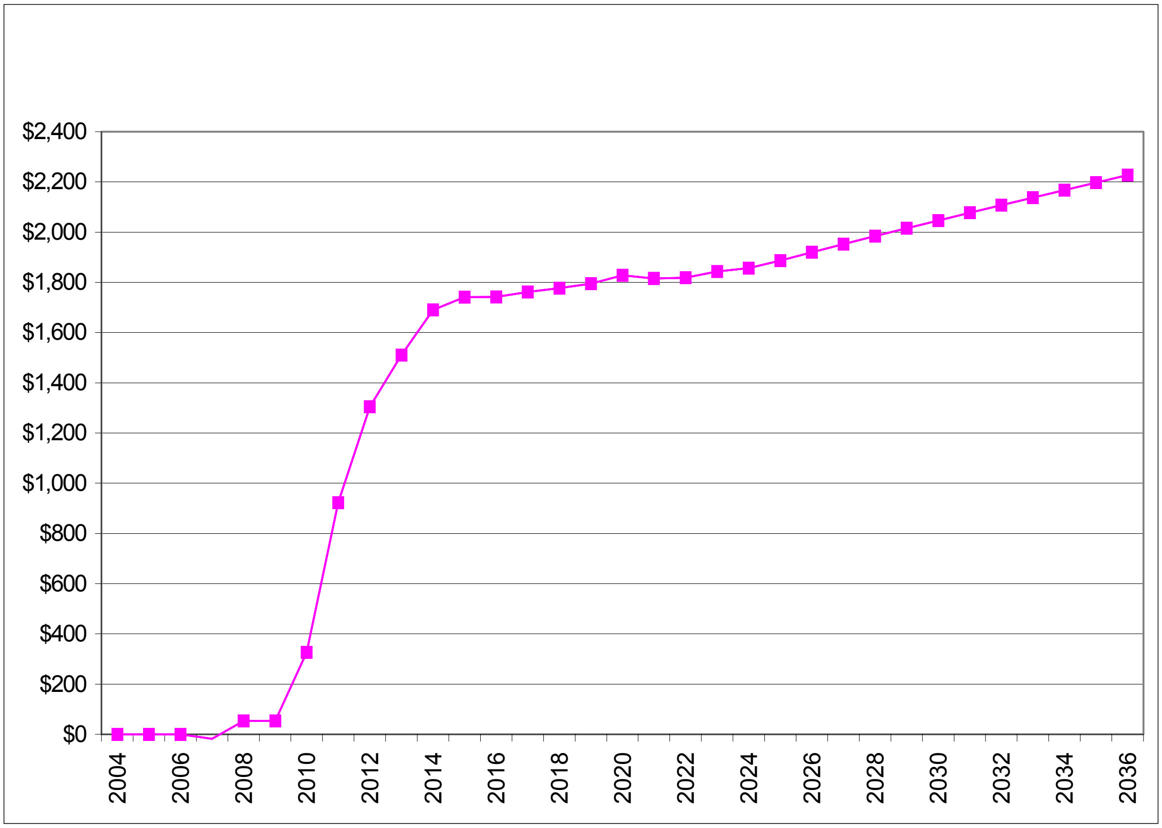
[b] Operating savings are shown as negative costs.

Table 10.1-5
Summary of Social Costs Estimates Associated with Primary Program:
NPV, 3%, 2004-2036 ($million)[a,b]

	Market Surplus ($$10^6$)	Operating Savings ($$10^6$)	Total	Percent
Engine Producers Total	**$256.0**		**$256.0**	**0.9%**
Equipment Producers Total	**$1,162.0**		**$1,162.0**	**4.3%**
Construction Equipment	$545.0		$545.0	
Agricultural Equipment	$397.0		$397.0	
Industrial Equipment	$220.0		$220.0	
Application Producers & Consumers Total	**$28,429.0**	**($3,757.0)**	**$24,672.0**	**90.6%**
Total Producer	*$11,838.0*			*41.6%*
Total Consumer	*$16,591.0*			*58.4%*
Construction	$11,526.0	($1,779.0)	$9,746.0	
Agriculture	$8,181.0	($1,208.0)	$6,973.0	
Manufacturing	**$8,723.0**	**($770.0)**	**$7,953.0**	
Fuel Producers Total	**$169.0**		**$169.0**	**0.6%**
PADD I&III	$85.0		$85.0	
PADD II	$69.0		$69.0	
PADD IV	$3.0		$3.0	
PADD V	$12.0		$12.0	
Transportation Services Total	**$1,653.0**	**($679.0)**	**$973.0**	**3.6%**
Locomotive	$31.0	($160.0)	($129.0)	
Marine	$18.0	($204.0)	($187.0)	
Application markets not included in NDEIM	$1,604.0	($315.0)	$1,228.0	
Total	**$31,669.0**	**($4,437.0)**	**$27,232.0**	**100.0%**

[a] Figures are in 2002 dollars.
[b] Operating savings are shown as negative costs.

Figure 10.1-4
Total Social Costs (2004-2036; $2002; $Million)



10.2 Economic Methodology

Economic impact analysis uses a combination of theory and econometric modeling to evaluate potential behavior changes associated with a new regulatory program. As noted above, the goal is to estimate the impact of the regulatory program on producers and consumers. This is done by creating a mathematical model based on economic theory and populating the model using publically available price and quantity data. A key factor in this type of analysis is estimating the responsiveness of the quantity of engines, equipment, and fuels demanded by consumers or supplied by producers to a change in the price of that product. This relationship is called the elasticity of demand or supply. This section discusses the economic theory underlying the modeling for this EIA and several key issues that affect the way the model was developed.

10.2.1 Behavioral Economic Models

Models incorporating different levels of economic decision making can generally be categorized as *with*-behavior responses or *without*-behavior responses (engineering cost analysis). Engineering cost analysis is an example of the latter and provides detailed estimates of the cost of a regulation based on the projected number of affected units and engineering estimates of the annualized costs.

The behavioral approach builds on the engineering cost analysis and incorporates economic theory related to producer and consumer behavior to estimate changes in market conditions. Owners of affected plants are economic agents that can make adjustments, such as changing production rates or altering input mixes, that will generally affect the market environment in which they operate. As producers change their production levels in response to a regulation, consumers are typically faced with changes in prices that cause them to alter the quantity that they are willing to purchase. These changes in price and output from the market-level impacts are used to estimate the distribution of social costs between consumers and producers.

Generally, the behavioral approach and engineering cost approach yield approximately the same total cost impact. However, the advantage of the behavioral approach is that it illustrates how the costs flow through the economic system and identifies which stakeholders, producers, and consumers are most affected.

10.2.2 Conceptual Economic Approach

This EIA models basic economic relationships between supply and demand to estimate behavioral changes expected to occur as a result of the rule. An overview of the basic economic theory used to develop the model to estimate the potential effect of the rule on market outcomes is presented in this section. Following the *OAQPS Economic Analysis Resource Document* (EPA, 1999), standard concepts in microeconomics are used to model the supply of affected products and the impacts of the regulations on production costs and the operating decisions.

10.2.2.1 Types of Models: Partial vs. General Equilibrium Modeling Approaches

In the broadest sense, all markets are directly or indirectly linked in the economy; thus, the rule will affect all commodities and markets to some extent. The appropriate level of market interactions to be included in an EIA is determined by the number of industries directly affected by the requirements and the ability of affected firms to pass along the regulatory costs in the form of higher prices. Alternative approaches for modeling interactions between economic sectors can generally be divided into three groups:

- *Partial equilibrium model*—Individual markets are modeled in isolation. The only factor affecting the market is the cost of the regulation on facilities in the industry being modeled; there are no interaction effects with other markets.
- *General equilibrium model*—All sectors of the economy are modeled together, incorporating interaction effects between all sectors included in the model. General

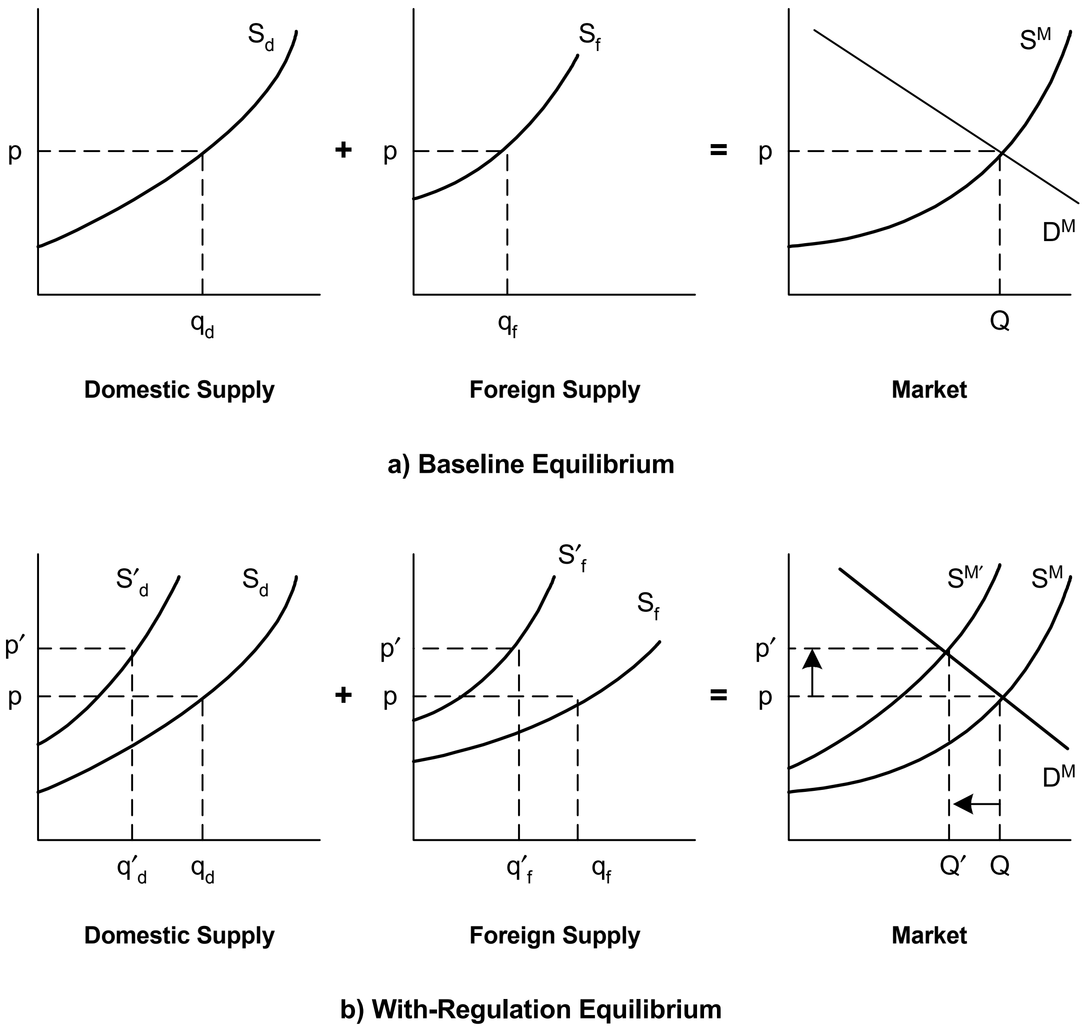
equilibrium models operationalize neoclassical microeconomic theory by modeling not only the direct effects of control costs but also potential input substitution effects, changes in production levels associated with changes in market prices across all sectors, and the associated changes in welfare economy-wide. A disadvantage of general equilibrium modeling is that substantial time and resources are required to develop a new model or tailor an existing model for analyzing regulatory alternatives.

- *Multimarket model*—A subset of related markets is modeled together, with sector linkages, and hence selected interaction effects, explicitly specified. This approach represents an intermediate step between a simple, single-market partial equilibrium approach and a full general equilibrium approach. This technique has most recently been referred to in the literature as "partial equilibrium analysis of multiple markets" (Berck and Hoffmann, 2002).

This analysis uses a behavioral multimarket framework because the benefits of increasing the dimensions of the model outweigh the cost associated with additional model detail. As Bingham and Fox (1999) note, this increased scope provides "a richer story" of the expected distribution of economic welfare changes across producers and consumers. Therefore, the NDEIM developed for this analysis consists of a spreadsheet model that links a series of standard partial equilibrium models by specifying the interactions between the supply and demand for products. Changes in prices and quantities are then solved across all markets *simultaneously*. The following markets were included in the model; their linkages are illustrated in Figure 10.2-1 and they are described in detail in Section 10.3.3 below:

- seven diesel engine markets categorized by engine size;
- 42 equipment markets, including construction, agriculture, refrigeration, lawn and garden, pumps and compressors, generators and welder sets, and general industrial equipment types—with five to seven horsepower size categories for each equipment type;
- eight fuel markets, four regions (PADDs) each with two nonroad diesel fuel markets (500 ppm and 15 ppm); and
- three application markets (construction, agriculture, and manufacturing).

Figure 10.2-1
Market Equilibrium without and with Regulation



10.2.2.2 Market Equilibrium in a Single Commodity Market

A graphical representation of a general economic competitive model of price formation, as shown in Figure 10.2-1(a), posits that market prices and quantities are determined by the intersection of the market supply and market demand curves. Under the baseline scenario, a market price and quantity (p,Q) are determined by the intersection of the downward-sloping market demand curve (D^M) and the upward-sloping market supply curve (S^M). The market supply curve reflects the sum of the domestic (S_d) and import (S_f) supply curves.

With the regulation, the costs of production increase for suppliers. The imposition of these regulatory control costs is represented as an upward shift in the supply curve for domestic and import supply, by the estimated compliance costs. As a result of the upward shift in the supply curve, the market supply curve will also shift upward as shown in Figure 10.2-1(b) to reflect the increased costs of production.

At baseline without regulation, the industry produces total output, Q, at price, p, with domestic producers supplying the amount q_d and imports accounting for Q minus q_d, or q_f. With the regulation, the market price increases from p to p′, and market output (as determined from the market demand curve) declines from Q to Q′. This reduction in market output is the net result of reductions in domestic and import supply.

10.2.2.3 Incorporating Multimarket Interactions

The above description is typical of the expected market effects for a single product market (e.g., diesel engine manufacturers) considered in isolation. However, the modeling problem for this EIA is more complicated because of the need to investigate affected equipment manufacturers and fuel producers as well as engine manufacturers.

For example, the Tier 4 standards will affect equipment producers in two ways. First, these producers are affected by higher input costs (increases in the price of diesel engines) associated with the rule. Second, the standards will also impose additional production costs on equipment producers associated with equipment changes necessary to accommodate changes in engine design.

The demand for diesel engines is directly linked to the production of diesel equipment. A single engine is typically used in each piece of equipment, and there are no substitutes (i.e., to make diesel equipment one needs a diesel engine). For this reason, it is reasonable to assume that the input-output relationship between the diesel engines and the equipment is strictly fixed and that the demand for engines varies directly with the demand for equipment.[C]

The demand for diesel equipment is directly linked to the production of final goods and services that use diesel equipment. For example, the demand for agricultural equipment depends on the final demand for agricultural products and the total price of supplying these products. Thus, any change in the price of agricultural equipment will shift the agriculture supply curve, leading to a decrease in agricultural production and hence decreased consumption of agricultural equipment. Assuming a fixed input-output relationship, the percentage change in agricultural production will equal the percentage change in agricultural equipment production.

These relationships link the demand for engines and equipment directly to the level of production of goods and services in the application markets. A demand curve specified in terms of its downstream consumption is referred to as a derived demand curve. Figure 10.2-2 graphically illustrates how a derived demand curve is identified. Consider an event in the

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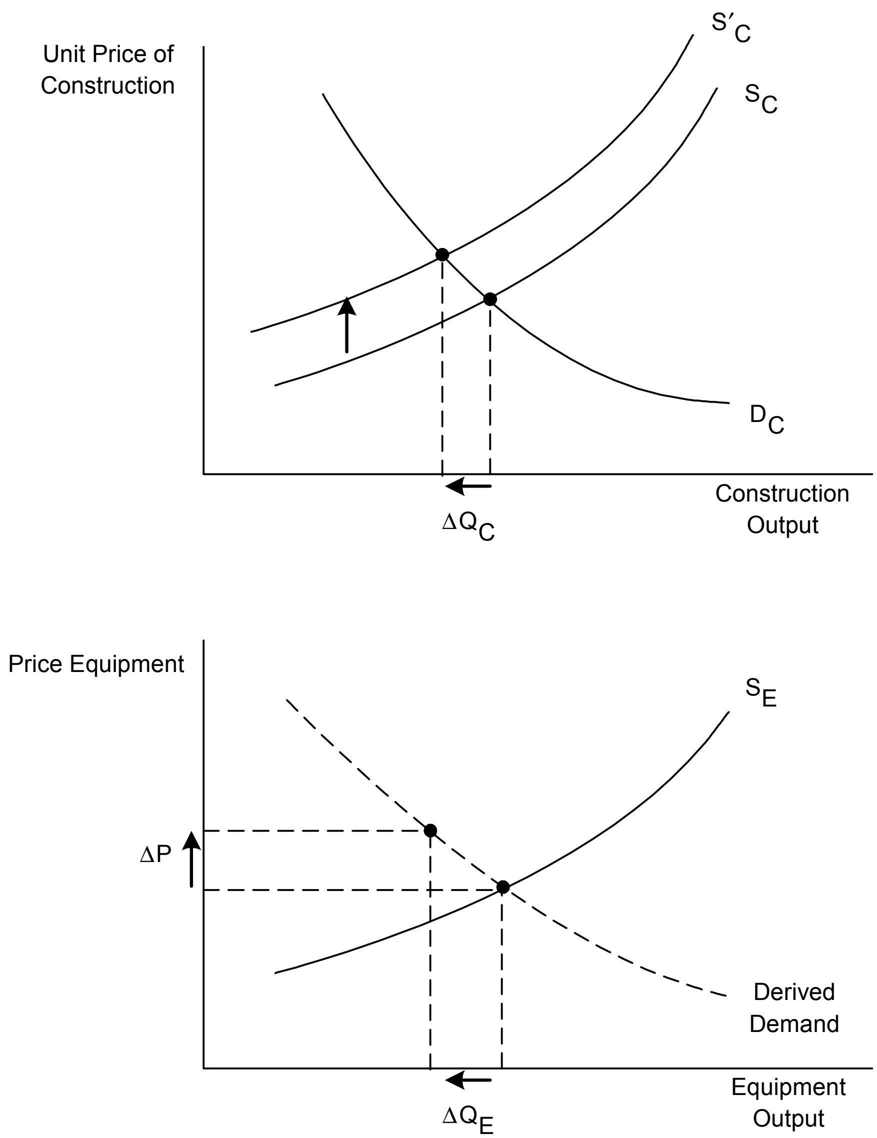
[C]This one-to-one relationship holds for engines sold on the market and for engines consumed internally by integrated engine/equipment manufacturers.

construction equipment market that causes the price of equipment to increase by ΔP (such as an increase in the price of engines). This increase in the price of equipment will cause the supply curve in the construction market to shift up, leading to a decreased quantity of construction activity (ΔQ_C). The change in construction activity leads to a decrease in the demand for construction equipment (ΔQ_E). The new point ($Q_E - \Delta Q_E$, $P - \Delta P$) traces out the derived demand curve. Note that the supply and demand curves in the construction applications market are needed to identify the derived demand in the construction equipment market. The construction application market supply and demand curves are functional form and elasticity parameters described in Appendix10F.

Figure 10.2-2
Derived Demand for Construction Equipment



ΔPrice Equipment $\longrightarrow$ Upward Shift Construction Supply Curve $\longrightarrow$ ΔQ_C $\longrightarrow$ ΔQ_E

Each point on the derived demand curve equals the construction industry's willingness to pay for the corresponding marginal input. This is typically referred to as the input's net value of marginal product (VMP), which is equal to the price of the output (P_x) times the input's marginal physical product (MPP). MPP is the incremental construction output attributable to a change in equipment inputs:

$$\text{Value Marginal Product (VMP)} = P_x * \text{MPP}.$$

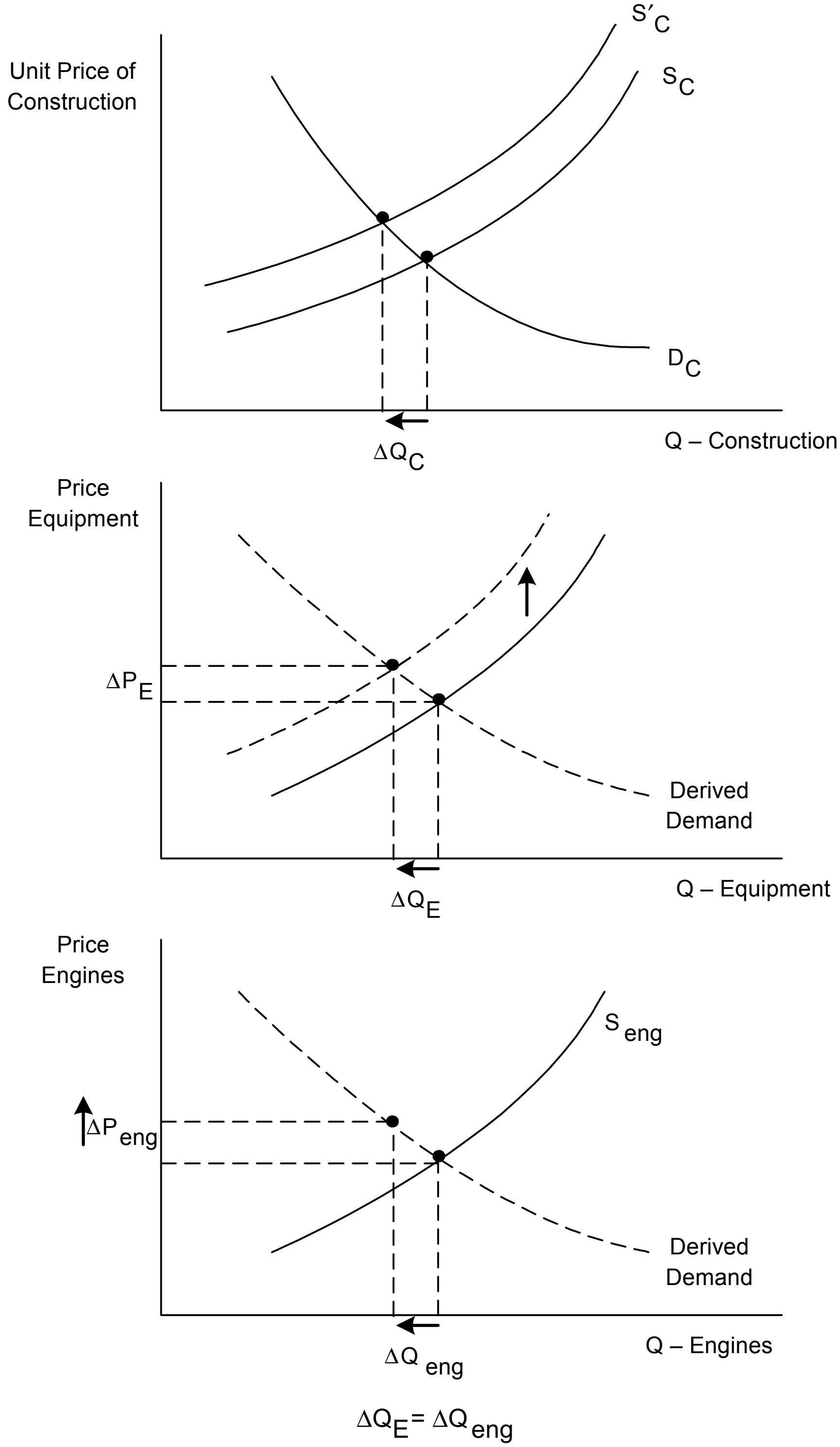
An increase in regulatory costs ©) associated with equipment will lower the VMP of all inputs, leading to a decrease in the net marginal product:

$$\text{Net Value Marginal Product} = (P_x - c) * \text{MPP}.$$

This decrease in the VMP of equipment, as price increases, is what leads the downward-sloping derived demand curve in the equipment market.

Similarly, derived demand curves are developed for the engine markets that supply the equipment markets. As shown in Figure 10.2-3, the increased price of engines resulting from regulatory costs shifts the supply curve for engines and leads to a shift in the supply curve for equipment. The resulting increased price of equipment leads to a shift in the supply curve for the construction industry, decreasing construction output. The decrease in construction output flows back through the equipment market, resulting in decreased demand for engines (ΔQeng).

Figure 10.2-3
Derived Demand for Engines



10.2.3 Key Modeling Elements

In addition to specifying the type of model used and the relationships between the markets, it is also necessary to specify several other key model characteristics. These characteristics include the degree of competition in each market, the time horizon of the analysis, and how fixed costs affect firms' production decisions. The specification of the industry/market characteristics and how regulatory costs are introduced into the model has an impact on the size and interpretation of the estimated economic impacts. These modeling issues are discussed below.

10.2.3.1 Perfect vs. Imperfect Competition

For all markets that are modeled, the analyst must characterize the degree of competition within each market. The discussion generally focuses on perfect competition (price-taking behavior) versus imperfect competition (the lack of price-taking behavior). The central issue is whether individual firms have sufficient market power to influence the market price.

Under imperfect (such as monopolistic) competition, firms produce products that have unique attributes that differentiate them from competitors' products. This allows them to limit supply, which in turn increases the market price, given the traditional downward-sloping demand curve. Decreasing the quantity produced increases the monopolist's profits but decreases total social surplus because a less than optimal amount of the product is being consumed. In the monopolistic equilibrium, the value society (consumers) places on the marginal product, the market price, exceeds the marginal cost to society (producers) of producing the last unit. Thus, social welfare is increased by inducing the monopolist to increase production.

Social cost estimates associated with a regulation are larger with monopolistic market structures because the regulation exacerbates an already existing social inefficiency of too little output from a social perspective. The Office of Management and Budget (OMB) explicitly mentions the need to consider these market power-related welfare costs in evaluating regulations under Executive Order 12866 (OMB, 1996).

However, as discussed in the industry profiles in Chapter 1, most of the diesel engine and equipment markets have significant levels of domestic and international competition. Even in markets where a few firms dominate the market, there is significant excess capacity enabling competitors to quickly respond to changes in price. In addition, there are no indications of barriers to entry, the firms in these markets are not price setters, and there is no evidence of high levels of strategic behavior in the price and quantity decisions of the firms. Also, the products produced within each market are somewhat homogeneous in that engines from one firm can be purchased instead of engines from another firm. Finally, according to contestable market theory, oligopolies and even monopolies will behave very much like firms in a competitive market if it is possible to enter particular markets costlessly (i.e., there are no sunk costs associated with market entry or exit).[D] With regard to the nonroad engine market, production capacity is not fully utilized. This means that manufacturers could potentially switch their product line to compete in another segment of the market without a significant investment. For these reasons, for the nonroad diesel rule analysis, it is assumed that within each modeled engine and equipment market the commodities of interest are similar enough to be considered homogeneous (e.g., perfectly substitutable) and that the number of buyers and sellers is large enough so that no individual buyer or seller has market power or influence on market prices (i.e., perfect competition). As a result of these conditions, producers and consumers take the market price as given when making their production and consumption choices. The assumption of perfect competition in this case is consistent with widely accepted economic practice for this type of analysis (see for example EPA 2000, p. 126).

With regard to the fuel market, the Federal Trade Commission (FTC) has developed an approach to ensure competitiveness in this sector. The FTC reviews oil company mergers and frequently requires divestiture of refineries, terminals, and gas stations to maintain a minimum level of competition. Therefore, it is reasonable to assume a competitive structure for this market. At the same time, however, there are several ways in which refiners may pass along their fuel compliance costs. This analysis explores three approaches. The primary modeling scenario is the average cost scenario, according to which the change in market price is driven by the average total (variable + fixed) regional cost of the regulation. The two other approaches are modeled in a sensitivity analysis and reflect the case in which the highest-cost producer sets the market price in a region. The first of these is the maximum variable cost scenario, according to which the market price is drive by the maximum variable regional cost of the regulation. The second is the maximum total (fixed + variable) regional cost of the regulation. The results of the sensitivity analyses for these two fuel scenarios are contained in Appendix 10I.

10.2.3.2 Short- vs. Long-Run Models

In developing the multimarket partial equilibrium model, the choices available to producers must be considered. For example, are producers able to increase their factors of production (e.g., increase production capacity) or alter their production mix (e.g., substitution between materials, labor, and capital)? These modeling issues are largely dependent on the time horizon for which the analysis is performed. Three benchmark time horizons are discussed below: the very short run, the long run, and the intermediate run. This discussion relies in large part on the material contained in the *OAQPS Economic Analysis Resource Guide* (U.S. EPA, 1999).

[D] A monopoly or firms in oligopoly may not behave as neo-classical economic theories of the firm predict because they may be fearful of new entrants to the market. If super-normal profits are earned potential competitors may enter the market, so it is argued that the existing firm(s) will keep prices and output at a level where only normal profits are made, setting price and output at or close to the competitive price and output. Baumol W J, Panzer J and Willig R D, (1982); Baumol, 1982.

In the very short run, all factors of production are assumed to be fixed, leaving the directly affected entity with no means to respond to increased costs associated with the regulation. Within a very short time horizon, regulated producers are constrained in their ability to adjust inputs or outputs due to contractual, institutional, or other factors and can be represented by a vertical supply curve as shown in Figure 10.2-4. In essence, this is equivalent to the nonbehavioral model described earlier. Neither the price nor quantity change and the manufacturer's compliance costs become fixed or sunk costs. Under this time horizon, the impacts of the regulation fall entirely on the regulated entity. Producers incur the entire regulatory burden as a one-to-one reduction in their profit. This is referred to as the "full-cost absorption" scenario and is equivalent to the engineering cost estimates. While there is no hard and fast rule for determining what length of time constitutes the very short run, it is inappropriate to use this time horizon for this analysis because it assumes economic entities have no flexibility to adjust factors of production.

In the long run, all factors of production are variable, and producers can be expected to adjust production plans in response to cost changes imposed by a regulation. Figure 10.2-5 illustrates a typical, if somewhat simplified, long-run industry supply function. The function is horizontal, indicating that the marginal and average costs of production are constant with respect to output.[E] This horizontal slope reflects the fact that, under long-run constant returns to scale, technology and input prices ultimately determine the market price, not the level of output in the market.

[E]The constancy of marginal costs reflects an underlying assumption of constant returns to scale of production, which may or may not apply in all cases.

Figure 10.2-6
Partial Cost Pass-Through of Regulatory Costs

Figure 10.2-4
Full Cost Absorption of Regulatory Costs

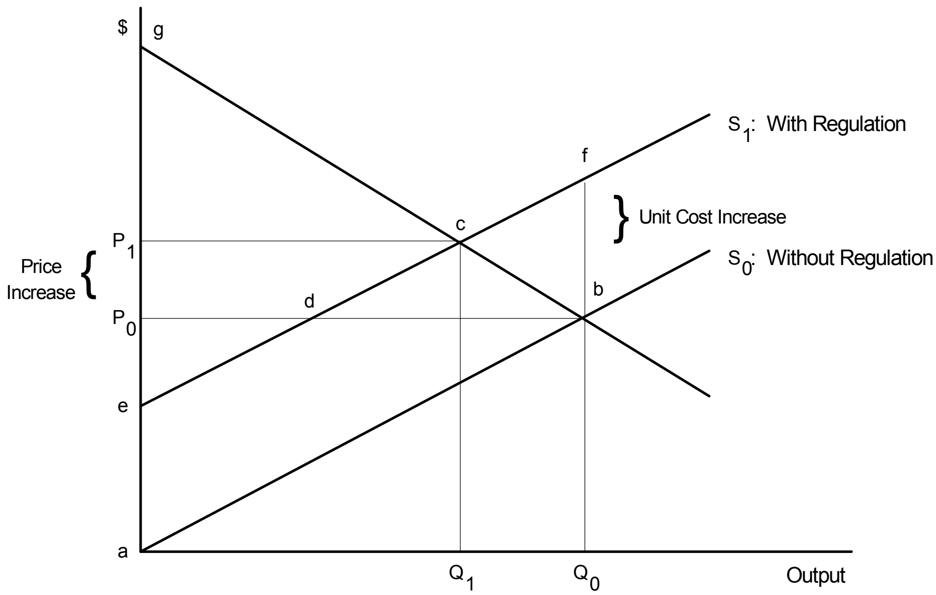
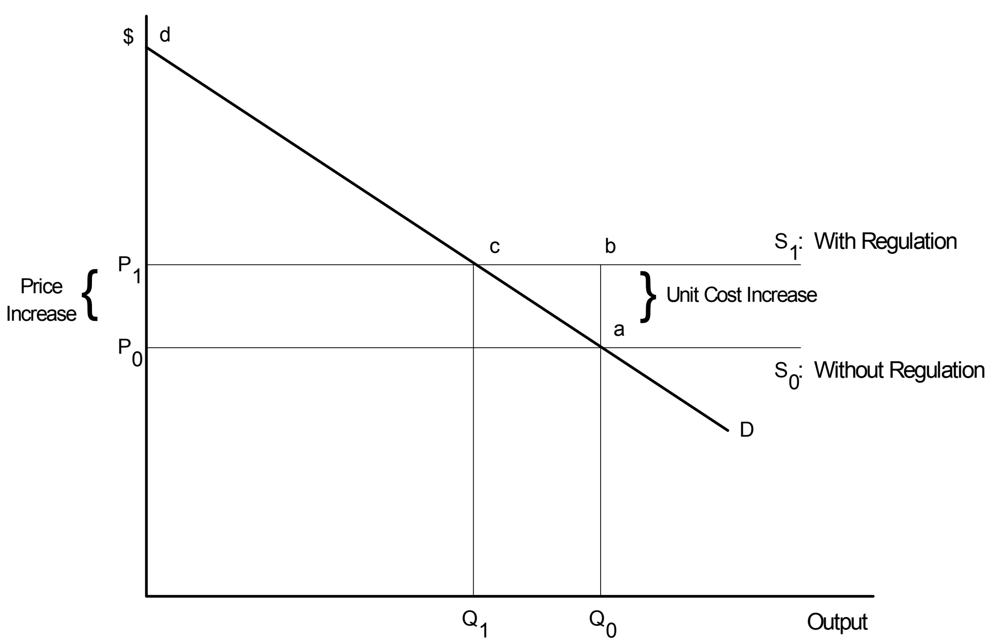


Figure 10.2-5
Full-Cost Pass-Through of Regulatory Costs



Market demand is represented by the standard downward-sloping curve. The market is assumed here to be perfectly competitive; equilibrium is determined by the intersection of the supply and demand curves. In this case, the upward parallel shift in the market supply curve represents the regulation's effect on production costs. The shift causes the market price to increase by the full amount of the per-unit control cost (i.e., from P_0 to P_1). With the quantity demanded sensitive to price, the increase in market price leads to a reduction in output in the new with-regulation equilibrium (i.e., Q_0 to Q_1). As a result, consumers incur the entire regulatory burden as represented by the loss in consumer surplus (i.e., the area P_0 ac P_1). In the nomenclature of EIAs, this long-run scenario is typically referred to as "full-cost pass-through," and is illustrated in Figure 10.2-5.

Taken together, impacts modeled under the long-run/full-cost-pass-through scenario reveal an important point: under fairly general economic conditions, a regulation's impact on producers is transitory. Ultimately, the costs are passed on to consumers in the form of higher prices. However, this does not mean that the impacts of a regulation will have no impact on producers of goods and services affected by a regulation. For example, the long run may cover the time taken to retire all of today's capital vintage, which could take decades. Therefore, transitory impacts could be protracted and could dominate long-run impacts in terms of present value. In addition, to evaluate impacts on current producers, the long-run is approach is not appropriate. Consequently an time horizon that falls between the very short-run/full-cost-absorption case and the long-run/full-cost-pass-through case is most appropriate for this EIA.

The intermediate run can best be defined by what it is not. It is not the very short run and it is not the long run. In the intermediate run, some factors are fixed; some are variable.[F] The existence of fixed production factors generally leads to diminishing returns to those fixed factors. This typically manifests itself in the form of a marginal cost (supply) function that rises with the output rate, as shown in Figure 10.2-6.

Again, the regulation causes an upward shift in the supply function. The lack of resource mobility may cause producers to suffer profit (producer surplus) losses in the face of regulation; however, producers are able to pass through some of the associated costs to consumers, to the extent the market will allow. As shown, in this case, the market-clearing process generates an increase in price (from P_0 to P_1) that is less than the per-unit increase in costs (fb), so that the regulatory burden is shared by producers (net reduction in profits) and consumers (rise in price). In other words there is a loss of both producer and consumer surplus.

10.2.3.3 Variable vs. Fixed Regulatory Costs

Related to short-run versus long-run modeling issues is the question of how fixed and variable cost increases affect market prices and quantities. The engineering estimates of fixed R&D and capital costs and variable material and operating and maintenance (O&M) costs provide an initial measure of total annual compliance costs without accounting for behavioral

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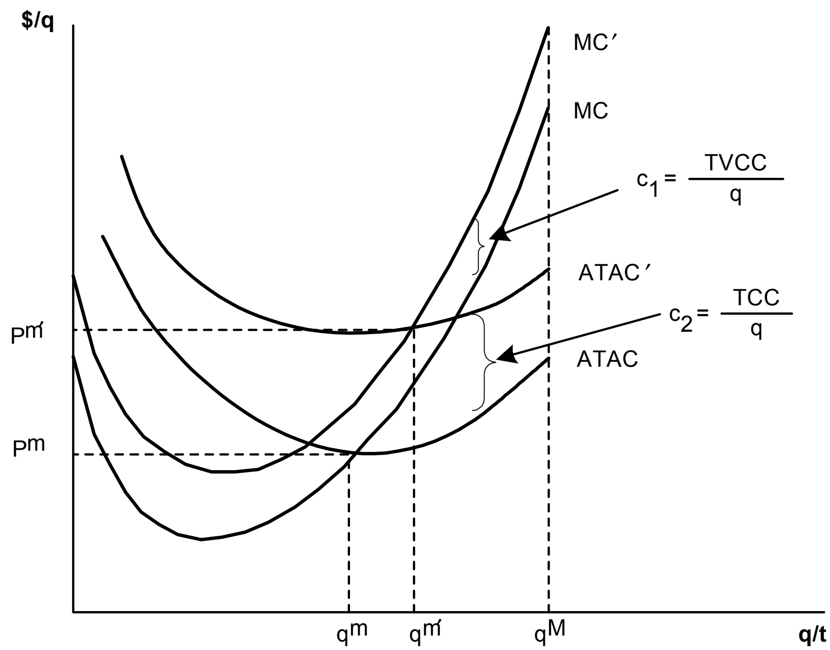
[F] As a semantical matter, the situation where some factors are variable and some are fixed is often referred to as the "short run" in economics, but the term "intermediate run" is used here to avoid any confusion with the term "very short run."

responses. The starting point for assessing the market impacts of a regulatory action is to incorporate the regulatory compliance costs into the production decision of the firm.

In general, shifting the supply curve by the total cost per unit implies that both capital and operating costs vary with output levels. At least in the case of capital, this raises some questions. In the long run, all inputs (and their costs) can be expected to vary with output. But a short(er)-run analysis typically holds some capital factors fixed. For instance, to the extent that a market supply function is tied to existing facilities, there is an element of fixed capital (or one-time R&D). As indicated above, the current market supply function might reflect these fixed factors with an upward slope. As shown in Figure 10.2-7, the MC curve will only be affected, or shift upwards, by the per-unit variable compliance costs, while the ATAC curve will shift up by the per-unit total compliance costs (c_2). Thus, the variable costs will directly affect the production decision (optimal output rate), and the fixed costs will affect the closure decision by establishing a new higher reservation price for the firm (i.e., $P^{m'}$). In other words, the fixed costs are important in determining whether the firm will stay in this line of business (i.e., produce anything at all), and the variable costs determine the level (quantity) of production.

Figure 10.2-7
Modeling Fixed Costs



(a) Upward-sloping supply function

In the EIA for this rule, it is assumed that only the variable cost influences the firm's production decision level and that the fixed costs are absorbed by the firm. Fixed costs associated with the engine emission standards are not included in the market analysis, because in an analysis of competitive markets the industry supply curve is based on its marginal cost curve, and fixed costs are not reflected in changes in the marginal cost curve. In addition, fixed costs are primarily R&D costs associated with design and engineering changes, and firms in the affected industries currently allocate funds for these costs (see below). These costs are still a cost to society because they displace other R&D activities that may improve the quality or performance of engines and equipment. However, in this example, the fixed costs do not influence the market price or quantity in the intermediate run. Therefore, fixed costs are not likely to affect the prices of engines or equipment.

R&D costs are a long-run concern, and decisions to invest or not invest in R&D are made in the long run. If funds have to be diverted from some other activity into R&D needed to meet the environmental regulations, then these costs represent a component of the social costs of the rule. Therefore, fixed R&D costs are included in the welfare impact estimates reported in Table 10.1-4 as unavoidable costs that reduce producer surplus. In other words, engine manufacturers budget for research and development programs and include these charges in their long-run strategies. In the absence of new standards, these resources would be focused on design changes to increase customer satisfaction. Engine manufacturers are expected to redirect these resources toward compliance with the standards, instead of adding additional resources to research and development programs.

Operationally, the model used in this EIA shifts the diesel engines' and equipment markets' supply curves by the variable cost per unit only. The rule's estimated fixed costs are calculated to reflect their opportunity costs and then added to the producer surplus decrease after the new market (with-regulation) equilibrium has been established.[G] The primary fixed costs in these markets are associated with one-time expenditures to redesign products and retool production lines to comply with the regulation. These fixed costs can be recovered as part of the industry's routine R&D budget and hence are not likely to lead to additional price increases. This assumption is supported by information received from a number of nonroad engine and equipment manufacturers, with whom EPA met to discuss redesign and equipment costs. The manufacturers indicated that their redesign budgets (for emissions or other product changes) are constrained by R&D budgets that are set annually as a percentage of annual revenues. While the decision to redesign may be driven by anticipated future revenues for an individual piece of equipment, the resources from with the redesign budget is allocated are determined from the current year's R&D budget. Thus, redesigns to meet emission standards represent a reallocation of resources that would have been spent for other kinds of R&D (i.e., a lost opportunity cost). To account for the value to the company of this loss, the engineering cost analysis includes a 7 percent rate of return for all fixed costs"recovered" over a defined period for the emission compliant products.

An alternative approach for R&D expenditures can be used, in which these costs are included in intermediate-run decision-making. This alternative assumes that manufacturers will change

[G]The fixed R&D costs capture the lost opportunity of forgone investments to the firm.

their behavior based on the R&D required for compliance with the standards. A sensitivity analysis in Appendix 10I reflects this approach.

Fixed costs on the refiner side are treated differently in the NDEIM. Unlike for engines and equipment where the fixed costs are primarily for up-front R&D, most of the petroleum refinery fixed costs are for production hardware. The decision to invest to increase, maintain, or decrease production capacity may be made in response to anticipated or actual changes in price. To reflect the different ways in which refiners can pass costs through to refiners, three scenarios were run for the following supply shifts in the diesel fuel markets:

- shift by average total (variable + fixed cost)
- shift by max total (variable + fixed cost)
- shift by max variable cost.

The first, shift by average total cost (variable + fixed), is the primary scenario and is included in the NDEIM. The other two are investigated using sensitivity analyses. These supply shifts are discussed further in sensitivity analysis presented in Appendix10I.

10.2.3.4 Substitution

In modeling the market impacts and social costs of this rule, the NDEIM considers only diesel equipment and fuel inputs to the production of goods in the applications markets. It does not explicitly model alternate production inputs that could serve as substitutes for new nonroad equipment or nonroad diesel fuel. In the model, market changes in the final demand for application goods and services directly correspond to changes in the demand for nonroad equipment and fuel (i.e., in normalized terms there is a one-to-one correspondence between the quantity of the final goods produced and the quantity of nonroad diesel equipment and fuel used as inputs to that production). We believe modeling the market in this manner is economically sound and reflects the general experience for the nonroad market.

Alternate means of production include pre-buying, delayed buying, extending the life of a current machine, and substituting with different (e.g., gasoline-powered) equipment. For the reasons described below, we conclude that revising the NDEIM to include these effects would be inappropriate.

The term “pre-buying” refers to the possibility that the suppliers in the application market could choose to buy additional unneeded quantities of nonroad equipment prior to the beginning of the Tier 4 program and then use that equipment as an alternate means of production during the time period of the Tier 4 program, thus avoiding the higher cost for the Tier 4 equipment. Although such pre-buying may be economically rational in some very limited situations, its use as a substitute is severely limited. First, it should be clear that this form of pre-buying only applies to equipment and not to nonroad diesel fuel. The high cost to storing any significant quantity of nonroad diesel fuel prior to Tier 4 makes such pre-buying unlikely. For nonroad equipment, the logic behind pre-buying is relatively straightforward and analogous to the average consumer deciding to buy a new car at the end of the model year in the anticipation that next year’s model will be more expensive. The critical difference is that the nonroad equipment is bought early and then held idle until it is needed as an input to production. The economic viability of such strategic purchases are limited by the cost of idle capital and the cost for maintaining unused equipment. In simple terms, if one assumed that the value of capital tied up in an idle piece of equipment would have returned 7 percent in some other investment and the cost of equipment were to go up by 7 percent, it would be economically rational to pre-buy equipment up to one-year earlier than needed. If the equipment will not be needed as an input to production in the next year, it would be more rational to invest the money elsewhere and then purchase the equipment when it is actually needed. In real terms, the window for which pre-buying can be a rational choice is even more limited due to the cost of maintaining, storing and insuring equipment that is not being used. In practice then, such strategic purchases are limited to a time period of a few months around the start of a new regulation. The NDEIM is intended to model market reactions in the intermediate run time frame and thus models a period of time well beyond the scope of the short time period during which any potential pre-buy might be rational. We therefore have not tried to include pre-buying as a means of substitution in NDEIM.

"Delayed-buying" refers to the possibility that producers in the application market would defer purchasing new equipment initially but would eventually (after a delay period?) buy new equipment. The economic rationality of such a delay is not clear (i.e., what cheaper substitute might be used). However, since in the end it is assumed that the new more expensive equipment is purchased, such a substitution method would appear to be inappropriate for an economic model designed to model the intermediate run time frame.

In addition, there are many other factors besides a new regulatory program that may affect a consumer's decision to pre-buy or delay a purchase. Specifically, manufacturer short-term pricing promotions or marketing strategies such as rebates, dealer incentives, and advertising can change consumer behavior. These effects are not well captured in a general equilibrium model such as the one used in the NDEIM, the goal of which is to estimate the rule's impact on equilibrium prices and quantities. Distinguishing these effects would require the use of a sales function, which is beyond the scope of the NDEIM.

Extending the life of a current machine is suggested as another alternative to purchasing new equipment. We believe this would also be a short term phenomenon that is not relevant for the intermediate time frame of the NDEIM. Based on our meetings with equipment users and suppliers, we do not believe that extending the life of nonroad equipment will prove to be an economically rational substitute to the purchase of new equipment. Based on our understanding of the nonroad equipment market, we believe that most users of nonroad equipment already do this to the maximum extent possible. That is, we believe it is already economically rational to extend the life of nonroad equipment as long as possible. It is our understanding that new nonroad equipment is only bought when: 1) the existing equipment can no longer perform its function; or 2) when new demand for production requires additional means for production; or 3) when new equipment offers a cheaper means of production than existing equipment. The changes in equipment due to the Tier 4 program will not substantially change these three primary reasons for purchasing new equipment. Further, were we to discover that extending equipment life is economically rational (i.e., if it were cheaper to extend equipment life rather than to buy new equipment), this would lower the cost of nonroad equipment as an input to production and thus would reduce the economic impact of the Tier 4 program compared to our estimate. For all of the reasons stated here, we have decided not to attempt to model an extended equipment life in the NDEIM.

Finally, stakeholders suggested that equipment users may choose to substitute with different equipment or perhaps more generally different inputs to production. These could include the use of gasoline powered equipment, or the use of additional labor (i.e., the use of a laborer and shovel instead of a backhoe), or some other unknown substitute. We have specifically considered the possibility of substitution to gasoline technology. Gasoline engines are an alternative power source for equipment in the lowest power categories (i.e., below 75 horsepower). Above this size range there are very limited viable gasoline engine substitutes today, and we do not believe that such substitutes will arise in the future. We should also note that there are a number of benefits to diesel engines and some stakeholders have argued that there are no acceptable substitutes for diesel powered equipment.[H] The fuel economy advantage of diesel engines compared to gasoline engines dominates the overall operating costs for larger equipment and makes the application of large gasoline engines to large nonroad equipment economically infeasible.[I] For smaller nonroad equipment, where the fuel portion of operating costs are not as important, gasoline and diesel engines are both provided today. The dominant reasons for choosing diesel engines over the substantially cheaper gasoline engines include better performance from diesel engines, lower fuel consumption from diesel engines, and the ability to use diesel fuel. This latter reason is a significant advantage for two reasons: diesel fuel is safer to store and dispense due to its lower volatility and, hence, greater resistance to accidental ignition, and it is compatible with the fuel needed for larger equipment at the same worksite. Thus, the costs for addressing safety issues with gasoline fuel storage and the costs for storing two fuels onsite (gasoline for small engines and diesel for large) acts as a barrier to entry to the market for gasoline powered equipment. Where such a barrier doesn't exist, gasoline engines already enjoy a substantial economic advantage over diesel. In cases where the more expensive diesel powered equipment is currently used, an incremental increase in new equipment cost is unlikely to provide the necessary economic incentives for switching to gasoline based power systems. In short, we believe that users who can economically dispense gasoline fuel already choose the substantially cheaper gasoline technology, while diesel users are already choosing a more expensive technology due to reasons that will persist independent of this rulemaking. The incremental equipment costs are not expected to be large enough to change these market characteristics. Therefore, we have not attempted to model the possibility of substitution to gasoline equipment in NDEIM.

[H] "To date, there is no substitute for diesel power." Associated General Contractors of America, OAR-2003-0012-0791.

[I] Preamble Table VI.C-1 documents the lifetime operating costs (for fuel and oil only) for a 500 hp bulldozer as $77,850. If simplistically, we assumed that a gasoline engine would have a 30 percent higher operating cost (in practice it would likely be higher), the extra operating cost for a gasoline engine would be in excess of $23,000 dwarfing any additional control cost from the Tier 4 program.

10.2.4 Estimation of Social Costs

The economic welfare implications of the market price and output changes with the regulation can be examined by calculating consumer and producer net “surplus” changes associated with these adjustments. This is a measure of the negative impact of an environmental policy change and is commonly referred to as the “social cost” of a regulation. It is important to emphasize that this measure does not include the benefits that occur outside of the market, that is, the value of the reduced levels of air pollution with the regulations. Including this benefit will reduce the net cost of the regulation and even make it positive.

The demand and supply curves that are used to project market price and quantity impacts can be used to estimate the change in consumer, producer, and total surplus or social cost of the regulation (see Figure 10.2-8).

The difference between the maximum price consumers are willing to pay for a good and the price they actually pay is referred to as “consumer surplus.” Consumer surplus is measured as the area under the demand curve and above the price of the product. Similarly, the difference between the minimum price producers are willing to accept for a good and the price they actually receive is referred to as “producer surplus.” Producer surplus is measured as the area above the supply curve below the price of the product. These areas can be thought of as consumers’ net benefits of consumption and producers’ net benefits of production, respectively.

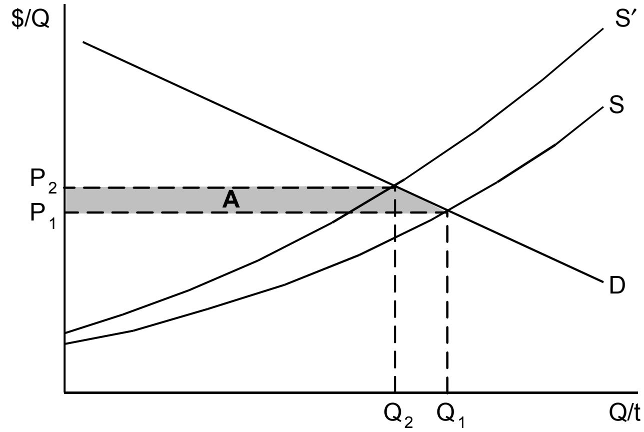
In Figure 10.2-8, baseline equilibrium occurs at the intersection of the demand curve, D, and supply curve, S. Price is P_1 with quantity Q_1. The increased cost of production with the regulation will cause the market supply curve to shift upward to S′. The new equilibrium price of the product is P_2. With a higher price for the product there is less consumer welfare, all else being unchanged. In Figure 10.2-8(a), area A represents the dollar value of the annual net loss in consumers’ welfare associated with the increased price. The rectangular portion represents the loss in consumer surplus on the quantity still consumed due to the price increase, Q_2, while the triangular area represents the foregone surplus resulting from the reduced quantity consumed, $Q_1 – Q_2$.

In addition to the changes in consumers’ welfare, there are also changes in producers’ welfare with the regulatory action. With the increase in market price, producers receive higher revenues on the quantity still purchased, Q_2. In Figure 10.2-8(b), area B represents the increase in revenues due to this increase in price. The difference in the area under the supply curve up to the original market price, area C, measures the loss in producer surplus, which includes the loss associated with the quantity no longer produced. The net change in producers’ welfare is represented by area B – C.

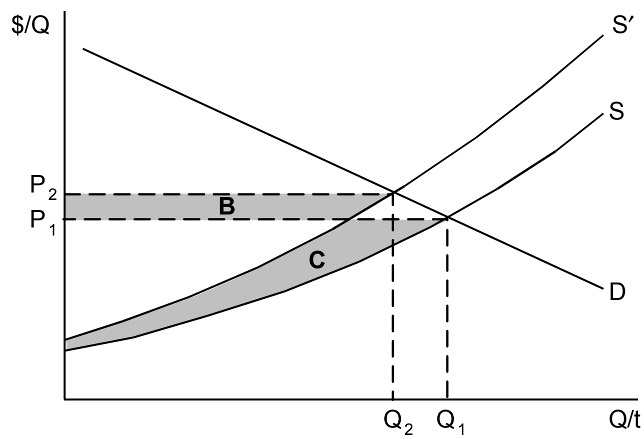
The change in economic welfare attributable to the compliance costs of the regulations is the sum of consumer and producer surplus changes, that is, – (A) + (B–C). Figure 10.2-8©) shows the net (negative) change in economic welfare associated with the regulation as area D.[J]

[J]However, it is important to emphasize that this measure does not include the benefits that occur outside the market, that is, the value of the reduced levels of air pollution with the regulations. Including this benefit may reduce the net cost of the regulation or even make it positive.

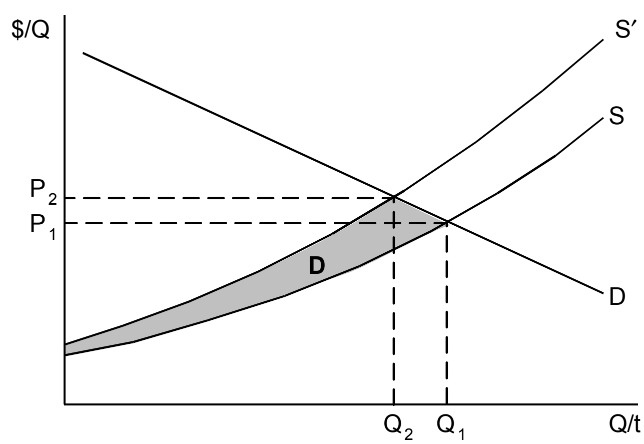
Figure 10.2-8
Market Surplus Changes with Regulation: Consumer and Producer Surplus



(a) Change in Consumer Surplus with Regulation



(b) Change in Producer Surplus with Regulation



(c) Net Change in Economic Welfare with Regulation

If not all the costs of the regulation are reflected in the supply shift, then the producer and consumer surplus changes reflected in Figure 10.2-5 will not capture the total social costs of the regulation. As discussed earlier, fixed R&D and capital costs are not included in the supply curve shift for the engine and equipment markets. The fixed costs in these instances are assumed to be borne totally by the producers in that none of these costs are passed on to consumers in the form of higher prices. The costs are added to the producer surplus estimates generated from the market analysis so that the accounting accurately reflects the total social cost of the regulation.

Operating savings are included in the total social cost estimates but not integrated into the market analysis. Operating savings are changes in operating costs are expected to be realized by diesel equipment users, for both existing and new equipment, as a result of the reduced sulfur content of nonroad diesel fuel. These include operating savings (cost reductions) due to fewer oil changes, which accrue to nonroad engines that are already in use as well as those that will comply with new emission standards. These savings (costs) also include any extra operating costs associated with the new PM emission control technology that may accrue to new engines that use this new technology. Operating savings are not included in the market analysis because some of the savings accrue to existing engines and because these savings are not expected to affect consumer decisions with respect to new engines (see Chapter 6). Operating savings are included in the social cost analysis, however, because they accrue to society. They are added into the estimated social costs as an additional savings to the application and transportation service markets, since it is the users of these engines and fuels that will see these savings. A sensitivity analysis was performed in which operating savings are included as inputs to the NDEIM market. The results of this analysis are presented in Appendix 10I.

