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# Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule

## Regulatory Impact Analysis

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## Regulatory Impact Analysis

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

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## List of Acronyms

A/F	air/fuel ratio
AAM	Alliance of Automobile Manufacturers
ABT	averaging, banking, and trading
ACS	American Cancer Society
AGO	atmospheric gasoil
AHS	U.S. Census Bureau's American Housing Survey
AIRS	Aerometric Information Retrieval System
AML	acute myeloid leukemia
ANPRM	Advanced Notice of Proposed Rulemaking
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
bbbl	barrel
BCA	benefit-cost analysis
BenMAP	Environmental Benefits Mapping and Analysis Program
BTU	British Thermal Unit
C-R	concentration response
CAA	Clean Air Act
CAP	Compliance Assurance Program (2000)
CARB	California Air Resources Board
CASAC	Clean Air Science Advisory Committee
CBI	confidential business information
DF	Deterioration Factor
CG	conventional gasoline
CMAQ	Community Multiscale Air Quality model
CML	chronic myeloid leukemia
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
COI	cost of illness
COPD	chronic obstructive pulmonary disease
cpsi	cells per square inch
CR	concentration-response
CRC	Coordinating Research Council
CRDM	Climatological Regional Dispersion Model
DMC	direct manufacturing costs
DOE	U.S. Department of Energy
E0	ethanol-free gasoline
E10	gasoline containing 10 percent ethanol by volume
E15	gasoline containing 15 percent ethanol by volume
ECA	Emission Control Area
EGR	exhaust gas recirculation
EHC	electrically heated catalyst
EIA	Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EPA or Agency	U.S. Environmental Protection Agency

EPAAct	Energy Policy Act of 2005
ERIC	Emissions Reduction and Intercept Control (system)
ESPN	EPA speciation network
EvOH	ethyl vinyl alcohol
FBP	final boiling point
FCC	fluidized catalytic cracker
FTP	Federal Test Procedure
GC/MS	gas chromatography/mass spectrometry
GDI	gasoline direct injection
GDP	gross domestic product
GPA	Geographic Phase-in Area
GVWR	gross vehicle weight rating
HAP	Hazardous Air Pollutant
HAPEM	Hazardous Air Pollutant Exposure Model
HC	hydrocarbon
HCUP	Healthcare Cost and Utilization Program
HDGV	heavy-duty gasoline vehicle
HDV	heavy-duty vehicle
HEGO	heated exhaust gas oxygen (sensor)
HEI	Health Effects Institute
I/M	inspection/maintenance
IBP	initial boiling point
ICI	independent commercial importer
ICM	indirect cost multiplier
IRFA	Initial Regulatory Flexibility Analysis
IRIS	Integrated Risk Information System
LCO	light cycle oil
LDT	light-duty truck
LDV	light-duty vehicle
LEV	low emission vehicle
LM	locomotive and marine diesel fuel
LML	lowest measured level
LPG	liquid petroleum gas
MDPV	medium-duty passenger vehicle
MECA	Manufacturers of Emission Controls Association
MLE	maximum likelihood estimate
MRAD	minor restricted activity days
MSAT	mobile source air toxic
MSAT2	Regulations for Control of Hazardous Air Pollutants from Mobile Sources, 72 FR 8428, 2/26/07
MSCF	thousand standard cubic feet
MTBE	methyl tertiary-butyl ether
MY	model year
NAAQS	National Ambient Air Quality Standards
NAC	NO <sub>x</sub> adsorption catalyst
NAICS	North American Industrial Classification System
NAPAP	National Acid Precipitation Assessment Program

NATA	National-Scale Air Toxics Assessment
NEMA	Northeast Mid-Atlantic
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFRAQS	Northern Front Range Air Quality Study
NGL	natural gas liquids
NLEV	national low emission vehicle
NMHC	non-methane hydrocarbons
NMMAPS	National Morbidity, Mortality, and Air Pollution Study
NMOG	non-methane organic gases
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	oxides of nitrogen
NPC	National Petroleum Council
NPRA	National Petrochemical & Refiners Association
NPRM	Notice of Proposed Rulemaking
NRC	National Research Council
NSR	New Source Review
OAQPS	Office of Air Quality Planning and Standards
OAR	EPA's Office of Air and Radiation
OBD	on-board diagnostics
OC/EC	organic carbon/elemental carbon
OMB	Office of Management and Budget
OMS	Office of Mobile Sources
ORNL	Oak Ridge National Laboratory
OSC	oxygen storage components
OSTP	(White House) Office of Science and Technology Policy
OTAG	Ozone Transport Assessment Group
PADD	Petroleum Administrative Districts for Defense
PAN	peroxy acetyl nitrate
PCM	powertrain control module
Pd	palladium
PFI	port fuel injection
PGM	platinum group metals
PM	particulate matter
PNGV	Partnership for a New Generation of Vehicles
POM	polycyclic organic matter
ppm	part per million
PSD	Prevention of Significant Deterioration
Pt	platinum
R+M/2	average octane, or antiknock index
R&D	research and development
REL	reference exposure level
RFA	Regulatory Flexibility Act
RfC	reference concentration
RfD	reference dose
RFG	reformulated gasoline
RFS2	Renewable Fuel Standard Program, 75 FR 14670, 3/26/2010

Rh	rhodium
ROI	return on investment
ROTR	Regional Ozone Transport Rule
RPE	retail price equivalent
RRF	relative reduction factor
RVP	Reid vapor pressure
S-R	Source-Receptor Matrix
S&P DRI	Standard & Poor's Data Research International
SAB	Science Advisory Board
SBA	U.S. Small Business Administration
SBAR or the Panel	Small Business Advocacy Review Panel
SBREFA	Small Business Regulatory Enforcement Fairness Act
SCR	selective catalytic reduction
SER	Small Entity Representative
SFTP	Supplemental Federal Test Procedure
SIC	Standard Industrial Classification
SIGMA	Society of Independent Gasoline Marketers of America
SIP	State Implementation Plan
SMAT	Speciated Modeled Attainment Test
SO <sub>2</sub>	sulfur dioxide
SO <sub>x</sub>	oxides of sulfur
SRU	sulfur recovery unit
SULEV	super ultra low emission vehicle
SVM	small volume manufacturer (of vehicles)
SVOC	semivolatile organic compound
SwRI	Southwest Research Institute
T10	average temperature at which 10 percent of gasoline is distilled
T50	average temperature at which 50 percent of gasoline is distilled
T90	average temperature at which 90 percent of gasoline is distilled
TC	total technology costs
TGDI	turbocharged gasoline direct injection
THC	total hydrocarbons
TOG	total organic gases
TW	test weight
UAM	Urban Airshed Model
UCL	upper confidence limit
UEGO	universal exhaust gas oxygen (sensor)
ULEV	ultra low emission vehicle
UMRA	Unfunded Mandates Reform Act
UV	ultra violet
VGO	vacuum gasoil
VTB	vacuum tower bottoms
VMT	vehicle miles traveled
VNA	Voronoi Neighbor Averaging
VOC	volatile organic compound
VSL	value of a statistical life

WLD  
WTP

work loss days  
willingness to pay

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## Executive Summary

EPA is adopting a comprehensive program to address air pollution from passenger cars and trucks. The final program, known as “Tier 3,” will establish more stringent vehicle emissions standards and reduce the sulfur content of gasoline, considering the vehicle and its fuel as an integrated system. The final Tier 3 standards will reduce concentrations of multiple air pollutants (ambient concentrations of ozone, particulate matter (PM), nitrogen dioxide (NO<sub>2</sub>), and mobile source air toxics (MSATs)) across the country and help state and local agencies in their efforts to attain and maintain health-based National Ambient Air Quality Standards (NAAQS).

This Regulatory Impact Analysis provides technical, economic, and environmental analyses of the new standards. Chapter 1 contains our technical feasibility justification for the final vehicle emission standards, and Chapter 2 contains the estimated costs of the final vehicle standards. In addition to the vehicle emission and gasoline standards, we are adopting an update to the specifications of the emission test fuel with which vehicles demonstrate compliance with emissions standards; our analysis of the emission test fuel parameter changes is found in Chapter 3. Chapters 4 and 5 contain our technical feasibility and cost analyses for the final gasoline sulfur standards, respectively. Chapter 6 describes the health and welfare effects associated with the air pollutants that will be impacted by the rule. Chapter 7 describes our analysis of the emission and air quality impacts of the Tier 3 rule. Our estimates of the program-wide costs, the societal benefits, and the cost per ton of emissions reduced due to the final Tier 3 program are presented in Chapter 8. Chapter 9 contains our analysis of the final rule’s economic impacts, and Chapter 10 provides the results of our small business final regulatory flexibility analysis.

### Tier 3 Standards

#### *Vehicle Emission Standards*

The Tier 3 standards include light- and heavy-duty vehicle tailpipe emission standards and evaporative emission standards.

#### Light-Duty Vehicle, Light-Duty Truck, and Medium-Duty Passenger Vehicle Tailpipe Emission Standards

The standards in this category apply to all light-duty vehicles (LDVs, or passenger cars), light-duty trucks (LDT1s, LDT2s, LDT3s, and LDT4s) and Medium-Duty Passenger Vehicles, or MDPVs. The new standards are for the sum of NMOG and NO<sub>x</sub> emissions, presented as NMOG+NO<sub>x</sub>, and for PM. For these pollutants, the standards are measured on test procedures that represent a range of vehicle operation, including the Federal Test Procedure (or FTP, simulating typical driving) and the Supplemental Federal Test Procedure (or SFTP, a composite test simulating higher temperatures, higher speeds, and quicker accelerations).

The FTP and SFTP NMOG+NO<sub>x</sub> standards are fleet-average standards, meaning that a manufacturer will calculate the weighted average emissions of the vehicles it sells in each model year and compare that average to the applicable standard for that model year. The fleet average

standards for NMOG+NO<sub>x</sub> evaluated over the FTP will begin in MY 2017 and then decline through MY 2025, as summarized in Table ES-1. Similarly, the NMOG+NO<sub>x</sub> standards measured over the SFTP will also be fleet-average standards, declining from MY 2017 until MY 2025, as shown in Table ES-2.

**Table ES-1 LDV, LDT, and MDPV Fleet Average NMOG+NO<sub>x</sub> FTP Standards (mg/mi)**

	Model Year								
	2017 <sup>a</sup>	2018	2019	2020	2021	2022	2023	2024	2025 and later
LDV/LDT1 <sup>b</sup>	86	79	72	65	58	51	44	37	30
LDT2,3,4 and MDPV	101	92	83	74	65	56	47	38	30

<sup>a</sup> For vehicles above 6000 lbs GVWR, the fleet average standards will apply beginning in MY 2018.

<sup>b</sup> These standards will apply for a 150,000 mile useful life. Manufacturers can choose to certify their LDVs and LDV1s to a useful life of 120,000 miles. If any of these families are certified to the shorter useful life, a proportionally lower numerical fleet-average standard will apply, calculated by multiplying the respective 150,000 mile standard by 0.85 and rounding to the nearest mg.

**Table ES-2 LDV, LDT, and MDPV Fleet-Average NMOG+NO<sub>x</sub> SFTP Fleet Average Standards (mg/mi)**

	Model Year								
	2017 <sup>a</sup>	2018	2019	2020	2021	2022	2023	2024	2025 and later
NMOG + NO <sub>x</sub>	103	97	90	83	77	70	63	57	50

<sup>a</sup> For vehicles above 6000 lbs GVWR, the fleet average standards will apply beginning in MY 2018.

The PM standard on the FTP for certification testing is 3 mg/mi for all vehicles and for all model years. Manufacturers can phase in their vehicle models as a percent of sales through MY 2022. The FTP PM standards will apply to each vehicle separately (i.e., not as a fleet average). The program also includes a separate FTP PM requirement of 6 mg/mi for the testing of in-use vehicles that will apply during the percent phase-in period only. Table ES-3 presents the FTP certification and in-use PM standards and the phase-in percentages.

**Table ES-3 Phase-In for FTP PM Standards**

	2017 <sup>a</sup>	2018	2019	2020	2021	2022 and later
Phase-In (percent of U.S. sales)	20	20	40	70	100	100
Certification Standard (mg/mi)	3	3	3	3	3	3
In-Use Standard (mg/mi)	6	6	6	6	6	3

<sup>a</sup> For vehicles above 6000 lbs GVWR, the FTP PM standards will apply beginning in MY 2018.

The Tier 3 program also includes certification PM standards evaluated over the SFTP (specifically the US06 component of the SFTP procedure) of 10 mg/mi for MYs 2017 and MY 2018, and a single final standard of 6 mg/mi for MY 2019 and later. For MYs 2019 through 2023, an in-use standard of 10 mg/mi will also apply.

#### Heavy-Duty Tailpipe Emission Standards

There are new Tier 3 exhaust emissions standards for complete heavy-duty vehicles (HDVs) between 8,501 and 14,000 lb GVWR. Vehicles in this GVWR range are often referred to as Class 2b (8,501-10,000 lb) and Class 3 (10,001-14,000 lb) vehicles, and are typically full-size pickup trucks and work vans. The key elements of these standards include a combined NMOG+NO<sub>x</sub> declining fleet average standard, new stringent PM standards phasing in on a separate schedule, extension of the regulatory useful life to 150,000 miles, and a new requirement to meet standards over the SFTP that will address real-world driving modes not well-represented by the FTP cycle alone. Table ES-4 presents the HDV fleet average NMOG+NO<sub>x</sub> standard, which becomes more stringent in successive model years from 2018 to 2022, with voluntary standards available in 2016 and 2017.

The PM standards are 8 mg/mi for Class 2b vehicles and 10 mg/mi for Class 3 vehicles, to be phased in on a percent-of-sales basis at 20-40-70-100 percent in 2018-2019-2020-2021, respectively.

**Table ES-4 HDV Fleet Average NMOG+NO<sub>x</sub> Standards (mg/mi)**

Model Year	Voluntary		Required Program				
	2016	2017	2018	2019	2020	2021	2022 and later
Class 2b	333	310	278	253	228	203	178
Class 3	548	508	451	400	349	298	247

The new SFTP requirements for HDVs include NMOG+NO<sub>x</sub>, carbon monoxide (CO) and PM standards. Compliance will be evaluated from a weighted composite of measured emissions from testing over the FTP cycle, the SC03 cycle, and an aggressive driving cycle, with the latter tailored to various HDV sub-categories: the US06 cycle for most HDVs, the highway

portion of the US06 cycle for low power-to-weight Class 2b HDVs, and the LA-92 cycle for Class 3 HDVs.

### Evaporative Emission Standards

To control evaporative emissions, more stringent standards will require covered vehicles to have essentially zero fuel vapor emissions in use, including more stringent evaporative emissions standards, new test procedures, and a new fuel/evaporative system leak standard. Tier 3 also includes refueling emission standards for complete heavy-duty gasoline vehicles (HDGVs) over 10,000 lbs GVWR. There are phase-in flexibilities as well as credit and allowance programs. The standards, harmonized with California’s zero evaporative emissions standards, are designed to essentially eliminate fuel vapor-related evaporative emissions. The Tier 3 evaporative emission standards will be phased in over a period of six MYs 2017-2022 as shown in Table ES-5.

**Table ES-5 Default Phase-in Schedule for Tier 3  
Evaporative Emission Standards**

Model year	Minimum percentage of vehicles subject to the Tier 3 standards
2017	40% <sup>1,2,3</sup>
2018	60%
2019	60%
2020	80%
2021	80%
2022	100%

<sup>1</sup> The phase-in percentage for model year 2017 applies only for vehicles at or below 6,000 pounds GVWR.

<sup>2</sup> The leak standard does not apply for model year 2017.

<sup>3</sup> There are three options for the 2017 MY, only one is shown here.

Table ES-6 presents the evaporative hot soak plus diurnal emission standards by vehicle class. Manufacturers may comply on average within each of the four vehicle categories but not across these categories. Tier 3 also includes separate high altitude emission standards for these vehicle categories.

**Table ES-6 Evaporative Emission Standards (g/test)**

Vehicle Category	Highest Diurnal + Hot Soak Level (over both 2-day and 3-day diurnal tests)
LDV, LDT1	0.300
LDT2	0.400
LDT3, LDT4, MDPV	0.500
HDGVs	0.600

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There is a new testing requirement referred to as the bleed emission test procedure. Manufacturers will be required to measure diurnal emissions over the 2-day diurnal test procedure from just the fuel tank and the evaporative emission canister and comply with a 0.020 g/test standard for all LDVs, LDTs, and MDPVs without averaging. The canister bleed emission standard test will apply only for low altitude testing conditions, but there is proportional control at higher altitudes.

EPA is including these Tier 3 evaporative emission controls for HDGVs as part of the overall scheme for LDVs and LDTs. The individual vehicle emission standard will be 0.600 g/test for both the 2-day and 3-day evaporative emission tests, the high altitude standard will be 1.75 g/test and the canister bleed test standard will be 0.030 g/test.

We are adding a new standard and test procedure related to controlling vapor leaks from vehicle fuel and vapor control systems. The standard, which will apply to all LDVs, LDTs, MDPVs, and Class 2b/3 HDGVs, will prohibit leaks larger than 0.02 inches of cumulative equivalent diameter in the fuel/evaporative system. The Tier 3 evaporative emission standards program requirements will be phased in over a period of six model years between MYs 2017 and 2022, with the leak test phasing in beginning in 2018 MY as a vehicle is certified to meet Tier 3 evaporative emission requirements.

There are new refueling emission control requirements for complete HDGVs equal to or less than 14,000 lbs GVWR (i.e., Class 2b/3 HDGVs), that start in the 2018 model year. For complete HDGVs > 14,000 lbs GVWR the refueling emission control requirement start in the 2022 model year.

We are adopting and incorporating by reference the current CARB onboard diagnostic system (OBD) regulations effective for the 2017 MY plus two minor provisions to enable OBD-based leak detection to be used in IUVP testing. EPA will retain the provision that certifying with CARB's program will permit manufacturers to seek a separate EPA certificate on that basis.

### *Emissions Test Fuel Requirements*

There are several changes to our federal gasoline emissions test fuel. Key changes include:

- Moving away from “indolene” (E0) to a test fuel containing 10 percent ethanol by volume (E10);
- Lowering octane to match regular-grade gasoline (except for premium-required vehicles);
- Adjusting distillation temperatures, aromatics and olefins to better match today's in-use fuel and to be consistent with anticipated E10 composition; and
- Lowering the existing sulfur specification and setting a benzene specification to be consistent with proposed Tier 3 gasoline sulfur requirements and recent MSAT2 gasoline benzene requirements.

- 
- E85 and premium test fuel specifications.

### *Gasoline Sulfur Standards*

Under the Tier 3 fuel program, federal gasoline will contain no more than 10 parts per million (ppm) sulfur on an annual average basis beginning January 1, 2017. There will be an averaging, banking, and trading (ABT) program that would allow refiners and importers to spread out their investments through an early credit program and rely on ongoing nationwide averaging to meet the 10 ppm sulfur standard. There will be a three-year delay for small refiners and “small volume refineries” (refiners processing less than or equal to 75,000 barrels per calendar day). In addition, we are maintaining the current refinery gate and downstream sulfur caps of 80 ppm and 95 ppm, respectively.

### **Projected Impacts**

#### *Changes to Analyses Since Proposal*

Since the proposal, we have made several updates to the analyses that estimate the projected impacts of the Tier 3 standards. We made several changes to our baseline (also referred to as the “reference case”), which is our projection of future conditions if the Tier 3 standards were not finalized. Specifically, our baseline now accounts for the fact that California and twelve additional states have adopted California’s Low Emission Vehicle III (LEV III) program. This change reduces the emissions and air quality impacts of the Tier 3 standards (and thus the monetized benefits), and it also reduces the cost of the Tier 3 vehicle standards. In addition, the baseline now accounts for the light-duty greenhouse gas emissions standards for 2017 and later model years, and the greenhouse gas emissions standards for medium- and heavy-duty engines and vehicles. This update affects the per-vehicle technology costs but has little impact on the emissions and air quality benefits of the Tier 3 program, because it is included in both the baseline and control cases. Finally, the baseline now uses the U.S. Energy Information Administration’s Annual Energy Outlook 2013 (AEO2013) as the source for future renewable fuel volumes and blends and future gasoline consumption. AEO2013 projects significantly lower gasoline consumption than AEO2011 (which was used in the proposal’s analysis), and this reduces the total cost of the Tier 3 fuel program. There are a number of other updates to our cost, emissions, air quality, and benefits analyses, as detailed in the RIA. Among the most significant are the changes to the vehicle and fuel cost estimates, which have resulted in costs that are lower than projected in the proposal. The updates with the most significant impacts on the per-vehicle costs include a more robust estimate of catalyst loading costs and the new baseline fleet that reflects implementation of the most recent greenhouse gas emissions standards. Both of these updates reduced per-vehicle costs. Total vehicle program costs were also significantly reduced because costs are no longer incurred for vehicles sold in states that have adopted the California LEV III program. With respect to fuel costs, the change with the most significant impact on per-gallon costs is the inclusion of nationwide credit trading (i.e., between companies). The proposal’s primary cost analysis was based only on trading within companies (although we also presented in the proposal the cost if trading between firms occurred). The reduction in per-gallon costs, when combined with significantly lower

projections of gasoline consumption from AEO2013, resulted in lower fuel program costs than the proposal had estimated.

*Emission and Air Quality Impacts*

The Tier 3 vehicle and fuel-related standards together will reduce emissions of NO<sub>x</sub>, VOC, PM<sub>2.5</sub>, and air toxics. The gasoline sulfur standards, which will take effect in 2017, will provide large immediate reductions in emissions from existing gasoline vehicles and engines. The emission reductions will increase over time as newer vehicles become a larger percentage of the fleet (e.g., in 2030, 70 percent of the miles travelled are from vehicles that meet the fully phased-in Tier 3 standards). Projected emission reductions from the Tier 3 standards for 2018 and 2030 are shown in Table ES-7. We expect these reductions to continue beyond 2030 as more of the fleet continues to turn over to Tier 3 vehicles.

**Table ES-7 Estimated Emission Reductions from the Final Tier 3 Standards  
(Annual U.S. short tons)**

	2018		2030	
	Tons	Percent of Onroad Inventory	Tons	Percent of Onroad Inventory
NO <sub>x</sub>	264,369	10%	328,509	25%
VOC	47,504	3%	167,591	16%
CO	278,879	2%	3,458,041	24%
Direct PM <sub>2.5</sub>	130	0.1%	7,892	10%
Benzene	1,916	6%	4,762	26%
SO <sub>2</sub>	14,813	56%	12,399	56%
1,3-Butadiene	257	5%	677	29%
Formaldehyde	513	2%	1,277	10%
Acetaldehyde	600	3%	2,067	21%
Acrolein	40	3%	127	15%
Ethanol	2,704	2%	19,950	16%

We project that the Tier 3 vehicle and fuel standards will reduce nitrous oxide (N<sub>2</sub>O) and methane (CH<sub>4</sub>) emissions from vehicles. The reductions in these potent greenhouse gases will be partially offset by the increase in CO<sub>2</sub> emissions from refineries. The combined impact is a net decrease on a CO<sub>2</sub>-equivalent basis (2.5 to 2.7 million metric tons of CO<sub>2</sub>-equivalent reduced in 2030).

Reductions in emissions of NO<sub>x</sub>, VOC, PM<sub>2.5</sub> and air toxics are projected to lead to nationwide decreases in ambient concentrations of ozone, PM<sub>2.5</sub>, NO<sub>2</sub>, CO, and air toxics. Specifically, the Tier 3 standards will significantly decrease ozone concentrations across the country, with an estimated population-weighted average decrease of 0.49 ppb in 2018 and 0.98 ppb in 2030. Few other strategies exist that would deliver the reductions needed for states to meet the current ozone standards. The Tier 3 standards will decrease ambient annual PM<sub>2.5</sub> concentrations across the county as well, with an estimated population-weighted average decrease of 0.04 µg/m<sup>3</sup> by 2030. Decreases in ambient concentrations of air toxics are also

projected with the Tier 3 standards, including notable nationwide reductions in benzene concentrations.

### Costs and Benefits

The costs that will be incurred from our final program fall into two categories – costs from the Tier 3 vehicle exhaust and evaporative standards and from reductions in sulfur content of gasoline. All costs represent the fleet-weighted average of light-duty vehicles and trucks. All costs are represented in 2011 dollars.

#### Vehicle Costs

The vehicle costs include the technology costs projected to meet the exhaust and evaporative standards, as show in Table ES-8. The fleet mix of light-duty vehicles, light duty trucks, and medium-duty trucks reflects the MY 2017-2025 light-duty and MY2014-2018 heavy-duty GHG final rulemakings.

**Table ES-8 Annual Vehicle Technology Costs, 2011\$**

Year	Vehicle Exhaust Emission Control Costs (\$Million)	Vehicle Evaporative Emission Control Costs (\$Million)	Operating Costs (\$Million)	Facility Costs (\$Million)	Total Vehicle Costs (\$Million) <sup>a</sup>
2017	\$268	\$26	\$0	\$4	\$297
2030	\$664	\$113	-\$19	\$4	\$761

<sup>a</sup> These estimates include costs associated with the Tier 3 vehicle standards in all states except California and states that have adopted the LEV III program.

#### Fuel Costs

The fuel costs consist of the additional operating costs and capital costs to the refiners to meet the sulfur average of 10 ppm. The sulfur control costs assume a cost of 0.65 cents per gallon which includes the refinery operating and capital costs. The annual fuel costs of the program are listed in Table ES-9.

**Table ES-9 Annual Fuel Costs, 2011\$**

Year	Fuel Sulfur Control Costs (\$Million) <sup>a</sup>
2017	\$804
2030	\$696

<sup>a</sup> These estimates include costs associated with the Tier 3 fuel standards in all states except California.

#### Total Costs

The sum of the vehicle technology costs to control exhaust and evaporative emissions, in addition to the costs to control the sulfur level in the fuel, represent the total costs of the

program, as shown in Table ES-10. The final fuel standards are projected to lead to an average cost of 0.65 cents per gallon of gasoline, and the vehicle standards would have an average technology cost of \$72 per vehicle

**Table ES-10: Total Annual Vehicle and Fuel Control Costs, 2011\$**

Year	Total Vehicle and Fuel Control Costs (\$Million) <sup>a</sup>
2017	\$1,101
2030	\$1,457

<sup>a</sup> These estimates include costs associated with both the Tier 3 vehicle standards in all states except California and states that have adopted the LEV III program, and the Tier 3 fuel standards in all states except California.

### Benefits

Exposure to ambient concentrations of ozone, PM<sub>2.5</sub>, and air toxics is linked to adverse human health impacts such as premature deaths as well as other important public health and environmental effects. The final Tier 3 standards are expected to reduce these adverse impacts and yield significant benefits, including those we can monetize and those we are unable to quantify.

The range of quantified and monetized benefits associated with this program are estimated based on the risk of several sources of PM- and ozone-related mortality effect estimates, along with other PM and ozone non-mortality related benefits information. Overall, we estimate that the final rule will lead to a net decrease in PM<sub>2.5</sub>- and ozone-related health and environmental impacts. The estimated range of total monetized ozone- and PM-related health impacts is presented in Table ES-11.

**Table ES-11: Estimated 2030 Monetized PM-and Ozone-Related Health Benefits  
(Billions, 2011\$)<sup>a</sup>**

Description	2030
Total Estimated Health Benefits <sup>b,c,d,e</sup>	
3 percent discount rate	\$7.4 - \$19
7 percent discount rate	\$6.7 - \$18

Notes:

<sup>a</sup> Totals are rounded to two significant digits and may not sum due to rounding.

<sup>b</sup> Total includes ozone and PM<sub>2.5</sub> estimated benefits. Range was developed by adding the estimate from the Bell et al., 2004 ozone premature mortality function to PM<sub>2.5</sub>-related premature mortality derived from the American Cancer Society cohort study (Krewski et al., 2009) for the low estimate and ozone premature mortality derived from the Levy et al., 2005 study to PM<sub>2.5</sub>-related premature mortality derived from the Six-Cities (Lepeule et al., 2012) study for the high estimate.

<sup>c</sup> Annual benefits analysis results reflect the use of a 3 percent and 7 percent discount rate in the valuation of premature mortality and nonfatal myocardial infarctions, consistent with EPA and OMB guidelines for preparing economic analyses.

<sup>d</sup> Valuation of premature mortality based on long-term PM exposure assumes discounting over the SAB recommended 20-year segmented lag structure described in the Regulatory Impact Analysis for the 2006 PM National Ambient Air Quality Standards (September, 2006).

<sup>c</sup> Not all possible benefits are quantified and monetized in this analysis; the total monetized benefits presented here may therefore be underestimated.

We estimate that by 2030, the annual emission reductions of the Tier 3 standards will annually prevent between 660 and 1,500 PM-related premature deaths, between 110 and 500 ozone-related premature deaths, 81,000 work days lost, and approximately 1.1 million minor restricted-activity days. The estimated annual monetized health benefits of the proposed Tier 3 standards in 2030 (2011\$) will be between \$7.4 and \$19 billion, assuming a 3-percent discount rate (or between \$6.7 billion and \$18 billion assuming a 7-percent discount rate).

### Comparison of Costs and Benefits

Using a conservative benefits estimate, the 2030 benefits outweigh the costs by a factor of 4.5. Using the upper end of the benefits range, the benefits could outweigh the costs by a factor of 13. Thus, even taking the most conservative benefits assumptions, benefits of the final standards are projected to outweigh the costs. The results are shown in Table ES-12.

**Table ES-12 Summary of Annual Benefits and Cost Associated with the Final Tier 3 Program (Billions, 2011\$)<sup>a</sup>**

<b>Description</b>	<b>2030</b>
Vehicle Program Costs	\$0.76
Fuels Program Costs	\$0.70
Total Estimated Costs <sup>b</sup>	\$1.5
Total Estimated Health Benefits <sup>c,d,e,f</sup>	
3 percent discount rate	\$7.4 - \$19
7 percent discount rate	\$6.7 - \$18
Annual Net Benefits (Total Benefits – Total Costs)	
3 percent discount rate	\$5.9 - \$18
7 percent discount rate	\$5.2 - \$17

Notes:

<sup>a</sup> All estimates represent annual benefits and costs anticipated for the year 2030. Totals are rounded to two significant digits and may not sum due to rounding.

<sup>b</sup> The calculation of annual costs does not require amortization of costs over time. Therefore, the estimates of annual cost do not include a discount rate or rate of return assumption (see Chapter 2 of the RIA for more information on vehicle costs, Chapter 5 for fuel costs, and Section 8.1.1 for a summary of total program costs).

<sup>c</sup> Total includes ozone and PM<sub>2.5</sub> estimated benefits. Range was developed by adding the estimate from the Bell et al., 2004 ozone premature mortality function to PM<sub>2.5</sub>-related premature mortality derived from the American Cancer Society cohort study (Krewski et al., 2009) for the low estimate and ozone premature mortality derived from the Levy et al., 2005 study to PM<sub>2.5</sub>-related premature mortality derived from the Six-Cities (Lepeule et al., 2012) study for the high estimate.

<sup>d</sup> Annual benefits analysis results reflect the use of a 3 percent and 7 percent discount rate in the valuation of premature mortality and nonfatal myocardial infarctions, consistent with EPA and OMB guidelines for preparing economic analyses.

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<sup>e</sup> Valuation of premature mortality based on long-term PM exposure assumes discounting over the SAB recommended 20-year segmented lag structure described in the Regulatory Impact Analysis for the 2012 PM National Ambient Air Quality Standards (December, 2012).

<sup>f</sup> 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 8-5.

### *Economic Impact Analysis*

The rule will affect two sectors directly: vehicle manufacturing and petroleum refining. The estimated increase in vehicle production cost because of the rule is expected to be small relative to the costs of the vehicle. Some or all of this production cost increase will be expected to be passed through to consumers. This increase in price is expected to lower the quantity of vehicles sold, though because the expected cost increase is small, we expect the decrease in sales to be negligible. This decrease in vehicle sales is expected to decrease employment in the vehicle manufacturing sector. However, costs related to compliance with the rule should also increase employment in this sector. While it is unclear which of these effects will be larger, because the increase in vehicle production costs and the decrease in vehicle sales are minor, the impact of the rule on employment in the vehicle manufacturing sector is expected to be small as well. The key change for refiners from the proposed standards will be more stringent sulfur requirements. Analogous to vehicle sales, this change to fuels is expected to increase manufacturers' costs of fuel production. Some or all of this increase in production costs is expected to be passed through to consumers which should lead to a decrease in fuel sales. As with the vehicle manufacturing sector, we expect the decrease in fuel sales to negatively affect employment in this sector, while the costs of compliance with the rule will be expected to increase employment. It is not evident whether the rule will increase or decrease employment in the refining sector as a whole. However, given the small anticipated increase in production costs of less than one cent per gallon and the small likely decrease in fuel sales, we expect that the rule will not have major employment consequences for this sector.

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# Chapter 1 Vehicle Program Technological Feasibility

## 1.1 Introduction

For the vehicles and emissions addressed in this final rule, EPA has comprehensively assessed the technological phenomena related to the generation of emissions of interest, the nature of the technological challenges facing manufacturers to produce emission reductions of the scale described in the Preamble, and the technologies that we expect to be available to manufacturers to meet those challenges during the rule implementation time frame. Our feasibility assessment recognizes that the Tier 3 program is composed of several new requirements for all types of new vehicles, including a range of vehicle classes from small cars to large pick-up trucks and MDPVs, and even heavy-duty vehicles with diverse applications and specific engine designs matched to the needs of the users. This assessment also recognizes the critical role of gasoline sulfur content in making it possible for us to adopt emission standards at these very stringent levels, particularly for certain vehicle types. We provide below a full assessment of our current knowledge of the effects of gasoline sulfur on current vehicle emissions as well as our projections of how sulfur can be expected to affect compliance with the Tier 3 standards.