10.3 NDEIM Model Inputs and Solution Algorithm

The NDEIM is a computer model comprising a series of spreadsheet modules. The model equations, presented in Appendix F to this chapter, are based on the economic relationships described in Section 10.2. The NDEIM analysis consists of four steps:

- Define the baseline characteristics of the supply and demand of affected commodities and specify the intermarket relationships.
- Introduce a policy "shock" into the model based on estimated compliance costs that shift the supply functions.
- Use a solution algorithm to estimate a new, with-regulation equilibrium price and quantity for all markets.
- Estimate the change in producer and consumer surplus in all markets included in the model.

This section describes the data inputs used to construct the model, the compliance costs used to shock it, and the algorithm used to solve it. The model results are presented in Appendices A through E.

10.3.1 Description of Product Markets

There are 60 integrated engine, equipment, fuel, transportation service, and application product markets included in the NDEIM.

10.3.1.1 Engine Markets

The engine markets are the markets associated with the production and consumption of engines. The producers in these markets are the engine manufacturers; the consumers are companies that make the nonroad equipment that use these engines. Seven engine markets are modeled, segmented by engine size (in horsepower).

- less than 25 hp
- 26 to 50 hp
- 51 to 75 hp
- 76 to 100 hp
- 101 to 175 hp
- 176 to 600 hp
- greater than 601 hp

The number of horsepower categories included in the NDEIM is larger than the number of nonroad engine standard horsepower categories. This allows more efficient use of the engine compliance cost estimates developed for this proposal. It also allows a more refined examination of economic impacts on equipment types.

The NDEIM distinguishes between “merchant” engines and “captive” engines. “Merchant” engines are produced for sale to another company and are sold on the open market to anyone who wants to buy them. “Captive” engines are produced by a manufacturer for use in its own nonroad equipment line (this equipment is said to be produced by “integrated” manufacturers). It is important to differentiate between merchant and captive engines because compliance costs affect them differently. All compliance costs for captive engines are absorbed into the equipment costs of integrated suppliers. In contrast, nonintegrated equipment suppliers who buy merchant engines pay only a portion of the engine compliance costs. As long as engine demand is not perfectly inelastic, the increased market price for merchant engines will reflect only a partial pass through of engine compliance costs. The rest of the compliance costs will be borne by the engine manufacturer.

10.3.1.2 Equipment Markets

The equipment markets are the markets associated with the production and consumption of equipment that use nonroad diesel engines. The producers in these markets are the equipment manufacturers; the consumers are companies that use this equipment to make goods sold in the application markets. Seven equipment markets are modeled:

- Construction

- Agricultural
- Pumps and compressors
- Generators and welder sets
- Refrigeration and air conditioning
- General industrial, and
- Lawn and garden.

Each of the 60 applications listed in the Power Systems Research OELink Sales Version 2002 (PSR) database were allocated to one of these categories to obtain a manageable number of equipment markets to be included in the NDEIM (Gallaher, 2003). The mapping is contained in Table 10.3-1. For each of these equipment types, up to seven horsepower size category markets are included in the model, for a total of 42 individual equipment markets.[K]

[K]There are seven horsepower/application categories that do not have sales in 2000 and are not included in the model. These are: agricultural equipment >600 hp; gensets & welders > 600 hp; refrigeration & A/C > 71 hp (4 hp categories); and lawn & garden >600 hp. Therefore, the total number of diesel equipment markets is 42 rather than 49.

Table 10.3-1
Mapping from PSR Equipment Categories to Equipment Markets

Application Markets	Equip Markets	Equipment Types
AGRICULTURE	AGRICULTURAL EQUIP	2-WHEEL TRACTORS
		AG TRACTORS
		BALERS
		COMBINES
		IRRIGATION SETS
		OTHER AG EQUIPMENT
		SPRAYERS
		WINDROWERS
CONSTRUCTION	CONSTRUCTION	AERIAL LIFTS
		BORE/DRILL RIGS
		CRANES
		CRAWLERS
		EXCAVATORS
		FINISHING EQUIPMENT
		FOREST EQUIPMENT
		GRADERS
		LT PLANTS/SIGNAL BDS
		MIXERS
		OFF-HWY TRACTORS
		OFF-HWY TRUCKS
		OTHER CONSTRUCTION
		PAVERS
		PLATE COMPACTORS
		ROLLERS
		S/S LOADERS
		SCRAPERS
		TAMPERS/RAMMERS
		TRACTR/LOADR/BCKHOES
		TRENCHERS
		WHEEL LOADERS/DOZERS
MANUFACTURING	GENERAL INDUSTRIAL	AIRCRFT SUPPRT EQUIP
		CHIPPERS/GRINDERS
		CONCRETE/IND SAWS
		CRUSH/PROC EQUIP
		DUMPERS/TENDERS
		FORKLIFTS
		OIL FIELD EQUIPMENT
		OTH MATERIAL HANDLNG
		OTHER GEN INDUSTRIAL
		RAILWAY MAINTENANCE
		ROUGH TRN FORKLFTS
		SCRUBBERS/SWEEPERS
		SPEC VEHICLES/CARTS
		SURFACING EQUIP
		TERMINAL TRACTORS
		UTILITY VEHICLES
	GENERATOR SETS & WELDERS	GENERATOR SETS

Application Markets	Equip Markets	Equipment Types
		WELDERS
	LAWN & GARDEN	COMMERCIAL MOWERS
		COMMERCIAL TURF
		LEAF BLOWERS/VACS
		LN/GDN TRACTORS
		OTHER LAWN&GARDEN
		TRIMMER/EDGER/CTTERS
	PUMPS & COMPRESSORS	AIR COMPRESSORS
		GAS COMPRESSORS
		HYD POWER UNITS
		PRESSURE WASHERS
		PUMPS
	REFRIGERATION/AC	REFRIGERATION/AC

Source: Gallaher (2003).

For the purpose of this analysis, nonroad diesel equipment is assumed to be a fixed factor of production in the application markets. Applying this assumption, a 1 percent decrease in agricultural output will lead to a 1 percent decrease in the demand for agricultural equipment (and fuel). The relationship between the percentage increase in equipment price and the percentage change in equipment demand (the elasticity of demand) is determined by the input share of diesel equipment relative to other inputs in the application markets and the supply and demand elasticities in the application markets.

10.3.1.3 Application Markets

The application markets are the markets associated with the production and consumption of goods that use the affected diesel engines, equipment, and fuel. The producers in these markets include farmers, ranchers, construction firms, industrial firms, and mines; consumers include other companies and households. Three application markets are modeled:

- Construction
- Agricultural
- Manufacturing

These three application markets created after considering various economic activity classification schemes, including the NAICS and SIC (Revelt, 2004; Gallaher, 2003). These three markets are included as separate groupings in each of those economic activity classification schemes. They are also the most significant categories of activities for which diesel engines, equipment, and fuel are most likely to be used, as suggested in the PSR data on which the equipment markets were chosen. Finally, they are a manageable number of markets to use in the NDEIM. Each of the 7 equipment markets listed above were allocated to one of these categories. The mapping is contained in Table 10.3-2.

Table 10.3-2
Mapping from Equipment Markets to Application Markets

Application Market	Equipment Market
Agricultural	Agricultural equipment
Construction	Construction equipment
Manufacturing	Pumps and compressors Gen sets and welding equipment Refrigeration Lawn and garden General industrial

One of the consequences of reducing economic activities that use diesel engines, equipment, and fuel into such a small number of application market categories is that seemingly unrelated activities are linked to aggregate trends and market responses. So, for example, if manufacturing application market production decreases by one percent, the demand for lawn and garden equipment, gen sets and welders, and forklifts will all decrease by the same one percent because they are all linked to the same application market. Similarly, forest equipment and signal boards are grouped with cranes and bulldozers in the construction application market. In addition, gen sets used in agricultural activities are considered to be used in the manufacturing application market. Unfortunately, this is a problem whenever a large number of different kinds of products or activities are reduced to a small number of categories. At the same time, most of the activity covered by each of the three categories, and thus most of the engines and equipment that are included in them, is directly related to the application category.

Analysis of the impacts on the three application markets is limited to market level changes. The results are reported in terms of average percent change for prices and quantities of goods sold in each of the three application markets. Changes in producer and consumer surplus at the market level are also reported. The economic impacts on suppliers or consumers in particular markets (e.g., farm production units or manufacturing or construction firms, or households and companies that consume agricultural goods, buildings, or durable or consumer goods) are not estimated.

10.3.1.4 Diesel Fuel Markets

The diesel fuel markets are the markets associated with the production and consumption of nonroad diesel fuel. Eight nonroad diesel fuel markets were modeled: two distinct nonroad diesel fuel commodities in four regional markets. The two fuels are:

- 500 ppm nonroad diesel fuel
- 15 ppm nonroad diesel fuel

The Department of Energy defines five Petroleum Administrative Districts for Defense (PADDs). For the purpose of this EIA, two of these PADDs are combined, giving four regional district fuel markets. These are:

- PADD 1 and 3
- PADD 2
- PADD 4
- PADD 5 (includes Alaska and Hawaii; California fuel volumes that are not affected by the program because they are covered by separate California nonroad diesel fuel standards are not included in the analysis)

PADD 1 and PADD 3 are combined because of the high level of interregional trade. Regional imports and exports across the remaining four regions included in the model are not included in the analysis.

Separate compliance costs are estimated for each 500 ppm and 15 ppm regional fuel market. As a result, the price and quantify impacts, as well as the changes in producer surplus, vary across the eight fuel markets.

As discussed in Section 10.2, the NDEIM is based on the assumption of perfect competition. Using this assumption, estimated social costs are obtained by using average per-unit variable compliance costs to shift the market supply curve (see Section 10.2.3.3). In the fuel market case, however, each regional supply curve is shifted by the average total (variable + fixed) regional cost of the regulation. This approach is used for the fuel market because, unlike for engines and equipment where the fixed costs are primarily for up-front R&D, most of the petroleum refinery fixed costs are for production hardware. This fuel market scenario (referred to as average total cost) is used when presenting disaggregated market results in Appendices 10.A through 10.D and sensitivity analysis results in Appendix 10I.

However, in some fuel regions, it may be more appropriate to let the “high cost” refinery’s compliance cost drive the new market price. If refiners' investment in desulfurization capacity is very close to that needed to satisfy demand for 15 ppm NRLM fuel, then refiners may have to often operate their equipment at a capacity beyond that which minimizes cost. For example, the temperature in the reactor can be increased, allowing greater fuel throughput. However, this speeds up catalyst deactiviation and shortens catalyst life. This effectively increases the operating cost per gallon of producing 15 ppm fuel. The long-term solution is for refiners not producing 15 ppm fuel to invest in desulfurization capacity. However, according to EPA's cost methodology, this incremental fuel would have a higher desulfurization cost than that experienced by those who have already invested. In order to justify this new 15 ppm fuel capacity, refiners have to anticipate not only covering their operating costs, but their capital costs as well. For this to occur, they would have to anticipates prices being at or above those of the "high cost" refineries as estimated here. Under this assumption it is the high cost producer’s dollars per gallon compliance cost increase that determines the new price. This is referred to as the max cost scenario and no longer reflects perfect competition because now individual firms have direct influence on market price. Two max cost scenarios are explored in the sensitivity analysis presented in Appendix 10I: one in which the high-cost refinery's total (variable + fixed) compliance costs determine price, and a second in which only the high-cost refinery's variable compliance costs determine price.

10.3.1.5 Locomotive and Marine Transportation Markets

The locomotive and marine sectors are affected by this rule through the limits on the sulfur content of fuel. These sectors provide inputs to a variety of end-use sectors in the form of transportation services. In this sense, their role is similar to other markets for intermediate goods already included in the NDEIM. For example, the equipment markets in the NDEIM are markets for intermediate goods that provide diesel-powered equipment to agriculture, construction, and manufacturing application markets. Using this analogy, locomotive and marine sectors are included in the NDEIM as two intermediate markets (see Figure 10.1-1). The intermediate goods/services in this context are the rail and water transportation services provided to end-use markets.

The U.S. Bureau of Economic Analysis (BEA) Industry Economic Program produces the input-output tables, which show how industries interact to provide input to, and take output from, each other. The data set can provide an appropriate measure transportation services purchased by the application markets included in NDEIM. The BEA data show that approximately 54 percent of rail and water transportation expenditures are made by the three application markets in the NDEIM (see Table 10.3-3). The remaining expenditures for these services are associated with explicitly modeled sectors not included in the model (e.g. electric utilities (transporting coal to electric power plants), nonmanufacturing service industries (public transportation), and governments). Costs flowing into these "other" sectors are included as a line item in the economic impact estimates but do not lead to changes in market prices or quantities.

Table 10.3-3
Distribution of Rail and Water Costs to Deliver Commodities by Industry: 1997

Application Market	Share of Rail Transportation Expenditures	Share of Water Transportation Expenditures
Agriculture	3.5%	2.5%
Construction	4.3%	8.3%
Manufacturing	45.9%	42.7%
Other	46.2%	45.5%

Source: U.S. Bureau of Economic Analysis (BEA). 1997 Benchmark I-O Supplementary Make, Use, and Direct Requirements Tables at the Detailed Level. Table 4. http://www.bea.gov/bea/dn2/i-o_benchmark.htm. Last updated November 24, 2003.

Locomotive and fuel costs were added only to the three application markets, even though equipment and engine manufacturers also use these services. This is a simplifying assumption and, is not expected to have an impact on the results of the market or social cost analysis because the share of these costs in total engine and equipment production is very small.

10.3.2 Market Linkages

In the national economy, the markets described above are connected in that changes in demand in one market will affect the supply of goods in a related market. For example, nonroad equipment manufacturers consume engines in their production processes in the sense that each piece of nonroad equipment has a nonroad engine. This equipment is then supplied to application market producers through the application markets. A decrease in the demand for equipment in the application market will lead to a decrease in the quantity of equipment produced, which will in turn lead to a decrease in the quantity of engines produced. Similarly, the fuel markets are also linked to the application markets, with the demand for No. 2 distillate being specified as a function of the production and consumption decisions made in the construction, agricultural, and manufacturer application markets. In the NDEIM, increased equipment costs decrease the demand for fuel, and increased fuel costs decrease the demand for equipment because both increase the costs of production in the application markets. This in turn leads to a decrease in production in the application markets and hence a decrease in the demand for inputs (fuel and equipment).

The linkages between the markets are illustrated in Figure 10.1-1. These interaction effects are accounted for by designing the model to derive the engine, equipment, transportation, and fuel market demand elasticities. The derived demand aspect of the model simulates connections between supply and demand among all the product markets and replicates the economic interactions between producers and consumers. Detailed specifications of the market model equations (supply and demand functions, equilibrium conditions) are provided in Appendix 10F.

10.3.3 Baseline Economic Data

This section describes the data used to define the baseline conditions in the model. These include baseline quantities and prices for the engines, equipment and fuel affected by the rule and for the transportation service sectors and application markets that use these engines, equipment, and fuel.

10.3.3.1 Baseline Quantities: Engines, Equipment and Fuel

Engines and Equipment: The NDEIM uses the same engine sales that are used in the engine and equipment cost analysis presented in Chapter 6. The engine sales are based on the Power Systems Research OELink Sales Version 2002 database, adjusted to eliminate stationary equipment and to maintain consistency with the 1998 Nonroad inventory model (see Chapter 8, Table 8.1-1 and related text). Sales data are used as a proxy for production data in the NDEIM because detailed production data by horsepower and equipment application are not available (modeling inventory decisions of engine and equipment manufacturers is beyond the scope of the NDEIM). The sales distribution by size and application is the same for equipment as for engines due to the assumption of a one-to-one relationship between engines and equipment. Engines and equipment are allocated to equipment type categories according to the PSR database categorization scheme (see Section 10.3.1.2 and Table 10.3-1, above). Table 10.3-4 lists sales data for affected diesel nonroad engines and equipment sold in the United States in 2000 by engine horsepower and equipment category.

Table 10.3-4
Engine/Equipment Sales in 2000

Engine Market	Agricultural Equipment	Construction	General Industrial	Generator Sets and Welders	Lawn and Garden	Pumps and Compressors	Refrigeration/ Air Condition	Grand Total
0<hp<25	13,195	17,043	3,173	54,971	17,118	4,980	8,677	119,159
25≤hp<50	38,303	30,233	6,933	32,540	10,323	4,254	10,394	132,981
50≤hp<75	19,156	30,919	7,074	13,234	1,456	3,930	18,145	93,914
75≤hp<100	11,788	30,146	14,204	5,567	2,722	4,238		68,665
100≤hp<175	35,226	49,503	17,757	7,313	1,556	985		112,340
175≤hp<600	41,678	42,126	8,327	1,813	509	1,494	—	95,947
hp > 600 hp	—	4,945	576	—	—	16	—	5,537
Grand Total	159,347	204,915	58,044	115,440	33,684	19,898	37,215	628,542

Source: Power Systems Research, OELink Sales Version, 2002.; see also Chapter 8, Table 8.1-1 and related text.

Fuel: Baseline nonroad, locomotive, and marine diesel fuel consumption is provided in Table 10.3-5. Fuel consumption is broken out by region (PADD) and application market (construction, agriculture, and manufacturing).

The fuel volumes used in NDEIM were developed from the information contained in Section 7.1 of Chapter 7 of the RIA. Only a brief summary of the methodology used to develop these volumes is contained here so the reader is directed to Chapter 7 of the RIA for a complete discussion. Demand volumes are first estimated for nonroad, locomotive and marine diesel fuel for 2001 for each PADD[L] and then grown to 2014. The analysis of varying regulatory scenarios always occurs using the 2014 estimated volumes. The three regulatory scenarios associated with the final rule are:

- NRLM meeting a 500 ppm sulfur standard in 2007 to 2010 exempting small refiners

- NR meeting a 15 ppm sulfur standard and LM meeting a 50 ppm sulfur standard in 2010 to 2012 exempting small refiners

- NRLM meeting a 15 ppm sulfur standard in 2010 to 2014 exempting some small refiners and allowing downgrade to meet demand except in PADD 1

- NRLM meeting a 15 ppm sulfur standard in 2014 which is fully phased in. The downgrade can be used in locomotive and marine diesel fuel except in PADD 1

The volume of pipeline downgrade and highway diesel fuel spillover are estimated and apportioned to nonroad, locomotive and marine diesel fuel depending on the distribution system constraints identified for each PADD and consistent with each regulatory scenario. After the downgrade and spillover are accounted for, the residual demands in each PADD are met by on-purpose production of low sulfur fuel.

The summary tables of 2014 volumes for each regulatory scenario are contained in Chapter 7. The volumes are summarized in Table 7.1.4-10 for the period from 2007 to 2010, Table 7.1.4-11 for the period from 2010 to 2012, Table 7.1.4-12 for the period from 2012 to 2014, and Table 7.1.4-13 for the period 2014 and thereafter.

The 2014 volumes are adjusted to estimated the volumes in each year from 2007 to 2040 using growth ratios compared to 2014 based on the growth rate factors in Tables 7.1.5-1 and 7.1.5-2. Each substream (i.e., spillover, downgrade, low sulfur fuel) within each fuel category is adjusted using the same growth factor.

The results of the volumes analysis are shown in Table 10.3-5. In the first column, the nonroad, locomotive and marine diesel fuel volume which must be desulfurized are summarized.

[L] Petroleum Administrative Districts for Defense.

The downgrade and spillover are aggregated together and shown in another column. Then a total is presented which represents the total of the two columns. The volumes are shown for PADDs 1 and 3 together, PADD 2, PADD 4 and PADD 5 without California, as well as a national total without California.

Table 10.3-5
Nonroad, Locomotive and Marine Diesel Fuel Consumption, 2007-2036 (million gallons)

	PADD I&III			PADD II			PADD IV			PADD V			Total		
Year	Nonroad, Locomotive, Marine	Highway Sulfur, Downgrade and Spillover	Total	Nonroad, Locomotive, Marine	Highway Sulfur, Downgrade and Spillover	Total	Nonroad, Locomotive, Marine	Highway Sulfur, Downgrade and Spillover	Total	Nonroad, Locomotive, Marine	Highway Sulfur, Downgrade and Spillover	Total	Nonroad, Locomotive, Marine	Highway Sulfur, Downgrade and Spillover	Total
2007	3,771	4,169	7,940	2,573	3,617	6,189	217	695	912	223	785	1,007	6,783	9,265	16,048
2008	6,592	1,503	8,095	4,503	1,817	6,319	380	551	931	390	639	1,029	11,864	4,510	16,374
2009	6,720	1,532	8,252	4,597	1,855	6,452	387	563	950	398	652	1,050	12,102	4,601	16,704
2010	7,008	1,405	8,412	4,392	2,195	6,587	337	633	970	420	652	1,072	12,158	4,883	17,041
2011	7,282	1,300	8,582	4,277	2,450	6,727	303	687	991	439	655	1,095	12,301	5,093	17,394
2012	7,414	1,323	8,737	4,359	2,498	6,857	309	700	1,010	448	669	1,116	12,530	5,189	17,719
2013	7,540	1,343	8,883	4,440	2,544	6,984	315	713	1,028	455	682	1,137	12,750	5,282	18,032
2014	7,669	1,365	9,034	4,521	2,591	7,111	321	725	1,046	553	605	1,158	13,064	5,286	18,350
2015	7,801	1,384	9,185	4,609	2,631	7,240	327	737	1,065	629	550	1,179	13,367	5,302	18,669
2016	7,932	1,403	9,336	4,696	2,673	7,369	334	749	1,083	641	560	1,200	13,603	5,385	18,988
2017	8,064	1,423	9,487	4,783	2,714	7,497	340	762	1,102	652	569	1,222	13,840	5,467	19,307
2018	8,200	1,442	9,643	4,871	2,753	7,625	347	773	1,120	664	579	1,243	14,083	5,548	19,630
2019	8,342	1,464	9,806	4,960	2,796	7,756	353	785	1,139	677	588	1,265	14,332	5,634	19,965
2020	8,545	1,411	9,956	4,934	2,948	7,882	353	804	1,157	688	598	1,286	14,520	5,760	20,280
2021	8,729	1,375	10,104	4,937	3,069	8,006	354	821	1,174	700	607	1,307	14,720	5,872	20,592
2022	8,872	1,395	10,266	5,022	3,114	8,137	360	833	1,193	712	616	1,329	14,966	5,958	20,925
2023	9,007	1,413	10,420	5,107	3,159	8,265	366	845	1,211	724	626	1,350	15,203	6,043	21,246
2024	9,145	1,432	10,577	5,191	3,204	8,395	372	857	1,230	736	636	1,371	15,445	6,128	21,573
2025	9,282	1,451	10,733	5,276	3,249	8,525	379	870	1,249	748	645	1,393	15,684	6,215	21,899
2026	9,420	1,469	10,889	5,360	3,294	8,653	385	882	1,267	759	655	1,414	15,924	6,300	22,224
2027	9,558	1,488	11,046	5,444	3,338	8,782	391	894	1,285	771	664	1,436	16,164	6,384	22,548
2028	9,696	1,506	11,203	5,528	3,382	8,910	397	907	1,304	783	674	1,457	16,405	6,469	22,874
2029	9,835	1,525	11,360	5,612	3,427	9,039	403	919	1,322	795	684	1,478	16,646	6,554	23,200
2030	9,974	1,544	11,518	5,697	3,472	9,168	410	931	1,341	807	693	1,500	16,887	6,640	23,527
2031	10,113	1,563	11,676	5,781	3,516	9,297	416	943	1,359	819	703	1,521	17,129	6,725	23,854
2032	10,253	1,582	11,835	5,865	3,561	9,427	422	956	1,377	831	712	1,543	17,371	6,811	24,182
2033	10,393	1,601	11,994	5,950	3,606	9,556	428	968	1,396	843	722	1,565	17,614	6,897	24,511
2034	10,534	1,620	12,154	6,034	3,651	9,686	434	980	1,414	855	732	1,586	17,857	6,983	24,840
2035	10,675	1,639	12,314	6,119	3,696	9,815	441	992	1,433	867	741	1,608	18,101	7,069	25,171
2036	10,816	1,659	12,475	6,204	3,742	9,945	447	1,005	1,452	879	751	1,630	18,345	7,156	25,501

10.3.3.2 Baseline Prices: Engines, Equipment and Fuel

Engines and Equipment: The baseline engine prices used in the NDEIM are the same as those contained in Table 6.2-5 in Chapter 6, above, sales weighting those values where appropriate. Table 10.3-6 provides the prices for the seven engine categories used in the model. The baseline equipment prices used in the NDEIM are contained in Table 10.3-7.[M] These were estimated by EPA using price data for the seven categories of equipment were complied from a variety of sources, including the U.S. General Services Administration and various websites. A relationship between price and horsepower was obtained using a linear interpolation method. The price estimates for the equipment were obtained using the sales weighted horsepower value for each power category and the corresponding linear equation (Guerra, 2004).

Table 10.3-6
Baseline Engine Prices

Power Range	Estimated Price
0<hp<25	$1,500
25≤hp<50	$2,900
50≤hp<75	$3,000
75≤hp<100	$4,000
100≤hp<175	$5,500
175≤hp<600	$20,000
hp > 600 hp	$80,500

Source: See also Chapter 6, Table 6.2-5.

[M]It should be noted that the equipment prices used in this analysis reflect current conditions and do not reflect any future price increases associated with EPA's nonroad Tier 3 standards.

Table 10.3-7
Baseline Prices of Nonroad Diesel Equipment[a]

Application	<25 hp	26-50 hp	51-75 hp	76-100 hp	101-175 hp	176-600 hp	>600 hp
Agricultural Equip	$6,900	$14,400	$22,600	$33,400	$69,100	$143,700	N/A
Construction Equip	$18,000	$29,700	$31,600	$57,900	$122,700	$312,900	$847,400
Pumps & Compressors	$6,000	$12,200	$10,600	$12,500	$23,800	$53,000	$88,000
GenSets & Welders	$6,800	$8,700	$8,300	$18,000	$21,400	$35,700	N/A
Refrigeration & A/C	$12,500	$27,000	$42,100	N/A	N/A	N/A	N/A
General Industrial	$17,300	$42,300	$56,400	$74,300	$116,900	$154,200	$345,700
Lawn & Garden	$9,300	$21,500	$33,100	$38,500	$29,900	$64,300	N/A

Source: Guerra, 2004.
[a] These equipment prices reflect current conditions and do not reflect any future price increases associated with EPA's nonroad Tier 3 standards.

Fuel Prices: The baseline fuel prices used in the NDEIM are the 2002 market prices for each PADD obtained from the U.S. Energy Information Administration's Petroleum Market Monthly. These prices are reported in Table 10.3-8 and are based on the average sales to end-users for high-sulfur diesel fuel.

Table 10.3-8
Average Market Prices for Diesel Fuel[a]: 2002

Market	Price ($/gallon)
PADD I&III	$0.91
PADD II	$0.94
PADD IV	$0.91
PADD V	$0.87

[a]High-Sulfur Diesel Fuel observation for December 2002.
Source: U.S. Energy Information Administration. 2004. Petroleum Marketing Monthly March 2004. Table 41.

10.3.3.3 Baseline Quantities and Prices for Transportation and Application Markets

For the three application markets, the NDEIM uses the values of production data reported by the U.S. Bureau of the Census and the U.S. Department of Agriculture. The Economic Census provides official measures of output for industries and geographic areas. It is the best publicly available data that measures market supply for the broadly defined application markets in the NDEIM, because its industrial classification system provides aggregate statistics for agriculture, constructing, and manufacturing. Trade data for agriculture and manufacturing is reported by the USDA and U.S. International Trade Commission (USITC)[N]. The NDEIM uses normalized commodities (e.g. price is one and value equals quantity) because of the great heterogeneity of products within each application market. To estimate production for future years, we applied average equipment growth rates to the value of output reported in Table 10.3-9 (see discussion of growth rates in Section 10.3.6).

Table 10.3-9
Baseline Data for NDEIM's Application Markets: 2000

Application Market	Value ($\$10^9$)
Agriculture	Domestic Production: $ 219 Imports: $ 39
Construction	Domestic Production: $ 820
Manufacturing	Domestic Production: $ 4,209 Imports: $ 1,074

Sources: U.S. Department of Agriculture, National Agricultural Statistics Service (USDA-NASS). 2002. Agricultural Statistics 2002. Washington, DC: U.S. Department of Agriculture. Table 9-39 and Table 15-1. U.S. Census Bureau. 2003b. Value of Construction Put In Place: December 2002. C30/02-12. Washington, DC: U.S. Census Bureau. Table 1. U.S. Census Bureau. 2003a. Annual Survey of Manufactures. 2001 Statistics for Industry Groups and Industries. M01(AS)-1. Washington, DC: U.S. Census Bureau. Table 1. U.S. International Trade Commission. 2004. ITC Trade DataWeb. http://dataweb.usitc.gov/ As obtained March, 2004.

For the transportation service sectors, the NDEIM uses the latest service expenditure data reported by the U.S. Bureau of Economic Analysis. These values come from the 1997 Benchmark I-O Supplementary Make, Use, and Direct Requirements Tables at the Detailed Level." BEA's Industry Economic Program produces the input-output tables, which show how industries interact to provide input to, and take output from, each other. The data set can provide an appropriate measure transportation services purchased by the application markets included in NDEIM. Similar to the application markets, the model uses normalized commodities (e.g. price is one and value equals quantity). To estimate production for future years, we applied SO_2 growth rates for these sectors to the service expenditures reported in Table 10.3-10 (see discussion of growth rates in Section 10.3.6).

[N]International trade in construction is not significant.

Table 10.3-10
Baseline Data for NDEIM's Transportation Service Markets: 1997

Transportation Service Market	Value of Services Used by Application Markets Included in NDEIM ($$10^9$)
Locomotive	$19
Marine	$4

Source: U.S. Bureau of Economic Analysis (BEA). 1997 Benchmark I-O Supplementary Make, Use, and Direct Requirements Tables at the Detailed Level. Table 4. http://www.bea.gov/bea/dn2/i-o_benchmark.htm. Last updated November 24, 2003.

10.3.4 Calibrating the Fuel Spillover Baseline

The economic impact of the nonroad diesel rule is measured relative to the highway diesel rule. The highway rule is scheduled to be phased in prior to the nonroad rule. Thus, the effect of the highway rule must be incorporated into the baseline prior to modeling the impact of the nonroad rule. The main factor to be addressed is "spillover" fuel from the highway market. The Agency estimates that approximately one-third of nonroad equipment currently uses highway grade fuel because of access and distribution factors. Nonroad equipment currently using highway diesel will experience increased fuel costs as a result of the highway rule, but not as a result of the nonroad rule. These costs have already been captured in the highway rule analysis; thus, it is important to discount "spillover" fuel in the nonroad market to avoid double counting of cost impacts.

In this analysis, the baseline model is shocked by applying the compliance costs for the highway fuel requirements to the spillover fuel volumes included in Table 10.3-5. This provides an adjusted baseline for the nonroad economic impact analysis from which the incremental impact of the nonroad rule is estimated. When this adjustment is performed, increasing the cost of producing spillover fuel leads to a slight increase in the cost of producing goods and services in the application markets, and a decrease in application quantity ripples through the derived-demand curves of the equipment and engine markets, slightly reducing the baseline equipment and engine population. We assume that there are no substitutions between spillover diesel fuel consumption and nonroad diesel fuel consumption as prices change because demand is primarily driven by availability constraints.

10.3.5 Compliance Costs

The NDEIM uses the compliance cost estimates described in Chapters 6 and 7. These cost are summarized in Tables 10.3-13 through 10.3-15. The compliance cost per unit vary over time and by industry sector (engine, equipment, or fuel producer). All costs are presented in 2002 dollars.

For the reasons described in Section 10.1 and 10.2, the NDEIM does not handle all compliance costs in the same way. While all compliance costs are included in the economic welfare analysis to estimate the total social costs associated with the program, only some compliance costs are included in the market analysis to estimate changes in price and quantities of goods produced using the engines, equipment, and fuel affected by the rule. Table 10.3-11 identifies which compliance costs are used as shocks in the market analysis and which are added to the social cost estimates after changes in market prices and quantifies have been determined.

Table 10.3-11
How Compliance Costs are Accounted for in the Economic Analysis

Compliance Costs used to Shock the Market Model	Compliance Costs added after Market Analysis
• Variable costs for diesel engines • Variable costs for diesel equipment • Fixed and variable costs for nonroad diesel fuel	• Fixed costs for diesel engines • Fixed costs for diesel equipment • Changes in operating costs of diesel equipment

As noted above, marker costs for home heating fuel are included in the estimate of fixed and variable costs for nonroad diesel fuel (see Section 10.3.3.2, above).

10.3.5.1 Engine and Equipment Compliance Costs

For diesel engines, the projected compliance costs are largely due to using new technologies, such as advanced emissions control technologies and low-sulfur diesel fuel, to meet the proposed Tier 4 emissions standards. Compliance costs for engines are broken out by horsepower category and impact year. The method used to estimate these compliance costs is described in Section 6.4.3; the per unit compliance costs for the 175 to 600 hp range were estimated by sales weighting the 175 to 300 hp and the 300 to 600 hp per unit costs. The costs per unit change from year to year because engine standards are implemented differently in each power category. As shown in Table 10.3-13, the fixed cost per engine typically decreases after 5 years as these annualized costs are depreciated. The regulation's market impacts are driven primarily by the per-engine variable costs that remain relatively constant over time.

Because the estimated compliance costs for the rule are not directly proportional to engine price, the relative supply shift in each of the engine size markets is expected to vary.[O] As illustrated in Table 10.3-12, the ratio of variable engine compliance costs to market price ranges from 29 percent for engines 25 to 50 hp to 3 percent for engines above 600 hp. These different ratios lead to different relative shifts in the supply curves, and different impacts on the changes in market price and quantity for each market.

Table 10.3-12

[O]Fixed engine costs are not included in the supply shift; see Section 10.2.3.3.

Ratio of Variable Engine Compliance Costs to Engine Price

Power Range	Variable Engine Compliance Cost / Engine Price
0<hp<25	8.2%
25≤hp<50	29.3%
50≤hp<75	27.9%
75≤hp<100	28.3%
100≤hp<175	25.0%
175≤hp<600	8.5%
hp > 600 hp	2.8%

For nonroad equipment, the majority of the projected compliance costs are due to the need to redesign the equipment. The method used to estimate these compliance costs is described in Section 6.4.3. The fixed cost consists of the redesign cost to accommodate new emissions control devices. The variable cost consists of the cost of new or modified equipment hardware and of labor to install the new emissions control devices. The per unit compliance costs are weighted average costs within the appropriate horsepower range. The equipment sector compliance costs are broken out by horsepower category and impact year in Table 10.3-14. The majority of costs per piece of equipment are the fixed costs. The overall compliance costs per piece of equipment are less than half the overall costs associated with the same horsepower category engine.

Table 10.3-13
Compliance Costs per Engine[a]

HP Category	Cost Types	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
0<hp<25	Variable	$129	$129	$123	$123	$123	$123	$123	$123	$123	$123
	Fixed	$33	$32	$31	$30	$30	$0	$0	$0	$0	$0
	Total	$162	$161	$154	$153	$152	$123	$123	$123	$123	$123
25≤hp<50	Variable	$147	$147	$139	$139	$139	$849	$849	$645	$645	$645
	Fixed	$49	$48	$47	$46	$45	$74	$73	$71	$70	$69
	Total	$196	$195	$187	$186	$185	$924	$922	$716	$715	$714
50≤hp<75	Variable	$167	$167	$158	$158	$158	$837	$837	$636	$636	$636
	Fixed	$50	$49	$49	$48	$47	$76	$75	$73	$72	$71
	Total	$217	$216	$206	$205	$205	$913	$912	$710	$709	$708
75≤hp<100	Variable	$0	$0	$0	$0	$1,133	$1,133	$1,122	$1,122	$1,122	$1,122
	Fixed	$0	$0	$0	$0	$80	$78	$108	$106	$104	$29
	Total	$0	$0	$0	$0	$1,213	$1,212	$1,229	$1,227	$1,226	$1,151
100≤hp<175	Variable	$0	$0	$0	$0	$1,375	$1,375	$1,351	$1,351	$1,351	$1,351
	Fixed	$0	$0	$0	$0	$78	$77	$106	$105	$103	$29
	Total	$0	$0	$0	$0	$1,453	$1,452	$1,457	$1,455	$1,454	$1,380
175≤hp<600	Variable	$0	$0	$0	$2,191	$2,190	$1,697	$2,137	$2,136	$2,136	$2,135
	Fixed	$0	$0	$0	$326	$321	$316	$437	$430	$122	$120
	Total	$0	$0	$0	$2,517	$2,511	$2,012	$2,574	$2,567	$2,258	$2,255
hp≥600hp	Variable	$0	$0	$0	$2,911	$2,910	$2,246	$2,733	$6,153	$6,153	$5,347
	Fixed	$0	$0	$0	$861	$848	$835	$1,083	$1,526	$705	$695
	Total	$0	$0	$0	$3,771	$3,758	$3,081	$3,817	$7,679	$6,857	$6,042

[a] 2002 dollars

(continued)

Table 10.3-13 (continued)
Compliance Costs per Engine[a]

HP Category	Cost Types	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
0<hp<25	Variable	$123	$123	$123	$123	$123	$123	$123	$123	$123	$123
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$123	$123	$123	$123	$123	$123	$123	$123	$123	$123
25≤hp<50	Variable	$645	$645	$645	$645	$645	$645	$645	$645	$645	$645
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$645	$645	$645	$645	$645	$645	$645	$645	$645	$645
50≤hp<75	Variable	$636	$636	$636	$636	$636	$636	$636	$636	$636	$636
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$636	$636	$636	$636	$636	$636	$636	$636	$636	$636
75≤hp<100	Variable	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122
	Fixed	$28	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$1,150	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122
100≤hp<175	Variable	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351
	Fixed	$29	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$1,380	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351
175≤hp<600	Variable	$2,134	$2,133	$2,132	$2,132	$2,131	$2,130	$2,130	$2,129	$2,128	$2,128
	Fixed	$119	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$2,253	$2,133	$2,132	$2,132	$2,131	$2,130	$2,130	$2,129	$2,128	$2,128
hp≥600hp	Variable	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347
	Fixed	$685	$433	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$6,032	$5,780	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347

[a] 2002 dollars

(continued)

Table 10.3-13 (continued)
Compliance Costs per Engine[a]

HP Category	Cost Types	2028	2029	2030	2031	2032	2033	2034	2035	2036
0<hp<25	Variable	$123	$123	$123	$123	$123	$123	$123	$123	$123
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$123	$123	$123	$123	$123	$123	$123	$123	$123
25≤hp<50	Variable	$645	$645	$645	$645	$645	$645	$645	$645	$645
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$645	$645	$645	$645	$645	$645	$645	$645	$645
50≤hp<75	Variable	$636	$636	$636	$636	$636	$636	$636	$636	$636
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$636	$636	$636	$636	$636	$636	$636	$636	$636
75≤hp<100	Variable	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122	$1,122
100≤hp<175	Variable	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351	$1,351
175≤hp<600	Variable	$2,127	$2,127	$2,126	$2,126	$2,125	$2,124	$2,124	$2,123	$2,123
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$2,127	$2,127	$2,126	$2,126	$2,125	$2,124	$2,124	$2,123	$2,123
hp≥600hp	Variable	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347

[a] 2002 dollars

Table 10.3-14
Costs per Piece of Equipment[a]

HP Category	Cost Types	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
0<hp<25	Variable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Fixed	$15	$15	$14	$14	$14	$13	$13	$13	$12	$12
	Total	$15	$15	$14	$14	$14	$13	$13	$13	$12	$12
25≤hp<50	Variable	$0	$0	$0	$0	$0	$20	$20	$16	$16	$16
	Fixed	$8	$8	$8	$7	$7	$42	$41	$40	$40	$39
	Total	$8	$8	$8	$7	$7	$62	$62	$57	$56	$55
50≤hp<75	Variable	$0	$0	$0	$0	$0	$21	$21	$17	$17	$17
	Fixed	$8	$8	$8	$8	$8	$44	$43	$42	$42	$41
	Total	$8	$8	$8	$8	$8	$65	$64	$59	$59	$58
75≤hp<100	Variable	$0	$0	$0	$0	$45	$45	$48	$48	$48	$48
	Fixed	$0	$0	$0	$0	$109	$107	$132	$130	$128	$126
	Total	$0	$0	$0	$0	$154	$152	$180	$178	$176	$174
100≤hp<175	Variable	$0	$0	$0	$0	$46	$46	$49	$49	$49	$49
	Fixed	$0	$0	$0	$0	$170	$168	$207	$204	$201	$197
	Total	$0	$0	$0	$0	$216	$213	$256	$253	$250	$246
175≤hp<600	Variable	$0	$0	$0	$75	$75	$60	$80	$80	$80	$80
	Fixed	$0	$0	$0	$378	$372	$366	$453	$446	$439	$433
	Total	$0	$0	$0	$453	$447	$426	$533	$526	$519	$513
hp≥600hp	Variable	$0	$0	$0	$57	$57	$46	$61	$123	$123	$111
	Fixed	$0	$0	$0	$690	$680	$670	$806	$1,404	$1,384	$1,365
	Total	$0	$0	$0	$748	$737	$716	$867	$1,527	$1,507	$1,475

[a] 2002 dollars

(continued)

Table 10.3-14 (continued)
Costs per Piece of Equipment[a]

HP Category	Cost Types	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
0<hp<25	Variable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25≤hp<50	Variable	$16	$16	$16	$16	$16	$16	$16	$16	$16	$16
	Fixed	$32	$31	$31	$30	$30	$0	$0	$0	$0	$0
	Total	$48	$47	$47	$46	$46	$16	$16	$16	$16	$16
50≤hp<75	Variable	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17
	Fixed	$33	$33	$32	$32	$31	$0	$0	$0	$0	$0
	Total	$50	$50	$49	$49	$48	$17	$17	$17	$17	$17
75≤hp<100	Variable	$48	$48	$48	$48	$48	$48	$48	$48	$48	$48
	Fixed	$124	$122	$120	$118	$24	$24	$0	$0	$0	$0
	Total	$172	$170	$168	$167	$72	$72	$48	$48	$48	$48
100≤hp<175	Variable	$49	$49	$49	$49	$49	$49	$49	$49	$49	$49
	Fixed	$194	$192	$189	$186	$37	$37	$0	$0	$0	$0
	Total	$243	$241	$238	$235	$86	$86	$49	$49	$49	$49
175≤hp<600	Variable	$80	$80	$79	$79	$79	$79	$79	$79	$79	$79
	Fixed	$427	$421	$415	$83	$82	$81	$0	$0	$0	$0
	Total	$506	$500	$494	$162	$161	$160	$79	$79	$79	$79
hp≥600hp	Variable	$111	$111	$111	$111	$111	$111	$111	$111	$111	$111
	Fixed	$1,346	$1,328	$1,310	$693	$684	$675	$540	$0	$0	$0
	Total	$1,457	$1,438	$1,421	$804	$795	$786	$650	$111	$111	$111

[a] 2002 dollars

(continued)

Table 10.3-14 (continued)
Costs per Piece of Equipment[a]

HP Category	Cost Types	2028	2029	2030	2031	2032	2033	2034	2035	2036
0<hp<25	Variable	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0
25≤hp<50	Variable	$16	$16	$16	$16	$16	$16	$16	$16	$16
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$16	$16	$16	$16	$16	$16	$16	$16	$16
50≤hp<75	Variable	$17	$17	$17	$17	$17	$17	$17	$17	$17
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$17	$17	$17	$17	$17	$17	$17	$17	$17
75≤hp<100	Variable	$48	$48	$48	$48	$48	$48	$48	$48	$48
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$48	$48	$48	$48	$48	$48	$48	$48	$48
100≤hp<175	Variable	$49	$49	$49	$49	$49	$49	$49	$49	$49
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$49	$49	$49	$49	$49	$49	$49	$49	$49
175≤hp<600	Variable	$79	$79	$79	$79	$79	$79	$79	$79	$79
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$79	$79	$79	$79	$79	$79	$79	$79	$79
hp≥600hp	Variable	$111	$111	$111	$111	$111	$111	$111	$111	$111
	Fixed	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$111	$111	$111	$111	$111	$111	$111	$111	$111

[a] 2002 dollars

10.3.5.2 Nonroad Diesel Fuel Compliance Costs

The fuel compliance costs used in the NDEIM are the same as those described in Chapter 7. The NDEIM uses different compliance costs for each PADD, and for different fuel sulfur levels (15 and 500 ppm fuel). Thus, the compliance costs change when the fuel standards change, reflecting the phase-in of the fuel requirements. From 2007 to 2010, nonroad, locomotive, and marine diesel fuels are required to meet a 500 ppm sulfur cap. During this period small refiners can continue producing high sulfur distillate fuel (~3000 ppm) and sell it into the nonroad, locomotive and marine diesel fuel pool. In 2010, the sulfur standard for nonroad, locomotive and marine diesel fuel changes to a 15 ppm sulfur cap. From 2010 to 2014, small refiners can provide fuel complying with a 500 ppm sulfur cap to the nonroad, locomotive and marine diesel fuel pool, except in most of PADD 1 where 500 ppm small refiner fuel cannot be sold. After 2014, the program is fully phased-in when the small refinery provisions cease. Table 10.3-15 presents a summary of the compliance costs used in the model. It should be noted that these compliance costs are weighted averages of the separate compliance costs for each grade of fuel sold in that period.

In contrast to the engine and equipment compliance costs, the fuel compliance costs include fixed costs. They also include the marker costs described in Section 10.1.3.6. See Chapter 7 for a more detailed description of the components of the fuel compliance costs and how they are estimated. See Section 10.2..2.3 for a discussion of how fixed and variable costs are handled in the model.

Table 10.3-15
Fuel Compliance Costs, Locomotive, and Marine Diesel Fuel by PADD
Selected Years

Year[a]	Average Cost		Maximum Total Cost	
	500 ppm	15 ppm	500 ppm	15 ppm
PADD I and III				
2007-9	1.8	—	4.5	—
2010	1.86	5.7	4.57	9.4
2011	2.7	5.7	6.1	9.4
2014-13	2.7	6.0	6.1	9.6
2015	2.7	6.3	6.1	9.8
PADD II				
2007-9	2.5	—	3.8	—
2010	2.55	7.4	3.94	10.8
2011-13	3.5	7.4	5.9	10.8

Year[a]	Average Cost		Maximum Total Cost	
	500 ppm	15 ppm	500 ppm	15 ppm
2014	3.5	7.7	5.9	11.1
2015	3.5	7.9	5.9	11.2
PADD IV				
2007-9	3.5	—	6.1	—
2010	3.83	12.6	6.26	13.6
2011-13	9.2	12.6	9.2	13.6
2014	9.2	12.8	9.2	13.8
2015	9.2	13	9.2	13.9
PADD V[b]				
2007-9	1.5	—	1.5	—
2010	1.58	5.1	1.62	5.2
2011	3.7	5.1	4.4	5.2
2014-13	3.7	6.1	4.4	6.4
2015	3.7	6.9	4.4	7.3

[a]Note that the 500 ppm standard begins in 6/06 and the 15 ppm standard begins in 6/10

[b] Excludes diesel fuel sold for use in California which is regulated by California's regulations.

10.3.5.3 Changes in Operating Costs

As described in Section 6.2.3 of Chapter 6, changes in operating costs are expected to be realized by all diesel equipment users as a result of the reduced sulfur content of nonroad diesel fuel. These changes in operating costs include the change in maintenance costs associated with applying new emission controls to the engines; the change in maintenance costs associated with low-sulfur fuel such as extended oil-change intervals (extended oil change intervals results in maintenance savings); the change in fuel costs associated with the incrementally higher costs for low-sulfur fuel (see Chapter 7), and the change in fuel costs due to any fuel consumption impacts associated with applying new emission controls to the engines (e.g., cost is attributed to the CDPF and its need for periodic regeneration). Some of these changes in operating costs will accrue to users of existing as well as new equipment.

The expected changes in operating costs are not included in the market analysis. This is because, as explained in Chapter 6, these savings are not expected to affect consumer decisions with respect to new engines. Changes in operating costs are included in the social cost analysis, however, because they accrue to society. They are added into the estimated social costs as an additional savings to the application markets, since it is the users of these engines and fuels who will see these savings. Appendix 10I contains a sensitivity analysis in which operating cost savings are introduced into the market analysis as a downward shift in the application supply functions.

The operating savings in the social cost analysis were estimated by EPA using the estimated ¢/gallon operating savings estimates and the fuel volumes described in Chapter 6 and 7. Total annual operating savings were estimated for nonroad, locomotive, and marine fuel. The annual operating savings associated with nonroad fuel were allocated to the three application markets (i.e., the users of nonroad equipment) based on the number of gallons of nonroad diesel consumed in each of the agriculture (32.1 percent), construction (47.4 percent), and manufacturing sectors (20.5 percent). A different approach was followed for locomotive and marine fuel. This is necessary because not all locomotive and marine transportation services are provided to the three application markets included in the NDEIM (see Section 10.1.5). In this case, 54 percent of the locomotive and marine operating savings were allocated to the marine and locomotive transportation services included in the NDEIM and 46 percent were allocated to marine and locomotive transportation services provided for application markets not included in the NDEIM.

Table 10.3-16
Operating Cost Savings ($Millions)

Year	Nonroad	Locomotive	Marine	Total
2007	140	12	9	161
2008	246	21	15	282
2009	251	21	16	288
2010	266	22	17	305
2011	271	23	18	311
2012	261	23	18	302
2013	243	23	18	285
2014	257	17	19	293
2015	256	13	20	288
2016	241	13	20	274
2017	228	13	20	261
2018	216	13	20	249
2019	205	13	21	239
2020	192	13	22	227
2021	182	13	23	218
2022	176	14	23	213
2023	171	14	23	208
2024	167	14	23	204
2025	163	14	24	201
2026	160	14	24	198
2027	157	14	24	196
2028	156	14	25	195
2029	155	14	25	194
2030	154	15	25	194
2031	154	15	26	194
2032	154	15	26	195
2033	154	15	26	195
2034	154	15	27	196
2035	155	15	27	197
2036	156	15	27	198

Source: See Chapter 6 for an explanation of operating savings; the above values are based on the values reported in Table 6.4-3, applied to the relevant fuel volumes.

10.3.6 Growth Rates

The growth rates used in this analysis for engines and equipment are the same as those provided in Section 8.1. The growth rate for nonroad diesel fuel is from the Nonroad Model. The growth rates for locomotive, marine, heating oil, and highway diesel fuel are all from EIA's Annual Energy Outlook 2003.

Growth rates for the application markets are the average of the growth rates for equipment used in the relevant markets. They range from 1.8 percent (>600 HP) to 3.5 percent (<25 HP). This method was used over a method applying sales weighted averages because it does not overestimate the application growth rate by giving more weight to higher growth rates of small HP equipment. If a weighted average were used, the small engine growth rate would dominate because there are so many more small engines. Using such a weighted average would then overstate the growth rate for the larger engines. The difference between the two approach is about 0.2 percent (about 2.3 percent for unweighted and about 2.5 percent for weighted).

Finally, for the locomotive and marine sectors, growth is based on EPA's SO_2 inventory growth projections for marine diesel engines that use distillate fuel (typically engines with displacement less than 30 liters per cylinder), 50-state annual inventories, 1999-2003.

10.3.7 Market Supply and Demand Elasticities

To operationalize the market model, supply and demand elasticities are needed to represent the behavior adjustments that are likely to be made by market participants. The following parameters are needed:

- supply and demand price elasticities for application markets (construction, agriculture, and manufacturing),
- supply elasticities for equipment markets,
- supply elasticities for engine markets, and
- supply elasticities for diesel fuel markets.

Note that, for the equipment, engine, and diesel fuel markets, demand-specific elasticity estimates are not needed because they are derived internally as a function of changes in output levels in the applications markets.

Tables 10.3-17 and 10.3-18 provides a summary of the demand and supply elasticities used to estimate the economic impact of the proposed rule. Most elasticities were derived econometrically using publicly available data, with the exception of the supply elasticities for the construction and agricultural application markets and the diesel fuel supply elasticity, which were obtained from previous studies.[P] The general methodologies for estimating the supply and

[P] A supply function was estimated as part of the simultaneous equations approach used for the construction and manufacturing application markets. However, the supply elasticity estimates were not statistically significant and were negative, which is inconsistent with generally demand elasticities are discussed below. The specific regression results are presented in Appendix 10G. It should be noted that these elasticities reflect intermediate run behavioral changes. In the long run, supply and demand are expected to be more elastic since more substitutes may become available.

accepted economic theory. For this reason, literature estimates were used for the supply elasticities in the construction and manufacturing application markets.

Table 10.3-17
Summary of Market Demand Elasticities Used in the NDEIM

Market	Estimate	Source	Method	Input Data Summary
Applications				
Agriculture	–0.20	EPA econometric estimate	Productivity shift approach (Morgenstern, Pizer, and Shih, 2002)	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Construction	–0.96	EPA econometric estimate	Simultaneous equation (log-log) approach	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Manufacturing	–0.58	EPA econometric estimate	Simultaneous equation (log-log) approach.	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Transportation Services				
Locomotive		Derived demand	In the derived demand approach, • compliance costs increase prices and decrease demand for products and services in the application markets; • this in turn leads to reduced demand for diesel equipment, engines and fuel, which are inputs into the production of products and services in the application markets	
Marine		Derived demand		
Equipment				
Agriculture		Derived demand		
Construction		Derived demand		
Pumps/ compressors		Derived demand		
Generators and Welders		Derived demand		
Refrigeration		Derived demand		
Industrial		Derived demand		
Lawn and Garden		Derived demand		
Engines		Derived demand		
Diesel fuel		Derived demand		

Table 10.3-18
Summary of Market Supply Elasticities Used in the NDEIM

Markets	Estimate	Source	Method	Input Data Summary
Applications				
Agriculture	0.32	Literature-based estimate	Production-weighted average of individual crop estimates ranging from 0.27 to 0.55. (Lin et al., 2000)	Agricultural Census data 1991 – 1995
Construction	1.0	Literature-based estimate	Based on Topel and Rosen, (1988).[a]	Census data, 1963 – 1983
Manufacturing	1.0	Literature-based estimate	Literature estimates are not available so assumed same value as for Construction market	Not applicable
Transportation Services				
Locomotive	0.6	Literature-based estimate	Method based on Ivaldi and McCollough (2001)	Association of American Railroads 1978-1997
Marine	0.6	Literature-based estimate	Literature estimates not available so assumed same value as for locomotive market	Not applicable
Equipment				
Agriculture	2.14	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3523
Construction	3.31	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3531
Pumps/ compressors	2.83	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3561 and 3563
Generators/ Welder Sets	2.91	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3548
Refrigeration	2.83	EPA econometric estimate		Assumed same as pumps/compressors
Industrial	5.37	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3537
Lawn and Garden	3.37	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3524
Engines	3.81	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3519
Diesel fuel	0.24	Literature based estimate	Based on Considine (2002).[b]	From Energy Intelligence Group (EIG); 1987-2000[c]

[a] Most other studies estimate ranges that encompass 1.0, including DiPasquale (1997) and DiPasquale and Wheaton (1994).

[b] Other estimates range from 0.02 to 1.0 (Greene and Tishchishyna, 2000). However, Considine (2002) is one of the few studies that estimates a supply elasticity for refinery operations. Most petroleum supply elasticities also include extraction.

[c] This source refers to the data used by Considine in his 2002 study.

10.3.8 Model Solution

10.3.8.1 Computing Baseline and With-Regulation Equilibrium Conditions

To perform the economic impact analysis, the model compares the baseline equilibrium conditions and the counterfactual with-regulation equilibrium conditions produced under a changed policy regime. The assumption of an "observable" baseline equilibrium leads directly to the need for and construction of a data set that fulfills the equilibrium conditions for markets included in NDEIM. For this analysis, we examine the impacts of the rule for 29 years (2007 to 2036). As a result, we need to develop an observable baseline for each of these future years. This section describes the data and approach used to establish these baselines.

Developing a Baseline Equilibrium: In order to construct a baseline for each year, equilibrium market conditions without the rule were computed using the following three steps:

- Collect baseline prices and production data for the most recently available year (2000).

- Apply appropriate growth rates to estimate future production for markets included in NDEIM, and

- Incorporate the impact of increased fuel costs associated with the highway rule prior to analysis of the final nonroad rule. We incorporate the impact of the highway rule costs in the baseline because they have already been captured in the highway rule analysis; thus, we avoid double counting of cost impacts of the highway rule. In effect, our baseline market projections are "shocked" by the highway rule and a new set of baseline prices and quantities is estimated for all linked markets. This new baseline is the appropriate point of departure for analysis of the final nonroad rule.

It is important to note that the baseline analysis of each year does not incorporate the cumulative regulatory effects from the highway and nonroad rule in previous years. For example, the regulatory effects impacts from year 2007 do not affect the baseline conditions for the years 2008 through 2036. These dynamic interactions would reduce the estimated impact of the regulation but are beyond the scope of the modeling effort. As a result, the impact estimates may be viewed as conservative in that they likely over estimate impacts.