Since there are multiple aspects to the Tier 3 program, it is necessary to consider technical feasibility in light of the different program requirements and their interactions with each other. For example, the technical feasibility of the finalized Tier 3 FTP NMOG+NO<sub>x</sub> and the PM standards is directly related to the specifications of the fuel, including fuel sulfur, RVP and ethanol content. Additionally, as mentioned above, the feasibility assessment must consider that different technologies may be needed on different types of vehicle applications (i.e., cars versus trucks) and must consider the effectiveness of these technologies to reduce emissions for the full useful life of the vehicle while operating on in-use fuels. Certain smaller vehicles with correspondingly small engines may be less challenged to meet FTP standards than larger vehicles with larger engines. Conversely, these smaller vehicles may have more difficulty meeting the SFTP requirements than the larger and more powerful vehicles. Additionally, the ability to meet the SFTP emission requirements can also be impacted by the path taken to meet the FTP requirements (i.e., larger volume catalysts for US06 emissions control vs. smaller catalysts for improved FTP cold-start emissions control).

The rule also contains revised evaporative emission standards to be met on 9RVPE10 test fuel for LDVs, LDTs, MDPVs, and HDGVs, as well as leak standard for all gasoline-powered LDVs, LDTs, MDPVs, and HDGVs rated at or below 14,000 lbs GVWR and new OBD requirements for LDVs, LDTs, MDPVs, and HDVs rated at or below 14,000 lbs GVWR. The feasibility of these standards is discussed below as well.

## 1.2 FTP NMOG+NO<sub>x</sub> Feasibility

The new emission requirements include stringent NMOG+ NO<sub>x</sub> standards over the FTP that would require new vehicle hardware and additional control of gasoline sulfur levels in order to achieve the 30 mg/mi fleet average level in 2025. The type of new hardware that would be required would vary depending on the specific application and emission challenges. Smaller

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vehicles with corresponding smaller engines would generally need less new hardware while larger vehicles and other vehicles with larger engines may need additional hardware and improvements beyond what would be needed for the smaller vehicles with smaller engines. Additionally, the fleet-average nature of the standards allows more challenged vehicles to be offset by vehicles that could outperform the required fleet averages.

In order to assess the technical feasibility of a 30 mg/mi NMOG+NO<sub>x</sub> national fleet average FTP standard and a 3 mg/mi PM vehicle standard, EPA conducted two primary analyses. The initial analyses performed were of the current Tier 2 and LEV II fleets. This provided a baseline for the current federal fleet emissions performance, as well as the emissions performance of the California LEV II fleet. The second consideration was a modal analysis of typical vehicle emissions under certain operating conditions. In this way EPA determined the specific emissions performance challenges that vehicle manufacturers would face in meeting the lower fleet average emission standards. Each of these considerations is described in greater detail below.

### 1.2.1 Assessment of the Current Federal Fleet Emissions

The current federal fleet is only required to be certified to an average of Tier 2 Bin 5, equivalent to 160 mg/mi NMOG+NO<sub>x</sub>.<sup>A</sup> For example, in MY 2009 92 percent of passenger cars and LDT1s were certified to Tier 2 Bin 5 and 91 percent of LDT2s through LDT4s were certified to Tier 2 Bin 5. This was not an unexpected result as there was no motivation for vehicle manufacturers to produce a federal fleet that over-complied with respect to the Tier 2 standards. By comparison, in the MY 2009 California fleet, where compliance with the LEVII declining NMOG requirement and the “PZEV” program encouraged manufacturers to certify to cleaner levels, only 30 percent of the passenger cars and LDT1s were certified to Tier 2 Bin 5 and 60 percent were certified to Tier 2 Bin 3. The situation regarding the truck fleet in California was similarly stratified, with 37 percent of the LDT2s through LDT4s being certified to Tier 2 Bin 5 and 55 percent being certified to Tier 2 Bin 3. In many cases, vehicles were being certified to a lower standard in California and a higher standard federally. In the proposal, EPA stated a belief that the patterns described above indicated that much of the Tier 2 fleet could be certified to a lower federal fleet average immediately, with no major feasibility concerns.<sup>B</sup>

For the final rule, we have looked at MY2013 certification data. The MY 2013 data indicate that more engine families are being certified to cleaner Tier 2 bins than what was observed in previous MYs. In fact, in MY2013, while only 68% of passenger car and LDT1 families and 65% of LDT2s through LDT4s are certified to Tier 2 Bin 5, 31% of passenger car and LDT1 and 29% of LDT2 through LDT4 are now certified to Tier 2 Bins 2 through 4. This supports our stated belief that the Tier 2 fleet could be certified to a lower federal fleet average without feasibility concerns. Table 1-1 shows that 58 MY2013 engine families have certified

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<sup>A</sup> The current Tier 2 program does not combine NMOG and NO<sub>x</sub> emissions into one fleet-average standard. The fleet-average standard in that program is for NO<sub>x</sub> emissions alone.

<sup>B</sup> Compliance with full useful life standards in California occurs at much lower in-use gasoline sulfur levels than is the case with federally certified vehicles. For further discussion of the impact of gasoline fuel sulfur on light-vehicle emissions feasibility and in-use compliance, please refer to Section 1.2.4.

emission levels well below the Tier 2 bin to which they have been certified. The table also shows that these engine families have emissions at or below the Tier 3 30 mg/mi NMOG+NOx level.

**Table 1-1 MY2013 Certified Engine Families with Certified Emission Levels at or Below the Tier 3 NMOG+NOx 30 mg/mi Standard**

Mfr	Model	NMOG (g/mi)	NOx (g/mi)	Certified NMOG +NOx (g/mi)	NMOG +NOx of Tier 2 bin (g/mi)	Certified emissions at or below Tier 3 bin
Audi	A3	0.005	0.011	0.016	0.085	20
BMW	John Cooper Works All4 Countryman	0.017	0.010	0.027	0.160	30
BMW	328i xDrive	0.010	0.010	0.020	0.160	30
BMW	328 Ci Convertible	0.010	0.010	0.020	0.160	30
BMW	ActiveHybrid 7	0.012	0.010	0.022	0.160	30
BMW	ActiveHybrid 7	0.012	0.010	0.022	0.160	30
Chrysler	Patriot 4wd	0.003	0.020	0.023	0.160	30
Chrysler	Patriot 2wd	0.003	0.010	0.013	0.160	20
Chrysler	Dart	0.003	0.010	0.013	0.110	20
Ford	Fusion FWD	0.006	0.010	0.016	0.085	20
Ford	FOCUS	0.004	0.010	0.014	0.085	20
Ford	MKZ (HEV)	0.011	0.000	0.011	0.085	20
Ford	MKZ (HEV)	0.011	0.000	0.011	0.085	20
Ford	C-Max (PHEV)	0.008	0.010	0.018	0.085	20
GM	REGAL	0.020	0.000	0.020	0.110	30
GM	MALIBU	0.005	0.010	0.015	0.110	20
GM	MALIBU	0.005	0.010	0.015	0.110	20
GM	XTS	0.008	0.020	0.028	0.110	30
Honda	INSIGHT EX	0.009	0.010	0.019	0.085	20
Honda	ILX HYBRID	0.011	0.010	0.021	0.085	30
Honda	CIVIC HYBRID	0.012	0.010	0.022	0.085	30
Jaguar Cars	XJ 3.0	0.008	0.020	0.028	0.160	30
Mazda	Mazda 3 DI 5-Door	0.008	0.010	0.018	0.160	20
Mercedes-Benz	GLK 350 4MATIC	0.008	0.010	0.018	0.110	20
Mercedes-Benz	S 400 HYBRID	0.005	0.010	0.015	0.110	20
Mercedes-Benz	E 400 HYBRID	0.007	0.010	0.017	0.110	20
Nissan	NISSAN TITAN 4WD Crew Cab XE LWB	0.024	0.000	0.024	0.160	30
Nissan	NISSAN VERSA S	0.018	0.000	0.018	0.160	20
Nissan	NISSAN ALTIMA 2.5SL	0.010	0.000	0.010	0.160	20
Subaru	OUTBACK WAGON AWD	0.005	0.020	0.025	0.110	30
Subaru	OUTBACK WAGON AWD	0.005	0.020	0.025	0.110	30
Suzuki	GRAND VITARA 4WD	0.024	0.005	0.029	0.160	30
Toyota	TACOMA 2WD	0.012	0.010	0.022	0.160	30
Toyota	RX 450h AWD	0.008	0.000	0.008	0.085	20
Toyota	RX 450h AWD	0.007	0.000	0.007	0.085	20
Toyota	FJ CRUISER 4WD	0.019	0.010	0.029	0.160	30
Toyota	LX 570	0.019	0.010	0.029	0.160	30
Toyota	iQ	0.017	0.010	0.027	0.160	30

Toyota	YARIS	0.018	0.010	0.028	0.160	30
Toyota	PRIUS c	0.006	0.000	0.006	0.085	20
Toyota	PRIUS v	0.004	0.000	0.004	0.085	20
Toyota	PRIUS	0.005	0.000	0.005	0.085	20
Toyota	PRIUS Plug-in Hybrid	0.005	0.000	0.005	0.085	20
Toyota	ES 300h	0.008	0.000	0.008	0.085	20
Toyota	ES 300h	0.007	0.000	0.007	0.085	20
Toyota	Camry Hybrid XLE	0.006	0.010	0.016	0.085	20
Toyota	CAMRY	0.006	0.020	0.026	0.160	30
Toyota	GS 450h	0.006	0.010	0.016	0.085	20
Toyota	LS 460 L AWD	0.018	0.010	0.028	0.160	30
Toyota	LS 600h L	0.006	0.000	0.006	0.085	20
Volkswagen	Jetta Hybrid	0.008	0.007	0.015	0.085	20
Volkswagen	Eos	0.004	0.008	0.012	0.085	20
Volkswagen	Eos	0.004	0.008	0.012	0.085	20
Volkswagen	Eos	0.004	0.008	0.012	0.085	20
Volkswagen	Jetta	0.010	0.002	0.012	0.085	20
Volkswagen	Jetta	0.010	0.002	0.012	0.085	20
Volkswagen	Jetta	0.010	0.002	0.012	0.085	20
Volkswagen	Jetta	0.010	0.002	0.012	0.085	20

Looking at the MY2013 certification data more closely and in the context of Tier 3 compliance, we find that 40 engine families are certified to emission levels low enough to provide sufficient compliance margin (30% compliance margin, or 70% of the standard) to enable Tier 3 compliance today.<sup>C</sup> Table 1-2 shows these 40 engine families, their certified emission levels, and the Tier 3 bin into which they could be certified while providing 30% compliance margin.

**Table 1-2 MY2013 Certified Engine Families with Certified Emission Levels that Could be Certified to Tier 3 Today\***

Mfr	Model	NMOG (g/mi)	NOx (g/mi)	Certified NMOG +NOx (g/mi)	Possible Tier 3 bin*
Audi	A3	0.005	0.011	0.016	30
BMW	328i xDrive	0.010	0.010	0.020	30
BMW	328 Ci Convertible	0.010	0.010	0.020	30
Chrysler	Patriot 2wd	0.003	0.010	0.013	20
Chrysler	Dart	0.003	0.010	0.013	20
Ford	Fusion FWD	0.006	0.010	0.016	30
Ford	FOCUS	0.004	0.010	0.014	20
Ford	MKZ (HEV)	0.011	0.000	0.011	20
Ford	MKZ (HEV)	0.011	0.000	0.011	20

<sup>C</sup> We believe that manufacturers will target compliance margins of 20-40% under Tier 3, as discussed in section 1.2.3 of this chapter. Here we have used 30% as it represents the midpoint of that expected range.

Ford	C-Max (PHEV)	0.008	0.010	0.018	30
GM	REGAL	0.020	0.000	0.020	30
GM	MALIBU	0.005	0.010	0.015	30
GM	MALIBU	0.005	0.010	0.015	30
Honda	INSIGHT EX	0.009	0.010	0.019	30
Honda	ILX HYBRID	0.011	0.010	0.021	30
Mazda	Mazda 3 DI 5-Door	0.008	0.010	0.018	30
Mercedes-Benz	GLK 350 4MATIC	0.008	0.010	0.018	30
Mercedes-Benz	S 400 HYBRID	0.005	0.010	0.015	30
Mercedes-Benz	E 400 HYBRID	0.007	0.010	0.017	30
Nissan	NISSAN VERSA S	0.018	0.000	0.018	30
Nissan	NISSAN ALTIMA 2.5SL	0.010	0.000	0.010	20
Toyota	RX 450h AWD	0.008	0.000	0.008	20
Toyota	RX 450h AWD	0.007	0.000	0.007	20
Toyota	PRIUS c	0.006	0.000	0.006	20
Toyota	PRIUS v	0.004	0.000	0.004	20
Toyota	PRIUS	0.005	0.000	0.005	20
Toyota	PRIUS Plug-in Hybrid	0.005	0.000	0.005	20
Toyota	ES 300h	0.008	0.000	0.008	20
Toyota	ES 300h	0.007	0.000	0.007	20
Toyota	Camry Hybrid XLE	0.006	0.010	0.016	30
Toyota	GS 450h	0.006	0.010	0.016	30
Toyota	LS 600h L	0.006	0.000	0.006	20
Volkswagen	Jetta Hybrid	0.008	0.007	0.015	30
Volkswagen	Eos	0.004	0.008	0.012	20
Volkswagen	Eos	0.004	0.008	0.012	20
Volkswagen	Eos	0.004	0.008	0.012	20
Volkswagen	Jetta	0.010	0.002	0.012	20
Volkswagen	Jetta	0.010	0.002	0.012	20
Volkswagen	Jetta	0.010	0.002	0.012	20
Volkswagen	Jetta	0.010	0.002	0.012	20

\*Including at least a 20% compliance margin (i.e., emissions 70% of the standard).

To support the FTP emission levels finalized for heavy duty vehicles, we analyzed the certification emission results from the 2010 through 2013 MY vehicles<sup>D</sup>. The new Tier 3 fleet average NMOG+NO<sub>x</sub> standard in 2022 for Class 2b vehicles is 178 mg/mi while the level for Class 3 vehicles is 247 mg/mi. Shown in Table 1-3 below are the emission levels of 2010 and 2011 MY heavy-duty vehicle models operating on various fuels. It is important to note that while we are finalizing a useful life of 150,000 miles, the current heavy duty vehicle requirements and therefore the reported emission results represent the 120,000 miles deteriorated results either calculated using deterioration factors applied to the 4,000 mile test or actual aged vehicles and components. It will be important for manufacturers to carefully manage emissions deterioration throughout the useful life of the vehicle to meet useful life emission requirements, consistent with the challenge for light-duty applications.

<sup>D</sup> Manufacturers will regularly carry-over data for several model years. Where available, the latest reported certification data was used for this analysis.

**Table 1-3: 2010 thru 2013 MY Heavy Duty Vehicle FTP 120k Certification Results**

	<b>Manufacturer</b>	<b>Models</b>	<b>Fuel Type</b>	<b>NMOG Level <sup>a</sup> (mg/mi)</b>	<b>NO<sub>x</sub> Level (mg/mi)</b>	<b>NMOG +NO<sub>x</sub> (mg/mi)</b>	<b>CO (g/mi)</b>	<b>PM (mg/mi)</b>
Class 2b <sup>b</sup>	Altech	F250	CNG	10	100	110	5.9	-
	Chrysler	Ram 2500	Gasoline	118	100	218	1.6	-
	Chrysler	Ram 2500	Diesel	63	200	263	.2	0
	Chrysler	Ram 2500	CNG	24	100	124	.8	-
	Ford	F250	Diesel	104	200	304	.9	10
	General Motors	Silverado 2500	Diesel	79	200	279	.7	1
	Mercedes-Benz	Sprinter	Diesel	4	100	104	.1	10
	Nissan	NV 3500 4.0L	Gasoline	57	0	57	1.4	
	Nissan	NV 3500 5.6L	Gasoline	66	100	166	1.3	-
Class 3 <sup>b</sup>	Baytech	Silverado 3500	CNG	11	100	111	1.3	-
	Chrysler	Ram 3500	Gasoline	133	200	333	2.6	-
	Chrysler	Ram 3500	Diesel	52	400	452	.2	3
	Ford	E350 <sup>c</sup>	Gasoline	51	82	133	2	-
	Ford	E350 <sup>c</sup>	E85	70	65	135	1.1	-
	Ford	F350	Diesel	89	300	389	.9	20
	Ford	F350	Gasoline	79	130	209	3.2	-
	Ford	F350	E85	76	83	159	1.8	-
	General Motors	Silverado 3500	Gasoline	131	150	281	3.4	-
	General Motors	Silverado 3500	Diesel	54	200	254	.5	0
	Mercedes-Benz	Sprinter	Diesel	11	100	111	.2	0

Notes:

<sup>a</sup> Diesel reported as NMHC

<sup>b</sup> Gasoline Class 2b models from General Motors and Ford certified using worst case Class 3 data

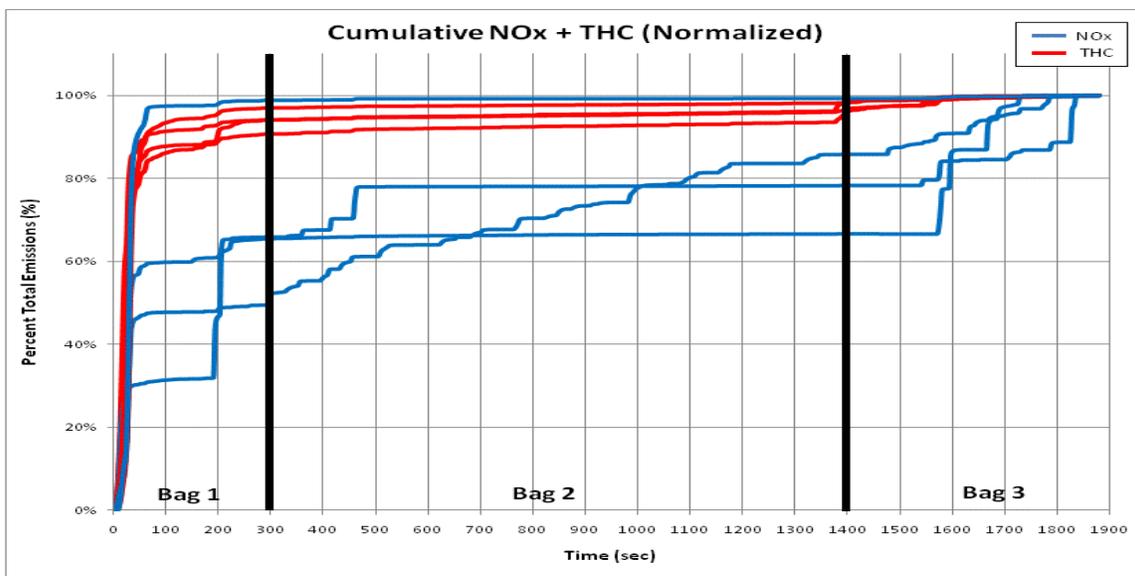
<sup>c</sup> Tested at LVW with MDPVs

### 1.2.2 NMOG and NO<sub>x</sub> Emissions on the FTP

To understand how several currently-used technologies described below could be used by manufacturers to reach the stringent Tier 3 NMOG+NO<sub>x</sub> standards, it is helpful to consider

emissions formation in common modes of operation for gasoline engines, or modal analysis.<sup>E</sup> As previously stated during the discussion of the NMOG+NO<sub>x</sub> standard, many gasoline engines produce very little NO<sub>x</sub> over the FTP. Thus, the challenge faced by manufacturers for producing Tier 3 compliant gasoline powertrains is to reduce the NMOG portion of the emissions. Based on modal analysis of a gasoline powered vehicle being operated on the FTP cycle, approximately 90 percent of the NMOG emissions occur during the first 50 seconds after a cold start. In addition, about 60 percent of the NO<sub>x</sub> emissions occur in this same period. The remainder of the emissions, particularly NO<sub>x</sub> emissions, are made during warmed up operation when the emission controls rely primarily on very high conversion efficiency of the catalyst. This is possible when catalyst performance, both on warm-up and during hot operation is not impeded by sulfur in the fuel. Figure 1-1 below shows the second-by-second emissions for NMOG and NO<sub>x</sub> following a cold start.

Thus, effective control of these cold-start emissions, especially NMOG emissions, would be the primary technological goal of manufacturers complying with the Tier 3 FTP standards. As discussed below, manufacturers are already applying several technologies capable of significant reductions in these cold start emission to vehicles currently on the road.



**Figure 1-1 Modal Analysis of NMOG and NO<sub>x</sub> Emissions (LA92)**

### 1.2.3 Compliance Margin

Vehicle manufacturers have historically designed vehicles to meet emissions targets which are 50-70 percent of the emission standards after the catalytic converters have been thermally aged and exposed to expected normal levels observed in-use of catalyst poisons (e.g.,

<sup>E</sup> A modal analysis provides a second-by-second view of the total amount of emissions over the entire cycle being considered.

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sulfur from fuel, phosphorous from lubricating oil, etc.) out to the vehicle's full useful life. This difference is referred to as "compliance margin" and is a result of manufacturers' efforts to address all the sources of variability and emissions control system degradation that could occur during the certification or in-use testing processes and during in-use operation. We believe that manufacturers will continue require a compliance margin however the combined MOG+NO<sub>x</sub> approach for Tier 3 will allow for some flexibility in the compliance margin targets. We expect that compliance margins for the Tier 3 combined standard will range from 20% to 40%, because the combined standard generally allows an increase in one emission constituent to be offset by a decrease in the other. Thus, the emission design targets for Tier 3 standards at full useful life would be approximately 18 to 24 mg/mi MOG+NO<sub>x</sub> for a Bin 30 certified vehicle at full useful life. These sources of variability include:

- Test-to-test variability (within one test site and lab-to-lab)
- Build variation and manufacturing tolerances
- Vehicle operation (for example: driving habits, ambient temperature, etc.)
- Fuel composition
  - The deleterious effects of fuel sulfur on exhaust catalysts and oxygen sensors
  - Other fuel composition impacts
- Oil consumption
  - The impact of direct emission of lubricating oil on semi-volatile organic PM emissions
  - The impact of oil additives and other components (e.g., phosphorous) and oil ash on exhaust catalysts and oxygen sensors

For MY 2013, the compliance margin for a Tier 2 Bin 5 vehicle averaged approximately 65 percent. In other words, actual vehicle emissions performance was on average about 35 percent of a 160 mg/mi NMOG+NO<sub>x</sub> standard, or about 56 mg/mi. By comparison, for MY 2013 California-certified vehicles, the average SULEV compliance margin was somewhat less for the more stringent standards, approximately 50 percent. We believe that the recent California experience is a likely indicator of the smaller compliance margins that manufacturers would design for in order to comply with the Tier 3 FTP standards. Thus, a typical Tier 2 Bin 5 vehicle, performing at 35 percent of the current standard (i.e., at about 56 mg/mi) would need improvements sufficient to achieve the Tier 3 targets for the 30 mg/mi combined NMOG+NO<sub>x</sub> standard.

#### 1.2.4 Impact of Gasoline Sulfur Control on the Feasibility of the Vehicle Emission Standards

In this section, we discuss the impact of gasoline sulfur control on the feasibility of the Tier 3 vehicle emissions standards and on the exhaust emissions of the existing in-use vehicle fleet. Section 1.2.4.1 describes the chemistry and physics of the impacts of gasoline sulfur compounds on exhaust catalysts. Sections 1.2.4.2, 1.2.4.3, and 1.2.4.4 summarize research on the impacts of gasoline sulfur on vehicles utilizing various degrees of emission control technology, with Section 1.2.4.2 summarizing historical studies on the impact of gasoline sulfur on vehicle emissions, Section 1.2.4.3 describing impacts on Tier 2 vehicles and the existing light-duty vehicle fleet, and Section 1.2.4.4 describing impacts on vehicles using technology consistent

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with what we expect to see in the future Tier 3 vehicle fleet. Section 1.2.4.5 provides EPA's assessment of the level of gasoline sulfur control necessary for light-duty vehicles to comply with Tier 3 exhaust emission standards.

EPA's primary findings are:

- Reducing gasoline sulfur content to a 10 ppm average will provide immediate and significant exhaust emissions reductions to the current, in-use fleet of light-duty vehicles.
- Reducing gasoline sulfur content to an average of 10 ppm will enable vehicle manufacturers to certify their entire product lines of new light-duty vehicles to the final Tier 3 Bin 30 fleet average standards. Without such sulfur control it would not be possible for vehicle manufacturers to reduce emissions sufficiently below Tier 2 levels to meet the new Tier 3 standards because it would require offsetting significantly higher exhaust emissions resulting from the higher sulfur levels. EPA has not identified any existing or developing technologies that would compensate for or offset the higher exhaust emissions resulting from higher fuel sulfur levels.

#### 1.2.4.1 Gasoline Sulfur Impacts on Exhaust Catalysts

Modern three-way catalytic exhaust systems utilize platinum group metals (PGM), metal oxides and other active materials to selectively oxidize organic compounds and carbon monoxide in the exhaust gases. These systems simultaneously reduce NO<sub>x</sub> when air-to-fuel ratio control operates in a condition of relatively low amplitude/high frequency oscillation about the stoichiometric point. Sulfur is a well-known catalyst poison. There is a large body of work demonstrating sulfur inhibition of the emissions control performance of PGM three-way exhaust catalyst systems.<sup>1,2,3,4,5,6,7,8,9,10</sup> The nature of sulfur interactions with washcoat materials, active catalytic materials and catalyst substrates is complex and varies with catalyst composition, exhaust gas composition and exhaust temperature. The variation of these interactions with exhaust gas composition and temperature means that the operational history of a vehicle is an important factor; continuous light-load operation, throttle tip-in events and enrichment under high-load conditions can all impact sulfur interactions with the catalyst.

Sulfur from gasoline is oxidized during spark-ignition engine combustion primarily to SO<sub>2</sub> and, to a much lesser extent, SO<sub>3</sub><sup>-2</sup>. Sulfur oxides selectively chemisorb (chemisorb) with, and in some cases react with, active sites and coating materials within the catalyst, thus inhibiting the intended catalytic reactions. Sulfur oxides inhibit pollutant catalysis chiefly by selective poisoning of active PGM, ceria sites, and the alumina washcoating material (see Figure 1-2).<sup>11</sup> The amount of sulfur retained by an exhaust catalyst system is primarily a function of the concentration of sulfur oxides in the incoming exhaust gases, air-to-fuel ratio feedback and control by the engine management system, the operating temperature of the catalyst and the active materials and coatings used within the catalyst.

In their supplemental comments on the proposed Tier 3 rule, API criticized the use of emissions data generated using gasoline with sulfur content outside of the range of 10 ppm to 30

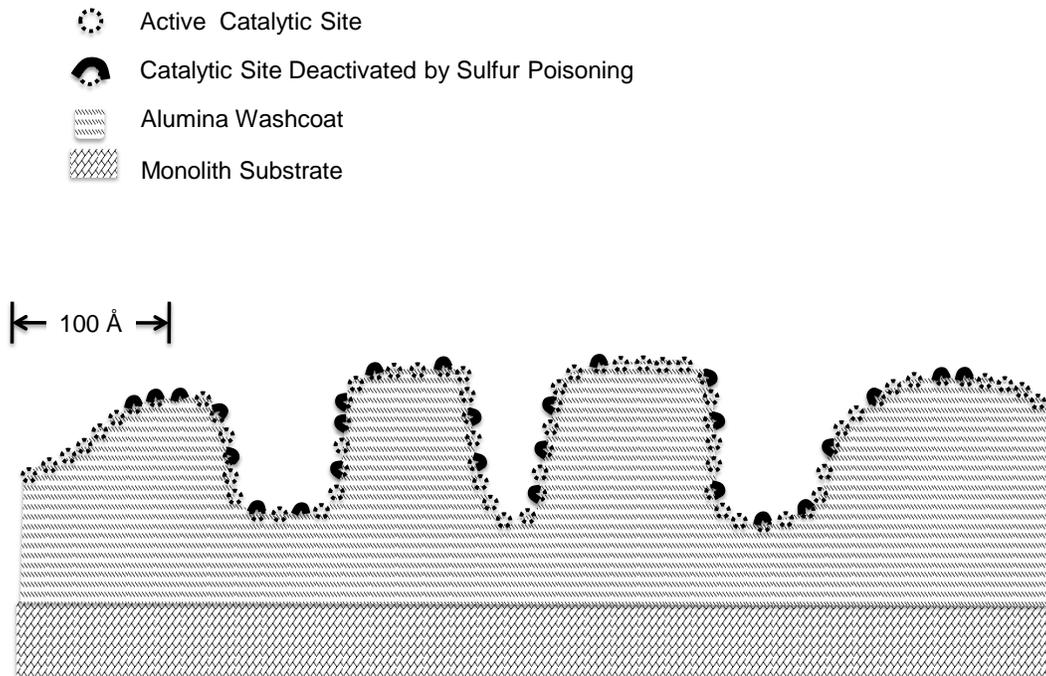
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ppm within EPA and other analyses of the impacts of gasoline sulfur on exhaust emissions from current in-use (Tier 2) and future (Tier 3) light-duty vehicles. Specific examples include:

- Comparisons of exhaust emissions at 5 ppm and 28 ppm gasoline sulfur levels within the recent EPA study of emissions from Tier 2 vehicles<sup>12</sup>
- Comparison of exhaust emissions of a SULEV vehicle at 8 ppm and 33 ppm gasoline sulfur levels within the Takei et al. study<sup>13</sup>
- Comparison of exhaust emissions of a PZEV vehicle at 3 ppm and 33 ppm gasoline sulfur levels within the Ball et al. study.<sup>14</sup>

The relationship between changes in gasoline sulfur content and NO<sub>x</sub>, HC, NMHC and NMOG emissions is typically linear. The linearity of sulfur impacts on NO<sub>x</sub>, NMHC and NMOG emissions is supported by past studies with multiple fuel sulfur levels all of which compare gasoline with differing sulfur levels that are below approximately 100 ppm (e.g. CRC E-60 and 2001 AAM/AIAM programs as well as by comments on this rulemaking submitted by MECA).<sup>15,16,17</sup> An assumption of linearity of the effect of gasoline sulfur level on catalyst efficiency between any two test fuels with differing sulfur levels is reasonable given that the mass flow rate of sulfur in exhaust gas changes in proportion to its concentration in the fuel, and that the chemistry of adsorption of sulfur on the active catalyst sites is an approximately-first-order chemisorption until all active sites within a catalyst reach an equilibrium state relative to further input of sulfur compounds. The relative linearity of the effect of gasoline sulfur level on NMOG and NO<sub>x</sub> emissions allows exhaust emissions results generated within EPA and other studies of gasoline sulfur at levels immediately above or below either 10 ppm or 30 ppm to be normalized to either 10 ppm sulfur (Tier 3 gasoline) or to 30 ppm sulfur (Tier 2 gasoline, which used in the analysis of the impacts of the Tier 3 gasoline standards on existing in-use vehicles and future Tier 3 vehicles).

In their supplemental comments to the Tier 3 proposal, API also commented that EPA did not show the sulfur impact on exhaust emissions at intermediate sulfur levels between 10 ppm and 30 ppm.<sup>18</sup> In response, based on the relative linearity of the effect of gasoline sulfur level on NMOG and NO<sub>x</sub> emissions allowing exhaust emissions to be estimated for gasoline sulfur levels between 10 and 30 ppm, data in EPA's analysis increased NMOG+NO<sub>x</sub> emissions (as fuel sulfur increases) that becomes more severe (i.e., higher percentage increase in NMOG+NO<sub>x</sub> emissions) for vehicles with extremely low<sup>19</sup> exhaust emission (SULEV, PZEV, LEV<sub>III</sub>, Tier 3) as described in further detail in Sections 1.2.4.4 and 1.2.4.5.



**Figure 1-2 Functional schematic showing selective poisoning of active catalytic sites by sulfur compounds. Adapted from Heck and Farrauto 2002.<sup>20</sup>**

Selective sulfur poisoning of platinum (Pt) and rhodium (Rh) is primarily from surface-layer chemisorption. Sulfur poisoning of palladium (Pd) and ceria appears to be via chemisorption combined with formation of more stable metallic sulfur compounds, e.g. PdS and Ce<sub>2</sub>O<sub>2</sub>S, present in both surface and bulk form (i.e., below the surface layer).<sup>21,22,23,24</sup> Ceria, zirconia and other oxygen storage components (OSC) play an important role that is crucial to NO<sub>x</sub> reduction over Rh as the engine air-to-fuel ratio oscillates about the stoichiometric closed-loop control point.<sup>25</sup> Ceria sulfation interferes with OSC functionality within the catalyst and thus can have a detrimental impact on the catalyst's ability to effectively reduce NO<sub>x</sub> emissions. Water-gas-shift reactions are important for NO<sub>x</sub> reduction over catalysts combining Pd and ceria. This reaction can be blocked by sulfur poisoning and may be responsible for observations of reduced NO<sub>x</sub> activity over Pd/ceria catalysts even with exposure to fairly low levels of sulfur (equivalent to 15 ppm in gasoline).<sup>26,27</sup> Pd is also of increased importance for meeting Tier 3 standards due to its unique application in the close-coupled-catalyst location required for vehicles certifying to very stringent emission standards. Close-coupling means that the exhaust catalyst is moved as close as possible to the engine's exhaust ports within the packaging constraints of an engine compartment. This ensures that the catalyst reaches its minimal operational, or "light-off," temperature as quickly as possible after the vehicle is started. It also means, however, that the exhaust catalyst(s) in the close-coupled location(s) are subject to higher exhaust temperatures during fully-warmed up operation. Pd is required in closed-coupled catalysts due to its resistance to high-temperature thermal sintering thereby maintaining sufficient durability of the emissions control system over the useful life of a vehicle. Sulfur

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removal from Pd requires rich operation at higher temperatures than required for sulfur removal from other PGM catalysts.<sup>27</sup>

In addition to its interaction with catalyst materials, sulfur can also react with the wash-coating itself to form alumina sulfate, which in turn can block coating pores and reduce gaseous diffusion to active materials below the coating surface (see Figure 1-2).<sup>28</sup> This may be a significant mechanism for the observed storage of sulfur compounds at light and moderate load operation with subsequent, rapid release as sulfate particulate matter emissions when high-load, high-temperature conditions are encountered.<sup>29</sup>

Operating the catalyst at a sufficiently high temperature under net reducing conditions (e.g., air-to-fuel equivalence that is net fuel-rich of stoichiometry) can effectively release the sulfur oxides from catalyst components. Thus, regular operation at sufficiently high temperatures at net fuel-rich air-to-fuel ratios can minimize the effects of fuel sulfur levels on catalyst active materials and catalyst efficiency; however, it cannot completely eliminate the effects of sulfur poisoning. In current vehicles, desulfurization conditions occur typically at high loads when there is a degree of commanded enrichment (i.e., fuel enrichment commanded by the engine management system primarily for protection of engine and/or exhaust system components). A study of Tier 2 vehicles in the in-use fleet recently completed by EPA<sup>30</sup> shows that emission levels immediately following high speed/load operation is still a function of fuel sulfur level for the gasoline used following desulfurization. If a vehicle operates on gasoline with less than 10 ppm sulfur, exhaust emissions stabilize over repeat FTP tests at emissions near those of the first FTP that follows the high speed/load operation and catalyst desulfurization. If the vehicle continues to operate on higher sulfur gasoline following desulfurization, exhaust emissions creep upward until a new equilibrium exhaust emissions level is established. This suggests that lower fuel sulfur levels achieve emission benefits unachievable by catalyst desulfurization procedures alone. Continued operation on gasoline with a 10 ppm average sulfur content or lower is necessary after catalyst desulfurization in order to achieve emissions reductions with the current in-use fleet.<sup>31</sup> Furthermore, regular operation at the high exhaust temperatures and rich air-to-fuel ratios necessary for catalyst desulfurization is not desirable and may not be possible for future Tier 3 vehicles for several reasons:

- Thermal sintering and resultant catalyst degradation: The temperatures necessary to release sulfur oxides are high enough to lead to thermal degradation of the catalyst over time via thermal sintering of active materials. Sintering reduces the surface area available to participate in reactions and thus reduces the overall effectiveness of the catalyst.
- Operational conditions: It is not always possible to maintain fuel-rich operational conditions and exhaust catalyst temperatures that are high enough for sulfur removal because of cold weather, idle conditions and light-load operation.
- Increased emissions: In order to achieve greater emission reductions across a fuller range of in-use driving conditions, vehicle manufacturers' use of commanded enrichment, which has been beneficial for sulfur removal, will be greatly reduced or eliminated under Tier 3. Additionally, the fuel-rich air-to-fuel ratios necessary for sulfur removal from active catalytic surfaces would result in

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increased PM, NMOG, CO and air toxic emissions, particularly at the high-temperature, high load conditions (e.g., US06 or comparable) necessary for sulfur removal. Previously used levels of commanded enrichment (e.g., under Tier 2) would interfere with the strategies necessary to comply with more stringent Tier 3 SFTP exhaust emissions standards. There are also additional provisions within the Tier 3 standards that further restrict the use of US06 and off-cycle commanded enrichment in an effort to reduce high-load and off-cycle PM, NMOG, CO and air toxic emissions.<sup>32</sup>

- Expected changes to engine performance necessary to reduce fuel consumption and greenhouse gas emissions will improve the thermal efficiency of engines and may result in reduced exhaust temperatures.

#### 1.2.4.2 Previous Studies of Gasoline Sulfur Impacts

This section summarizes studies to provide historical context regarding what is known about the direct impacts of gasoline sulfur on vehicle exhaust emissions. Reducing fuel sulfur levels has been the primary regulatory mechanism EPA has used to minimize sulfur contamination of exhaust catalysts and to ensure optimum emissions performance over the useful life of a vehicle. The impact of gasoline sulfur on exhaust catalyst systems has become even more important as vehicle emission standards have become more stringent. Studies have suggested a progressive increase in catalyst sensitivity to sulfur (in terms of percent conversion efficiency) when standards increase in stringency and emissions levels decrease. Emission standards under the programs that preceded the Tier 2 program (Tier 0, Tier 1 and National LEV, or NLEV) were high enough that the impact of sulfur was considered of little importance. The Tier 2 program recognized the importance of sulfur and reduced the sulfur levels in the fuel from around 300 ppm to 30 ppm in conjunction with the new emission standards.<sup>33</sup> At that time, very little work had been done to evaluate the effect of further reductions in fuel sulfur, especially on in-use vehicles that may have some degree of catalyst deterioration due to real-world operation or on vehicles with extremely low tailpipe emissions, as described earlier.

In 2005, EPA and several automakers jointly conducted a research program, the Mobile Source Air Toxics (MSAT) Study that examined the effects of sulfur and other gasoline properties such as benzene and volatility on emissions from a fleet of nine Tier 2 compliant vehicles.<sup>34</sup> The study found significant reductions in NO<sub>x</sub>, CO and total hydrocarbons (HC) when the vehicles were tested on low sulfur fuel, relative to 32 ppm fuel. In particular, the study found a 48 percent increase in NO<sub>x</sub> over the FTP when gasoline sulfur was increased from 6 ppm to 32 ppm. Given the preparatory procedures related to catalyst clean-out and loading used by these studies, these results may represent a “best case” scenario relative to what would be expected under more typical driving conditions. Nonetheless, these data suggested the effect of in-use sulfur loading was largely reversible for Tier 2 vehicles, and that there were likely to be significant emission reductions possible with further reductions in gasoline sulfur level. More recently, EPA completed a comprehensive study on the effects of gasoline sulfur on the exhaust emissions of Tier 2 vehicles at low to moderate mileage levels.<sup>35</sup> Further details of this study are summarized in Section 1.2.4.3 of this preamble.

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In the NPRM, we summarized the limited data available regarding the impact of gasoline sulfur on the near-zero exhaust emission vehicle technologies that will be necessary for Tier 3 compliance. Vehicles certified to California LEV II SULEV and PZEV standards and federal Tier 2 Bin 2 standards achieve levels of exhaust emissions control consistent with the levels of control that will be necessary for Tier 3 compliance. While these vehicles represent only a relatively small subset (e.g., typically small light-duty vehicles and light-duty trucks with limited GVWR or towing utility) of the broad range of vehicles that will need to comply with Tier 3 standards as part of a fleet-wide average, data on these vehicles provides an opportunity to study the impact of gasoline sulfur on near-zero exhaust emission technologies and is generally representative of technology that are expected to be used with mid-size and smaller light-duty vehicles for Tier 3 compliance. Vehicle testing by Toyota (Takei et al.) of LEV I, LEV II ULEV and prototype SULEV vehicles showed larger percentage increases in NO<sub>x</sub> and HC emissions for SULEV vehicles as gasoline sulfur increased from 8 ppm to 30 ppm, as compared to other LEV vehicles they tested<sup>36</sup>. Ball et al. of Umicore Autocat USA, Inc. studied the impact of gasoline fuel sulfur levels of 3 ppm and 33 ppm on the emissions of a 2009 Chevrolet Malibu PZEV<sup>37</sup>. Umicore's testing of the Malibu PZEV vehicle showed a pronounced and progressive trend of increasing NO<sub>x</sub> emissions (referred to as "NO<sub>x</sub> creep") when switching from a 3 ppm sulfur gasoline to repeated, back-to-back FTP tests using 33 ppm sulfur gasoline. The PZEV Chevrolet Malibu, after being aged to an equivalent of 150,000 miles, demonstrated emissions at a level consistent with the Tier 3 Bin 30 NMOG+NO<sub>x</sub> standards when operated on 3 ppm sulfur fuel and for at least one FTP test after switching to 33 ppm certification fuel. Following operation over 2 FTP cycles on 33 ppm sulfur fuel, NO<sub>x</sub> emissions alone were more than double the Tier 3 30 mg/mi NMOG+NO<sub>x</sub> standard.<sup>10</sup> This represents a 70% NO<sub>x</sub> increase between 3 ppm sulfur and 33 ppm sulfur gasolines, approximately 2-3 times of what has been previously reported for similar changes in fuel sulfur level for Tier 2 and older vehicles.<sup>38,39</sup>

Both the Umicore and Toyota studies suggest that the emissions from vehicles using near-zero exhaust emissions control technology similar to what is expected for compliance with the Tier 3 standards are more sensitive to changes in gasoline sulfur content at low (sub-30 ppm) sulfur concentrations than technology used to meet the higher Federal Tier 2 and California LEV II standards. The Umicore and Toyota studies clearly indicate that a progressive increase in catalyst sensitivity to sulfur continues as exhaust emissions decrease from levels required by federal Tier 2 and California LEV II emissions standards to the lower levels required by Tier 3 emissions standards. In addition, although vehicles with Tier 2 technology have somewhat less sulfur sensitivity compared to future Tier 3 vehicles, there is still significant opportunity for further emissions reductions from the existing in-use fleet by reducing gasoline sulfur content from 30 ppm to 10 ppm. The results of recent testing demonstrating the potential for in-use emissions reductions from further gasoline sulfur control are summarized in Section 1.2.43). Recent data on the impact of gasoline sulfur on vehicles with exhaust emission control technologies that we expect to be used with Tier 3 vehicles is summarized in Sections 1.2.4.4 and 1.2.4.5.

#### 1.2.4.3 EPA Testing of Gasoline Sulfur Effects on Tier 2 Vehicles and the In-Use Fleet

Both the MSAT<sup>40</sup> and Umicore<sup>41</sup> studies showed the emission reduction potential of lower sulfur fuel on Tier 2 and later technology vehicles over the FTP cycle. However, assessing the potential for reduction on the in-use fleet requires understanding how sulfur exposure over

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time impacts emissions, and what the state of catalyst sulfur loading is for the typical vehicle in the field. In response to these data needs, EPA conducted a new study to assess the emission reductions expected from the in-use Tier 2 fleet with a reduction in fuel sulfur level from current levels.<sup>42</sup> It was designed to take into consideration what was known from prior studies on sulfur build-up in catalysts over time and the effect of periodic regeneration events that may result from higher speed and load operation over the course of day-to-day driving.

The study sample described in this analysis consisted of 93 cars and light trucks recruited from owners in southeast Michigan, covering model years 2007-9 with approximately 20,000-40,000 odometer miles.<sup>43</sup> The makes and models targeted for recruitment were chosen to be representative of high sales vehicles covering a range of types and sizes. Test fuels were two non-ethanol gasolines with properties typical of certification test fuel, one at a sulfur level of 5 ppm and the other at 28 ppm. All emissions data was collected using the FTP cycle at a nominal temperature of 75 °F.

Using the 28 ppm test fuel, emissions data were collected from vehicles in their as-received state as well as following a high-speed/load “clean-out” procedure consisting of two back-to-back US06 cycles intended to reduce sulfur loading in the catalyst. A statistical analysis of this data showed highly significant reductions in several pollutants including NO<sub>x</sub> and hydrocarbons, demonstrating that sulfur loadings have a large effect on exhaust catalyst performance, and that Tier 2 vehicles can achieve significant reductions based on removing, at least in part, the negative impact of the sulfur loading on catalyst efficiency (Table 1-4). For example, Bag 2 NO<sub>x</sub> emissions dropped 31 percent between the pre- and post-cleanout tests on 28 ppm fuel.

**Table 1-4 Percent Reduction in In-Use Emissions After the Clean-out  
Using 28 ppm Test Fuel<sup>a</sup>**

	NO <sub>x</sub> (p-value)	THC (p-value)	CO (p-value)	NMHC (p-value)	CH <sub>4</sub> (p-value)	PM (p-value)
Bag 1	–	–	6.0% (0.0151)	–	–	15.4% ( 0.0001)
Bag 2	31.4% (0.0003)	14.9% (0.0118)	–	18.7% (0.0131)	14.4% (0.0019)	–
Bag 3	35.4% (<0.0001)	20.4% (<0.0001)	21.5% (0.0001)	27.7% (<0.0001)	10.3% (<0.0001)	24.5% (<0.0001)
FTP Composite	11.4% (0.0002)	3.8% (0.0249)	6.8% (0.0107)	3.5% (0.0498)	6.0% (0.0011)	13.7% (<0.0001)
Bag 1 – Bag 3	–	–	7.2% (0.0656)	–	–	–

<sup>a</sup> The clean-out effect is not significant at  $\alpha = 0.10$  when no reduction estimate is provided.

To assess the impact of lower sulfur fuel on in-use emissions, further testing was conducted on a representative subset of vehicles on 28 ppm and 5 ppm fuel with accumulated mileage. A first step in this portion of the study was to assess the differences in the effectiveness of the clean-out procedure under different fuel sulfur levels. Table 1-5 presents a comparison of emissions immediately following (<50 miles) the clean-out procedures at the low vs. high sulfur level. These results show significant emission reductions for the 5 ppm fuel relative to the 28 ppm fuel immediately after this clean-out; for example, Bag 2 NO<sub>x</sub> emissions were 34 percent lower on the 5 ppm fuel vs. the 28 ppm fuel. This indicates that the catalyst is not fully desulfurized, even after a clean out procedure, as long as there is sulfur in the fuel. This further indicates that current sulfur levels in gasoline continue to have a long-term, adverse effect on exhaust emissions control that is not fully removed by intermittent clean-out procedures that can occur in day-to-day operation of a vehicle and demonstrates that lowering sulfur levels to 10 ppm on average will significantly reduce the effects of sulfur impairment on emissions control technology.

**Table 1-5 Percent Reduction in Exhaust Emissions When Going from 28 ppm to 5 ppm  
Sulfur Gasoline for the First Three Repeat FTP Tests Immediately Following Clean-out**

	NO <sub>x</sub> (p-value)	THC (p-value)	CO (p-value)	NMHC (p-value)	CH <sub>4</sub> (p-value)	PM <sup>a</sup>
Bag 1	5.3% (0.0513)	6.8% (0.0053)	6.2% (0.0083)	5.7% (0.0276)	14.0% (<0.0001)	–
Bag 2	34.4% (0.0036)	33.9% (<0.0001)	– <sup>a</sup>	26.4% (0.0420)	49.4% (<0.0001)	–
Bag 3	42.5% (<0.0001)	36.9% (<0.0001)	14.7% (0.0041)	51.7% (<0.0001)	28.5% (<0.0001)	–
FTP Composite	15.0%	13.3%	8.5%	10.9%	23.6%	–

	(0.0002)	(<0.0001)	(0.0050)	(0.0012)	(<0.0001)	
Bag 1 – Bag 3	– <sup>a</sup>	–				

<sup>a</sup>The effectiveness of clean-out cycle is not significant at  $\alpha = 0.10$ .

To assess the overall in-use reduction between high and low sulfur fuel, a mixed model analysis of all data as a function of fuel sulfur level and miles driven after cleanout was performed. This analysis found highly significant reductions for several pollutants, as shown in Table 1-6. Reductions for Bag 2 NO<sub>x</sub> were particularly high, estimated at 52 percent between 28 ppm and 5 ppm overall. For all pollutants, the model fitting did not find a significant miles-by-sulfur interaction, suggesting the relative differences were not dependent on miles driven after clean-out.

**Table 1-6 Percent Reduction in Emissions from 28 ppm to 5 ppm Fuel Sulfur on In-Use Tier 2 Vehicles**

	NO <sub>x</sub> (p-value)	THC (p-value)	CO (p-value)	NMHC (p-value)	CH <sub>4</sub> (p-value)	NO <sub>x</sub> +NMOG (p-value)	PM <sup>a</sup>
Bag 1	7.1% (0.0216)	9.2% (0.0002)	6.7% (0.0131)	8.1% (0.0017)	16.6% (< 0.0001)	N/A	–
Bag 2	51.9% (< 0.0001)	43.3% (< 0.0001)	– <sup>a</sup>	42.7% (0.0003)	51.8% (< 0.0001)	N/A	–
Bag 3	47.8% (< 0.0001)	40.2% (< 0.0001)	15.9% (0.0003)	54.7% (< 0.0001)	29.2% (< 0.0001)	N/A	–
FTP Composite	14.1% (0.0008)	15.3% (< 0.0001)	9.5% (< 0.0001)	12.4% (< 0.0001)	29.3% (< 0.0001)	14.4% (< 0.0001)	–
Bag 1 – Bag 3	– <sup>a</sup>	5.9% (0.0074)	– <sup>a</sup>	– <sup>b</sup>	– <sup>b</sup>	N/A	–

<sup>a</sup> Sulfur level not significant at  $\alpha = 0.10$ .

<sup>b</sup> Inconclusive because the mixed model did not converge.

Major findings from this study include:

- Largely reversible sulfur loading is occurring in the in-use fleet of Tier 2 vehicles and has a measureable effect on emissions of NO<sub>x</sub>, hydrocarbons, and other pollutants of interest.
- The effectiveness of high speed/load procedures in restoring catalyst efficiency is limited when operating on higher sulfur fuel.

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- Reducing fuel sulfur levels from current levels to levels in the range of the Tier 3 gasoline sulfur standards is expected to achieve significant reductions in emissions of NO<sub>x</sub>, hydrocarbons, and other pollutants of interest in the current in-use fleet.
  - Assuming that the emissions impacts vs. gasoline sulfur content are approximately linear, changing gasoline sulfur content from 30 ppm to 10 ppm would result in NMOG+NO<sub>x</sub> emissions decreasing from 52 mg/mi to 45 mg/mi, respectively (a 13% decrease), and NO<sub>x</sub> emissions decreasing from 19 mg/mi to 16 mg/mi, respectively (a 16% decrease), for the vehicles in the study.

To evaluate the robustness of the statistical analyses assessing the overall in-use emissions reduction between operation on high and low sulfur fuel (Table 1-6), a series of sensitivity analyses were performed to assess the impacts on study results of measurements from low-emitting vehicles and influential vehicles, as documented in detail in the report.<sup>44</sup> The sensitivity analyses showed that the magnitude and the statistical significance of the results were not impacted and thus demonstrated that the results are statistically robust. We also subjected the design of the experiment and data analysis to a contractor-led independent peer-review process in accordance with EPA's peer review guidance. The results of the peer review<sup>45,46</sup> largely supported the study design, statistical analyses, and the conclusions from the program and raised only minor concerns that have not changed the overall conclusions and have subsequently been addressed in the final version of the report.<sup>47</sup>

Overall, the reductions found in this study are in agreement with other low sulfur studies conducted on Tier 2 vehicles, namely MSAT and Umicore studies mentioned above, in terms of the magnitude of NO<sub>x</sub> and HC reductions when switching from 28 ppm to 5 ppm fuel.<sup>48</sup> We have reviewed the results of the emission effects study performed by SGS, which was included with API's comments on the Tier 3 proposal, and have concluded that these results are also consistent with the findings of EPA's Tier 2 in-use study, specifically that exhaust emissions performance is sensitive to fuel sulfur level.<sup>49</sup> The SGS study also suggests that negative effects of exposure to a somewhat higher sulfur level (80 ppm in this case) are largely reversible for Tier 2 vehicles, meaning that reducing fuel sulfur levels nationwide will bring significant immediate benefits by reducing emissions of the existing fleet. For further details regarding the Tier 2 In-Use Gasoline Sulfur Effects Study, see the final report.<sup>50</sup>

As a follow-on phase to the Tier 2 in-use study, EPA analyzed five vehicles<sup>51</sup> certified to Tier 2 Bin 4, LEV II ULEV and LEV II SULEV exhaust emissions standards to assess the gasoline sulfur sensitivity of Tier 2 and California LEV II vehicles with emission levels approaching or comparable to the Tier 3 standards. The analysis found that these low-emitting Tier 2 vehicles showed similar or greater sensitivity to fuel sulfur levels compared to the original Tier 2 test fleet – for example, a 24 percent reduction in FTP composite NO<sub>x</sub> emissions when sulfur is reduced from 28 ppm to 5 ppm.<sup>52</sup> Test results discussed below in Section 1.2.4.4 also confirm that there is significantly increased sensitivity of exhaust emissions to gasoline sulfur as vehicle technologies advance towards exhaust emissions approaching near-zero emissions (e.g., Tier 3 Bin 50 and lower). The impact of fuel sulfur on vehicles with exhaust emission control technologies that we expect to be used with Tier 3 vehicles is summarized in the next two Sections (1.2.4.4 and 1.2.4.5).

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EPA believes that the studies by EPA and others described in this Section strongly support our conclusion that reducing gasoline sulfur content to a 10 ppm average will result in significant exhaust emissions reductions from the current in-use fleet. However, some commenters have expressed concerns about the relevance and appropriateness of the data, as well as the conclusions drawn from them. The Summary and Analysis of Comments document, available in the docket for this rulemaking, provides our responses to those comments.

#### 1.2.4.4 Testing of Gasoline Sulfur Effects on Vehicles with Tier 3/LEV III Technology

The Tier 3 fleet average exhaust emissions standards of 30 mg/mi NMOG+NO<sub>x</sub> will require large reductions of emissions across a broad range of light-duty vehicles and trucks with differing degrees of utility. Previous studies of sulfur impacts on extremely low exhaust emission vehicles (e.g., Toyota, Umicore) were limited to mid-size or smaller light-duty vehicles. There are currently nonhybrid LDT3 or any LDT4 vehicles certified at or below Federal Tier 2 Bin 3 or to the California LEV II SULEV exhaust emission standards. At the time of the Tier 3 NPRM, EPA was not aware of any existing data demonstrating the impact of changes in gasoline sulfur content on larger vehicles with technology comparable to what would be expected for compliance with Tier 3 exhaust emission standards. In their supplemental comments to the Tier 3 proposal, API criticized EPA's reliance on emissions data from older vehicles that were not considered to be examples of future Tier-3-like vehicles. In order to further evaluate this issue, the Agency initiated a test program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL) in Ann Arbor, Michigan. The Agency obtained a heavy-light-duty truck and applied changes to the design and layout of the exhaust catalyst system and to the calibration of the engine management system consistent with our engineering analyses of technology necessary to meet Tier 3 Bin 30 emissions with a 20 to 40% compliance margin at 150,000 miles. EPA also requested that Umicore loan the Agency the vehicle tested in their study to undergo further evaluation of gasoline sulfur impacts on exhaust emissions. In addition, Ford Motor Company completed testing of fuel sulfur effects on a Tier 3/LEV III developmental heavy-light-duty truck and submitted a summary report of their findings as part of their supplemental comments to the Tier 3 NPRM. The results of these three test programs are summarized below.

##### *1.2.4.4.1 Ford Motor Company Tier 3 Sulfur Test Program*

Ford Motor Company recently completed testing of a heavy-light-duty truck (i.e., between 6000 and 8500 pounds GVWR) under development to meet the Tier 3 Bin 50 standards on two different fuel sulfur levels and submitted the resulting data to EPA as part of its supplemental comments.<sup>53,54</sup> The test results from this vehicle are particularly important when considering the following factors:

- These are the first detailed emissions data submitted by a vehicle manufacturer to the Agency demonstrating emissions of a heavy-light-duty-truck consistent with Tier 3 Bin 50 or lower emissions levels.
- The truck tested uses a version of Ford's 2.0 L GTDI engine, an engine with high BMEP (approximately 23-bar) that can allow significant engine displacement

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downsizing while maintaining the truck's utility. This is a key enabling GHG reduction strategy analyzed by EPA in the 2017-2025 GHG Final Rule.<sup>55</sup>

- The vehicle was specifically under development by a vehicle manufacturer with an engineering target of meeting Tier 3 Bin 50 and LEV III ULEV50 exhaust emissions standards.

Turbocharged, downsized engines are key technologies within Ford's strategy to reduce GHG emissions.<sup>56</sup> EPA expects that trucks with configurations similar to this developmental Ford Explorer (downsized engines with reduced GHG emissions and very low emissions of NMOG+NO<sub>x</sub>) will become increasingly prevalent within the timeframe of the implementation of the Tier 3 regulations.

The developmental truck used close-coupling of both catalyst substrates and relatively high PGM loading (150 g/ft<sup>3</sup>). Ford used accelerated aging of the catalysts and O<sub>2</sub> sensors to an equivalent of 150,000 miles (the Tier 3 full useful life). The developmental hardware and engine management calibration configuration of this truck was designed to meet federal Tier 3 Bin 50 and California LEV III ULEV50 standards of 50 mg/mi NMOG+NO<sub>x</sub> at 150,000 miles. The emissions data submitted by Ford included NO<sub>x</sub> and NMHC emissions during operation on E10 California LEV III certification fuel at two different sulfur levels, 10 ppm and 26.5 ppm. Ford did not provide NMOG emissions data but there was sufficient information for EPA to calculate NMOG emissions from the provided NMHC data using calculations from Title 40 CFR § 1066.665.

The truck demonstrated average FTP NMOG+NO<sub>x</sub> emissions of 37 mg/mi on the 10 ppm E10 California LEV III fuel, emissions that are consistent with compliance with Bin 50 and ULEV50 standards with a reasonable margin of compliance (emissions at approximately 70% of the standard). Retesting of the same vehicle on LEV3 E10 blended<sup>57</sup> to 26.5 ppm S resulted in average NMOG+NO<sub>x</sub> emissions of 53 mg/mi, 6% above the Tier 3 Bin 50 standard. Ford found a high level of statistical significance with respect to the increase of emissions with increasing fuel sulfur. Assuming a linear effect of sulfur on emissions performance, NMOG+NO<sub>x</sub> emissions would be approximately 56 mg/mi at 30 ppm sulfur, which is approximately 12% above the Bin 50 exhaust emissions standard. This also represents an increase in NMOG+NO<sub>x</sub> emissions of 53% with an approximate doubling of NO<sub>x</sub> emissions and a 13 % increase in NMOG for 30 ppm sulfur gasoline vs. 10 ppm sulfur gasoline.

The advanced technology Ford truck, which was shown to be capable of complying with the Tier 3 Bin 50 standard with a reasonable margin of compliance on 10 ppm sulfur gasoline, in effect reverted to approximately LEV II ULEV exhaust emissions levels when tested on higher sulfur gasoline, equivalent to the previous level of emissions control to which earlier models of this vehicle were certified for MY 2013. The effect of increasing gasoline sulfur levels from 10 ppm to 30 ppm<sup>58</sup> on this vehicle essentially negated the entire benefit of the advances in emissions control technology that were applied by the vehicle manufacturer to meet developmental goals for compliance with Tier 3 standards. This clearly indicates, for this vehicle model using technology representative of what would be expected for compliance with Tier 3 Bin 50 and post 2017 GHG standards, reducing gasoline sulfur to 10 ppm is needed for the advances in technology to achieve their intended effectiveness in reducing NMOG+NO<sub>x</sub>

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emissions. The advances in vehicle technology and the reduction in gasoline sulfur clearly are both needed to achieve the emissions reductions called for by Tier 3.

#### *1.2.4.4.2 EPA Re-test of Umicore 2009 Chevrolet Malibu PZEV*

Ball et al. of Umicore Autocat USA, Inc. previously studied the impact of gasoline fuel sulfur levels of 3 ppm and 33 ppm on the emissions of a 2009 Chevrolet Malibu PZEV.<sup>59</sup> In their supplemental comments to the Tier 3 proposal, API commented that the composition of the two test fuels outside of sulfur content was not held constant and thus the exhaust emissions differences attributed to the difference in gasoline sulfur levels may have been due to other fuel property differences.<sup>60</sup> For example, the 3 ppm fuel used by Ball et al. was nonoxygenated EEE Clear test fuel (essentially, Tier 2 Federal certification gasoline except with near-zero sulfur) while the 33 ppm fuel was an oxygenated California Phase 2 LEV II certification fuel. Thus it was not entirely clear if the changes in NO<sub>x</sub> emissions observed between tests with the two fuels were significantly impacted by fuel composition variables other than gasoline sulfur content. EPA obtained the same test vehicle from Umicore for retesting at the EPA NVFEL facility using the 5 ppm and 28 ppm sulfur E0 test fuels and vehicle test procedures used in EPA gasoline sulfur effects testing on Tier 2 vehicles (see Section 1.2.4.2).

In EPA's retest of the 2009 Chevrolet Malibu PZEV, when sulfur was the only difference between the test fuels, the gasoline with higher sulfur resulted in significantly higher increases in NO<sub>x</sub> emissions with increasing fuel sulfur content than was observed in the previous testing by Ball et al. at Umicore. Assuming emissions impacts vs. gasoline sulfur content are approximately linear, the original data from Ball et al. result in a predicted increase in NO<sub>x</sub> emissions of approximately 40% when increasing gasoline sulfur from 10 ppm to 30 ppm. The EPA re-testing of the same vehicle that controlled for other fuel composition differences result in a predicted increase in NO<sub>x</sub> emissions of 93% when increasing gasoline sulfur from 10 ppm to 30 ppm, with NO<sub>x</sub> emissions approximately doubling from 22 g/mi to 43 g/mi, with no statistically significant difference in NMOG emissions and with an increase in NMOG+NO<sub>x</sub> emissions of 56%. The approximate doubling in NO<sub>x</sub> emissions with the Malibu PZEV between 10 ppm and 30 ppm sulfur was nearly identical to the results found during testing of the Tier 3 Bin 50 developmental Ford Explorer discussed above. The results confirm that fuel compositional differences other than sulfur may have impacted exhaust emissions results in the Ball et al. study by masking a substantial portion of the effect of increased fuel sulfur on NO<sub>x</sub> emissions. When controlling for other fuel composition differences, the resultant increase in NO<sub>x</sub> exhaust emissions due to increasing gasoline sulfur was more than double that of the original Ball et al. study. The observed increase in NMOG+NO<sub>x</sub> emissions during EPA testing of the Malibu PZEV was also comparable to results found with the developmental Tier 3 Bin 50 Ford Explorer. There was also a much higher increase in NO<sub>x</sub> and NMOG+NO<sub>x</sub> emissions for both the Malibu PZEV and the Tier 3 Bin 50 Explorer with increased gasoline sulfur than was observed with Tier 2 vehicles in the EPA Tier 2 in-use study.<sup>61</sup>

#### *1.2.4.4.3 EPA Prototype Tier 3 Heavy-light-duty Truck Test Program*

EPA purchased a 2011 Chevrolet Silverado heavy-light-duty (LDT4) pickup truck with a developmental goal of modifying the truck to achieve exhaust emissions consistent with compliance with the Tier 3 Bin 30 emissions standards. The truck was equipped with a 5.3L V8

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with General Motors' "Active Fuel Management" cylinder deactivation system. This particular truck was chosen in part because cylinder deactivation is a key technology for light-truck compliance with future GHG standards and in part because it achieved very low emissions in its OEM, Tier 2-compliant configuration (certified to Tier 2 Bin 4). A prototype exhaust system was obtained from MECA consisting of high-cell-density (900 cpsi) thin-wall (2.5 mil), high-PGM, close-coupled Pd-Rh catalysts with an additional under-body Pd-Rh catalyst. The total catalyst volume was approximately 116 in<sup>3</sup> with a specific PGM loading of 125 g/ft<sup>3</sup> and approximate loading ratio of 0:80:5 (Pt:Pd:Rh). Third-party (non-OEM) EMS calibration tools were used to modify the powertrain calibration in an effort to improve catalyst light-off performance. The final test configuration used approximately 4 degrees of timing retard and approximately 200 rpm higher idle speed relative to the OEM configuration during and immediately following cold-start. The exhaust catalyst system and HEGO sensors were bench aged to an equivalent 150,000 miles using standard EPA accelerated catalyst bench-aging procedures.<sup>62</sup> The truck was tested on California LEV III E10 certification fuel at 9 and 29 ppm gasoline sulfur levels.

The EPA Tier 3 prototype Silverado achieved NMOG+NO<sub>x</sub> emissions of 18 mg/mi on the 9 ppm S fuel. The NMOG+NO<sub>x</sub> emissions were approximately 60% of the Bin 30 standard and thus are consistent with meeting the Tier 3 Bin 30 exhaust emissions standard with a moderate compliance margin. NMOG+NO<sub>x</sub> emissions increased to 29 mg/mi on the 29 ppm S fuel and one out of four tests exceeded the Bin 30 exhaust emissions standards. NMOG+NO<sub>x</sub> emissions would be at 19 mg/mi and 30 mg/mi with 10 ppm and 30 ppm gasoline sulfur, respectively, assuming a linear effect of sulfur on emissions performance. This represents an increase in NMOG+NO<sub>x</sub> emissions of approximately 55%, comparable to increases observed with both the EPA-tested Chevrolet Malibu PZEV and the developmental Tier 3 Bin 50 Ford Explorer. The impact of increased gasoline sulfur on NMOG+NO<sub>x</sub> emissions was due to comparable increases (on a percentage basis) in both NMOG and NO<sub>x</sub> emissions. This effect of gasoline sulfur on the Prototype Silverado truck's emissions differed from the sulfur impacts observed on the developmental Ford Explorer, which primarily affected NO<sub>x</sub> emissions, and the Malibu PZEV, where the impact was entirely on NO<sub>x</sub> emissions.

#### 1.2.4.5 Gasoline Sulfur Level Necessary for New Light-duty Vehicles to Achieve Tier 3 Exhaust Emissions Standards

Meeting Tier 3 NMOG+NO<sub>x</sub> standards will require major reductions in exhaust emissions across the entire fleet of new light-duty vehicles. As discussed in previous sections, the Tier 3 program will require reductions in fleet average NMOG+NO<sub>x</sub> emissions of over 80 percent for the entire fleet of light-duty vehicles and light-duty trucks. This significant level of fleet average emission reduction will require reductions from all parts of the fleet, including vehicles models with exhaust emissions currently at or near the level of the fully phased-in Tier 3 FTP NMOG+NO<sub>x</sub> fleet average standard of 30 mg/mi.