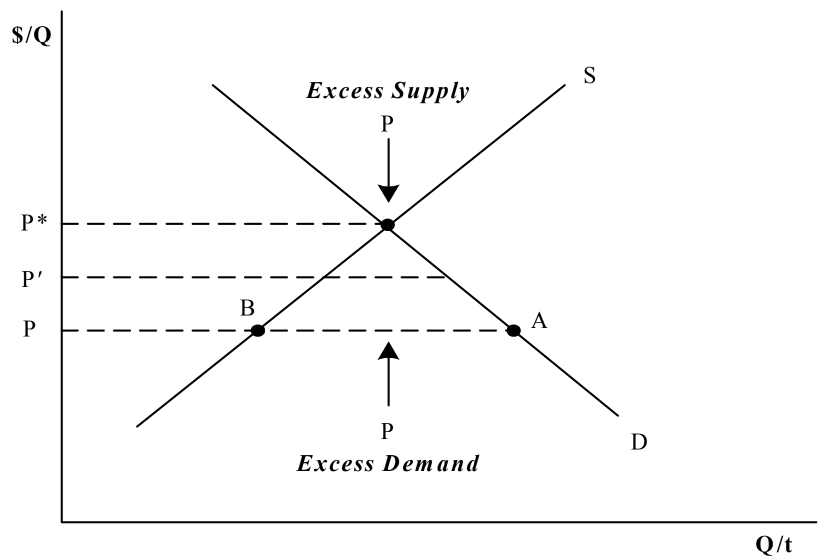
Shifting the Supply Function: The starting point for assessing the market impacts of a regulatory action is to incorporate the regulatory compliance costs into the production decision of the firm. In order to quantify this upward shift, the model the per-unit compliance cost estimates as the measure of additional cost per unit of producing output[Q]. Treatment of compliance costs in this manner is the conceptual equivalent of a unit tax on output.

[Q]We discuss the calculation of the appropriate per-unit compliance cost measure used in each market in Section 10.2.3.3 of the RIA.

Computing With-Regulation Equilibrium Conditions: The French economist Léon Walras proposed one early model of market price adjustment by using the following thought experiment. Suppose there is a hypothetical agent that facilitates market adjustment by playing the role of an "auctioneer." He announces prices, collects information about supply and demand responses (without transactions actually taking place), and continues this process until market equilibrium is achieved.

For example, suppose the auctioneer calls out a price (P) that is lower than the equilibrium price (P*) (see Figure 10.3-1). He then determines that the quantity demanded (A) exceeds the quantity supplied (B) and calls out a new (higher) price (P'). This process continues until P=P*. A similar analysis takes place when excess supply exists. The auctioneer calls out lower prices when the price is higher than the equilibrium price.

Figure 10.3-1.
For Prices Higher (Lower) than P*, Price Will Fall (Rise)



10.3.8.2 Solution Algorithm

Supply responses and market adjustments can be conceptualized as an interactive process. Producers facing increased production costs due to compliance are willing to supply smaller quantities at the baseline price. This reduction in market supply leads to an increase in the market price that all producers and consumers face, which leads to further responses by producers and consumers and thus new market prices, and so on. The new with-regulation equilibrium is the result of a series of iterations in which price is adjusted and producers and consumers respond, until a set of stable market prices arises where total market supply equals market demand. Market price adjustment takes place based on a price revision rule, described below, that adjusts price upward (downward) by a given percentage in response to excess demand (excess supply).

The NDEIM model uses a similar type of algorithm for determining with-regulation equilibria and the process can be summarized by six recursive steps:

1. Impose the control costs on affected supply segments, thereby affecting their supply decisions.

2. Recalculate the market supply in each market. Excess demand currently exists.

3. Determine the new prices via a price revision rule. We use a rule similar to the factor price revision rule described by Kimbell and Harrison (1986). P_i is the market price at iteration I, q_d is the quantity demanded, and q_s is the quantity supplied. The parameter z influences the magnitude of the price revision and speed of convergence. The revision rule increases the price when excess demand exists, lowers the price when excess supply exists, and leaves the price unchanged when market demand equals market supply. The price adjustment is expressed as follows:

$$P_{i+1} = P_1 \bullet \left(\frac{q_d}{q_s} \right)^z \tag{10.1}$$

4. Recalculate market supply with new prices,

5. Compute market demand in each market.

6. Compare supply and demand in each market. If equilibrium conditions are not satisfied, go to Step 3, resulting in a new set of market prices. Repeat until equilibrium conditions are satisfied (i.e., the ratio of supply and demand is arbitrarily close to one). When the ratio is appropriately close to one, the market- clearing condition of supply equals demand is satisfied.

10.4 Estimating Impacts

Using the static partial equilibrium analysis, the NDEIM model loops through each year calculating new market equilibriums based on the projected baseline economic conditions and compliance cost estimates that shift the supply curves in the model. The model calculates price and quantity changes and uses these measures to estimate the social costs of the rule and partition the impact between producers and consumers. This approach follows the classical treatment of tax burden distribution in the public finance literature (e.g., Harberger, 1974).

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APPENDIX 10A: Impacts on the Engine Markets

This appendix provides the time series of impacts from 2007 through 2036 for the engine markets. Seven separate engine markets were modeled segmented by engine size in horsepower (the EIA includes more horsepower categories than the standards, allowing more efficient use of the engine compliance cost estimates developed for this rule):

- less than 25 hp
- 26 to 50 hp
- 51 to 75 hp
- 76 to 100 hp
- 101 to 175 hp
- 176 to 600 hp
- greater than 601 hp

Tables 10A-1 through 10A-7 provide the time series of impacts for the seven horsepower markets included in the analysis. Each table includes the following:

- average engine price
- average engineering costs (variable and fixed) per engine
  - Note that in the engineering cost analysis, fixed costs for engine manufacturers are recovered in the first five years (see Chapter 6)
- absolute change in the market price ($)
  - Note that the estimated absolute change in market price is based on variable costs only; see Appendix 10I for a sensitivity analysis including fixed costs as well
- relative change in market price (%)
- relative change in market quantity (%)
- total engineering (regulatory) costs for merchant engines ($)
- change in producer surplus from merchant engine manufacturers

As described in Section 10.3.3.1, approximately 65 percent of engines are sold on the market and these are referred to as "merchant" engines. The remaining 35 percent are consumed internally by integrated equipment manufacturers and are referred to as "captive" engines. The total engineering costs and changes in producer surplus presented in this appendix include only merchant engines because captive engines never pass through the engines markets. Fixed and variable engineering costs and changes in producer surplus associated with captive engines are included in equipment manufacture impact estimates presented in Appendix 10B.

All prices and costs are presented in $2002, and real engine prices are assumed to be constant. The engineering cost per engine typically decreases after 5 years as the annualized fixed costs are recovered. The price increase after that time is driven by the per-engine variable costs and remains relatively constant over time.

For all the engine size categories, the majority of the cost of the regulation is passed along through increased engine prices. Price increases in 2036 are estimated to be $123 (8.2 percent) for engines <25 hp, $645 (22.2 percent) for engines 26 to 50 hp, $636 (21.2 percent) for engines 51 to 75 hp, $1,121 (28 percent) for engines 76 to 100 hp, $1,350 (24.6 percent) for engines 101 to 175 hp, $2,122 (10.6 percent) for engines 176 to 600 hp, and $5,343 (6.6 percent) for engines above 601 hp.

While the cost per engine and market impacts (in terms of percentage change in price and quantity) stabilize in the later years of the regulation, the engineering costs and producer surplus changes continue to gradually increase because the projected baseline population of engines increases over time.

Table 10A-1. Impacts on the Engine Market and Engine Manufacturers: ≤25hp (Average Price per Engine = $1,500)[a]

	Engine (≤25Hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.001%	—	—
2008	$162	$129	8.6%	–0.002%	$20,017	–$4,043
2009	$161	$129	8.6%	–0.002%	$20,449	–$4,043
2010	$154	$123	8.2%	–0.004%	$20,007	–$4,044
2011	$153	$123	8.2%	–0.007%	$20,417	–$4,045
2012	$152	$123	8.2%	–0.009%	$20,827	–$4,047
2013	$123	$123	8.2%	–0.010%	$17,195	–$5
2014	$123	$123	8.2%	–0.011%	$17,605	–$6
2015	$123	$123	8.2%	–0.011%	$18,015	–$6
2016	$123	$123	8.2%	–0.011%	$18,425	–$6
2017	$123	$123	8.2%	–0.011%	$18,835	–$6
2018	$123	$123	8.2%	–0.011%	$19,245	–$6
2019	$123	$123	8.2%	–0.011%	$19,654	–$6
2020	$123	$123	8.2%	–0.011%	$20,064	–$7
2021	$123	$123	8.2%	–0.011%	$20,474	–$7
2022	$123	$123	8.2%	–0.011%	$20,884	–$7
2023	$123	$123	8.2%	–0.011%	$21,294	–$7
2024	$123	$123	8.2%	–0.011%	$21,704	–$7
2025	$123	$123	8.2%	–0.011%	$22,114	–$7
2026	$123	$123	8.2%	–0.011%	$22,524	–$7
2027	$123	$123	8.2%	–0.011%	$22,934	–$7
2028	$123	$123	8.2%	–0.011%	$23,344	–$8
2029	$123	$123	8.2%	–0.011%	$23,753	–$8
2030	$123	$123	8.2%	–0.011%	$24,163	–$8
2031	$123	$123	8.2%	–0.011%	$24,573	–$8
2032	$123	$123	8.2%	–0.011%	$24,983	–$8
2033	$123	$123	8.2%	–0.011%	$25,393	–$8
2034	$123	$123	8.2%	–0.011%	$25,803	–$8
2035	$123	$123	8.2%	–0.011%	$26,213	–$9
2036	$123	$123	8.2%	–0.011%	$26,623	–$9
NPV[b]					$370,428	–$17,043

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10A-2. Impacts on the Engine Market and Engine Manufacturers: 26–50hp (Average Price per Engine = $2,900)[a]

	Engine (26hp to 50hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.002%	—	–$1
2008	$196	$147	5.1%	–0.003%	$26,163	–$6,592
2009	$195	$147	5.1%	–0.003%	$26,589	–$6,592
2010	$187	$139	4.8%	–0.006%	$25,943	–$6,595
2011	$186	$139	4.8%	–0.011%	$26,347	–$6,600
2012	$185	$139	4.8%	–0.014%	$26,750	–$6,604
2013	$924	$849	29.3%	–0.015%	$136,464	–$10,981
2014	$922	$849	29.3%	–0.016%	$138,927	–$10,983
2015	$716	$645	22.2%	–0.016%	$110,004	–$10,983
2016	$715	$645	22.2%	–0.016%	$111,875	–$10,984
2017	$714	$645	22.2%	–0.016%	$113,746	–$10,984
2018	$645	$645	22.2%	–0.016%	$104,651	–$19
2019	$645	$645	22.2%	–0.016%	$106,522	–$19
2020	$645	$645	22.2%	–0.016%	$108,392	–$19
2021	$645	$645	22.2%	–0.016%	$110,263	–$20
2022	$645	$645	22.2%	–0.016%	$112,134	–$20
2023	$645	$645	22.2%	–0.016%	$114,005	–$20
2024	$645	$645	22.2%	–0.016%	$115,875	–$21
2025	$645	$645	22.2%	–0.016%	$117,746	–$21
2026	$645	$645	22.2%	–0.016%	$119,617	–$21
2027	$645	$645	22.2%	–0.016%	$121,488	–$22
2028	$645	$645	22.2%	–0.016%	$123,359	–$22
2029	$645	$645	22.2%	–0.016%	$125,229	–$22
2030	$645	$645	22.2%	–0.016%	$127,100	–$23
2031	$645	$645	22.2%	–0.016%	$128,971	–$23
2032	$645	$645	22.2%	–0.016%	$130,842	–$23
2033	$645	$645	22.2%	–0.016%	$132,712	–$24
2034	$645	$645	22.2%	–0.016%	$134,583	–$24
2035	$645	$645	22.2%	–0.016%	$136,454	–$24
2036	$645	$645	22.2%	–0.016%	$138,325	–$25
NPV[b]					$1,722,675	–$67,561

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table10.A-3. Impacts on the Engine Market and Engine Manufacturers: 51–75hp
(Average Price per Engine = $3,000)[a]

	Engine (51hp to 75hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.002%	—	–$1
2008	$217	$167	5.6%	–0.004%	$18,388	–$4,259
2009	$216	$167	5.6%	–0.004%	$18,650	–$4,259
2010	$206	$158	5.3%	–0.006%	$18,102	–$4,261
2011	$205	$158	5.3%	–0.011%	$18,350	–$4,264
2012	$205	$158	5.3%	–0.014%	$18,597	–$4,267
2013	$913	$837	27.9%	–0.015%	$84,465	–$7,033
2014	$912	$837	27.9%	–0.017%	$85,780	–$7,035
2015	$710	$636	21.2%	–0.017%	$67,870	–$7,035
2016	$709	$636	21.2%	–0.017%	$68,869	–$7,035
2017	$708	$636	21.2%	–0.017%	$69,868	–$7,035
2018	$636	$636	21.2%	–0.017%	$63,844	–$13
2019	$636	$636	21.2%	–0.017%	$64,843	–$13
2020	$636	$636	21.2%	–0.017%	$65,842	–$13
2021	$636	$636	21.2%	–0.017%	$66,841	–$13
2022	$636	$636	21.2%	–0.017%	$67,840	–$13
2023	$636	$636	21.2%	–0.017%	$68,840	–$13
2024	$636	$636	21.2%	–0.017%	$69,839	–$14
2025	$636	$636	21.2%	–0.017%	$70,838	–$14
2026	$636	$636	21.2%	–0.017%	$71,837	–$14
2027	$636	$636	21.2%	–0.017%	$72,836	–$14
2028	$636	$636	21.2%	–0.017%	$73,835	–$14
2029	$636	$636	21.2%	–0.017%	$74,834	–$15
2030	$636	$636	21.2%	–0.017%	$75,833	–$15
2031	$636	$636	21.2%	–0.017%	$76,832	–$15
2032	$636	$636	21.2%	–0.017%	$77,832	–$15
2033	$636	$636	21.2%	–0.017%	$78,831	–$15
2034	$636	$636	21.2%	–0.017%	$79,830	–$16
2035	$636	$636	21.2%	–0.017%	$80,829	–$16
2036	$636	$636	21.2%	–0.017%	$81,828	–$16
NPV[b]					$1,052,492	–$43,432

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table10A-4. Impacts on the Engine Market and Engine Manufacturers: 76–100hp
(Average Price per Engine = $4,000)[a]

	Engine (76hp to 100hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.002%	—	–$1
2008	—	—	0.0%	–0.004%	—	–$1
2009	—	—	0.0%	–0.004%	—	–$2
2010	—	—	0.0%	–0.006%	—	–$3
2011	—	—	0.0%	–0.011%	—	–$6
2012	$1,213	$1,133	28.3%	–0.015%	$69,454	–$4,576
2013	$1,212	$1,133	28.3%	–0.016%	$70,577	–$4,577
2014	$1,229	$1,121	28.0%	–0.017%	$72,815	–$6,379
2015	$1,227	$1,121	28.0%	–0.017%	$73,926	–$6,379
2016	$1,226	$1,121	28.0%	–0.017%	$75,037	–$6,379
2017	$1,151	$1,121	28.0%	–0.017%	$71,580	–$1,812
2018	$1,150	$1,121	28.0%	–0.017%	$72,691	–$1,812
2019	$1,122	$1,121	28.0%	–0.017%	$72,001	–$11
2020	$1,122	$1,121	28.0%	–0.017%	$73,112	–$11
2021	$1,122	$1,121	28.0%	–0.017%	$74,223	–$11
2022	$1,122	$1,121	28.0%	–0.017%	$75,334	–$11
2023	$1,122	$1,121	28.0%	–0.017%	$76,445	–$12
2024	$1,122	$1,121	28.0%	–0.017%	$77,556	–$12
2025	$1,122	$1,121	28.0%	–0.017%	$78,667	–$12
2026	$1,122	$1,121	28.0%	–0.017%	$79,778	–$12
2027	$1,122	$1,121	28.0%	–0.017%	$80,889	–$12
2028	$1,122	$1,121	28.0%	–0.017%	$82,000	–$12
2029	$1,122	$1,121	28.0%	–0.017%	$83,111	–$13
2030	$1,122	$1,121	28.0%	–0.017%	$84,222	–$13
2031	$1,122	$1,121	28.0%	–0.017%	$85,333	–$13
2032	$1,122	$1,121	28.0%	–0.017%	$86,444	–$13
2033	$1,122	$1,121	28.0%	–0.017%	$87,555	–$13
2034	$1,122	$1,121	28.0%	–0.017%	$88,666	–$13
2035	$1,122	$1,121	28.0%	–0.017%	$89,777	–$14
2036	$1,122	$1,121	28.0%	–0.017%	$90,889	–$14
NPV[b]					$1,098,490	–$23,502

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10A-5. Impacts on the Engine Market and Engine Manufacturers: 101–175hp (Average Price per Engine = $5,500)[a]

	Engine (101hp to 175hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.003%	—	–$1
2008	—	—	0.0%	–0.004%	—	–$3
2009	—	—	0.0%	–0.004%	—	–$3
2010	—	—	0.0%	–0.007%	—	–$5
2011	—	—	0.0%	–0.013%	—	–$11
2012	$1,453	$1,375	25.0%	–0.017%	$90,913	–$4,892
2013	$1,452	$1,375	25.0%	–0.018%	$92,337	–$4,894
2014	$1,457	$1,350	24.6%	–0.019%	$94,162	–$6,885
2015	$1,455	$1,350	24.6%	–0.020%	$95,561	–$6,886
2016	$1,454	$1,350	24.6%	–0.020%	$96,960	–$6,886
2017	$1,380	$1,350	24.6%	–0.020%	$93,480	–$2,008
2018	$1,380	$1,350	24.6%	–0.020%	$94,879	–$2,009
2019	$1,351	$1,350	24.6%	–0.020%	$94,288	–$19
2020	$1,351	$1,350	24.6%	–0.020%	$95,687	–$19
2021	$1,351	$1,350	24.6%	–0.020%	$97,086	–$19
2022	$1,351	$1,350	24.6%	–0.020%	$98,485	–$19
2023	$1,351	$1,350	24.6%	–0.020%	$99,884	–$20
2024	$1,351	$1,350	24.6%	–0.020%	$101,283	–$20
2025	$1,351	$1,350	24.6%	–0.020%	$102,682	–$20
2026	$1,351	$1,350	24.6%	–0.020%	$104,081	–$21
2027	$1,351	$1,350	24.6%	–0.020%	$105,480	–$21
2028	$1,351	$1,350	24.6%	–0.020%	$106,879	–$21
2029	$1,351	$1,350	24.6%	–0.020%	$108,278	–$21
2030	$1,351	$1,350	24.6%	–0.020%	$109,677	–$22
2031	$1,351	$1,350	24.6%	–0.020%	$111,075	–$22
2032	$1,351	$1,350	24.6%	–0.020%	$112,474	–$22
2033	$1,351	$1,350	24.6%	–0.020%	$113,873	–$23
2034	$1,351	$1,350	24.6%	–0.020%	$115,272	–$23
2035	$1,351	$1,350	24.6%	–0.020%	$116,671	–$23
2036	$1,351	$1,350	24.6%	–0.020%	$118,070	–$23
NPV[b]					$1,431,405	–$25,444

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10A-6. Impacts on the Engine Market and Engine Manufacturers: 176–600hp (Average Price per Engine = $20,000)[a]

	Engine (176hp to 600hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.003%	—	–$3
2008	—	—	0.0%	–0.004%	—	–$7
2009	—	—	0.0%	–0.004%	—	–$7
2010	—	—	0.0%	–0.008%	—	–$13
2011	$2,517	$2,191	11.0%	–0.014%	$101,112	–$13,109
2012	$2,511	$2,189	10.9%	–0.018%	$102,473	–$13,118
2013	$2,012	$1,696	8.5%	–0.019%	$83,408	–$13,121
2014	$2,574	$2,136	10.7%	–0.021%	$108,339	–$18,421
2015	$2,567	$2,135	10.7%	–0.021%	$109,668	–$18,423
2016	$2,258	$2,135	10.7%	–0.021%	$97,915	–$5,342
2017	$2,255	$2,134	10.7%	–0.021%	$99,244	–$5,342
2018	$2,253	$2,133	10.7%	–0.021%	$100,573	–$5,343
2019	$2,133	$2,132	10.7%	–0.021%	$96,607	–$48
2020	$2,132	$2,131	10.7%	–0.021%	$97,936	–$48
2021	$2,132	$2,131	10.7%	–0.021%	$99,265	–$49
2022	$2,131	$2,130	10.7%	–0.021%	$100,594	–$49
2023	$2,130	$2,129	10.6%	–0.021%	$101,923	–$50
2024	$2,130	$2,129	10.6%	–0.021%	$103,253	–$51
2025	$2,129	$2,128	10.6%	–0.021%	$104,582	–$51
2026	$2,128	$2,127	10.6%	–0.021%	$105,911	–$52
2027	$2,128	$2,127	10.6%	–0.021%	$107,240	–$53
2028	$2,127	$2,126	10.6%	–0.021%	$108,570	–$54
2029	$2,127	$2,126	10.6%	–0.021%	$109,899	–$54
2030	$2,126	$2,125	10.6%	–0.021%	$111,228	–$55
2031	$2,126	$2,124	10.6%	–0.021%	$112,557	–$56
2032	$2,125	$2,124	10.6%	–0.021%	$113,887	–$56
2033	$2,124	$2,123	10.6%	–0.021%	$115,216	–$57
2034	$2,124	$2,123	10.6%	–0.021%	$116,545	–$58
2035	$2,123	$2,122	10.6%	–0.021%	$117,874	–$58
2036	$2,123	$2,122	10.6%	–0.021%	$119,203	–$59
NPV[b]					$1,561,195	–$69,509

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10A-7. Impacts on the Engine Market and Engine Manufacturers: ≥601hp (Average Price per Engine = $80,500)[a]

	Engine (≥601hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Engine Manufacturers (10^3)
2007	—	—	0.0%	–0.002%	—	—
2008	—	–$1	0.0%	–0.004%	—	–$1
2009	—	–$1	0.0%	–0.004%	—	–$1
2010	—	–$1	0.0%	–0.007%	—	–$2
2011	$3,771	$2,908	3.6%	–0.013%	$6,156	–$1,409
2012	$3,758	$2,907	3.6%	–0.017%	$6,228	–$1,410
2013	$3,081	$2,242	2.8%	–0.017%	$5,182	–$1,411
2014	$3,817	$2,730	3.4%	–0.019%	$6,514	–$1,856
2015	$7,679	$6,149	7.6%	–0.020%	$13,296	–$2,649
2016	$6,857	$6,149	7.6%	–0.020%	$12,044	–$1,244
2017	$6,042	$5,343	6.6%	–0.020%	$10,761	–$1,244
2018	$6,032	$5,343	6.6%	–0.020%	$10,893	–$1,244
2019	$5,780	$5,343	6.6%	–0.020%	$10,582	–$800
2020	$5,347	$5,343	6.6%	–0.020%	$9,921	–$7
2021	$5,347	$5,343	6.6%	–0.020%	$10,054	–$7
2022	$5,347	$5,343	6.6%	–0.020%	$10,187	–$7
2023	$5,347	$5,343	6.6%	–0.020%	$10,319	–$8
2024	$5,347	$5,343	6.6%	–0.020%	$10,452	–$8
2025	$5,347	$5,343	6.6%	–0.020%	$10,584	–$8
2026	$5,347	$5,343	6.6%	–0.020%	$10,717	–$8
2027	$5,347	$5,343	6.6%	–0.020%	$10,850	–$8
2028	$5,347	$5,343	6.6%	–0.020%	$10,982	–$8
2029	$5,347	$5,343	6.6%	–0.020%	$11,115	–$8
2030	$5,347	$5,343	6.6%	–0.020%	$11,248	–$8
2031	$5,347	$5,343	6.6%	–0.020%	$11,380	–$8
2032	$5,347	$5,343	6.6%	–0.020%	$11,513	–$8
2033	$5,347	$5,343	6.6%	–0.020%	$11,646	–$9
2034	$5,347	$5,343	6.6%	–0.020%	$11,778	–$9
2035	$5,347	$5,343	6.6%	–0.020%	$11,911	–$9
2036	$5,347	$5,343	6.6%	–0.020%	$12,044	–$9
NPV[b]					$150,134	–$9,762

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

APPENDIX 10B: Impacts on Equipment Markets

This appendix provides the time series of impacts from 2007 through 2036 for the equipment markets. The equipment markets are the markets associated with the production and consumption of equipment that use nonroad diesel engines. Seven equipment types were modeled:

- agricultural
- construction
- pumps and compressors
- generators and welder sets
- refrigeration and air conditioning
- general industrial
- lawn and garden

Forty-two equipment markets were modeled, representing 7 horsepower categories within 7 application categories. There are 7 horsepower/application categories that did not have sales in 2000 and are not included in the model, so the total number of diesel equipment markets is 42 rather than 49.[R]

There are two sets of tables in this appendix. Tables 10B-1 through 10B-7 provide a summary of the time series of impacts for the seven equipment markets included in the analysis. Tables 10B-8 through 10B-49 provide the time series impacts for each equipment market by horsepower grouping. Each table includes the following:

- average equipment price
- average engineering costs (variable and fixed) per piece of equipment
  - Note that in the engineering cost analysis, fixed costs for equipment manufacturers are recovered in the first ten years (see Chapter 6)
- absolute change in the market price ($)
  - Note that the estimated absolute change in market price is based on variable costs only; see Appendix 10I for a sensitivity analysis including fixed costs as well
- relative change in the market price (%)
- relative change in the market quantity (%)
- total engineering (regulatory) costs associated with each market ($)
- change in producer surplus for all manufacturers in the market

As described in Section 10.3.3.1, approximately 65 percent of engines are sold on the market and these are referred to as “merchant” engines. The remaining 35 percent are consumed

[R]These seven equipment categories that did not have sales in 2000 are: agricultural equipment >600 hp; gensets & welders > 600 hp; refrigeration & A/C > 71 hp (4 hp categories); and lawn & garden >600 hp.

internally by integrated equipment manufacturers and are referred to as "captive" engines. The engineering costs and changes in producer surplus presented in this appendix include total equipment costs as well as captive engine costs. Because captive engines never pass through the engines markets, they therefore present an additional cost for integrated equipment producers.

All prices and costs are presented in $2002, and real equipment prices are assumed to be constant. The engineering cost per piece of equipment peak around 2014 as the fixed cost per equipment are phased in and then are depreciated over the next several years.

A greater percentage of the cost of the regulation is borne by the various equipment markets than is borne by the engine market. However, a substantial percentage of the cost is still passed along through increased equipment prices. For each equipment market as a whole, price increases range from an average increase of 1.31 percent in the general industrial equipment market to 5.4 percent in the pumps and compressors market. For specific types of equipment, the price increases range from 0.7 percent for construction <25, 176-600 and >600 hp, and general industrial equipment (<25 hp), to 9.4 percent for pumps and compressors 76-100 hp.

Even though the cost per piece of equipment and market impacts (in terms of percentage change in price and quantity) stabilize after the initial years of the regulation, the engineering costs and produce surplus changes continue to gradually increase because the projected baseline population of equipment increases over time.

Table 10B-1. Impacts on Agricultural Equipment Market and Manufacturers (Average Price per Equipment = $24,200)[a,b]

	Agricultural Equipment					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	–$1	0.0%	–0.004%	—	–$114
2008	$94	$67	0.5%	–0.006%	$6,217	–$2,359
2009	$93	$67	0.5%	–0.006%	$6,304	–$2,364
2010	$89	$62	0.5%	–0.010%	$6,163	–$2,578
2011	$836	$630	0.9%	–0.019%	$136,011	–$36,021
2012	$1,278	$1,021	1.6%	–0.024%	$201,592	–$48,332
2013	$1,432	$1,158	3.1%	–0.025%	$205,681	–$51,844
2014	$1,611	$1,268	3.2%	–0.027%	$242,214	–$65,974
2015	$1,529	$1,191	2.7%	–0.027%	$238,948	–$65,991
2016	$1,448	$1,191	2.7%	–0.027%	$227,805	–$52,188
2017	$1,423	$1,191	2.7%	–0.027%	$227,549	–$49,273
2018	$1,390	$1,191	2.7%	–0.027%	$227,388	–$46,453
2019	$1,349	$1,190	2.7%	–0.027%	$223,284	–$39,690
2020	$1,347	$1,190	2.7%	–0.027%	$225,968	–$39,703
2021	$1,263	$1,190	2.7%	–0.027%	$209,555	–$20,621
2022	$1,230	$1,190	2.7%	–0.027%	$203,133	–$11,540
2023	$1,218	$1,190	2.7%	–0.027%	$203,137	–$8,884
2024	$1,190	$1,190	2.7%	–0.027%	$198,628	–$1,716
2025	$1,189	$1,189	2.7%	–0.027%	$201,312	–$1,740
2026	$1,189	$1,189	2.7%	–0.027%	$203,996	–$1,764
2027	$1,189	$1,189	2.7%	–0.027%	$206,680	–$1,788
2028	$1,189	$1,189	2.7%	–0.027%	$209,364	–$1,813
2029	$1,189	$1,189	2.7%	–0.027%	$212,048	–$1,837
2030	$1,189	$1,189	2.7%	–0.027%	$214,731	–$1,861
2031	$1,188	$1,188	2.7%	–0.027%	$217,415	–$1,885
2032	$1,188	$1,188	2.7%	–0.027%	$220,099	–$1,909
2033	$1,188	$1,188	2.7%	–0.027%	$222,783	–$1,933
2034	$1,188	$1,188	2.7%	–0.027%	$225,467	–$1,957
2035	$1,188	$1,188	2.7%	–0.027%	$228,151	–$1,982
2036	$1,188	$1,188	2.7%	–0.027%	$230,834	–$2,006
NPV[c]					$3,203,099	–$396,969

[a] Figures are in 2002 dollars.

[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.

[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-2. Impacts on Construction Equipment Market and Manufacturers (Average Price per Equipment = $128,100)[a,b]

Year	Construction Equipment					Change in Producer Surplus for Equipment Manufacturers (10^3)
	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	–$1	0.0%	–0.004%	—	–$227
2008	$82	$58	0.2%	–0.006%	$2,791	–$1,822
2009	$81	$58	0.2%	–0.006%	$2,819	–$1,831
2010	$77	$53	0.2%	–0.011%	$2,764	–$2,307
2011	$771	$567	0.4%	–0.021%	$129,258	–$41,345
2012	$1,342	$1,073	0.9%	–0.027%	$222,497	–$60,765
2013	$1,455	$1,172	1.6%	–0.028%	$215,758	–$64,049
2014	$1,621	$1,268	1.6%	–0.031%	$252,584	–$81,136
2015	$1,658	$1,285	1.4%	–0.032%	$277,706	–$87,572
2016	$1,574	$1,285	1.4%	–0.032%	$265,984	–$72,975
2017	$1,523	$1,266	1.4%	–0.032%	$260,346	–$68,895
2018	$1,495	$1,266	1.4%	–0.032%	$261,583	–$67,318
2019	$1,452	$1,266	1.4%	–0.032%	$257,237	–$60,158
2020	$1,440	$1,266	1.4%	–0.032%	$257,684	–$57,783
2021	$1,359	$1,265	1.4%	–0.032%	$237,148	–$34,427
2022	$1,323	$1,265	1.4%	–0.032%	$225,352	–$19,817
2023	$1,313	$1,265	1.4%	–0.032%	$225,367	–$17,019
2024	$1,285	$1,265	1.4%	–0.032%	$218,660	–$7,497
2025	$1,272	$1,265	1.4%	–0.032%	$217,689	–$3,712
2026	$1,272	$1,265	1.4%	–0.032%	$220,554	–$3,763
2027	$1,272	$1,265	1.4%	–0.032%	$223,419	–$3,814
2028	$1,272	$1,264	1.4%	–0.032%	$226,284	–$3,865
2029	$1,272	$1,264	1.4%	–0.032%	$229,149	–$3,915
2030	$1,272	$1,264	1.4%	–0.032%	$232,014	–$3,966
2031	$1,271	$1,264	1.4%	–0.032%	$234,880	–$4,017
2032	$1,271	$1,264	1.4%	–0.032%	$237,745	–$4,068
2033	$1,271	$1,264	1.4%	–0.032%	$240,610	–$4,119
2034	$1,271	$1,264	1.4%	–0.032%	$243,475	–$4,170
2035	$1,271	$1,264	1.4%	–0.032%	$246,340	–$4,221
2036	$1,271	$1,263	1.4%	–0.032%	$249,206	–$4,272
NPV[c]					$3,510,842	–$545,099

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-3. Impacts on Pumps and Compressor Equipment Market and Manufacturers (Average Price per Equipment = $13,700)[a,b]

	Pumps and Compressors					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$135	$98	1.1%	–0.001%	$176	–$177
2009	$134	$98	1.1%	–0.001%	$176	–$177
2010	$128	$93	1.1%	–0.001%	$176	–$177
2011	$340	$255	1.4%	–0.002%	$1,011	–$876
2012	$682	$563	3.6%	–0.003%	$2,102	–$1,668
2013	$952	$817	6.1%	–0.003%	$2,685	–$2,051
2014	$1,006	$847	6.1%	–0.003%	$3,136	–$2,432
2015	$923	$766	5.4%	–0.003%	$3,115	–$2,444
2016	$899	$766	5.4%	–0.003%	$3,126	–$2,444
2017	$878	$765	5.4%	–0.003%	$3,137	–$2,444
2018	$842	$765	5.4%	–0.003%	$2,971	–$2,268
2019	$826	$765	5.4%	–0.003%	$2,982	–$2,268
2020	$824	$765	5.4%	–0.003%	$2,993	–$2,268
2021	$800	$765	5.4%	–0.003%	$2,306	–$1,571
2022	$793	$765	5.4%	–0.003%	$1,526	–$779
2023	$780	$765	5.4%	–0.003%	$1,155	–$398
2024	$773	$765	5.4%	–0.003%	$785	–$17
2025	$772	$764	5.4%	–0.003%	$784	–$5
2026	$772	$764	5.4%	–0.003%	$795	–$5
2027	$772	$764	5.4%	–0.003%	$805	–$5
2028	$772	$764	5.4%	–0.003%	$816	–$5
2029	$772	$764	5.4%	–0.003%	$827	–$5
2030	$772	$764	5.4%	–0.003%	$838	–$5
2031	$772	$764	5.4%	–0.003%	$849	–$5
2032	$772	$764	5.4%	–0.003%	$860	–$5
2033	$772	$764	5.4%	–0.003%	$871	–$5
2034	$772	$764	5.4%	–0.003%	$882	–$5
2035	$772	$764	5.4%	–0.003%	$893	–$5
2036	$772	$764	5.4%	–0.003%	$904	–$6
NPV[c]					$27,665	–$17,056

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-4. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (Average Price per Equipment = $9,200)[a,b]

	Generator Sets and Welders					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$169	$123	1.6%	–0.001%	$7,721	–$2,899
2009	$168	$123	1.6%	–0.001%	$7,832	–$2,899
2010	$161	$117	1.5%	–0.001%	$7,677	–$2,902
2011	$202	$149	1.6%	–0.002%	$11,511	–$4,090
2012	$354	$285	2.3%	–0.003%	$25,652	–$7,014
2013	$631	$553	5.5%	–0.003%	$41,613	–$9,151
2014	$644	$558	5.5%	–0.003%	$43,801	–$10,345
2015	$563	$479	4.6%	–0.003%	$40,244	–$10,345
2016	$557	$479	4.6%	–0.003%	$40,403	–$9,992
2017	$548	$479	4.6%	–0.003%	$40,314	–$9,391
2018	$512	$479	4.6%	–0.003%	$37,930	–$6,496
2019	$507	$479	4.6%	–0.003%	$38,054	–$6,109
2020	$507	$479	4.6%	–0.003%	$38,566	–$6,109
2021	$502	$479	4.6%	–0.003%	$38,247	–$5,278
2022	$493	$479	4.6%	–0.003%	$36,440	–$2,959
2023	$481	$479	4.6%	–0.003%	$34,816	–$824
2024	$478	$479	4.6%	–0.003%	$34,523	–$19
2025	$478	$479	4.6%	–0.003%	$35,035	–$19
2026	$478	$479	4.6%	–0.003%	$35,547	–$19
2027	$478	$479	4.6%	–0.003%	$36,058	–$20
2028	$478	$478	4.6%	–0.003%	$36,570	–$20
2029	$478	$478	4.6%	–0.003%	$37,082	–$20
2030	$478	$478	4.6%	–0.003%	$37,594	–$21
2031	$478	$478	4.6%	–0.003%	$38,106	–$21
2032	$478	$478	4.6%	–0.003%	$38,618	–$21
2033	$478	$478	4.6%	–0.003%	$39,130	–$22
2034	$478	$478	4.6%	–0.003%	$39,642	–$22
2035	$478	$478	4.6%	–0.003%	$40,154	–$22
2036	$478	$478	4.6%	–0.003%	$40,666	–$23
NPV[c]					$563,662	–$69,507

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-5. Impacts on Refrigeration and Air-Conditioning Equipment Market and Manufacturers (Average Price per Equipment = $6,314)[a,b]

Year	Refrigeration and Air Conditioning					Change in Producer Surplus for Equipment Manufacturers (10^3)
	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$208	$152	0.6%	–0.001%	$447	–$449
2009	$206	$152	0.6%	–0.001%	$447	–$449
2010	$197	$144	0.6%	–0.001%	$447	–$452
2011	$196	$143	0.6%	–0.002%	$447	–$456
2012	$195	$143	0.6%	–0.003%	$447	–$459
2013	$768	$676	2.1%	–0.003%	$2,551	–$1,792
2014	$766	$676	2.1%	–0.003%	$2,565	–$1,793
2015	$610	$521	1.7%	–0.003%	$2,418	–$1,793
2016	$609	$521	1.7%	–0.003%	$2,429	–$1,793
2017	$607	$521	1.7%	–0.003%	$2,440	–$1,793
2018	$546	$521	1.7%	–0.003%	$2,005	–$1,347
2019	$546	$521	1.7%	–0.003%	$2,016	–$1,347
2020	$545	$521	1.7%	–0.003%	$2,027	–$1,347
2021	$545	$521	1.7%	–0.003%	$2,038	–$1,348
2022	$545	$521	1.7%	–0.003%	$2,049	–$1,348
2023	$522	$521	1.7%	–0.003%	$732	–$19
2024	$522	$521	1.7%	–0.003%	$743	–$20
2025	$522	$521	1.7%	–0.003%	$754	–$20
2026	$522	$521	1.7%	–0.003%	$765	–$20
2027	$522	$521	1.7%	–0.003%	$776	–$21
2028	$522	$521	1.7%	–0.003%	$787	–$21
2029	$522	$521	1.7%	–0.003%	$798	–$21
2030	$522	$521	1.7%	–0.003%	$810	–$21
2031	$522	$521	1.7%	–0.003%	$821	–$22
2032	$522	$521	1.7%	–0.003%	$832	–$22
2033	$522	$521	1.7%	–0.003%	$843	–$22
2034	$522	$521	1.7%	–0.003%	$854	–$23
2035	$522	$521	1.7%	–0.003%	$865	–$23
2036	$522	$521	1.7%	–0.003%	$876	–$23
NPV[c]					$22,468	–$12,722

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-6. Impacts on General Industrial Equipment Market and Manufacturers (Average Price per Equipment = $91,200)[a,b]

	General Industrial					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	$1
2008	$64	$46	0.1%	–0.001%	$557	–$287
2009	$63	$46	0.1%	–0.001%	$563	–$287
2010	$60	$44	0.1%	–0.001%	$552	–$294
2011	$516	$387	0.3%	–0.002%	$7,656	–$4,870
2012	$1,320	$1,101	1.1%	–0.003%	$27,925	–$11,353
2013	$1,429	$1,200	1.4%	–0.003%	$29,960	–$12,069
2014	$1,549	$1,260	1.4%	–0.003%	$33,740	–$15,024
2015	$1,537	$1,242	1.3%	–0.003%	$34,239	–$15,489
2016	$1,483	$1,242	1.3%	–0.003%	$34,263	–$15,216
2017	$1,431	$1,234	1.3%	–0.003%	$33,767	–$14,467
2018	$1,409	$1,234	1.3%	–0.003%	$33,729	–$14,131
2019	$1,372	$1,234	1.3%	–0.003%	$33,618	–$13,723
2020	$1,366	$1,234	1.3%	–0.003%	$33,896	–$13,705
2021	$1,313	$1,234	1.3%	–0.003%	$29,901	–$9,412
2022	$1,268	$1,234	1.3%	–0.003%	$24,474	–$3,688
2023	$1,260	$1,233	1.3%	–0.003%	$24,119	–$3,036
2024	$1,236	$1,233	1.3%	–0.003%	$21,873	–$493
2025	$1,231	$1,233	1.3%	–0.003%	$21,724	–$47
2026	$1,231	$1,233	1.3%	–0.003%	$22,021	–$47
2027	$1,231	$1,233	1.3%	–0.003%	$22,319	–$48
2028	$1,231	$1,233	1.3%	–0.003%	$22,616	–$48
2029	$1,231	$1,233	1.3%	–0.003%	$22,914	–$49
2030	$1,231	$1,233	1.3%	–0.003%	$23,212	–$50
2031	$1,230	$1,233	1.3%	–0.003%	$23,509	–$50
2032	$1,230	$1,233	1.3%	–0.003%	$23,807	–$51
2033	$1,230	$1,233	1.3%	–0.003%	$24,104	–$52
2034	$1,230	$1,232	1.3%	–0.003%	$24,402	–$52
2035	$1,230	$1,232	1.3%	–0.003%	$24,700	–$53
2036	$1,230	$1,232	1.3%	–0.003%	$24,997	–$54
NPV[c]					$401,039	–$102,642

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-7. Impacts on Lawn and Garden Equipment Market and Manufacturers (Average Price per Equipment = $17,700)[a,b]

	Lawn and Garden					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$164	$119	1.0%	–0.001%	$2,293	–$838
2009	$163	$119	1.0%	–0.001%	$2,331	–$838
2010	$156	$113	0.9%	–0.001%	$2,289	–$839
2011	$195	$144	1.0%	–0.002%	$2,604	–$1,074
2012	$361	$292	1.4%	–0.003%	$3,590	–$1,780
2013	$604	$530	2.5%	–0.003%	$5,759	–$2,097
2014	$616	$535	2.5%	–0.003%	$6,106	–$2,338
2015	$544	$465	2.2%	–0.003%	$5,667	–$2,338
2016	$539	$465	2.2%	–0.003%	$5,734	–$2,338
2017	$529	$465	2.2%	–0.003%	$5,801	–$2,338
2018	$496	$465	2.2%	–0.003%	$5,266	–$1,736
2019	$491	$465	2.2%	–0.003%	$5,333	–$1,736
2020	$491	$465	2.2%	–0.003%	$5,400	–$1,736
2021	$486	$465	2.2%	–0.003%	$5,234	–$1,503
2022	$479	$465	2.2%	–0.003%	$4,596	–$799
2023	$469	$465	2.2%	–0.003%	$4,113	–$249
2024	$467	$465	2.2%	–0.003%	$3,940	–$9
2025	$467	$465	2.2%	–0.003%	$4,007	–$9
2026	$467	$465	2.2%	–0.003%	$4,075	–$9
2027	$467	$465	2.2%	–0.003%	$4,142	–$10
2028	$467	$465	2.2%	–0.003%	$4,209	–$10
2029	$467	$465	2.2%	–0.003%	$4,276	–$10
2030	$467	$465	2.2%	–0.003%	$4,343	–$10
2031	$466	$465	2.2%	–0.003%	$4,410	–$10
2032	$466	$465	2.2%	–0.003%	$4,477	–$10
2033	$466	$465	2.2%	–0.003%	$4,544	–$10
2034	$466	$465	2.2%	–0.003%	$4,611	–$11
2035	$466	$465	2.2%	–0.003%	$4,678	–$11
2036	$466	$465	2.2%	–0.003%	$4,745	–$11
NPV[b]					$76,592	–$17,642

[a] Figures are in 2002 dollars.
[b] Average price per equipment for the market is a weighted average of the price of equipment by hp.
[c] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-8. Impacts on Agricultural Equipment Market and Manufacturers (<25 hp) (Average Price per Equipment = $6,900)[a]

	Agricultural Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$1
2008	$177	$129	1.9%	–0.006%	$666	–$341
2009	$176	$129	1.9%	–0.006%	$675	–$341
2010	$168	$122	1.8%	–0.010%	$666	–$343
2011	$167	$122	1.8%	–0.019%	$674	–$348
2012	$166	$122	1.8%	–0.024%	$683	–$351
2013	$136	$122	1.8%	–0.025%	$608	–$269
2014	$136	$122	1.8%	–0.027%	$617	–$271
2015	$135	$122	1.8%	–0.027%	$625	–$271
2016	$135	$122	1.8%	–0.027%	$634	–$272
2017	$135	$122	1.8%	–0.027%	$642	–$272
2018	$123	$122	1.8%	–0.027%	$395	–$17
2019	$123	$122	1.8%	–0.027%	$404	–$18
2020	$123	$122	1.8%	–0.027%	$412	–$18
2021	$123	$122	1.8%	–0.027%	$421	–$18
2022	$123	$122	1.8%	–0.027%	$429	–$19
2023	$123	$122	1.8%	–0.027%	$437	–$19
2024	$123	$122	1.8%	–0.027%	$446	–$19
2025	$123	$122	1.8%	–0.027%	$454	–$20
2026	$123	$122	1.8%	–0.027%	$463	–$20
2027	$123	$122	1.8%	–0.027%	$471	–$21
2028	$123	$122	1.8%	–0.027%	$479	–$21
2029	$123	$122	1.8%	–0.027%	$488	–$21
2030	$123	$122	1.8%	–0.027%	$496	–$22
2031	$123	$122	1.8%	–0.027%	$505	–$22
2032	$123	$122	1.8%	–0.027%	$513	–$22
2033	$123	$122	1.8%	–0.027%	$522	–$23
2034	$123	$122	1.8%	–0.027%	$530	–$23
2035	$123	$122	1.8%	–0.027%	$538	–$24
2036	$123	$122	1.8%	–0.027%	$547	–$24
NPV[b]					$9,600	–$2,622

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-9. Impacts on Agricultural Equipment Market and Manufacturers (26-50 hp) (Average Price per Equipment = $14,400)[a]

Year	Agricultural Equipment (25≤hp<50) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	–0.004%	—	–$7
2008	$204	$147	1.0%	–0.006%	$3,707	–$1,225
2009	$203	$147	1.0%	–0.006%	$3,762	–$1,225
2010	$194	$139	1.0%	–0.010%	$3,679	–$1,238
2011	$193	$138	1.0%	–0.019%	$3,731	–$1,268
2012	$192	$138	1.0%	–0.024%	$3,782	–$1,284
2013	$986	$868	6.0%	–0.025%	$20,616	–$3,639
2014	$984	$868	6.0%	–0.027%	$20,951	–$3,648
2015	$773	$660	4.6%	–0.027%	$17,064	–$3,649
2016	$771	$660	4.6%	–0.027%	$17,319	–$3,651
2017	$769	$660	4.6%	–0.027%	$17,575	–$3,653
2018	$693	$660	4.6%	–0.027%	$16,061	–$1,886
2019	$692	$660	4.6%	–0.027%	$16,316	–$1,887
2020	$692	$660	4.6%	–0.027%	$16,571	–$1,888
2021	$691	$660	4.6%	–0.027%	$16,826	–$1,890
2022	$691	$660	4.6%	–0.027%	$17,081	–$1,891
2023	$661	$660	4.6%	–0.027%	$15,546	–$103
2024	$661	$660	4.6%	–0.027%	$15,801	–$105
2025	$661	$660	4.6%	–0.027%	$16,057	–$107
2026	$661	$660	4.6%	–0.027%	$16,312	–$108
2027	$661	$660	4.6%	–0.027%	$16,567	–$110
2028	$661	$660	4.6%	–0.027%	$16,822	–$112
2029	$661	$660	4.6%	–0.027%	$17,077	–$114
2030	$661	$660	4.6%	–0.027%	$17,332	–$115
2031	$661	$660	4.6%	–0.027%	$17,587	–$117
2032	$661	$660	4.6%	–0.027%	$17,842	–$119
2033	$661	$660	4.6%	–0.027%	$18,097	–$121
2034	$661	$660	4.6%	–0.027%	$18,353	–$122
2035	$661	$660	4.6%	–0.027%	$18,608	–$124
2036	$661	$660	4.6%	–0.027%	$18,863	–$126
NPV[b]					$248,449	–$25,062

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-10. Impacts on Agricultural Equipment Market and Manufacturers (51-75 hp)
(Average Price per Equipment = $22,600)[a]

	Agricultural Equipment (50≤hp<75)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$5
2008	$226	$167	0.7%	–0.006%	$1,844	–$582
2009	$225	$167	0.7%	–0.006%	$1,867	–$583
2010	$214	$157	0.7%	–0.010%	$1,818	–$592
2011	$213	$156	0.7%	–0.019%	$1,840	–$615
2012	$212	$155	0.7%	–0.024%	$1,863	–$627
2013	$978	$856	3.8%	–0.025%	$9,199	–$1,771
2014	$976	$856	3.8%	–0.027%	$9,326	–$1,778
2015	$769	$651	2.9%	–0.027%	$7,616	–$1,778
2016	$767	$651	2.9%	–0.027%	$7,713	–$1,780
2017	$765	$651	2.9%	–0.027%	$7,810	–$1,781
2018	$687	$651	2.9%	–0.027%	$7,086	–$961
2019	$686	$651	2.9%	–0.027%	$7,183	–$962
2020	$686	$651	2.9%	–0.027%	$7,280	–$963
2021	$685	$651	2.9%	–0.027%	$7,377	–$964
2022	$685	$651	2.9%	–0.027%	$7,474	–$965
2023	$653	$651	2.9%	–0.027%	$6,681	–$76
2024	$653	$651	2.9%	–0.027%	$6,777	–$77
2025	$653	$651	2.9%	–0.027%	$6,874	–$78
2026	$653	$651	2.9%	–0.027%	$6,971	–$79
2027	$653	$651	2.9%	–0.027%	$7,068	–$80
2028	$653	$651	2.9%	–0.027%	$7,165	–$81
2029	$653	$651	2.9%	–0.027%	$7,262	–$82
2030	$653	$651	2.9%	–0.027%	$7,359	–$84
2031	$653	$651	2.9%	–0.027%	$7,456	–$85
2032	$653	$651	2.9%	–0.027%	$7,553	–$86
2033	$653	$651	2.9%	–0.027%	$7,650	–$87
2034	$653	$651	2.9%	–0.027%	$7,747	–$88
2035	$653	$651	2.9%	–0.027%	$7,844	–$89
2036	$653	$651	2.9%	–0.027%	$7,941	–$90
NPV[b]					$108,842	–$12,491

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-11. Impacts on Agricultural Equipment Market and Manufacturers (76-100 hp) (Average Price per Equipment = $22,400)[a]

	Agricultural Equipment (70≤hp<100)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$5
2008	—	–$1	0.0%	–0.006%	—	–$10
2009	—	–$1	0.0%	–0.006%	—	–$10
2010	—	–$1	0.0%	–0.010%	—	–$18
2011	—	–$3	0.0%	–0.019%	—	–$39
2012	$1,303	$1,175	3.5%	–0.024%	$13,727	–$2,422
2013	$1,302	$1,175	3.5%	–0.025%	$13,923	–$2,426
2014	$1,325	$1,166	3.5%	–0.027%	$14,767	–$3,146
2015	$1,324	$1,166	3.5%	–0.027%	$14,962	–$3,146
2016	$1,322	$1,166	3.5%	–0.027%	$15,157	–$3,147
2017	$1,247	$1,166	3.5%	–0.027%	$14,600	–$2,396
2018	$1,246	$1,166	3.5%	–0.027%	$14,796	–$2,397
2019	$1,218	$1,166	3.5%	–0.027%	$14,695	–$2,102
2020	$1,218	$1,166	3.5%	–0.027%	$14,890	–$2,102
2021	$1,218	$1,166	3.5%	–0.027%	$15,085	–$2,103
2022	$1,218	$1,166	3.5%	–0.027%	$13,661	–$485
2023	$1,218	$1,166	3.5%	–0.027%	$13,857	–$486
2024	$1,218	$1,166	3.5%	–0.027%	$13,635	–$70
2025	$1,218	$1,166	3.5%	–0.027%	$13,830	–$71
2026	$1,218	$1,166	3.5%	–0.027%	$14,026	–$72
2027	$1,218	$1,166	3.5%	–0.027%	$14,221	–$73
2028	$1,218	$1,166	3.5%	–0.027%	$14,416	–$74
2029	$1,218	$1,166	3.5%	–0.027%	$14,612	–$75
2030	$1,218	$1,166	3.5%	–0.027%	$14,807	–$76
2031	$1,218	$1,166	3.5%	–0.027%	$15,002	–$77
2032	$1,218	$1,166	3.5%	–0.027%	$15,198	–$78
2033	$1,218	$1,166	3.5%	–0.027%	$15,393	–$79
2034	$1,218	$1,166	3.5%	–0.027%	$15,588	–$80
2035	$1,218	$1,166	3.5%	–0.027%	$15,784	–$81
2036	$1,218	$1,166	3.5%	–0.027%	$15,979	–$82
NPV[b]					$206,738	–$18,829

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-12. Impacts on Agricultural Equipment Market and Manufacturers (101-175 hp) (Average Price per Equipment = $69,100)[a]

Year	Agricultural Equipment (100≤hp<175) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	–$1	0.0%	–0.004%	—	–$28
2008	—	–$1	0.0%	–0.006%	—	–$59
2009	—	–$1	0.0%	–0.006%	—	–$60
2010	—	–$3	0.0%	–0.010%	—	–$113
2011	—	–$6	0.0%	–0.019%	—	–$241
2012	$1,623	$1,414	2.0%	–0.024%	$50,277	–$9,980
2013	$1,619	$1,414	2.0%	–0.025%	$50,949	–$10,007
2014	$1,664	$1,391	2.0%	–0.027%	$53,852	–$12,849
2015	$1,659	$1,391	2.0%	–0.027%	$54,515	–$12,853
2016	$1,654	$1,391	2.0%	–0.027%	$55,178	–$12,859
2017	$1,577	$1,391	2.0%	–0.027%	$53,654	–$10,677
2018	$1,574	$1,391	2.0%	–0.027%	$54,317	–$10,684
2019	$1,542	$1,391	2.0%	–0.027%	$54,087	–$9,797
2020	$1,539	$1,391	2.0%	–0.027%	$54,750	–$9,800
2021	$1,537	$1,391	2.0%	–0.027%	$55,413	–$9,804
2022	$1,388	$1,391	2.0%	–0.027%	$48,590	–$2,324
2023	$1,387	$1,391	2.0%	–0.027%	$49,253	–$2,330
2024	$1,351	$1,391	2.0%	–0.027%	$48,004	–$424
2025	$1,351	$1,391	2.0%	–0.027%	$48,667	–$430
2026	$1,351	$1,391	2.0%	–0.027%	$49,330	–$436
2027	$1,351	$1,391	2.0%	–0.027%	$49,993	–$442
2028	$1,351	$1,391	2.0%	–0.027%	$50,656	–$448
2029	$1,351	$1,391	2.0%	–0.027%	$51,319	–$454
2030	$1,351	$1,391	2.0%	–0.027%	$51,982	–$460
2031	$1,351	$1,391	2.0%	–0.027%	$52,645	–$466
2032	$1,351	$1,391	2.0%	–0.027%	$53,308	–$472
2033	$1,351	$1,391	2.0%	–0.027%	$53,971	–$478
2034	$1,351	$1,391	2.0%	–0.027%	$54,634	–$484
2035	$1,351	$1,391	2.0%	–0.027%	$55,298	–$491
2036	$1,351	$1,391	2.0%	–0.027%	$55,961	–$497
NPV[b]					$741,939	–$81,965

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-13. Impacts on Agricultural Equipment Market and Manufacturers (176-600 hp) (Average Price per Equipment = $143,700)[a]

Year	Agricultural Equipment (175≤hp<600) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	–$1	0.0%	–0.004%	—	–$68
2008	—	–$3	0.0%	–0.006%	—	–$143
2009	—	–$3	0.0%	–0.006%	—	–$146
2010	—	–$6	0.0%	–0.010%	—	–$274
2011	$2,970	$2,255	1.6%	–0.019%	$129,766	–$33,510
2012	$2,958	$2,251	1.6%	–0.024%	$131,260	–$33,668
2013	$2,439	$1,741	1.2%	–0.025%	$110,384	–$33,733
2014	$3,107	$2,200	1.5%	–0.027%	$142,701	–$44,283
2015	$3,092	$2,199	1.5%	–0.027%	$144,166	–$44,293
2016	$2,777	$2,198	1.5%	–0.027%	$131,803	–$30,479
2017	$2,768	$2,197	1.5%	–0.027%	$133,268	–$30,494
2018	$2,759	$2,197	1.5%	–0.027%	$134,733	–$30,508
2019	$2,634	$2,196	1.5%	–0.027%	$130,600	–$24,924
2020	$2,627	$2,195	1.5%	–0.027%	$132,065	–$24,931
2021	$2,294	$2,194	1.5%	–0.027%	$114,433	–$5,842
2022	$2,292	$2,194	1.5%	–0.027%	$115,898	–$5,856
2023	$2,291	$2,193	1.5%	–0.027%	$117,363	–$5,870
2024	$2,209	$2,192	1.5%	–0.027%	$113,965	–$1,021
2025	$2,208	$2,191	1.5%	–0.027%	$115,430	–$1,035
2026	$2,208	$2,191	1.5%	–0.027%	$116,895	–$1,048
2027	$2,207	$2,190	1.5%	–0.027%	$118,360	–$1,062
2028	$2,206	$2,189	1.5%	–0.027%	$119,824	–$1,076
2029	$2,206	$2,189	1.5%	–0.027%	$121,289	–$1,090
2030	$2,205	$2,188	1.5%	–0.027%	$122,754	–$1,104
2031	$2,204	$2,187	1.5%	–0.027%	$124,219	–$1,118
2032	$2,204	$2,187	1.5%	–0.027%	$125,684	–$1,132
2033	$2,203	$2,186	1.5%	–0.027%	$127,149	–$1,145
2034	$2,203	$2,186	1.5%	–0.027%	$128,614	–$1,159
2035	$2,202	$2,185	1.5%	–0.027%	$130,079	–$1,173
2036	$2,202	$2,185	1.5%	–0.027%	$131,544	–$1,187
NPV[b]					$1,887,531	–$256,000

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-14. Impacts on Construction Equipment Market and Manufacturers (<25 hp) (Average Price per Equipment = $18,000)[a]

	Construction Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$3
2008	$177	$129	0.7%	–0.006%	$370	–$343
2009	$176	$129	0.7%	–0.006%	$371	–$344
2010	$168	$122	0.7%	–0.011%	$370	–$350
2011	$167	$122	0.7%	–0.021%	$371	–$363
2012	$166	$121	0.7%	–0.027%	$372	–$371
2013	$136	$121	0.7%	–0.028%	$364	–$365
2014	$136	$121	0.7%	–0.031%	$365	–$370
2015	$135	$121	0.7%	–0.032%	$366	–$372
2016	$135	$121	0.7%	–0.032%	$367	–$373
2017	$135	$121	0.7%	–0.032%	$368	–$374
2018	$123	$121	0.7%	–0.032%	$39	–$46
2019	$123	$121	0.7%	–0.032%	$40	–$47
2020	$123	$121	0.7%	–0.032%	$41	–$48
2021	$123	$121	0.7%	–0.032%	$42	–$48
2022	$123	$121	0.7%	–0.032%	$42	–$49
2023	$123	$121	0.7%	–0.032%	$43	–$50
2024	$123	$121	0.7%	–0.032%	$44	–$51
2025	$123	$121	0.7%	–0.032%	$45	–$52
2026	$123	$121	0.7%	–0.032%	$46	–$53
2027	$123	$121	0.7%	–0.032%	$47	–$54
2028	$123	$121	0.7%	–0.032%	$47	–$55
2029	$123	$121	0.7%	–0.032%	$48	–$56
2030	$123	$121	0.7%	–0.032%	$49	–$57
2031	$123	$121	0.7%	–0.032%	$50	–$58
2032	$123	$121	0.7%	–0.032%	$51	–$59
2033	$123	$121	0.7%	–0.032%	$52	–$60
2034	$123	$121	0.7%	–0.032%	$52	–$61
2035	$123	$121	0.7%	–0.032%	$53	–$62
2036	$123	$121	0.7%	–0.032%	$54	–$63
NPV[b]					$3,325	–$3,348

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-15. Impacts on Construction Equipment Market and Manufacturers (26-50 hp) (Average Price per Equipment = $29,700)[a]

	Construction Equipment (25≤hp<50)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$8
2008	$204	$146	0.5%	–0.006%	$438	–$345
2009	$203	$146	0.5%	–0.006%	$440	–$345
2010	$194	$138	0.5%	–0.011%	$437	–$362
2011	$193	$137	0.5%	–0.021%	$439	–$397
2012	$192	$137	0.5%	–0.027%	$441	–$420
2013	$986	$867	2.9%	–0.028%	$3,293	–$1,864
2014	$984	$867	2.9%	–0.031%	$3,323	–$1,875
2015	$773	$659	2.2%	–0.032%	$3,006	–$1,882
2016	$771	$659	2.2%	–0.032%	$3,030	–$1,884
2017	$769	$659	2.2%	–0.032%	$3,053	–$1,885
2018	$693	$659	2.2%	–0.032%	$2,723	–$1,534
2019	$692	$659	2.2%	–0.032%	$2,747	–$1,536
2020	$692	$659	2.2%	–0.032%	$2,770	–$1,538
2021	$691	$659	2.2%	–0.032%	$2,794	–$1,540
2022	$691	$659	2.2%	–0.032%	$2,817	–$1,543
2023	$661	$659	2.2%	–0.032%	$1,428	–$132
2024	$661	$659	2.2%	–0.032%	$1,451	–$134
2025	$661	$659	2.2%	–0.032%	$1,475	–$137
2026	$661	$659	2.2%	–0.032%	$1,498	–$139
2027	$661	$659	2.2%	–0.032%	$1,521	–$141
2028	$661	$659	2.2%	–0.032%	$1,545	–$143
2029	$661	$659	2.2%	–0.032%	$1,568	–$145
2030	$661	$659	2.2%	–0.032%	$1,592	–$148
2031	$661	$659	2.2%	–0.032%	$1,615	–$150
2032	$661	$659	2.2%	–0.032%	$1,639	–$152
2033	$661	$659	2.2%	–0.032%	$1,662	–$154
2034	$661	$659	2.2%	–0.032%	$1,685	–$156
2035	$661	$659	2.2%	–0.032%	$1,709	–$159
2036	$661	$659	2.2%	–0.032%	$1,732	–$161
NPV[b]					$32,256	–$14,120

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-16. Impacts on Construction Equipment Market and Manufacturers (51-75 hp) (Average Price per Equipment = $31,600)[a]

	Construction Equipment (50≤hp<70)					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	–0.004%	—	–$8
2008	$226	$167	0.5%	–0.006%	$1,983	–$710
2009	$225	$167	0.5%	–0.006%	$2,007	–$711
2010	$214	$157	0.5%	–0.011%	$1,957	–$728
2011	$213	$156	0.5%	–0.021%	$1,980	–$764
2012	$212	$155	0.5%	–0.027%	$2,002	–$788
2013	$978	$856	2.7%	–0.028%	$10,288	–$2,484
2014	$976	$856	2.7%	–0.031%	$10,422	–$2,495
2015	$769	$650	2.1%	–0.032%	$8,629	–$2,502
2016	$767	$650	2.1%	–0.032%	$8,731	–$2,504
2017	$765	$650	2.1%	–0.032%	$8,834	–$2,505
2018	$687	$650	2.1%	–0.032%	$7,991	–$1,561
2019	$686	$650	2.1%	–0.032%	$8,093	–$1,563
2020	$686	$650	2.1%	–0.032%	$8,196	–$1,565
2021	$685	$650	2.1%	–0.032%	$8,298	–$1,567
2022	$685	$650	2.1%	–0.032%	$8,401	–$1,569
2023	$653	$650	2.1%	–0.032%	$7,067	–$134
2024	$653	$650	2.1%	–0.032%	$7,169	–$136
2025	$653	$650	2.1%	–0.032%	$7,272	–$138
2026	$653	$650	2.1%	–0.032%	$7,374	–$140
2027	$653	$650	2.1%	–0.032%	$7,477	–$142
2028	$653	$650	2.1%	–0.032%	$7,580	–$144
2029	$653	$650	2.1%	–0.032%	$7,682	–$146
2030	$653	$650	2.1%	–0.032%	$7,785	–$148
2031	$653	$650	2.1%	–0.032%	$7,887	–$150
2032	$653	$650	2.1%	–0.032%	$7,990	–$152
2033	$653	$650	2.1%	–0.032%	$8,092	–$154
2034	$653	$650	2.1%	–0.032%	$8,195	–$156
2035	$653	$650	2.1%	–0.032%	$8,297	–$158
2036	$653	$650	2.1%	–0.032%	$8,400	–$160
NPV[b]					$118,863	–$17,987

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-17 Impacts on Construction Equipment Market and Manufacturers (76-100 hp) (Average Price per Equipment = $57,900)[a]

	Construction Equipment (70≤hp<100)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	–0.004%	—	–$15
2008	—	–$1	0.0%	–0.006%	—	–$30
2009	—	–$1	0.0%	–0.006%	—	–$31
2010	—	–$2	0.0%	–0.011%	—	–$62
2011	—	–$3	0.0%	–0.021%	—	–$127
2012	$1,303	$1,174	2.0%	–0.027%	$23,156	–$5,449
2013	$1,302	$1,174	2.0%	–0.028%	$23,465	–$5,460
2014	$1,325	$1,165	2.0%	–0.031%	$25,237	–$6,995
2015	$1,324	$1,164	2.0%	–0.032%	$25,545	–$7,007
2016	$1,322	$1,164	2.0%	–0.032%	$25,854	–$7,011
2017	$1,247	$1,164	2.0%	–0.032%	$25,024	–$5,875
2018	$1,246	$1,164	2.0%	–0.032%	$25,333	–$5,879
2019	$1,218	$1,164	2.0%	–0.032%	$25,192	–$5,434
2020	$1,218	$1,164	2.0%	–0.032%	$25,501	–$5,437
2021	$1,218	$1,164	2.0%	–0.032%	$25,809	–$5,440
2022	$1,218	$1,164	2.0%	–0.032%	$21,977	–$1,303
2023	$1,218	$1,164	2.0%	–0.032%	$22,285	–$1,306
2024	$1,218	$1,164	2.0%	–0.032%	$21,527	–$244
2025	$1,218	$1,164	2.0%	–0.032%	$21,836	–$247
2026	$1,218	$1,164	2.0%	–0.032%	$22,144	–$251
2027	$1,218	$1,164	2.0%	–0.032%	$22,452	–$254
2028	$1,218	$1,164	2.0%	–0.032%	$22,761	–$258
2029	$1,218	$1,164	2.0%	–0.032%	$23,069	–$262
2030	$1,218	$1,164	2.0%	–0.032%	$23,377	–$265
2031	$1,218	$1,164	2.0%	–0.032%	$23,686	–$269
2032	$1,218	$1,164	2.0%	–0.032%	$23,994	–$272
2033	$1,218	$1,164	2.0%	–0.032%	$24,303	–$276
2034	$1,218	$1,164	2.0%	–0.032%	$24,611	–$279
2035	$1,218	$1,164	2.0%	–0.032%	$24,919	–$283
2036	$1,218	$1,164	2.0%	–0.032%	$25,228	–$287
NPV[b]					$339,723	–$45,057

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-18. Impacts on Construction Equipment Market and Manufacturers (101-175 hp) (Average Price per Equipment = $122,700)[a]

Year	Construction Equipment (100≤hp<175) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	–$1	0.0%	–0.004%	—	–$51
2008	—	–$2	0.0%	–0.006%	—	–$105
2009	—	–$2	0.0%	–0.006%	—	–$107
2010	—	–$4	0.0%	–0.011%	—	–$215
2011	—	–$7	0.0%	–0.021%	—	–$438
2012	$1,623	$1,412	1.2%	–0.027%	$68,698	–$14,076
2013	$1,619	$1,411	1.2%	–0.028%	$69,612	–$14,114
2014	$1,664	$1,389	1.1%	–0.031%	$73,652	–$18,081
2015	$1,659	$1,388	1.1%	–0.032%	$74,553	–$18,122
2016	$1,654	$1,388	1.1%	–0.032%	$75,455	–$18,134
2017	$1,577	$1,388	1.1%	–0.032%	$73,387	–$15,171
2018	$1,574	$1,388	1.1%	–0.032%	$74,289	–$15,183
2019	$1,542	$1,388	1.1%	–0.032%	$73,979	–$13,984
2020	$1,539	$1,388	1.1%	–0.032%	$74,881	–$13,994
2021	$1,537	$1,388	1.1%	–0.032%	$75,783	–$14,004
2022	$1,388	$1,388	1.1%	–0.032%	$66,164	–$3,496
2023	$1,387	$1,388	1.1%	–0.032%	$67,065	–$3,508
2024	$1,351	$1,388	1.1%	–0.032%	$65,280	–$833
2025	$1,351	$1,388	1.1%	–0.032%	$66,182	–$844
2026	$1,351	$1,388	1.1%	–0.032%	$67,083	–$856
2027	$1,351	$1,388	1.1%	–0.032%	$67,985	–$868
2028	$1,351	$1,388	1.1%	–0.032%	$68,887	–$880
2029	$1,351	$1,388	1.1%	–0.032%	$69,788	–$891
2030	$1,351	$1,388	1.1%	–0.032%	$70,690	–$903
2031	$1,351	$1,388	1.1%	–0.032%	$71,592	–$915
2032	$1,351	$1,388	1.1%	–0.032%	$72,493	–$927
2033	$1,351	$1,388	1.1%	–0.032%	$73,395	–$939
2034	$1,351	$1,388	1.1%	–0.032%	$74,297	–$950
2035	$1,351	$1,388	1.1%	–0.032%	$75,198	–$962
2036	$1,351	$1,388	1.1%	–0.032%	$76,100	–$974
NPV[b]					$1,011,838	–$118,002

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-19. Impacts on Construction Equipment Market and Manufacturers (176-600 hp) (Average Price per Equipment = $312,900)[a]

Year	Construction Equipment (175≤hp<600) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	–$2	0.0%	–0.004%	—	–$110
2008	—	–$5	0.0%	–0.006%	—	–$225
2009	—	–$5	0.0%	–0.006%	—	–$229
2010	—	–$9	0.0%	–0.011%	—	–$461
2011	$2,970	$2,248	0.7%	–0.021%	$103,262	–$30,609
2012	$2,958	$2,241	0.7%	–0.027%	$104,397	–$30,925
2013	$2,439	$1,731	0.6%	–0.028%	$88,557	–$31,005
2014	$3,107	$2,189	0.7%	–0.031%	$114,342	–$40,265
2015	$3,092	$2,187	0.7%	–0.032%	$115,456	–$40,352
2016	$2,777	$2,186	0.7%	–0.032%	$106,203	–$30,010
2017	$2,768	$2,185	0.7%	–0.032%	$107,317	–$30,022
2018	$2,759	$2,184	0.7%	–0.032%	$108,431	–$30,046
2019	$2,634	$2,184	0.7%	–0.032%	$105,349	–$25,874
2020	$2,627	$2,183	0.7%	–0.032%	$106,462	–$25,894
2021	$2,294	$2,182	0.7%	–0.032%	$88,274	–$6,612
2022	$2,292	$2,181	0.7%	–0.032%	$89,388	–$6,637
2023	$2,291	$2,181	0.7%	–0.032%	$90,502	–$6,661
2024	$2,209	$2,180	0.7%	–0.032%	$86,700	–$1,769
2025	$2,208	$2,179	0.7%	–0.032%	$87,814	–$1,793
2026	$2,208	$2,178	0.7%	–0.032%	$88,928	–$1,817
2027	$2,207	$2,178	0.7%	–0.032%	$90,042	–$1,841
2028	$2,206	$2,177	0.7%	–0.032%	$91,156	–$1,865
2029	$2,206	$2,176	0.7%	–0.032%	$92,270	–$1,889
2030	$2,205	$2,176	0.7%	–0.032%	$93,384	–$1,913
2031	$2,204	$2,175	0.7%	–0.032%	$94,498	–$1,936
2032	$2,204	$2,175	0.7%	–0.032%	$95,612	–$1,960
2033	$2,203	$2,174	0.7%	–0.032%	$96,726	–$1,984
2034	$2,203	$2,173	0.7%	–0.032%	$97,839	–$2,008
2035	$2,202	$2,173	0.7%	–0.032%	$98,953	–$2,032
2036	$2,202	$2,172	0.7%	–0.032%	$100,067	–$2,056
NPV[b]					$1,477,053	–$250,397

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-20. Impacts on Construction Equipment Market and Manufacturers (>600 hp) (Average Price per Equipment = $847,400)[a]

	Construction Equipment (≥600hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	–$6	0.0%	–0.004%	—	–$31
2008	—	–$11	0.0%	–0.006%	—	–$63
2009	—	–$11	0.0%	–0.006%	—	–$65
2010	—	–$22	0.0%	–0.011%	—	–$130
2011	$4,519	$2,923	0.4%	–0.021%	$23,207	–$8,646
2012	$4,496	$2,909	0.4%	–0.027%	$23,431	–$8,735
2013	$3,797	$2,230	0.3%	–0.028%	$20,179	–$8,757
2014	$4,684	$2,727	0.4%	–0.031%	$25,243	–$11,056
2015	$9,206	$6,205	0.8%	–0.032%	$50,150	–$17,335
2016	$8,364	$6,205	0.8%	–0.032%	$46,344	–$13,058
2017	$7,517	$5,387	0.7%	–0.032%	$42,363	–$13,061
2018	$7,489	$5,387	0.7%	–0.032%	$42,777	–$13,068
2019	$7,218	$5,387	0.7%	–0.032%	$41,837	–$11,720
2020	$6,767	$5,388	0.7%	–0.032%	$39,833	–$9,307
2021	$6,151	$5,388	0.7%	–0.032%	$36,149	–$5,214
2022	$6,142	$5,388	0.7%	–0.032%	$36,563	–$5,221
2023	$6,133	$5,388	0.7%	–0.032%	$36,978	–$5,227
2024	$5,997	$5,388	0.7%	–0.032%	$36,488	–$4,330
2025	$5,458	$5,388	0.7%	–0.032%	$33,066	–$500
2026	$5,458	$5,388	0.7%	–0.032%	$33,480	–$506
2027	$5,458	$5,388	0.7%	–0.032%	$33,895	–$513
2028	$5,458	$5,388	0.7%	–0.032%	$34,309	–$519
2029	$5,458	$5,388	0.7%	–0.032%	$34,724	–$526
2030	$5,458	$5,388	0.7%	–0.032%	$35,138	–$532
2031	$5,458	$5,388	0.7%	–0.032%	$35,552	–$539
2032	$5,458	$5,388	0.7%	–0.032%	$35,967	–$545
2033	$5,458	$5,388	0.7%	–0.032%	$36,381	–$551
2034	$5,458	$5,388	0.7%	–0.032%	$36,795	–$558
2035	$5,458	$5,388	0.7%	–0.032%	$37,210	–$564
2036	$5,458	$5,388	0.7%	–0.032%	$37,624	–$571
NPV[b]					$527,785	–$96,188

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-21. Impacts on Pumps and Compressor Equipment Market and Manufacturers (<25 hp)
(Average Price per Equipment = $6,000)[a]

	Pumps and Compressor Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$177	$129	2.2%	–0.001%	$96	–$96
2009	$176	$129	2.2%	–0.001%	$96	–$96
2010	$168	$123	2.0%	–0.001%	$96	–$96
2011	$167	$123	2.0%	–0.002%	$96	–$97
2012	$166	$123	2.0%	–0.003%	$96	–$97
2013	$136	$123	2.0%	–0.003%	$96	–$97
2014	$136	$123	2.0%	–0.003%	$96	–$97
2015	$135	$123	2.0%	–0.003%	$96	–$97
2016	$135	$123	2.0%	–0.003%	$96	–$97
2017	$135	$123	2.0%	–0.003%	$96	–$97
2018	$123	$123	2.0%	–0.003%	—	–$1
2019	$123	$123	2.0%	–0.003%	—	–$1
2020	$123	$123	2.0%	–0.003%	—	–$1
2021	$123	$123	2.0%	–0.003%	—	–$1
2022	$123	$123	2.0%	–0.003%	—	–$1
2023	$123	$123	2.0%	–0.003%	—	–$1
2024	$123	$123	2.0%	–0.003%	—	–$1
2025	$123	$123	2.0%	–0.003%	—	–$1
2026	$123	$123	2.0%	–0.003%	—	–$1
2027	$123	$123	2.0%	–0.003%	—	–$1
2028	$123	$123	2.0%	–0.003%	—	–$1
2029	$123	$123	2.0%	–0.003%	—	–$1
2030	$123	$123	2.0%	–0.003%	—	–$1
2031	$123	$123	2.0%	–0.003%	—	–$1
2032	$123	$123	2.0%	–0.003%	—	–$1
2033	$123	$123	2.0%	–0.003%	—	–$1
2034	$123	$123	2.0%	–0.003%	—	–$1
2035	$123	$123	2.0%	–0.003%	—	–$1
2036	$123	$123	2.0%	–0.003%	—	–$1
NPV[b]					$752	–$760

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-22. Impacts on Pumps and Compressor Equipment Market and Manufacturers (26-50 hp)
(Average Price per Equipment = $12,200)[a]

Year	Pumps and Compressor Equipment (25≤hp<50) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$204	$147	1.2%	–0.001%	$41	–$41
2009	$203	$147	1.2%	–0.001%	$41	–$41
2010	$194	$139	1.1%	–0.001%	$41	–$41
2011	$193	$139	1.1%	–0.002%	$41	–$42
2012	$192	$139	1.1%	–0.003%	$41	–$42
2013	$986	$870	7.1%	–0.003%	$356	–$241
2014	$984	$870	7.1%	–0.003%	$359	–$241
2015	$773	$661	5.4%	–0.003%	$337	–$241
2016	$771	$661	5.4%	–0.003%	$339	–$241
2017	$769	$661	5.4%	–0.003%	$340	–$241
2018	$693	$661	5.4%	–0.003%	$301	–$200
2019	$692	$661	5.4%	–0.003%	$303	–$200
2020	$692	$661	5.4%	–0.003%	$305	–$200
2021	$691	$661	5.4%	–0.003%	$307	–$200
2022	$691	$661	5.4%	–0.003%	$309	–$200
2023	$661	$661	5.4%	–0.003%	$112	–$1
2024	$661	$661	5.4%	–0.003%	$113	–$1
2025	$661	$661	5.4%	–0.003%	$115	–$1
2026	$661	$661	5.4%	–0.003%	$117	–$1
2027	$661	$661	5.4%	–0.003%	$119	–$1
2028	$661	$661	5.4%	–0.003%	$121	–$1
2029	$661	$661	5.4%	–0.003%	$123	–$1
2030	$661	$661	5.4%	–0.003%	$124	–$1
2031	$661	$661	5.4%	–0.003%	$126	–$1
2032	$661	$661	5.4%	–0.003%	$128	–$1
2033	$661	$661	5.4%	–0.003%	$130	–$1
2034	$661	$661	5.4%	–0.003%	$132	–$1
2035	$661	$661	5.4%	–0.003%	$134	–$1
2036	$661	$661	5.4%	–0.003%	$135	–$1
NPV[b]					$3,189	–$1,673

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-23. Impacts on Pumps and Compressor Equipment Market and Manufacturers (51-75 hp)
(Average Price per Equipment = $10,600)[a]

Year	Pumps and Compressor Equipment (50≤hp<70)					Change in Producer Surplus for Equipment Manufacturers (10^3)
	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$226	$167	1.6%	–0.001%	$39	–$39
2009	$225	$167	1.6%	–0.001%	$39	–$39
2010	$214	$158	1.5%	–0.001%	$39	–$39
2011	$213	$158	1.5%	–0.002%	$39	–$39
2012	$212	$158	1.5%	–0.003%	$39	–$39
2013	$978	$858	8.1%	–0.003%	$328	–$222
2014	$976	$858	8.1%	–0.003%	$329	–$222
2015	$769	$653	6.2%	–0.003%	$309	–$222
2016	$767	$653	6.2%	–0.003%	$311	–$222
2017	$765	$653	6.2%	–0.003%	$312	–$222
2018	$687	$653	6.2%	–0.003%	$275	–$183
2019	$686	$653	6.2%	–0.003%	$276	–$183
2020	$686	$653	6.2%	–0.003%	$278	–$183
2021	$685	$653	6.2%	–0.003%	$279	–$183
2022	$685	$653	6.2%	–0.003%	$281	–$183
2023	$653	$653	6.2%	–0.003%	$99	–$1
2024	$653	$653	6.2%	–0.003%	$101	–$1
2025	$653	$653	6.2%	–0.003%	$102	–$1
2026	$653	$653	6.2%	–0.003%	$104	–$1
2027	$653	$653	6.2%	–0.003%	$105	–$1
2028	$653	$653	6.2%	–0.003%	$107	–$1
2029	$653	$653	6.2%	–0.003%	$108	–$1
2030	$653	$653	6.2%	–0.003%	$110	–$1
2031	$653	$653	6.2%	–0.003%	$111	–$1
2032	$653	$653	6.2%	–0.003%	$112	–$1
2033	$653	$653	6.2%	–0.003%	$114	–$1
2034	$653	$653	6.2%	–0.003%	$115	–$1
2035	$653	$653	6.2%	–0.003%	$117	–$1
2036	$653	$653	6.2%	–0.003%	$118	–$1
NPV[b]					$2,896	–$1,542

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-24. Impacts on Pumps and Compressor Equipment Market and Manufacturers (76-100 hp)
(Average Price per Equipment = $12,500)[a]

	Pumps and Compressor Equipment (70≤hp<100)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	—	—	0.0%	–0.002%	—	—
2012	$1,303	$1,178	9.4%	–0.003%	$823	–$583
2013	$1,302	$1,178	9.4%	–0.003%	$827	–$583
2014	$1,325	$1,169	9.4%	–0.003%	$998	–$733
2015	$1,324	$1,169	9.4%	–0.003%	$1,003	–$733
2016	$1,322	$1,169	9.4%	–0.003%	$1,007	–$733
2017	$1,247	$1,169	9.4%	–0.003%	$1,011	–$733
2018	$1,246	$1,169	9.4%	–0.003%	$1,016	–$733
2019	$1,218	$1,169	9.4%	–0.003%	$1,020	–$733
2020	$1,218	$1,169	9.4%	–0.003%	$1,025	–$733
2021	$1,218	$1,169	9.4%	–0.003%	$1,029	–$733
2022	$1,218	$1,169	9.4%	–0.003%	$452	–$151
2023	$1,218	$1,169	9.4%	–0.003%	$456	–$151
2024	$1,218	$1,169	9.4%	–0.003%	$311	–$1
2025	$1,218	$1,169	9.4%	–0.003%	$315	–$1
2026	$1,218	$1,169	9.4%	–0.003%	$320	–$1
2027	$1,218	$1,169	9.4%	–0.003%	$324	–$1
2028	$1,218	$1,169	9.4%	–0.003%	$328	–$1
2029	$1,218	$1,169	9.4%	–0.003%	$333	–$1
2030	$1,218	$1,169	9.4%	–0.003%	$337	–$1
2031	$1,218	$1,169	9.4%	–0.003%	$342	–$1
2032	$1,218	$1,169	9.4%	–0.003%	$346	–$1
2033	$1,218	$1,169	9.4%	–0.003%	$351	–$1
2034	$1,218	$1,169	9.4%	–0.003%	$355	–$1
2035	$1,218	$1,169	9.4%	–0.003%	$360	–$1
2036	$1,218	$1,169	9.4%	–0.003%	$364	–$1
NPV[b]					$9,294	–$5,030

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-25. Impacts on Pumps and Compressor Equipment Market and Manufacturers (101-175 hp)
(Average Price per Equipment = $23,800)[a]

	Pumps and Compressor Equipment (100≤hp<175)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	—	—	0.0%	–0.002%	—	—
2012	$1,623	$1,421	6.0%	–0.003%	$266	–$210
2013	$1,619	$1,421	6.0%	–0.003%	$267	–$210
2014	$1,664	$1,399	5.9%	–0.003%	$325	–$263
2015	$1,659	$1,399	5.9%	–0.003%	$326	–$263
2016	$1,654	$1,399	5.9%	–0.003%	$327	–$263
2017	$1,577	$1,399	5.9%	–0.003%	$328	–$263
2018	$1,574	$1,399	5.9%	–0.003%	$329	–$263
2019	$1,542	$1,399	5.9%	–0.003%	$330	–$263
2020	$1,539	$1,399	5.9%	–0.003%	$331	–$263
2021	$1,537	$1,399	5.9%	–0.003%	$332	–$263
2022	$1,388	$1,399	5.9%	–0.003%	$124	–$54
2023	$1,387	$1,399	5.9%	–0.003%	$125	–$54
2024	$1,351	$1,399	5.9%	–0.003%	$72	—
2025	$1,351	$1,399	5.9%	–0.003%	$73	—
2026	$1,351	$1,399	5.9%	–0.003%	$74	—
2027	$1,351	$1,399	5.9%	–0.003%	$75	—
2028	$1,351	$1,399	5.9%	–0.003%	$76	—
2029	$1,351	$1,399	5.9%	–0.003%	$77	—
2030	$1,351	$1,399	5.9%	–0.003%	$78	—
2031	$1,351	$1,399	5.9%	–0.003%	$79	—
2032	$1,351	$1,399	5.9%	–0.003%	$80	—
2033	$1,351	$1,399	5.9%	–0.003%	$81	—
2034	$1,351	$1,399	5.9%	–0.003%	$82	—
2035	$1,351	$1,399	5.9%	–0.003%	$83	—
2036	$1,351	$1,399	5.9%	–0.003%	$84	—
NPV[b]					$2,796	–$1,807

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-26. Impacts on Pumps and Compressor Equipment Market and Manufacturers (176-600 hp)
(Average Price per Equipment = $53,000)[a]

	Pumps and Compressor Equipment (175≤hp<600)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	–$1	0.0%	–0.001%	—	—
2011	$2,970	$2,265	4.3%	–0.002%	$821	–$685
2012	$2,958	$2,264	4.3%	–0.003%	$823	–$685
2013	$2,439	$1,755	3.3%	–0.003%	$797	–$686
2014	$3,107	$2,216	4.2%	–0.003%	$1,010	–$860
2015	$3,092	$2,215	4.2%	–0.003%	$1,012	–$860
2016	$2,777	$2,214	4.2%	–0.003%	$1,015	–$860
2017	$2,768	$2,213	4.2%	–0.003%	$1,017	–$860
2018	$2,759	$2,212	4.2%	–0.003%	$1,019	–$860
2019	$2,634	$2,211	4.2%	–0.003%	$1,021	–$860
2020	$2,627	$2,210	4.2%	–0.003%	$1,023	–$860
2021	$2,294	$2,210	4.2%	–0.003%	$341	–$176
2022	$2,292	$2,209	4.2%	–0.003%	$343	–$176
2023	$2,291	$2,208	4.2%	–0.003%	$345	–$176
2024	$2,209	$2,207	4.2%	–0.003%	$173	–$1
2025	$2,208	$2,207	4.2%	–0.003%	$175	–$1
2026	$2,208	$2,206	4.2%	–0.003%	$177	–$1
2027	$2,207	$2,205	4.2%	–0.003%	$180	–$1
2028	$2,206	$2,205	4.2%	–0.003%	$182	–$1
2029	$2,206	$2,204	4.2%	–0.003%	$184	–$1
2030	$2,205	$2,203	4.2%	–0.003%	$186	–$1
2031	$2,204	$2,203	4.2%	–0.003%	$188	–$1
2032	$2,204	$2,202	4.2%	–0.003%	$190	–$1
2033	$2,203	$2,202	4.2%	–0.003%	$192	–$1
2034	$2,203	$2,201	4.2%	–0.003%	$195	–$1
2035	$2,202	$2,200	4.2%	–0.003%	$197	–$1
2036	$2,202	$2,200	4.2%	–0.003%	$199	–$1
NPV[b]					$8,508	–$6,048

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-27. Impacts on Pumps and Compressor Equipment Market and Manufacturers (>600 hp)
(Average Price per Equipment = $88,000)[a]

Year	Pumps and Compressor Equipment (≥600hp) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	–$1	0.0%	–0.001%	—	—
2009	—	–$1	0.0%	–0.001%	—	—
2010	—	–$2	0.0%	–0.001%	—	—
2011	$4,519	$2,965	3.4%	–0.002%	$15	–$14
2012	$4,496	$2,964	3.4%	–0.003%	$15	–$14
2013	$3,797	$2,287	2.6%	–0.003%	$14	–$14
2014	$4,684	$2,790	3.2%	–0.003%	$18	–$16
2015	$9,206	$6,271	7.1%	–0.003%	$32	–$29
2016	$8,364	$6,271	7.1%	–0.003%	$32	–$29
2017	$7,517	$5,453	6.2%	–0.003%	$31	–$29
2018	$7,489	$5,453	6.2%	–0.003%	$31	–$29
2019	$7,218	$5,453	6.2%	–0.003%	$32	–$29
2020	$6,767	$5,453	6.2%	–0.003%	$32	–$29
2021	$6,151	$5,453	6.2%	–0.003%	$18	–$16
2022	$6,142	$5,453	6.2%	–0.003%	$18	–$16
2023	$6,133	$5,453	6.2%	–0.003%	$18	–$16
2024	$5,997	$5,453	6.2%	–0.003%	$15	–$13
2025	$5,458	$5,453	6.2%	–0.003%	$3	—
2026	$5,458	$5,453	6.2%	–0.003%	$3	—
2027	$5,458	$5,453	6.2%	–0.003%	$3	—
2028	$5,458	$5,453	6.2%	–0.003%	$3	—
2029	$5,458	$5,453	6.2%	–0.003%	$3	—
2030	$5,458	$5,453	6.2%	–0.003%	$3	—
2031	$5,458	$5,453	6.2%	–0.003%	$3	—
2032	$5,458	$5,453	6.2%	–0.003%	$3	—
2033	$5,458	$5,453	6.2%	–0.003%	$3	—
2034	$5,458	$5,453	6.2%	–0.003%	$3	—
2035	$5,458	$5,453	6.2%	–0.003%	$3	—
2036	$5,458	$5,453	6.2%	–0.003%	$3	—
NPV[b]					$231	–$196

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-28. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (<25 hp)
(Average Price per Equipment = $6,800)[a]

	Generator Sets and Welding Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$177	$129	1.9%	–0.001%	$3,795	–$1,615
2009	$176	$129	1.9%	–0.001%	$3,854	–$1,615
2010	$168	$123	1.8%	–0.001%	$3,794	–$1,616
2011	$167	$123	1.8%	–0.002%	$3,850	–$1,618
2012	$166	$123	1.8%	–0.003%	$3,906	–$1,619
2013	$136	$123	1.8%	–0.003%	$3,410	–$1,068
2014	$136	$123	1.8%	–0.003%	$3,466	–$1,069
2015	$135	$123	1.8%	–0.003%	$3,522	–$1,069
2016	$135	$123	1.8%	–0.003%	$3,578	–$1,069
2017	$135	$123	1.8%	–0.003%	$3,634	–$1,069
2018	$123	$123	1.8%	–0.003%	$2,627	–$6
2019	$123	$123	1.8%	–0.003%	$2,683	–$7
2020	$123	$123	1.8%	–0.003%	$2,739	–$7
2021	$123	$123	1.8%	–0.003%	$2,795	–$7
2022	$123	$123	1.8%	–0.003%	$2,851	–$7
2023	$123	$123	1.8%	–0.003%	$2,907	–$7
2024	$123	$123	1.8%	–0.003%	$2,963	–$7
2025	$123	$123	1.8%	–0.003%	$3,019	–$7
2026	$123	$123	1.8%	–0.003%	$3,075	–$7
2027	$123	$123	1.8%	–0.003%	$3,131	–$8
2028	$123	$123	1.8%	–0.003%	$3,187	–$8
2029	$123	$123	1.8%	–0.003%	$3,243	–$8
2030	$123	$123	1.8%	–0.003%	$3,299	–$8
2031	$123	$123	1.8%	–0.003%	$3,355	–$8
2032	$123	$123	1.8%	–0.003%	$3,411	–$8
2033	$123	$123	1.8%	–0.003%	$3,467	–$8
2034	$123	$123	1.8%	–0.003%	$3,523	–$9
2035	$123	$123	1.8%	–0.003%	$3,579	–$9
2036	$123	$123	1.8%	–0.003%	$3,634	–$9
NPV[b]					$58,866	–$10,712

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-29. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (26-50 hp)
(Average Price per Equipment = $8,700)[a]

	Generator Sets and Welding Equipment (25≤hp<50)					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$204	$147	1.7%	–0.001%	$1,896	–$713
2009	$203	$147	1.7%	–0.001%	$1,922	–$713
2010	$194	$139	1.6%	–0.001%	$1,883	–$714
2011	$193	$139	1.6%	–0.002%	$1,907	–$715
2012	$192	$139	1.6%	–0.003%	$1,932	–$716
2013	$986	$870	10.0%	–0.003%	$10,977	–$2,502
2014	$984	$870	10.0%	–0.003%	$11,143	–$2,502
2015	$773	$661	7.6%	–0.003%	$9,227	–$2,502
2016	$771	$661	7.6%	–0.003%	$9,354	–$2,502
2017	$769	$661	7.6%	–0.003%	$9,481	–$2,502
2018	$693	$661	7.6%	–0.003%	$8,631	–$1,525
2019	$692	$661	7.6%	–0.003%	$8,758	–$1,525
2020	$692	$661	7.6%	–0.003%	$8,885	–$1,525
2021	$691	$661	7.6%	–0.003%	$9,012	–$1,525
2022	$691	$661	7.6%	–0.003%	$9,139	–$1,525
2023	$661	$661	7.6%	–0.003%	$7,746	–$5
2024	$661	$661	7.6%	–0.003%	$7,873	–$5
2025	$661	$661	7.6%	–0.003%	$8,000	–$5
2026	$661	$661	7.6%	–0.003%	$8,127	–$5
2027	$661	$661	7.6%	–0.003%	$8,254	–$5
2028	$661	$661	7.6%	–0.003%	$8,381	–$5
2029	$661	$661	7.6%	–0.003%	$8,508	–$5
2030	$661	$661	7.6%	–0.003%	$8,635	–$5
2031	$661	$661	7.6%	–0.003%	$8,762	–$5
2032	$661	$661	7.6%	–0.003%	$8,889	–$5
2033	$661	$661	7.6%	–0.003%	$9,017	–$6
2034	$661	$661	7.6%	–0.003%	$9,144	–$6
2035	$661	$661	7.6%	–0.003%	$9,271	–$6
2036	$661	$661	7.6%	–0.003%	$9,398	–$6
NPV[b]					$128,538	–$16,831

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-30. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (51-75 hp)
(Average Price per Equipment = $8,300)[a]

	Generator Sets and Welding Equipment (50≤hp<70)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$226	$167	2.0%	–0.001%	$2,029	–$570
2009	$225	$167	2.0%	–0.001%	$2,056	–$570
2010	$214	$158	1.9%	–0.001%	$2,000	–$570
2011	$213	$158	1.9%	–0.002%	$2,025	–$571
2012	$212	$158	1.9%	–0.003%	$2,051	–$571
2013	$978	$858	10.3%	–0.003%	$9,825	–$1,472
2014	$976	$858	10.3%	–0.003%	$9,966	–$1,472
2015	$769	$653	7.9%	–0.003%	$8,049	–$1,472
2016	$767	$653	7.9%	–0.003%	$8,157	–$1,472
2017	$765	$653	7.9%	–0.003%	$8,265	–$1,472
2018	$687	$653	7.9%	–0.003%	$7,518	–$617
2019	$686	$653	7.9%	–0.003%	$7,626	–$617
2020	$686	$653	7.9%	–0.003%	$7,734	–$617
2021	$685	$653	7.9%	–0.003%	$7,842	–$617
2022	$685	$653	7.9%	–0.003%	$7,950	–$617
2023	$653	$653	7.9%	–0.003%	$7,443	–$2
2024	$653	$653	7.9%	–0.003%	$7,551	–$2
2025	$653	$653	7.9%	–0.003%	$7,659	–$2
2026	$653	$653	7.9%	–0.003%	$7,767	–$2
2027	$653	$653	7.9%	–0.003%	$7,875	–$2
2028	$653	$653	7.9%	–0.003%	$7,983	–$2
2029	$653	$653	7.9%	–0.003%	$8,091	–$2
2030	$653	$653	7.9%	–0.003%	$8,199	–$2
2031	$653	$653	7.9%	–0.003%	$8,307	–$2
2032	$653	$653	7.9%	–0.003%	$8,415	–$2
2033	$653	$653	7.9%	–0.003%	$8,523	–$2
2034	$653	$653	7.9%	–0.003%	$8,631	–$2
2035	$653	$653	7.9%	–0.003%	$8,739	–$2
2036	$653	$653	7.9%	–0.003%	$8,847	–$2
NPV[b]					$118,426	–$9,648

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-31. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (76-100 hp)
(Average Price per Equipment = $18,000)[a]

	Generator Sets and Welding Equipment (70≤hp<100)					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	—	—	0.0%	–0.002%	—	–$1
2012	$1,303	$1,178	6.5%	–0.003%	$2,241	–$842
2013	$1,302	$1,178	6.5%	–0.003%	$2,265	–$842
2014	$1,325	$1,169	6.5%	–0.003%	$2,527	–$1,069
2015	$1,324	$1,169	6.5%	–0.003%	$2,552	–$1,069
2016	$1,322	$1,169	6.5%	–0.003%	$2,576	–$1,069
2017	$1,247	$1,169	6.5%	–0.003%	$2,524	–$993
2018	$1,246	$1,169	6.5%	–0.003%	$2,548	–$993
2019	$1,218	$1,169	6.5%	–0.003%	$2,543	–$963
2020	$1,218	$1,169	6.5%	–0.003%	$2,567	–$963
2021	$1,218	$1,169	6.5%	–0.003%	$2,592	–$963
2022	$1,218	$1,169	6.5%	–0.003%	$1,851	–$198
2023	$1,218	$1,169	6.5%	–0.003%	$1,876	–$199
2024	$1,218	$1,169	6.5%	–0.003%	$1,703	–$2
2025	$1,218	$1,169	6.5%	–0.003%	$1,727	–$2
2026	$1,218	$1,169	6.5%	–0.003%	$1,752	–$2
2027	$1,218	$1,169	6.5%	–0.003%	$1,776	–$2
2028	$1,218	$1,169	6.5%	–0.003%	$1,801	–$2
2029	$1,218	$1,169	6.5%	–0.003%	$1,825	–$2
2030	$1,218	$1,169	6.5%	–0.003%	$1,849	–$2
2031	$1,218	$1,169	6.5%	–0.003%	$1,874	–$2
2032	$1,218	$1,169	6.5%	–0.003%	$1,898	–$2
2033	$1,218	$1,169	6.5%	–0.003%	$1,923	–$2
2034	$1,218	$1,169	6.5%	–0.003%	$1,947	–$2
2035	$1,218	$1,169	6.5%	–0.003%	$1,971	–$2
2036	$1,218	$1,169	6.5%	–0.003%	$1,996	–$2
NPV[b]					$30,552	–$7,004

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-32. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (101-175 hp)
(Average Price per Equipment = $21,400)[a]

Year	Generator Sets and Welding Equipment (100≤hp<175) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	–$1
2011	—	—	0.0%	–0.002%	—	–$1
2012	$1,623	$1,421	6.6%	–0.003%	$11,755	–$2,081
2013	$1,619	$1,421	6.6%	–0.003%	$11,915	–$2,081
2014	$1,664	$1,399	6.5%	–0.003%	$12,544	–$2,692
2015	$1,659	$1,399	6.5%	–0.003%	$12,702	–$2,692
2016	$1,654	$1,399	6.5%	–0.003%	$12,860	–$2,692
2017	$1,577	$1,399	6.5%	–0.003%	$12,493	–$2,167
2018	$1,574	$1,399	6.5%	–0.003%	$12,651	–$2,168
2019	$1,542	$1,399	6.5%	–0.003%	$12,595	–$1,953
2020	$1,539	$1,399	6.5%	–0.003%	$12,753	–$1,953
2021	$1,537	$1,399	6.5%	–0.003%	$12,911	–$1,953
2022	$1,388	$1,399	6.5%	–0.003%	$11,515	–$399
2023	$1,387	$1,399	6.5%	–0.003%	$11,673	–$399
2024	$1,351	$1,399	6.5%	–0.003%	$11,434	–$2
2025	$1,351	$1,399	6.5%	–0.003%	$11,591	–$2
2026	$1,351	$1,399	6.5%	–0.003%	$11,749	–$3
2027	$1,351	$1,399	6.5%	–0.003%	$11,907	–$3
2028	$1,351	$1,399	6.5%	–0.003%	$12,065	–$3
2029	$1,351	$1,399	6.5%	–0.003%	$12,223	–$3
2030	$1,351	$1,399	6.5%	–0.003%	$12,381	–$3
2031	$1,351	$1,399	6.5%	–0.003%	$12,539	–$3
2032	$1,351	$1,399	6.5%	–0.003%	$12,697	–$3
2033	$1,351	$1,399	6.5%	–0.003%	$12,855	–$3
2034	$1,351	$1,399	6.5%	–0.003%	$13,013	–$3
2035	$1,351	$1,399	6.5%	–0.003%	$13,171	–$3
2036	$1,351	$1,399	6.5%	–0.003%	$13,329	–$3
NPV[b]					$174,772	–$16,116

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-33. Impacts on Generator Sets and Welding Equipment Market and Manufacturers (176-600 hp)
(Average Price per Equipment = $21,400)[a]

	Generator Sets and Welding Equipment (175≤hp<600)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	$2,970	$2,266	6.3%	–0.002%	$3,728	–$1,185
2012	$2,958	$2,265	6.3%	–0.003%	$3,767	–$1,185
2013	$2,439	$1,756	4.9%	–0.003%	$3,221	–$1,186
2014	$3,107	$2,216	6.2%	–0.003%	$4,154	–$1,540
2015	$3,092	$2,215	6.2%	–0.003%	$4,192	–$1,540
2016	$2,777	$2,214	6.2%	–0.003%	$3,877	–$1,187
2017	$2,768	$2,214	6.2%	–0.003%	$3,916	–$1,187
2018	$2,759	$2,213	6.2%	–0.003%	$3,954	–$1,187
2019	$2,634	$2,212	6.2%	–0.003%	$3,850	–$1,044
2020	$2,627	$2,211	6.2%	–0.003%	$3,888	–$1,044
2021	$2,294	$2,210	6.2%	–0.003%	$3,096	–$213
2022	$2,292	$2,210	6.2%	–0.003%	$3,134	–$213
2023	$2,291	$2,209	6.2%	–0.003%	$3,173	–$213
2024	$2,209	$2,208	6.2%	–0.003%	$3,000	–$1
2025	$2,208	$2,207	6.2%	–0.003%	$3,038	–$1
2026	$2,208	$2,207	6.2%	–0.003%	$3,077	–$1
2027	$2,207	$2,206	6.2%	–0.003%	$3,115	–$1
2028	$2,206	$2,205	6.2%	–0.003%	$3,154	–$1
2029	$2,206	$2,205	6.2%	–0.003%	$3,192	–$1
2030	$2,205	$2,204	6.2%	–0.003%	$3,231	–$1
2031	$2,204	$2,203	6.2%	–0.003%	$3,269	–$1
2032	$2,204	$2,203	6.2%	–0.003%	$3,308	–$1
2033	$2,203	$2,202	6.2%	–0.003%	$3,346	–$1
2034	$2,203	$2,202	6.2%	–0.003%	$3,385	–$1
2035	$2,202	$2,201	6.2%	–0.003%	$3,423	–$1
2036	$2,202	$2,201	6.2%	–0.003%	$3,462	–$1
NPV[b]					$52,508	–$9,195

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-34. Impacts on Refrigeration and Air-Conditioning Equipment Market and Manufacturers (<25 hp)
(Average Price per Equipment = $12,500)[a]

	Refrigeration and Air-Conditioning Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$177	$129	1.0%	–0.001%	$168	–$168
2009	$176	$129	1.0%	–0.001%	$168	–$168
2010	$168	$123	1.0%	–0.001%	$168	–$168
2011	$167	$123	1.0%	–0.002%	$168	–$169
2012	$166	$123	1.0%	–0.003%	$168	–$169
2013	$136	$123	1.0%	–0.003%	$168	–$169
2014	$136	$123	1.0%	–0.003%	$168	–$170
2015	$135	$123	1.0%	–0.003%	$168	–$170
2016	$135	$123	1.0%	–0.003%	$168	–$170
2017	$135	$123	1.0%	–0.003%	$168	–$170
2018	$123	$123	1.0%	–0.003%	—	–$2
2019	$123	$123	1.0%	–0.003%	—	–$2
2020	$123	$123	1.0%	–0.003%	—	–$2
2021	$123	$123	1.0%	–0.003%	—	–$2
2022	$123	$123	1.0%	–0.003%	—	–$2
2023	$123	$123	1.0%	–0.003%	—	–$2
2024	$123	$123	1.0%	–0.003%	—	–$2
2025	$123	$123	1.0%	–0.003%	—	–$2
2026	$123	$123	1.0%	–0.003%	—	–$2
2027	$123	$123	1.0%	–0.003%	—	–$2
2028	$123	$123	1.0%	–0.003%	—	–$2
2029	$123	$123	1.0%	–0.003%	—	–$2
2030	$123	$123	1.0%	–0.003%	—	–$2
2031	$123	$123	1.0%	–0.003%	—	–$2
2032	$123	$123	1.0%	–0.003%	—	–$2
2033	$123	$123	1.0%	–0.003%	—	–$3
2034	$123	$123	1.0%	–0.003%	—	–$3
2035	$123	$123	1.0%	–0.003%	—	–$3
2036	$123	$123	1.0%	–0.003%	—	–$3
NPV[b]					$1,310	–$1,340

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-35. Impacts on Refrigeration and Air-Conditioning Equipment Market and Manufacturers (26-50 hp)
(Average Price per Equipment = $27,000)[a]

	Refrigeration and Air-Conditioning Equipment (25≤hp<50)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$204	$147	0.5%	–0.001%	$100	–$101
2009	$203	$147	0.5%	–0.001%	$100	–$101
2010	$194	$139	0.5%	–0.001%	$100	–$102
2011	$193	$139	0.5%	–0.002%	$100	–$103
2012	$192	$139	0.5%	–0.003%	$100	–$104
2013	$986	$869	3.2%	–0.003%	$871	–$590
2014	$984	$869	3.2%	–0.003%	$876	–$590
2015	$773	$661	2.4%	–0.003%	$823	–$590
2016	$771	$661	2.4%	–0.003%	$827	–$591
2017	$769	$661	2.4%	–0.003%	$832	–$591
2018	$693	$661	2.4%	–0.003%	$736	–$490
2019	$692	$661	2.4%	–0.003%	$740	–$490
2020	$692	$661	2.4%	–0.003%	$745	–$490
2021	$691	$661	2.4%	–0.003%	$749	–$490
2022	$691	$661	2.4%	–0.003%	$754	–$490
2023	$661	$661	2.4%	–0.003%	$273	–$5
2024	$661	$661	2.4%	–0.003%	$277	–$5
2025	$661	$661	2.4%	–0.003%	$281	–$5
2026	$661	$661	2.4%	–0.003%	$286	–$5
2027	$661	$661	2.4%	–0.003%	$290	–$5
2028	$661	$661	2.4%	–0.003%	$295	–$5
2029	$661	$661	2.4%	–0.003%	$299	–$5
2030	$661	$661	2.4%	–0.003%	$304	–$5
2031	$661	$661	2.4%	–0.003%	$308	–$6
2032	$661	$661	2.4%	–0.003%	$313	–$6
2033	$661	$661	2.4%	–0.003%	$317	–$6
2034	$661	$661	2.4%	–0.003%	$322	–$6
2035	$661	$661	2.4%	–0.003%	$326	–$6
2036	$661	$661	2.4%	–0.003%	$331	–$6
NPV[b]					$7,790	–$4,126

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10B-36. Impacts on Refrigeration and Air-Conditioning Equipment Market and Manufacturers (51-75 hp)
(Average Price per Equipment = $42,100)[a]

	Refrigeration and Air-Conditioning Equipment (50≤hp<70)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$226	$167	0.4%	–0.001%	$179	–$180
2009	$225	$167	0.4%	–0.001%	$179	–$180
2010	$214	$158	0.4%	–0.001%	$179	–$182
2011	$213	$157	0.4%	–0.002%	$179	–$184
2012	$212	$157	0.4%	–0.003%	$179	–$187
2013	$978	$858	2.0%	–0.003%	$1,512	–$1,032
2014	$976	$858	2.0%	–0.003%	$1,521	–$1,033
2015	$769	$653	1.6%	–0.003%	$1,428	–$1,033
2016	$767	$653	1.6%	–0.003%	$1,434	–$1,033
2017	$765	$653	1.6%	–0.003%	$1,441	–$1,033
2018	$687	$653	1.6%	–0.003%	$1,269	–$855
2019	$686	$653	1.6%	–0.003%	$1,276	–$855
2020	$686	$653	1.6%	–0.003%	$1,282	–$855
2021	$685	$653	1.6%	–0.003%	$1,289	–$855
2022	$685	$653	1.6%	–0.003%	$1,295	–$855
2023	$653	$653	1.6%	–0.003%	$459	–$12
2024	$653	$653	1.6%	–0.003%	$466	–$13
2025	$653	$653	1.6%	–0.003%	$472	–$13
2026	$653	$653	1.6%	–0.003%	$479	–$13
2027	$653	$653	1.6%	–0.003%	$486	–$13
2028	$653	$653	1.6%	–0.003%	$492	–$13
2029	$653	$653	1.6%	–0.003%	$499	–$13
2030	$653	$653	1.6%	–0.003%	$506	–$14
2031	$653	$653	1.6%	–0.003%	$512	–$14
2032	$653	$653	1.6%	–0.003%	$519	–$14
2033	$653	$653	1.6%	–0.003%	$526	–$14
2034	$653	$653	1.6%	–0.003%	$532	–$14
2035	$653	$653	1.6%	–0.003%	$539	–$15
2036	$653	$653	1.6%	–0.003%	$546	–$15
NPV[b]					$13,368	–$7,255

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-37. Impacts on General Industrial Equipment Market and Manufacturers (<25 hp) (Average Price per Equipment = $17,300)[a]

	General Industrial Equipment (<25hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$177	$129	0.7%	–0.001%	$61	–$61
2009	$176	$129	0.7%	–0.001%	$61	–$61
2010	$168	$123	0.7%	–0.001%	$61	–$61
2011	$167	$123	0.7%	–0.002%	$61	–$62
2012	$166	$123	0.7%	–0.003%	$61	–$62
2013	$136	$123	0.7%	–0.003%	$61	–$62
2014	$136	$123	0.7%	–0.003%	$61	–$62
2015	$135	$123	0.7%	–0.003%	$61	–$62
2016	$135	$123	0.7%	–0.003%	$61	–$62
2017	$135	$123	0.7%	–0.003%	$61	–$62
2018	$123	$123	0.7%	–0.003%	—	–$1
2019	$123	$123	0.7%	–0.003%	—	–$1
2020	$123	$123	0.7%	–0.003%	—	–$1
2021	$123	$123	0.7%	–0.003%	—	–$1
2022	$123	$123	0.7%	–0.003%	—	–$1
2023	$123	$123	0.7%	–0.003%	—	–$1
2024	$123	$123	0.7%	–0.003%	—	–$1
2025	$123	$123	0.7%	–0.003%	—	–$1
2026	$123	$123	0.7%	–0.003%	—	–$1
2027	$123	$123	0.7%	–0.003%	—	–$1
2028	$123	$123	0.7%	–0.003%	—	–$1
2029	$123	$123	0.7%	–0.003%	—	–$1
2030	$123	$123	0.7%	–0.003%	—	–$1
2031	$123	$123	0.7%	–0.003%	—	–$1
2032	$123	$123	0.7%	–0.003%	—	–$1
2033	$123	$123	0.7%	–0.003%	—	–$1
2034	$123	$123	0.7%	–0.003%	—	–$1
2035	$123	$123	0.7%	–0.003%	—	–$1
2036	$123	$123	0.7%	–0.003%	—	–$1
NPV[b]					$479	–$487

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-38. Impacts on General Industrial Equipment Market and Manufacturers (26-50 hp) (Average Price per Equipment = $42,300)[a]

Year	General Industrial Equipment (25≤hp<50) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$204	$147	0.3%	–0.001%	$83	–$71
2009	$203	$147	0.3%	–0.001%	$83	–$71
2010	$194	$139	0.3%	–0.001%	$83	–$72
2011	$193	$139	0.3%	–0.002%	$83	–$72
2012	$192	$139	0.3%	–0.003%	$83	–$73
2013	$986	$870	2.1%	–0.003%	$664	–$400
2014	$984	$869	2.1%	–0.003%	$670	–$400
2015	$773	$661	1.6%	–0.003%	$616	–$400
2016	$771	$661	1.6%	–0.003%	$620	–$400
2017	$769	$661	1.6%	–0.003%	$624	–$400
2018	$693	$661	1.6%	–0.003%	$555	–$326
2019	$692	$661	1.6%	–0.003%	$559	–$327
2020	$692	$661	1.6%	–0.003%	$563	–$327
2021	$691	$661	1.6%	–0.003%	$567	–$327
2022	$691	$661	1.6%	–0.003%	$571	–$327
2023	$661	$661	1.6%	–0.003%	$251	–$3
2024	$661	$661	1.6%	–0.003%	$256	–$3
2025	$661	$661	1.6%	–0.003%	$260	–$3
2026	$661	$661	1.6%	–0.003%	$264	–$3
2027	$661	$661	1.6%	–0.003%	$268	–$3
2028	$661	$661	1.6%	–0.003%	$272	–$3
2029	$661	$661	1.6%	–0.003%	$276	–$3
2030	$661	$661	1.6%	–0.003%	$280	–$3
2031	$661	$661	1.6%	–0.003%	$284	–$3
2032	$661	$661	1.6%	–0.003%	$289	–$3
2033	$661	$661	1.6%	–0.003%	$293	–$3
2034	$661	$661	1.6%	–0.003%	$297	–$3
2035	$661	$661	1.6%	–0.003%	$301	–$3
2036	$661	$661	1.6%	–0.003%	$305	–$3
NPV[b]					$6,249	–$2,785