Compliance with the more stringent Tier 3 fleet average standards will require vehicle manufacturers to certify a significant amount of vehicles to bin standards that are below the Bin 30 fleet average standard to offset other vehicles that are certified to bin standards that remain somewhat above the Bin 30 fleet average even after significantly reducing their emissions. At the same time, the stringency of the Tier 3 standards will push almost all vehicle models to be

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close to or below the Bin 30 fleet average standard. There are only 2 compliance bins below Bin 30, i.e., Bin 20 and Bin 0, available to offset emissions of vehicles certifying above Bin 30. There is also very limited ability for vehicle manufacturers to certify vehicles below the stringent Tier 3 fleet average exhaust emissions standard since Bin 20 and Bin 30 standards for individual vehicle certification families are approaching the engineering limits of what can be achieved for vehicles using an internal combustion engine and Bin 0 can only be achieved by electric-only vehicle operation. The result is that there is a very limited ability to offset sales of vehicles certified above the 30 mg/mi fleet average emission standard. This means in general that vehicle models currently with higher emissions will have to achieve significant emissions reductions to minimize the gap, if any, between their certified bin levels under Tier 3 and the Tier 3 Bin 30 fleet average standard, and vehicle models currently at or below Bin 30 will also have to achieve further emissions reductions under Tier 3 to offset the vehicles that remain certified to bin standards somewhat above Bin 30. The end result is a need for major reductions from all types of vehicles in the light-duty fleet, including those above as well as most vehicles that are already near, at, or below the Tier 3 Bin 30 fleet average standard.

Achieving exhaust emissions reductions of over 80% for the fleet, with major reductions across all types of light-duty vehicles and light-duty trucks, will be a major technological challenge. Vehicles already have made significant advances in controlling cold start emissions and maximizing exhaust catalyst efficiency (e.g., improving warm-up and catalyst light-off after cold starts and maintaining very high catalyst efficiency once warmed up) in order to meet Tier 2 and LEV II emissions standards. There are no “low-hanging fruit” remaining for additional NMOG+NO<sub>x</sub> reductions from light-duty vehicles from a technology perspective, meaning that vehicle manufacturers cannot merely change one aspect of emissions control and thereby achieve all of the required reductions. Instead, compliance with light-duty Tier 3 exhaust emissions standards will require significant improvements in all areas of emissions control – with further improvements in fuel-system management and mixture preparation during cold start, improvements in achieving catalyst light-off immediately after cold start, and improved catalyst efficiency during stabilized, fully-warmed-up conditions. Manufacturers will need further improvements in each of these areas with nearly every vehicle in order to comply with the fleet-average Tier 3 standards.

From a technology perspective, the most likely control strategies will involve using exhaust catalyst technologies and powertrain calibration primarily focused on reducing cold-start emissions of NMOG, and on reducing both cold-start and warmed-up (running) emissions of NO<sub>x</sub>. An important part of this strategy, particularly for larger vehicles having greater difficulty achieving cold-start NMOG emissions control, will be to reduce NO<sub>x</sub> emissions to near-zero levels. This will involve controlling engine-out NO<sub>x</sub> emissions during cold start, shortening the cold start period prior to catalyst light-off of NO<sub>x</sub> reduction reactions, and better controlling NO<sub>x</sub> emissions once the catalyst is fully warmed up. This is needed to allow a sufficient NMOG compliance margin so that vehicles can meet the combined NMOG+NO<sub>x</sub> emissions standards for their full useful life.

While significant NMOG+NO<sub>x</sub> emissions reductions can be achieved from better control of cold start NMOG emissions, there are practical engineering limits to NMOG control for larger displacement vehicles (e.g., large light-duty trucks with significant payload and trailer towing capabilities). This is based in part on the impact on NMOG emissions of the larger engine

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surface-to-volume ratio and resultant heat conduction from the combustion chamber during warm-up. There are also tradeoffs between some cold-start NMOG controls and cold-start NO<sub>x</sub> control. For example, secondary air injection and/or leaner fueling strategies improve catalyst light-off for NMOG after a cold-start but also place OSC components in an oxidation state that limits potential for NO<sub>x</sub> reduction and thus often result in higher cold-start NO<sub>x</sub> emissions. Some applications achieve lower NMOG+NO<sub>x</sub> emissions without the use of secondary air injection by careful calibration, changes to the catalyst formulation and balancing of catalyst HC and NO<sub>x</sub> activity. The EPA Prototype Silverado and the developmental Ford Explorer are specific examples of this approach.

Because of engineering limitations with large vehicles, heavy-light-trucks and other vehicles with significant utility, we expect many applications will need close to 100% efficiency in NO<sub>x</sub> control under fully warmed-up conditions and very fast light-off of NO<sub>x</sub> reduction reactions over the exhaust catalyst almost immediately after cold-start for those applications. This will require significant improvements in catalytic and engine-out NO<sub>x</sub> reduction compared with Tier 2 vehicles and will be especially important for heavier vehicles due to the challenges of achieving low NMOG.

These technology improvements - improving warm-up and catalyst light-off after cold starts and maintaining very high catalyst efficiency - - once warmed up – all rely on 10 ppm average sulfur fuel to achieve the very significant emissions reductions required for the fleet to achieve the Tier 3 Bin 30 fleet average emissions standard. The evidence from the test results and specific vehicle examples discussed above clearly indicate that leaving the gasoline sulfur level at 30 ppm would largely negate the benefits of key technology improvements expected to be used for compliance with Tier 3 exhaust emissions standards. Without the lower 10 ppm gasoline sulfur content, the Tier 3 exhaust fleet average emissions standards would not be achievable across the broad range of vehicles that must achieve significant exhaust emissions reductions.

One aspect of the need for sulfur levels of 10 ppm average stems from the fact that achieving the Tier 3 emission standards will require very careful control of the exhaust chemistry and exhaust temperatures to ensure high catalyst efficiency. The impact of sulfur on OSC components in the catalyst makes this a challenge even at relatively low (10 ppm) gasoline sulfur levels. NO<sub>x</sub> conversion by exhaust catalysts is strongly influenced by the OSC components like ceria. Ceria sulfation may play an important role in the large degradation of NO<sub>x</sub> emission control with increased fuel sulfur levels observed in the MSAT, Umicore and EPA Tier 2 In-Use Gasoline Sulfur Effects studies and the much more severe NO<sub>x</sub> emissions degradation observed in recent test data from PZEV and prototype/developmental Tier 3/LEV III vehicles.<sup>63</sup>

The importance of lower sulfur gasoline is also demonstrated by the fact that vehicles certified to California SULEV are typically certified to higher bins for the federal Tier 2 program. Light-duty vehicles certified to CARB SULEV and federal Tier 2 Bin 2 exhaust emission standards accounted for approximately 3.1 percent and 0.4 percent, respectively, of vehicle sales for MY2009. Light-duty vehicles certified to SULEV under LEV II are more typically certified federally to Tier 2 Bin 3, Bin 4 or Bin 5, and vehicles certified to SULEV and Tier 2 Bins 3-5 comprised approximately 2.5 percent of sales for MY2009. In particular, nonhybrid vehicles certified in California as SULEV are not certified to federal Tier 2 Bin 2

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emissions standards even though the numeric limits for NO<sub>x</sub> and NMOG are shared between the California LEV II and federal Tier 2 programs for SULEV and Bin 2. Confidential business information shared by the auto companies indicate that the primary reason is an inability to demonstrate compliance with SULEV/Bin 2 emission standards after vehicles have operated in-use on gasoline with greater than 10 ppm sulfur and with exposure to the higher sulfur gasoline sold nationwide. While vehicles certified to the LEV II SULEV and Tier 2 Bin 2 standards both demonstrate compliance using certification gasoline with 15-40 ppm sulfur content, in-use compliance of SULEV vehicles in California occurs after significant, sustained operation on gasoline with an average of 10 ppm sulfur and a maximum cap of 30 ppm sulfur while federally certified vehicles under the Tier 2 program operate on gasoline with an average of 30 ppm sulfur and a maximum cap of 80 ppm sulfur. Although the SULEV and Tier 2 Bin 2 standards are numerically equivalent, the increased sulfur exposure of in-use vehicles certified under the federal Tier 2 program results in a need for a higher emissions compliance margin to take into account the impact of in-use gasoline sulfur on full useful life vehicle emissions. As a result, vehicles certified to California SULEV typically certify to emissions standards under the federal Tier 2 program that are 1-2 certification bins higher (e.g., SULEV certified federally as Tier 2 Bin 3 or Bin 4) in order to ensure in-use compliance with emissions standards out to the full useful life of the vehicle when operating on higher-sulfur gasoline.

There are currently no LDTs larger than LDT2 with the exception of a single hybrid electric SUV certified to Tier 2 Bin 2 or SULEV emissions standards. We expect that additional catalyst technologies, for example increasing catalyst surface area (volume or substrate cell density) and/or increased PGM loading, will need to be applied to larger vehicles in order to achieve the catalyst efficiencies necessary to comply with the Tier 3 standards, and any sulfur impact on catalyst efficiency will have a larger impact on vehicles and trucks that rely more on very high catalyst efficiencies in order to achieve very low emissions. The vehicle emissions data referenced in Section 1.2.4.4 represents the only known data on non-hybrid vehicles spanning a range from mid-size LDVs to heavy-light-trucks at the very low criteria pollutant emissions levels that will be needed to comply with the Tier 3 exhaust emissions standards. The developmental Ford Explorer, Chevrolet Malibu PZEV and EPA prototype Chevrolet Silverado vehicles described in Section 1.2.4.3 also represent a range of different technology approaches to both criteria pollution control and GHG reduction (e.g., use of secondary air vs. emphasizing cold-start NO<sub>x</sub> control, use of engine downsizing via turbocharging vs. cylinder deactivation for GHG control, etc.) and represent a broad range of vehicle applications and utility (mid-size LDV, LDT3, LDT4). All of the vehicles with Tier 3/LEV III technology demonstrated greater than 50% increases in NMOG+NO<sub>x</sub> emissions when increasing gasoline sulfur from 10 ppm to 30 ppm. Two of the vehicles showed a doubling of NO<sub>x</sub> emissions when increasing gasoline sulfur from 10 ppm to 30 ppm. Both of the heavy-light-duty trucks with specific engineering targets of meeting Tier 3 emissions were capable of meeting their targeted emission standards with a sufficient compliance margin on 10 ppm sulfur gasoline and could not meet their targeted emissions standards or could not achieve a reasonable compliance margin when tested with 30 ppm sulfur gasoline.

The negative impact of gasoline sulfur on catalytic activity and the resultant loss of exhaust catalyst effectiveness to chemically reduce NO<sub>x</sub> and oxidize NMOG occur across all vehicle categories. However, the impact of gasoline sulfur on the effectiveness of exhaust

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catalysts to control NO<sub>x</sub> emissions in the fully-warmed-up condition is particularly of concern for larger vehicles (the largest LDVs and LDT3s, LDT4s, and MDPVs). Manufacturers face the most significant challenges in reducing cold-start NMOG emissions for these vehicles. Because of the need to reach near-zero NO<sub>x</sub> emissions levels in order to offset engineering limitations on further NMOG exhaust emissions control with these vehicles, any significant degradation in NO<sub>x</sub> emissions control over the useful life of the vehicle would likely prevent some if not most larger vehicles from reaching a combined NMOG+NO<sub>x</sub> low enough to comply with the 30 mg/mi fleet-average standard. Any degradation in catalyst performance due to gasoline sulfur would reduce or eliminate the margin necessary to ensure in-use compliance with the Tier 3 emissions standards. Certifying to a useful life of 150,000 miles versus the current 120,000 miles will further add to manufacturers' compliance challenge for Tier 3 large light trucks (See Section IV.7.b of the preamble for more on the useful life requirements.) These vehicles represent a sufficiently large segment of light-duty vehicle sales now and for the foreseeable future such that their emissions could not be sufficiently offset (and thus the fleet-average standard could not be achieved) by certifying other vehicles to bins below the fleet average standard.

As discussed above, achieving Tier 3 levels as an average across the light-duty fleet will require fleet wide reductions of approximately 80%. This will require significant reductions from all light duty vehicles, with the result that some models and types of vehicles will be at most somewhat above the Tier 3 level, and all other models will be at or somewhat below Tier 3 levels. Achieving these reductions presents a major technology challenge. The required reductions are of a magnitude that EPA expects manufacturers to employ advances in technology in all of the relevant areas of emissions control – reducing engine-out emissions, reducing the time to catalyst lightoff, improving exhaust catalyst durability at 120,000 or 150,000 miles and improving efficiency of fully warmed up exhaust catalysts. All of these areas of emissions control need to be improved, and gasoline sulfur reduction to a 10 ppm average is a critical part of achieving Tier 3 levels through these emissions control technology improvements.

The use of 10 ppm average sulfur fuel is an essential part of achieving Tier 3 levels while applying an array of advancements in emissions control technology to the light-duty fleet. The testing of Tier 2 and Tier 3 type technology vehicles, as well as other information, shows that sulfur has a very large impact on the effectiveness of the control technologies expected to be used in Tier 3 vehicles. Without the reduction in sulfur to a 10 ppm average, the major technology improvements projected under Tier 3 would only result in a limited portion of the emissions reductions needed to achieve Tier 3 levels. For example, without the reduction in sulfur from a 30 ppm to 10 ppm average, the technology improvements would not come close to achieving Tier 3 levels, and in some cases might have no more effectiveness than current Tier 2 technology and achieve only approximately Tier 2 levels of exhaust emissions control.

Achieving Tier 3 levels without a reduction in sulfur to 10 ppm levels would only be possible if there were technology improvements significantly above and beyond those discussed above. Theoretically, without reducing sulfur levels to 10 ppm average, emissions control technology improvements would need to provide upwards of twice as much, and in some cases significantly more than twice as much, emissions control effectiveness as the Tier 3 technology improvements discussed above in Section 1.2.4.4. EPA has not identified technology improvements that could provide such a large additional increase in emissions control

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effectiveness, across the light-duty fleet, above and beyond that provided by the major improvements in technology discussed above, without any additional gasoline reductions in gasoline sulfur content. The impact of sulfur reduction on the effectiveness of the available technology improvements plays such a large role in achieving the Tier 3 levels that there would be no reasonable basis to expect that technology would be available, at the 30 ppm sulfur level, to fill the emission control gap left from no sulfur reduction, and achieve the very significant fleetwide reductions needed to meet the Tier 3 fleet average standards. In effect reducing sulfur from 30 ppm to 10 ppm has such a large impact on the ability of the technology improvements to achieve Tier 3 emissions levels that absent these sulfur reductions there is not a suite of technology advancements available to fill the resulting gap in emissions reductions. Technology would not be available that would achieve the Tier 3 Bin 30 average standard, across the fleet, with sulfur at 30 ppm levels, and as a result Tier 3 levels would not be technically feasible and achievable.

This analysis also applies to gasoline sulfur levels between 10 and 30 ppm, e.g. 20 ppm. The Tier 3 required emissions reductions are so large and widespread across the fleet, and the technology challenges are sufficiently high, especially for heavier vehicles, that the large increase in emissions that would occur from a higher average sulfur level compared to a 10 ppm average would lead to an inability for vehicle technologies to widely achieve Tier 3 levels as a fleet wide average in order to meet the Tier 3 Bin 30 fleet average standard.

EPA acknowledges that some models in the light-duty fleet, when viewed in isolation, may be able to achieve Tier 3 levels at current sulfur levels of 30 ppm average. Under the Tier 3 fleet average standards, it is not sufficient for one or a few of a manufacturer's vehicle models to meet Tier 3 levels because the manufacturer's light-duty vehicle fleet as a whole must achieve the Tier 3 30 mg/mi exhaust emissions standard as a fleet-wide average. As discussed above, all vehicle models will need to achieve further reductions and be either below or no more than somewhat above Tier 3 levels to achieve the Tier 3 standard as a fleet wide average. Absent the reductions in sulfur levels to 10 ppm average, this is not achievable from a technology perspective.

As discussed in Section V.A.2 of the preamble, the 10 ppm standard for sulfur in gasoline represents the lowest practical limit from a standpoint of fuel production, handling and transport. While lowering gasoline sulfur to average levels below 10 ppm would further help ensure in-use vehicle compliance with the Tier 3 standards, the Agency believes that a gasoline sulfur standard of 10 ppm, combined with the advances in emissions control technology discussed above, will enable vehicle manufacturers to achieve compliance with a national fleet average standard of 30 mg/mi NMOG+NO<sub>x</sub>. Not only will a 10 ppm sulfur standard enable vehicle manufacturers to certify their entire product line of vehicles to the Tier 3 fleet average standards, but based on the results of testing both Tier 2 vehicles and SULEV vehicles as discussed above, reducing gasoline sulfur to a 10 ppm average should enable these vehicles to maintain their emission performance in-use over their full useful life.

### 1.3 SFTP NMOG+NO<sub>x</sub> Feasibility

The new Tier 3 emission requirements include stringent NMOG+ NO<sub>x</sub> composite standards over the SFTP that will generally only require additional focus on fuel control of the engines and diligent implementation of new technologies like gasoline direct injection (GDI) and turbocharged engines. Additionally, the fleet-average nature of the standards will allow more challenged vehicles to be offset by vehicles that could outperform the required fleet averages.

In order to assess the technical feasibility of a 50 mg/mi NMOG+NO<sub>x</sub> national fleet average SFTP composite standard EPA conducted an analysis of data from the in-use verification program (IUVP). The IUVP vehicles are tested by manufacturers at various ages and mileages and the results are reported to EPA. The analysis was performed on Tier 2 and LEV II vehicles. This provided a baseline for the current federal fleet emissions performance, as well as the emissions performance of the California LEV II fleet.

#### 1.3.1 Assessment of the Current Federal Fleet Emissions

To investigate feasibility, we acquired and analyzed IUVP certification results for model years 2010 and 2011 which represent the most recent model years of which complete IUVP data sets are currently available. These data included FTP composites, as well as results for the US06, and SC03 cycles. We focused on results for hydrocarbons (HC) and NO<sub>x</sub>. For the FTP results HC represents non-methane organic gases (NMOG). The US06 and SC03 results represent NMHC+NO<sub>x</sub>.

As a first step, we averaged the results by model year and test group (engine family). After compiling results on all three cycles for each test group, we calculated SFTP composite estimates for each engine family as

$$\text{SFTP} = 0.35 \cdot (\text{FTP}_{\text{NO}_x} + \text{FTP}_{\text{NMOG}}) + 0.28 \cdot \text{US06} + 0.37 \cdot \text{SC03}$$

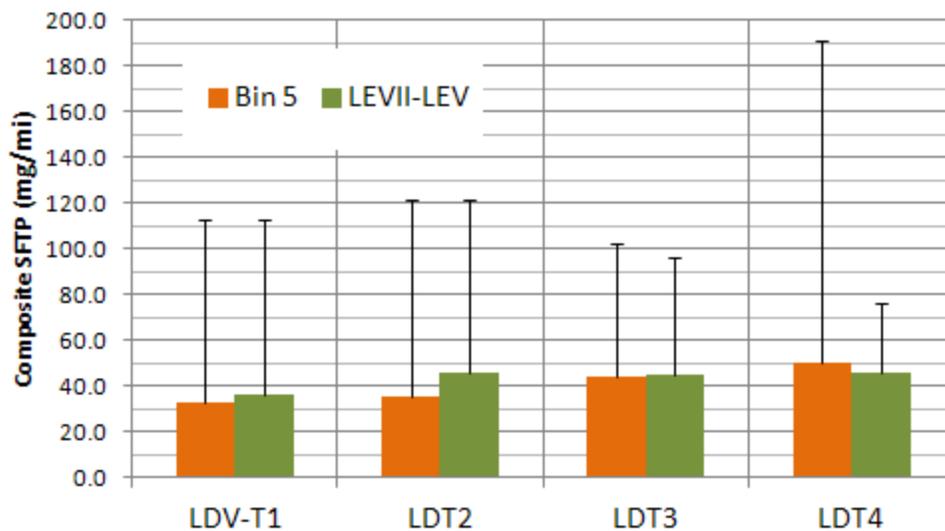
As a second step, we then averaged the SFTP composite results by standard level and vehicle class, focusing on results in Bins 2, 3 and 5, as well as vehicles certified to LEV-II LEV and SULEV standards. In averaging, we treated Bin 2 and LEV-II/SULEV standards as equivalent, and accordingly, pooled their results. Table 1-7 shows the numbers of test groups in each combination of standard level and vehicle class.

**Table 1-7 Numbers of Test Groups Certified to Selected Tier-2 and LEV-II Standards in Model Years 2010 and 2011**

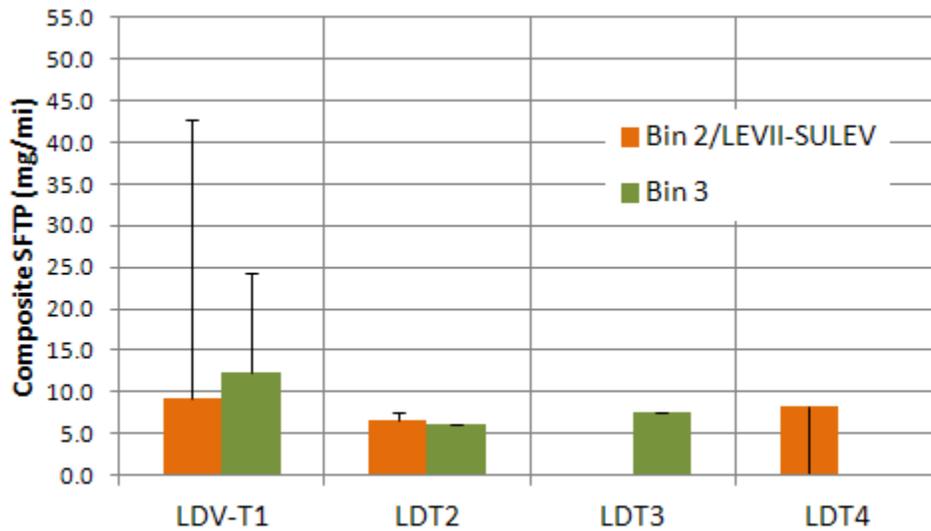
Standard Level	Vehicle Class			
	LDV-LDT1	LDT2	LDT3	LDT4
Bin 2 + LEV-II/SULEV	88	3		1
Bin 3	26	1		
Bin 5	331	37	13	14
LEV-II/LEV	124	17	4	4

Figure 1-3 shows results for Bin-5 and LEV-II/LEV vehicles. It is clear that vehicles in all four vehicle classes, from LDV to LDT4, are certified to these standards. The means show a modest, but not striking increase with vehicle class, from approximately 30 mg/mi for LDV to approximately 50 mg/mi for LDT4. However, an equivalent trend among the maxima is not evident. The results also show that assuming equivalence between these two standards is reasonable. On average it is clear that test groups certified at the Bin-5 level are capable of meeting the target level of 50 mg/mi, although with small compliance margins. However, relatively small numbers of families exceed this level, ranging to over 100 mg/mi.

Additionally, Figure 1-4 shows results for test groups certified to Bin-2 and Bin-3 standards. For these test groups, a trend with vehicle class is not evident, although very small numbers of test groups are certified as trucks. In contrast to the Bin-5 vehicles, most families certified at the Bin-2 and Bin-3 levels are well below the 50-mg/mi level, and maxima are no higher than 7 percent below this level.



**Figure 1-3: Mean and Maximum Composite SFTP Results for HC+NO<sub>x</sub> for Test Groups certified to Bin-5 and LEV-II/LEV Standards (bars and error-bars represent means and maxima for sets of test groups, respectively)**



**Figure 1-4: Mean and Maximum Composite SFTP Results for HC+NO<sub>x</sub> for Test Groups certified to Bin-2 and Bin-3 Standards (bars and error-bars represent means and maxima for sets of test groups, respectively)**

#### 1.4 Technology Description for NMOG+NO<sub>x</sub> Control

A range of technology options exist to reduce NMOG and NO<sub>x</sub> emissions from both gasoline fueled spark ignition and diesel engines below the current Tier 2 standards. Available options include modifications to the engine calibration, engine design, exhaust system, and after treatment systems. The different available options have specific benefits and limitations. This section describes the technical challenges to reducing emissions from current levels, describes available technologies for reducing emissions, estimates the potential emissions reduction of the different technologies, describes if there are other ancillary benefits to engine and vehicle performance with the technology, and reviews the limits of each technology. Except where noted, these technologies are applicable to all gasoline vehicles covered by this rule. Unique diesel technologies are addressed in Section 1.4.2.

##### 1.4.1 Summary of the Technical Challenge for NMOG+NO<sub>x</sub> control

The Tier 3 emission standards will require vehicle manufacturers to reduce the level of both NMOG and NO<sub>x</sub> emissions from the existing Tier 2 fleet by approximately 80 percent over the FTP by 2025. The FTP measures emissions during cold start, hot start, and warmed-up vehicle city driving. The majority of NMOG and NO<sub>x</sub> emissions from gasoline fueled vehicles measured during the FTP test historically occur during the cold start phase however emissions during warmed-up and hot operation cannot be ignored and must be limited in order to meet Tier 3 standards. Figure 1-1, above, graphically demonstrates when NMOG and NO<sub>x</sub> emissions are produced during a cold start. As shown in the figure, approximately 90 percent of the NMOG emissions occur during the first 50 seconds after the cold start. In addition, about 60 percent of the NO<sub>x</sub> emissions occur during this same 50 second period. Unlike NMOG which is mostly controlled after the first 50 seconds, NO<sub>x</sub> emissions tend to be released throughout the remainder of the FTP test and are particularly sensitive to fuel sulfur content. Achieving the Tier 3

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NMOG+NO<sub>x</sub> FTP emissions standard may require manufacturers to reduce both cold start NMOG and NO<sub>x</sub> emissions and further reduce NO<sub>x</sub> emissions when the vehicle is warmed up.

The Tier 3 emission standards will also require manufacturers to maintain their current vehicle high load NMOG+NO<sub>x</sub> emission performance as measured during the US06 operation of the Supplemental Federal Test Procedure (SFTP). The US06 component of the SFTP is designed to simulate higher speeds and acceleration rates during warmed up vehicle operation. Significant quantities of NMOG and NO<sub>x</sub> emissions are produced during the US06 portion of the SFTP if enrichment events occur to reduce exhaust temperatures during high-load operation. Most vehicles are now avoiding these enrichment events during the US06 and achieve relatively low NMOG+NO<sub>x</sub> emissions.

It is anticipated that manufacturers will change the design of their exhaust and catalyst systems to reduce catalyst light-off times and reduce warmed-up and hot running emissions, particularly NO<sub>x</sub> to almost zero, in order to achieve the Tier 3 30 mg/mi FTP NMOG+NO<sub>x</sub> standard. Design changes to reduce catalyst light-off time can also result in higher catalyst temperatures during high-load operation as seen during the US06 test. To achieve the NMOG+NO<sub>x</sub> Tier 3 SFTP standard manufacturers will need to develop and implement technologies to manage catalyst temperatures during high-load operation without using fuel enrichment.

In addition, it is anticipated that the technologies manufacturers will use for reducing warmed up NO<sub>x</sub> emissions during the FTP will also reduce NO<sub>x</sub> emissions during warmed up operation on the US06.

For the catalyst to effectively reduce NMOG+NO<sub>x</sub> emissions it must reach the light-off temperature of approximately 250 °C. Emissions during the catalyst warm up period can be reduced by reducing the emissions produced by the engine during the catalyst warm up phase. Emissions can also be reduced by shortening the time period required for the catalyst to reach the light-off temperature. Reducing warmed-up NO<sub>x</sub> emissions requires improving the efficiency of the catalyst system which will generally require little to no presence of sulfur contaminants in the fuel.

To achieve the Tier 3 NMOG+NO<sub>x</sub> FTP emissions standards it is anticipated that vehicle manufacturers will focus on three areas to reduce emissions:

- minimizing the emissions produced by the engine before the catalyst reaches the light-off temperature;
- reducing the time required for the catalyst to reach the light-off temperature; and,
- improving the NO<sub>x</sub> efficiency of the catalyst during warmed-up operation.

It is anticipated that improvements in all three areas will be required particularly for heavier passenger cars, light-duty trucks in classes LDT3 and LDT4, and MDPVs. The NO<sub>x</sub> efficiency during warmed-up operation of vehicles certified to the Tier 2 Bin 4 emission level and operating on low sulfur fuel (i.e. 10 ppm or lower) are such that it is anticipated that

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reductions in cold start emissions are primarily what will be required to achieve the Tier 3 NMOG+NO<sub>x</sub> standard.

Heavy-duty trucks (8,501 up to 14,000 lbs) will have a similar challenge to meet their Tier 3 standards along with the new SFTP requirements for this vehicle class. In addition to the new test requirements and tighter standards, these vehicles useful life is being extended from 120,000 to 150,000 miles. Unlike lighter weight vehicles, heavy-duty trucks tend to operate at higher loads for greater periods of time and therefore have different constraints to meet the new requirements and more stringent standards.

For spark-ignition engines, the higher operating load of these vehicles limits the ability to move the catalyst close to the cylinder head due to durability concerns from higher thermal loading. This limit will constrain the ability of these trucks to quickly light-off the catalyst, it will, however, allow them to stay out of fuel-enriched operation to maintain catalyst temperatures when the vehicle is being operated under high load. The emissions produced during fuel-enrichment events, which occur at high loads can be significantly greater than the reductions achievable during the cold start and idle phase. Fuel enrichment events cause criteria pollutant and CO<sub>2</sub> emission rates to increase and also reduces the vehicle's fuel economy. To achieve the NMOG+NO<sub>x</sub> FTP emissions standards while also meeting the new SFTP requirements it is anticipated that heavy-duty vehicle manufacturers will focus on four areas for spark ignition engines:

- reducing the emissions produced by the engine before the catalyst reaches light-off temperature;
- reducing the time required for the catalyst to reach the light-off temperature;
- improving the NO<sub>x</sub> efficiency of the catalyst during warmed up operation; and,
- minimizing the time spent in fuel enrichment to reduce the operating temperature of the catalyst.

Compression ignition or diesel engines also have limitations with thermal goals and location of the emission control system on the vehicle. With the similar goal of providing engine exhaust heat to the catalysts, SCR and DPF, these emission control systems may compete with each other for thermal energy. Additionally, the SCR system and the DPF generally require sufficient capacity or size to handle the emissions from the engine which may limit the ability to locate them in the optimal location.

To meet Tier 3 NMOG+NO<sub>x</sub> FTP emissions standards while also meeting the new SFTP requirements it is anticipated that heavy-duty vehicle manufacturers will focus on three areas for compression ignition:

- reducing the emissions produced by the engine while the catalysts and SCR system are being brought to proper operating temperature;

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- reducing the time required for the catalysts and SCR system to reach the proper operating temperature;
  - improving the NO<sub>x</sub> efficiency of the SCR during warmed up operation through refinement in engine out emission controls and SCR strategies.

#### 1.4.1.1 Reducing Engine Emissions Produced Before Catalyst Light-Off

During the first 50 seconds of the cold start phase of the FTP the engine is operating either at idle or low speed and load in non-hybrid vehicles. The engine temperature is between 20 and 30 °C (68 and 86 °F). At these temperatures and under these low loads the cold engine produces lower concentrations of NO<sub>x</sub> than NMOG. As the engine warms up and as the load increases the concentration of NO<sub>x</sub> produced by the engine increases and the concentration of NMOG decreases.

The design of the air induction system, combustion chamber, spark plug, and fuel injection system determines the quantity of fuel required for stable combustion to occur in the cold engine. Optimizing the performance of these components can provide reductions in the amount of fuel required to produce stable combustion during these cold operating conditions. Reductions in the amount of fuel required leads to reductions in cold start NMOG emissions.

The design considerations to minimize cold start emissions are also dependent on the fuel injection method. Port fuel injected (PFI) engines have different design constraints than gasoline direct injection (GDI) spark ignition engines. For both PFI and GDI engines, however, attention to the details affecting the in cylinder air/fuel mixture can reduce cold start NMOG emissions.

It has been shown that cold start NMOG emissions in PFI engines can be reduced by reducing the size of the fuel spray droplets and optimizing the spray targeting. Fuel impinging on cold engine surfaces in the cylinder does not readily vaporize and does not combust. Improving injector targeting to reduce the amount of fuel reaching the cylinder walls reduces the amount of fuel needed to create a combustible air fuel mixture. Reducing the size of the spray droplets improves the vaporization of the fuel and creation of a combustible mixture.<sup>64</sup>

Droplet size can be reduced by modifying the injector orifice plate and also by increasing the fuel pressure. Reducing droplet size and improving fuel vaporization during cold start has been shown to reduce cold transient emissions by up to 40 percent during the cold start phase of the FTP emission test.<sup>65</sup> This and other PFI injector technology improvements have been used to optimize the cold start performance of today's vehicles certified to the CA LEV II SULEV standards.

The mixture formation process in a DISI engine is different than a PFI engine. In a PFI engine the fuel is injected during the intake stroke of the engine in the intake runner. The fuel has time to evaporate during the intake stroke as the fuel and air are drawn into the cylinder. In addition, as the engine warms up the fuel can be injected into the intake runner and engine heat can assist in evaporating the fuel prior to the intake valve opening.

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The DISI engine injects fuel at higher fuel pressures than PFI engines directly into the combustion chamber. In a DISI engine the fuel droplets need to evaporate and mix with the air in the cylinder in order to form a flammable mixture.