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-39. Impacts on General Industrial Equipment Market and Manufacturers (51-75 hp) (Average Price per Equipment = $56,400)[a]

	General Industrial Equipment (50≤hp<70)					Change in Producer
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$226	$167	0.3%	–0.001%	$413	–$150
2009	$225	$167	0.3%	–0.001%	$418	–$150
2010	$214	$158	0.3%	–0.001%	$408	–$150
2011	$213	$158	0.3%	–0.002%	$412	–$151
2012	$212	$157	0.3%	–0.003%	$417	–$151
2013	$978	$858	1.5%	–0.003%	$2,167	–$532
2014	$976	$858	1.5%	–0.003%	$2,195	–$533
2015	$769	$653	1.2%	–0.003%	$1,824	–$533
2016	$767	$653	1.2%	–0.003%	$1,845	–$533
2017	$765	$653	1.2%	–0.003%	$1,867	–$533
2018	$687	$653	1.2%	–0.003%	$1,687	–$332
2019	$686	$653	1.2%	–0.003%	$1,708	–$332
2020	$686	$653	1.2%	–0.003%	$1,730	–$332
2021	$685	$653	1.2%	–0.003%	$1,751	–$332
2022	$685	$653	1.2%	–0.003%	$1,772	–$332
2023	$653	$653	1.2%	–0.003%	$1,465	–$3
2024	$653	$653	1.2%	–0.003%	$1,486	–$3
2025	$653	$653	1.2%	–0.003%	$1,507	–$4
2026	$653	$653	1.2%	–0.003%	$1,529	–$4
2027	$653	$653	1.2%	–0.003%	$1,550	–$4
2028	$653	$653	1.2%	–0.003%	$1,571	–$4
2029	$653	$653	1.2%	–0.003%	$1,592	–$4
2030	$653	$653	1.2%	–0.003%	$1,614	–$4
2031	$653	$653	1.2%	–0.003%	$1,635	–$4
2032	$653	$653	1.2%	–0.003%	$1,656	–$4
2033	$653	$653	1.2%	–0.003%	$1,677	–$4
2034	$653	$653	1.2%	–0.003%	$1,699	–$4
2035	$653	$653	1.2%	–0.003%	$1,720	–$4
2036	$653	$653	1.2%	–0.003%	$1,741	–$4
NPV[b]					$24,870	–$3,615

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-40. Impacts on General Industrial Equipment Market and Manufacturers (76-100 hp)
(Average Price per Equipment = $74,300)[a]

	General Industrial Equipment (75≤hp<100)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	–$1
2009	—	—	0.0%	–0.001%	—	–$1
2010	—	—	0.0%	–0.001%	—	–$2
2011	—	—	0.0%	–0.002%	—	–$4
2012	$1,303	$1,178	1.6%	–0.003%	$8,518	–$2,336
2013	$1,302	$1,178	1.6%	–0.003%	$8,625	–$2,337
2014	$1,325	$1,169	1.6%	–0.003%	$9,382	–$2,990
2015	$1,324	$1,169	1.6%	–0.003%	$9,489	–$2,990
2016	$1,322	$1,169	1.6%	–0.003%	$9,596	–$2,990
2017	$1,247	$1,169	1.6%	–0.003%	$9,325	–$2,611
2018	$1,246	$1,169	1.6%	–0.003%	$9,432	–$2,611
2019	$1,218	$1,169	1.6%	–0.003%	$9,390	–$2,462
2020	$1,218	$1,169	1.6%	–0.003%	$9,497	–$2,462
2021	$1,218	$1,169	1.6%	–0.003%	$9,604	–$2,462
2022	$1,218	$1,169	1.6%	–0.003%	$7,760	–$511
2023	$1,218	$1,169	1.6%	–0.003%	$7,867	–$511
2024	$1,218	$1,169	1.6%	–0.003%	$7,471	–$9
2025	$1,218	$1,169	1.6%	–0.003%	$7,578	–$9
2026	$1,218	$1,169	1.6%	–0.003%	$7,685	–$9
2027	$1,218	$1,169	1.6%	–0.003%	$7,792	–$10
2028	$1,218	$1,169	1.6%	–0.003%	$7,899	–$10
2029	$1,218	$1,169	1.6%	–0.003%	$8,006	–$10
2030	$1,218	$1,169	1.6%	–0.003%	$8,113	–$10
2031	$1,218	$1,169	1.6%	–0.003%	$8,220	–$10
2032	$1,218	$1,169	1.6%	–0.003%	$8,327	–$10
2033	$1,218	$1,169	1.6%	–0.003%	$8,434	–$10
2034	$1,218	$1,169	1.6%	–0.003%	$8,541	–$10
2035	$1,218	$1,169	1.6%	–0.003%	$8,648	–$11
2036	$1,218	$1,169	1.6%	–0.003%	$8,756	–$11
NPV[b]					$122,225	–$18,884

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-41. Impacts on General Industrial Equipment Market and Manufacturers (101-175 hp)
(Average Price per Equipment = $116,900)[a]

Year	General Industrial Equipment (100≤hp<175) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	–$2
2009	—	—	0.0%	–0.001%	—	–$2
2010	—	—	0.0%	–0.001%	—	–$5
2011	—	–$1	0.0%	–0.002%	—	–$8
2012	$1,623	$1,420	1.2%	–0.003%	$11,708	–$4,156
2013	$1,619	$1,420	1.2%	–0.003%	$11,833	–$4,160
2014	$1,664	$1,399	1.2%	–0.003%	$13,023	–$5,276
2015	$1,659	$1,399	1.2%	–0.003%	$13,147	–$5,276
2016	$1,654	$1,399	1.2%	–0.003%	$13,272	–$5,276
2017	$1,577	$1,399	1.2%	–0.003%	$13,025	–$4,905
2018	$1,574	$1,399	1.2%	–0.003%	$13,150	–$4,905
2019	$1,542	$1,399	1.2%	–0.003%	$13,123	–$4,754
2020	$1,539	$1,399	1.2%	–0.003%	$13,247	–$4,754
2021	$1,537	$1,399	1.2%	–0.003%	$13,371	–$4,755
2022	$1,388	$1,399	1.2%	–0.003%	$9,722	–$981
2023	$1,387	$1,399	1.2%	–0.003%	$9,846	–$981
2024	$1,351	$1,399	1.2%	–0.003%	$9,007	–$18
2025	$1,351	$1,399	1.2%	–0.003%	$9,131	–$18
2026	$1,351	$1,399	1.2%	–0.003%	$9,256	–$18
2027	$1,351	$1,399	1.2%	–0.003%	$9,380	–$18
2028	$1,351	$1,399	1.2%	–0.003%	$9,504	–$19
2029	$1,351	$1,399	1.2%	–0.003%	$9,629	–$19
2030	$1,351	$1,399	1.2%	–0.003%	$9,753	–$19
2031	$1,351	$1,399	1.2%	–0.003%	$9,878	–$19
2032	$1,351	$1,399	1.2%	–0.003%	$10,002	–$20
2033	$1,351	$1,399	1.2%	–0.003%	$10,127	–$20
2034	$1,351	$1,399	1.2%	–0.003%	$10,251	–$20
2035	$1,351	$1,399	1.2%	–0.003%	$10,375	–$20
2036	$1,351	$1,399	1.2%	–0.003%	$10,500	–$21
NPV[b]					$159,307	–$34,647

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-42. Impacts on General Industrial Equipment Market and Manufacturers (176-600 hp)
(Average Price per Equipment = $154,200)[a]

Year	General Industrial Equipment (175≤hp<600) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	–$1
2009	—	—	0.0%	–0.001%	—	–$1
2010	—	–$1	0.0%	–0.001%	—	–$3
2011	$2,970	$2,265	1.5%	–0.002%	$6,434	–$4,061
2012	$2,958	$2,264	1.5%	–0.003%	$6,470	–$4,063
2013	$2,439	$1,755	1.1%	–0.003%	$5,975	–$4,065
2014	$3,107	$2,215	1.4%	–0.003%	$7,625	–$5,135
2015	$3,092	$2,214	1.4%	–0.003%	$7,662	–$5,135
2016	$2,777	$2,213	1.4%	–0.003%	$7,457	–$4,894
2017	$2,768	$2,213	1.4%	–0.003%	$7,494	–$4,895
2018	$2,759	$2,212	1.4%	–0.003%	$7,530	–$4,895
2019	$2,634	$2,211	1.4%	–0.003%	$7,469	–$4,797
2020	$2,627	$2,210	1.4%	–0.003%	$7,506	–$4,798
2021	$2,294	$2,209	1.4%	–0.003%	$3,727	–$982
2022	$2,292	$2,209	1.4%	–0.003%	$3,763	–$982
2023	$2,291	$2,208	1.4%	–0.003%	$3,799	–$982
2024	$2,209	$2,207	1.4%	–0.003%	$2,864	–$11
2025	$2,208	$2,206	1.4%	–0.003%	$2,901	–$11
2026	$2,208	$2,206	1.4%	–0.003%	$2,937	–$11
2027	$2,207	$2,205	1.4%	–0.003%	$2,974	–$11
2028	$2,206	$2,204	1.4%	–0.003%	$3,010	–$11
2029	$2,206	$2,204	1.4%	–0.003%	$3,046	–$11
2030	$2,205	$2,203	1.4%	–0.003%	$3,083	–$12
2031	$2,204	$2,203	1.4%	–0.003%	$3,119	–$12
2032	$2,204	$2,202	1.4%	–0.003%	$3,156	–$12
2033	$2,203	$2,201	1.4%	–0.003%	$3,192	–$12
2034	$2,203	$2,201	1.4%	–0.003%	$3,229	–$12
2035	$2,202	$2,200	1.4%	–0.003%	$3,265	–$12
2036	$2,202	$2,200	1.4%	–0.003%	$3,302	–$12
NPV[b]					$76,149	–$35,032

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-43. Impacts on General Industrial Equipment Market and Manufacturers (>600 hp) (Average Price per Equipment = $345,700)[a]

	General Industrial Equipment (≥600hp)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	–$1	0.0%	–0.001%	—	—
2009	—	–$1	0.0%	–0.001%	—	—
2010	—	–$2	0.0%	–0.001%	—	—
2011	$4,519	$2,964	0.9%	–0.002%	$665	–$512
2012	$4,496	$2,963	0.9%	–0.003%	$667	–$512
2013	$3,797	$2,287	0.7%	–0.003%	$634	–$513
2014	$4,684	$2,789	0.8%	–0.003%	$783	–$629
2015	$9,206	$6,270	1.8%	–0.003%	$1,439	–$1,095
2016	$8,364	$6,270	1.8%	–0.003%	$1,410	–$1,061
2017	$7,517	$5,452	1.6%	–0.003%	$1,371	–$1,061
2018	$7,489	$5,452	1.6%	–0.003%	$1,375	–$1,061
2019	$7,218	$5,452	1.6%	–0.003%	$1,369	–$1,050
2020	$6,767	$5,452	1.6%	–0.003%	$1,355	–$1,031
2021	$6,151	$5,452	1.6%	–0.003%	$881	–$554
2022	$6,142	$5,452	1.6%	–0.003%	$886	–$554
2023	$6,133	$5,452	1.6%	–0.003%	$890	–$554
2024	$5,997	$5,452	1.6%	–0.003%	$789	–$449
2025	$5,458	$5,452	1.6%	–0.003%	$346	–$2
2026	$5,458	$5,452	1.6%	–0.003%	$351	–$2
2027	$5,458	$5,452	1.6%	–0.003%	$355	–$2
2028	$5,458	$5,452	1.6%	–0.003%	$359	–$2
2029	$5,458	$5,452	1.6%	–0.003%	$364	–$2
2030	$5,458	$5,452	1.6%	–0.003%	$368	–$2
2031	$5,458	$5,452	1.6%	–0.003%	$372	–$2
2032	$5,458	$5,452	1.6%	–0.003%	$377	–$2
2033	$5,458	$5,452	1.6%	–0.003%	$381	–$2
2034	$5,458	$5,452	1.6%	–0.003%	$385	–$2
2035	$5,458	$5,452	1.6%	–0.003%	$390	–$2
2036	$5,458	$5,452	1.6%	–0.003%	$394	–$2
NPV[b]					$11,760	–$7,192

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-44. Impacts on Lawn and Garden Equipment Market and Manufacturers (<25 hp) (Average Price per Equipment = $9,300)[a]

	Lawn and Garden Equipment (<25hp)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$177	$129	1.4%	–0.001%	$1,805	–$629
2009	$176	$129	1.4%	–0.001%	$1,836	–$629
2010	$168	$123	1.3%	–0.001%	$1,804	–$629
2011	$167	$123	1.3%	–0.002%	$1,834	–$630
2012	$166	$123	1.3%	–0.003%	$1,864	–$630
2013	$136	$123	1.3%	–0.003%	$1,597	–$333
2014	$136	$123	1.3%	–0.003%	$1,627	–$333
2015	$135	$123	1.3%	–0.003%	$1,657	–$333
2016	$135	$123	1.3%	–0.003%	$1,687	–$333
2017	$135	$123	1.3%	–0.003%	$1,717	–$333
2018	$123	$123	1.3%	–0.003%	$1,417	–$2
2019	$123	$123	1.3%	–0.003%	$1,447	–$2
2020	$123	$123	1.3%	–0.003%	$1,477	–$2
2021	$123	$123	1.3%	–0.003%	$1,507	–$3
2022	$123	$123	1.3%	–0.003%	$1,537	–$3
2023	$123	$123	1.3%	–0.003%	$1,568	–$3
2024	$123	$123	1.3%	–0.003%	$1,598	–$3
2025	$123	$123	1.3%	–0.003%	$1,628	–$3
2026	$123	$123	1.3%	–0.003%	$1,658	–$3
2027	$123	$123	1.3%	–0.003%	$1,688	–$3
2028	$123	$123	1.3%	–0.003%	$1,718	–$3
2029	$123	$123	1.3%	–0.003%	$1,749	–$3
2030	$123	$123	1.3%	–0.003%	$1,779	–$3
2031	$123	$123	1.3%	–0.003%	$1,809	–$3
2032	$123	$123	1.3%	–0.003%	$1,839	–$3
2033	$123	$123	1.3%	–0.003%	$1,869	–$3
2034	$123	$123	1.3%	–0.003%	$1,900	–$3
2035	$123	$123	1.3%	–0.003%	$1,930	–$3
2036	$123	$123	1.3%	–0.003%	$1,960	–$3
NPV[b]					$29,853	–$3,868

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-45. Impacts on Lawn and Garden Equipment Market and Manufacturers (26-50 hp) (Average Price per Equipment = $21,500)[a]

	Lawn and Garden Equipment (25≤hp<50)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	$204	$147	0.7%	–0.001%	$474	–$194
2009	$203	$147	0.7%	–0.001%	$480	–$194
2010	$194	$139	0.6%	–0.001%	$471	–$195
2011	$193	$139	0.6%	–0.002%	$477	–$196
2012	$192	$139	0.6%	–0.003%	$482	–$196
2013	$986	$870	4.0%	–0.003%	$2,817	–$742
2014	$984	$870	4.0%	–0.003%	$2,858	–$742
2015	$773	$661	3.1%	–0.003%	$2,391	–$742
2016	$771	$661	3.1%	–0.003%	$2,422	–$742
2017	$769	$661	3.1%	–0.003%	$2,453	–$742
2018	$693	$661	3.1%	–0.003%	$2,228	–$485
2019	$692	$661	3.1%	–0.003%	$2,259	–$485
2020	$692	$661	3.1%	–0.003%	$2,290	–$485
2021	$691	$661	3.1%	–0.003%	$2,321	–$486
2022	$691	$661	3.1%	–0.003%	$2,353	–$486
2023	$661	$661	3.1%	–0.003%	$1,901	–$3
2024	$661	$661	3.1%	–0.003%	$1,933	–$3
2025	$661	$661	3.1%	–0.003%	$1,964	–$3
2026	$661	$661	3.1%	–0.003%	$1,995	–$3
2027	$661	$661	3.1%	–0.003%	$2,026	–$3
2028	$661	$661	3.1%	–0.003%	$2,057	–$4
2029	$661	$661	3.1%	–0.003%	$2,089	–$4
2030	$661	$661	3.1%	–0.003%	$2,120	–$4
2031	$661	$661	3.1%	–0.003%	$2,151	–$4
2032	$661	$661	3.1%	–0.003%	$2,182	–$4
2033	$661	$661	3.1%	–0.003%	$2,213	–$4
2034	$661	$661	3.1%	–0.003%	$2,245	–$4
2035	$661	$661	3.1%	–0.003%	$2,276	–$4
2036	$661	$661	3.1%	–0.003%	$2,307	–$4
NPV[b]					$32,380	–$5,037

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-46. Impacts on Lawn and Garden Equipment Market and Manufacturers (51-75 hp) (Average Price per Equipment = $33,100)[a]

	Lawn and Garden Equipment (50≤hp<75)					
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	$226	$167	0.5%	–0.001%	$14	–$14
2009	$225	$167	0.5%	–0.001%	$14	–$14
2010	$214	$158	0.5%	–0.001%	$14	–$15
2011	$213	$158	0.5%	–0.002%	$14	–$15
2012	$212	$157	0.5%	–0.003%	$14	–$15
2013	$978	$858	2.6%	–0.003%	$121	–$83
2014	$976	$858	2.6%	–0.003%	$122	–$83
2015	$769	$653	2.0%	–0.003%	$115	–$83
2016	$767	$653	2.0%	–0.003%	$115	–$83
2017	$765	$653	2.0%	–0.003%	$116	–$83
2018	$687	$653	2.0%	–0.003%	$102	–$68
2019	$686	$653	2.0%	–0.003%	$102	–$68
2020	$686	$653	2.0%	–0.003%	$103	–$68
2021	$685	$653	2.0%	–0.003%	$103	–$68
2022	$685	$653	2.0%	–0.003%	$104	–$68
2023	$653	$653	2.0%	–0.003%	$37	–$1
2024	$653	$653	2.0%	–0.003%	$37	–$1
2025	$653	$653	2.0%	–0.003%	$38	–$1
2026	$653	$653	2.0%	–0.003%	$38	–$1
2027	$653	$653	2.0%	–0.003%	$39	–$1
2028	$653	$653	2.0%	–0.003%	$40	–$1
2029	$653	$653	2.0%	–0.003%	$40	–$1
2030	$653	$653	2.0%	–0.003%	$41	–$1
2031	$653	$653	2.0%	–0.003%	$41	–$1
2032	$653	$653	2.0%	–0.003%	$42	–$1
2033	$653	$653	2.0%	–0.003%	$42	–$1
2034	$653	$653	2.0%	–0.003%	$43	–$1
2035	$653	$653	2.0%	–0.003%	$43	–$1
2036	$653	$653	2.0%	–0.003%	$44	–$1
NPV[b]					$1,072	–$577

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-47. Impacts on Lawn and Garden Equipment Market and Manufacturers (76-100 hp) (Average Price per Equipment = $38,500)[a]

Year	Lawn and Garden Equipment (70≤hp<100) Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Equipment Manufacturers (10^3)
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	—	—	0.0%	–0.002%	—	–$1
2012	$1,303	$1,178	3.1%	–0.003%	$529	–$375
2013	$1,302	$1,178	3.1%	–0.003%	$531	–$375
2014	$1,325	$1,169	3.0%	–0.003%	$641	–$471
2015	$1,324	$1,169	3.0%	–0.003%	$644	–$471
2016	$1,322	$1,169	3.0%	–0.003%	$647	–$471
2017	$1,247	$1,169	3.0%	–0.003%	$650	–$471
2018	$1,246	$1,169	3.0%	–0.003%	$653	–$471
2019	$1,218	$1,169	3.0%	–0.003%	$655	–$472
2020	$1,218	$1,169	3.0%	–0.003%	$658	–$472
2021	$1,218	$1,169	3.0%	–0.003%	$661	–$472
2022	$1,218	$1,169	3.0%	–0.003%	$290	–$98
2023	$1,218	$1,169	3.0%	–0.003%	$293	–$98
2024	$1,218	$1,169	3.0%	–0.003%	$200	–$1
2025	$1,218	$1,169	3.0%	–0.003%	$202	–$1
2026	$1,218	$1,169	3.0%	–0.003%	$205	–$1
2027	$1,218	$1,169	3.0%	–0.003%	$208	–$2
2028	$1,218	$1,169	3.0%	–0.003%	$211	–$2
2029	$1,218	$1,169	3.0%	–0.003%	$214	–$2
2030	$1,218	$1,169	3.0%	–0.003%	$217	–$2
2031	$1,218	$1,169	3.0%	–0.003%	$220	–$2
2032	$1,218	$1,169	3.0%	–0.003%	$222	–$2
2033	$1,218	$1,169	3.0%	–0.003%	$225	–$2
2034	$1,218	$1,169	3.0%	–0.003%	$228	–$2
2035	$1,218	$1,169	3.0%	–0.003%	$231	–$2
2036	$1,218	$1,169	3.0%	–0.003%	$234	–$2
NPV[b]					$5,970	–$3,244

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-48. Impacts on Lawn and Garden Equipment Market and Manufacturers (101-175 hp)
(Average Price per Equipment = $29,200)[a]

	Lawn and Garden Equipment (100≤hp<175)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	Engineering Cost/Unit	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	—	0.0%	–0.001%	—	—
2011	—	—	0.0%	–0.002%	—	—
2012	$1,623	$1,421	4.8%	–0.003%	$420	–$331
2013	$1,619	$1,421	4.8%	–0.003%	$421	–$331
2014	$1,664	$1,399	4.7%	–0.003%	$514	–$416
2015	$1,659	$1,399	4.7%	–0.003%	$515	–$416
2016	$1,654	$1,399	4.7%	–0.003%	$517	–$416
2017	$1,577	$1,399	4.7%	–0.003%	$518	–$416
2018	$1,574	$1,399	4.7%	–0.003%	$520	–$416
2019	$1,542	$1,399	4.7%	–0.003%	$521	–$416
2020	$1,539	$1,399	4.7%	–0.003%	$523	–$416
2021	$1,537	$1,399	4.7%	–0.003%	$525	–$416
2022	$1,388	$1,399	4.7%	–0.003%	$195	–$85
2023	$1,387	$1,399	4.7%	–0.003%	$197	–$85
2024	$1,351	$1,399	4.7%	–0.003%	$114	–$1
2025	$1,351	$1,399	4.7%	–0.003%	$116	–$1
2026	$1,351	$1,399	4.7%	–0.003%	$117	–$1
2027	$1,351	$1,399	4.7%	–0.003%	$119	–$1
2028	$1,351	$1,399	4.7%	–0.003%	$120	–$1
2029	$1,351	$1,399	4.7%	–0.003%	$122	–$1
2030	$1,351	$1,399	4.7%	–0.003%	$124	–$1
2031	$1,351	$1,399	4.7%	–0.003%	$125	–$1
2032	$1,351	$1,399	4.7%	–0.003%	$127	–$1
2033	$1,351	$1,399	4.7%	–0.003%	$128	–$1
2034	$1,351	$1,399	4.7%	–0.003%	$130	–$1
2035	$1,351	$1,399	4.7%	–0.003%	$131	–$1
2036	$1,351	$1,399	4.7%	–0.003%	$133	–$1
NPV[b]					$4,418	–$2,856

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10.B-49. Impacts on Lawn and Garden Equipment Market and Manufacturers (176-600 hp)
(Average Price per Equipment = $64,300)[a]

	Lawn and Garden Equipment (175≤hp<600)					Change in Producer Surplus for Equipment Manufacturers (10^3)
Year	**Engineering Cost/Unit**	**Absolute Change in Price**	**Change in Price (%)**	**Change in Quantity (%)**	**Total Engineering Costs (10^3)**	
2007	—	—	0.0%	0.000%	—	—
2008	—	—	0.0%	–0.001%	—	—
2009	—	—	0.0%	–0.001%	—	—
2010	—	–$1	0.0%	–0.001%	—	—
2011	$2,970	$2,265	3.5%	–0.002%	$279	–$233
2012	$2,958	$2,264	3.5%	–0.003%	$280	–$233
2013	$2,439	$1,755	2.7%	–0.003%	$271	–$233
2014	$3,107	$2,216	3.4%	–0.003%	$344	–$293
2015	$3,092	$2,215	3.4%	–0.003%	$345	–$293
2016	$2,777	$2,214	3.4%	–0.003%	$346	–$293
2017	$2,768	$2,213	3.4%	–0.003%	$346	–$293
2018	$2,759	$2,212	3.4%	–0.003%	$347	–$293
2019	$2,634	$2,211	3.4%	–0.003%	$348	–$293
2020	$2,627	$2,210	3.4%	–0.003%	$349	–$293
2021	$2,294	$2,210	3.4%	–0.003%	$116	–$60
2022	$2,292	$2,209	3.4%	–0.003%	$117	–$60
2023	$2,291	$2,208	3.4%	–0.003%	$118	–$60
2024	$2,209	$2,207	3.4%	–0.003%	$59	—
2025	$2,208	$2,207	3.4%	–0.003%	$60	—
2026	$2,208	$2,206	3.4%	–0.003%	$60	—
2027	$2,207	$2,205	3.4%	–0.003%	$61	—
2028	$2,206	$2,205	3.4%	–0.003%	$62	—
2029	$2,206	$2,204	3.4%	–0.003%	$63	—
2030	$2,205	$2,203	3.4%	–0.003%	$63	—
2031	$2,204	$2,203	3.4%	–0.003%	$64	—
2032	$2,204	$2,202	3.4%	–0.003%	$65	—
2033	$2,203	$2,202	3.4%	–0.003%	$66	—
2034	$2,203	$2,201	3.4%	–0.003%	$66	—
2035	$2,202	$2,200	3.4%	–0.003%	$67	—
2036	$2,202	$2,200	3.4%	–0.003%	$68	–$1
NPV[b]					$2,898	–$2,060

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

APPENDIX 10C: Impacts on Application Markets

This appendix provides the time series of impacts from 2007 through 2036 for the application markets and the transportation service markets included in the model.

There are 3 application markets: construction, agriculture, and manufacturing.

There are 2 transportation service markets: locomotive and marine.

Tables 10C-1 through 10C-5 provide the time series of impacts for these markets. Each table includes the following:

- relative change in market price (%)
- relative change in market quantity (%)
- change in producer and consumer surplus for each application market

For the three application markets, prices are expected to increase 0.02 percent in the manufacturing sector, 0.1 percent in the agricultural sector, and 0.5 percent in the construction sector. Price increase are highest in about 2015, and decrease thereafter. Quantity decreases stabilize in about 2015 as well.

For the transportation service markets, prices are expected to increase 0.03 percent in the locomotive sector and 0.006 percent in the marine sector. Price increases and quantity decreases stabilize in about 2015.

Table 10C-1. Impacts on Agricultural Application Market[a]

Year	Agriculture: Change in Price (%)	Agriculture: Change in Quantity (%)	Change in Producer and Consumer Surplus ($$10^3$)
2007	0.030%	0.000%	–$35,860
2008	0.050%	–0.001%	–$75,265
2009	0.050%	–0.001%	–$76,967
2010	0.104%	–0.002%	–$144,827
2011	0.142%	–0.003%	–$309,684
2012	0.139%	–0.004%	–$394,695
2013	0.136%	–0.005%	–$429,981
2014	0.147%	–0.005%	–$478,692
2015	0.154%	–0.005%	–$484,874
2016	0.152%	–0.005%	–$493,522
2017	0.150%	–0.005%	–$502,205
2018	0.148%	–0.005%	–$510,901
2019	0.146%	–0.005%	–$519,570
2020	0.143%	–0.005%	–$524,291
2021	0.140%	–0.005%	–$530,035
2022	0.138%	–0.005%	–$538,585
2023	0.136%	–0.005%	–$547,123
2024	0.134%	–0.005%	–$555,669
2025	0.132%	–0.005%	–$564,198
2026	0.130%	–0.005%	–$572,713
2027	0.128%	–0.005%	–$581,228
2028	0.127%	–0.005%	–$589,742
2029	0.125%	–0.005%	–$598,257
2030	0.123%	–0.005%	–$606,770
2031	0.121%	–0.005%	–$615,284
2032	0.119%	–0.005%	–$623,797
2033	0.118%	–0.005%	–$632,309
2034	0.116%	–0.005%	–$640,821
2035	0.114%	–0.005%	–$649,333
2036	0.113%	–0.005%	–$657,844
NPV[b]			–$8,180,632

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10C-2. Impacts on Construction Application Market[a]

Year	Construction: Change in Price (%)	Construction: Change in Quantity (%)	Change in Producer and Consumer Surplus ($$10^3$)
2007	0.105%	–0.001%	–$47,524
2008	0.176%	–0.001%	–$97,113
2009	0.174%	–0.001%	–$99,303
2010	0.382%	–0.002%	–$199,991
2011	0.526%	–0.004%	–$409,111
2012	0.517%	–0.005%	–$548,053
2013	0.508%	–0.006%	–$584,333
2014	0.553%	–0.006%	–$650,082
2015	0.587%	–0.006%	–$689,966
2016	0.579%	–0.006%	–$702,193
2017	0.573%	–0.006%	–$709,196
2018	0.568%	–0.006%	–$721,412
2019	0.565%	–0.006%	–$733,610
2020	0.559%	–0.006%	–$744,027
2021	0.554%	–0.006%	–$754,910
2022	0.550%	–0.006%	–$767,057
2023	0.544%	–0.006%	–$779,171
2024	0.539%	–0.006%	–$791,302
2025	0.533%	–0.006%	–$803,409
2026	0.527%	–0.006%	–$815,495
2027	0.522%	–0.006%	–$827,581
2028	0.517%	–0.006%	–$839,668
2029	0.512%	–0.006%	–$851,754
2030	0.507%	–0.006%	–$863,841
2031	0.502%	–0.006%	–$875,929
2032	0.497%	–0.006%	–$888,016
2033	0.492%	–0.006%	–$900,104
2034	0.487%	–0.006%	–$912,193
2035	0.482%	–0.006%	–$924,281
2036	0.478%	–0.006%	–$936,370
NPV[b]			–$11,525,673

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10C-3. Impacts on Manufacturing Application Market[a]

Year	Manufacturing: Change in Price (%)	Manufacturing: Change in Quantity (%)	Change in Producer and Consumer Surplus ($$10^3$)
2007	0.007%	–0.003%	–$40,523
2008	0.015%	–0.004%	–$104,885
2009	0.015%	–0.004%	–$106,956
2010	0.028%	–0.007%	–$190,735
2011	0.059%	–0.013%	–$289,933
2012	0.074%	–0.016%	–$382,352
2013	0.079%	–0.017%	–$482,357
2014	0.086%	–0.019%	–$519,105
2015	0.086%	–0.019%	–$517,361
2016	0.086%	–0.019%	–$525,764
2017	0.086%	–0.019%	–$533,562
2018	0.086%	–0.019%	–$542,061
2019	0.086%	–0.019%	–$550,840
2020	0.086%	–0.019%	–$557,759
2021	0.085%	–0.018%	–$564,953
2022	0.085%	–0.019%	–$573,644
2023	0.085%	–0.019%	–$582,045
2024	0.085%	–0.019%	–$590,571
2025	0.085%	–0.019%	–$599,072
2026	0.085%	–0.019%	–$607,560
2027	0.085%	–0.019%	–$616,061
2028	0.085%	–0.019%	–$624,576
2029	0.085%	–0.019%	–$633,104
2030	0.085%	–0.019%	–$641,646
2031	0.086%	–0.019%	–$650,201
2032	0.086%	–0.019%	–$658,771
2033	0.086%	–0.019%	–$667,355
2034	0.086%	–0.019%	–$675,953
2035	0.086%	–0.019%	–$684,566
2036	0.086%	–0.019%	–$693,194
NPV[b]			–$8,722,570

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10C-4. Impacts on the Locomotive Transportation Market[a]

Year	Manufacturing		Change in Producer and Consumer Surplus ($10^3)
	Change in Price (%)	Change in Quantity (%)	
2007	0.003%	–0.004%	–$44
2008	0.005%	–0.006%	–$234
2009	0.005%	–0.006%	–$240
2010	0.010%	–0.011%	–$519
2011	0.020%	–0.021%	–$970
2012	0.027%	–0.027%	–$1,314
2013	0.028%	–0.028%	–$1,579
2014	0.031%	–0.031%	–$1,739
2015	0.032%	–0.032%	–$1,773
2016	0.032%	–0.032%	–$1,813
2017	0.032%	–0.032%	–$1,850
2018	0.032%	–0.032%	–$1,892
2019	0.032%	–0.032%	–$1,936
2020	0.032%	–0.032%	–$1,973
2021	0.032%	–0.032%	–$2,013
2022	0.032%	–0.032%	–$2,059
2023	0.032%	–0.032%	–$2,106
2024	0.032%	–0.032%	–$2,155
2025	0.032%	–0.032%	–$2,204
2026	0.032%	–0.032%	–$2,255
2027	0.032%	–0.032%	–$2,306
2028	0.032%	–0.032%	–$2,359
2029	0.032%	–0.032%	–$2,413
2030	0.032%	–0.032%	–$2,469
2031	0.032%	–0.032%	–$2,525
2032	0.032%	–0.032%	–$2,583
2033	0.032%	–0.032%	–$2,643
2034	0.032%	–0.032%	–$2,704
2035	0.032%	–0.032%	–$2,766
2036	0.032%	–0.032%	–$2,829
NPV[b]			–$31,271

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10C-3. Impacts on the Marine Transportation Market[a]

Year	Manufacturing: Change in Price (%)	Manufacturing: Change in Quantity (%)	Change in Producer and Consumer Surplus ($$10^3$)
2007	0.001%	0.000%	–$32
2008	0.001%	–0.001%	–$132
2009	0.001%	–0.001%	–$135
2010	0.002%	–0.001%	–$289
2011	0.004%	–0.002%	–$549
2012	0.005%	–0.003%	–$744
2013	0.006%	–0.003%	–$876
2014	0.006%	–0.003%	–$967
2015	0.006%	–0.003%	–$996
2016	0.006%	–0.003%	–$1,019
2017	0.006%	–0.003%	–$1,038
2018	0.006%	–0.003%	–$1,062
2019	0.006%	–0.003%	–$1,087
2020	0.006%	–0.003%	–$1,108
2021	0.006%	–0.003%	–$1,131
2022	0.006%	–0.003%	–$1,157
2023	0.006%	–0.003%	–$1,184
2024	0.006%	–0.003%	–$1,211
2025	0.006%	–0.003%	–$1,239
2026	0.006%	–0.003%	–$1,267
2027	0.006%	–0.003%	–$1,296
2028	0.006%	–0.003%	–$1,326
2029	0.006%	–0.003%	–$1,357
2030	0.006%	–0.003%	–$1,388
2031	0.006%	–0.003%	–$1,420
2032	0.006%	–0.003%	–$1,452
2033	0.006%	–0.003%	–$1,486
2034	0.006%	–0.003%	–$1,520
2035	0.006%	–0.003%	–$1,555
2036	0.006%	–0.003%	–$1,591
NPV[b]			–$17,569

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

APPENDIX 10D: Impacts on the Nonroad Fuel Market

This appendix provides the time series of impacts from 2007 through 2036 for the nonroad diesel fuel market. Eight nonroad diesel fuel markets were modeled: 2 sulfur content levels (15 ppm and 500 ppm) for each of 4 PADDs (PADDs 1&3, PADD 2, PADD 4, and PADD 5). Note that PADD 5 includes Alaska and Hawaii but excludes California fuel volumes that are not affected by the program because they are covered by separate California nonroad diesel fuel standards.

Tables 10D-1 through 10D-4 provide the time series of impacts for the diesel fuel market for the four regional fuel markets. Each table includes the following:

- average price per gallon
- average engineering costs (variable and fixed) per gallon
- absolute change in the PADDs' nonroad diesel price ($)
  - Note that the estimated absolute change in market price is based on average variable and fixed costs; see Appendix 10I for sensitivity analyses reflecting maximum total costs and maximum variable costs
- relative change in the PADDs' nonroad diesel price (%)
- relative change in the PADDs' nonroad diesel quantity (%)
- total engineering (regulatory) costs associated with each PADD's fuel market ($)
- change in producer surplus for all fuel producers

In 2001, about 68 percent of high-sulfur diesel fuel was consumed in nonroad diesel equipment and about 32 percent was consumed in marine equipment and locomotive engines.[S] The engineering costs and changes in producer surplus presented in this appendix include both of these diesel fuel segments.

All prices and costs are presented in $2002, and the real per-gallon prices are assumed to be constant within each regional fuel market. For each regional fuel market, the majority of the cost of the regulation is passed along through increased fuel prices.

[S]These percentages exclude heating oil; if high-sulfur heating oil is included, then about 35 percent of high-sulfur fuel was consumed in nonroad diesel equipment and about 17 percent was consumed in marine equipment and locomotive engines.

Table 10D-1. Impacts on the Nonroad Fuel Market in PADD 1&3
(Average Price per Gallon = $0.91)[a]

Year	Engineering Cost/Unit 15ppm	Engineering Cost/Unit 500ppm	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs ($$10^3$)	Change in Producer Surplus for Fuel Producers ($$10^3$)
2007	—	$0.02	$0.01	1.0%	–0.002%	$56,985	–$54
2008	—	$0.02	$0.02	1.8%	–0.004%	$99,743	–$613
2009	—	$0.02	$0.02	1.8%	–0.004%	$101,806	–$629
2010	$0.06	$0.02	$0.04	4.1%	–0.007%	$236,629	$65
2011	$0.06	$0.03	$0.05	5.7%	–0.013%	$339,851	–$2,313
2012	$0.06	$0.03	$0.05	5.7%	–0.017%	$346,465	–$3,292
2013	$0.06	$0.03	$0.05	5.6%	–0.018%	$352,867	–$3,624
2014	$0.06	$0.03	$0.06	6.1%	–0.019%	$390,537	–$4,187
2015	$0.06	$0.03	$0.06	6.5%	–0.020%	$421,492	–$4,532
2016	$0.06	$0.03	$0.06	6.5%	–0.020%	$429,036	–$4,625
2017	$0.06	$0.03	$0.06	6.5%	–0.020%	$436,616	–$4,689
2018	$0.06	$0.03	$0.06	6.5%	–0.020%	$444,324	–$4,783
2019	$0.06	$0.03	$0.06	6.5%	–0.020%	$452,220	–$4,877
2020	$0.06	$0.03	$0.06	6.5%	–0.020%	$462,196	–$5,027
2021	$0.06	$0.03	$0.06	6.6%	–0.020%	$471,507	–$5,164
2022	$0.06	$0.03	$0.06	6.6%	–0.020%	$479,447	–$5,259
2023	$0.06	$0.03	$0.06	6.6%	–0.020%	$487,125	–$5,353
2024	$0.06	$0.03	$0.06	6.6%	–0.020%	$494,924	–$5,448
2025	$0.06	$0.03	$0.06	6.6%	–0.020%	$502,671	–$5,542
2026	$0.06	$0.03	$0.06	6.6%	–0.020%	$510,413	–$5,636
2027	$0.06	$0.03	$0.06	6.6%	–0.020%	$518,166	–$5,730
2028	$0.06	$0.03	$0.06	6.6%	–0.020%	$525,932	–$5,824
2029	$0.06	$0.03	$0.06	6.6%	–0.020%	$533,710	–$5,918
2030	$0.06	$0.03	$0.06	6.6%	–0.020%	$541,500	–$6,012
2031	$0.06	$0.03	$0.06	6.6%	–0.020%	$549,303	–$6,106
2032	$0.06	$0.03	$0.06	6.6%	–0.020%	$557,119	–$6,200
2033	$0.06	$0.03	$0.06	6.6%	–0.020%	$564,948	–$6,294
2034	$0.06	$0.03	$0.06	6.6%	–0.020%	$572,789	–$6,388
2035	$0.06	$0.03	$0.06	6.6%	–0.020%	$580,644	–$6,482
2036	$0.06	$0.03	$0.06	6.6%	–0.020%	$588,512	–$6,576
NPV[b]						$7,422,281	–$76,083

[a] Figures are in 2002 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

Table 10D-2. Impacts on the Nonroad Fuel Market in PADD 2
(Average Price per Gallon = $0.94)[a]

Year	Engineering Cost/Unit 15ppm	Engineering Cost/Unit 500ppm	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs (10^3)	Change in Producer Surplus for Fuel Producers (10^3)
2007	—	$0.02	$0.01	1.5%	–0.003%	$57,852	$64
2008	—	$0.02	$0.02	2.6%	–0.005%	$101,359	–$544
2009	—	$0.02	$0.02	2.6%	–0.005%	$103,564	–$558
2010	$0.07	$0.03	$0.05	5.0%	–0.008%	$204,945	$578
2011	$0.07	$0.03	$0.06	6.7%	–0.015%	$281,683	–$932
2012	$0.07	$0.03	$0.06	6.7%	–0.019%	$287,389	–$1,649
2013	$0.07	$0.03	$0.06	6.7%	–0.021%	$293,011	–$1,903
2014	$0.08	$0.03	$0.07	7.3%	–0.022%	$323,985	–$2,523
2015	$0.08	$0.03	$0.07	7.7%	–0.023%	$349,620	–$2,889
2016	$0.08	$0.03	$0.07	7.7%	–0.023%	$356,353	–$2,957
2017	$0.08	$0.03	$0.07	7.7%	–0.023%	$363,096	–$3,012
2018	$0.08	$0.03	$0.07	7.7%	–0.023%	$369,869	–$3,083
2019	$0.08	$0.03	$0.07	7.7%	–0.023%	$376,682	–$3,151
2020	$0.08	$0.03	$0.07	7.5%	–0.023%	$374,491	–$2,895
2021	$0.08	$0.03	$0.07	7.4%	–0.023%	$374,573	–$2,733
2022	$0.08	$0.03	$0.07	7.4%	–0.023%	$381,107	–$2,791
2023	$0.08	$0.03	$0.07	7.4%	–0.023%	$387,586	–$2,849
2024	$0.08	$0.03	$0.07	7.4%	–0.023%	$394,090	–$2,907
2025	$0.08	$0.03	$0.07	7.4%	–0.023%	$400,582	–$2,964
2026	$0.08	$0.03	$0.07	7.4%	–0.023%	$407,040	–$3,021
2027	$0.08	$0.03	$0.07	7.4%	–0.023%	$413,500	–$3,079
2028	$0.08	$0.03	$0.07	7.4%	–0.023%	$419,963	–$3,136
2029	$0.08	$0.03	$0.07	7.4%	–0.023%	$426,429	–$3,194
2030	$0.08	$0.03	$0.07	7.4%	–0.023%	$432,896	–$3,251
2031	$0.08	$0.03	$0.07	7.4%	–0.023%	$439,367	–$3,308
2032	$0.08	$0.03	$0.07	7.5%	–0.023%	$445,840	–$3,366
2033	$0.08	$0.03	$0.07	7.5%	–0.023%	$452,315	–$3,423
2034	$0.08	$0.03	$0.07	7.5%	–0.023%	$458,794	–$3,480
2035	$0.08	$0.03	$0.07	7.5%	–0.023%	$465,275	–$3,537
2036	$0.08	$0.03	$0.07	7.5%	–0.023%	$471,758	–$3,594
NPV[b]						$6,075,867	–$42,383

[a] Figures are in 2001 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2030 time period.

Table 10D-3. Impacts on the Nonroad Fuel Market in PADD 4
(Average Price per Gallon = $0.91)[a]

Year	Engineering Cost/Unit 15ppm	Engineering Cost/Unit 500ppm	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs ($10^3)	Change in Producer Surplus for Fuel Producers ($10^3)
2007	—	$0.04	$0.02	2.0%	–0.003%	$6,826	$34
2008	—	$0.04	$0.03	3.4%	–0.005%	$11,955	–$34
2009	—	$0.04	$0.03	3.4%	–0.005%	$12,214	–$35
2010	$0.13	$0.04	$0.07	6.8%	–0.009%	$24,781	$432
2011	$0.13	$0.09	$0.09	9.1%	–0.016%	$33,824	$459
2012	$0.13	$0.09	$0.09	9.1%	–0.020%	$34,500	$401
2013	$0.13	$0.09	$0.09	9.1%	–0.021%	$35,166	$390
2014	$0.13	$0.09	$0.09	9.9%	–0.023%	$39,254	$324
2015	$0.13	$0.09	$0.10	10.6%	–0.024%	$42,621	$273
2016	$0.13	$0.09	$0.10	10.6%	–0.024%	$43,461	$276
2017	$0.13	$0.09	$0.10	10.6%	–0.024%	$44,301	$280
2018	$0.13	$0.09	$0.10	10.6%	–0.024%	$45,142	$281
2019	$0.13	$0.09	$0.10	10.6%	–0.024%	$45,982	$284
2020	$0.13	$0.09	$0.10	10.4%	–0.024%	$45,886	$322
2021	$0.13	$0.09	$0.10	10.3%	–0.024%	$46,029	$349
2022	$0.13	$0.09	$0.10	10.3%	–0.024%	$46,840	$352
2023	$0.13	$0.09	$0.10	10.3%	–0.024%	$47,652	$356
2024	$0.13	$0.09	$0.10	10.3%	–0.024%	$48,463	$359
2025	$0.13	$0.09	$0.10	10.4%	–0.024%	$49,275	$363
2026	$0.13	$0.09	$0.10	10.4%	–0.024%	$50,081	$366
2027	$0.13	$0.09	$0.10	10.4%	–0.024%	$50,886	$369
2028	$0.13	$0.09	$0.10	10.4%	–0.024%	$51,692	$373
2029	$0.13	$0.09	$0.10	10.4%	–0.024%	$52,498	$376
2030	$0.13	$0.09	$0.10	10.4%	–0.024%	$53,304	$379
2031	$0.13	$0.09	$0.10	10.4%	–0.024%	$54,109	$383
2032	$0.13	$0.09	$0.10	10.4%	–0.024%	$54,915	$386
2033	$0.13	$0.09	$0.10	10.4%	–0.024%	$55,721	$390
2034	$0.13	$0.09	$0.10	10.4%	–0.024%	$56,527	$393
2035	$0.13	$0.09	$0.10	10.4%	–0.024%	$57,333	$397
2036	$0.13	$0.09	$0.10	10.4%	–0.024%	$58,138	$400
NPV[b]						$742,250	$5,626

[a] Figures are in 2001 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2030 time period.

Table 10D-4. Impacts on the Nonroad Fuel Market in PADD 5
(Average Price per Gallon = $0.87)[a]

Year	Engineering Cost/Unit 15ppm	Engineering Cost/Unit 500ppm	Absolute Change in Price	Change in Price (%)	Change in Quantity (%)	Total Engineering Costs ($10^3)	Change in Producer Surplus for Fuel Producers ($10^3)
2007	—	$0.01	$0.01	0.5%	–0.003%	$3,004	–$24
2008	—	$0.01	$0.01	0.9%	–0.005%	$5,266	–$68
2009	—	$0.01	$0.01	0.9%	–0.005%	$5,382	–$70
2010	$0.05	$0.02	$0.02	1.8%	–0.008%	$11,146	–$44
2011	$0.05	$0.04	$0.03	2.8%	–0.015%	$17,727	–$171
2012	$0.05	$0.04	$0.03	2.8%	–0.019%	$18,083	–$287
2013	$0.05	$0.04	$0.03	2.8%	–0.020%	$18,428	–$322
2014	$0.06	$0.04	$0.04	4.4%	–0.022%	$29,541	–$321
2015	$0.07	$0.04	$0.06	5.9%	–0.023%	$40,159	–$377
2016	$0.07	$0.04	$0.06	5.9%	–0.023%	$40,915	–$385
2017	$0.07	$0.04	$0.06	5.9%	–0.023%	$41,678	–$390
2018	$0.07	$0.04	$0.06	5.9%	–0.023%	$42,453	–$398
2019	$0.07	$0.04	$0.06	5.9%	–0.023%	$43,236	–$406
2020	$0.07	$0.04	$0.06	5.9%	–0.023%	$44,001	–$413
2021	$0.07	$0.04	$0.06	5.9%	–0.023%	$44,768	–$420
2022	$0.07	$0.04	$0.06	5.9%	–0.023%	$45,551	–$428
2023	$0.07	$0.04	$0.06	5.9%	–0.023%	$46,317	–$436
2024	$0.07	$0.04	$0.06	5.9%	–0.023%	$47,090	–$444
2025	$0.07	$0.04	$0.06	5.9%	–0.023%	$47,859	–$452
2026	$0.07	$0.04	$0.06	5.9%	–0.023%	$48,627	–$460
2027	$0.07	$0.04	$0.06	5.9%	–0.023%	$49,396	–$468
2028	$0.07	$0.04	$0.06	5.9%	–0.023%	$50,166	–$476
2029	$0.07	$0.04	$0.06	5.9%	–0.023%	$50,936	–$485
2030	$0.07	$0.04	$0.06	5.9%	–0.023%	$51,707	–$493
2031	$0.07	$0.04	$0.06	5.9%	–0.023%	$52,478	–$501
2032	$0.07	$0.04	$0.06	5.9%	–0.023%	$53,251	–$509
2033	$0.07	$0.04	$0.06	5.9%	–0.023%	$54,024	–$517
2034	$0.07	$0.04	$0.06	6.0%	–0.023%	$54,797	–$525
2035	$0.07	$0.04	$0.06	6.0%	–0.023%	$55,572	–$533
2036	$0.07	$0.04	$0.06	6.0%	–0.023%	$56,347	–$541
NPV[b]						$647,478	–$6,343

[a] Figures are in 2001 dollars.
[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2030 time period.

APPENDIX 10E: Time Series of Social Cost

This appendix provides a time series of the rule's estimated social costs from 2007 through 2036. Costs are presented in 2002 dollars.

Table 10E-1. Time Series of Market Impacts

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Engine Producers Total	**$0.0**	**$14.9**	**$14.9**	**$14.9**	**$29.4**	**$38.9**	**$42.0**	**$51.6**	**$52.4**	**$37.9**
Equipment Producers Total	**$0.3**	**$8.8**	**$8.8**	**$9.6**	**$88.7**	**$131.4**	**$143.1**	**$179.0**	**$186.0**	**$156.9**
Construction Equipment	$0.2	$1.8	$1.8	$2.3	$41.3	$60.8	$64.0	$81.1	$87.6	$73.0
Agricultural Equipment	$0.1	$2.4	$2.4	$2.6	$36.0	$48.3	$51.8	$66.0	$66.0	$52.2
Industrial Equipment	$0.0	$4.6	$4.7	$4.7	$11.4	$22.3	$27.2	$31.9	$32.4	$31.8
Application Producers & Consumers Total	**$123.9**	**$277.3**	**$283.2**	**$535.6**	**$1,008.7**	**$1,325.1**	**$1,496.7**	**$1,647.9**	**$1,692.2**	**$1,721.5**
Total Producer	*$45.5*	*$108.4*	*$110.8*	*$216.5*	*$418.5*	*$553.0*	*$620.9*	*$685.2*	*$706.4*	*$718.6*
Total Consumer	*$78.4*	*$168.8*	*$172.4*	*$319.1*	*$590.2*	*$772.1*	*$875.7*	*$962.7*	*$985.8*	*$1,002.8*
Construction	$47.5	$97.1	$99.3	$200.0	$409.1	$548.1	$584.3	$650.1	$690.0	$702.2
Agriculture	$35.9	$75.3	$77.0	$144.8	$309.7	$394.7	$430.0	$478.7	$484.9	$493.5
Manufacturing	$40.5	$104.9	$107.0	$190.7	$289.9	$382.4	$482.4	$519.1	$517.4	$525.8
Fuel Producers Total	**$0.2**	**$1.7**	**$1.7**	**–$0.2**	**$4.7**	**$7.2**	**$8.0**	**$9.6**	**$10.5**	**$10.7**
PADD 1 & 3	$0.1	$0.7	$0.7	$0.1	$2.6	$3.7	$4.1	$4.7	$5.1	$5.2
PADD 2	$0.0	$0.8	$0.8	–$0.1	$1.9	$2.9	$3.3	$4.0	$4.4	$4.5
PADD 4	$0.0	$0.1	$0.1	–$0.3	–$0.2	$0.0	$0.0	$0.1	$0.2	$0.2
PADD 5	$0.0	$0.1	$0.1	$0.1	$0.4	$0.6	$0.6	$0.7	$0.7	$0.8
Transportation Services, Total	**$18.9**	**$33.1**	**$33.5**	**$71.5**	**$102.0**	**$103.6**	**$104.9**	**$95.5**	**$88.3**	**$89.2**
Locomotive	$0.0	$0.2	$0.2	$0.5	$1.0	$1.3	$1.6	$1.7	$1.8	$1.8
Marine	$0.0	$0.1	$0.1	$0.3	$0.5	$0.7	$0.9	$1.0	$1.0	$1.0
Application Markets Not Included in	$18.9	$32.7	$33.1	$70.7	$100.5	$101.6	$102.4	$92.8	$85.5	$86.4
Operating Savings	**–$160.9**	**–$281.9**	**–$288.0**	**–$304.6**	**–$311.4**	**–$302.2**	**–$284.7**	**–$293.0**	**–$288.0**	**–$273.6**
Total	**–$17.6**	**$53.9**	**$54.2**	**$326.7**	**$922.3**	**$1,304.0**	**$1,510.0**	**$1,690.5**	**$1,741.3**	**$1,742.6**

(continued)

Table 10E-1. Time Series of Market Impacts (continued)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Engine Producers Total	**$28.4**	**$10.4**	**$0.9**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**
Equipment Producers Total	**$148.6**	**$139.7**	**$125.0**	**$122.7**	**$74.2**	**$40.9**	**$30.4**	**$9.8**	**$5.6**	**$5.6**
Construction Equipment	$68.9	$67.3	$60.2	$57.8	$34.4	$19.8	$17.0	$7.5	$3.7	$3.8
Agricultural Equipment	$49.3	$46.5	$39.7	$39.7	$20.6	$11.5	$8.9	$1.7	$1.7	$1.8
Industrial Equipment	$30.4	$26.0	$25.2	$25.2	$19.1	$9.6	$4.5	$0.6	$0.1	$0.1
Application Producers & Consumers Total	**$1,745.0**	**$1,774.4**	**$1,804.0**	**$1,826.1**	**$1,849.9**	**$1,879.3**	**$1,908.3**	**$1,937.5**	**$1,966.7**	**$1,995.8**
Total Producer	*$728.2*	*$740.5*	*$752.9*	*$762.2*	*$772.3*	*$784.6*	*$796.8*	*$809.0*	*$821.2*	*$833.4*
Total Consumer	*$1,016.8*	*$1,033.9*	*$1,051.1*	*$1,063.8*	*$1,077.6*	*$1,094.7*	*$1,111.6*	*$1,128.5*	*$1,145.5*	*$1,162.4*
Construction	$709.2	$721.4	$733.6	$744.0	$754.9	$767.1	$779.2	$791.3	$803.4	$815.5
Agriculture	$502.2	$510.9	$519.6	$524.3	$530.0	$538.6	$547.1	$555.7	$564.2	$572.7
Manufacturing	$533.6	$542.1	$550.8	$557.8	$565.0	$573.6	$582.0	$590.6	$599.1	$607.6
Fuel Producers Total	**$10.9**	**$11.1**	**$11.3**	**$11.2**	**$11.2**	**$11.5**	**$11.7**	**$11.9**	**$12.1**	**$12.3**
PADD 1 & 3	$5.3	$5.4	$5.5	$5.6	$5.8	$5.9	$6.0	$6.1	$6.2	$6.3
PADD 2	$4.6	$4.7	$4.8	$4.6	$4.5	$4.5	$4.6	$4.7	$4.8	$4.9
PADD 4	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
PADD 5	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9	$0.9
Transportation Services, Total	**$90.2**	**$91.3**	**$92.6**	**$95.6**	**$98.1**	**$99.5**	**$100.5**	**$101.7**	**$102.9**	**$104.1**
Locomotive	$1.8	$1.9	$1.9	$2.0	$2.0	$2.1	$2.1	$2.2	$2.2	$2.3
Marine	$1.0	$1.1	$1.1	$1.1	$1.1	$1.2	$1.2	$1.2	$1.2	$1.3
Application Markets Not Included in	$87.3	$88.3	$89.6	$92.6	$95.0	$96.2	$97.2	$98.4	$99.4	$100.6
Operating Savings	**–$260.8**	**–$249.4**	**–$239.3**	**–$227.4**	**–$218.2**	**–$212.8**	**–$208.1**	**–$204.2**	**–$200.7**	**–$198.0**
Total	**$1,762.2**	**$1,777.6**	**$1,794.6**	**$1,828.3**	**$1,815.3**	**$1,818.5**	**$1,843.0**	**$1,856.9**	**$1,886.6**	**$1,919.9**

(continued)

Table 10E-1. Time Series of Market Impacts (continued)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Engine Producers Total	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.1**	**$0.2**	**$0.2**	**$0.2**
Equipment Producers Total	**$5.7**	**$5.8**	**$5.9**	**$5.9**	**$6.0**	**$6.1**	**$6.2**	**$6.2**	**$6.3**	**$6.4**
Construction Equipment	$3.8	$3.9	$3.9	$4.0	$4.0	$4.1	$4.1	$4.2	$4.2	$4.3
Agricultural Equipment	$1.8	$1.8	$1.8	$1.9	$1.9	$1.9	$1.9	$2.0	$2.0	$2.0
Industrial Equipment	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Application Producers & Consumers Total	***$2,024.9***	***$2,054.0***	***$2,083.1***	***$2,112.3***	***$2,141.4***	***$2,170.6***	***$2,199.8***	***$2,229.0***	***$2,258.2***	***$2,287.4***
Total Producer	*$845.6*	*$857.8*	*$870.0*	*$882.2*	*$894.4*	*$906.6*	*$918.8*	*$931.1*	*$943.3*	*$955.5*
Total Consumer	*$1,179.3*	*$1,196.2*	*$1,213.1*	*$1,230.1*	*$1,247.0*	*$1,264.0*	*$1,280.9*	*$1,297.9*	*$1,314.9*	*$1,331.9*
Construction	$827.6	$839.7	$851.8	$863.8	$875.9	$888.0	$900.1	$912.2	$924.3	$936.4
Agriculture	$581.2	$589.7	$598.3	$606.8	$615.3	$623.8	$632.3	$640.8	$649.3	$657.8
Manufacturing	$616.1	$624.6	$633.1	$641.6	$650.2	$658.8	$667.4	$676.0	$684.6	$693.2
Fuel Producers Total	**$12.5**	**$12.7**	**$13.0**	**$13.2**	**$13.4**	**$13.6**	**$13.8**	**$14.0**	**$14.2**	**$14.5**
PADD 1 & 3	$6.4	$6.5	$6.6	$6.7	$6.8	$6.9	$7.0	$7.1	$7.2	$7.3
PADD 2	$5.0	$5.1	$5.2	$5.2	$5.3	$5.4	$5.5	$5.6	$5.7	$5.8
PADD 4	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
PADD 5	$0.9	$0.9	$0.9	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Transportation Services, Total	**$105.3**	**$106.5**	**$107.8**	**$109.0**	**$110.3**	**$111.6**	**$112.9**	**$114.2**	**$115.6**	**$116.9**
Locomotive	$2.3	$2.4	$2.4	$2.5	$2.5	$2.6	$2.6	$2.7	$2.8	$2.8
Marine	$1.3	$1.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.6	$1.6
Application Markets Not Included in	$101.7	$102.8	$104.0	$105.2	$106.3	$107.5	$108.8	$110.0	$111.2	$112.5
Operating Savings	**–$196.0**	**–$194.9**	**–$194.3**	**–$194.1**	**–$194.3**	**–$194.8**	**–$195.4**	**–$196.1**	**–$197.1**	**–$198.4**
Total	**$1,952.5**	**$1,984.2**	**$2,015.5**	**$2,046.4**	**$2,076.9**	**$2,107.2**	**$2,137.4**	**$2,167.5**	**$2,197.3**	**$2,227.0**

[a] Figures are in 2002 dollars.