Injecting directly into the cylinder reduces the time available for the fuel to evaporate and mix with the intake air in a DISI engine compared to a PFI engine. An advantage of the DISI design is that the fuel spray does not impinge on the walls of the intake manifold or other surfaces in the cylinder.

DISI systems have the ability to split the injection timing event. At least one study has indicated that significant reductions in hydrocarbon emissions can be achieved by splitting the injections during the cold start of a DISI engine. An initial injection occurs during the intake stroke and a second injection is timed to occur during the compression stroke. This injection method reduced unburned hydrocarbon emissions 30 percent compared to a compression stroke only injection method.<sup>66</sup>

These are two examples of specific engine design characteristics, fuel injector design and fuel system pressure on PFI engines and injection timing on GDI engines which can be used to reduce cold start NMOG emissions significantly during the engine warm up prior to the catalyst reaching the light-off temperature.

Optimizing the fuel injection system design and calibration is anticipated to be used in all vehicle classes, including heavy-duty vehicles. It is anticipated that these described improvements, along with improvements to other engine design characteristics, will be used to reduce cold start emissions for passenger cars, LDTs, MDPVs, and HDTs.

Because the engine is relatively cold and the operating loads are low during the first 50 seconds of the FTP the engines typically do not produce significant quantities of NO<sub>x</sub> emissions during this phase. In addition manufacturers tend to retard the combustion timing during the catalyst warm up phase. Retarding combustion timing has been shown also to reduce the concentration of NMOG in the exhaust. This calibration method further reduces peak combustion temperatures while increasing the exhaust gas temperature compared to optimized combustion timing. The increased exhaust gas temperature leads to improved heating of the catalyst and reduced catalyst light-off times. Retarding combustion and other technologies for reducing catalyst light-off time are discussed in the following section.

#### 1.4.1.2 Reducing Catalyst Light-Off Time

The effectiveness of current vehicle emissions control systems depends in large part on the time it takes for the catalyst to light-off, which is typically defined as the catalyst reaching a temperature of 250°C. In order to reduce catalyst light-off time, it is expected manufacturers will use technologies that will improve heat transfer to the catalyst during the cold start phase and improve catalyst efficiency at lower temperatures. Technologies to reduce catalyst light-off time include calibration changes, thermal management, close-coupled catalysts, catalyst PGM loading, and secondary air injection. It is anticipated that in some cases where the catalyst light-off time and efficiency are not sufficient to reduce cold start NMOG emissions, hydrocarbon adsorbers may be utilized. The adsorbers trap hydrocarbons until such time that the catalyst is

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fully warmed up and the emissions can be oxidized by the catalyst. Note that with the exception of hydrocarbon adsorbers each of these technologies addresses NMOG and NO<sub>x</sub> performance. The technologies are described in greater detail below.

#### *1.4.1.2.1 Calibration Changes to Reduce Catalyst Light-Off Time*

These include calibration changes to increase the temperature and mass flow of the exhaust prior to the catalyst reaching the light-off temperature. By reducing the time required for the catalyst to light-off engine calibration changes can affect NMOG and NO<sub>x</sub> emissions.

Retarding combustion in a cold engine by retarding the spark advance is a well known method for reducing the concentration of NMOG emissions in the exhaust and increasing the exhaust gas temperature.<sup>67,68</sup> The reduction in NMOG concentrations is due to a large fraction of the unburned fuel within the cylinder combusting before the flame is extinguished on the cylinder wall. Reductions of total hydrocarbon mass of up to 40 percent have been reported from studies evaluating the effect of spark retard on exhaust emissions.

In addition to reducing the NMOG exhaust concentrations retarding the spark advance reduces the torque produced by the engine. In order to produce the same torque and maintain the engine speed and load at the desired level when retarding the spark advance, the air flow into the engine is increased causing the manifold pressure to increase which can also improve combustion stability. Retarding the combustion process also results in an increase in the exhaust gas temperature. The retarded ignition timing during the cold start phase in addition to reducing the NMOG emissions increases the exhaust mass flow and exhaust temperature. These changes lead to a reduction in the time required to heat the catalyst.

The torque produced by the engine will begin to vary as the spark retard amount reaches engine combustion limits. As the torque variations increase, the combustion process is deteriorating and the engine performance begins to degrade due to the partial burning. It is the level of this variability which defines the absolute maximum reduction in spark advance that can be utilized to reduce NMOG emissions and reduce the catalyst light-off time.

Retarding combustion during cold start can be applied to spark-ignition engines in all vehicle classes. The exhaust temperatures and NMOG emission reductions will vary based on engine design. This calibration methodology is anticipated to be used to improve catalyst warm-up times and reduce cold start NMOG emissions for all vehicle classes, passenger cars, LDTs, MDPVs, and HDTs.

With the penetration of variable valve timing technology increasing in gasoline-fueled engines additional work is being performed to characterize the impact of valve timing on cold start emissions. The potential exists that calibration changes to the valve timing during the cold start phase will lead to additional reductions in cold start NMOG emissions.<sup>69</sup>

#### *1.4.1.2.2 Exhaust System Thermal Management to Reduce Catalyst Light-Off Time*

This category of technologies includes all design attributes meant to conduct combustion heat into the catalyst with minimal cooling. This includes insulating the exhaust piping between

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the engine and the catalyst, reducing the wetted area of the exhaust path, reducing the thermal mass of the exhaust system, and/or using close-coupled catalysts (i.e., the catalysts are packaged as close to the engine cylinder head as possible to mitigate the cooling effects of longer exhaust piping). By reducing the time required to light-off the catalyst, thermal management technologies reduce NMOG and NO<sub>x</sub> emissions.

Moving the catalyst closer to the cylinder head is a means manufacturers have been using to reduce both thermal losses and the catalyst light-off time. Many vehicles today use close-coupled catalysts, a catalyst which is physically located as close as possible to the cylinder head. Moving the catalyst from an underbody location to within inches of the cylinder head reduces the light-off time significantly.

Another means for reducing heat losses are to replace cast exhaust manifolds with thin-wall stamped manifolds. Reducing the mass of the exhaust system reduces the heat losses of the system. In addition an insulating air gap can be added to the exhaust system which further reduces the heat losses from the exhaust system, insulating air gap manifolds are also known as dual-wall manifolds.

With thin- and dual-wall exhaust manifolds, close-coupled catalyst housings can be welded to the manifold. This reduces the needed for manifold to catalyst flanges which further reduces the thermal inertia of the exhaust system. Close coupling of the catalyst and reducing the thermal mass of the exhaust system significantly reduces the light-off time of the catalyst compared to an underbody catalyst with flanges and pipes connected to a cast exhaust manifold.

Using close-coupled catalysts reduces the heat losses between the cylinder head and catalyst. While reducing the time required to light-off the catalyst the close-coupled catalyst can be subject to higher temperatures than underbody catalysts during high load operating conditions. To ensure the catalyst does not degrade manufacturers currently use fuel enrichment to maintain the exhaust temperatures below the levels which would damage the catalyst. It is anticipated that to meet the Tier 3 SFTP standards, manufacturers will need to ensure that fuel enrichment is not required on the US06 portion of the FTP. Calibration measures, other than fuel enrichment, may be required to ensure the catalyst temperature does not exceed the maximum limits.

Another technology beginning to be used for both reducing heat loss in the exhaust and limiting exhaust gas temperatures under high load conditions is integrating the exhaust manifold into the cylinder head. Honda utilized this technology on the Insight's 1.0 L VTEC-E engine. The advantage of this technology is that it minimizes exhaust system heat loss during warm-up. In addition with the exhaust manifold integrated in the cylinder head the cooling system can be used to reduce the exhaust temperatures during high load operation. It is anticipated that manufacturers will further develop this technology as means to both quickly light-off the catalyst and reduce high-load exhaust temperatures.

To achieve the Tier 3 NMOG and NO<sub>x</sub> emissions standards it is expected that manufacturers will optimize the thermal inertia of the exhaust system to minimize the time needed for the catalyst to achieve the light-off temperature. In addition, the manufacturers will need to ensure the high load performance does not cause thermal degradation of the catalyst

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system. It is expected that methods and technologies will be developed to reduce the need to use fuel enrichment to reduce high load exhaust temperatures.

Optimizing the catalyst location and reducing the thermal inertia of the exhaust system are design options manufacturers can apply to all vehicle classes (PCs, LDTs, MDPVs, and HDTs) for improving vehicle cold start emission performance.

It is not anticipated HDTs with spark-ignition engines will utilize catalysts close-coupled to the exhaust manifold. The higher operating loads of these engines results in durability concerns due to high thermal loading. It is expected that manufacturers will work to optimize the thermal mass of the exhaust systems to reduce losses along with optimizing the underbody location of the catalyst. These changes are expected to improve the light-off time while not subjecting the catalysts to the higher thermal loadings from a close coupled location.

#### *1.4.1.2.3 Catalyst Design Changes*

A number of different catalyst design changes can be implemented to reduce the time for the catalyst to light-off. Changes include modifying the substrate design, replacing a large volume catalyst with a cascade of two or more catalysts, and optimizing the loading and composition of the platinum group metals (PGM).

Progress continues to be made in the development of the catalyst substrates which provide the physical support for the catalyst components which typically include a high surface area alumina carrier, ceria used for storing oxygen, PGM catalysts, and other components. A key design parameter for substrates is the cell density. Today catalyst substrates can be fabricated with cell densities up to 900 and 1,200 cells per square inch (cpsi) with wall thicknesses approaching 0.05 mm.

Increasing the surface area of the catalyst improves the performance of the catalyst. Higher substrate cell densities increases the surface area for a given catalyst volume. Higher surface areas improve the catalyst efficiency and durability reducing NMOG and NO<sub>x</sub> emissions.

The limitation of the higher cell density substrates include increased exhaust system pressures at high load conditions. The cell density and substrate frontal area are significant factors that need to be considered to optimize the catalyst performance while limiting flow loss at high load operation.

During the cold start phase of the FTP the engine speeds and load are low during the first 50 seconds of the test. One method for reducing the catalyst light-off time is to replace a larger volume catalyst with two catalysts which total the same volume as the single catalyst. The reduced volume close-coupled catalyst reduces the heat needed for this front catalyst to reach the light-off temperature. The front catalyst of the two catalyst system will reach operating temperature before the larger volume single catalyst, reducing the light-off time of the system.

All other parameters held constant, increasing the PGM loading of the catalyst also improves the efficiency of the catalyst. The ratio of PGM metals is important as platinum, palladium, and rhodium have different levels of effectiveness promoting oxidation and reduction

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reactions. Therefore, as the loading levels and composition of the PGM changes the light-off performance for both NMOG and NO<sub>x</sub> need to be evaluated. Based on confidential conversations with manufacturers it appears that there is an upper limit to the PGM loading, beyond which further increases do not improve light-off or catalyst efficiency.

To achieve the Tier 3 NMOG and NO<sub>x</sub> emission standards it is anticipated that manufacturers will make changes to catalyst substrates and PGM loadings.<sup>70</sup> To achieve the emission levels required to meet the Tier 3 NMOG+NO<sub>x</sub> standard of 30 mg/mi with a compliance margin will require very low sulfur levels in the fuel. As described in Section 1.2.3.3 even low levels (greater than 10 ppm) of sulfur in gasoline inhibit the ability of PGM catalysts to achieve the low levels NO<sub>x</sub> emission levels of the Tier 3 standard. For the Tier 3 FTP emission standards to be achieved and maintained, particularly in use, it is required that the sulfur content of the fuel be reduced to 10 ppm or lower.

Manufacturers will optimize the design of their aftertreatment systems for their different vehicles. Primary considerations include cost, light-off performance, warmed-up conversion efficiency and the exhaust temperatures encountered by the vehicle during high load operation. Vehicles having low power to weight ratios will tend to have higher exhaust gas temperatures and exhaust gas flow which will result in a different design when compared to vehicles having higher power to weight ratios.

Manufacturers and catalyst suppliers perform detailed studies evaluating the cost and emission performance of aftertreatment systems. It is anticipated that manufacturers will optimize their aftertreatment systems to achieve the Tier 3 standards and meet the durability criteria for all vehicle classes (PCs, LDTs, MDPVs, and HDTs).

#### *1.4.1.2.4 Secondary Air Injection*

By injecting air directly into the exhaust stream, close to the exhaust valve, combustion can be maintained within the exhaust, creating additional heat thereby further increasing the catalyst temperature. The air/fuel mixture must be adjusted to provide a richer exhaust gas for the secondary air to be effective.

Secondary air injection has been used by a variety of passenger vehicle manufacturers to assist with achieving the emission levels required of the CA LEV II SULEV standard. Secondary air injection systems are used after the engine has started and once exhaust port temperatures are sufficiently high to sustain combustion in the exhaust port. When the secondary air pump is turned on the engine control module increases the amount of fuel being injected into the engine. Sufficient fuel is added so that the air/fuel ratio in the cylinder is rich of stoichiometry. The exhaust contains significant quantities of CO and hydrocarbons. The rich exhaust gas mixes with the secondary air in the exhaust port and the combustion process continues increasing the temperature of the exhaust and rapidly heating the manifold and close-coupled catalyst.<sup>71,72</sup>

Engines which do not use secondary air injection cannot operate rich of stoichiometry as the added enrichment would cause increased NMOG emissions. The richer cold start calibration used with vehicles that have a secondary air injection system provides a benefit as combustion

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stability is improved. In addition, the richer calibration is not as sensitive to changes in fuel volatility. Less volatile fuels found in the market may result in poor start and idle performance on engines calibrated to run lean during the cold operation. Engines which use secondary air and have a richer warm up calibration would have a greater combustion stability margin. Manufacturers may perceive this to be a benefit for the operation of their vehicles during the cold start and warm up phase.

Installing a secondary air injection system combined with calibration changes can be used by manufacturers to reduce the cold start emissions and improve the catalyst light-off on existing engine designs. It is anticipated that manufacturers will utilize this technology to improve the cold start performance on heavier vehicles and vehicles with low power to weight ratios. Secondary air injection has been used on vehicles to achieve the CA LEVII SULEV emission standards. This technology can be used on engines in all vehicle classes.

It is anticipated that secondary air injection will be used primarily in combination with close coupled catalysts. Therefore, it is not anticipated that this technology will be used with HDTs as it is not expected that the catalyst in these vehicles will be moved to a location sufficiently close to the exhaust manifold to provide any improvement in catalyst light-off.

HDTs tend to operate at higher loads and catalyst durability is a concern due to the increased thermal loading as the catalyst is moved closer to the cylinder head. Moving the catalyst closer to the exhaust manifold would result in increasing the time spent in fuel enrichment modes to ensure the temperatures are maintained below the threshold which would reduce the durability of the catalyst. Using fuel enrichment to control catalyst temperature causes significant increases in criteria pollutant emissions, CO<sub>2</sub> emissions and reductions in fuel economy.

#### *1.4.1.2.5 Hydrocarbon Adsorbers*

Hydrocarbon adsorbers trap hydrocarbons emitted by the engine when the adsorber is at low temperatures. As the temperature of the hydrocarbon adsorber increases the trapped hydrocarbons are released. Passive adsorbers use an additional washcoat on an existing three-way catalyst. The adsorber is a zeolite-based material which absorbs hydrocarbons at low exhaust temperatures and desorbs hydrocarbons as the temperature increases. A significant technical challenge to using a passive adsorber is to design the system such that the three-way catalyst has reached the light-off temperature prior to the adsorber coating releasing the adsorbed hydrocarbons.

Active adsorbers use a substrate with an adsorber washcoat over which the exhaust is directed when the exhaust temperature is below the desorption temperature of the material. Once the exhaust temperature reaches the desorption temperature the exhaust is routed such that it no longer passes over the adsorber. As the adsorber continues to heat in the exhaust the captured hydrocarbons are released and oxidized by the warmed-up catalyst system.

Adsorbers have been used to reduce cold start NMOG emissions on CA LEV II SULEV vehicles. Additional work is being performed to further improve the performance of hydrocarbon adsorbers.

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It is anticipated that if manufacturers have difficulty achieving the Tier 3 NMOG+NO<sub>x</sub> emission standards because of challenging NMOG emission levels on the cold start,, they may evaluate hydrocarbon adsorbers as an option to further reduce the NMOG emissions during the cold start. One manufacturer used this approach to achieve the CA LEV II SULEV standard on a large displacement V-8 engine with the application of an active hydrocarbon adsorber.<sup>73</sup>

Hydrocarbon adsorbers can be used on all spark-ignition engines and all classes of vehicles. It is anticipated that these technologies may be required for engines with larger displacement and in some of the larger vehicles. It is anticipated that HDTs will be able to achieve the emissions levels required without the use of hydrocarbon adsorbers to meet the standard.

#### 1.4.1.3 Improving Catalyst NO<sub>x</sub> Efficiency during Warmed-up Operation

Significant quantities of NO<sub>x</sub> emissions are produced by vehicles during warmed-up vehicle operation on the FTP for Tier 2 certified vehicles. The stabilized NO<sub>x</sub> emission levels will need to be reduced to achieve the Tier 3 NMOG+NO<sub>x</sub> emission standard. Improving the NO<sub>x</sub> performance of the vehicle can be achieved by improving the catalyst efficiency during warmed-up operation. As previously described the performance of the catalyst can be improved by modifications to the catalyst substrate, increasing cell density, increasing PGM loadings and particularly important, reducing the sulfur level of gasoline. Three-way catalyst efficiency is also affected by frequency and amplitude of the air/fuel ratio. For some vehicles warmed-up catalyst NO<sub>x</sub> efficiency can be improved by optimizing the air/fuel ratio control and limiting the amplitude of the air fuel ratio excursions. It is anticipated that a combination of changes will be made by manufacturers including further improvements to air/fuel ratio calibration and catalyst changes including cell density and PGM loadings.

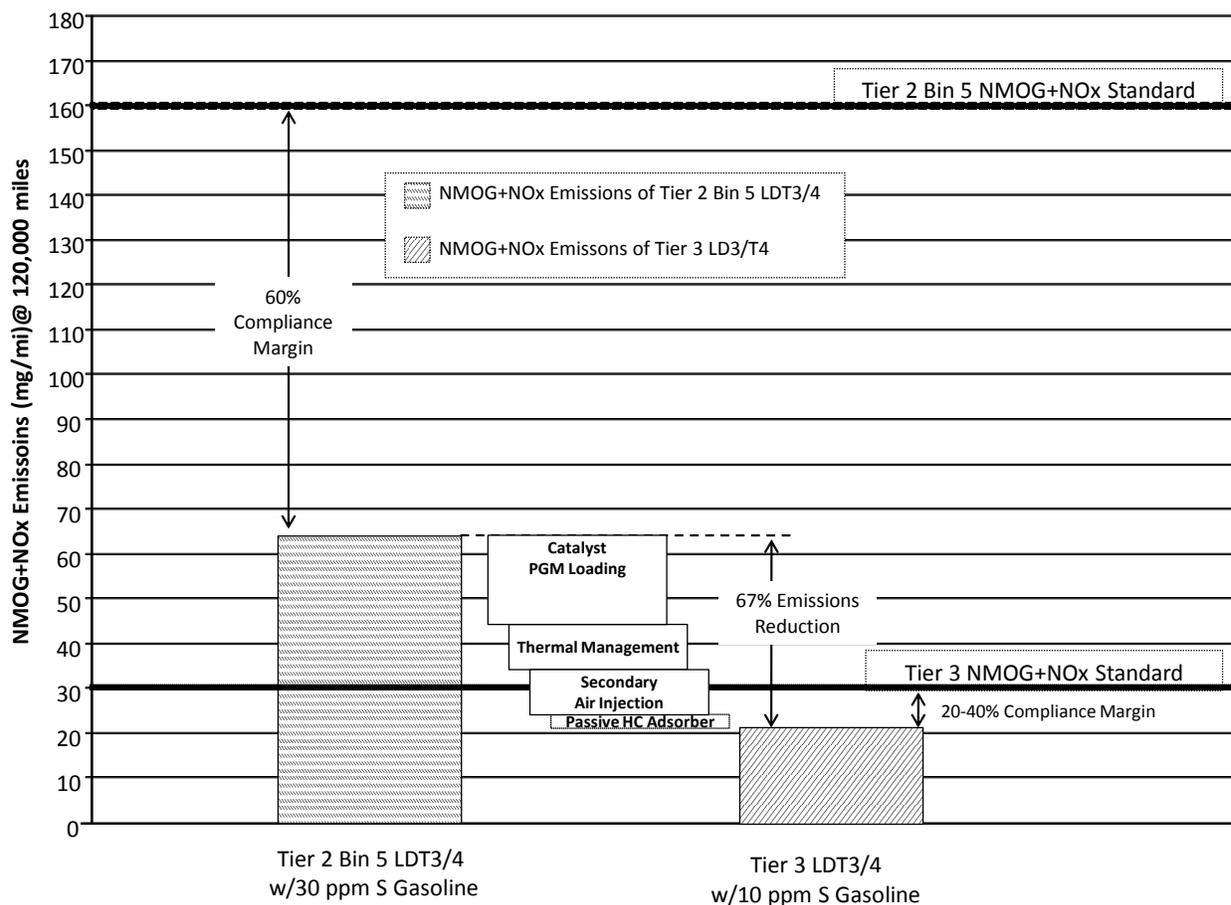
A requirement to ensure that the NO<sub>x</sub> emission performance of the vehicles is maintained at or below the 30 mg/mi NMOG+NO<sub>x</sub> emission standard is reduced fuel sulfur concentrations. As described in detail in Section 1.2.3.3 further reductions in fuel sulfur concentration are required to ensure the catalyst performance is not degraded which causes increases in NO<sub>x</sub> emissions beyond the Tier 3 standard.

It is anticipated that manufacturers will use these catalyst and calibration technologies to improve the warmed up NO<sub>x</sub> emissions performance of vehicles in all classes, passenger cars, LDTs, MDPVs, and HDTs.

#### 1.4.1.4 EPA Estimates of Technology Improvements Required for Large Light-Duty Trucks

Discussions with and comments from vehicle manufacturers indicated that large light-duty trucks (e.g., pickups and full-size SUVs in the LDT3 and LDT4 categories) will likely be the most challenging light-duty vehicles to bring into compliance with the Tier 3 NMOG+NO<sub>x</sub> standards at the 30 mg/mi corporate average emissions level. A similar challenge was addressed when large light-duty trucks were brought into compliance with the Tier 2 standards in the previous decade. Figure 1-5 provides a graphical representation of the effectiveness of Tier 3 technologies when combined with gasoline sulfur control for large light-duty truck applications.

The Tier 3 technologies shown are those that can be utilized on existing vehicles and do not require engine design changes. A compliance margin is shown in both cases. Note that the graphical representation of the effectiveness of catalyst technologies on NO<sub>x</sub> and NMOG when going from Tier 2 to Tier 3 also includes a reduction in gasoline sulfur levels from 30 ppm to 10 ppm.



**Figure 1-5: Contribution of the expected Tier 3 technologies to large light-duty truck compliance with the Tier 3 standards with a comparison to Tier 2 Bin 5. The technologies and levels of control are based on a combination of confidential business information submitted by auto manufacturers and suppliers, public data and EPA staff engineering judgment.**

#### 1.4.2 Diesel Technologies for Achieving Tier 3 NMOG and NO<sub>x</sub> Emission Requirements

Compared to spark-ignition engines, diesel engines typically produce very low NMOG emissions. However, diesel engines do not operate at stoichiometry preventing them from using emission control approaches similar to spark-ignition engines to control NO<sub>x</sub> emissions. The technical challenge for diesel engines to achieve the Tier 3 NMOG+NO<sub>x</sub> emission levels will be to obtain significant NO<sub>x</sub> emission reductions. It is anticipated that improvements in NO<sub>x</sub> emissions performance of diesel exhaust catalysts during the cold start phase will be a major

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technical challenge. Depending on the performance of the exhaust catalyst system, additional reductions in warmed-up NO<sub>x</sub> emissions may also be required to achieve the Tier 3 emission levels.

It is not anticipated that diesel engines will have difficulty achieving the Tier 3 SFTP emission standards. The exhaust catalyst system is fully warmed up and operational on the high load portion of the SFTP, the US06. It is anticipated that manufacturers may need to optimize the calibration of the selective catalytic reduction (SCR) system or the NO<sub>x</sub> adsorption catalyst (NAC) system to ensure the systems achieve the required performance.

The technical task for achieving the Tier3 standards on all diesel engines in all vehicle classes will be to have the exhaust catalysts reach operating temperatures early in the cold-start phase of the FTP. To achieve these improvements it is anticipated that diesel manufacturers will focus on means to reduce NO<sub>x</sub> emissions during the engine warm-up phase after the cold start and reducing the time required for the SCR or NAC system to begin reducing (SCR) or capturing and reducing (NAC) the NO<sub>x</sub>.

By controlling the timing of the fuel injection event, the number of fuel injection events and the timing of intake and exhaust valve events, the temperature of the exhaust can be increased. Diesel engine manufacturers will optimize the injection and valvetrain calibration to increase the exhaust temperature after the engine is started and before it has reached operating temperature.

As with gasoline engines, locating the exhaust catalyst system closer to the cylinder head and air-gap insulating the exhaust system or reducing the mass of the exhaust components upstream of the catalysts can be used to build and maintain heat in the exhaust system. A variety of technologies are available to conduct combustion heat into the exhaust catalyst system with minimal cooling. This includes uses of dual-wall, air-gapped exhaust piping between the engine and the catalyst or trap; reducing the wetted area of the exhaust path; and reducing the thermal mass of the exhaust system through use of thinner wall materials. By reducing the time required to light-off the catalysts, thermal management technologies can reduce NO<sub>x</sub> emissions from diesel engines. Once light-off has been achieved, NO<sub>x</sub> emissions reduction for modern, base-metal zeolite SCR systems approaches that of modern three-way catalyst systems used for stoichiometric gasoline spark-ignition applications.<sup>74</sup>

## **1.5 PM Feasibility**

Particulate matter emitted from internal combustion engines is a multi-component mixture composed of elemental carbon (or soot), semi-volatile organic compounds, sulfate compounds (primarily sulfuric acid) with associated water, nitrate compounds and trace quantities of metallic ash. At temperatures above 1,300K, fuel hydrocarbons without access to oxidants can pyrolyze to form particles of elemental carbon. Fuel pyrolysis can occur as the result of operation at richer than stoichiometric air-to-fuel ratio (primarily PFI gasoline GDI engines), direct fuel impingement onto surfaces exposed to combustion (primarily GDI and diesel engines) and non-homogeneity of the air-fuel mixture during combustion (primarily diesel engines). Elemental carbon particles that are formed can be oxidized during later stages of combustion via in-cylinder charge motion and reaction with oxidants. Semi-volatile organic compounds (SVOC)

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are composed primarily of organic compounds from lubricant and partial combustion products from fuel. PM emissions from SVOC are typically gas phase when exhausted from the engine and contribute to PM emissions via particle adsorption and nucleation after mixing with air and cooling. Essentially, PM-associated SVOC represent the condensable fraction of NMOG emissions. Sulfur and nitrogen compounds are emitted primarily as gaseous species (SO<sub>2</sub>, NO and NO<sub>2</sub>). Sulfate compounds can be a significant contributor to PM emissions from stratified lean-burn gasoline engines and diesel engines, particularly under conditions where PGM-containing exhaust catalysts used for control of gaseous and PM emissions oxidize a large fraction of the SO<sub>2</sub> emissions to sulfate (primarily sulfuric acid). Sulfate compounds do not significantly contribute to PM emissions from spark-ignition engines operated at near stoichiometric air-fuel ratios due to insufficient availability of oxygen in the exhaust for oxidation of SO<sub>2</sub> over PGM catalysts.

Elemental carbon PM emissions can be controlled by:

- Reducing fuel impingement on piston and cylinder surfaces
- Inducing charge motion and air-fuel mixing via charge motion (e.g., tumble and swirl) or via multiple injection (e.g., GDI and diesel/common rail applications)
- Reducing or eliminating operation at net-fuel-rich air-to-fuel ratios (PFI gasoline and GDI applications)
- Use of wall-flow or partial-wall-flow exhaust filters (diesel applications)

SVOC PM emissions can be controlled by:

- Reducing lubricating oil consumption
- Improvements in exhaust catalyst systems used to control gaseous NMOG emissions (e.g., increased PGM surface area in the catalyst, improvements in achieving catalyst light-off following cold-starts, etc.)

Sulfate PM emission can be controlled by:

- Reducing or eliminating sulfur from fuels

#### 1.5.1 PM Emissions from Light-duty Tier 2 Vehicles

In order to establish the feasibility of the Tier 3 PM emission standards, EPA conducted a test program to measure PM emissions from Tier 2 light-duty vehicles. The test program was designed to measure PM emissions from late model year vehicles that represented a significant volume of annual light duty-sales and included vehicles that ranged from small cars through trucks. In addition, GDI vehicles were included in the program as were vehicles with known high oil consumption.

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The Agency investigated PM emissions from Tier 2 light-duty vehicles. Seventeen model year 2005-2010 Tier 2 Bin 4, 5, and 8 vehicles were tested at the U.S. EPA National Vehicle and Fuel Emissions Laboratory (NVFEL) facility. A summary of their characteristics are provided in Table 1-8. They included ten cars and seven trucks. Fifteen of these vehicles had accumulated 102,000-124,000 miles prior to the launch of the test program. One vehicle had accumulated 75,000 miles and another accumulated 21,000. Three cars and one truck were equipped with GDI engines. Twelve of the fifteen test vehicles had previously been used in the DOE V4 Program. The remaining five vehicles were recruited in southeastern Michigan. One vehicle (vehicle K) was suspected of having atypically high oil consumption and had only 37,000 miles of mileage accumulation. Vehicle K was a duplicate of Vehicle C and was determined to consume two and one half times the average oil consumption of vehicle C and three vehicles of the same make, model and model year when tested within the DOE V4 program.<sup>F</sup>

The twelve vehicles acquired from the DOE V4 Program were selected to represent a broad cross section of some of the highest sales vehicles in the U.S. market for model years 2005-2009. These vehicles had originally been purchased by DOE with odometer readings ranging from 10,000-60,000 miles, placed in a mileage accumulation program and operated over the EPA Standard Road Cycle on a test track or on mileage accumulation dynamometers to 110,000-120,000 miles.<sup>75</sup> Immediately prior to inclusion in the EPA PM Test Program, the test vehicles were serviced per the manufacturer's published service schedule and maintenance procedures and underwent engine oil aging over a distance of 1,000 miles accumulated over the EPA Standard Road Cycle to stabilize engine oil contribution to PM emissions<sup>76</sup>.

Three recruited test vehicles were selected because they used GDI technology. An additional GDI equipped vehicle was obtained from the DOE V4 Program. An attempt was made to only recruit vehicles approaching the 120,000 mile useful life level. Testing was completed for two of the four vehicles prior to the proposal of this rule. All of the recruited test vehicles were thoroughly inspected, but otherwise tested as received.

All vehicles were tested on an E15 fuel with RVP, aromatic content, sulfur content, T50 and T90 of 9.1 psi, 23.8 vol%, 7 ppm, 160F and 311F, respectively. The properties of this fuel approximated those of a projected E15 market fuel.

The test program included three cold start and three hot start UDSS tests and three US06 tests conducted on each vehicle. FTP results were calculated for gaseous and PM emissions by applying the cold-start and hot-start weighting factors to the complete cold and hot UDSS results, respectively. This eliminated separate analysis of the typically very low concentration FTP phase-2 gaseous and PM emissions samples and represented one method proposed within 40 CFR 1066 for increasing sample integration of measured gaseous and PM mass. During these tests, triplicate PM samples were collected in parallel on PTFE membranes and single (composite) PM samples were collected on primary and secondary quartz filters for TOT/TOR OC/EC PM speciation analysis. Additional quartz filters were collected to determine the

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<sup>F</sup> Vehicle K consumed approximately 1 quart per 3,000 miles vs. an average of approximately 1 quart per 8,000 miles for the other four vehicles of this make, model and year tested within the DOE V4 program.

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contribution of gas-phase artifact to the OC collected on the quartz filter samples. The compositing of quartz filters over three repeats of each test was done to enhance the precision of subsequent OC/EC thermogravimetric measurements. Single background (dilution air) PM samples were also taken during each emissions test. Weekly tunnel blank and field blank PM samples were also collected.

The following parameters were measured: NO<sub>x</sub>, NMHC, NMOG, alcohols, carbonyls, CO, CH<sub>4</sub>, CO<sub>2</sub> and fuel consumption and PM mass as per the 40 CFR 1065 and the proposed 40 CFR part 1066 test procedures. Limited exhaust HC speciation was also performed.

PM composition was determined from filter samples taken on both quartz filters and PTFE membranes. PM compositional analyses include determination of the contribution of elemental and organic carbon to PM mass,<sup>77</sup> elemental analysis via EDXRF, sulfate analysis via ion chromatography and determination of the contribution of unresolved complex organic PM compounds by GC/MS.

Note that during the compositional analysis of the PM, EPA discovered a significant amount of silicon deposited on some of the filters. The source of the silicon was determined to be a silicone elastomer transfer tube used to connect vehicles to the emissions measurement equipment. The data below reflect test results that are not subject to silicone contamination. For additional information, refer to our memo to the docket<sup>78</sup> which describes the original analysis and corrective actions in greater detail.

**Table 1-8: Vehicles Tested as part of EPA’s Light-Duty Vehicle PM Test Program**

Vehicle Make, Model and Designation		Model Year	Certified to Emissions Standard	Odometer at Start of Program, miles	Fuel Delivery <sup>a</sup>	Used in DOE V4 Program?
Honda Civic	A	2009	Tier 2/Bin 5	121,329	PFI	Yes
Toyota Corolla	B	2009	Tier 2/Bin 5	120,929	PFI	Yes
Honda Accord	C	2007	Tier 2/Bin 5	123,695	PFI	Yes
Dodge Caliber	D	2007	Tier 2/Bin 5	114,706	PFI	Yes
Chevrolet Impala	E	2006	Tier 2/Bin 5	114,284	PFI	Yes
Ford Taurus	F	2008	Tier 2/Bin 5	115,444	PFI	Yes
Toyota Tundra	G	2005	Tier 2/Bin 5	121,243	PFI	Yes
Chrysler Caravan	H	2007	Tier 2/Bin 5	116,742	PFI	Yes
Jeep Liberty	I	2009	Tier 2/Bin 5	121,590	PFI	Yes
Ford Explorer	J	2009	Tier 2/Bin 4	121,901	PFI	Yes
Honda Accord	K	2007	Tier 2/Bin 5	36,958	PFI	Yes
Ford F150	L	2005	Tier 2/Bin 8	111,962	PFI	No
Chevrolet Silverado	P	2006	Tier 2/Bin 8	110,898	PFI	No
VW Passat	M	2006	Tier 2/Bin 5	102,886	TGDI	No
Manufacturer’s Development Vehicle <sup>b</sup>	N	PC	None (Tier 2/LEV II Prototype)*	120,011	TGDI	No
Saturn Outlook	O	2009	Tier 2/Bin 5	123,337	GDI	Yes
Cadillac STS4	Q	2010	Tier 2/Bin 5	21,266	GDI	No

Notes:

<sup>a</sup> PFI is Naturally aspirated, port fuel injected; GDI is Naturally aspirated, gasoline direct injection; TGDI is Turbocharged, gasoline direct injection

<sup>b</sup> Manufacturer’s developmental vehicle. Vehicle used a spray-guided GDI fuel system with a centrally-mounted injector. Emissions were targeted at Tier 2 Bin 5 or better.

#### 1.5.1.1 PM Emissions Test Results

The results of exhaust emissions tests conducted in this program are summarized in Table 1-9 and Table 1-10 for the FTP and US06 test cycles, respectively. FTP NMOG +NO<sub>x</sub> and PM results are also plotted in Figure 1-7 and Figure 1-8, respectively. The US06 NMOG+NO<sub>x</sub> and PM results are shown in Figure 1-9 and Figure 1-10, respectively. In all figures, the vehicles are divided into two groups: PFI and GDI. Within each group they are listed in the sequence of increasing CO<sub>2</sub> emissions on the FTP test cycle. The bars shown in the figures represent the means of triplicate measurements. The individual data points are indicated in all figures together with the corresponding standard deviations. Vehicle Q only had one valid PM test on the FTP test cycle and no error bars are plotted.

**Table 1-9: FTP Composite Emissions Results**

Vehicle	CO <sub>2</sub> g/mile	CO g/mile	NO <sub>x</sub> g/mile	NMOG g/mile	NO <sub>x</sub> +NMOG g/mile	PM mg/mile
A	284.6	0.358	0.0239	0.0316	0.056	0.27
B	286.3	0.434	0.0461	0.0408	0.087	0.22
C	324.4	0.382	0.0231	0.0299	0.053	0.18
D	364.8	6.740	0.1432	0.0663	0.210	0.45
E	410.8	0.571	0.0600	0.0359	0.096	0.14
F	419.2	0.271	0.0151	0.0206	0.036	0.11
G	447.2	0.626	0.0424	0.0439	0.086	0.36
H	462.9	1.617	0.0507	0.0493	0.100	0.40
I	495.7	0.719	0.0317	0.0429	0.075	1.36
J	554.8	1.072	0.0281	0.0525	0.081	0.10
K	332.5	0.202	0.0165	0.0171	0.034	0.93
L	568.8	2.264	0.1024	0.0822	0.185	0.39
M	365.2	0.346	0.0342	0.0261	0.060	-
N	411.0	0.735	0.0279	0.0258	0.054	2.55
O	505.2	0.599	0.0173	0.0399	0.057	4.72
P	547.0	0.649	0.3578	0.0429	0.401	0.18
Q	465.0	0.475	0.0279	0.0221	0.050	7.15

**Table 1-10: US06 Emissions Results**

Vehicle	CO <sub>2</sub> g/mile	CO g/mile	NO <sub>x</sub> g/mile	NMOG g/mile	NO <sub>x</sub> +NMOG g/mile	PM mg/mile
A	289.0	7.092	0.0212	0.0162	0.0374	0.76
B	312.8	9.315	0.0530	0.0248	0.0779	2.05
C	318.2	1.293	0.0257	0.0105	0.0362	1.05
D	413.7	9.077	0.1324	0.0127	0.1451	-
E	393.3	0.660	0.1019	0.0163	0.1183	0.46
F	422.8	1.237	0.0274	0.0124	0.0398	1.61
G	490.9	3.462	0.0369	0.0172	0.0540	-
H	467.0	1.128	0.0910	0.0134	0.1044	2.04
I	516.0	0.833	0.1852	0.0037	0.1889	3.31
J	555.9	3.015	0.1121	0.0159	0.1280	0.27
K	320.4	1.800	0.0247	0.0079	0.0326	2.84
L	595.6	5.519	0.0036	0.0125	0.0160	2.13
M	352.8	9.225	0.0481	0.0297	0.0779	-
N	401.7	0.330	0.1614	0.0048	0.1662	2.37
O	547.4	9.862	0.0377	0.0282	0.0659	-
P	529.1	2.728	0.1427	0.0116	0.1543	1.83
Q	436.6	2.595	0.0265	0.0204	0.0470	-

As shown in Figure 1-6, with the exception of one PFI passenger car (vehicle D), the FTP NMOG+NO<sub>x</sub> emissions of all tested vehicles remained below their respective fleet average 2017 standards, but none performed below the 2025 standard.

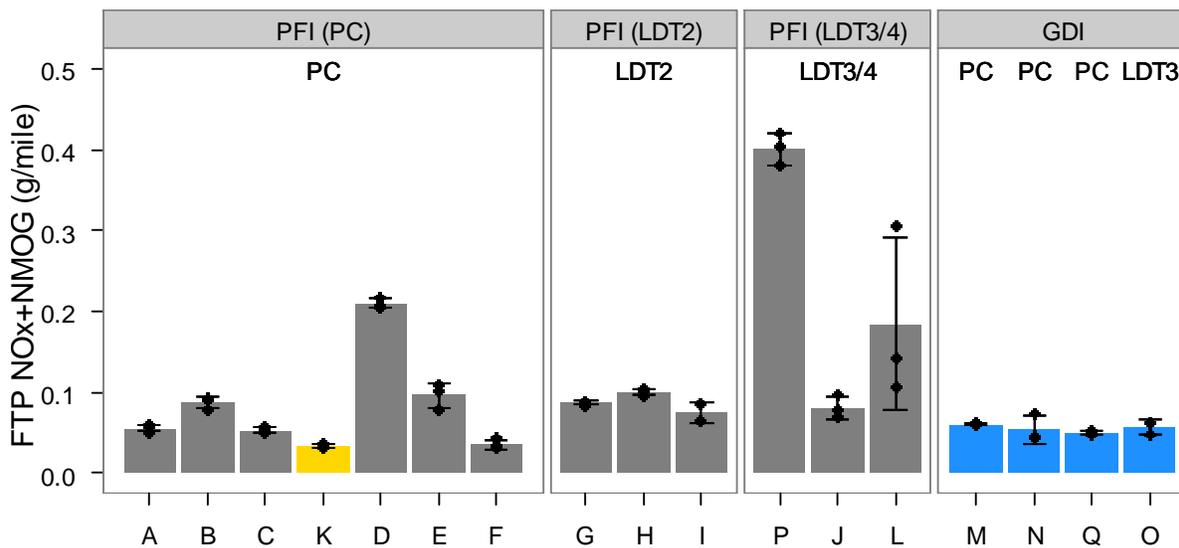
The FTP PM from PFI vehicles remained well below the Tier 3 PM standard of 3 mg/mile, confirming that most current light duty vehicles are already capable of meeting the Tier 3 PM standard (Figure 1-7). Two GDI vehicles demonstrated FTP PM emissions above final Tier 3 standard, indicating that additional combustion system development would be necessary in some vehicles to achieve compliance.

As shown in Figure 1-8, with the exception of two LDTs (vehicles I and J), all vehicles met their respective fleet average 2017 (for vehicles below 6,000pounds GVWR) or 2018 (for

vehicles above 6,000 pounds GVWR) US06 NMOG+NO<sub>x</sub> standards. Five vehicles, four passenger cars (vehicles A, B, F and L) and one LDT (vehicle L), produced US06 NMOG+NO<sub>x</sub> emissions lower than the 2025 standard.

As in the case of FTP results, all PFI passenger cars remained well below the proposed US06 10 mg/mile standard (Figure 1-9). One GDI passenger car (vehicle N) performed well below its respective US06 PM standard and achieved PM emissions over the US06 comparable to its performance over the FTP. In summary, all of the vehicles tested met the Tier 3 US06 PM standards.

The suspected high oil consumption vehicle (vehicle K) emitted 3 and 2.3 times more PM in this program than a comparable vehicle with average oil consumption (vehicle C) in the FTP and US06 tests, respectively.



**Figure 1-6: Composite FTP NMOG+NO<sub>x</sub> Emissions Results**

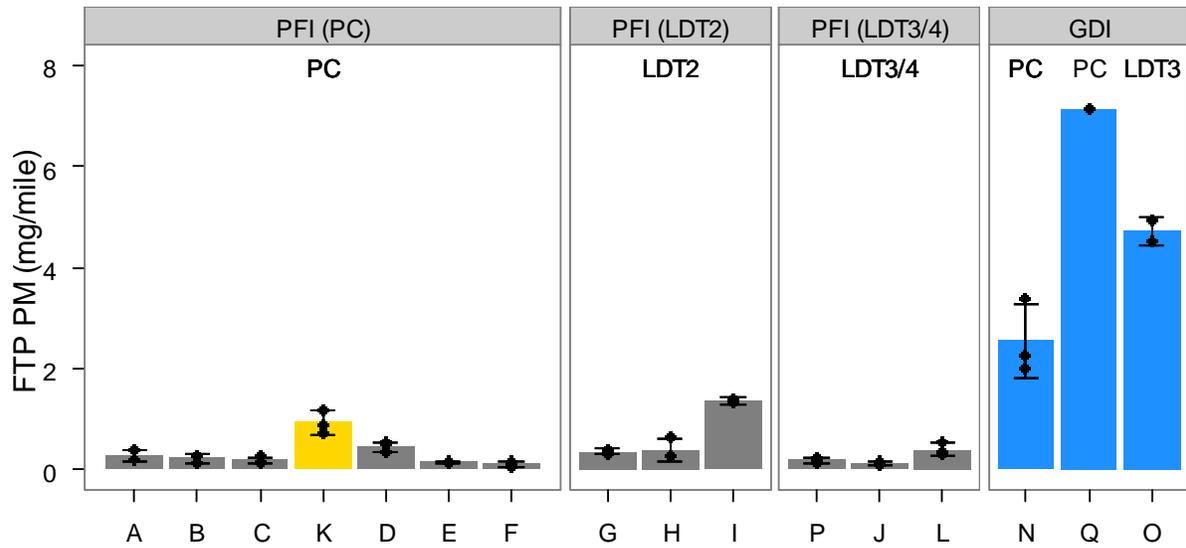


Figure 1-7: Composite FTP PM Emission Results

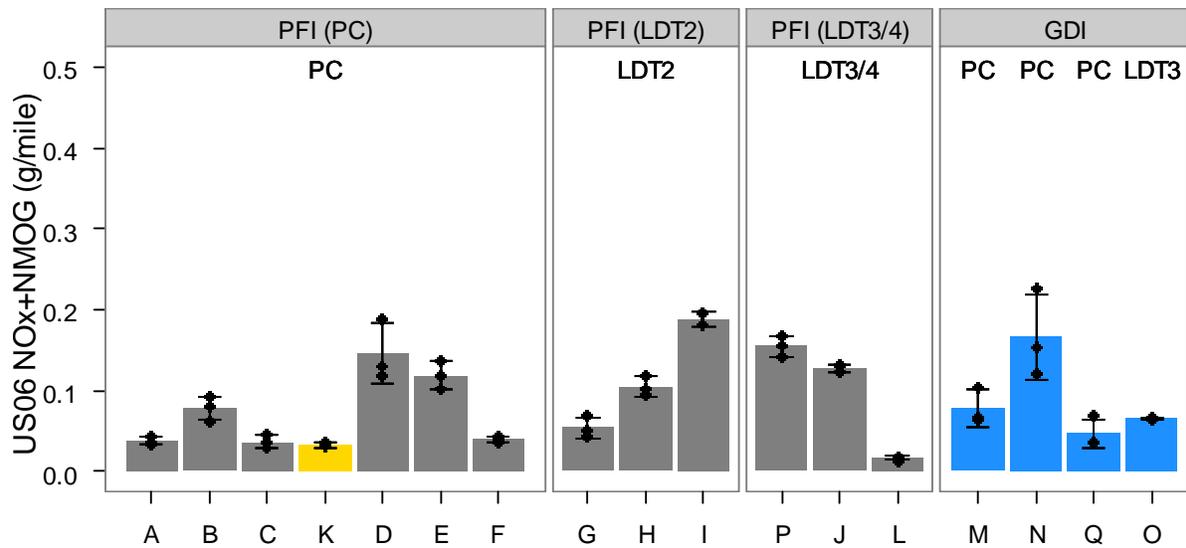
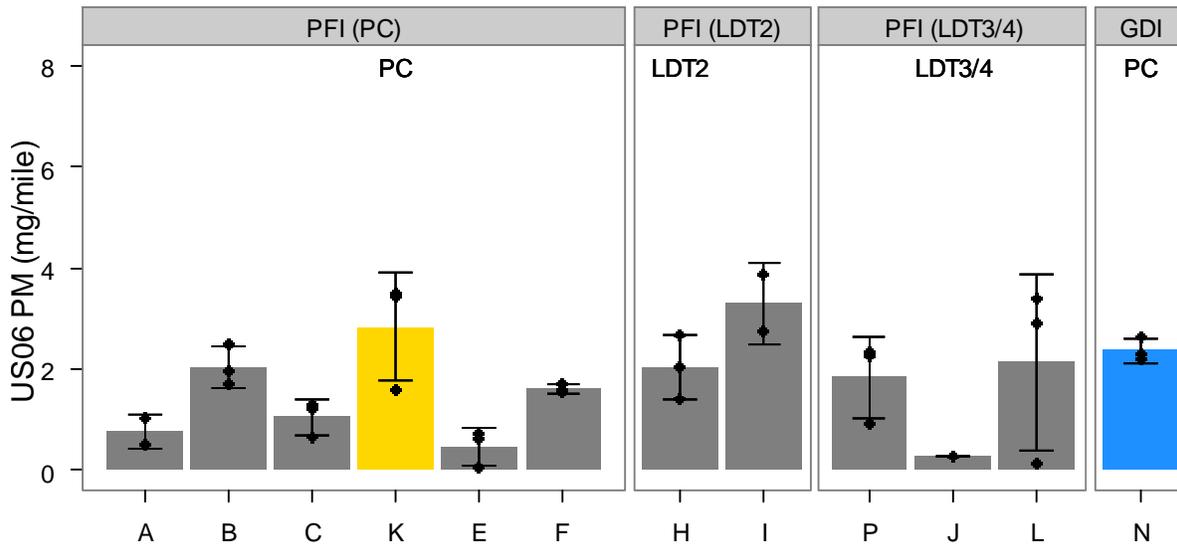


Figure 1-8 US06 NMOG+NO<sub>x</sub> Emissions Results



**Figure 1-9: US06 PM Emissions Results**

### 1.5.2 FTP PM Feasibility

With regard to the feasibility of the light-duty fleet to meet the Tier 3 PM standards over the FTP and US06, we based our conclusions on the PM performance of the existing fleet. Data on both low and high mileage light-duty vehicles demonstrate that the majority of vehicles are currently achieving levels in the range of the Tier 3 FTP standards. A small number of vehicles are at or just over the finalized Tier 3 standard at low mileage and would require calibration changes, catalyst changes and/or further combustion system improvements to meet the new standards. It is our expectation that the same calibration and catalyst changes required to address NMOG would also provide some additional PM control. Vehicles that are currently demonstrating higher PM emissions over the FTP at higher mileages would likely be required to control oil consumption and combustion chamber deposits.

### 1.5.3 SFTP PM

Also, US06 test data shows that many vehicles are already at or below the Tier 3 standards for US06. Vehicles that are demonstrating high PM on the US06 would need to control enrichment and oil consumption. The oil consumption strategies are much like that described above for controlling oil consumption on the FTP. However, given the higher engine RPMs experienced on the US06 and the commensurate increase in oil consumption, manufacturers will most likely focus on oil sources stemming from the piston to cylinder interface and positive crankcase ventilation (PCV). With respect to enrichment, changing the fuel/air mixture by increasing the fuel fraction is no longer the only tool that manufacturers have available to them to protect engine and exhaust system components from over-temperature conditions. With application of electronic throttle controls on nearly every light-duty vehicle,

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the manufacturer has the option to richen the air/fuel mixture by maintaining the amount of fuel being delivered and closing the throttle plate. Previously, on manual throttle control vehicles, the throttle plate position was established by the driver and the engine controls had no capability to change the amount of air in the intake. While it is possible that this solution may result in a small reduction in vehicle performance we believe that it is an effective way to reduce PM emissions over the US06 cycle.

#### 1.5.4 Full Useful Life: Durability and Oil Consumption

Manufacturers have informed us that they have already or are planning to reduce oil consumption by improved sealing of the paths of oil into the combustion chamber, including improved piston-to-cylinder interfaces. They are taking or considering these actions to address issues of customer satisfaction, cost of ownership and improved emission control system performance as vehicles age.

Over the past decade, many manufacturers have extended oil change intervals from the historically required 3,000 miles interval to a now typical 10,000 mile interval or more in some vehicle models. In order to allow for these longer intervals, improvements were made to limit pathways for oil to enter the combustion chamber, resulting in significantly reduced oil consumption. While customer satisfaction and longer oil change intervals, particularly for leased vehicles where owners may be less inclined to perform frequent oil changes, were a motivation for reducing oil consumption, improvements in the performance of the emission control system are a secondary benefit of reduced oil consumption. Oil consumption can damage catalytic converters by coating the areas of the catalyst that convert and oxidize the pollutants. Over time, this can cause permanent inactivity of those areas, resulting in reduced catalytic conversion efficiency. Reductions in oil consumption can extend the life of the catalytic converter and help manufacturers meet longer useful life requirements. This is particularly important on vehicles meeting the most stringent emission standards, because they will need to maintain high catalyst efficiencies in order to meet the stringent emission standards at higher mileage.

### 1.6 Evaporative Emissions Feasibility

The basic technology for controlling evaporative emissions was first introduced in the 1970s. Manufacturers routed fuel tank and carburetor vapors to a canister filled with activated carbon, where vapors were stored until engine operation allowed for purge air to be drawn through the canister to extract the vapors for delivery to the engine intake. Over the past 30 years, evaporative emission standards and test procedures have changed several times, most notably in the mid-1990s when enhanced evaporative controls were required to address 2- and 3-day diurnal emissions and running losses. Refueling emission controls were added with phase-in beginning in the 1998 MY. Almost universally manufacturers elected to integrate evaporative and refueling emission control systems. In the mid-2000s more stringent evaporative emission standards with E10 durability gasoline led to the development and adoption of technology to identify and eliminate permeation of fuel through fuel tanks, fuel lines, and other fuel-system components.

The Tier 3 evaporative emission requirements include more stringent hot-soak plus diurnal standards that are expected to require new vehicle hardware and improved fuel system

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designs. The type of new hardware that will be required will vary depending on the specific application and emission challenges and are described in the following section. Additionally, the fleet-average nature of the standards would allow more challenged vehicles to be offset by vehicles that could outperform the required fleet averages.

In order to assess the technical feasibility of the evaporative emission standards, EPA conducted three analyses. The first analysis was a review of technology in the fleet as well as a literature review of the technologies used to meet PZEV “zero evap” requirements in California. The second analysis performed was based on the certification results for the current EPA-certified evaporative families. This provided a baseline for the current fleet emissions performance. The third analysis looked at the list of PZEV-certified vehicles in the California LEV II/ZEV fleets. The Tier 3 evaporative emission standards are similar to the current evaporative requirements for PZEVs in California. These analyses are described in greater detail below.

#### 1.6.1 Tier 3 Evaporative Emissions/Leak Control Technology Approaches

Vehicles designed to meet the Tier 3 evaporative emission standards for the full useful life will incorporate a variety of technologies. The choice of technologies will be based on three key elements. The first is related to hardware and designs focused on reducing emissions to achieve “zero” fuel vapor emissions. While the emission standards are not numerically zero, the 2 and 3-day hot soak plus diurnal standards are intended primarily to allow for the non-fuel hydrocarbons which arise from the vehicle and its interior components. The push for “zero” fuel vapor emissions is emphasized by the inclusion of the canister bleed emission standard which is less than 10 percent of the hot soak plus diurnal standard. Thus, we expect the technology to focus on the largest remaining sources of emissions. The second element is related to full-life durability. Maintaining “zero” evaporative emission levels over many years and many miles of driving will require a focus on preventing the deterioration in fuel/evaporative control system performance which arises from factors such as vibration, environmental conditions, and fuel effects. The new leak standard and the related OBD evaporative control system leak monitoring requirement are intended to get focus on elements of technology and design which will reduce the impacts of these factors on in-use emissions by encouraging the use of more durable integrated technologies and systems. The third element is related to fuel effects. While EPA has kept the RVP of the fuel at 9 psi, the Tier 3 certification fuel includes 10 percent ethanol which will have to be further considered in choices of fuel system materials and vapor lines. EPA does not expect the change in certification fuel to affect refueling, spit back, or running loss compliance technology or strategies.

While the three elements discussed above are important considerations in the evaporative emission control system design, there are two other factors which come into play when considering which technologies will come in to the fleet and on which vehicles. First, in many cases a given technology will provide emission reduction benefits against more than one emission standard. For example, improved activated carbon canister technology to meet the canister bleed standard will help to meet the hot soak plus diurnal standard or reducing fuel/evaporative system connection points to meet the leak standard will help to meet the hot soak plus diurnal standard. Second, to varying degrees, the technologies discussed below are in use in the fleet today, resulting in reduced emissions relative to the current requirements for

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evaporative emission standards and improved durability. Thus, not every vehicle model will use every technology either because it is already being implemented or the required reductions to meet the Tier 3 emission targets are not large enough to warrant its application.

In preparing this assessment EPA considered two key sources of information. The first was the developmental studies in the literature to identify the technologies best capable of reducing emissions.<sup>79,80</sup> Second, we examined the technologies used on various PZEV zero evaporative vehicles certified in the CARB ZEV program. The technologies identified as a result of our review are summarized below first for technologies expected to see widespread use and then for technologies with a more limited application because they are in common use today.

#### 1.6.1.1 Technologies expected to see widespread use

Engine/fuel system conversion: As projected in our final rule RIA for the 2017-2025 GHG emissions, EPA projects a significant movement from port fuel injection (PFI) engines to gasoline direct injection (GDI) engines. This ranges from 60-100 percent of products for all categories except gasoline-powered trucks over 14,000 lbs GVWR. This reduces air induction systems emissions by 90 percent since the GDI uses a different fuel injection timing strategy than the PFI.<sup>81</sup>

Air Induction System (AIS) Scrubber: For vehicles/engine models not converted to GDI, EPA projects the use of an AIS scrubber as is now used on some PZEV models. These would reduce air induction system emissions by about 90 percent.<sup>82,83</sup>

Canister honeycomb: This is a lower gasoline working capacity activated carbon device designed to load and purge very easily and quickly. This device reduces canister bleed emissions by 90 percent but also provides control for the hot soak plus diurnal test. It comes in various sizes and can be optimized based on the anticipated bleed emission rate.

Fuel system architecture: This includes reducing connections and improve seals and o-rings and moving parts into the fuel tank: Vapor leaks from connections and the emission rates from these leaks is exacerbated if poor sealing techniques or low grade seal materials are use in connectors such as o-rings. Reducing connections in the fuel and evaporative systems and improving techniques and materials could reduce these emissions by 90 percent. This would reduce hot soak plus diurnal emissions, improve durability, and help to assure compliance with the leak standard. Another means to reduce leak-related vapor emissions is to move fuel evaporative system parts which are external to the fuel tank to the inside. Emissions from these parts would be completely eliminated. This would reduce hot soak plus diurnal emissions, improve durability, and help to assure compliance with the leak standard.

OBD evaporative system leak monitoring: Beginning in the 2017 model year, the OBD system will need to be able to find, confirm, and signal a leak in the evaporative system of 0.020” cumulative diameter or greater. This is done on most vehicles today as a part of meeting CARB requirements, but will be mandatory under EPA regulations.

The evaporative emission standards discussed above also apply to gaseous-fueled vehicles. EPA expects manufacturers to comply through the use of good design practices such as

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those specified in published consensus standards to address issues such as leaks from micro-cracks and system connections and in a broader sense system mechanical and structural integrity.

1.6.1.2 Technologies expected to be optimized if necessary to achieve further reductions:

Upgrade canister and optimize purge: This strategy is mostly available for higher powered V-8 engines. A canister with greater working capacity and/or more purge air volume could reduce hot soak plus diurnal emissions by 80-90 percent and create capacity for the hot soak plus diurnal and canister bleed emissions. However, it should be noted that the available emission reductions are not large, because of the amount of purge needed to accomplish these reductions relative to the reductions achieved from current canisters and purge strategies.<sup>84,85</sup>

Fuel tank and fuel line upgrades: Fuel vapor permeation contributes to hot soak plus diurnal emissions. There are upgrades to fuel line materials which could reduce emissions in models where these best practices are not yet used. In these situations, current permeation emission rates could be reduced by 90 percent.

Improve fuel tank barrier layer and seam weld manufacturing: Fuel tanks are designed to limit permeation emissions. Fuel tanks are typically made of high-density polyethylene with an embedded barrier layer of ethyl vinyl alcohol (EvOH) representing about 1.8 percent of the average wall thickness for reducing permeation emissions. In some cases manufacturers could increase the EvOH barrier thickness to about 3 percent of the average wall thickness to provide a more uniform barrier layer, to provide better protection with ethanol-based fuels, and to improve permeation resistance generally. Recent developments in production processes have led to improved barrier coverage around the ends of the tank where the molded plastic is pinch-welded to form a closed vessel. This technology would likely be coupled with the increase in EvOH in the overall tank material or other techniques to reduce permeation from these seams. These changes are expected to decrease emission rates over the diurnal test from about 40 mg per day to 15 mg per day from the fuel tank assembly. It is likely that this change would be done as part of a fuel tank design changeover and not out of a normal tooling cycle.

Upgrade fill tube material and connection to fuel tank: The connection of the fill tube to the fuel tank is the largest connection in the fuel system. Improving the security of the fill tube connection to the tank could reduce vapor leaks. The fill tube itself has a larger diameter than other fuel or vapor lines and thus has a relatively large diameter. For higher permeation resistance the tube can be upgraded to one having an FKM inner layer. We would expect such changes to occur together.

Table 1-11 presents a summary of EPA projections of the application of the widespread technologies across the LDV, LDT, MDPV, and HDGV fleets. These projections are based on consideration of the most effective technologies to achieve the required reductions. In this context, effective means not only what technologies might provide the largest reductions which could be used to meet more than one standard, but also which technologies provide these reductions in the most cost efficient way. The baseline emission rates and percent efficiencies from the various technologies are both EPA estimates based on review of the literature and discussion with various manufacturers and vendors. The reductions achieved are larger than the

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difference between the baseline and design target because of the need to cover for the non-fuel hydrocarbons which are measured in certification but decay in use. Note that the last column in Table 1-11 identifies which standards the technology will address. In some cases the expected emission reductions are larger from HDGVs. This is due primarily to the volume of their fuel tanks and unique aspects of some elements of their fuels systems relative to smaller passenger cars and light trucks.

**Table 1-11 Application of Evaporative Emission Control Technologies for Tier 3**

Vehicle Class	LDV	LDT1	LDT2	LDT3	LDT4	MDPV	LHDGV	HHDGV
nonfuel (g)	0.1	0.1	0.125	0.15	0.15	0.175	0.2	0.25
MSAT std(3d/2d)(g)	0.5/0.65	0.65/0.85	0.65/0.85	0.9/1.15	0.9/1.15	1.0/1.25	1.4/1.75	1.9/2.3
T3 std (g)	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6
Canister bleed std (g)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
MSAT Baseline (g) <sup>1</sup>	0.47	0.47	0.42	0.72	0.72	0.72	0.96	0.96
T3 Target (g) <sup>2</sup>	0.2	0.2	0.3	0.37	0.37	0.37	0.45	0.45
Red Needed (g)	0.27	0.27	0.12	0.35	0.35	0.35	0.51	0.51
Red Achieved (g)	0.39	0.39	0.39	0.39	0.39	0.39	0.55	0.52

Technology	Current Emissions	Control Efficiency	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	mg red & % applied	net red mg	Standard Addressed
Canister honeycomb 35mmx75mm (V-4 & V-6)	150-200mg <sup>3</sup> (use 150mg)	90%	135_100%	135	135_100%	135	135_76%	103	135_10%	13	0	0	0	0	0	0	0	0	T3/ bleed
Canister honeycomb 35mmx50mm (V-8)	150-225mg (use 150mg exc HDGV)	90%	0	0	0	0	135_24%	32	135_90%	122	135_100%	135	135_100%	135	200_100%	200	200-100%	200	T3/ bleed
AIS scrubber	150-300 mg (use 225 mg) exc HDGV <sup>4</sup>	90%	200_40%	80	200_27%	54	200_27%	54	200_27%	54	200_27%	54	200_27%	54	0	0	270_100%	270	T3
PFI to GDI <sup>5</sup>	150-300mg (use 225mg) exc HDGV	90%	200_60%	120	200_73%	146	200_73%	146	200_73%	146	200_73%	146	200_73%	146	270_100%	270	0	0	T3
<b>Fuel system architecture</b>																			
(a) reduce connections & improve seals/ o-rings <sup>6</sup>	25-50mg (use 25mg) exc HDGV	90%	22_100%	22	22_100%	22	22_100%	22	22_100%	22	22_100%	22	22_100%	22	45_100%	45	45_100%	45	T3/leak
(b) move parts into tank	75-100mg (use 75mg)	100%	75_50%	37	75_50%	37	75_50%	37	75_50%	37	75_50%	37	75_50%	37	75_50%	37	-	-	T3/leak
OBd software upgrades <sup>7</sup>	n/a	n/a	100%	-	100%	-	100%	-	100%	-	100%	-	100%	-	100%	-	-	-	leak

<sup>1</sup> based on mean plus one standard deviation for 2013 MY 2-day cert results on Tier 2 fuel

<sup>2</sup> 100 mg or 25% below T3 std whichever is greater

<sup>3</sup> (365 day per year)(1 gal per 5.6 lbs)(1 lb per 454g)(mg reduction/day)(1 g/1000 mg)(0.9 energy density effect); needs to be further multiplied by(15yr) (avg surv fraction for fleet)(gas price)

<sup>4</sup> based SAE 2001-01-0733

<sup>5</sup> based on SAE 2005-01-0113 and US patent 6464761

<sup>6</sup> % conversion from PFI to GDI based on RIA for 2017-2025 EPA GHG Final Rule

<sup>7</sup> reduce fuel/ evap system connections, improve seal material (FKM) in engine & fuel/ evap systems, and employ o-rings as needed

<sup>8</sup> Most manufacturers meet the 0.020" evaporative system leak monitoring provision now; no new hardware expected

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Table 1-12 presents the information for the technologies expected to see more limited use, but does not project application rates. It does show however, that these technologies would in most cases provide smaller reductions than those identified in Table 1-11. In the case of the upgraded canister and purge optimization, to the degree it is used it is more likely to be a replacement for the canister honeycomb on V-8 engines than as an additional technology by itself.

**Table 1-12 Technologies Which May Be Optimized If Necessary to Achieve Further Reductions in Tier 3**

Upgrade canister & improve purge (mostly V-8s)	120-150mg	80-90%	~100mg
Improve fuel tank barrier layer thickness and reduce pinch seam gaps	75mg	70%	~50mg
Filler neck connection and materials upgrade <sup>1</sup>	60mg	80%	~50mg
Fuel line material upgrade	40mg	90%	~35mg
<sup>1</sup> Kawasaki.M., et al, Low Gasoline Permeable Fuel Filler Hose, SAE Technical Paper Series 971080, 1997.			

### 1.6.2 Assessment of the Current EPA Certification Emissions

EPA's current evaporative emission standards vary by vehicle category. Table 1-13 shows the currently applicable hot-soak plus diurnal emission standards and Table 1-14 shows the Tier 3 standards.