[b] Net present values are calculated using a social discount rate of 3 percent over the 2004 to 2036 time period.

APPENDIX 10F: Model Equations

To enhance understanding of the economic model EPA used in this report, additional details about the model's structure are provided in this appendix. The equations describing supply, final demand, and intermediate (i.e., derived) demand relationships are presented below along with a brief description of the solution algorithm.

10F.1 Model Equations

A constant-elasticity functional form was selected for all supply and final demand functions. The general form and description of these equations are presented below:

$$\text{Supply Equation: } Q_x = a(P_x - \Delta c - \Delta c_y)^{\varepsilon} \qquad (10F.1)$$

$$\text{Final Demand Equation: } Q_x = aP_x^{\eta} \qquad (10F.2)$$

where

- x = production output,
- y = production input,
- Q_x = quantity of output (x) supplied or demanded,
- P_x = market price for output (x),
- a = constant,
- Δc = direct supply shift ($/Q_x$),
- Δc_y = indirect supply shift resulting from change in the price of input y, and
- ε,η = these parameters can be interpreted as the own-price elasticity of supply/demand for the economic agent (see Tables 10.3-12 and 10.3-13 for values of these parameters).

With this choice of functional form, the supply and demand elasticities are assumed to remain constant over the range of output affected by the regulation. This can be demonstrated by applying the definition of own-price elasticity of demand:

$$\frac{dq}{dp} \bullet \frac{p}{q} = Eap^{(1-\varepsilon)} \bullet \frac{p^{(1-\varepsilon)}}{a} = \varepsilon. \qquad (10F.3)$$

The intermediate input (Q_y) demands is specified within the supply chain as a function of output (Q_x). The subscript "0" denotes baseline and the subscript "1" denotes with regulation.

$$\text{Derived Demand Equation: } Q_y = f(Q_x) \qquad (10F.4a)$$

$$Q_{y1} = Q_{y0}(1+\Delta Q_x/Q_x) \qquad (10F.4b)$$

Computing Supply/Demand Function Constants. Using the baseline price, quantity, and elasticity parameter, the value of the constants can be computed. For example, supply function constants can be calculated as follows:

$$\text{Constant Calibration: } a = \frac{Q_{x0}}{(P_{x0})^{\varepsilon}} \qquad (10F.5)$$

Direct Supply Shift (Dc). The direct upward shift in the supply function is calculated by using the annualized compliance cost estimates provided by the engineering cost analysis. Computing the supply shift in this manner treats the compliance costs as the conceptual equivalent of a unit tax on output.

Indirect Supply Shift (Dc_y). The indirect upward shift in the supply function is calculated by using the change in input (y) prices (i.e., engines, equipment, and/or fuel) that result from the direct compliance costs introduced into the model. Only two types of suppliers are affected by these changes: equipment producers that use diesel engines and application markets that use equipment with diesel engines and diesel fuel. The term Dc_y is computed as follows:

$$\Delta c_y = \frac{\Delta P_y \bullet Q_{y0}}{Q_{x0}}. \qquad (10F.6)$$

10F.2 Engine Markets

As described in Section 10.3.3.1, seven separate engine markets were modeled segmented by engine size in horsepower (the EIA includes more horsepower categories than the standards, allowing more efficient use of the engine compliance cost estimates developed for this rule):

- less than 25 hp
- 26 to 50 hp
- 51 to 75 hp
- 76 to 100 hp
- 101 to 175 hp
- 176 to 600 hp
- greater than 601 hp

In each of these engine markets, there are three types of suppliers: captive suppliers (engines are consumed internally by integrated equipment manufacturers), merchant suppliers (engines are sold on the open market), and foreign suppliers. These supply segments are represented by upward-sloping supply functions. On the demand side, consumers of engines include integrated and nonintegrated equipment manufacturers[T] and are represented by derived demand functions (Eqs. [10F-4a] and [10F.4b]).

Captive Domestic Supply Equation: $a\, S_{engcap} = {}_1(p-c)^{\varepsilon}$ (10F.7)

Merchant Domestic Supply Equation: $a\; S_{engmer} = {}_2(p-c)^{\varepsilon}$ (10F.8)

Import Supply Equation: $M_{eng} = a(p-c)^{\varepsilon}$ (10F.9)

Integrated Demand Equation: $D_I = S\,(S_{equip})$ (10F.10)

Nonintegrated Demand Equation: $D_{NI} = S(S_{equip})$ (10F.11)

Market Clearing Condition: $S_{engcap} + S_{engmer} + M_{eng} = D_I + D_{NI}$ (10F.12)

10F.3 Equipment Markets

As described in Section 10.3.3.2, integrated and nonintegrated equipment manufacturers supply their products into a series of 42 equipment markets (7 horsepower categories within 7 application categories; there are 7 horsepower/application categories that did not have sales in 2000 and are not included in the model, so the total number of diesel equipment markets is 42, not 49).[U] The equipment types are:

[T]Note that engines sold to foreign equipment manufacturers are not included in the domestic engine market because they are subject to different (foreign) environmental regulations and hence are considered different products.

[U] These are: agricultural equipment >600 hp; gensets & welders > 600 hp; refrigeration & A/C > 71 hp (4 hp categories); and lawn & garden >600 hp.

- agricultural
- construction
- refrigeration
- generators and welder sets
- lawn and garden
- pumps and compressors
- general industrial

Each individual equipment market is comprised of two aggregate suppliers groups: (1) domestic integrated suppliers that produce and consume their own engines (captive engines) and (2) domestic nonintegrated suppliers that purchase engines from the open market to be used in their equipment (merchant engines).

On the demand side, each of the 42 equipment markets is linked to one of three application markets (agricultural, construction, and manufacturers) is represented by derived demand functions (Eq. [10F.4a and 10F.4b])

Domestic Integrated Supply Equation: $$S_{eqI} = a(p-c)^{\varepsilon} \qquad (10F.13)$$

Domestic Nonintegrated Supply Equation: $$S_{eqNI} = a(p-c-c_y)^{\varepsilon} \qquad (10F.14)$$

Domestic Demand Equation: $$D_{eq} = \sum Q_{eq}\left(1+\frac{\Delta Q_{qpp}}{Q_{qpp0}}\right) \qquad (10F.15)$$

Market Clearing Condition: $$S_{eqI} + S_{eqNI} = D_{eq} \qquad (10F.16)$$

10F.4 Application Markets

As described in Section 10.3.3.3, there are three application markets that supply products and services to consumers:

- agricultural
- construction
- manufacturing

The supply in each of these three application markets is the sum of a domestic supply and an foreign (import) supply. The consumers in the application markets are represented by a domestic demand and a foreign (export) demand function.

Supply Equation: $$S_{app} = a(p_{app} - c - \beta\Delta p)^{E_{kS}} \qquad (10F.17)$$

Foreign (Import) Supply Equation: $$S_{app} = ap_{app}{}^{E} \qquad (10F.18)$$

Domestic Demand Equation: $$D_{app} = ap^{\eta} \qquad (10F.19)$$

Foreign (Export) Demand Equation: $$X_{app} = ap^{\eta} \qquad (10F.20)$$

Market Clearing Condition: $$S_{app} + M_{app} = D_{app} + X_{app} \qquad (10F.21)$$

β_0, $\beta_{1,}$ and β_2 are the baseline input shares of equipment, fuel, and transportation services.

10F.5 Fuel Markets

As described in Section 10.3.3.4, eight nonroad diesel fuel markets were modeled: two distinct nonroad diesel fuel commodities in four regional markets. The two fuels are:

- 500 ppm nonroad diesel fuel, and
- 15 ppm nonroad diesel fuel.

The four regional nonroad diesel fuel markets are

- PADD 1 and 3
- PADD 2
- PADD 4
- PADD 5 (includes Alaska and Hawaii; California fuel volumes that are not affected by the program because they are covered by separate California nonroad diesel fuel standards are not included in the analysis)

The supply and demand for nonroad diesel fuel is specified for the model for four regional diesel fuel markets. Derived demand of diesel fuel comes from three application markets. The equations for PADD district j are specified below:

Supply Equation: $$S_j = a(P_j - \Delta c)\varepsilon \qquad (10F.22)$$

Derived Demand Equation: $$D_j = \Sigma\, Q_{j0}\left(1 + \frac{\Delta Q_{app}}{Q_{app0}}\right) \qquad (10F.23)$$

Market Clearing Condition: $$S_j = D_j \qquad (10F.24)$$

10F.6 Locomotive and Marine Transportation Markets

There are two transportation service markets that supply services to the application markets:

- locomotive
- marine

The supply in each of these three application markets is the sum of a domestic supply

Supply Equation: $$S_{trans} = a(p_{trans} - c - \beta\Delta p_{fuel})^{E_{kS}} \qquad (10F.25)$$

Market Clearing Condition: $$S_{trans} = D_{trans} \qquad (10F.26)$$

β is the baseline input share of fuel $\left(\frac{Q_{fuel0}}{Q_{app0}}\right)$.

10F.7 Market-Clearing Process and Equations

Supply responses and market adjustments can be conceptualized as an interactive process. Producers facing increased production costs due to compliance with the control program are willing to supply smaller quantities at the baseline price. This reduction in market supply leads to an increase in the market price that all producers and consumers face, which leads to further responses by producers and consumers and thus new market prices, and so on. The new with-regulation equilibrium is the result of a series of iterations in which price is adjusted and producers and consumers respond, until a set of stable market prices arises where total market supply equals market demand.

Market-Clearing Equation: Total Supply = Total Demand. (10F.27)

The algorithm for determining with-regulation equilibria can be summarized by six recursive steps:

1. Impose the control costs on affected supply segments, thereby affecting their supply decisions.

2. Recalculate the market supply in each market. Excess demand currently exists.
3. Determine the new prices via a price revision rule. A rule similar to the factor price revision rule described by Kimbell and Harrison (1986) is used. P_i is the market price at iteration i, q_d is the quantity demanded, and q_s is the quantity supplied. The parameter z influences the magnitude of the price revision and speed of convergence. The revision rule increases the price when excess demand exists, lowers the price when excess supply exists, and leaves the price unchanged when market demand equals market supply. The price adjustment is expressed as follows:

$$P_{i+1} = P_1 \bullet \left(\frac{q_d}{q_s}\right)^z \tag{10F.26}$$

4. Recalculate market supply with new prices.
5. Compute market demand in each market.
6. Compare supply and demand in each market. If equilibrium conditions are not satisfied, go to Step 3, resulting in a new set of market prices. Repeat until equilibrium conditions are satisfied (i.e., the ratio of supply and demand is arbitrarily close to one).

APPENDIX 10G: Elasticity Parameters for Economic Impact Modeling

The Nonroad Diesel Economic Impact Model (NDEIM) relies on elasticity parameters to estimate the behavioral response of consumers and producers to the regulation and its associated costs. To operationalize the market model, supply and demand elasticities are needed to represent the behavioral adjustments that are likely to be made by market participants. The following parameters are needed:

- supply and demand elasticities for application markets (agriculture, construction, and manufacturing)
- supply elasticities for equipment markets
- supply elasticities for engine markets
- supply elasticities for diesel fuel markets
- supply elasticities for locomotive and marine transportation markets

Note that demand elasticities for the equipment, engine, diesel fuel, and transportation markets are not estimated because they are derived internally in the model. They are a function of changes in output levels in the applications markets.

Tables 10G-1 and 10G-2 contain the demand and supply elasticities used to estimate the economic impact of the rule. Two methods were used to obtain the supply and demand elasticities used in the NDEIM. First, the professional literature was surveyed to identify elasticity estimates used in published studies. Second, when literature estimates were not available for specific markets, established econometric techniques were used to estimate supply and demand elasticity parameters directly. Specifically, the supply elasticities for the agricultural and construction application markets and the supply elasticity for the diesel fuel market were obtained from the literature. The supply elasticity for the manufacturing market is assumed to be the same as for the construction market. The supply elasticities for all of the application markets and for equipment and engine markets were estimated econometrically.

This appendix discusses the literature for elasticities based on existing studies and presents the data sources and estimation methodology and regression results for the econometric estimation.

Finally, it should be noted that these elasticities reflect intermediate run behavioral changes. In the long run, supply and demand are expected to be more elastic since more substitutes may become available.

Table 10G-1
Summary of Market Demand Elasticities Used in the NDEIM

Market	Estimate	Source	Method	Input Data Summary
Applications				
Agriculture	–0.20	EPA econometric estimate	Productivity shift approach (Morgenstern, Pizer, and Shih, 2002)	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Construction	–0.96	EPA econometric estimate	Simultaneous equation (log-log) approach	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Manufacturing	–0.58	EPA econometric estimate	Simultaneous equation (log-log) approach.	Annual time series from 1958 – 1995 developed by Jorgenson et al. (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987)
Transportation Services				
Locomotive		Derived demand	In the derived demand approach, • compliance costs increase prices and decrease demand for products and services in the application markets; • this in turn leads to reduced demand for diesel equipment, engines and fuel, which are inputs into the production of products and services in the application markets	
Marine		Derived demand		
Equipment				
Agriculture		Derived demand		
Construction		Derived demand		
Pumps/ compressors		Derived demand		
Generators and Welders		Derived demand		
Refrigeration		Derived demand		
Industrial		Derived demand		
Lawn and Garden		Derived demand		
Engines		Derived demand		
Diesel fuel		Derived demand		

Table 10G-2
Summary of Market Supply Elasticities Used in the NDEIM

Markets	Estimate	Source	Method	Input Data Summary
Applications				
Agriculture	0.32	Literature-based estimate	Production-weighted average of individual crop estimates ranging from 0.27 to 0.55. (Lin et al., 2000)	Agricultural Census data 1991 – 1995
Construction	1	Literature-based estimate	Based on Topel and Rosen, (1988).[a]	Census data, 1963 – 1983
Manufacturing	1	Literature-based estimate	Literature estimates are not available so assumed same value as for Construction market	Not applicable
Transportation Services				
Locomotive	0.6	Literature-based estimate	Method based on Ivaldi and McCollough (2001)	Association of American Railroads 1978-1997
Marine	0.6	Literature-based estimate	Literature estimates not available so assumed same value as for locomotive market	Not applicable
Equipment				
Agriculture	2.14	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3523
Construction	3.31	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3531
Pumps/ compressors	2.83	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3561 and 3563
Generators/ Welder Sets	2.91	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3548
Refrigeration	2.83	EPA econometric estimate		Assumed same as pumps/compressors
Industrial	5.37	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3537
Lawn and Garden	3.37	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3524
Engines	3.81	EPA econometric estimate	Cobb-Douglas production function	Census data 1958-1996; SIC 3519
Diesel fuel	0.24	Literature based estimate	Based on Considine (2002).[b]	From Energy Intelligence Group (EIG); 1987-2000[c]

[a] Most other studies estimate ranges that encompass 1.0, including DiPasquale (1997) and DiPasquale and Wheaton (1994).

[b] Other estimates range from 0.02 to 1.0 (Greene and Tishchishyna, 2000). However, Considine (2002) is one of the few studies that estimates a supply elasticity for refinery operations. Most petroleum supply elasticities also include extraction.

[c] This source refers to the data used by Considine in his 2002 study.

10G.1 Application Markets - Demand Elasticities

There are three application markets in the NDEIM: agricultural, construction, and manufacturing. Demand elasticities for the construction and manufacturing application markets were estimated using a simultaneous equation (two-stage least squares) method. This approach was also investigated for the agricultural application market; however, the estimated demand elasticity parameter for that market was not statistically significant. For this reason, a production function approach (Morgenstern, Pizer and Shih, 2002) was employed for the agricultural application market. Publicly available data developed by Dale Jorgenson and his associates (Jorgenson, 1990; Jorgenson, Gollop, and Fraumeni, 1987) were used in the regression analysis. A time series of 38 observations, from 1958 to 1995, was used to estimate the demand elasticities in both the two-stage least squares and production function approach. Both of these techniques are described below.

10G.1.1 Construction and Manufacturing Demand Elasticities

10G.1.1.1 Description of Simultaneous Equation Method

The demand elasticities for the construction and manufacturing application markets were estimated using a simultaneous equation (two-stage least squares) approach. The methodology is described below and the individual regression results are presented in Appendix 10F.

In a partial equilibrium model, supply and demand are represented by a series of simultaneous interdependent equations, in which the price and quantity produced of a product are simultaneously determined by the interaction of producers and consumers in the market. In simultaneous equations models, where one variable feeds back in to the other equations, the error terms are correlated with the endogenous variable. As a result, estimating parameter values using the ordinary least squares (OLS) regression method for each individual equation yields biased and inconsistent parameter estimates. Therefore, OLS is not an appropriate estimation technique.

Instead, a simultaneous equations approach is used. In the simultaneous equations approach both the supply and demand equations for the market are specified and parameters for the two-equation system are estimated simultaneously.

The log-log version of the model is specified as follows:

$$\text{Supply: } Q_{ts} = a_0 + a_1P_t + a_2PL_t + a_3PK_t + a_4PM_t + e_t \qquad (10G.1a)$$

$$\text{Demand: } Q_{td} = b_0 + b_1P_t + b_2HH_t + b_3I_t + v_t \qquad (10G.1b)$$

where

Q_t = log of quantity of the market product in year t
P_t = log of price of the market product in year t
PL_t = log of cost of labor inputs in year t

PK_t = log of cost of capital inputs in production in year t
PM_t = log of cost of material inputs in production in year t
HH_t = log of number of households in year t
I_t = average income per household in year t
e_t, v_t = error terms in year t

The parameter estimates $\hat{a}_1$ and $\hat{b}_1$ are the estimated price elasticity of supply and price elasticity of demand, respectively.

The first equation defines quantity supplied in each year as a function of the product price and the cost of inputs: labor, capital and materials. The second equation defines the quantity demanded in each year as a function of the production price, the number of households, and the average income per household. The equilibrium condition is that supply equals demand

$$\text{equilibrium:}\ Q_{ts} = Q_{td}$$

Application of this two-stage least square regression approach was successful for estimating the demand elasticity parameters for use here but was unsuccessful for estimating the supply elasticities. The supply elasticity estimates were negative and not statistically significant. Therefore, as noted above, literature estimates were used for the supply elasticities for the three application markets in the NDEIM.

To estimate the demand elasticities using this two-stage least squares approach, it is necessary to first estimate the reduced-form equation for price using OLS. The reduced-form equation expresses price as a function of all exogenous variables in the system:

$$P_t = fn(PL_t, PK_t, PM_t, HH_t, I_t)$$

The results of this regression are used to develop fitted values of the dependent price variable P_t (this is a new instrumental variable for price). The fitted values by construction will be independent of error terms in the demand equation. In the second stage regression, the fitted price variable P_t (the instrumental variable) is used as a replacement for P_t, in the demand equation. An OLS is performed on this equation, which produces a consistent, unbiased estimate of the demand elasticity b_1.

10G.1.1.2 Construction Application Market Demand Elasticity

The results of the simultaneous equation method for the construction demand elasticity are presented in Table 10G-3. The estimated demand elasticity is −0.96 and is statistically significant with a t-statistic of –3.83. This inelastic estimate implies that a 1 percent increase in price will lead to a 0.96 percent decrease in demand for construction, and means that the quantity of goods and services demanded is expected to be fairly insensitive to price changes.

Table 10G-3. Construction Demand Elasticity

Number of Observations = 29
R squared = 0.78
Adjusted R squared = 0.75

Variable	Estimated Coefficients	t-statistic
intercept	18.83	5.19
In price	–0.96	–3.83
In number of households	–1.73	–3.37
In average income per household	–1.67	5.34

10G.1.1.3 Manufacturing Application Market Demand Elasticity

The results of the simultaneous equation method for the manufacturing market are presented in Table 10G-4. The estimated demand elasticity is −0.58 and is statistically significant with a t-statistic of –2.24. This inelastic estimate implies that a 1 percent increase in price will lead to a 0.58 percent decrease in the demand for manufactured products, and means that the quantity of goods and services demanded is expected to be fairly insensitive to price changes.

Table 10G-4. Manufacturing Demand Elasticity

Number of Observations = 29
R squared = 0.83
Adjusted R squared = 0.81

Variable	Estimated Coefficients	t-statistic
intercept	6.16	0.84
In price	–0.58	–2.24
In number of households	0.19	0.23
In average income per household	0.62	1.49

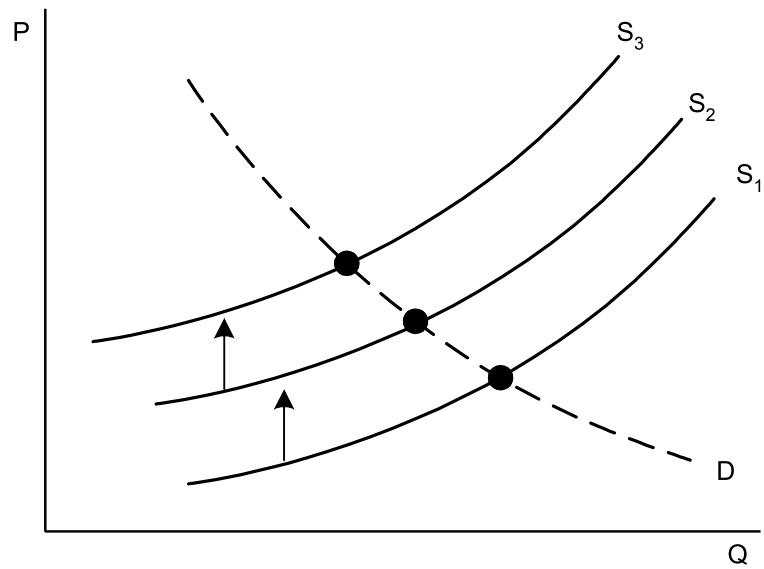
10G.1.2 Agricultural Application Market Demand Elasticity

10G.1.2.1: Description of Productivity Shift Approach

When the simultaneous equation method was attempted for the agricultural application market, the resulting demand elasticity parameter estimate was not statistically significant. Thus, the demand elasticity for the agricultural market was estimated using the productivity shift approach. This is a technique that regresses historical data for aggregate output on industry productivity (Morgenstern, Pizer, and Shih, 2002).

As shown in Figure 10G-1, changes in industry productivity represent shifts in the supply curve. The supply curve shifts in conjunction with the known output values trace-out the demand curve and enables the estimation of the demand elasticity. Because the agricultural sector is relatively small compared to the entire economy, it is reasonable to assume that the productivity changes do not shift the demand curve through income effects.

Figure 10G-1
Productivity Shifts Trace-Out Demand Curve



The demand elasticity (ξd) is estimated through a simple regression of the annual change in the natural log of outputs on change in the natural log of productivity:

$$\Delta \ln output_t = \xi_d \Delta \ln prod_t + \varepsilon_t$$

where
$output_t$ = output t is the industry output in year t
$prod_t$ = industry productivity in year t
ε_t = random error term

The change in the natural log of productivity is computed as the log difference between the annual change in input price and the annual change in output price:

$$\Delta \ln prod_t = \sum_{sh} \frac{(\upsilon_{sh,t}+\upsilon_{sh,t-1})}{\partial} (\ln P_{sh,t}-\ln P_{sh,t-1}) - (\ln PO_t - \ln PO_{t-1}) \qquad (10.G\text{-}2)$$

where
P = input prices
PO = output prices
υ = input shares

Eq. (10G.2) is a similar to a standard quantity-based definition of productivity (output divided by input), but expressed in terms of input and output prices. Under a competitive market with zero-profit assumptions, revenue equals cost, and the price of output must equal the price of input divided by the standard definition of productivity:

$$P_O = P_I (Q_I / Q_O)$$

Thus,

$$P_I / P_O = Q_O / Q_I$$

where

Q_O = quantity of output
Q_I = quantity of input

Since Q_O / Q_I is a quantity based productivity, P_I / P_O is an equivalent measure of productivity according to the above equation. The difference in logged changes in P_I and P_O is a valid measure of productivity growth (Pizer, 2002).

10G.1.2.2 Agricultural Application Market Demand Elasticity

The results of the estimated agricultural model are presented in Table 10G-5. The demand elasticity estimate is −0.20 and is statistically significant with a t-statistic of 2.31. This implies that a 1 percent increase in price will lead to a 0.2 percent decrease in demand, and means that the quantity of goods and services demanded is expected to be fairly insensitive to price changes.

Table 10G-5. Agricultural Demand Elasticity

Number of Observations = 38
R squared = 0.13
Adjusted R squared = 0.11

Variable	Estimated Coefficients	t-statistic
intercept	0.02	3.49
ln productivity t	–0.20	2.31

10G.2 Application Market - Supply Elasticities

Professional literature sources were used to obtain supply elasticity estimates for the applications markets. These literature sources used are described below.

It should be noted that both of the econometric estimation methods described above, the simultaneous equation approach and the production function approach, were also attempted for the supply elasticities. However, because of the great variety of the production processes in these aggregate industry sectors (heterogeneity), parameter estimates were either not statistically significant or did not conform with standard microeconomic theory (i.e., estimates were not upward sloping).

10G.2.1 Agricultural Application Market Supply Elasticity

Obtaining reasonable estimates of supply response in agriculture has been a persistent problem since the inception of farm price support programs in the 1930s. The nonrecourse marketing loans, deficiency payments, and conservation set-asides that make up the current farm price support system distort equilibrium prices to the point that any econometric estimates are difficult to formulate or support.

A recent study by economists at the USDA's Economic Research Service provides an approach to estimating agricultural demand elasticities (Lin et al., 2000). Taking into account recent changes in the 1996 Farm Bill, the authors measure nationwide acreage price elasticity values for the seven major agricultural crops, obtaining values ranging from 0.269 for soybeans to 0.550 for sorghum. Although a composite number for all farm output is not reported, an average value of 0.32 can be obtained by weighting the reported values by the acreage planted for each crop. This value was used for the supply elasticity in the agriculture application market. This estimated elasticity is inelastic, which means that the quantity of goods and services supplied is expected to be fairly insensitive to price changes.

Although the literature estimates vary, this estimate conforms closely to historical evidence and economic theory of small but positive supply elasticities. This determination of price having little impact on supply (referred to as inelastic supply) is consistent with a historical observation that total acreage cultivated varies little from year to year. Between 1986 and 2001, for instance, U.S. cropland harvested has ranged from 289 to 318 million acres, with an average of 305 million acres over that 15-year period. A low supply elasticity is also supported by the fact that there are few alternative uses (except in the very long run) for cropland, capital, and labor employed in farming. Abandonment or redeployment of farm assets is an often irreversible decision, and one not greatly affected by annual price swings.

10G.2.2 Construction Application Market Supply Elasticity

Although the construction market does not suffer from government-induced distortions to prices and quantities, the evidence on supply elasticity is even more varied than that for agriculture. Estimates of supply elasticity ranging from near zero to infinity have been reported in credible papers on housing construction published during the past 20 to 30 years. A literature survey paper by DiPasquale (1997) describes the methodological issues that have led to this variety of responses. A key issue is the conceptual problem of distinguishing between increases in the stock the of housing (or other structures) through new construction and changes in the flow of housing services, which can also include renovation, apartment or condominium conversion, and abandonment.

DiPasquale cites a number of published studies that suggest that a value of 1.0 for supply elasticity is appropriate. In the study that most closely matches the analysis for this regulation, Poterba (1984) estimated elasticity of new construction with respect to real house prices ranging from 0.5 to 2.3, depending on the specification. A study by Topel and Rosen investigating asset-markets and also found a short-run elasticity value of 1.0 (Topel and Rosen, 1988). Finally, DiPasquale cites one of her own papers that estimated values of 1.0 to 1.2 for the price elasticity of construction (DiPasquale and Wheaton, 1994). Based on these studies, a value of 1.0 was used for the supply elasticity in the construction application market. This unit elastic elasticity means that the quantity supplied is expected to vary directly with changes in prices.

Estimates of supply response for other portions of the construction market, namely nonresidential buildings and nonbuilding (roads and bridges, water and sewer systems, etc.), are not available in the literature. However, the similarity between technologies employed in construction of residential and other nonindustrial buildings suggests that supply elasticities should be comparable. In addition, residential construction accounts for a significant portion of construction activity. According to the Census Bureau's most recent Annual Value of Construction Put in Place report, residential and nonindustrial buildings accounted for about 77 percent of the $842 billion in construction spending in 2001, with new residential housing making up about 33 percent (U.S. Census Bureau, 2002).

10G.2.3 Manufacturing Application Market Supply Elasticity

No supply elasticity estimates were available in the professional literature for the aggregate manufacturing sector. For this reason, a unitary supply elasticity of 1.0 was used in the model. This unit elastic elasticity means that the quantity supplied is expected to vary directly with changes in prices. A sensitivity analysis for this assumed elasticity is presented in Appendix 10I.

10G.3 Engine and Equipment Markets Supply Elasticity

Published sources for the price elasticity of supply for diesel engine and diesel equipment markets were not available. Therefore, the supply elasticities used in the model were estimated econometrically using a production function cost minimization approach.

10G.3.1 Production Function Cost Minimization Approach

The production function cost minimization approach for econometrically estimating the supply elasticities is based on the cost-minimizing behavior of the firm subject to production function constraints. The production function describes the relationship between output and inputs. For this analysis, a Cobb-Douglas, or multiplicative form, was used as the functional form of the production function:

$$Q_t = A\, k_t^{\alpha k}\, L_t^{\alpha L}\, M_t^{\alpha k}\, t^{\lambda} \qquad (10G\text{-}3)$$

where

Q_t = output in year t

K_t = real capital consumed in production in year t[V]
L_t = quantify of labor used in year t
M_t = material inputs in year t
t = a time trend variable to reflect technology changes

This equation can be written in linear form by taking the natural logarithms of each side of the equation. The parameters of this model, α_K, α_L, α_M, can then be estimated using linear regression techniques:

$$\ln Q_t = \ln A + \alpha_k \ln k_t + \alpha \ln L_t + \alpha_m \ln M_t + \lambda \ln t.$$

Under the assumptions of a competitive market and perfect competition, the elasticity of supply with respect to the price of the final product can be expressed in terms of the parameters of the production function:

$$\text{Supply Elasticity} = (\alpha_l + \alpha_m) / (1 - \alpha_l - \alpha_m) \qquad (10G\text{-}4)$$

This underlying relationship is derived from the technical production function and the behavioral profit maximization conditions. The derivation for equation (10G-4) is provided in Appendix 10H.

In a competitive market, a firm will supply output as long as the marginal cost (MC) of producing the next unit does not exceed the marginal revenue (MR, i.e., the price). In a short-run analysis, where capital stock is assumed to be fixed (or a sunk cost of production), the firm will adjust its variable inputs of labor and material to minimize the total cost of producing a given level of output.

The supply function is estimated by minimization, subject to the technical constraints of the production function, and then setting the MC = P to determine the quantity produced as a function of market price. To maintain the desired properties of the Cobb-Douglas production function, it is necessary to place restrictions on the estimated coefficients. For example, if $\alpha_L + \alpha_M = 1$, then the supply elasticity will be undefined. Alternatively, if $\alpha_L + \alpha_M > 1$, this yields a negative supply elasticity. Thus, a common assumption is that $\alpha_K + \alpha_L + \alpha_M = 1$. This implies constant returns to scale, which is consistent with most empirical studies.

10G.3.2 Data for Estimating Engine and Equipment Supply Elasticities

The data for the supply elasticity estimation were obtained from the National Bureau of Economic Research-Center for Economic Studies (NBER-CES). All nominal values were deflated into $1987, using the appropriate price index. The following variables were used:

- value of shipments

[V]Capital consumed is defined as the value added minus labor expenditures, divided by the price index for capital.

- price index of value shipments
- production worker wages
- implicit GDP deflators
- cost of materials
- price index for materials
- real capital stock
- investment
- price index for investment
- value added
- price index for capital

The capital (k) variable used in the Cobb-Douglas regression analysis is calculated as:

$$K = (\text{Value Added} - \text{Labor Costs}) / \text{Price Index for Capital}$$

This provides a measure of capital consumed as opposed to using a measure of total capital stock in place at the firm.

10G.3.3 Engine Supply Elasticity Regression Results

The results of the estimated production function is presented in Table 10G-6. All parameter estimates are statistically significant at the 95 percent confidence level and the supply elasticity is calculated to be 3.81. This elastic elasticity estimate means that the quantities supplied in this market are expected to be very responsive to price changes.

Table 10G-6. Engine Supply Elasticity

Supply Elasticity = 3.81
Number of Observations = 33
R-squared = 0.9978
Goldfeld-Quandt F = 1.88
Note: F(14,14) = 2.46.

Variable	Estimated Coefficients	t-statistic
Intercept	0.954	24.76
ln K	0.2081	4.77
ln T	0.0215	2.37
ln M	0.5909	13.4
ln L	0.201	5.55

10G.3.4 Equipment Supply Elasticity Regression Results

The results of the estimated production functions are presented in Tables 10G-7 through 10G-12. The supply elasticities are calculated from the estimated coefficients for lnM and lnL as described in Equation G10-4. The supply elasticities range from approximately 1.0 for refrigeration to 5.4 for general industrial equipment. The average supply elasticity is 3.6. These elastic elasticity estimates means that the quantities supplied in this market are expected to be responsive to price changes.

Table 10G-7. Agricultural Supply Elasticity

Supply Elasticity = 2.14
Number of Observations = 33
R-squared = 0.9969
Goldfeld-Quandt F = 2.01
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	1.1289	20.81
ln K	0.3189	11.12
ln T	–0.0241	–3.10
ln M	0.4952	10.29
ln L	0.1858	4.64

Table 10G-8. Construction Supply Elasticity

Supply Elasticity = 3.31
Number of Observations = 33
R-squared = 0.9926
Goldfeld-Quandt F = 1.76
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	1.172	28.54
ln K	0.2318	5.83
ln T	–0.0617	–7.08
ln M	0.1511	4.54
ln L	0.6172	13.97

Table 10G-9. Industrial Supply Elasticity

Supply Elasticity = 5.37
Number of Observations = 33
R-squared = 0.9949
Goldfeld-Quandt F = 1.23
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	0.6927	18.29
ln K	0.157	3.47
ln T	–0.00739	–0.76
ln M	0.0412	0.96
ln L	0.8018	21.9

Table 10G-10. Garden

Supply Elasticity = 3.37
Number of Observations = 33
R-squared = 0.9963
Goldfeld-Quandt F = 1.18
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	0.6574	13.34
ln K	0.2287	3.75
ln T	0.0413	2.78
ln M	0.0644	1.72
ln L	0.7069	11.23

Table 10G-11. Gensets

Supply Elasticity = 2.91
Number of Observations = 33
R-squared = 0.9909
Goldfeld-Quandt F = 1.16
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	1.1304	11.09
ln K	0.2557	3.6
ln T	0.0325	2.73
ln M	0.3797	4.67
ln L	0.3646	4.51

Table 10G-12. Pumps

Supply Elasticity = 2.83
Number of Observations = 33
R-squared = 0.9979
Goldfeld-Quandt F = 1.40
Note: F(14,14) = 2.46

Variable	Estimated Coefficients	t-statistic
Intercept	0.9367	19.01
ln K	0.2608	4.45
ln T	–0.207	–1.74
ln M	0.0891	1.57
ln L	0.6501	14.48

10G.4 Diesel Fuel Supply Elasticity: Literature Estimate

Very few studies have attempted to quantify supply responsiveness for individual refined products, such as diesel fuel. For example, a study for the California Energy Commission stated "There do not seem to be credible estimates of gasoline supply elasticity" (Finizza, 2002). However, sources agree that refineries have little or no ability to change output in response to price: high fixed costs compel them to operate as close to their capacity limit as possible. The Federal Trade Commission (FTC) analysis made this point explicitly (FTC, 2001).

Greene and Tishchishyna (2000) reviewed supply elasticity estimates available in the literature. The supply elasticity values cited in most of these studies were for "petroleum" or "oil" production in the United States, which includes exploration, distribution and refining activities. The lowest short-term numbers cited were 0.02 to 0.05, with long-run values ranging from 0.4 to 1.0. It seems likely that these extremely low numbers are influenced by the limited domestic supply of crude petroleum and the difficulty of extraction.

A recent paper by Considine (2002) provides one of the few supply elasticity estimates for refining production (excluding extraction and distribution) based on historical price and quantity data. In this study, Considine estimates a refining production supply elasticity of 0.24. This estimate is for aggregate refinery production and includes distillate and nondistillate fuels. Because petroleum products are made in strict proportion and refineries have limited ability to adjust output mix in the short to medium run, it is reasonable to assume that supply is relatively inelastic and similar across refinery products. This value of 0.24 was used for the supply elasticity for this market. This estimated elasticity is inelastic, which means that the quantity of goods and services supplied is expected to be fairly insensitive to price changes.

10G.4 Locomotive and Marine Supply Elasticities: Literature Estimate

Over the past three decades, several studies have empirically estimated railroad cost functions (see for example Braeutigam, 1999). One of the most recent studies by Ivald and McCullough (2001) estimated a multi-product cost function for railroad services using data from the Association of American Railroads (1978 to 1997). They report cost elasticities for which we can derive a supply elasticity parameter for rail transportation services[W]. The supply parameters are slightly elastic (1.6), suggesting a one percent change in the market price of the services would induce producers increase service supply more than one percent.

Similar studies for marine transportation services are generally restricted to the study of the liner shipping industry (see for example Klein and Kyle, 1997). However, these ocean carrier services are not directly comparable to commercial marine services in the Great Lakes and Inland River Ports in the United States. Instead, they are more likely to be consistent with on-land transportation services provided by the railroad sector. As a result, we have assumed the supply elasticity parameter for best characterizes the supply responses of the marine transportation market included in NDEIM.

[W]Under the assumption of perfect competition, supply elasticities can be derived by taking the inverse of the reported cost elasticities. Therefore, Invalid and McCullough's cost elasticity of 0.6 is used to compute a supply elasticity of 1/0.6 = 1.6.

APPENDIX 10H: Derivation of Supply Elasticity

This appendix derives the underlying relationship for the supply elasticity used in the production function approach described in Appendix 10G.

Cobb-Douglas:

$Q = L^{\alpha} k^{1-\alpha}$ where Q = output
L = labor input
k = capital input

Cost Minimization:

Marginal Revenue Product of Labor = Wage Rate

$MRP_L = P \bullet MP_L = w$

$$MP_L = \frac{\partial Q}{\partial L} = \alpha L^{\alpha-1} k^{1-\alpha}$$

$$P \bullet MP_L = P\alpha\, L^{\alpha-1} k^{1-\alpha} = w$$

$$L^{\alpha-1} = \frac{w}{P\alpha k^{1-\alpha}}$$

$$L^{1-\alpha} = \frac{P\alpha k^{1-\alpha}}{w}$$

$$L = \left(\frac{P\alpha k^{1-\alpha}}{w}\right)^{\frac{1}{1-\alpha}} = \left(\frac{P\alpha}{w}\right)^{\frac{1}{1-\alpha}} k$$

Substitute Back into Cobb-Douglas:

$$y = \left[\left(\frac{P\alpha}{w}\right)^{\frac{1}{1-\alpha}} k\right]^{\alpha} k^{1-\alpha}$$

$$y = \left(\frac{P\alpha}{w}\right)^{\frac{\alpha}{1-\alpha}} k = p^{\frac{\alpha}{1-\alpha}} \left(\frac{\alpha}{w}\right)^{\frac{\alpha}{1-\alpha}} k$$

$$\ln y = \frac{\alpha}{1-\alpha} \ln P + \frac{\alpha}{1-\alpha} \ln\left(\frac{\alpha}{w}\right) + \ln k$$

$$\boxed{\frac{\partial \ln y}{\partial \ln P} = \frac{\alpha}{1-\alpha} = \text{Supply Elasticity}}$$

APPENDIX 10I: Sensitivity Analysis

The Economic Impact Analysis presented in this Chapter 10 is based on the Nonroad Diesel Economic Impact Model (NDEIM) developed for this analysis. The NDEIM reflects certain assumptions about behavioral responses (modeled by supply and demand elasticities) and how costs are treated by producers. This appendix presents a sensitivity analysis for several model components by varying how they are treated. Five model components are examined:

- Scenario 1: alternative market supply and demand elasticity parameters
- Scenario 2: alternative ways to treat fuel market costs
- Scenario 3: alternative way to treat operating costs
- Scenario 4: alternatives way to treat engine and equipment fixed costs
- Scenario 5: alternative discount rates

The results of these sensitivity analyses are presented below. All of the results are presented for 2013 only. The results for the application and transportation service markets do not include the operating savings. Instead, operating savings are added into the total social costs as a separate item.

In general, varying the model parameters does not significantly change the results of the economic impact assessment analysis presented above. Total social costs are about the same across all sensitivity analysis scenarios, $1,510 million. In addition, varying these model parameters does not significantly affect the way the social costs are borne. In all cases, the application markets bear the majority of the burden (about 83 percent), although there are small differences in the way the costs are borne among the scenarios. The exception is Scenario 2, the fuel cost scenario. In the maximum total cost scenario, the share of the social costs borne by the application market exceeds the social costs of the rule ($2,029 million versus $1,510.9 million for the rule), indicating that refiners will gain from the rule (about $526 million). In the maximum variable cost scenario, the share of the social costs borne by the application market also exceeds the social costs of the rule ($1,584 million versus $1,510.9 million for the rule), indicating that refiners would gain from the rule in this scenario as well (about $79 million). There are also differences in the way the application market costs are shared among producers and consumers in that market, especially for Scenario 1.

With regard to the market analysis, expected percentage changes for price and price and quantity for each market are about the same as in the base case. Prices are expected to increase about 2.14. 2.9, and 6 percent for the engine, equipment, and fuel markets respectively, while quantities. These engine and equipment percentage price increases are stable across scenarios except in Scenario 4, in which engine and equipment fixed costs and included in the model. In this case, the expected engine price increase goes up from about 21.4 percent to 23.0 percent and the expected equipment price increase goes up from about 2.9 percent to 3.4 percent. The fuel percentage price increases are also stable across scenarios, with the exception of Scenario 2, in which a price increase of 11 percent is expected in the maximum total cost scenario and a 7 percent increase is expected in the maximum variable cost scenario.

Percentage decreases in the quantities produced in the markets are also relatively stable across the scenarios with decreases of 0.01, 0.02, and 0.02 percent expected for the engine, equipment, and fuel markets respectively. There is some variation in absolute quantities across the scenarios, but these are negligible when compared to the total output of each market. The largest change in absolute quantity of output is associated with Scenario 1, when supply elasticities are varied. The largest decline is 107 engines, 189 equipment units, and 3.25 million gallons of fuel; the smallest is 44 engines, 74 equipment units, and 1.29 million gallons of fuel. This is in comparison to 79 engines, 139 equipment units, and 2.38 million gallons of fuel in the base case.

For the application market, the expected price increase remains stable across the scenarios at about 0.1 percent, and the expected quantity decrease at about 0.02. Prices in the transportation service markets are expected to increase about 0.0.01 percent and quantity to decrease about 0.01 percent.

10I.1 Model Elasticity Parameters

Key model parameters include supply and demand elasticity estimates used by the model to characterize behavioral responses of producers and consumers in each market.

Consumer demand and producer supply responsiveness to changes in the commodity prices are referred to by economists as “elasticity.” The measure is typically expressed as the percentage change in quantity (demanded or supplied) brought about by a percent change in own price. A detailed discussion regarding the estimation and selection of the elasticities used in the NDEIM are discussed in Appendix 10G. This component of the sensitivity analysis examines the impact of changes in selected elasticity values, holding other parameters constant. The goal is to determine whether alternative elasticity values significantly alter conclusions in this report.

10I.1.1 Application Markets (Supply and Demand Elasticity Parameters)

The choice of supply and demand elasticities for the *application market* is important because changes in quantities in the application markets are the key drivers in the derived demand functions used to link impacts in the engine, equipment, and fuel markets. In addition, the distribution of regulatory costs depends on the *relative supply and demand elasticities* used in the analysis. For example, consumers will bear less of the regulatory burden if they are more responsive to price changes than producers.

Table 10I-1 reports the upper- and lower-bound values of the application market elasticity parameters (supply and demand) used in the sensitivity analysis. The variation in estimates reported in the literature were used for supply elasticity ranges. For the manufacturing market, an assumed elasticity of 1.0 was used. For the purpose of this sensitivity analysis, the same upper and lower bounds were used as for the construction market. For demand elasticity values, a 90 percent confidence interval was computed using the coefficient and standard error values reported in the econometric analysis (see Appendix 10G).

Table 10I-1. Sensitivity Analysis of the Supply and Demand Elasticities for the Application Markets

Parameter/Market	Elasticity Source	Upper Bound	Base Case	Lower Bound
Supply elasticity				
Agriculture	Literature estimate	0.55	0.32	0.027
Construction	Literature estimate	2.3	1	0.5
Manufacturing	Assumed value	2.3	1	0.5
Demand elasticity				
Agriculture	EPA estimate	–0.35	–0.20	–0.054
Construction	EPA estimate	–1.39	–0.96	–0.534
Manufacturing	EPA estimate	–1.02	–0.58	–0.140

Note: For literature estimates, the variations in estimates reported were used to develop elasticity ranges. In contrast, EPA computed upper- and lower-bound estimates using the coefficient and standard error values associated with its econometric analysis and reflect a 90 percent confidence interval.

The results of the NDEIM using these alternative elasticity values for the application markets are reported in Tables 10I-2 and 10I-3. As can be seen in those tables, market prices are stable across the upper- and lower-bound sensitivity scenarios. Absolute quantities vary but the percentage changes in output are negligible for the two scenarios.

The change in total social surplus for 2013 also remains nearly unchanged across all scenarios and is approximately the same as for the rule ($1,510 million). However, consumers in the application market bear a *smaller* share of the social costs when they are more responsive to price changes relative to producers (supply lower bound and demand upper bound scenarios). As shown, consumers bear approximately 34.5 and 46.5 percent, respectively, in these scenarios compared to 58.5 percent in the base case. In contrast, they bear a *higher* share (up to 78.5 percent) when they are less responsive to price changes relative to producers (supply upper bound and demand lower bound scenarios). While the burden of the fuel market changes slightly, it always remain below 1 percent of the social costs.

Table 10I-2. Application Market Sensitivity Analysis for Supply Elasticities[a,b]

Scenario	Base Case Absolute	Base Case Relative	Supply Upper Bound Absolute	Supply Upper Bound Relative	Supply Lower Bound Absolute	Supply Lower Bound Relative
Application Markets						
Price ($/q)	NA	0.10%	NA	0.11%	NA	0.05%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.01%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$1,113	NA	$520	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	$377	NA	$985	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,490	NA	$1,505	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$973	2.9%	$977	2.9%
Quantity (gal/yr)	–139	–0.02%	–189	–0.02%	–74	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$145	NA	$141	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.4%	$821	21.4%
Quantity (gal/yr)	–79	–0.01%	–107	–0.02%	–44	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–3.25	–0.03%	–1.29	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	$12	NA	$3	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$3	NA	$2	NA
Applications Not Included in NDEIM ($$10^6$/yr)	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,509.9	NA	$1,510.1	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

Table 10I-3. Application Market Sensitivity Analysis for Demand Elasticities[a,b]

Scenario	Base Case		Demand Upper Bound		Demand Lower Bound	
	Absolute	Relative	Absolute	Relative	Absolute	Relative
Application Markets						
Price ($/q)	NA	0.10%	NA	0.08%	NA	0.12%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.01%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$695	NA	$1,181	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	$798	NA	$323	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,493	NA	$1,503	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$974	2.9%	$977	2.9%
Quantity (gal/yr)	–139	–0.02%	–170	–0.02%	–88	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$144	NA	$142	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.4%	$821	21.4%
Quantity (gal/yr)	–79	–0.01%	–96	–0.02%	–50	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–2.89	–0.02%	–1.54	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	$10	NA	$4	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	0.00%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$3	NA	$1	NA
Applications Not Included in NDEIM ($$10^6$/yr)	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,509.9	NA	$1,510.0	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

10I.1.2 Equipment, Engine and Diesel Fuel Markets (Supply Elasticity Parameters)

Sensitivity analysis was also conducted for the engine, equipment, and diesel fuel market supply elasticities. The range of supply elasticity values evaluated for each market are provided in Table 10I-4. The engine and equipment market supply elasticities are derived econometrically. Therefore, the upper and lower bound values were computed using the coefficient and standard error values associated with the econometric analysis and reflect a 90 percent confidence interval (see Appendix 10G).

The fuel market supply elasticity was obtained from the literature. The value for the lower bound for the sensitivity analysis is based on the range of available estimates. The value for the upper bound was derived from a set of regulatory studies of the petroleum refining industry that were conducted using a techno-economic method to estimate supply costs at the individual refinery level (EPA, 2000; CRA/BOB, 2000; MathPro, 2002). Synthetic industry supply curves (i.e., marginal cost curves) were developed from these studies and yielded supply elasticities ranging from 0.2 to 2.0. Therefore, the sensitivity analysis uses 2.0 as an upper bound for the supply elasticity of nonroad diesel fuel.

Three sets of sensitivity results are presented in Tables 10I-5, 10I-6, and 10I-7, where supply elasticities are changed in the equipment, engines, and fuel markets, respectively.

Table 10I-4
Engine, Equipment, and Diesel Fuel Market Sensitivity Analysis for Supply Elasticity Parameters

Market	Elasticity Source	Upper Bound	Base Case	Lower Bound
Supply				
Engines	EPA Estimate	7.64	3.81	2.33
Equipment				
Agriculture	EPA Estimate	3.72	2.14	1.31
Construction	EPA Estimate	6.06	3.31	2.09
Refrigeration	EPA Estimate	5.62	2.83	1.62
Industrial	EPA Estimate	12.93	5.37	2.9
Garden	EPA Estimate	7.96	3.37	1.82
Generator	EPA Estimate	12.14	2.91	1.12
Pumps	EPA Estimate	5.62	2.83	1.62
Diesel fuel	Literature Estimate	2	0.2	0.04

Note: For literature estimates, the variations in estimates reported were used to develop elasticity ranges. In contrast, EPA computed upper- and lower-bound estimates using the coefficient and standard error values associated with its econometric analysis and reflect a 90 percent confidence interval.

Tables 10I-5 and 10I-6 contain the results of varying the engine and equipment supply elasticities. When these elasticities are allowed to vary, all quantitative estimates for both market impacts (price and quantity changes) and social impacts (how the burden is shared across markets) remain nearly unchanged when compared with the rule, across both the upper and lower bound supply elasticity scenarios for equipment and engines. These results imply that the results presented in Section 10.1 are not sensitive to the supply elasticity values used in the engine and equipment markets, because the derived demand for engines and equipment is highly inelastic (it is a function of the inelastic demand and supply in the application markets), and so almost all of the compliance costs are passed on to the application markets through price increases.

Table 10I-7 contains the results of varying the fuel supply elasticity. The results for the upper bound is nearly identical to the base case. However, in the case of the lower bound (producers are less sensitive to price changes), the expected percentage change in the price of fuel decreases from 6 percent in the base case to 5.6 percent. There is a reallocation of surplus loss from the application markets to the fuel markets. In the base case, the application markets are expected to bear about 83 percent of the social costs ($1,497 million), while the fuel market is expected to bear about 0.5 percent ($8 million). When the lower bound of the supply elasticity for the fuel market is used, the share of the application markets decreases to 80 percent ($1,436 million) while the share of the fuel markets increases to about 4 percent ($70 million). The total welfare losses are stable, however, at $1,510.

The demand elasticities for the equipment and engine diesel fuel markets are derived as part of the model, and therefore sensitivity analysis was not conducted on those parameters.[X] In other words, the change in the application market quantities determines the demand responsiveness in the engine, equipment, and diesel fuel markets. As a result, the demand sensitivity analysis for these markets is indirectly shown in Table 10I-2. Nonroad diesel equipment and fuel expenditures are relatively small shares of total production costs for the application markets. Therefore changes in these input prices do not significantly alter input demand (i.e., demand in these markets is highly inelastic).

[X]For a discussion of the concept of derived demand, see Section 10.2.2.3 Incorporating Multimarket Interactions.

Table 10I-5. Equipment Market Supply Elasticity Sensitivity Analysis[a,b]

	Base Case		Supply Upper Bound		Supply Lower Bound	
Scenario	**Absolute**	**Relative**	**Absolute**	**Relative**	**Absolute**	**Relative**
Application Markets						
Price ($/q)	NA	0.10%	NA	0.10%	NA	0.10%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.02%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$877	NA	$874	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	$622	NA	$620	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,499	NA	$1,494	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$977	2.9%	$972	2.9%
Quantity (q/yr)	–139	–0.02%	–139	–0.02%	–139	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$141	NA	$146	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.4%	$821	21.4%
Quantity (q/yr)	–79	–0.01%	–76	–0.01%	–79	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–2.39	–0.02%	–2.38	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	$8	NA	$8	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$2	NA	$2	NA
Applications Not Included in NDEIM ($$10^6$/yr)	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,510.0	NA	$1,510.0	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

Table 10I-6. Engine Market Supply Elasticity Sensitivity Analysis[a,b]

Scenario	Base Case		Supply Upper Bound		Supply Lower Bound	
	Absolute	Relative	Absolute	Relative	Absolute	Relative
Application Markets						
Price ($/q)	NA	0.10%	NA	0.10%	NA	0.10%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.02%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$876	NA	$876	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	$621	NA	$621	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,497	NA	$1,497	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$975	2.9%	$975	2.9%
Quantity (q/yr)	–139	–0.02%	–139	–0.02%	–139	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$143	NA	$143	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.4%	$821	21.4%
Quantity (q/yr)	–79	–0.01%	–79	–0.01%	–77	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–2.38	–0.02%	–2.38	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	$8	NA	$8	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$2	NA	$2	NA
Applications Not Included in NDEIM ($$10^6$/yr)	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,510.0	NA	$1,510.0	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

Table 10I-7. Fuel Market Supply Elasticity Sensitivity Analysis[a,b]

	Base Case		Supply Upper Bound		Supply Lower Bound	
Scenario	**Absolute**	**Relative**	**Absolute**	**Relative**	**Absolute**	**Relative**
Application Markets						
Price ($/q)	NA	0.10%	NA	0.10%	NA	0.09%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.01%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$878	NA	$839	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	$623	NA	$597	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,501	NA	$1,436	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$975	2.9%	$975	2.9%
Quantity (q/yr)	–139	–0.02%	–140	–0.02%	–134	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$143	NA	$143	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.4%	$821	21.4%
Quantity (q/yr)	–79	–0.01%	–78	–0.01%	–75	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.06	6.0%	$0.05	5.6%
Quantity (q/yr)	–2.38	–0.02%	–2.39	–0.02%	–2.31	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	–$2	NA	$70	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$2	NA	$3	NA
Applications Not Included in NDEIM ($$10^6$/yr)	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,510.6	NA	$1,510.6	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

10.I.2 Fuel Market Supply Shift Alternatives

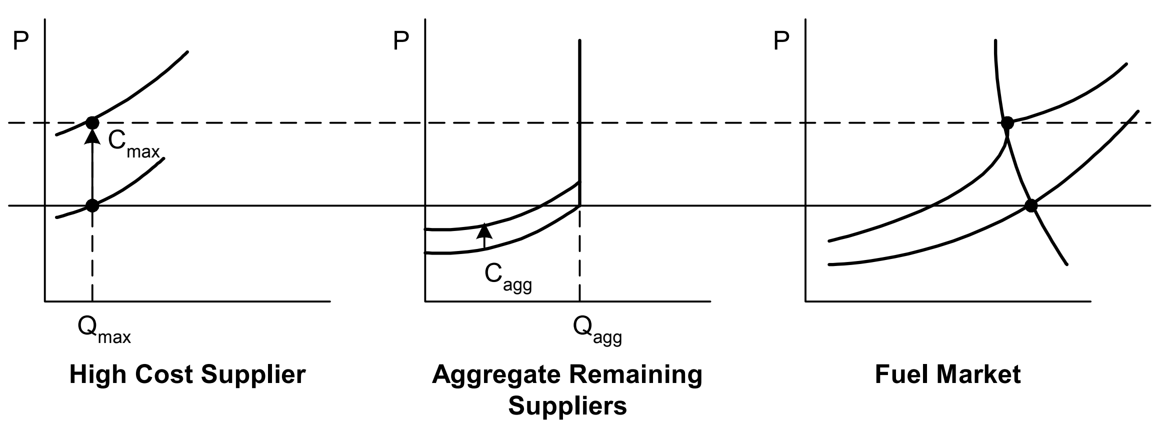
Section 10.2 discusses alternative approaches to shifting the supply curve in the market model. Three alternatives for the fuel market supply shift are investigated in this sensitivity analysis:

- Total average (variable + fixed) cost shift—the results presented in Section 10.1 and the appendices are generated using this cost shift.
- Total maximum (variable + fixed) cost shift
- Variable maximum cost shift

To model the total and variable maximum cost scenarios, the high-cost producer is represented by a separate supply curve as shown in Figure 10I-1. The remainder of the market is represented as a single aggregate supplier. The high-cost producer's supply curve is then shifted by C_{max} (either total or variable), and the aggregate supply curve is shifted by C_{agg}. Using this structure, the high-cost producer will determine price as long as

- the decrease in market quantity does not shut down the high-cost producer, and
- the supply from aggregate producers is highly inelastic (i.e., remaining producers are operating close to capacity); thus, the aggregate producers cannot expand output in response to the price increase.