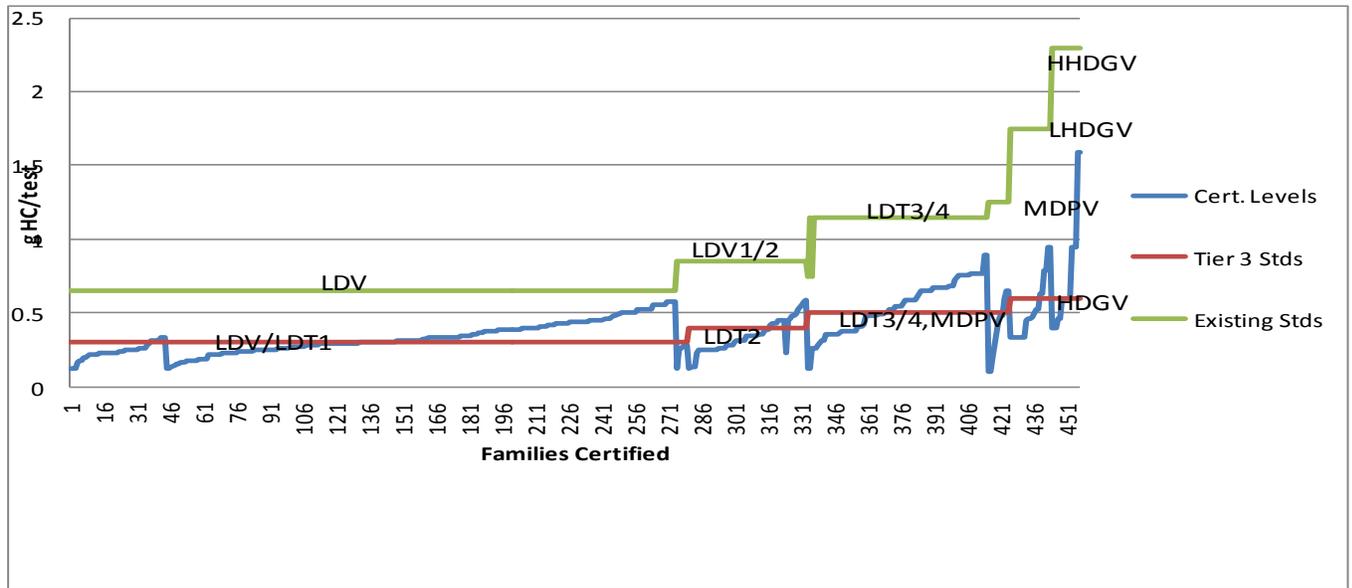
**Table 1-13 Existing EPA Evaporative Emission Standards**

<b>Vehicle Category</b>	<b>Hot-soak plus Diurnal (2-day)</b>	<b>Hot-soak plus Diurnal (3-day)</b>
LDV	0.65 g/test	0.50 g/ test
LDT1/LDT2	0.85 g/test	0.65 g/test
LDT3/LDT4	1.15 g/test	0.90 g/test
MDPV	1.25 g/test	1.00 g/test
HDGV ≤14,000 lbs GVWR	1.75 g/test	1.4 g/test
HDGV > 14,000 lbs GVWR	2.3 g/test	1.9 g/test

**Table 1-14 Final Tier 3 Evaporative Emission Standards**

<b>Vehicle Category/Averaging Sets</b>	<b>Highest Hot Soak + Diurnal Level (over both 2-day and 3-day diurnal tests)</b>
LDV, LDT1	0.300 g/test
LDT2	0.400 g/test
LDT3, LDT4, MDPV	0.500 g/test
HDGVs	0.600 g/test

Based on MY2013 certification data, EPA analyzed the certification hot-soak plus diurnal emission levels for all vehicle categories that will be subject to the Tier 3 standards. The following figure shows the hot-soak plus diurnal certification levels (based on the 2-day diurnal test) for each vehicle category ordered from the lowest to the highest emission levels. (While not presented in this analysis, the data based on the 3-day diurnal tests shows a similar trend.) Figure 1-10 also shows the existing and Tier 3 evaporative emission standards.



**Figure 1-10: MY2013 PZEV & Federal Hot-soak Plus Diurnal (2-Day) Emission Certification Levels<sup>G</sup>**

It should be noted that the current evaporative emission data is based on a different certification test fuel than what is being implemented for the Tier 3 program. While both the current and Tier 3 certification fuels have a Reid vapor pressure of nominally 9.0 psi, EPA’s current certification test fuel contains no ethanol, whereas the Tier 3 certification fuel contains 10 percent ethanol. Nevertheless, EPA believes this information is still useful in gaging the level of effort needed by manufacturers to comply with the Tier 3 standards. It is generally understood that ethanol can impact permeation emissions from the fuel tank and fuel lines to some degree, but the bulk of evaporative emissions are from diurnal emissions which are primarily a function of the Reid vapor pressure of the fuel which will be maintained at 9.0 psi and therefore should not be impacted by the presence of ethanol in the certification fuel.

As can be seen from the figure, there are many families certified below the Tier 3 hot-soak plus diurnal standards. Of the nearly 450 evaporative families included in the analysis, 40 percent had certification levels below the Tier 3 standards. Some of these families (~50) are certified to the more stringent PZEV standards, upon which the Tier 3 evaporative emission standards are based, but most of the families are not. However, the Tier 3 evaporative emission standards include a new canister bleed test that is not required under the current EPA regulations. (The families certified to the PZEV requirements are subject to a similar requirement and would likely meet that new canister bleed test requirement and longer useful life period without further modification.) Therefore, even though many families are certified below the Tier 3 evaporative emission standards, manufacturers would still need to make additional changes with many of the evaporative control systems to ensure compliance with the standards. We expect that

<sup>G</sup> Note that LHDGVs are vehicles rated 8,501-14,000 lbs GVWR; HHDGVs are vehicles rated greater than 14,000 lbs GVWR.

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manufacturers would use the technologies discussed above and use allowances and ABT to minimize costs and assist in an orderly phase-in of compliant products. In 2013, the baseline certification values used for our analysis were 0.41 g HC/test for LDVs, LDT1/2s, 0.5 for LDT3/4 and MDPVs, and 0.63 for HDGVs.

### 1.6.3 Assessment of California-certified PZEVs

Based on the California Air Resources Board's MY2013 certification list, EPA identified the vehicles certified by manufacturers to the PZEV requirements. As noted earlier, the Tier 3 evaporative emission standards are very similar to the PZEV evaporative emission requirements and, as allowed with one of the options for MY2017, manufacturers could sell their evaporative emission compliant PZEV vehicles nationwide in MY2017. Manufacturers have certified over 50 models of passenger cars and light-duty trucks to the PZEV requirements. EPA believes that manufacturer's experience with PZEV technologies will assist them as they work to apply similar technologies across their fleets to comply with the Tier 3 evaporative emission standards. As described in more detail above, EPA expects manufacturers will employ a number of technologies to meet the Tier 3 standards. The anticipated control technologies to comply with the emission standards have already been included on many of the PZEVs. Table 1-15 shows the 12 manufacturers and over 50 models certified to the PZEV standards in MY2013. Two other manufacturers certified PZEVs in previous model years as well.

**Table 1-15 List of MY2013 Models Certified to CARB's PZEV Requirements<sup>H</sup>**

<b>Manufacturer</b>	<b>Models</b>
AUDI/VOLKSWAGEN	Audi A3, Volkswagen GTI, Volkswagen Jetta, Volkswagen Golf, Volkswagen Jetta Sportwagen, Volkswagen Jetta, Volkswagen Jetta GLI, Volkswagen GTI, Volkswagen CC, Volkswagen Beetle, Volkswagen Passsat
BMW	BMW 128i, BMW 328i, BMW 328Ci
CHRYSLER	Chrysler 200, Dodge Avenger
FORD	Ford Escape Hybrid, C-MAX Hybrid, Ford Focus, Ford Fusion Hybrid
GENERAL MOTORS	Chevy Volt, Chevy Malibu Hybrid, Chevy Cruze, Chevy Sonic, Buick LaCrosse, Buick Regal, Cadillac ATS, Chevy Equinox, Chevy Impala, GMC Terrain
HONDA	Honda Civic GX (CNG), Honda Civic Hybrid, Honda CR-Z Hybrid, Honda Insight, Honda Insight Hybrid, Honda Accord
HYUNDAI	Elantra, Tucson, Sonata, Sonata Hybrid
KIA	Kia Sportage, Kia Forte, Kia Forte ECO, Kia Forte KOUP, Kia Optima Hybrid
MAZDA	Mazda 3
MERCEDES	Mercedes S400 Hybrid, Mercedes C300/C350/E350/GLK350/E400 Hybrid
SUBARU	Subaru Legacy, Subaru Outback Wagon, Subaru Forester, Subaru Impreza, Subaru XV Crosstrek
TOYOTA	Toyota Prius, Toyota Camry, Toyota Camry Hybrid, Toyota Prius Hybrid

**1.7 ORVR for Complete HDGVs over 10,000 lbs GVWR**

This final rule includes onboard refueling vapor recovery (ORVR) requirements for complete HDGVs over 10,000 lbs but equal to or less than 14,000 lbs GVWR beginning in the 2018 model year. Due to the similarity of the vehicle chassis and fuel systems and the commonality of chassis production lines, manufacturers have all implemented ORVR hardware on complete Class 3 HDGVs (10,001-14,000 lbs GVWR) since the 2006 MY when the ORVR phase-in covering Class 2b vehicles (8,501- 10,000 lbs GVWR) ended. Today, about XX percent of Class 3 vehicles are incomplete chassis. EPA is including this requirement in Tier 3 to ensure no backsliding and to give states the opportunity to claim the ORVR reductions for Tier 3 vehicles in their SIPs. This is especially important to states removing Stage II vapor recovery. Furthermore, EPA is including ORVR requirements for any complete HDGVs over 14,000 lbs GVWR effective in the 2022 model year when the Tier 3 evaporative emissions phase-in ends.

<sup>H</sup> See [http://driveclean.ca.gov/searchresults\\_by\\_smog.php?smog\\_slider\\_value=9&x=12&y=12](http://driveclean.ca.gov/searchresults_by_smog.php?smog_slider_value=9&x=12&y=12), downloaded on December 6, 2013.

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While sales of HDGVs over 14,000 lbs are relatively low, today all would be classified as incomplete chassis for the purposes of the ORVR requirement.

EPA is not extending the ORVR requirement to incomplete HDGV chassis in this rule. There is no question of the basic technical feasibility of the requirement. However, manufacturers have stated that ORVR for incomplete HDGVs presents some system design and integration issues with regard to the larger fuel tanks and vehicles with two tanks but more importantly with regard to the activities of secondary manufacturers. Close coordination and installation instructions are needed to ensure that integrated ORVR/evaporative control systems are installed in an effective and safe manner. EPA estimates that incomplete HDGV sales are about (85,000) per year, but with their low fuel economy (~15 mpg) control of refueling emissions through ORVR may become important as Stage II vapor recovery is removed in ozone nonattainment areas.

The ORVR requirements discussed above also apply to gaseous-fueled vehicles. EPA expects manufacturers to comply through the use of good design practices such as those specified in published consensus standards to address issues such as refueling connections and system integrity.

### **1.8 Onboard Diagnostics for Vehicles less than 14,000 lbs GVWR**

As part of the Tier 3 final rule, EPA is incorporating by reference the July 31, 2013 version of the California ARB OBD II regulations for vehicles equal to or less than 14,000 lbs GVWR. These requirements apply in the 2017 MY, at least two years after they must be met in California. As permitted in EPA regulations, manufacturers generally receive an Executive Order for OBD compliance from the CARB for each test group and EPA will accept that Executive Order as evidence that the vehicles covered by the test group meet CARB requirements and therefore meet the identical EPA requirements. Thus, in the case of the 2017 model year requirements for EPA, we expect manufacturers will already comply with these requirements before 2017 for their LEV III vehicles and have Executive Orders available.

EPA is adding two requirements related to the leak standard. The first is a requirement that manufacturers demonstrate before production that their vehicle test groups' OBD-based evaporative system monitor can detect the presence of a leak with an effective leak diameter at or above 0.020 inches, illuminate the MIL, and store the appropriate a confirmed diagnostic trouble codes. Such activity is normally done as part of the evaporative system leak monitor development and is demonstrated in the Production Vehicle Evaluation Testing program prescribed in 13 CCR 1968.2(j). However, if the OBD-based evaporative system leak monitor is to be used in IUVP, its performance needs to be certified before production begins instead of afterwards. Since this requirement is compatible with CARBs current regulations for OBD-based evaporative system leak-based monitoring and the Production Vehicle Evaluation Testing program and is phasing in with the leak standard, there should be no feasibility or lead time issues.

EPA is also implementing a requirement that OBD systems revise the software so that a scan readable record is created which indicates if the OBD-based evaporative system leak monitor has run within the previous 750 miles and if so what was the result. The means by

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which this record will be created and stored is being done in a manner compatible with SAE J1979 as suggested by the commenters. Since this requirement is phasing in with the leak standard, there should be no feasibility or lead time issues.

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- <sup>46</sup> EPA In-Use Sulfur Report – Response to Peer-Review Comments, EPA-HQ-OAR-2011-0135-1848.
- <sup>47</sup> The Effects of Ultra-Low Sulfur Gasoline on Emissions from Tier 2 Vehicles in the In-Use Fleet, EPA-420-R-14-002.
- <sup>48</sup> Ball, D., Clark, D., Moser, D. (2011). Effects of Fuel Sulfur on FTP NO<sub>x</sub> Emissions from a PZEV 4 Cylinder Application. SAE Technical Paper 2011-01-0300.
- <sup>49</sup> American Petroleum Institute. 2013. Supplemental Comments of the American Petroleum Institute. Available in the docket for this final rule, docket no. EPA-HQ-OAR-2011-0135
- <sup>50</sup> The Effects of Ultra-Low Sulfur Gasoline on Emissions from Tier 2 Vehicles in the In-Use Fleet, EPA-420-R-14-002.
- <sup>51</sup> The make and model of the tested vehicles are Honda Crosstour, Chevrolet Malibu, Chevrolet Silverado, Ford Focus and Subaru Outback.
- <sup>52</sup> The Effects of Ultra-Low Sulfur Gasoline on Emissions from Tier 2 Vehicles in the In-Use Fleet, EPA-420-R-14-002.
- <sup>53</sup> Ford Motor Company. 2013. “Quality Changes Needed to Meet Tier 3 Emission Standards and Future Greenhouse Gas Requirements.” Attachment 2: “Tier 3 Sulfur Test Program – Ford Motor Company Summary Report.” Available within EPA Docket for this final rule, EPA-HQ-2011-0135.

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<sup>54</sup> Dominic DiCicco, Ford Motor Company. 2013. “Additional data as requested. RE: Ford Supplemental Comments on Tier 3.” Available within EPA Docket for this final rule, EPA-HQ-2011-0135.

<sup>55</sup> See 77 FR 62840-62862, October 15, 2012; and Joint Technical Support Document: Final Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards (EPA-420-R-12-901), August 2012, Chapter 3.4.1.7 - 3.4.1.8 (pages 3-88 – 3-95).

<sup>56</sup> Ford Motor Company, 2012. “Sustainability 2011/2012 – Improving Fuel Economy.” Accessed on the Internet on 11/21/2013 at: <http://corporate.ford.com/microsites/sustainability-report-2011-12/environment-products-plan-economy>. Available within EPA Docket for this final rule, EPA-HQ-2011-0135.

<sup>57</sup> Ford used the same tert-butyl sulfide fuel sulfur additives used within the EPA testing in IV.A.6.c and d.

<sup>58</sup> Emissions at 30 ppm sulfur estimated assuming approximately linear emissions effects between 10, 26.5 and 30 ppm gasoline sulfur levels.

<sup>59</sup> Ball, D., Clark, D., Moser, D. (2011). Effects of Fuel Sulfur on FTP NOX Emissions from a PZEV 4 Cylinder Application. SAE Technical Paper 2011-01-0300. Available in the docket for this final rule.

<sup>60</sup> American Petroleum Institute. 2013. Supplemental Comments of the American Petroleum Institute. Available in the docket for this final rule, docket no. EPA-HQ-OAR-2011-0135

<sup>61</sup> Add citation to document number and docket number for Tier 3 RIA

<sup>62</sup> U.S. Code of Federal Regulations, Title 40, §86.1823–08 “Durability demonstration procedures for exhaust emissions.”

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- <sup>80</sup> "Evaporative Emission Control Technologies for Gasoline Powered Vehicles", Manufacturers of Emission Controls Association, December, 2010.
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## Chapter 2 Vehicle Program Costs

### 2.1 Changes to Vehicle Costs between Proposed and Final Rules

We have made several changes to vehicle program costs since the proposal, but two changes have significant impacts on the final rule costs and help to explain the large reduction in cost estimates between proposal and final rule. The first of these significant changes involves the catalyst platinum group metal (PGM) loading costs. As commenters pointed out, the cost estimates in the proposal have become dated, as they were based largely on four-year-old estimates of the CARB LEVIII program. For this final rule, we have developed a more robust catalyst loading cost estimate using a methodology suggested by one commenter.<sup>1</sup> This more robust estimate results in lower costs than estimated in the proposal.

The second significant contributor to reduced final rule cost estimates is the use of the MY 2017-2025 fleet mix projected to result from the most recent GHG and fuel economy rules. That projected fleet mix shows a large percentage of four-cylinder engines, which are less costly to modify to achieve Tier 3 compliance than the proposal's projected MY 2012-2016 fleet mix, which included many more V-configuration six-cylinder (V6) and eight-cylinder (V8) engines. We mentioned in the preamble to the proposal our intention to use the projected MY 2017-2025 fleet for our final rule cost analysis (see 78 FR 29970).

We have made many other updates to the analysis for this final rule. For example, we reviewed the MY2013 certification database to evaluate the certified emissions levels of the fleet. We found that many vehicles are already being certified with emissions levels that would meet final Tier 3 standards. Further, many vehicles have certified emission levels that are 70% of the 0.30 g/mi NO<sub>x</sub>+NMOG standard, meaning that sufficient compliance margin exists for those vehicle to comply with Tier 3 without any additional costs. Our final rule estimates no exhaust emission-related Tier 3 costs for these vehicles (they still incur evaporative emission-related costs, discussed below).

We have also concluded that active HC adsorbers, which we projected for use on some vehicles in the proposal, are not likely to be used. Instead, as we discuss in Section 2.3.6, those vehicles will probably use a passive HC adsorber. The passive HC adsorber is considerably less costly. We have also decreased our evaporative emission control costs, in part because of the high penetration of gasoline engines with direct injection projected by the MY 2017-2025 GHG and fuel economy rules. Direct injection removes a large source of evaporative emissions and, thus, means fewer vehicles need to add certain evaporative control technologies. We have also decreased the penetration rates of secondary air injection in the later years of the program, for reasons described below. Lastly, we have modified very slightly our indirect cost markups to account for the fact that most of the research and development efforts required of auto makers are in response to CARB's LEVIII rule and need not be conducted again for Tier 3 compliance.

We have made some changes that have increased costs, although these are smaller than those that have decreased costs so, on net, estimated vehicle-level costs are lower than in the proposal. One such change was to double the engine calibration costs (from roughly \$2/vehicle to \$5/vehicle), to cover expected calibration efforts associated with PM control on direct injected

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gasoline engines. We discuss this in more detail in Section 2.3.5, below. We have also increased the penetration rates of the technology we term “optimized thermal management” for some vehicle categories. We discuss our rationale for this change in Section 2.5, below. Another change was to update all costs from 2010 dollars to 2011 dollars.<sup>A</sup>

With respect to total program costs, the significant change since proposal was to exclude costs incurred on vehicles sold in all states (California and elsewhere) that have adopted the California LEVIII program. As a result, our estimated costs per vehicle are applied to millions fewer vehicles in the final rule, thus making the total program costs considerably lower. And finally, we have included operating savings (fuel savings) associated with avoiding the loss of fuel that would have otherwise evaporated absent the new Tier 3 controls. The otherwise evaporated fuel is ultimately used to propel the vehicle, thus providing a savings to the consumer. We discuss operating costs in Section 2.6, below.

## **2.2 General Methodology**

Although the increase in standard stringency is substantial for the vehicles affected by this final rule, we do not expect that the associated vehicle costs will be high. Our analysis shows that the federal fleet is already demonstrating actual emissions performance that is much cleaner than the level to which it is currently being certified. In fact, many MY2013 vehicles were certified to levels below the 30 mg combined NMOG+NO<sub>x</sub> standard, some of which were certified below 70 percent of the 30 mg standard, an important level since it provides necessary compliance margin. Although the vehicles that make up the federal light-duty fleet are capable of meeting lower standards there is no impetus for vehicle manufacturers to certify their respective fleets to anything lower than the current requirements. In addition, we anticipate that not every technology will be required on all vehicles to meet the standards. While catalyst loading and engine calibration changes will most likely be applied on all vehicles, only the most difficult powertrain applications will require very expensive emissions control solutions such as secondary air injection. We expect that manufacturers will implement emission control solutions as a function of increasing cost and will avoid implementing very expensive designs whenever possible.

To determine the cost for vehicles, we first determined which technologies were most likely to be applied by vehicle manufacturers to meet the standards. These technologies are then combined into technology packages which reflect vehicle design attributes that directly contribute to a vehicle’s emissions performance. The attributes considered include vehicle type: car or truck, number of cylinders, engine displacement and the type of fuel used, either gas or diesel. We also created separate packages for light-duty and heavy-duty trucks and vans.

Once we know the individual technologies that will likely be used, our next step is to estimate direct manufacturing costs (DMC) for those technologies. As part of this process, we

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<sup>A</sup> We have updated 2010 dollars to 2011 dollars using the Gross Domestic Product (GDP) price deflator as reported by the Bureau of Economic Analysis on May 30, 2013. The factor used, taken from Line 1 of Table 1.1.4 Price Indexes for Gross Domestic Product was 1.035 to convert from 2009\$ and 1.021 to convert from 2010\$. For example, to convert from 2010\$ to 2011\$, we calculated the (value in 2010\$)x1.021=(value in 2011\$).

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determine the model year for which our estimated cost is deemed valid—i.e., if a widget is estimated to cost \$100, is that valid today when none have been sold or after a few years when thousands or millions have been sold? This “cost basis” serves as the point in time where learning effects—discussed below—are set to neutral. In other words, beyond that cost basis, learning effects serve to decrease the DMC of the technology and, in contrast, prior to that cost basis, the lack of any learning effects serves to increase the DMC of the technology.

The next step is to apply an indirect cost multiplier (ICM) to estimate the indirect cost of the technology to the auto maker. This is the same process used in the recent MY 2012-2016 and MY 2017-2025 GHG rules, and the proposal for this rule. The cost calculation approach presumes that the Tier 3 technologies will be purchased by original equipment manufacturers (OEMs) from Tier 1 suppliers. So, while the DMC estimates include the indirect costs and profits incurred by the supplier, the ICMs we apply are meant to cover the indirect costs incurred by OEMs to incorporate the new technologies into their vehicles and to cover the profits that the OEM must earn to remain viable. We discuss ICMs and indirect costs in more detail in Section 2.2.2.

We have also estimated costs associated with construction of new PM testing facilities. We have included these costs separately, rather than as part of the ICMs, since the work conducted to derive our ICMs (details below) did not include new facility construction by OEMs. We could have included a new factor within the ICM, but believed a separate analysis of these costs would be more transparent and allows an easier presentation of them as a line item cost in our analysis. We present the facility costs in Section 2.7.

The next step is to determine the penetration rate of each of the technologies. As noted above, we do not believe that each of the Tier 3 technologies will be applied to all engines/vehicles across the board. An obvious example of this would be the evaporative emission control technologies that will be added to gasoline vehicles but not to diesel vehicles.<sup>B</sup> We expect many of the technologies to be used on only a portion of the Tier 3 fleet. Further, the Tier 3 standards are not implemented 100% in MY2017 and, instead, increase in stringency from MY2017 through MY2025. Additionally, and new for this final rule, we know that many vehicles are already being certified with emissions below the Tier 3 30 mg NMOG+NO<sub>x</sub> level, even if we give due consideration to compliance margin. Penetration rates and the resultant technology costs (i.e., inclusive of the penetration rates) are presented below in Section 2.5 where we also sum these costs to arrive at vehicle package costs.

We have also estimated operating costs associated with the evaporative emission standards and present them in Section 2.6.

The final step is to calculate the vehicle program costs to arrive at annual costs of the Tier 3 vehicle program. We present the vehicle program costs in Section 2.7.

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<sup>B</sup> Diesel fuel has very low volatility so the fuel does not vaporize the way gasoline does.

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### 2.2.1 Direct Manufacturing Costs

In making our estimates for both direct manufacturing cost (DMC) and application of technology, we have relied on our own technology assessments. These assessments include publicly available information, such as that developed by the California Air Resources Board, as well as confidential information supplied by individual manufacturers and suppliers.<sup>2</sup> We have also considered the results of our own in-house testing.<sup>3</sup> The technology packages that we developed represent what we consider to be the most likely average emissions control solution for each vehicle type.

In general, we expect that the majority of vehicles will be able to comply with the Tier 3 standards through refinements of current emissions control components and systems. Some vehicles, for example large trucks with large displacement engines, in particular LDT3s and LDT4s, may require additional emission controls such as HC adsorbers. Overall, smaller lighter-weight vehicles will require less extensive improvements than larger vehicles and trucks. Specifically, we anticipate a combination of technology upgrades for reducing exhaust emissions as described below.

### 2.2.2 Indirect Costs

We are using an approach to estimating indirect costs that is consistent with that used in our recent 2017-2025 Greenhouse Gas (GHG) final rule.<sup>4</sup> Rather than a traditional retail price equivalent markup (RPE), as described below we are marking up DMCs using an indirect cost multiplier (ICM). Furthermore, we are applying the ICMs in a manner that differs from the traditional RPE approach in which the DMC would be multiplied by the RPE factor in any given year. As such, as the DMC decreased with learning, the product of the RPE factor and the DMC decreased along with it. However, we have more recently decided that learning impacts (discussed below) should be applied only to the DMC and not to the indirect costs. Our approach with ICMs, consistent with the recent 2017-2025 GHG final rule, is to determine the indirect costs based on the initial value of direct costs and then hold that constant until the long-term ICM is applied. This is done for all ICM factors except warranties, which are influenced by the learned value of direct costs.

The ICMs used in this final rule are the same as those used in the proposal with one exception. For this final rule, we have adjusted the R&D portion of the indirect costs to account for the fact that the research for Tier 3 compliance and a good portion of the development have been done or are being done in response to the California LEV III rule. Because that research and development work is attributable to the LEV III rule, we believe it is double counting to also consider it in the final Tier 3 costs. Below, we discuss this change in greater detail along with providing a comparison between ICMs in the proposal and this final rule.

To produce a unit of output, auto manufacturers incur direct and indirect costs. Direct costs include the cost of materials and labor costs. Indirect costs may be related to production (such as research and development [R&D]), corporate operations (such as salaries, pensions, and health care costs for corporate staff), or selling (such as transportation, dealer support, and marketing). Indirect costs are generally recovered by allocating a share of the costs to each unit of goods sold. Although it is possible to account for direct costs allocated to each unit of goods

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sold, it is more challenging to account for indirect costs allocated to a unit of goods sold. To make a cost analysis process more feasible, markup factors, which relate total indirect costs to total direct costs, have been developed. These factors are often referred to as retail price equivalent (RPE) multipliers.

Cost analysts and regulatory agencies including EPA have frequently used these multipliers to estimate the resultant impact on costs associated with manufacturers' responses to regulatory requirements. The best approach to determining the impact of changes in direct manufacturing costs on a manufacturer's indirect costs would be to actually estimate the cost impact on each indirect cost element. However, doing this within the constraints of an agency's time or budget is not always feasible, and the technical, financial, and accounting information to carry out such an analysis may simply be unavailable.

RPE multipliers provide, at an aggregate level, the relative shares of revenues (Revenue = Direct Costs + Indirect Costs + Net Income) to direct manufacturing costs. Using RPE multipliers implicitly assumes that incremental changes in direct manufacturing costs produce common incremental changes in all indirect cost contributors as well as net income. A concern in using the RPE multiplier in cost analysis for new technologies added in response to regulatory requirements is that the indirect costs of vehicle modifications are not likely to be the same for different technologies. For example, less complex technologies could require fewer R&D efforts or less warranty coverage than more complex technologies. In addition, some simple technological adjustments may, for example, have no effect on the number of corporate personnel and the indirect costs attributable to those personnel. The use of RPEs, with their assumption that all technologies have the same proportion of indirect costs, is likely to overestimate the costs of less complex technologies and underestimate the costs of more complex technologies.

To address this concern, the agency has developed modified multipliers. These multipliers are referred to as indirect cost multipliers (ICMs). In contrast to RPE multipliers, ICMs assign unique incremental changes to each indirect cost contributor

$$\text{ICM} = (\text{direct cost} + \text{adjusted indirect cost} + \text{profit}) / (\text{direct cost})$$

Developing the ICMs from the RPE multipliers requires developing adjustment factors based on the complexity of the technology and the time frame under consideration. The ICMs were developed in a peer-reviewed report from RTI International and were subsequently discussed in a peer-reviewed journal article.<sup>5</sup> Note that the cost of capital (reflected in profit) is included because of the assumption implicit in ICMs (and RPEs) that capital costs are proportional to direct costs, and businesses need to be able to earn returns on their investments. The capital costs are those associated with the incremental costs of the new technologies.

As noted above, for the analysis supporting the Tier 3 proposed rulemaking, EPA used the ICM approach but made some changes to both the ICM factors and to the method of applying those factors to arrive at a final cost estimate since the ICM work was originally done by RTI. Both of these changes make the ICMs used in this analysis consistent with those used in the MY 2017-2025 GHG final rule. The first of these changes was done in response to continued

thinking about how past ICMs have been developed and what are the most appropriate data sources to rely upon in determining the appropriate ICMs. We have a detailed discussion of this change in Chapter 3 of the joint TSD supporting the 2017-2025 GHG rule.<sup>6</sup> Because that discussion is meant to present changes made in the time between the original RTI work (and the MY 2012-2016 GHG final rule) and the MY 2017-2025 GHG final rule, the full text is not really relevant in the context of Tier 3. The second change has been done both due to staff concerns and public feedback suggesting that the agency was inappropriately applying learning effects to indirect costs via the multiplicative approach to applying the ICMs. This change is detailed below because it is critical to understanding how indirect costs are calculated in the context of Tier 3.

Table 2-1 shows the ICMs used in the proposal. As noted, these ICMs are consistent with those used in our recent MY 2017-2025 GHG final rule. Despite the fact that these ICMs were developed with GHG technologies in mind, we are using them here to estimate indirect costs associated with criteria emission control technology. We believe the ICMs are applicable here because, as with the GHG requirements, the technologies considered in Tier 3 are or can be provided to the auto maker by suppliers and their integration into the end vehicle involves the same sorts of methods and demands as integrating GHG improving technologies.

**Table 2-1 Indirect Cost Multipliers Used in the Proposal**

Complexity	Near term	Long term
Low	1.24	1.19
Medium	1.39	1.29
High1	1.56	1.35
High2	1.77	1.50

The second change noted above made to the ICMs has to do with the way in which they are applied. In the MY 2012-2016 GHG final rule, we applied the ICMs, as done in any analysis that relied on RPEs, as a pure multiplicative factor. This way, a direct manufacturing cost of, say, \$100 would be multiplied by an ICM of 1.24 to arrive at a marked up technology cost of \$124. However, as learning effects (discussed below) are applied to the direct manufacturing cost, the indirect costs are also reduced accordingly. Therefore, in year two the \$100 direct manufacturing cost might reduce to \$97 and the marked up cost would become \$120 ( $\$97 \times 1.24$ ). As a result, indirect costs would be reduced from \$24 to \$23. Given that indirect costs cover many things such as facility-related costs, electricity, etc., it is perhaps not appropriate to apply the ICM to the learned direct costs, at least not for those indirect cost elements unlikely to change with learning. EPA believes that it is appropriate to allow only warranty costs to decrease with learning since warranty costs are tied to direct manufacturing costs (warranty typically involves replacement of actual parts which should be less costly with learning). The remaining elements of the indirect costs should remain constant year-over-year, at least until some of those indirect costs, such as R&D, are no longer attributable to the rulemaking effort that imposed them.

As a result, the ICM calculation has become more complex than originally devised by RTI. We must first establish the year in which the direct manufacturing costs are considered “valid.” For example, a cost estimate might be considered valid today, or perhaps not until high

volume production is reached—which will not occur until MY2015 or later. That year is known as the base year for the estimated cost. That cost is the cost used to determine the “non-warranty” portion of the indirect costs. For example, the non-warranty portion of the medium complexity ICM in the short-term is 0.343 (the warranty versus non-warranty portions of the ICMs are shown in Table 2-2). Consider a technology with an estimated direct manufacturing cost of \$70 and valid in MY2015. For this technology, the non-warranty portion of the indirect costs would be \$24.01 ( $\$70 \times 0.343$ ). This value would be added to the learned direct manufacturing cost for each year through 2018, the hypothetical last year of short term indirect costs for this technology. Beginning in 2019, when long-term indirect costs begin, the additive factor would become \$18.13 ( $\$70 \times 0.259$ ). Additionally, the \$70 cost in MY2015 would become \$67.90 in MY2016 due to learning (assuming a 3% learning-by-doing cost reduction from MY2015 to MY2016, or  $\$70 \times (1-3\%)$ ). So, while the warranty portion of the indirect costs would be \$3.15 ( $\$70 \times 0.045$ ) in MY2015, the warranty portion would decrease to \$3.06 ( $\$67.90 \times 0.045$ ) in 2016 as warranty costs decrease with learning. The resultant indirect costs of the example technology would be \$27.16 ( $\$24.01 + \$3.15$ ) in MY2015 and \$27.07 ( $\$24.01 + \$3.06$ ) in MY2016, and so on for subsequent years.