Figure 10I-1
High Cost Producer Drives Price Increases



Note that the aggregate supply curve is no longer shifted by the average compliance costs but slightly less than the average because the high-cost producer has been removed. The adjusted average aggregate cost shift (C_{agg}) is calculated from the following:

$$C_{ave}*Q_{tot} = C_{max} * Q_{max} + C_{agg} * Q_{agg} \qquad (10I.2)$$

where C_{ave} is the average control cost for the total population; Q_{max}, C_{max}, and Q_{agg}, C_{agg} are the baseline output and cost shift for the maximum cost producer; and the baseline output and cost shift for the remaining aggregate producers, respectively.

The results of this sensitivity analysis are reported in Table 10I-8.

Table 10I-8
Sensitivity Analysis to Cost Shifts in the Diesel Fuel Market

	Average Total Scenario		Maximum Total Scenario		Maximum Variable Scenario	
Scenario	**Absolute Change**	**Relative Change (%)**	**Absolute Change**	**Relative Change (%)**	**Absolute Change**	**Relative Change (%)**
Application Markets						
Price ($/q)	NA	0.10%	NA	0.14%	NA	0.10%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%	NA	–0.02%
Change in Consumer Surplus ($$10^6$/yr)	$876	NA	$1,176	NA	$919	NA
Change in Producer Surplus ($$10^6$/yr)	$621	NA	852	NA	665	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$2,029	NA	$1,584	NA
Equipment Markets						
Price ($/q)	$975	2.9%	$973	2.9%	$975	2.9%
Quantity (q/yr)	–139	–0.02%	–177	–0.02%	–138	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$143	NA	$145	NA	$143	NA
Engine Markets						
Price ($/q)	$821	21.4%	$821	21.0%	$821	21.0%
Quantity (q/yr)	–79	–0.01%	–100	–0.02%	–78	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$42	NA	$42	NA	$42	NA
Fuel Markets						
Price ($/q)	$0.06	6.0%	$0.10	11.0%	$0.06	7.0%
Quantity (q/yr)	–2.38	–0.02%	–3.02	–0.02%	–2.36	–0.02%
Change in Producer Surplus ($$10^6$/yr)	$8	NA	–$526	NA	–$79	NA
Transportation Services						
Price ($/q)	NA	0.01%	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%	NA	–0.01%
Change in Producer Surplus ($$10^6$/yr)	$2	NA	$4	NA	$3	NA
Applications Not Included in NDEIM	$102.4	NA	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$284.7	NA	–$284.7	NA
Social Costs ($$10^6$/yr)	$1,510.0	NA	$1,510.9	NA	$1,510.9	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

The total and variable maximum cost shift scenarios lead to different conclusions for two important variables: the estimated market price increase for diesel fuel and the estimated welfare impact for affected refineries. Under the base case (total average cost scenario), refiners pass most of the average compliance costs on to the application markets, and the net decrease in producer surplus for refiners is relatively small (about $7.8 million, or 0.6 percent of total social costs), and prices are expected to increase about 6.0 percent. Note that these are industry averages, and individual refiners will gain or lose because compliance costs vary across individual refineries.

In the total maximum cost scenario, the highest operating cost refinery determines the new market price through the impacts on both fixed and variable costs. This refinery has the highest per-unit supply shift, which leads to a higher price increase relative to the average cost scenario. As a result, all refiners except the highest cost refiner are expected to benefit from the rule, by about $526 million, because the change in market price exceeds the additional per-unit compliance costs for most of the refineries (i.e., most refiners have costs less than the costs for the highest operating cost refinery). Consequently, in this scenario the producers and consumers in the application market are expected to bear a larger share of the total cost of the program: $2,029 million compared to $1,497 million, out of total social costs of about $1,510 million for the welfare costs of the rule without considering the operating savings.

The variable maximum cost scenario is similar to the total maximum cost scenario because the highest cost refinery determines the with-regulation market price. However, the variable maximum cost scenario leads to an expected price increase that is smaller than the total maximum cost scenario because the refiner supply shift includes only variable compliance costs. In other words, the refiners do not pass along any fixed costs; they absorb the fixed costs. However, the refinery industry still experiences a small net surplus gain ($79 million) because the change in market price (driven by the maximum variable cost) exceeds the additional per-unit compliance costs for many of the refineries (i.e., many refiners still have total costs less than the costs for the highest operating cost refinery in this scenario).[Y] The net surplus gain for refiners is smaller than the total maximum scenario ($79 million compared to $596 million) because refiners absorb fixed costs, and the projected market price increase is smaller. Again, consumers and producers in the application markets are expected to bear a larger share of the total cost of the program, about $1,584 million.

The results of this sensitivity analysis suggest that the expected impacts on producers and consumers in the application markets and on refiners is affected by how refinery costs are modeled. The NDEIM models these costs based on the average (variable + fixed) cost scenario, reflecting a competitive market situation in all regional markets. However, if the highest cost refinery drives the new market price, then prices are expected to increase more, with a larger contraction in output. In this case, consumers and producers in the application market are expected to bear more than the cost of the rule. When the highest cost refinery's variable costs drive the new market price, then prices will increase slightly more that the base case (from 6 percent to 7 percent), producers and consumer will again bear more of the burden of the rule, and refiners bear less than in the base case.

[Y]Also, see Table 7.6-1 and related text in Chapter 7 regarding the possible diesel fuel price increases for the maximum operating cost scenario

10I.3 Operating Cost Scenario

In the base case analysis presented in Chapter 10, operating savings are not included in the market analysis. As explained in Section 10.3.5.3, this approach is used because these operating savings are not expected to affect consumer decisions with respect to new engines and equipment. However, these operating savings accrue to society and so they are added to social costs after changes in price and quantity are estimated. In the analysis for 2013, $284.7 million in operating savings are applied to the application markets; these savings are expected to accrue to producers in these markets. Specifically, $265.5 million are applied to the social costs for the three application markets and for the transportation services providers ($243.2 million and $22.3 million, respectively) and $19.2 million are applied to the social costs for those markets not included in NDEIM.[Z] The results of this base case analysis are set out in Table 10.1-4. In the summary presented in Table 10I-9, all of the operating savings are presented as a separate item.

In this sensitivity analysis, we modify the analysis to include operating savings in the market analysis. This scenario considers the possibility that some portion of the operating savings realized by users of nonroad engines, equipment, and fuel can be transmitted to consumers through the market relationships specified in the model, thereby affecting prices and output. The operating savings are modeled as a cost reduction (benefit) for producers in the application markets and service providers in the locomotive and marine sectors.[AA] Specifically, they are treated as negative supply shift for the supply curves in these markets. Treating operating savings like this reduces the size of the supply shift and illustrates how operating savings may be shared among producers and consumers in these markets.

The results of this sensitivity analysis are included in Table I-9. In this scenario, the price increase and quantity decrease in the application markets are expected to be smaller (0.08 percent compared to 0.10 percent for price, and -0.01 percent compared to -0.02 percent for quantity). This is a direct result of the smaller supply shift. Although the estimated total social costs associated with the rule are comparable for both scenarios, $1,510.1 million compared to $1.510.0 million in the base case, there are two important *distributional* consequences associated with including operating savings in the market analysis. First, almost all of the locomotive and marine savings ($22 million) are now directly passed to the application markets in the form of lower prices. As a result, the application markets benefit from operating savings in transportation services and they bear 80.6 percent of the total social costs instead of 83.4 percent (the change in total application market surplus decreases from $1,254 to $1,234 million). Second, a portion of the operating savings is now distributed to consumers in application markets. In 2013, the change in consumer surplus in the application markets decreases from $876 million to $709 million. The change in producer surplus is smaller, and decreases from

[Z] See Section 10.3.5.3 for a description of how the operating savings are estimated.

[AA] We only consider cost savings for market included in NDEIM (the three application markets and the transportation service markets). This amounts to $265 million, or 93 percent of the operating savings. The remaining $19 million is added as a line item to the social costs for application markets not included in NDEIM.

$621 to $525 million.

Table 10I-9
Operating Savings Included in the Market Analysis[a,b]

Scenario	Base Case (2013) Absolute Change	Base Case (2013) Relative Change (%)	Adding Operating Savings To App Absolute Change	Adding Operating Savings To App Relative Change (%)
Application Markets				
Price ($/q)	NA	0.10%	NA	0.08%
Quantity (q/yr)	NA	–0.02%	NA	–0.01%
Change in Consumer Surplus	$876	NA	$709	NA
Change in Producer Surplus	$621	NA	$525	NA
Change in Total Surplus ($$10^6$/yr)	$1,497	NA	$1,234	NA
Equipment Markets				
Price ($/q)	$975	2.9%	$976	2.9%
Quantity (q/yr)	–139	–0.02%	–93	–0.01%
Change in Producer Surplus	$143	NA	$142	NA
Engine Markets				
Price ($/q)	$821	21.4%	$821	21.4%
Quantity (q/yr)	–79	–0.01%	–53	–0.01%
Change in Producer Surplus	$42	NA	$42	NA
Fuel Markets				
Price ($/q)	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–1.57	–0.01%
Change in Producer Surplus	$8	NA	$6	NA
Transportation Services				
Price ($/q)	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%
Change in Producer Surplus	$2	NA	$2	NA
Applications Not Included in	$102.4	NA	$102.4	NA
Operating Savings ($$10^6$/yr)	–$284.7	NA	–$19.2	NA
Total Social Cost	$1,510.0	NA	$1,510.1	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

10I.4 Engine and Equipment Fixed Cost Shift Scenario

As discussed in Section 10.3 only the variable costs are used to shift the supply curve in the engines and equipment markets. Fixed costs are assumed to be R&D costs that are absorbed by engine and equipment markets over a 5-year period and hence do not affect market prices or quantities. As a result, producers are not able to pass any of these costs on and bear all fixed costs as a decrease in producer surplus.

In this scenario, the supply shift for engine producers includes the fixed and variable compliance costs. The results are presented in Table 10I-10. In this scenario, engine producers are able to pass along the majority of the fixed compliance costs to the downstream markets rather than absorb them as a one-to-one reduction in profits. As expected, this scenario leads to a higher projected price increases for the engine and equipment markets (from 2.9 percent in the baseline case to 3.4 percent for equipment markets and from 21.4 percent in the baseline case to 23.0 percent for engine markets), and the share of the social costs borne by these markets decreases from 9.5 percent to 0.2 percent for the equipment markets, and from 2.8 percent to 0 percent for the engine markets. These costs are passed on to the application markets, and their expected share of the compliance burden increases from 83 percent to 93 percent. However, the total social costs of the regulation are not expected to change measurably as the higher prices lead to almost no change in the demand for equipment and engines.

Table 10I-10 Fixed Costs Added to Supply Shift in Engine and Equipment Markets[a,b]

Scenario	Base Case (2013) Absolute Change	Base Case (2013) Relative Change (%)	Shocking Engine and Equipment Markets by Total Costs Absolute Change	Shocking Engine and Equipment Markets by Total Costs Relative Change (%)
Application Markets				
Price ($/q)	NA	0.10%	NA	0.11%
Quantity (q/yr)	NA	–0.02%	NA	–0.02%
Change in Consumer Surplus	$876	NA	$978	NA
Change in Producer Surplus	$621	NA	$697	NA
Change in Total Surplus	$1,497	NA	$1,675	NA
Equipment Markets				
Price ($/q)	$975	2.9%	$1,192	3.4%
Quantity (q/yr)	–139	–0.02%	–156	–0.02%
Change in Producer Surplus	$143	NA	$5	NA
Engine Markets				
Price ($/q)	$821	21.4%	$898	23.0%
Quantity (q/yr)	–79	–0.01%	–87	–0.02%
Change in Producer Surplus	$42	NA	$0	NA
Fuel Markets				
Price ($/q)	$0.06	6.0%	$0.06	6.0%
Quantity (q/yr)	–2.38	–0.02%	–2.67	–0.02%
Change in Producer Surplus	$8	NA	$9	NA
Transportation Services				
Price ($/q)	NA	0.01%	NA	0.01%
Quantity (q/yr)	NA	–0.01%	NA	–0.01%
Change in Producer Surplus	$2	NA	$3	NA
Applications Not Included in	$102.4	NA	$102.4	NA
Operating Savings ($\$10^6$/yr)	–$284.7	NA	–$284.7	NA
Social Costs ($\$10^6$/yr)	$1,510.0	NA	$1,509.9	NA

[a] Sensitivity analysis is presented for 2013.
[b] Figures are in 2002 dollars.

10I.5 Alternative Social Discount Rates

Future benefits and costs are commonly discounted to account for the time value of money.

The market and economic impact estimates presented in Section 10.1 calculate the present value of economic impacts using a social discount rate of 3 percent, yielding a total social cost of $27.2 billion. The 3 percent discount rate reflects the commonly used substitution rate of consumption over time. An alternative is the OMB-recommended discount rate of 7 percent that reflects the commonly used real private rate of investment. Table 10I-11 shows the present value calculated over 2004 to 2030 using both the 3 and 7 percent social discount rates. With the 7 percent social discount rate, the present value of total social costs decreases to $13.9 billion.

Table 10I-11. Net Present Values[a]

	NPV (3%)			NPV (7%)		
	Market Surplus (10^6)	Operating Cost Savings (10^6)	Total	Market Surplus (10^6)	Operating Cost Savings (10^6)	Total
Engine Producers Total	$256		$256	$180		$180
Equipment Producers Total	$1,162		$1,162	$740		$740
Construction Equipment	$545		$545	$343		$343
Agricultural Equipment	$397		$397	$255		$255
Industrial Equipment	$220		$220	$141		$141
Application Producers & Consumers Total	$28,429	–$3,757	$24,672	$14,663	–$2,309	$12,354
Total Producer	$11,838			$6,096		
Total Consumer	$16,591			$8,567		
Construction	$11,526	–$1,779	$9,746	$5,922	–$1,093	$4,829
Agriculture	$8,181	–$1,208	$6,973	$4,222	–$742	$3,480
Manufacturing	$8,723	–$770	$7,953	$4,519	–$473	$4,046
Fuel Producers Total	$169		$169	$86		$86
PADD 1 & 3	$85		$85	$43		$43
PADD 2	$69		$69	$35		$35
PADD 4	$3		$3	$1		$1
PADD 5	$12		$12	$6		$6
Transportation Services Total	$1,653		$973	$900		$508
Locomotive	$31	–$160	–$129	$16	–$97	–$82
Marine	$18	–$204	–$187	$9	–$113	–$104
Application Markets Not Included in NDEIM	$1,604	–$315	$1,288	$875	–$182	$693
Total	$31,669	–$4,437	$27,232	$16,569	–$2,701	$13,868

[a] Figures are in 2001 dollars.
[b] Figures are in 2002 dollars.

CHAPTER 11: Small-Business Flexibility Analysis

This chapter discusses our Final Regulatory Flexibility Analysis, which evaluates the potential impacts of new standards on small entities. Pursuant to the requirements of the Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), which generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Prior to issuing a proposal for this rulemaking, we analyzed the potential impacts of these regulations on small entities. As a part of this analysis, we convened a Small Business Advocacy Review Panel (SBAR Panel, or 'the Panel'). During the Panel process, we gathered information and recommendations from Small Entity Representatives (SERs) on how to reduce the impact of the rule on small entities, and those comments are detailed in the Final Panel Report which is located in the public record for this rulemaking (Docket A-2001-28, Document No. II-A-172).

11.1 Overview of the Regulatory Flexibility Act

In accordance with section 609(b) of the Regulatory Flexibility Act, we convened an SBAR Panel before conducting the Regulatory Flexibility Analysis. A summary of the Panel's recommendations can be found in our proposal. Further, the Final Panel Report contains a detailed discussion of the Panel's advice and recommendations (as well as the SER recommendations). The regulatory alternatives that are being adopted in this final rule are described below.

Section 609(b) of the Regulatory Flexibility Act further directs the Panel to report on the comments of small entity representatives and make findings on issues related to identified elements of the Regulatory Flexibility Analysis under section 603 of the Regulatory Flexibility Act. Key elements of a Regulatory Flexibility Analysis are:

- a description and, where feasible, an estimate of the number of small entities to which the proposed rule applies;
- projected reporting, record keeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that would be subject to the rule and the type of professional skills necessary to prepare reports or other records;
- an identification, to the extent practicable, of all other relevant federal rules that may duplicate, overlap, or conflict with the proposed rule;
- any significant alternatives to the proposed rule that accomplish the stated objectives of applicable statutes and that minimize any significant economic impact of the proposed rule on small entities.

The Regulatory Flexibility Act was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. Although we are not required by the Clean Air Act to provide special treatment to small businesses, the Regulatory Flexibility Act requires us to carefully consider the economic impacts that our rules will have on small entities. The recommendations made by the Panel may serve to help lessen these economic impacts on small entities when consistent with Clean Air Act requirements.

11.2 Need for the Rulemaking and Rulemaking Objectives

A detailed discussion on the need for and objectives of this rule are in the preamble to the final rule. Controlling emissions from nonroad engines and equipment, in conjunction with diesel fuel controls, has important public health and welfare benefits. With the advent of more stringent controls on highway vehicles and their fuels, emissions from nonroad sources, unless controlled, will contribute significantly more harmful pollution than those from highway sources.

Section 213(a)(3) of the Clean Air Act requires EPA to regulate NOx emissions from nonroad engines and vehicles upon an EPA determination that nonroad engines contribute to emissions in a nonattainment area. In part, section 213(a)(3) authorizes EPA to promulgate standards for designated pollutants (including NOx) that require the greatest degree of emission reduction achievable from application of technology to nonroad engines (or vehicles) while giving "appropriate consideration to the cost of applying such technology within the period of time available to manufacturers and to noise, energy, and safety factors associated with the application of such technology." Section 213(a)(4) applies to all pollutants not specifically identified in section 213(a)(3), and authorizes EPA to promulgate "appropriate" standards for such pollutants, taking into account "costs, noise, safety, and energy factors associated with the application of technology which the Administrator determines will be available" for those engines (or vehicles). Controls on PM implement this provision.

Similarly, section 211(c)(1) authorizes EPA to regulate fuels if any emission product of the fuel causes or contributes to air pollution that may endanger public health or welfare, or that may impair the performance of emission-control technology on engines and vehicles. We believe there is an opportunity for cost-effective emission reductions on a large scale.

11.3 Issues Raised by Public Comments

During the public comment period we received numerous comments regarding various aspects of the NPRM, including our proposed small business provisions. The following section provides a summary of the comments that we received on our proposed provisions. More information on these comments can be found in the Final Summary and Analysis of Comments, which is a part of the rulemaking record.

11.3.1 Comments Regarding Small Business Engine and Equipment Manufacturers

One small business engine manufacturer commented that the proposed provisions for small manufacturers are appropriate and strongly supported their inclusion in the final rule. The manufacturer raised many concerns of why it believes that it is necessary to include such provisions, such as: larger/higher-volume manufacturers will have priority in supply of new technologies and will thus have more R&D time to complete development of these systems before they are available to smaller manufacturers; and, smaller manufacturers do not command the same amount of attention from potential suppliers of critical technologies for T4 controls, and are thus concerned that they may not be able to attract a manufacturer to work with them on the development of compliant technologies. The small manufacturer believes that the additional three-year time period proposed for small business engine manufacturers in the NPRM is necessary for its company, and is the company's estimate of the time that it will take for these technologies to be available to small engine manufacturers.

The Small Business Administration's Office of Advocacy ("Advocacy") raised the concern that the rule would impose significant burdens on a substantial number of small entities with little corresponding environmental benefit. Advocacy commented that we should exclude smaller engines (those under 75 hp) from further regulation in order to comply with the Regulatory Flexibility Act and fulfill the requirement of reducing the burden on small engine classes. Advocacy recommended that PM standards for engines in the 25-75 hp powerband should not be based on performance of aftertreatment technologies. Advocacy believes that the proposed flexibilities will not suffice on their own to appropriately minimize the regulatory burdens on small entities; and Advocacy noted that during the SBREFA process, some small equipment manufacturers stated that although EPA would allow some equipment to be sold which would not require new emissions controls, engine manufacturers would not produce or sell such equipment. Advocacy also commented that we have not shown that substantial numbers of small businesses have taken advantage of previous small business flexibilities, or that small businesses would be able to take advantage of the flexibilities under this rule. Lastly, Advocacy commented that although full compliance with the more stringent emissions controls requirements would be delayed for small manufacturers, small business manufacturers eventually will be required to produce equipment meeting the new requirements.

11.3.2 Comments Regarding Small Fuel Refiners, Distributors, and Marketers

11.3.2.1 General Comments on Small Refiner Flexibility

One small refiner commented that it is not plausible at this time to evaluate the impact of the three fuels regulations on the refining industry (and small refiners), however it stated that we should continue to evaluate the impacts and act quickly to avoid shortages and price spikes and we should be prepared, if necessary, to act quickly in considering changes in the regulations to avoid these problems. We also received comment that some small refiners that produce locomotive and marine fuels fear that future sulfur reductions to these markets could be very damaging.

11.3.2.2 Comments on the Small Refiner Definition

A small refiner commented that the proposed redefinition of a small refiner (to not grandfather as small refiners those that were small for highway diesel) would both negate the benefits afforded under the small refiner provisions in the Highway Diesel Sulfur rule and disqualify its status as a small refiner. The refiner suggested that we clarify the language and include provisions for continuance of small refiner flexibility for refiners who qualified under the Highway Diesel Sulfur rule (and have not been disqualified as the result of a merger or acquisition).

11.3.2.3 Comments on the Baseline Approach

A coalition of small refiners provided comments on a few aspects of concern. The small refiners believe that the fuel segregation, and ensuing marking and dying, provisions are quite complex. One small refiner believes that mandating a minimum volume of NRLM production would conflict with the purpose of maintaining adequate on-highway volumes of 15ppm sulfur fuel and unnecessarily restricts small refiners, and offered suggestions in their comments on how to improve the language.

11.3.2.4 Comments on Small Refiner 'Option 4'

A coalition of small refiners commented that if the final rule is not issued before January 1, 2004, a provision should be made to accommodate those small refiners planning to take advantage of the proposed small refiner "Option 4" (the NRLM/Gasoline Compliance option). A small refiner echoed the concerns of the small refiner coalition, commenting that delayed finalization of the final rule would undermine the benefits of small refiner flexibility Option 4. The small refiner is concerned that a delay in issuing the rule, and subsequent delay in the opportunity to apply the interim gasoline flexibility, would negate its opportunity to take full advantage of the credits the refiner now has, as it would not be able to comply with the 300 ppm cap. The small refiner suggested that we allow small refiners to apply for temporary relief and operate under the Option 4 provision.

A small refiner commented that, in the NPRM, it was unclear if a small refiner could elect to use any or all of the first three of the small refiner provisions if it did not elect to use Option 4. Further, the refiner understood that if Option 4 was chosen, a small refiner could not use any of the first three options. The refiner believes that it is important that a small refiner be able to use Options 1, 2, and 3 in combination with each other, and stated that we need to clarify the intent in the final rule. The small refiner also commented that the provisions in 40 CFR §§ 80.553 and 80.554 are not clear and should be revised to clarify their intent. Specifically, the refiner questioned whether or not a small refiner who committed to producing ULSD by June 1, 2006 in exchange for an extension of its interim gasoline sulfur standards (under 40 CFR 80.553) could elect to exercise the options allowed under 40 CFR 80.554.

Another small refiner raised the concern that the small refiner Option 4 only provides an adjustment to those small refiners whose small refiner gasoline sulfur standards were established through the hardship process of 40 CFR § 80.240. The small refiner suggested that we finalize a compliance option that allows a 20% increase in small refiner gasoline sulfur standards be extended to all small refiners, not just those with standards established pursuant 40 CFR § 80.240(a), and offers suggested language in its comments.

11.3.2.5 Comments on Emission Impacts of the Small Refiner Provisions

A state environmental group commented that the provisions for small refiners raise substantial environmental concerns. The group is concerned that these provisions will allow small refiners the ability to produce gasoline with an unknown sulfur content for an unknown length of time; this fuel may then be sold at the refiner's retail outlet, and may become the primary fuel for some vehicles, which alters vehicle fleet emissions performance. This environmental group also commented that the absence of any process of notification regarding small business provisions to notify States of these provisions is troubling. The group's concern is that any deviations from fuel content regulations that affect fuels consumed, can significantly alter their inventories and can undermine the State planning process. The group suggested that in the future there should be greater communication from us regarding decisions that impact the quality of fuels consumed in a state, and thus impact the quality of that state's air.

Another state environmental group commented on the flexibility provisions for small refiners; the group is concerned that the exemption will *not* have a minor effect on the nation's fuel supply, as the state is an intermountain western state. The group comments that the impact of this exemption is concentrated in these states, namely Washington and Oregon- states which are served primarily by refineries that will be allowed to delay compliance with the ULSD standards until 2014. Therefore, the group commented, residents of these areas are denied air quality benefits equivalent to those promised the rest of the country. The group is concerned that those seeking to purchase and use equipment in the West will be subject to the ULSD standard regardless of fuel supply and availability in their area. Further, they would be faced with problems such as misfueling, the need to defer the purchase of new equipment, or paying a premium for a 'boutique' fuel.

11.3.2.6 Comments on Inclusion of a Crude Capacity Limit for Small Refiners

Two non-small refiners supported the inclusion of the 155,000 bpcd limit; further, one refiner commented that any refiner with the financial wherewithal to acquire additional refineries to allow its crude capacity to exceed 155,000 bpcd should not be able to retain status as a small refiner. Another commenter stated that if we were to finalize the 155,000 bpcd limit, we should not apply it in cases of a merger between two small refiners. The commenter further stated that a merger of two small companies in a hardship condition does not imply improved financial health in the same way that an acquisition would. A small refiner is commented that it supports the addition of the capacity limit in the small refiner definition as it would correct the problem of the inadvertent loop-hole in the two previous fuel rules. Though the refiner did raise the concern that the wording of the proposed language may result in small refiners such as itself, who grew by normal business practice, being disqualified as small refiners.

11.3.2.7 Comments on Leadtime Afforded for Mergers and Acquisitions

A non-small refiner suggested that we limit the provision of affording a two-year leadtime to small refiners who lose their small status due to merger or acquisition to the case where a small refiner merges with another small refiner. Further, the refiner commented that it would be inappropriate to allow such small refiners to be able to generate credits for "early" production of lower sulfur diesels during this two-year leadtime. Lastly, the refiner commented that a small refiner which acquires a non-small refiner, and thus loses its small refiner status, should not be eligible for hardship provisions. Another non-small refiner commented that it supports the two-year lead time for refineries that lose their status as a small refiner due to a merger or acquisition.

11.3.2.8 Necessity of Small Refiner Program

A non-small refiner provided comment on the NPRM stating the belief that the proposed provisions for small refiners are not practical. The refiner is concerned that having provisions for small refiners adds a level of complication, results in emissions losses, increases the potential for ULSD contamination, and create an unfair situation in the marketplace. Similarly, another non-small refiner and a trade group representing many refiners and others in the fuels industry commented that they oppose the extension of compliance deadlines for small refiners, as this can result in inequitable situations that may affect the refining industry for some time and can put the distribution system at risk for contamination of lower sulfur fuels. They further stated that all refiners will face challenges in complying with the upcoming standards and would not significantly alter the business decisions that small refiners would make. They also stated that non-small refiners face similar issues with their older and/or smaller refineries, but will not have the benefit of being able to postpone making these decisions as small refiners will.

11.3.2.9 Comments on Fuel Marker

We received comments from terminal operators stating that the proposed heating oil marker requirements would force small terminal operators to install expensive injection equipment and that they would not be able to recoup the costs.

11.4 Description of Affected Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For assessing the impacts of the rule on small entities, a small entity is defined as: (1) a small business that meets the definition for business based on the Small Business Administration's (SBA) size standards (see Table 11-1); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field. Table 11-1 provides an overview of the primary SBA small business categories potentially affected by this regulation.

The following sections discuss the small entities directly regulated by this final rule—namely nonroad diesel engine manufacturers, nonroad diesel equipment manufacturers, and nonroad fuel refiners and fuel marketers/distributors. Also, Table 11-2 lists our assessment of the number of small entities that will be directly affected by this rulemaking.

Table 11-1
Small Business Definitions

Industry	Defined as small entity by SBA if:	Major SIC Codes[a]
Engine manufacturers	Less than 1,000 employees	Major Group 35
Equipment manufacturers: - construction equipment - industrial truck manufacturers (i.e., forklifts) - all other nonroad equipment manufacturers	 Less than 750 employees Less than 750 employees Less than 500 employees	 Major Group 35 Major Group 35 Major Group 35
Fuel refiners	Less than 1500 employees[b]	2911
Fuel distributors	*varies*	*varies*

[a] Standard Industrial Classification
[b] In previous rulemakings to set fuel requirements, we have included a provision that a refiner must also have a company-wide crude refining capacity of no greater than 155,000 barrels per calendar day to qualify for the small-refiner flexibilities,. We have included this criterion in the small-refiner definition for this final rule.

Table 11-2
Number of Small Entities To Which the Nonroad Diesel Rule Will Apply

Industry	Defined as small entity by SBA if:	Number of Affected Entities
Engine manufacturers	Less than 1,000 employees	4[a]
Equipment manufacturers	(see criteria in Table 11-1)	335[a]
Fuel refiners	Less than 1500 employees	26
Fuel distributors	*varies*	(see discussion in 11.4.2.2)

[a] The numbers of affected entities for these categories are taken from the total number of companies that were used in our screening analysis (i.e., companies with publicly available employee and sales data).

11.4.1 Description of Nonroad Diesel Engine and Equipment Manufacturers

To assess how many small engine and equipment manufacturers would be directly affected by the rule, we first created a database consisting of firms listed in the Power Systems Research (PSR) database and compared this with the list of companies from the analysis performed for the 1998 nonroad final rule and with membership lists from trade organizations. We then found sales and employment data for the parent companies of these firms using databases such as the Thomas Register and Dun and Bradstreet. Due to the wide variety in the types of equipment that use nonroad diesel engines, there are numerous SIC codes in which the equipment manufacturers report their sales, though the majority of the firms are listed under the SIC major group 35xx-*Industrial and Commercial Machinery and Computer Equipment*.

We conducted a preliminary industry profile to identify the engine and equipment manufacturers that are in the nonroad diesel sector. We identified more than 1,000 businesses that fit this description; however, due to a lack of publicly available sales or employment data, some of these entities could not be confirmed for consideration in the analysis.

11.4.1.1 Nonroad Diesel Engine Manufacturers

Using information from the preliminary industry profile, we identified a total of 61 engine manufacturers. The top 10 engine manufacturers comprise over 80 percent of the total market, while the other 51 companies make up the remaining percentage.[A] Of the 61 manufacturers, four fit the SBA definition of a small entity. These four manufacturers were Anadolu Motors, Farymann Diesel GmbH, Lister-Petter Group, and V & L Tools (parent company of Wisconsin Motors LLC, formerly 'Wis-Con Total Power'). These businesses comprise approximately 8 percent of the total engine sales for the year 2000. Lister Petter and V & L Tools were the only two manufacturers which had certified engines for model year 2000.

Wisconsin Motors produces diesel engines for a small niche market and served as a Small Entity Representative (SER) during the Small Business Advocacy Review Panel process, speaking to the needs of small engine manufacturers.

11.4.1.2 Nonroad Diesel Equipment Manufacturers

This rule will result in equipment manufacturers incurring some increased costs as a result of the need to make changes to their equipment to accommodate the addition of aftertreatment technologies. The vast majority of equipment manufacturers are not integrated companies, meaning that they do not make the engines they install. Thus, most equipment manufacturers are largely dependent on engine manufacturers for the availability of pre-production information about the new engines and for a sufficient supply of the engines once production begins. Equipment manufacturers that are small businesses may, in general, face a disproportionate degree of hardship in adapting to these types of changes in design and increased costs of new, cleaner engines.

To determine the number of equipment manufacturers, we also used the industry profile that was conducted. From this, we identified more than 700 manufacturers with sales and/or employment data that could be included in the screening analysis. These businesses included manufacturers in the construction, agricultural, and outdoor power equipment (mainly, lawn and garden equipment) sectors of the nonroad diesel market. The equipment produced by these manufacturers ranged from small (sub-25 hp walk-behind equipment) to large (in excess of 750

[A] All sales information used for this analysis was 2000 data.

hp, such as mining and construction equipment). Of the manufacturers with available sales *and* employment data (approximately 500 manufacturers), small equipment manufacturers represent 68 percent of total equipment manufacturers (and these manufacturers account for 11 percent of nonroad diesel equipment industry sales). Thus, the majority of the small entities that could potentially experience a significant impact as a result of this rulemaking are in the nonroad equipment manufacturing sector.

While a few small equipment manufacturers did serve as SERs during the SBREFA Panel process, a trade association representing many equipment manufacturers also served as a SER. We believe that due to the large number of small equipment manufacturers, this SER was better able to contact and disseminate information to the large universe of small entities in this category and serve as a voice for some of the extremely small equipment manufacturers.

11.4.2 Description of the Nonroad Diesel Fuel Industry

The analysis that we developed for the refining industry is built on analyses that were performed for the gasoline and highway diesel sulfur programs in recent years. Information about the characteristics of refiners came from sources including the Energy Information Administration within the U.S. Department of Energy, and from oil industry literature. Our assessment was that the refining industry is located primarily in SIC 2911. In both the gasoline sulfur and highway diesel sulfur rules, we applied specific small-refiner flexibilities to refiners that have no more than 1500 employees and no greater than 155,000 barrels per calendar day crude capacity. For transporters, distributors, and marketers of nonroad diesel fuel, trade groups were our key sources for information about this industry. We determined that this industry sector includes several types of businesses that fall into several different SBA small entity criteria; our assessment was that the vast majority of these entities are small.

11.4.2.1 Nonroad Diesel Fuel Refiners

Our assessment is that 26 high-sulfur (nonroad and locomotive and marine) refiners, collectively owning 33 refineries, meet SBA's definition of a small business for the refining industry. The 33 refineries appear to meet both of the employee number and production volume criteria mentioned above, out of a total of approximately 91 nonroad refineries. These small refiners produce approximately 6 percent of the total high-sulfur diesel fuel. Note that because of the dynamics in the refining industry (such as mergers and acquisitions), this figure could likely change.

A few small refiners, as well as representatives of an ad-hoc coalition of some of the small refiners participated in the SBREFA process. These small refiners, and those in which they represented, provide high sulfur diesel fuel for various non-highway markets and applications, and own and operate refineries throughout the country.

11.4.2.2 Nonroad Diesel Fuel Distributors and Marketers

The industry that transports, distributes, and markets nonroad diesel fuel encompasses a wide range of businesses, including bulk terminals, bulk plants, fuel oil dealers, and diesel fuel trucking operations, and totals thousands of entities that have some role in this activity. More than 90 percent of these entities meet small-entity criteria. Common carrier pipeline companies are also a part of the distribution system; 10 of them are small businesses.

Similar to the nonroad small business equipment sector, the universe of nonroad fuel distributors and marketers is quite large, so representatives of fuel pipeline and fuel marketing trade groups participated in the SBREFA process. We believe that these representatives were very capable of speaking to the needs of their members that are small entities and were also better able to disseminate SER outreach information to these markets.

11.5 Projected Reporting, Recordkeeping, and Other Compliance Requirements of the Regulation

For engine and equipment manufacturers, EPA is continuing many of the reporting, recordkeeping, and compliance requirements prescribed for these categories in 40 CFR part 89. These include, certification requirements and provisions related to reporting of production, emissions information, use of transition provisions, etc. The types of professional skills required to prepare reports and records is also similar to the types of skills set out in 40 CFR part 89. Key differences in the requirements of this final rule, as compared to 40 CFR part 89, are the reporting of emissions information and defect reporting -- we are finalizing an increase in the number of data points (i.e. transient testing) that will be required for reporting emissions information, as well as adopting an increased reporting burden for Tier 3 and earlier engines for defect reporting. In addition, we are requiring that manufacturers report to us if they learn that a substantial number of their engines have emission-related defects. This is generally not an affirmative requirement to collect information. However, if manufacturers learn that there are, or might be, a substantial number of emission-related defects, then they must send us information describing the defects.

For any fuel control program, we must have the assurance that fuel produced by refiners meets the applicable standard, and that the fuel continues to meet this standard as it passes downstream through the distribution system to the ultimate end user. Which is of particular importance in regards to diesel fuel, since the aftertreatment technologies expected to be used to meet the engine standards are highly sensitive to sulfur. Many of the recordkeeping, reporting, and compliance provisions we are finalizing are fairly consistent with those currently in place for other fuel programs, including the current 15 ppm highway diesel regulation. For example, recordkeeping involves the use of product transfer documents, which are already required under the 15 ppm highway diesel sulfur rule (40 CFR 80.560). We are finalizing additional recordkeeping and reporting requirements for refiners, importers, and fuel distributors to implement the designate and track provisions. Discussions with parties from all segments of the distribution system indicated that the records necessary were analogous to records already kept as a normal process of conducting business. Consequently, the only significant additional burden would be associated with the reporting requirement.

General requirements for reporting for refiners and importers include: registration (if the refiner or importer is not registered under a previous fuel program), pre-compliance reports (on a refiner or importer's progress towards meeting the nonroad diesel fuel requirements as specified in this rule), quarterly designation reports, and annual reports. All parties, from the refiner to the terminal, will be required to report volumes of designated fuels received and distributed, as well as compliance with quarterly and annual limits. All parties in the distribution system will be required to keep product transfer documents (PTDs), though refiners and importers are required to initially generate and provide information on commercial PTDs that identify the diesel fuel with meeting specific needs (i.e. 15 ppm highway diesel, 500 ppm highway diesel, etc.). Also, small refiners in Alaska that choose to delay compliance must, at a minimum, report end users of their fuel. These end users must at a minimum also keep records of these fuel purchases. As with previous fuel regulations, small refiners will be required to apply for small refiner status and small refiner baselines.

In general, we are requiring that all records be kept for at least five years. This recordkeeping requirement should impose little additional burden, as five years is the applicable statute of limitations for current fuel programs.

Section X.B of the preamble to the final rule includes a discussion of the estimated burden hours and costs of the recordkeeping and reporting that will be required by this final rule. Detailed information on the reporting and recordkeeping measures associated with this rulemaking are described in the Information Collection Requests (ICRs), also located in the preamble to this rulemaking-- 1897.05 for nonroad diesel engines, and 1718.05 for fuel-related items.

11.6 Steps to Minimize Significant Economic Impact on Small Entities

As a part of the SBREFA process, we conducted outreach to a number of small entities representing the various sectors covered in this rulemaking and convened a Panel to gain feedback and advice from these representatives. Prior to convening the Panel, we held outreach meetings with the SERs to learn the needs of small businesses and potential challenges that these entities may face. The outreach meetings also helped to provide the SERs an opportunity to gain a better understanding of the upcoming standards. The feedback that we received from SERs as a result of these meetings was used during the Panel convening for developing regulatory alternatives to mitigate the impacts of the rulemaking on small businesses. General concerns raised by SERs during the SBREFA process were potential difficulty and costs of compliance with the upcoming standards.

The Panel consisted of members from EPA, the Office of Management and Budget (OMB), and the Small Business Administration's Office of Advocacy ('Advocacy'). Following the Panel convening, a Final Panel Report detailing all of the alternatives that were recommended by the

Panel (as well as individual Panel members) was issued. We either proposed or requested comment on the various recommendations put forth by the Panel. Below we discuss those flexibility options recommended in the Panel Report, our proposed regulatory alternatives, and those provisions which are being finalized. We are finalizing many of the provisions recommended by the Panel, with exceptions noted below. We believe that the provisions that we are finalizing will help to mitigate the burden imposed upon small entities in complying with this rule.

11.6.1 Transition and Hardship Provisions for Small Engine Manufacturers

11.6.1.1 Panel Recommendations

The following provisions were recommended by the Panel for nonroad diesel small business engine manufacturers. During the SBREFA process and the development of the rule, we considered both a one-step approach as well as the two-step approach in the final rule. To be eligible for the recommended provisions set out below, a manufacturer would have to have certified in model year 2002 or earlier and would be limited to 2500 units per year (to allow for some market growth). The Panel recommended these qualifications to prevent misuse of the transition and hardship provisions as a way to enter the nonroad diesel market or to gain unfair market position relative to other manufacturers.

For an approach that entails only one phase of standards, the Panel recommended that a manufacturer could opt to delay compliance for a period of up to three years. The Panel also recommended that we take comment on whether this delay period should be two, three, or four years. Each delay would be pollutant-specific (i.e., the delay would apply to each pollutant as it is phased in).

For an approach with two phases of standards the Panel recommended the following transition provisions:

- an engine manufacturer could skip the first phase and comply on time with the second; or,
- a manufacturer could delay compliance with each phase of standards for up to two years.

The Panel recommended that there should not be any PM aftertreatment-based standards for engines between 25 and 75 hp. It was also recommended by the Panel that an emission-credit program of averaging, banking, and trading (ABT) be included as part of the overall rulemaking program.

The Panel recommended that two types of hardship provisions be extended to small engine manufacturers. These provisions are:

- for the case of a catastrophic event or other extreme unforseen circumstances beyond the control of the manufacturer that could not have been avoided with reasonable discretion (such as fire, tornado, or supplier not fulfilling contract); and

- for the case where a manufacturer has taken all reasonable business, technical, and economic steps to comply but cannot do so.

The Panel recommended that either hardship relief provision could provide lead time for up to 2 years- in addition to the transition provisions- and a manufacturer would have to demonstrate to the Agency's satisfaction that failure to sell the noncompliant engines would jeopardize the company's solvency. The Panel further recommended that the Agency may require that the manufacturer make up the lost environmental benefit through the use of programs such as supplemental environmental projects.

11.6.1.2 What We Proposed

Due to the structure of the standards and their timing, we proposed transition provisions, for small engine manufacturers encompassing both approaches recommended by the Panel (with the inclusion of the 2,500 unit limit for each manufacturer). Following the recommendations of the Panel, we proposed the following transition provisions for small business engine manufacturers:

- for PM-
  - small engine manufacturers could delay compliance with the standards for up to three years for engines under 25 hp, and for engines between 75 and 175 hp (as these engines only have one standard)
  - small engine manufacturers could have the option to delay compliance for one year if interim standards are met for engines between 50 and 75 hp (for this power category we would be treating the PM standard as a two phase standard) with the stipulation that small manufacturers could not use PM credits to meet the interim standard; also, if a small manufacturer elects the optional approach to the standard (elects to skip the interim standard), no further relief would be provided

- for NOx[B]-
  - a three year delay in the program for engines in the 25-50 hp and the 75-175 hp categories, consistent with the one-phase approach recommendation above;
  - a small engine manufacturer could be afforded up to two years of hardship (in addition to the transition flexibilities) upon demonstrating to EPA a significant hardship situation;
  - small engine manufacturers would be able to participate in an averaging, banking, and trading (ABT) program (which we proposed as part of the overall rulemaking program for all manufacturers); and,
  - no NOx aftertreatment-based standards for engines 75 hp and under.

We did propose ABT provisions for all nonroad engine manufacturers to enhance the flexibility offered to engine manufacturers as they make the transition to meet the more stringent

[B] EPA did not propose a change in the NOx standard for engines under 25 hp and those between 50 and 75 hp. For these two power bands, EPA would retain the Tier 3 standards.

standards. We proposed to retain the basic structure of the current nonroad diesel ABT program, with some changes to accommodate implementation of the emission standards. Though the Panel recommended small engine manufacturer-specific ABT provisions, we did not believe it would be appropriate to provide a different ABT program for small business engine manufacturers. Discussions during the SBAR process indicated that small-volume manufacturers would need extra time to comply due to cost and personnel constraints, and we found little reason to believe that ABT provisions specific to small manufacturers would create an incentive to accelerate compliance. Small manufacturers would, of course, always be able to participate in the general ABT program.

We proposed the majority of the Panel's recommendations for small business engine manufacturers, with noted specific provision elements for PM and NOx. As we disagreed strongly with the Panel's recommendation that there not be any PM aftertreatment-based standards for engines between 25 and 75 hp, we requested comment on this recommendation, noting our strong reservations. In addition, we proposed the Panel recommended hardship provisions for small business engine manufacturers to provide a useful safety valve in the event of unforeseen extreme hardship.

11.6.1.3 Provisions Being Finalized in This Rule

For nonroad diesel small business engine manufacturers, we are finalizing many of the transition and hardship provisions that we proposed; we are finalizing some revisions to the transition provisions, as described below, and we are finalizing all of the hardship provisions that were proposed. While we believe that emissions from nonroad engines have a significant effect on emissions, we also believe that offering these transition provisions to small business engine manufacturers will have a negligible effect on air quality and the emissions inventory, and provide an appropriate measure of lead time for these small entities. Further, we continue to believe that a complete exemption from the upcoming standards (even assuming that such an exemption could be justified legally) would put small business engine manufacturers at a competitive disadvantage as eventually the rest of the market will be producing engines that are compliant with these new standards and the equipment produced will only be able to accommodate these compliant engines. With the transition provisions, small business engine manufacturers will be in compliance with the Tier 4 standards in the long run and the flexibility options will give them appropriate lead time to comply. Further, we received comments from a small business engine manufacturer stating that such provisions are necessary and adequate to ease the burden of compliance with the upcoming standards. As such, we believe that the transition provisions we are adopting will be of significant help for small business engine manufacturers, and is part of our consideration of appropriate costs in assessing lead time pursuant to section 213 (b) of the Act.

We are finalizing the following transition provisions for small business engine manufacturers:

For engines under 25 hp-

- PM- a manufacturer may elect to delay compliance with the standard for up to three years.
- NOx- there is no change in the level of the existing NOx standard for engines in this category, so no special provisions are being provided.

For engines in the 25-50 hp category-

- PM- manufacturers must comply with the interim standards (the Tier 4 requirements that begin in model year 2008) on time, and may elect to delay compliance with the 2013 Tier 4 requirements (0.02 g/bhp-hr PM standard) for up to three years.
- NOx- a manufacturer may elect to delay compliance with the standard for up to three years.

For engines in the 50-75 hp category-

- PM- A small business engine manufacturer may delay compliance with the 2013 Tier 4 requirement of 0.02 g/bhp-hr PM for up to three years provided that it complies with the interim Tier 4 requirements that begin in model year 2008 on time, without the use of credits. Alternatively, a manufacturer may elect to skip the interim standard completely. Manufacturers choosing this option will receive only one additional year for compliance with the 0.02 g/bhp-hr standard (i.e. compliance in 2013, rather than 2012). See Section III.C of the preamble to the final rule for a fuller explanation of these provisions.
- NOx- there is no change in the level of the NOx standard for engines in this category, therefore no special provisions are being provided.

For engines in the 75 to 175 hp category-

- PM- a manufacturer may elect to delay compliance with the standard for up to three years.
- NOx- a manufacturer may elect to delay compliance with the standard for up to three years.

Regarding the Office of Advocacy's comments on the technical feasibility of PM and NOx aftertreatment devices. As we proposed in the NPRM, we are not adopting standards based on performance of NOx aftertreatment technologies for engines under 75 hp. We believe the factual record, as documented in the preamble, the Summary and Analysis of Comments (e.g., the response to comment 3.1.4.3), and elsewhere in this RIA, does not support the claim that the PM standards will not be technically feasible in 2013 for the 25-75 hp engines. As set out at length in Section 4.1.3, among other places, performance of PM traps is not dependent on engine size. Furthermore, as we discussed in the preamble to this final rule and earlier in Chapter 6, we believe that such standards are feasible for these engines at reasonable cost[C], and will help to improve very significant air quality problems, especially by reducing exposure to diesel PM and by aiding in attainment of the PM 2.5 and ozone National Ambient Air Quality Standards. Indeed, given these facts, we do not believe that an alternative of no aftertreatment-based PM standards for these engines would be appropriate under section 213(a)(4). We believe the transition and hardship provisions being finalized for small business engine manufacturers in this

[C] As the cost issues raised in SBA's comments relate to all manufacturers (not just small business manufacturers), further information on the costs of this technology as well as the benefits analysis, can be found in Section VI of this preamble (and also Chapters 6 and 9, respectively).

rule are reasonable and are a factor in our ultimate finding that the PM standards for engines in the 25-75 hp range are appropriate, and that the lead time provided for these standards is the earliest possible after appropriate consideration of compliance costs.

11.6.2 Transition and Hardship Provisions for Nonroad Diesel Equipment Manufacturers

11.6.2.1 Panel Recommendations

For small business equipment manufacturers the Panel recommended that we propose to continue the transition provisions offered for the Tier 1 and Tier 2 nonroad diesel emission standards, as set out in 40 CFR 89.102, with some modifications. Those recommended transition provisions were:

- *Percent-of-Production Allowance*: Over a period of seven model years, equipment manufacturers may install engines not certified to the new emission standards in an amount of equipment equivalent to 80 percent of one year's production. This would be implemented by power category with the average determined over the period in which the flexibility is used.

- *Small-Volume Allowance*: A manufacturer could exceed the 80 percent allowance in seven years as described above, provided that the previous Tier engine use does not exceed 700 total over seven years, and 200 in any given year. This would be limited to one family per power category. Alternatively, the Panel recommended, at the manufacturer's choice by power category, a program that eliminates the "single family provision" restriction with revised total and annual sales limits as shown below:
    - For power categories below 175 hp, a manufacturer could use 525 previous Tier engines (over seven years) with an annual cap of 150 units (these engine numbers are separate for each of the three power categories defined in the regulations).
    - For power categories above 175 hp, a manufacturer could use 350 previous Tier engines (over seven years) with an annual cap of 100 units (these engine numbers are separate for each of the two power categories defined in the regulations).

  The Panel recommended that we seek comment on the total number of engines and annual cap values listed above. Advocacy believed the transition to the Tier 4 technology will be more costly and technically difficult, and therefore suggested that small business equipment manufacturers may therefore need more liberal flexibility allowances especially for equipment using the lower hp engines. SBA and OMB recommended that we seek comment on implementing the small-volume allowance (700 engine provision) for small equipment manufacturers without a limit on the number of engine families that could be covered in any power category, as these Panel members were concerned that the Panel's recommended flexibility might not adequately address the approximately 50 percent of small business equipment models where the annual sales per model is less than 300 and the fixed costs are higher.

- An allowance for small business equipment manufacturers to be able to borrow from the Tier3/Tier 4 flexibilities for use in the Tier 2/Tier 3 time frame.

The Panel recommended that - similar to the application of flexibility options that are currently in place - the three transition provisions listed above should be provided to all equipment manufacturers to maximize the likelihood that the application of these flexibilities would result in the availability of previous Tier engines for use by the small business equipment manufacturers. (See discussion on transition provisions for all equipment manufacturers in Section III.B of the preamble to this final rule.)

The Panel also recommended that we seek comment on the need for and value of special "application-specific" alternative standards for small equipment manufacturers for equipment configurations that present unusually challenging technical issues for compliance. Further, Advocacy suggested that we include a technological review of the standards in the 2008 timeframe in the proposal, and the Panel recommended that we consider this.

The Panel recommended that the following two types of hardship provisions be extended to small equipment manufacturers:

- for the case of a catastrophic event or other extreme unforseen circumstances beyond the control of the manufacturer that could not have been avoided with reasonable discretion (such as fire, tornado, or supplier not fulfilling contract); and
- for the case where a manufacturer has taken all reasonable business, technical, and economic steps to comply but cannot. In this case relief would have to be sought before there is imminent jeopardy that a manufacturer's equipment could not be sold and a manufacturer would have to demonstrate to the Agency's satisfaction that failure to get permission to sell equipment with a previous Tier engine would create a serious economic hardship. Hardship relief of this nature could not be sought by a manufacturer that also manufactures the engines for its own equipment.

11.6.2.2 What We Proposed

Following the Panel's recommendation, we proposed both the Percent-of-Production and Small-Volume Allowances for all equipment manufacturers. Within limits, small business equipment manufacturers would be able to continue to use their current engine/equipment configuration and avoid out-of-cycle equipment redesign until the allowances are exhausted or the time limit passes. We did not propose the Panel's suggested exemption and annual cap values; however, we did request comment on these items. We also requested comment on implementing the small-volume allowance provision without the single family limit provision using caps slightly lower than 700 units, with the provision being applied separately to each engine power category subject to the proposed standards.

We also proposed and requested comment on requirements associated with the use of transition provisions by foreign importers. During the SBREFA Panel process, the Panel discussed the possible misuse of the transition provisions by using them as a loophole to enter the nonroad diesel equipment market or to gain unfair market position relative to other manufacturers. The Panel recognized that this was a possible problem, and believed that the requirement for small business equipment manufacturers and importers to have reported equipment sales using certified engines in model year 2002 or earlier was a sufficient safeguard.

Upon further analysis, we found that importers of equipment from a foreign equipment manufacturer could as a group import more excepted equipment from that foreign manufacturer than 80 percent of that manufacturer's production for the U.S. market or more than the small-volume allowances identified in the transition provisions. This would create a potentially significant disparity between the treatment of foreign and domestic equipment manufacturers. We did not intend this situation, and we believe it is not needed to provide reasonable lead time for foreign equipment manufacturers.

To ensure that the transition provisions meet the intended goal of alleviating the burden on small business equipment manufacturers, we requested comment on the additional requirement that only the small business nonroad diesel equipment manufacturer that is most responsible for the installing engines, and the designing, manufacturing, and assembling processes, would qualify for the allowances provided under the small equipment manufacturer transition provisions. For importers, only a small importer that produced or manufactured nonroad diesel equipment would be eligible for these transition provisions. A small importer that does not manufacture or produce equipment does not face a burden in meeting the standards, and therefore would not receive any allowances under the transition provisions directly, but could import exempt equipment if it is covered by an allowance or by transition provisions associated with a foreign small business equipment manufacturer. We proposed this requirement to transfer the flexibility offered in the transition provisions to the party with the burden. We would also allow transition provisions and allowances to be used by foreign small business equipment manufacturers in the same way as domestic small business equipment manufacturers, while avoiding the potential for misuse by importers of unnecessary allowances.

We also proposed the Panel's recommendation that equipment manufacturers be allowed to borrow from Tier 4 flexibilities in the Tier2/3 time frame. A more detailed discussion on this issue, as well as the proposed recommendations for importers, can be found in Section VII.B of the preamble to the proposed rule, and Section III.B of the preamble to the final rule.

With regard to the Panel recommendation of a provision allowing small business manufacturers to request limited "application-specific" alternative standards for equipment configurations that present unusually challenging technical issues for compliance, we requested comment on this recommendation (in Section VII.C of the preamble to the proposed rule); however, we did not receive any public comments on this matter. We believed (and continue to believe) that the transition provisions that we proposed would provide latitude, at least in the near term, and a properly structured emission credit program for the engine manufacturers. Even if one were to assume that these flexibilities provide insufficient lead time (which may not be the case), application-specific standards would still be cumbersome for both the small business equipment manufacturers and for the Agency. Further, this provision could potentially have provided more lead time than could be justified and undermine achievable emission reductions. Moreover, no participant in the SBAR process offered any empirical support that such a problem existed, nor have such issues been demonstrated (or raised) by any equipment manufacturers in implementing the current nonroad standards. We do note, however, that we are adopting a Technical Hardship provision for all equipment manufacturers, which allows a case-by-case showing of extreme and unpreventable technical difficulty which can justify additional lead time for specific applications. See Section III.B.2.b to the preamble to the final rule. We believe that this provision meets some of the concerns voiced by the Panel.

We proposed that the Panel's recommended hardship provisions be extended to small business equipment manufacturers in addition to the transition provisions described above. To be eligible for these hardship provisions (as well as for the proposed transition provisions), equipment manufacturers and importers must have reported equipment sales using certified engines in model year 2002 or earlier. As discussed earlier, we noted this requirement to thwart misuse of the provisions as a loophole to enter the nonroad diesel equipment market or to gain unfair market position relative to other manufacturers and we request comment on this restriction. Either relief provision would provide additional lead time for small business equipment manufacturers for up to two model years based on the circumstances, and hardship relief would not be available until other allowances have been exhausted.

11.6.2.3 Provisions in the Final Rule

We are finalizing many of the transition and hardship provisions that we proposed for small business nonroad equipment manufacturers, with some modifications as noted below. Adopting an alternative on which we solicited comment, the final rule will allow all equipment manufacturers the opportunity to choose between two options:

- manufacturers would be allowed to exempt 700 pieces of equipment over seven years, with one engine family; or,
- manufacturers using the small-volume allowance could exempt
    - 525 machines over seven years (with a maximum of 150 in any given year) for each of the three power categories below 175 horsepower, and
    - 350 machines over seven years (with a maximum of 100 in any given year) for the two power categories above 175 horsepower.

Concurrent with the revised caps, manufacturers could exempt engines from more than one engine family under the small-volume allowance program. Based on sales information for small businesses, we estimated that the alternative small-volume allowance program to include lower caps and allow manufacturers to exempt more than one engine family would keep the total number of engines eligible for the allowance at roughly the same overall level as the 700-unit program.

We believe that these provisions will afford small manufacturers the type of transition leeway recommended by the Panel. Further, these transition provisions could allow small business equipment manufacturers to postpone any redesign needed on low sales volume or difficult equipment packages, thus saving decreasing the strain on financial resources and- in many cases, limited- engineering personnel. Within limits, small business equipment manufacturers would be able to continue to use their current engine/equipment configuration and avoid out-of-cycle equipment redesign until the allowances are exhausted or the time limit passes.

We are not finalizing the requirement that small equipment manufacturers and importers have reported equipment sales using certified engines in model year 2002 or earlier. Please see

Section III.C.2.a.ii of the preamble for a detailed discussion on our decision to eliminate this requirement from ths rule.

We are also finalizing three additional provisions. Two of these provisions are being finalized for all equipment manufacturers, and therefore small business equipment manufacturers may also take advantage of them. These are the Technical Hardship Provision and the Early Tier 4 Engine Incentive Program, and are discussed in greater detail in Sections III.B.2.b and e of the preamble. The third provision is being finalized for small business equipment manufacturers only, for the 20-50 hp category. This provision is discussed in greater detail in Section III.C.2.b.ii of the preamble.

11.6.3 Transition and Hardship Provisions for Nonroad Diesel Fuel Small Refiners

11.6.3.1 Panel Recommendations

During the SBREFA process, the Panel considered a range of options and regulatory alternatives for providing small refiners with flexibility in complying with new sulfur standards for nonroad diesel fuel. Taking into consideration the comments received on these ideas during the outreach meetings with SERs, as well as additional business and technical information gathered about potentially affected small entities, the Panel recommended that whether we propose a one-step or a two-step approach, we should provide for delayed compliance for small refiners as shown in Table 11-3 below.

Table 11-3
SBREFA Panel Small-Refiner Options Under
Potential 1-Step and 2-Step Nonroad Diesel Base Programs
Recommended Sulfur Standards (in parts per million, ppm) [a]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015+
1-Step Program										
Non-small [b]	--	--	15	15	15	15	15	15	15	15
Small	--	--	--	–	–	–	15	15	15	15
2-Step Program										
Non-small [c]	--	500	500	500	15	15	15	15	15	15
Small	--	--	--	--	500	500	500	500	15	15

[a] New standards are assumed to take effect June 1 of the applicable year.
[b] Assumes 500 ppm standard for marine + locomotive fuel for nonsmall refiners for 2008, and for small refiners for 2012 and later.
[c] Assumes 500 ppm standard for marine + locomotive fuel for nonsmall refiners for 2007, and for small refiners for 2010 and later.

The Panel also recommended that we propose certain provisions to encourage early compliance with lower sulfur standards. The Panel recommended that we propose that small refiners be eligible to select one of the two following options (with the maximum per-gallon sulfur cap for any small refiner remaining at 450 ppm):

- *Credits for Early Desulfurization*- The Panel recommended that we propose, as part of an overall trading program, a credit trading system that allows small refiners to generate and sell credits for nonroad diesel fuel that meets the small-refiner standards earlier than that required in the above table. Such credits could be used to offset higher sulfur fuel produced by that refiner or by another refiner that purchases the credits.

- *Limited Relief on Small-Refiner Interim Gasoline Sulfur Standards*- The Panel recommended that a small refiner producing its entire nonroad diesel fuel pool at 15 ppm sulfur by June 1, 2006, and that chooses not to generate nonroad credits for its early compliance, receive a 20 percent relaxation in its assigned small-refiner interim gasoline sulfur standards.

The Panel recommended that we propose small refiner hardship provisions modeled after those established under the gasoline sulfur and highway diesel fuel sulfur programs (see 40 CFR 80.270 and 80.560). Specifically, it was recommended that we propose a process that, like the hardship provisions of the gasoline and highway diesel rules, would allow small refiners to seek case-by-case approval of applications for temporary waivers to the nonroad diesel sulfur standards, based on a demonstration of extreme hardship circumstances. This provision was recommended as it would allow domestic and foreign refiners, including small refiners, to request additional flexibility based on a showing of unusual circumstances resulting in extreme hardship and significantly affecting the ability of the small refiner to comply by the applicable date, despite its best efforts.

11.6.3.2 What We Proposed

We proposed the small refiner transition provisions as recommended by the Panel for a two-step program (as we chose to propose a two-step fuel implementation program), which are shown in Table 11-4 below.

Table 11-4
Small-Refiner Options 2-Step Nonroad Diesel Base Programs
Recommended Sulfur Standards (in parts per million (ppm))[a]

Under 2-Step Program	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015+
Non-small[b]	—	500	500	500	15	15	15	15	15	15
Small	—	—	—	—	500	500	500	500	15	15

[a] New standards are assumed to take effect June 1 of the applicable year.
[b] Assumes 500 ppm standard for marine + locomotive fuel for nonsmall refiners for 2007 and later and for small refiners for 2010 and later.

The proposed provisions were to address the concerns that small refiners raised during the SBREFA process and during the development of the proposal, while still expeditiously achieving air quality benefits and ensuring timely availability of 15 ppm nonroad diesel fuel for the introduction of 2011 model year nonroad diesel engines and equipment.

In accordance with the Panel recommendation of encouraging early compliance with the standards, we proposed that small refiners be able to choose between the two Panel-recommended options discussed above ('Credits for Early Desulfurization' and 'Limited Relief on Small-Refiner Interim Gasoline Sulfur Standards') to provide incentives for such early compliance. Following the Panel's recommendation, we proposed that the per-gallon cap for either option could not exceed 450 ppm under any circumstances (this is also consistent with the gasoline sulfur program).

For the 'Credits for Early Desulfurization' option, we proposed that a small refiner would be able to generate NRLM diesel sulfur credits for production of 500 ppm NRLM diesel fuel before June 1, 2010, and for production of 15 ppm nonroad fuel from June 1, 2010 through May 31, 2012. During discussions with small refiners during the development of the proposal, some small refiners indicated that they might find it necessary to produce fuel meeting the nonroad diesel sulfur standards earlier than required under the small-refiner program. These small refiners listed various reasons for this, including: a limited number of grades of diesel fuel that their respective distribution systems would carry; economically advantageous to make 500 ppm or 15 ppm fuel earlier so as not to lose market share; and one small refiner indicated that it may decide to desulfurize its nonroad pool at the same time as its highway diesel fuel, in June of 2006 (due to limitations in its distribution system and to take advantage of economies of scale).

For the option of 'Limited Relief on Small-Refiner Interim Gasoline Sulfur Standards', we proposed that a small refiner qualifying for this option would receive a 20 percent revision in its interim small-refiner gasoline sulfur standards for the duration of the program (i.e., through either 2007 or 2010, depending on whether the refiner had extended its participation in the gasoline sulfur interim program by complying with the highway diesel standard at the beginning of that program (June, 2006, as provided in 40 CFR 80.552(c))), beginning January 1, 2004. In addition, we proposed that a small refiner wishing to use this option would be required to produce a minimum of 85 percent of the volume represented by its non-highway distillate baseline percentage at 15 ppm by June 1, 2006. Further, if the refiner began to produce gasoline in 2004 at the higher interim standard of this provision but then either failed to meet the 15 ppm standard for its nonroad fuel or failed to meet the 85 percent requirement, the small refiner's original interim gasoline sulfur standard would be reinstated. The refiner would then need to compensate for the higher gasoline levels that it had enjoyed by either purchasing gasoline sulfur credits or producing an equivalent volume of gasoline below the required sulfur levels.

We also requested comment on a slightly different compliance schedule which would have required small refiners to produce 15 ppm nonroad diesel fuel beginning June 1, 2013, one year earlier than proposed above. Such a schedule would align the end of the interim small-refiner provisions with the end of the proposed phase-in for nonroad engines and equipment and eliminate higher sulfur nonroad fuel from the distribution system by the time all new engines required 15 ppm fuel.

We also proposed small refiner hardship provisions, as recommended by the Panel, which are identical to those offered under the gasoline sulfur and highway diesel fuel sulfur programs. These provisions would be evaluated on a case-by-case basis to provide short-term relief to those refiners needing additional lead time due to extreme hardship circumstances.

11.6.3.3 Provisions in the Final Rule

In addition to regulating nonroad diesel fuel to a 15 ppm sulfur limit, we are also finalizing a 15 ppm standard for locomotive and marine diesel fuel. As a result, we have modified the proposed provisions to also incorporate flexibility for small refiners in meeting the 15 ppm locomotive and marine standard. Given the regulatory transition provisions that we are finalizing for small refiners and small terminal operators, we are confident about going forward with the 500 ppm sulfur standard for NRLM diesel fuel in 2007, and the 15 ppm sulfur standard for nonroad diesel fuel in 2010 and locomotive and marine diesel fuel in 2012, as part of our general program.

We are finalizing the Panel's recommendation of delayed compliance for small refiners along with transition provisions to encourage early compliance with the new standards. The transition provisions that we are finalizing for small refiners are as follows:

- *NRLM Delay Option*- Small refiners will be required to comply with the standards set out in Table 11-5 below, meeting the 500 ppm sulfur standard in 2010 and the 15 ppm sulfur standard in 2014.[D] This is identical to the relief proposed in the NPRM (which small refiners considered sufficient and supported) with the exception that it applies not only to

[D] Since new engines with sulfur sensitive emission controls will begin to become widespread during this time, small refiner fuel will need to be segregated and only supplied for use in pre-2011 nonroad equipment or in locomotives or marine engines.

nonroad fuel, but also to locomotive and marine fuel. However, this delay option is not being finalized for the Northeast and Mid-Atlantic areas due to the removal of the heating oil marker in these areas (see discussion in Section V of the preamble). Removal of the marker provision for heating oil in these areas will help to alleviate the concern raised by small terminal operators in their comments regarding the cost of adding a marker to heating oil. At the same time, its removal is not expected to impact small refiners since we do not anticipate that they would have marketed fuel in this area. Further, this provision will be finalized in Alaska only if a refiner gets an approved compliance plan for segregating their fuel to the end user.

- *The NRLM Credit Option*- Some small refiners have indicated that they might need to produce fuel meeting the NRLM diesel fuel sulfur standards earlier than required under the small refiner program described above (distribution systems might limit the number of grades of diesel fuel that will be carried, it may be economically advantageous to make compliant NRLM diesel fuel earlier to prevent losing market share, etc.) This option allows small refiners to participate in the NRLM diesel fuel sulfur credit banking and trading program discussed in Section IV of the preamble. Generating and selling credits could provide small refiners with funds to help defray the costs of early NRLM compliance.

- *The NRLM/Gasoline Compliance Option*- This option is available to small refiners that produce greater than 95 percent of their NRLM diesel fuel at the 15 ppm sulfur standard by June 1, 2006 and elect not to use the provision described above to earn NRLM diesel fuel sulfur credits for this early compliance.[E] For small refiners choosing this option, the applicable small refiner annual average and per-gallon cap gasoline sulfur standards will be increased by 20 percent for the duration of the interim program; however, in no case may the per-gallon gasoline sulfur cap exceed 450 ppm.

[E] This is down from the 100% requirement proposed to allow for some contamination losses in the process of delivering fuel from the refinery. Production volumes in the final rule are based upon actual delivered volumes. The 5% allowance for greater than 15 ppm fuel should provide adequate flexibility for any refiner's contamination issues, while not providing any opportunity to significantly alter their compliance plans.

Table 11-5
Sulfur Standards for the NRLM Diesel Fuel Small Refiner Program
(*in parts per million (ppm)*)[a]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015+
Non-Small- NR	--	500	500	500	15	15	15	15	15	15
Non-Small- LM	--	500	500	500	500	500	15	15	15	15
Small- all NRLM	--	--	--	--	500	500	500	500	15	15

Notes:
[a] New standards are assumed to take effect June 1 of the applicable year.

A small refiner may choose to use the relaxed standards (the NRLM Delay option), the NRLM Credit option, or both in combination. Thus any fuel that it produces from crude at or below the sulfur standards earlier than required will qualify for generating credits. However, the NRLM/Gasoline Compliance option may not be used in combination with either the NRLM Delay option or the NRLM Credit option, since a small refiner must produce at least 85 percent of its NRLM diesel fuel at the 15 ppm sulfur standard under the NRLM/Gasoline Compliance option.

Combined with the transition provisions for small refiners, the compliance schedule that we are adopting will achieve the air quality benefits of the nonroad diesel program as soon as possible, while helping to ensure that small refiners will have adequate time to raise capital for new or upgraded fuel desulfurization equipment. Most small refiners have limited additional sources of income beyond refinery earnings for financing and typically do not have the financial backing that larger and generally more integrated companies have. They can therefore benefit from this additional time to accumulate capital internally or to secure capital financing from lenders. This will help to offset the disproportionate financial burden facing small refiners.

We recognize that while the sulfur levels in the proposed program can be achieved using conventional refining technologies, new technologies are also being developed that may reduce the capital and/or operational costs of sulfur removal. We believe that allowing small refiners some additional time for newer technologies to be proven out by other refiners may have the added benefit of reducing the risks faced by small refiners. Further, this additional time may also increase the availability of engineering and construction resources. Some refiners will need to install additional processing equipment to meet the nonroad diesel sulfur requirements. Vendors will be more likely to contract their services with the larger refiners first, as their projects will offer larger profits for the vendors. Therefore, we anticipate that there may be significant competition for technology services, engineering resources, and construction management and labor. Temporarily delaying compliance for small refiners will allow for lower costs of improvements in desulfurization technology and would spread out the demand for construction and engineering resources, and likely reduce any cost premiums caused by limited supply.

11.6.4 Transition and Hardship Provisions for Nonroad Diesel Fuel Small Distributors and Marketers

11.6.4.1 Panel Recommendations

During the SBREFA process, we were considering both a one-step fuel approach, and the two-step approach that we are finalizing. The Panel recognized that a two-step fuel approach would include the possibility of there being two grades of nonroad diesel fuel in the market place for at least a transition period, the Panel recommended that we study the issue of multiple fuel grades in the distribution system further during our development of the NPRM. In discussions that took place during the SBREFA process, distributors supported a one-step approach as it would have no significant impact on their operations. However, they did offer suggestions on how they might deal with this issue, but indicated that there would be adverse impacts in some circumstances. (A more complete discussion of costs and related issues relevant to fuel distributors under the proposed program is located in Chapter 7 of the Draft Regulatory Impact Analysis.)

11.6.4.2 What We Proposed

Our proposed fuel sulfur program was designed to minimize the need for additional product segregation and the associated feasibility and cost issues for fuel distributors associated with it. Beyond the accommodation of fuel distributor concerns during the overall design of the proposed program, we did not believe it possible for us to provide special provisions for particular (i.e., small) fuel distributors to further limit the potential impact of the proposed rule. However, to allow for a smooth transition of diesel fuel in the distribution system to 15 ppm, we proposed that parties downstream of the refineries be allowed a small amount of additional time to turnover their tanks to 15 ppm. Specifically, we proposed that at the terminal level, nonroad diesel fuel would be required to meet the 15 ppm standard beginning July 15, 2010. At bulk plants, wholesale purchaser-consumers, and any retail stations carrying nonroad diesel, this fuel would have to meet the 15 ppm standard by September 1, 2010. The proposed transition schedule for compliance with the 15 ppm standard at refineries, terminals, and secondary distributors would be the same as those allowed under the recently promulgated highway diesel fuel program. Lastly, to avoid the costs associated with segregating 500 ppm NRLM diesel fuel from 500 ppm highway fuel, we proposed that the existing requirement that NRLM diesel fuel be dyed leaving the refinery would need to be made voluntary (this element of the proposed rule is discussed in more detail in Section 11.7 of the proposed RIA).

11.6.4.3 Provisions in the Final Rule

We are finalizing provisions to alleviate the problems raised in the public comments on our NPRM regarding small terminal operators (heating oil marker requirements would force small terminal operators to install expensive injection equipment and they would not be able to recoup these costs). To decrease the burden on these small operators, we are not requiring the addition of a fuel marker to home heating oil for terminals in much of PADD 1 (Northeast/Mid-Atlantic Area). This Northeast/Mid-Atlantic Area covers the vast majority of heating oil that will be marketed; however, we are not allowing small refiner or credit fuel to be sold in the Northeast/Mid-Atlantic Area. Further, we expect that few terminals outside of Northeast/Mid-Atlantic Area would need to put in injection equipment, since very little fuel above 500 ppm will be marketed outside of this area except directly from the refinery gate.

11.7 Conclusion

Throughout the entire rulemaking process, we conducted substantial outreach- including convening a Panel during the SBREFA process as well as meetings with other stakeholders- to gather information about the effect of this final rule on small entities. We also took into account comments received during the public comment period and information from contractor studies in developing regulatory transition provisions to ease the burden on small entities. From this information (and performing a cost-to-sales ratio test- a ratio of the estimated annualized compliance costs to the value of sales per company)[F], we found that approximately 4 percent (13 companies) of small entities in the engine and equipment manufacturing industry were affected between 1 and 3 percent of sales (i.e., the estimated costs of compliance with the final rule will be greater than 1 percent, but less than 3 percent, of their sales). One percent of small entities (4 companies) were affected at greater than 3 percent. In all, 17 of the 518 potentially affected small engine and equipment manufacturers are estimated to have compliance costs that could exceed 1 percent of their sales.

Similarly, small refiners in general would likely experience a significant and disproportionate financial hardship in complying with the fuel-sulfur requirements in this rule. One indication of this disproportionate hardship for small refiners is the relatively high projected cost per gallon for producing compliant nonroad diesel fuel. Refinery modeling (of all refineries) indicates that without special provisions, refining costs for small refiners on average would be about 2.3 cents per gallon higher than the costs for non-small refiners. The majority of the cost for meeting the fuel requirements in this final rule are related to refining, with only 15 to 25 percent of the estimated costs being related to distribution. Allowing highway and off-highway diesel fuel meeting the same sulfur specification to be shipped fungibly until it leaves the terminal obviates the need for additional storage tankage in this segment of the distribution system.[G] The final rule allows 500 ppm highway and 500 ppm NRLM fuel to be shipped fungibly as proposed. However, it also allows high sulfur NRLM and heating oil to be shipped fungibly. Furthermore, the final rule allows 500 ppm off-highway diesel engine fuel to be mixed with high-sulfur diesel fuel as long as its designation changes.

[F] The cost-to-sales ratio test assumes that control costs are completely absorbed by each entity and does not account for or consider interaction between manufacturers/producers and consumers in a market context.

[G] Including the refinery, pipeline, marine tanker, and barge segments of the distribution system.

CHAPTER 12: Regulatory Alternatives

CHAPTER 12: Regulatory Alternatives

Our final program represents a combination of engine and fuel standards and their associated timing that we believe to be superior to the alternatives considered given feasibility, cost, and environmental impact. In this chapter we present the alternative program options that we evaluated in order to make this determination. These alternatives are cast as twelve specific program options.

12.1 Overview

In the Draft RIA supplementing our Notice of Proposed Rulemaking, we presented a detailed analysis of twelve specific program options. These options were used to illustrate variations in both the timing and level of the engine and fuel standards, as well as the applicability of those standards to different segments of off-highway engines and fuels. To evaluate each option, we conducted emission-inventory modeling, estimated costs and benefits, and calculated cost-effectiveness. We then assessed the appropriateness of each option in comparison to our proposed engine and fuel program, and presented our rationale for not proposing to implement each of the options.

Following release of the proposal, we received comments on some of the options that we evaluated. Our detailed responses to those comments can be found in Section 8 of the Summary and Analysis of Comments document. Our reasoning set forth in Chapter 12 of the Draft RIA supporting the proposal also still applies as well for options we have not adopted.

We examined the costs, inventory impacts, benefits, and cost-effectiveness of each of the options as presented in the Draft RIA incrementally to our proposed program. Given that the final program includes some elements that differ from the proposed program, these same new elements would need to be included in each of the options in order to maintain the same incremental differences in program structure between the final program and each option. As a result, we do not believe that a complete revision to the calculated values for costs, inventory impacts, benefits, and cost-effectiveness is warranted, since we would expect them to be very similar to those presented in the Draft RIA. Also, we would not expect recent modifications to the NONROAD emissions model to change the incremental differences between the final program and each of the options. We refer the reader to the detailed evaluations of the options presented in the Draft RIA.

The remainder of this section will present a description of the twelve options originally evaluated in the context of the NPRM to remind readers of the program issues we investigated. However, during the course of reviewing comments on our proposed program, we determined that an additional evaluation of small engine standards was warranted. This additional scenario was labeled Option 5c, and the results of that evaluation are presented below In Section 12.2.2.2.

12.2 Description of Options

Our proposed emission-control program consisted of a two-step program to reduce the sulfur content of nonroad diesel fuel in conjunction with the NOx and PM engine standards. During the development of our program, we also considered a one-step fuel program wherein all sulfur reductions in the diesel fuel occur in a single step. Since the fuel provisions and timing dictate to a large extent the possible engine standards, we structured this section to first discuss issues of variations in the fuel program. Thus, the Program Options are divided into One-Step and Two-Step options, to highlight the fuel sulfur program and its driving impact on the engine standards. Within each of these fuel program approaches, we considered several variations and combinations with engine standards.

This Section provides both text summaries of each Program Option as well as diagrams showing how the engine and fuel standards would be implemented over time. For the diagrams, previous standards are labelled as Tier 1, Tier 2, or Tier 3 as appropriate. For reference, Figure 12.2-1 shows the actual standards associated with Tier 1, Tier 2, and Tier 3 labels (40 CFR 89.112).

Figure 12.2-1
Existing Engine and Fuel Standards

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25	Tier 2: 5.6 NOx+NMHC, 0.6 PM										
25 ≤ hp hp < 50	Tier 2: 5.6 NOx+NMHC, 0.4 PM										
50 ≤ hp hp < 75	Tier 2: 5.6 NOx+NMHC 0.3 PM			Tier 3: 3.5 NOx+NMHC 0.3 PM							
75 ≤ hp hp < 100	Tier 2: 5.6 NOx+NMHC 0.3 PM			Tier 3: 3.5 NOx+NMHC 0.3 PM							
100 ≤ hp hp < 175	Tier 2: 4.9 NOx+NMHC 0.2 PM		Tier 3: 3.0 NOx+NMHC 0.2 PM								
175 ≤ hp hp < 750	Tier 2: 4.8 NOx+NMHC 0.1 PM	Tier 3: 3.0 NOx+NMHC 0.1 PM									
hp ≥ 750	Tier 1: 6.9 NOx 0.4 PM	Tier 2: 4.8 NOx+NMHC 0.1 PM									
Fuel sulfur standard (ppm)											
Loco & marine	Uncontrolled										
Nonroad	Uncontrolled										

[α] Applies to model years.

12.2.1 One-Step Options

One-step options were those in which the fuel sulfur standard was applied in a single step; there were no phase-ins or step changes. In all one-step options, the transient test cycle was required concurrently with the introduction of the transitional Tier 4 engine standards in any horsepower group.

Option 1a differed from Options 1 and 1b in terms of the engine standards and their associated timing. Option 1b differed from Option 1 only in the timing of the fuel sulfur standard, and was intended to generate additional early sulfate PM reductions. As a result, we did not lower the certification fuel sulfur level to 15ppm in 2007 and 2008 when modeling this Option, since doing so would permit manufacturers to take advantage of the lower sulfur and thus reduce the PM reductions associated with their certified engines.

The one-step options are summarized in Table 12.2.1-1. The specifics of the three one-step options are shown in the standard charts in Figures 12.2.1-2, 3, and 4, while the previous Tier 1, Tier 2, and Tier 3 standards were shown in Figure 12.2-1. Only changes to the standards are shown in these three figures, i.e. if no new standard for a given pollutant is indicated, the previous standard applies.

Table 12.2.1-1
Summary of One-Step Options

Option	Summary Description
Option 1	• Fuel sulfur ≤ 15ppm in June 2008 for nonroad, ≤ 500ppm for locomotives and marine engines • <50 hp: PM stds only in 2009 • 25-75 hp: PM aftertreatment-based standards and EGR or equivalent NOx technology in 2013; no NOx aftertreatment • >75 hp: PM aftertreatment-based standards phasing in beginning in 2009; NOx aftertreatment-based standards phasing in beginning in 2011 *See Figure 12.2.1-1*
Option 1a	• Fuel sulfur ≤ 15ppm in June 2008 • PM aftertreatment-based standards introduced in 2009-10 • NOx aftertreatment-based standards introduced in 2011-12 *See Figure 12.2.1-2*
Option 1b	Same as Option 1a, except fuel sulfur standard required two years earlier *See Figure 12.2.1-3*

Figure 12.2.1-1
Engine and Fuel Standards Under Option 1

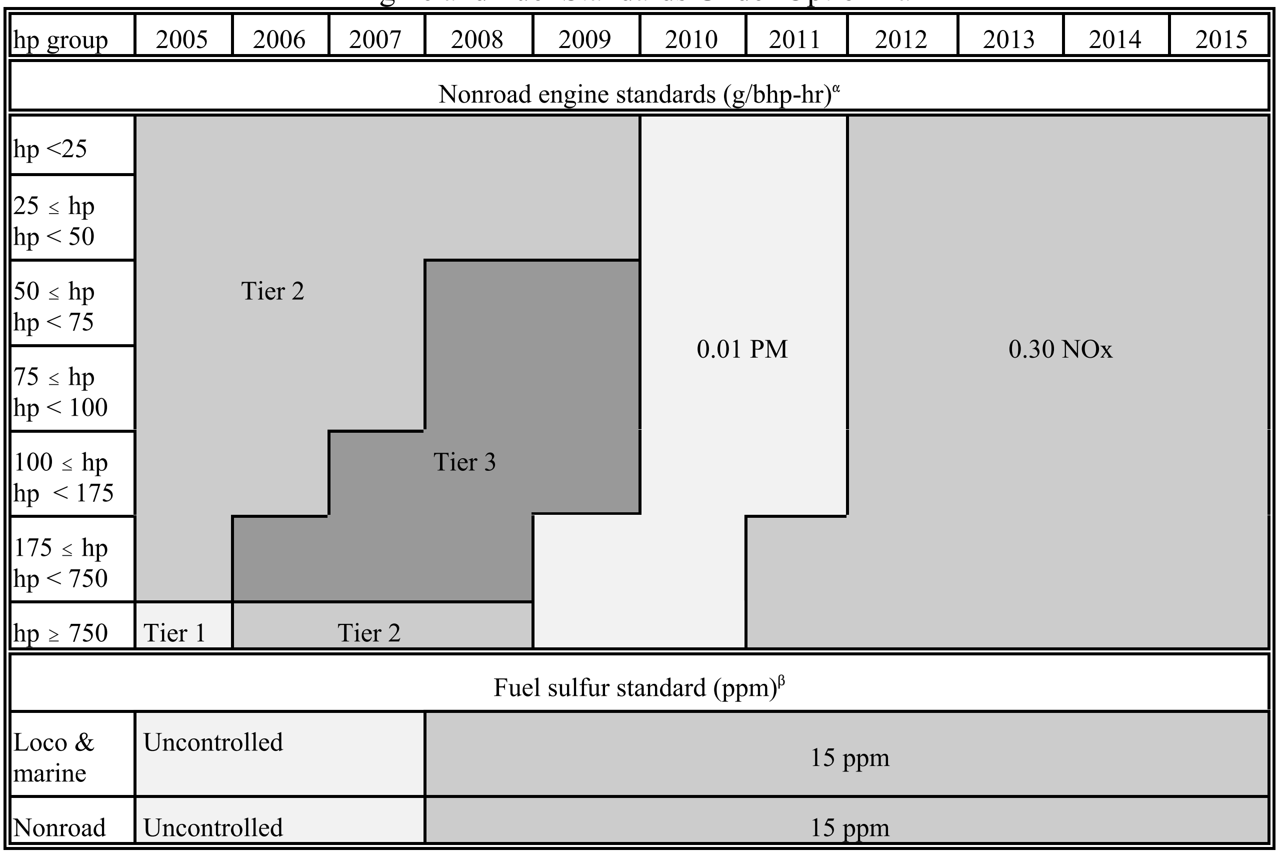
hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25	Tier 2				0.30 PM						
25 ≤ hp hp < 50	Tier 2				0.22 PM				0.02 PM, 3.3[γ] NOx		
50 ≤ hp hp < 75	Tier 2			Tier 3					0.02 PM, 3.3[γ] NOx		
75 ≤ hp hp < 100	Tier 2			Tier 3		50%: 0.01 PM		0.01 PM 50%: 0.30 NOx		0.30 NOx	
100 ≤ hp hp < 175	Tier 2		Tier 3			50%: 0.01 PM		0.01 PM 50%: 0.30 NOx		0.30 NOx	
175 ≤ hp hp < 750	Tier 2	Tier 3			50%: 0.01 PM		0.01 PM 50%: 0.30 NOx			0.30 NOx	
hp ≥ 750	Tier 1	Tier 2					50%: 0.01 PM, 0.30 NOx			0.30 NOx	
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled			500 ppm							
Nonroad	Uncontrolled			15 ppm							

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

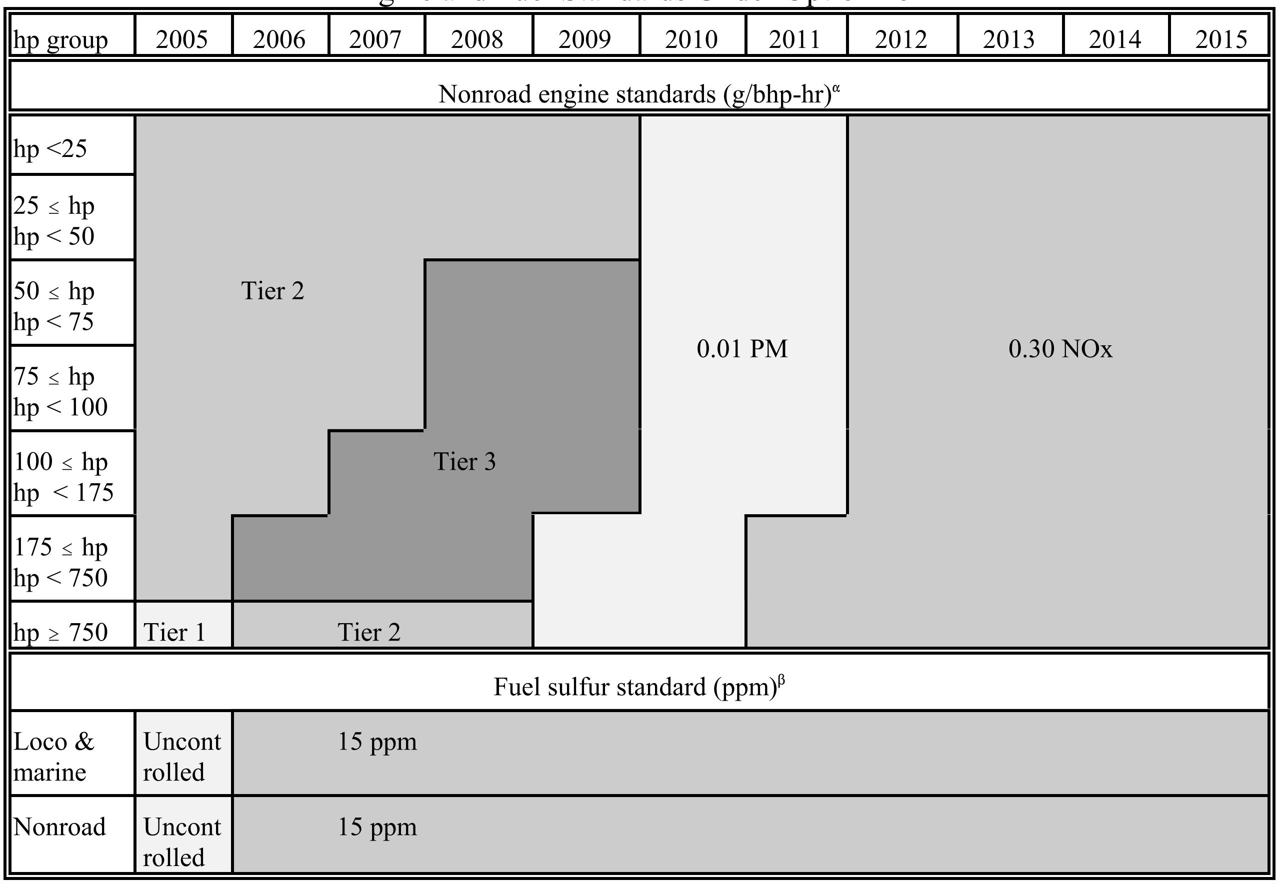
Figure 12.2.1-2
Engine and Fuel Standards Under Option 1a



α Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

β Applies to calender years. Begins in June.

Figure 12.2.1-3
Engine and Fuel Standards Under Option 1b



α Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

β Applies to calender years. Begins in June.

12.2.2 Two-Step Options

Two-step options were those in which the fuel sulfur standard was set first at 500ppm for several years, and then was lowered further to 15ppm. The exact timing of the introduction of the 500ppm and the 15ppm standards varied among each of the two-step options. In addition, we considered a variety of engine standards and phase-ins. In the two-step options, the transient test cycle was required concurrently with the introduction of the transitional Tier 4 engine standards. The one exception was Option 5b, under which the existing steady-state test applied indefinitely for engines below 75 hp.

12.2.2.1 Options Evaluated for Proposal

The proposed program formed the basis for all of the two-step alternative program options. The two-step options that we evaluated for the NPRM are summarized in Table 12.2.2-1. The specifics of these two-step options are shown in the standard charts in Figures 12.1.2-2 through

11, while the previous Tier 1, Tier 2, and Tier 3 standards were shown in Figure 12.2-1. As for the one-step standard charts, only changes to the standards are shown, i.e. if no new standard for a given pollutant is indicated, the previous standard applies.

Table 12.2.2-1
Summary of Two-Step Options

Option	Summary Description
Proposed program	• 500 ppm in 2007; 15 ppm in 2010 for nonroad engines only • >25 hp: PM aftertreatment-based standards introduced 2011-2013 • >75 hp: NOx aftertreatment-based standards introduced and phased-in 2011-2014 • <25 hp: PM standards in 2008 • 25-75 hp: PM standards in 2008 (optional for 50-75 hp) • >750hp: PM and NOx standards phased-in 2011-2014 *See Figure 12.2.2-1*
Option 2a	Same as our proposed program, except: • Transitional sulfur standard of 500 ppm is introduced one year earlier *See Figure 12.2.2-2*
Option 2b	Same as our proposed program, except: • Final sulfur standard of 15 ppm is introduced one year earlier • Trap-based PM standards begin one year earlier for all engines *See Figure 12.2.2-3*
Option 2c	Same as our proposed program, except: • Final sulfur standard of 15 ppm is introduced one year earlier • Trap-based PM standards begin one year earlier for 175 - 750 hp engines *See Figure 12.2.2-4*
Option 2d	Same as our proposed program, except: • Final NOx standard for 25 - 75 hp engines is lowered to 0.30 g/bhp-hr • A phase-in for the NOx standard for this horsepower group is included *See Figure 12.2.2-5*
Option 2e	Same as our proposed program, except: • No new Tier 4 NOx standards. *See Figure 12.2.2-6*
Option 3	Same as our proposed program, except: • Above-ground mining equipment >750 hp remains at the Tier 2 standards *See Figure 12.2.2-7*
Option 4	Same as our proposed program, except: • 15 ppm final sulfur standard applies to fuel used by locomotives and marine engines in addition to all other nonroad engines *See Figure 12.2.2-8*
Option 5a	Same as our proposed program, except: • No new Tier 4 standards for <75 hp engines *See Figure 12.2.2-9*
Option 5b	Same as our proposed program, except: • No trap-based PM standards for <75 hp engines • No new Tier 4 NOx standards for <75 hp engines *See Figure 12.2.2-10*

Figure 12.2.2-1
Engine and Fuel Standards under the Proposed Program

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25								0.30 PM			
25 ≤ hp hp < 50						0.22 PM			0.02 PM, 3.3[ε] NOx		
50 ≤ hp hp < 75		Tier 2									
75 ≤ hp hp < 100											
100 ≤ hp hp < 175					Tier 3			100%[γ] : 0.01 PM 50%[γ] : 0.30 NOx		0.01 PM	
175 ≤ hp hp < 750										0.30 NOx	
hp ≥ 750	Tier 1	Tier 2					50%[δ] : 0.01 PM, 0.30 NOx				
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled		500 ppm								
Nonroad	Uncontrolled		500 ppm			15 ppm					

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

[ε] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-2
Engine and Fuel Standards under Option 2a

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25				0.30 PM							
25 ≤ hp hp < 50				0.22 PM					0.02 PM, 3.3[ε] NOx		
50 ≤ hp hp < 75	Tier 2										
75 ≤ hp hp < 100											
100 ≤ hp hp < 175			Tier 3					100%[γ] : 0.01 PM 50%[γ] : 0.30 NOx		0.01 PM	
175 ≤ hp hp < 750										0.30 NOx	
hp ≥ 750	Tier 1	Tier 2					50%[δ] : 0.01 PM, 0.30 NOx				
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncon-trolled	500 ppm									
Nonroad	Uncon-trolled	500 ppm				15 ppm					

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.
[β] Applies to calender years. Begins in June.
[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.
[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.
[ε] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-3
Engine and Fuel Standards under Option 2b

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25				0.30 PM							
25 ≤ hp hp < 50				0.22 PM				0.02 PM	0.02 PM, 3.3[ε] NOx		
50 ≤ hp hp < 75		Tier 2									
75 ≤ hp hp < 100							0.01 PM				
100 ≤ hp hp < 175				Tier 3				50%[γ] : 0.30 NOx		0.01 PM	
175 ≤ hp hp < 750						0.01 PM				0.30 NOx	
hp ≥ 750	Tier 1	Tier 2				50%: 0.01 PM	50%[δ] : 0.01 PM, 0.30 NOx		100%: 0.01 PM		
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled		500 ppm								
Nonroad	Uncontrolled		500 ppm		15 ppm						

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.
[β] Applies to calender years. Begins in June.
[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.
[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.
[ε] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-4
Engine and Fuel Standards under Option 2c

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25	Tier 2			0.30 PM							
25 ≤ hp hp < 50				0.22 PM					0.02 PM, 3.3[ε] NOx		
50 ≤ hp hp < 75											
75 ≤ hp hp < 100				Tier 3				100%[γ] : 0.01 PM 50%[γ] : 0.30 NOx		0.01 PM 0.30 NOx	
100 ≤ hp hp < 175											
175 ≤ hp hp < 750						0.01 PM					
hp ≥ 750	Tier 1	Tier 2					50%[δ] : 0.01 PM, 0.30 NOx				
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled		500 ppm								
Nonroad	Uncontrolled		500 ppm		15 ppm						

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

[ε] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-5
Engine and Fuel Standards under Option 2d

<table>
<tr><td>hp group</td><td>2005</td><td>2006</td><td>2007</td><td>2008</td><td>2009</td><td>2010</td><td>2011</td><td>2012</td><td>2013</td><td>2014</td><td>2015</td><td>2016</td></tr>
<tr><td colspan="13">Nonroad engine standards (g/bhp-hr)[α]</td></tr>
<tr><td>hp <25</td><td rowspan="4" colspan="3">Tier 2</td><td colspan="9">0.30 PM</td></tr>
<tr><td>25 ≤ hp
hp < 50</td><td rowspan="2" colspan="5">0.22 PM</td><td rowspan="2" colspan="3">0.02 PM
50%: 0.30 NOx</td><td rowspan="2">0.30
NOx</td></tr>
<tr><td>50 ≤ hp
hp < 75</td></tr>
<tr><td>75 ≤ hp
hp < 100</td><td colspan="4">Tier 3</td><td rowspan="2" colspan="2">100%[γ] : 0.01 PM
50%[γ] : 0.30 NOx</td><td rowspan="4" colspan="3">0.01 PM
0.30 NOx</td></tr>
<tr><td>100 ≤ hp
hp < 175</td><td colspan="2"></td><td colspan="5"></td></tr>
<tr><td>175 ≤ hp
hp < 750</td><td></td><td colspan="5"></td><td colspan="3"></td></tr>
<tr><td>hp ≥ 750</td><td>Tier 1</td><td colspan="5">Tier 2</td><td colspan="3">50%[δ] : 0.01 PM, 0.30 NOx</td></tr>
<tr><td colspan="13">Fuel sulfur standard (ppm)[β]</td></tr>
<tr><td>Loco & marine</td><td colspan="2">Uncontrolled</td><td colspan="10">500 ppm</td></tr>
<tr><td>Nonroad</td><td colspan="2">Uncontrolled</td><td colspan="3">500 ppm</td><td colspan="7">15 ppm</td></tr>
</table>

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

Figure 12.2.2-6
Engine and Fuel Standards under Option 2e

<table>
<tr><th>hp group</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th><th>2015</th></tr>
<tr><td colspan="12">Nonroad engine standards (g/bhp-hr)[α]</td></tr>
<tr><td>hp <25</td><td colspan="3" rowspan="4">Tier 2</td><td colspan="8">0.30 PM</td></tr>
<tr><td>25 ≤ hp
hp < 50</td><td colspan="5" rowspan="2">0.22 PM</td><td colspan="3" rowspan="2">0.02 PM</td></tr>
<tr><td>50 ≤ hp
hp < 75</td></tr>
<tr><td>75 ≤ hp
hp < 100</td><td colspan="4">Tier 3</td><td colspan="4" rowspan="3">0.01 PM</td></tr>
<tr><td>100 ≤ hp
hp < 175</td><td colspan="2"></td><td colspan="5"></td></tr>
<tr><td>175 ≤ hp
hp < 750</td><td></td><td colspan="5"></td><td></td></tr>
<tr><td>hp ≥ 750</td><td>Tier 1</td><td colspan="5">Tier 2</td><td colspan="3">50%[δ] : 0.01 PM</td><td colspan="2">0.01 PM</td></tr>
<tr><td colspan="12">Fuel sulfur standard (ppm)[β]</td></tr>
<tr><td>Loco & marine</td><td colspan="2">Uncontrolled</td><td colspan="9">500 ppm</td></tr>
<tr><td>Nonroad</td><td colspan="2">Uncontrolled</td><td colspan="3">500 ppm</td><td colspan="6">15 ppm</td></tr>
</table>

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[δ] Only 50% of engines must meet the new PM standard on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

Figure 12.2.2-7
Engine and Fuel Standards under Option 3

<table>
<tr><th>hp group</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th><th>2015</th></tr>
<tr><td colspan="12">Nonroad engine standards (g/bhp-hr)$^{\alpha}$</td></tr>
<tr><td>hp <25</td><td colspan="3"></td><td colspan="8">0.30 PM</td></tr>
<tr><td>25 ≤ hp
hp < 50</td><td colspan="3"></td><td rowspan="2" colspan="5">0.22 PM</td><td rowspan="2" colspan="3">0.02 PM, 3.3$^{\epsilon}$ NOx</td></tr>
<tr><td>50 ≤ hp
hp < 75</td><td colspan="3">Tier 2</td></tr>
<tr><td>75 ≤ hp
hp < 100</td><td colspan="3"></td><td colspan="4"></td><td colspan="2"></td><td rowspan="3" colspan="2">0.01 PM

0.30 NOx</td></tr>
<tr><td>100 ≤ hp
hp < 175</td><td colspan="2"></td><td colspan="5">Tier 3</td><td colspan="2">100%$^{\gamma}$: 0.01 PM
50%$^{\gamma}$: 0.30 NOx</td></tr>
<tr><td>175 ≤ hp
hp < 750</td><td></td><td colspan="5"></td><td colspan="3"></td></tr>
<tr><td>hp ≥ 750</td><td>Tier 1</td><td colspan="5">Tier 2</td><td colspan="3">50%$^{\delta}$: 0.01 PM, 0.30 NOx
Mining equipment remains at Tier 2</td><td colspan="2">0.01 PM
0.30 NOx
Mining equipment at Tier 2</td></tr>
<tr><td colspan="12">Fuel sulfur standard (ppm)$^{\beta}$</td></tr>
<tr><td>Loco & marine</td><td colspan="2">Uncontrolled</td><td colspan="9">500 ppm</td></tr>
<tr><td>Nonroad</td><td colspan="2">Uncontrolled</td><td colspan="3">500 ppm</td><td colspan="6">15 ppm</td></tr>
</table>

$^{\alpha}$ Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

$^{\beta}$ Applies to calender years. Begins in June.

$^{\gamma}$ All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

$^{\delta}$ Only 50% of engines not used in mining equipment must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

$^{\epsilon}$ Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-8
Engine and Fuel Standards under Option 4

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25				0.30 PM							
$25 \le$ hp hp < 50				0.22 PM					0.02 PM, 3.3[ε] NOx		
$50 \le$ hp hp < 75	Tier 2										
$75 \le$ hp hp < 100											
$100 \le$ hp hp < 175				Tier 3				100%[γ] : 0.01 PM 50%[γ] : 0.30 NOx		0.01 PM	
$175 \le$ hp hp < 750										0.30 NOx	
hp $\ge$ 750	Tier 1	Tier 2					50%[δ] : 0.01 PM, 0.30 NOx				
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled		500 ppm		15 ppm						
Nonroad	Uncontrolled		500 ppm		15 ppm						

[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

[ε] Actual standard is 3.5g/bhp-hr NOx+NMHC, equivalent to the Tier 3 standard for 50-75hp. For modeling purposes, NOx portion of this standard is assumed to be 3.3g/bhp-hr.

Figure 12.2.2-9
Engine and Fuel Standards under Option 5a

hp group	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nonroad engine standards (g/bhp-hr)[α]											
hp <25											
25 ≤ hp hp < 50											
50 ≤ hp hp < 75		Tier 2									
75 ≤ hp hp < 100											
100 ≤ hp hp < 175					Tier 3			100%[γ] : 0.01 PM 50%[γ] : 0.30 NOx		0.01 PM	
175 ≤ hp hp < 750										0.30 NOx	
hp ≥ 750	Tier 1		Tier 2					50%[δ] : 0.01 PM, 0.30 NOx			
Fuel sulfur standard (ppm)[β]											
Loco & marine	Uncontrolled						500 ppm				
Nonroad	Uncontrolled		500 ppm					15 ppm			

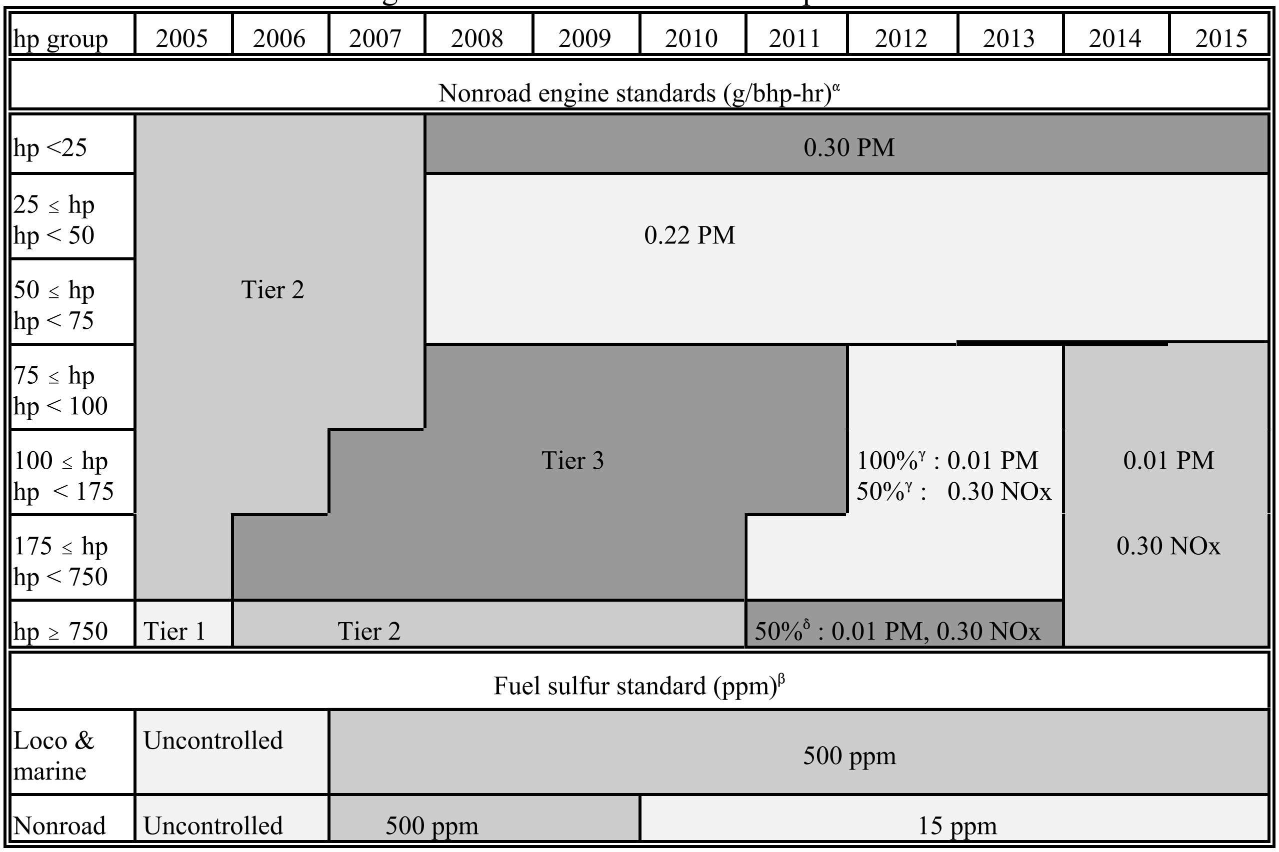
[α] Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.

[β] Applies to calender years. Begins in June.

[γ] All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.

[δ] Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

Figure 12.2.2-10
Engine and Fuel Standards under Option 5b



α Applies to model years. If no standard is shown for a given pollutant, the previous standard applies.
β Applies to calender years. Begins in June.
γ All engines must meet 0.01 PM, but only 50% of engines must meet the new NOx standard of 0.30. All engines must use the transient test cycle.
δ Only 50% of engines must meet both the new PM and NOx standards on the transient test cycle. Remaining engines meet Tier 2 standards on the steady-state test cycle.

12.2.2.2 Option 5c

As described in Section 12.2.2.1, Option 5b represented an alternative program in which we would not apply trap-based PM standards or new NOx standards to engines under 75hp. As described in Sections II.A and II.B of the preamble, we continue to believe that the application of PM filters to small engines is both feasible and is an important element of our efforts to address air quality concerns associated with nonroad engines. Therefore, we have not finalized Option 5b and the proposed Tier 4 PM and NOx standards for <75hp engines are included in the program we are finalizing.

Some of the original concerns raised about <75hp engines were again raised in response to the NPRM for a smaller group of engines with rated horsepower between 25 and 50 hp. In the process of considering this issue, we evaluated a new Option 5c in which the trap-based PM standard and the Tier 4 NOx standard would not be applied to 25 - 50 hp engines, but would continue to apply to above 50 hp engines. This specific option is a refinement of Option 5b, but was not evaluated for the NPRM. We evaluated this Option 5c as part of our overall evaluation of a wide variety of alternative options. We are presenting the results of our analysis here.

As described above, we did not repeat the analyses for Options 1 through 5b for this final rule, but instead refer the reader to the draft RIA for those analyses. The draft RIA presented the inventory impacts, benefits, costs, and cost-effectiveness of each of the options in comparison to the proposed program. For Option 5c, however, we evaluated the inventory impacts, benefits, costs, and cost-effectiveness in comparison to the final program.

12.2.2.2.1 Emission Inventory Impacts

Option 5c is identical to our final program, except that it would not require 25-50hp engines to meet the trap-based PM standards that are in our final program, nor would it require these engines to meet the Tier 4 NOx standards. As a result, the PM and NOx emission reductions for Option 5c would be lower than those for our final program. However, under this option pollutants other than PM and NOx would also be affected. For instance, the reductions in hydrocarbons and CO that will occur for our final program are generated primarily through the presence of catalyzed diesel particulate traps, so the removal of the trap-based PM standards for 25-50 hp engines will also produce a corresponding reduction in the HC and CO benefits.

In evaluating the inventory impacts of Option 5c, we assumed that the 2008 PM standards for 25-50 hp engines were met using a steady-state test cycle for both our final program and Option 5c. Whether these engines should be required to meet standards under a transient test procedure is a separate issue from the use of after-treatment. Our analysis was designed to focus in the impacts of requiring the use of aftertreatment.

Thus Option 5c produces fewer benefits for all pollutants starting in 2013 in comparison to our final program. Table 12.2.2.2.1-1 shows the net impact of Option 5c on the 30-year net present value inventory estimates.

Table 12.2.2.2.1-1
50-State 30-Year Net Present Value Emission Increases
For Option 5c In Comparison to Final Program (tons)

	3% discount rate	7% discount rate
PM	56,833	25,238
NOx + NMHC	381,459	170,819

12.2.2.2.2 Cost Analysis

Option 5c would reduce the overall costs of the program since 25-50 hp engines would not need to install PM traps nor make engine modifications to comply with more stringent NOx standards. We calculated the total nationwide cost savings by summing the per-engine savings across all engines for each year starting in 2013. Table 12.2.2.2.2-1 shows the resulting 30-year net present value cost savings for Option 5c. Costs were allocated to the various pollutants according to the methodology described in Chapter 8 of the RIA.

Table 12.2.2.2.2-1
50-State 30-Year Net Present Value Cost Savings
For Option 5c In Comparison to Final Program ($million)

	3% discount rate	7% discount rate
All pollutants	2,041	997
PM	1,514	735
NOx + NMHC	527	263

12.2.2.2.3 Benefits Comparison

We were able to estimate the benefits of Option 5c using the benefit-transfer methodology developed in Chapter 9 for estimating the monetized benefits of the final program. The specific methodology is described in Section 9.5 "Development of Intertemporal Scaling Factors and Calculation of Benefits Over Time" and will not be repeated here. To use that methodology requires input of 48-state emission reductions for NOx, PM2.5 and SO_2 associated with Option 5c. We cannot estimate 50-state benefits due to the fact that our air quality modeling work covers only 48 states, and we are unable to extrapolate those results to Alaska or Hawaii. PM2.5 is used for these calculations rather than PM10 because the underlying health effect studies rely on PM2.5 data.

Accounting for the reduction in monetised health and welfare benefits from the net emission inventory impacts of Option 5c in comparison to our final program produces 30-year net present value of loss in benefits of $36.6 billion at a 3 percent discount rate, and $14.8 billion at a 7 percent discount rate. This loss in benefits is much larger than the costs savings associated with not applying trap-based PM standards to 25-50-hp engines as shown in Table 12.2.2.2.2-1, highlighting the fact that there is a substantial net benefit to society of applying the trap-based PM standards to 25-50 hp engines.

12.2.2.2.4 Costs Per Ton

The cost-effectiveness of the final standards for 25-50 hp engines can be calculated from the values in Tables Table 12.2.2.2.1-1 and Table 12.2.2.2.2-1. The results are given in Table 12.2.2.2.4-1.

Table 12.2.2.2.4-1
50-State 30-Year Net Present Value Cost-Effectiveness
For Option 5c In Comparison to Final Program ($/ton)

	3% discount rate	7% discount rate
PM	26,600	29,100
NOx + NMHC	1,400	1,500