**Table 2-2 Warranty and Non-Warranty Portions of ICMs used in the Proposal**

Complexity	Near term		Long term	
	Warranty	Non-warranty	Warranty	Non-warranty
Low	0.012	0.230	0.005	0.187
Medium	0.045	0.343	0.031	0.259
High1	0.065	0.499	0.032	0.314
High2	0.074	0.696	0.049	0.448

With that as background, we have made minor changes relative to the proposal to the ICMs used in this final rule. We have made this change because we believe it is appropriate that the Tier 3 rule not incur costs for research and development that is being incurred by OEMs to comply with California’s LEV III. As such, we have considered half the R&D portion of the ICM to be research and half to be development. Further, we have set the research portion to 0.0 and the development portion to 50% of the proposal level. These changes mean that our final rule cost estimates consider all research dollars and 50% of all development dollars to have been spent in complying with LEV III. The R&D portion of the proposal’s ICMs ranges from 3.6% to 7% of total technology costs depending on complexity level. The changes described here result in the R&D portion ranging from 1% to 2% of total technology costs. In other words, a \$100 DMC would have resulted in a \$124 total cost in the proposal (at low complexity in the near term, the ICM being 1.24). In the final rule, the \$100 DMC will result in a \$121 total cost (at low complexity in the near term, the ICM being 1.21).

Table 2-3 shows the resultant warranty and non-warranty factors used in the final rule. These values are used in the final rule instead of those shown in Table 2-2.

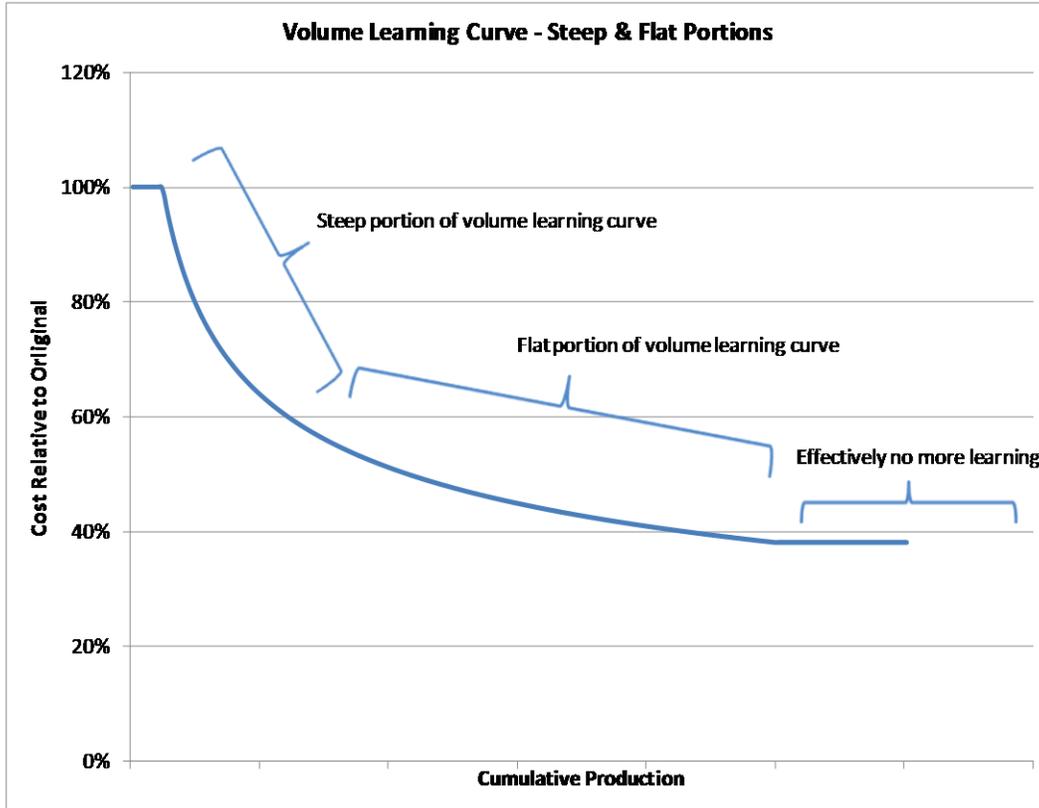
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**Table 2-3 Warranty and Non-Warranty Portions of ICMs used in the Final Rule**

Complexity	Near term		Long term	
	Warranty	Non-warranty	Warranty	Non-warranty
Low	0.012	0.196	0.005	0.172
Medium	0.045	0.282	0.031	0.222
High1	0.065	0.417	0.032	0.301
High2	0.074	0.543	0.049	0.365

### 2.2.3 Cost Reduction through Manufacturer Learning

For this final rule, we have not changed our estimates of learning and how learning will impact costs going forward from what was employed in the proposal. We consider there to be one learning effect—learning by doing—which results in cost reductions occurring with every doubling of production. In the past, we have referred to volume-based and time-based learning. Those terms were meant only to denote where on the volume learning curve a certain technology was—“volume-based learning” meant the steep portion of the curve where learning effects are greatest, while “time-based learning” meant the flatter portion of the curve where learning effects are less pronounced. Unfortunately, that terminology led some to believe that we were implementing two completely different types of learning—one based on volume of production and the other based on time in production. We now use new terminology—steep portion of the curve and flat portion of curve—simply meant to make clear that there is one learning curve and some technologies can be considered to be on the steep portion while others are well into the flatter portion of the curve. This updated terminology was described in the recent heavy-duty GHG final rule (see 76 FR 57320) and is entirely consistent with our approach used in the recent MY 2017-2025 GHG final rule (see 77 FR 62711). These two portions of the volume learning curve are shown in Figure 2-1.



**Figure 2-1 Step and Flat Portions of the Volume Learning Curve**

For some of the technologies considered in this analysis, manufacturer learning effects would be expected to play a role in the actual end costs. The “learning curve” or “experience curve” describes the reduction in unit production costs as a function of accumulated production volume. In theory, the cost behavior it describes applies to cumulative production volume measured at the level of an individual manufacturer, although it is often assumed—as both agencies have done in past regulatory analyses—to apply at the industry-wide level, particularly in industries like the light duty vehicle production industry that utilize many common technologies and component supply sources. We believe there are indeed many factors that cause costs to decrease over time. 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 these factors allow manufacturers to lower the per-unit cost of production. We refer to this phenomenon as the manufacturing learning curve.

EPA included a detailed description of the learning effect in the MY 2012-2016 and 2017-2025 light-duty GHG rules, the more recent heavy-duty GHG rule and the proposal to this rule.<sup>7</sup> In past rulemaking analyses, EPA has used a learning curve algorithm that applied a learning factor of 20 percent for each doubling of production volume. EPA has simplified the approach by using an “every two years” based learning progression rather than a pure production volume progression (i.e., after two years of production it was assumed that production volumes

would have doubled and, therefore, costs would be reduced by 20 percent).<sup>c</sup> We apply learning effects on the steep portion of the learning curve for those technologies considered to be newer technologies likely to experience rapid cost reductions through manufacturer learning, and learning effects on the flat portion learning curve for those technologies considered to be more mature technologies likely to experience only minor cost reductions through manufacturer learning. As noted above, the steep portion learning algorithm results in 20 percent lower costs after two full years of implementation (*i.e.*, the MY2016 costs would be 20 percent lower than the MYs 2014 and 2015 costs). Once two steep portion learning steps have occurred, flat portion learning at 3 percent per year becomes effective for 5 years. Beyond 5 years of learning at 3 percent per year, 5 years of learning at 2 percent per year, then 5 at 1 percent per year become effective.

For this analysis, learning effects are applied to all technologies because, while most are already widely used, the technologies would undergo changes relative to their Tier 2 level design, and we believe auto makers will find ways to reduce costs in the years following introduction. The steep portion learning algorithm has not been applied to any technologies in this analysis because we believe that the technologies considered in this analysis have already experienced the large cost reductions due to learning in the early years of use. The learning algorithm applied to each technology and the applicable timeframes are summarized in Table 2-4.

**Table 2-4 Learning Effect Algorithms Applied to Technologies Used in this Analysis**

Technology	Steep learning	Flat learning	No learning
Catalyst Loading		2015-2025	
Optimized Close-coupled Catalyst		2015-2025	
Optimized Thermal Management		2015-2025	
Secondary Air Injection		2015-2025	
Engine Calibration		2015-2025	
Hydrocarbon Adsorber		2015-2025	
Evaporative Emissions Controls		2015-2025	
Selective Catalytic Reduction Optimization		2015-2025	

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<sup>c</sup> To clarify, EPA has simplified the steep portion of the volume learning curve by assuming that production volumes of a given technology will have doubled within two years time. This has been done largely to allow for a presentation of estimated costs during the years of implementation, without the need to conduct a feedback loop that ensures that production volumes have indeed doubled. The assumption that volumes have doubled after two years is based solely on the assumption that year two sales are of equal or greater number than year one sales and, therefore, have resulted in a doubling of production. This could be done on a daily basis, a monthly basis, or, as we have done, a yearly basis.

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## 2.3 Individual Technology Costs

### 2.3.1 Catalyst Platinum Group Metal (PGM) Loading

Increased application of precious metals in the catalyst is expected to be one of the primary means of mitigating NMOG and NO<sub>x</sub> to meet the Tier 3 standards. Increasing the catalyst PGM loading results in greater catalyst efficiency. In the proposal, we noted that vehicle manufacturers and suppliers had supplied Confidential Business Information (CBI) that estimates the cost of increasing the PGM loading and modifications to increase the surface area within the catalyst. These costs ranged from \$80 to \$260 and were estimated as being incremental to an existing Tier 2 Bin 5 compliant vehicle. We went on to state that we believed that the incremental costs for PGM loading would be less than those CBI estimates we received, and we estimated the costs to be \$60, \$80, and \$100 for an I4, V6 and V8, respectively (all in 2009 dollars).

For this final rule, we have updated our PGM loading costs using a more robust approach tailored after the methodology presented by ICCT in a recent SAE paper.<sup>8</sup> In that paper, ICCT outlines a costing methodology based on PGM loads, swept volume ratio (the ratio of catalyst volume to engine displacement), and some equations that can be used to estimate catalyst washcoating and canning costs based on catalyst volume. This approach is actually similar to an approach used by EPA in past cost analyses that focused heavily on aftertreatment device costs.<sup>9</sup> We have made these changes for several reasons, but primarily because some commenters believed our cost estimates were dated, having relied heavily on the CARB LEVIII analysis now several years old. We agreed with this assessment and also liked the ICCT methodology since it allows us to provide more detail behind the estimates and to be transparent with the estimate allowing others to adjust things in ways they may believe make more sense.

In their recent SAE paper, ICCT estimates the PGM loading of Tier 2 catalysts at 0.1 g/L Platinum (Pt), 1.6 g/L Palladium (Pd) and 0.1 g/L Rhodium (Rh). Further, they estimate that the swept volume ratio of Tier 2 catalysts is 1.0 (i.e., the catalyst volume equals the engine displacement). They also provide 3 equations that can be used to estimate catalyst substrate, washcoating and canning costs. Those equations are shown in Table 2-5. ICCT also included labor costs in a manner described as consistent with past EPA work.<sup>D</sup> ICCT notes that their methodology considers the catalyst system as a unit and does not distinguish between close coupled and underfloor catalysts. This was done in an effort to simplify the approach even though close coupled and underfloor catalysts may well have different loadings.

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<sup>D</sup> ICCT references the source as EPA's Nonroad Tier 4 Regulatory Impact Analysis (EPA420-R-04-007, May 2004). In that analysis, a labor rate of \$30/hour (2003\$) was used. Updating that to 2011\$ using the GDP price deflator mentioned earlier results in a labor rate of \$36/hour for this analysis.

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**Table 2-5 ICCT Equations for Estimating Catalyst Component Costs (2011\$)**

Component	ICCT Cost equation
Catalyst substrate	$\$6.0 \times \text{Vol} + \$1.92$
Catalyst washcoat	$\$5.0 \times \text{Vol}$
Catalyst canning	$\$2.4 \times \text{Vol}$

Note: Vol = catalyst volume

Source: SAE 2013-01-0534

In their comments, ICCT notes recent research by Honda and Johnson Matthey showing PGM usage could be reduced by 25% with respect to current Tier 2 Bin 5 levels and still provide LEVIII SULEV30 compliance (i.e., Tier 3 Bin 30). This could be done using an improved layered catalyst and improved oxygen storage capacity (OSC) via adding zirconia along with ceria. ICCT also notes research by Umicore showing LEV70 to SULEV30 reductions via a 32% increase in PGM loading on one vehicle and only 16% increase on another. ICCT notes that these two vehicles did increase catalyst volume between 40% and 200% which would serve to increase costs. In that study, Umicore stresses the importance of a combined NMOG+NO<sub>x</sub> standard versus separate NMOG and NO<sub>x</sub> standards noting that the combined standard is much less demanding.<sup>10</sup> This is discussed in more detail in Chapter 1 of this RIA, but the combined standard provides much more flexibility to auto makers than does separate standards, thus allowing them to control costs much more effectively. What is important here is that the Umicore catalyst volume increases and subsequent costs were done assuming separate standards (the California PZEV standards), not a combined standard. Also important in the Umicore study was that the PZEV catalysts made no use of Pt for NMOG control, relying only on Pd for NMOG control and Rh for NO<sub>x</sub> control. This is important because Pd is, generally, less costly and exhibits less price volatility than Pt. All told, the increased costs in the Umicore study—again, for separate, not a combined standard—were on the order of \$15-\$46, well below our NPRM costs of \$60 to \$100 (both in 2009\$). ICCT also provided their assessment that a 20% increase in PGM loading is the most that would be required for Tier 3.

We believe that, in general, catalyst loading will increase in the front most portion of the catalyst system but not necessarily the entire system. We believe this, in part, because of the strong cases made by commenters and in the recent studies mentioned. We also believe this because the Tier 3 standards are, in effect, cold start emission standards, and we believe that the catalyst loading will be increased for the purpose of controlling cold start emissions. This can be most effectively done by adding metals to the portion of the catalyst system that will reach operating temperatures most quickly—i.e., that portion closest to the point where gases are exhausted from the engine. As such, we have estimated that Pd loading will increase 50% and Rh loading 20% but only in the front most 50% of the catalyst system. We have also estimated that Pt will be eliminated in favor of Pd, and that total catalyst volume (swept catalyst volume, SVR) will increase by 20%.

Using these metrics, the equations shown in Table 2-5 and the price of PGMs,<sup>E</sup> we can calculate the increased cost of any Tier 3 catalyst relative to its Tier 2 counterpart provided we know the Tier 2 catalyst system's volume. For fleet average incremental costs, we need both the Tier 2 catalyst volumes for each vehicle in the fleet and the sales of each vehicle to get a proper sales weighted average catalyst cost. To get these, we have used the baseline file used in support of our recent GHG/CAFE final rule for MY 2017-2025. That baseline file represented the 2008 model year fleet and has in it the engine displacement (i.e., the catalyst volume since we consider the SVR of Tier 2 catalysts to be 1.0) and the projected sales of each vehicle model in the light-duty fleet for MY 2012 through 2025. Using that fleet in conjunction with the projected MY2013 sales, we were able to calculate the catalyst costs shown in Table 2-6.

**Table 2-6 Catalyst Loading Direct Manufacturing Costs for Gasoline Vehicles (2011\$)**

	Standard	PC I4 G	PC V6 G	PC V8 G	LT I4 G	LT V6 G	LT V8 G
Sales weighted engine displacement (L)		2.1	3.3	4.9	2.4	3.6	5.2
Sales weighted catalyst volume (L)	Tier 2	2.1	3.3	4.9	2.4	3.6	5.2
PGM cost	Tier 2	\$94	\$150	\$223	\$111	\$164	\$239
Substrate cost	Tier 2	\$14	\$22	\$31	\$17	\$24	\$33
Washcoat cost	Tier 2	\$10	\$16	\$24	\$12	\$18	\$26
Canning cost	Tier 2	\$5	\$8	\$12	\$6	\$9	\$13
Labor cost	Tier 2	\$9	\$9	\$9	\$9	\$9	\$9
Catalyst cost per vehicle	Tier 2	\$132	\$204	\$299	\$155	\$224	\$320
Sales weighted catalyst volume (L)	Tier 3	2.5	3.9	5.9	2.9	4.3	6.3
PGM cost	Tier 3	\$125	\$200	\$298	\$148	\$220	\$319
Substrate cost	Tier 3	\$17	\$26	\$37	\$19	\$28	\$40
Washcoat cost	Tier 3	\$12	\$20	\$29	\$15	\$22	\$31
Canning cost	Tier 3	\$6	\$9	\$14	\$7	\$10	\$15
Labor cost	Tier 3	\$9	\$9	\$9	\$9	\$9	\$9
Catalyst cost per vehicle	Tier 3	\$169	\$264	\$387	\$199	\$289	\$414
Sales weighted catalyst volume (L)	Increment	0.4	0.7	1.0	0.5	0.7	1.0
PGM cost	Increment	\$32	\$50	\$75	\$37	\$55	\$80
Substrate cost	Increment	\$2	\$4	\$6	\$3	\$4	\$6
Washcoat cost	Increment	\$2	\$3	\$5	\$2	\$4	\$5
Canning cost	Increment	\$1	\$2	\$2	\$1	\$2	\$3
Labor cost	Increment	\$0	\$0	\$0	\$0	\$0	\$0
<b>Catalyst cost per vehicle (2011\$)</b>	<b>Increment</b>	<b>\$37</b>	<b>\$59</b>	<b>\$88</b>	<b>\$44</b>	<b>\$65</b>	<b>\$94</b>
DMC in our proposal (2009\$)	Increment	\$62	\$83	\$104	\$62	\$83	\$104

In their study, Umicore estimated the LEV-III PGM costs for a 2.0L engine ranging from \$81-117. These estimates compare favorably to our estimate of \$125 for an I4 passenger car.

<sup>E</sup> For this analysis, we have used the PGM spot price as of July 16, 2013, reported at 9:30AM in New York. Those values were: Pt=\$1,426/troy oz.; Pd=\$735/troy oz.; Rh=\$1,000/troy oz.

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While our final estimates are lower than those in our proposed rule, we consider these final rule costs to be much more robust, transparent and appropriate. Several years have passed since generating the catalyst loading costs presented in our proposal—as explained, they were generated as part of the LEV-III rule and our early work on Tier 3. Several commenters suggested that our proposed costs were now dated, and CARB also recommended that we revisit our cost estimates in light of the passage of time and more recent information.<sup>11</sup>

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We also consider catalyst loading to be a low complexity technology with near term markup factors applied through 2022 and long term thereafter. The resultant DMC, indirect costs (IC) and total costs (TC) are shown in Table 2-7. Note that the values shown do not include penetration rates.

Note that we have not changed the catalyst loading costs for heavy-duty vehicles relative to the proposal, with the exception of updating them to 2011 dollars. We do not show costs for diesel or >14,000 pound gasoline vehicles since those vehicles are not expected to incur any new catalyst loading costs.

**Table 2-7 Catalyst Loading Costs for Gasoline Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC I4	DMC	\$37	\$36	\$35	\$34	\$33	\$32	\$31	\$31	\$30	\$29	\$29
PC V6	DMC	\$59	\$57	\$56	\$54	\$52	\$51	\$50	\$49	\$48	\$47	\$46
PC V8	DMC	\$88	\$85	\$83	\$80	\$78	\$76	\$74	\$73	\$71	\$70	\$68
LT I4	DMC	\$44	\$43	\$41	\$40	\$39	\$38	\$37	\$36	\$35	\$35	\$34
LT V6	DMC	\$65	\$63	\$61	\$59	\$58	\$56	\$55	\$54	\$53	\$51	\$50
LT V8	DMC	\$94	\$91	\$89	\$86	\$83	\$81	\$79	\$78	\$76	\$75	\$73
Class 2b	DMC	\$52	\$50	\$49	\$47	\$46	\$44	\$44	\$43	\$42	\$41	\$40
Class 3	DMC	\$52	\$50	\$49	\$47	\$46	\$44	\$44	\$43	\$42	\$41	\$40
PC I4	IC	\$8	\$8	\$8	\$8	\$8	\$8	\$8	\$8	\$7	\$7	\$7
PC V6	IC	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$10	\$10	\$10
PC V8	IC	\$18	\$18	\$18	\$18	\$18	\$18	\$18	\$18	\$16	\$16	\$16
LT I4	IC	\$9	\$9	\$9	\$9	\$9	\$9	\$9	\$9	\$8	\$8	\$8
LT V6	IC	\$14	\$14	\$13	\$13	\$13	\$13	\$13	\$13	\$11	\$11	\$11
LT V8	IC	\$20	\$20	\$20	\$20	\$19	\$19	\$19	\$19	\$17	\$17	\$17
Class 2b	IC	\$11	\$11	\$11	\$11	\$11	\$11	\$11	\$11	\$9	\$9	\$9
Class 3	IC	\$11	\$11	\$11	\$11	\$11	\$11	\$11	\$11	\$9	\$9	\$9
PC I4	TC	\$45	\$44	\$43	\$41	\$40	\$39	\$39	\$38	\$36	\$36	\$35
PC V6	TC	\$71	\$70	\$68	\$66	\$65	\$63	\$62	\$61	\$58	\$57	\$56
PC V8	TC	\$106	\$104	\$101	\$99	\$96	\$94	\$92	\$91	\$87	\$85	\$84
LT I4	TC	\$53	\$52	\$50	\$49	\$48	\$47	\$46	\$45	\$43	\$43	\$42
LT V6	TC	\$79	\$77	\$75	\$73	\$71	\$69	\$68	\$67	\$64	\$63	\$62
LT V8	TC	\$114	\$111	\$108	\$106	\$103	\$100	\$99	\$97	\$93	\$91	\$90
Class 2b	TC	\$63	\$61	\$59	\$58	\$57	\$55	\$54	\$53	\$51	\$50	\$49
Class 3	TC	\$63	\$61	\$59	\$58	\$57	\$55	\$54	\$53	\$51	\$50	\$49

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

### 2.3.2 Optimized Close-coupled Catalyst

Close-coupled catalyst technologies include improvements to the catalyst system design, structure, and packaging to reduce light-off time. As catalysts are moved closer to the engine the temperature of the exhaust gases to which catalysts are exposed under high load operation goes up substantially. As a result some of the materials used in the catalyst construction, as well as the precious metals used in close-coupled applications, must be improved to survive in the higher operating temperatures. In the proposal, we stated that cost estimates for close-coupled catalyst designs received from vehicle manufacturers ranged from \$25 to \$50, however, they did not include all of the considerations identified above. Consistent with the proposal but updated to 2011 dollars, we have estimated the cost for an I4 gasoline engine to be \$21, a V6 to be \$41, and a V8 to be \$62. As noted, all DMC are in 2011 dollars.

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider close coupled catalysts to be a low complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-8. Note that the values shown do not include penetration rates.

We do not show costs for any diesel or heavy-duty vehicles since those vehicles are not expected to incur new close coupled catalyst costs.

**Table 2-8 Optimized Close Coupled Catalyst Costs for Gasoline Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC I4 LT I4	DMC	\$21	\$20	\$19	\$19	\$18	\$18	\$17	\$17	\$17	\$16	\$16
PC V6 LT V6	DMC	\$41	\$40	\$39	\$38	\$37	\$36	\$35	\$34	\$33	\$33	\$32
PC V8 LT V8	DMC	\$62	\$60	\$58	\$57	\$55	\$53	\$52	\$51	\$50	\$49	\$48
PC I4 LT I4	IC	\$4	\$4	\$4	\$4	\$4	\$4	\$4	\$4	\$4	\$4	\$4
PC V6 LT V6	IC	\$9	\$9	\$9	\$9	\$9	\$9	\$9	\$9	\$7	\$7	\$7
PC V8 LT V8	IC	\$13	\$13	\$13	\$13	\$13	\$13	\$13	\$13	\$11	\$11	\$11
PC I4 LT I4	TC	\$25	\$24	\$24	\$23	\$23	\$22	\$22	\$21	\$20	\$20	\$20
PC V6 LT V6	TC	\$50	\$49	\$48	\$46	\$45	\$44	\$43	\$43	\$41	\$40	\$39
PC V8 LT V8	TC	\$75	\$73	\$71	\$70	\$68	\$66	\$65	\$64	\$61	\$60	\$59

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

### 2.3.3 Optimized Thermal Management

Overall thermal management of the emissions control system to shorten the time it takes for the catalyst to light-off will most likely be a primary technology for mitigating NMOG on gasoline vehicles and NOx on diesel vehicles. This technology includes dual wall exhaust manifolds and pipe that will help maintain exhaust gas temperatures from the exhaust port of the engine to the close-coupled catalyst or, in the case of diesel engines, the Selective Catalyst Reduction (SCR) system. In some cases, the packaging of the exhaust system will be modified to reduce the wetted area of the exhaust path. This will, in turn, reduce the decrease in exhaust gas temperatures associated with a longer exhaust path. Consistent with the proposal and based on CBI submitted by exhaust system suppliers and vehicle manufacturers, we estimate that the cost of implementing dual wall exhaust designs are approximately \$31 (2011\$) for all engine applications.

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider optimized thermal management to be a low complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-9. Note that the values shown do not include penetration rates.

We do not show costs for >14,000 pound gasoline vehicles since those vehicles are not expected to incur new optimized thermal management costs.

**Table 2-9 Optimized Thermal Management Costs for Gasoline and Diesel Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC LT Class 2b Class 3	DMC	\$31	\$30	\$29	\$28	\$27	\$27	\$26	\$26	\$25	\$25	\$24
PC LT Class 2b Class 3	IC	\$6	\$6	\$6	\$6	\$6	\$6	\$6	\$6	\$5	\$5	\$5
PC LT Class 2b Class 3	TC	\$38	\$37	\$36	\$35	\$34	\$33	\$33	\$32	\$31	\$30	\$30

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

#### 2.3.4 Secondary Air Injection

Secondary air injection is a technology that provides a source of combustion air such that a portion of the exhaust gases are burned in the exhaust manifold. This technology provides increased heat in the exhaust system that provides for faster catalyst light-off. It is used only during cold start and requires that the air/fuel mixture is rich such that a small amount of fuel is available for combustion outside of the combustion chamber. We expect that some gasoline V6's and V8's will require the application of secondary air injection to reduce NMOG emissions. The secondary air injection system consists of an air pump (normally electrically powered), plumbing from the pump to the exhaust manifold, an electrically controlled valve, control circuitry in the powertrain control module, wiring and calibration. CBI estimates received from vehicle manufacturers and suppliers ranged from \$50 to \$310. Consistent with the proposal, we have estimated that the final direct manufacturing cost for secondary air is \$104 (2011\$) for any application that may need to add it.

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider secondary air to be a low complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-10. Note that the values shown do not include penetration rates.

We do not show costs for gasoline I4, diesel or heavy-duty vehicles since none of those vehicles are expected to incur new secondary air injection costs.

**Table 2-10 Secondary Air Injection Costs for Gasoline Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC V6 PC V8 LT V6 LT V8	DMC	\$104	\$100	\$97	\$94	\$92	\$89	\$87	\$85	\$84	\$82	\$80
PC V6 PC V8 LT V6 LT V8	IC	\$22	\$22	\$21	\$21	\$21	\$21	\$21	\$21	\$18	\$18	\$18
PC V6 PC V8 LT V6 LT V8	TC	\$125	\$122	\$119	\$116	\$113	\$110	\$108	\$107	\$102	\$100	\$99

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

### 2.3.5 Engine Calibration

Product changes considered for engine calibration include engine control and calibration modifications to improve air and fuel mixtures, particularly at cold start and/or to control secondary air. While typically there are no direct manufacturing costs associated with the calibration itself, we recognize that some additional engineering efforts will be required to implement the changes described above. As in the proposal, we have estimated the per vehicle cost at \$2 (2011\$). For gasoline engines, we have added a new engine calibration cost to address GDI PM-related concerns. We have estimated these new costs for gasoline engines at an additional \$2 (2011\$) per engine. The result being a total engine calibration cost of \$4 (2011\$) per gasoline engine and \$2 (2011\$) per diesel engine.

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider engine calibration to be a low complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-11. Note that the values shown do not include penetration rates.

We do not show costs for >14,000 pound gasoline vehicles since none of those vehicles are expected to incur new engine calibration costs.

**Table 2-11 Engine Calibration Costs for Gasoline and Diesel Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC, LT, Class 2b, 3 Gasoline	DMC	\$4	\$4	\$4	\$4	\$4	\$4	\$3	\$3	\$3	\$3	\$3
PC, LT, Class 2b, 3 Diesel	DMC	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2
PC, LT, Class 2b, 3 Gasoline	IC	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1
PC, LT, Class 2b, 3 Diesel	IC *	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PC, LT, Class 2b, 3 Gasoline	TC	\$5	\$5	\$5	\$5	\$5	\$4	\$4	\$4	\$4	\$4	\$4
PC, LT, Class 2b, 3 Diesel	TC	\$3	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

\*Actual values are less than 50 cents and appear here as \$0 due to rounding for simplicity of presentation.

### 2.3.6 Hydrocarbon Adsorber

Hydrocarbon adsorbers trap hydrocarbons during cold start and release the hydrocarbons after the catalyst lights off. Hydrocarbon adsorbers can be applied in two different manners: The first is a passive device which traps hydrocarbons at cold start and releases them as the temperature of the device increases. The catalyst may or may not have lit off at the time of desorption making a rapid catalyst temperature rise and light off critical. The second is an active hydrocarbon adsorber. This device controls the adsorber exposure to exhaust gases based on temperature and is able to trap the hydrocarbons until the catalyst has lit off. The effectiveness of the active hydrocarbon system is much greater than the passive system. However, the active system is also much more costly. In the proposal, we anticipated that manufacturers would apply only active systems due to a perception that passive systems were limited in their ability to mitigate NMOG. We estimated the cost of active hydrocarbon adsorber systems at \$150 (2009\$). For the final rule, we have changed our expectations and now expect that any HC adsorber use will be passive rather than active. We base this on comments from MECA and ICCT and on CBI provided by Tier 1 suppliers after the proposal.<sup>12</sup> We have estimated the DMC of a passive HC adsorber at \$16 (2011\$, or \$15 in 2009\$), and we expect their use on only a portion of the largest gasoline engines.

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider passive HC adsorbers to be a medium complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-12. Note that the values shown do not include penetration rates.

We do not show costs for I4 or V6 gasoline or for diesel vehicles since none of those vehicles are expected to incur new HC adsorber costs.

**Table 2-12 Passive HC Adsorber Costs for Gasoline Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC V8, LT V8, Class 2b, 3	DMC	\$16	\$15	\$15	\$14	\$14	\$13	\$13	\$13	\$13	\$12	\$12
PC V8, LT V8, Class 2b, 3	IC	\$5	\$5	\$5	\$5	\$5	\$5	\$5	\$5	\$4	\$4	\$4
PC V8, LT V8, Class 2b, 3	TC	\$21	\$20	\$20	\$19	\$19	\$18	\$18	\$18	\$16	\$16	\$16

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

## 2.4 Evaporative Emission, Canister Bleed, and Leak Controls

### 2.4.1 DMCs of Technologies Expected to See Widespread Implementation

Chapter 1 identified six different technologies EPA expected to see widespread use in achieving the emission reductions needed to meet the Tier 3 evaporative emission standard (hot soak plus diurnal, canister bleed, and leak). These technologies are in-use to varying degrees in the fleet today. The technologies of interest are identified in Table 1-11 of Chapter 1. That table is replicated here, but with different entries to address the fleet penetration and costs of the various technologies by vehicle category. The DMCs presented below are EPA estimates based on discussions with manufacturers and vendors and review of the comments on the CARB LEV III evaporative emissions rule. See Table 2-13. All DMC are in 2011 dollars. Each of these is discussed below.

**Table 2-13 Tier 3 Evaporative, Leak and OBD DMCs**

Vehicle Class	LDV	LDT1	LDT2	LDT3	LDT4	MDPV	LHDGV	HHGV
nonfuel (g)	0.1	0.1	0.125	0.15	0.15	0.175	0.2	0.25
MSAT std(3d/2d)(g)	0.5/0.65	0.65/0.85	0.65/0.85	0.9/1.15	0.9/1.15	1.0/1.25	1.4/1.75	1.9/2.3
T3 std (g)	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6
Canister bleed std (g)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
MSAT Baseline(g) <sup>1</sup>	0.47	0.47	0.42	0.72	0.72	0.72	0.96	0.96
T3 Target (g) <sup>2</sup>	0.2	0.2	0.3	0.37	0.37	0.37	0.45	0.45
Red Needed(g)	0.27	0.27	0.12	0.35	0.35	0.35	0.51	0.51
Red Achieved(g)	0.39	0.39	0.39	0.39	0.39	0.39	0.55	0.52

Technology	DMC	Control Efficiency	Cost &		Cost &		Cost %		Cost &		Cost &		Cost &		Cost &		Cost &	
			%Application	DMC	%Application	DMC	%Application	DMC										
Canister honeycomb	\$8.50 35mmx 75mm	90%	\$8.50_100%	\$8.50	\$8.50_100%	\$8.50	\$8.50_76%	\$6.46	\$8.50_10%	\$0.85	0	0	0	0	0	0	0	0
Canister honeycomb	\$7.50 for V-8s 35mm x 50mm	90%	0	0	0	0	\$7.5_24%	\$1.82	\$7.5_90%	\$6.75	\$7.5_100%	\$7.50	\$7.5_100%	\$7.50	\$7.5_100%	\$7.50	\$7.5_100%	\$7.50
ALS scrubber	\$6	90%	\$6_40%	\$2.40	\$6_27%	\$1.62	\$6_27%	\$1.62	\$6_27%	\$1.62	\$6_27%	\$1.62	\$6_27%	\$1.62	0	0	\$6_100%	\$6
PFI to GDI	\$0	90%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel system architecture																		
(a) reduce connections & improve seals/ o-rings as needed	\$2	90%	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2	\$2_100%	\$2
(b) move parts into tank	\$0.50	100%	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0.5_0.50	\$0.25	0	0
OBD software upgrades	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Tota DMC</b>				<b>\$13.15</b>		<b>\$12.37</b>		<b>\$12.15</b>		<b>\$11.47</b>		<b>\$11.37</b>		<b>\$11.37</b>		<b>\$9.75</b>		<b>\$15.50</b>
fuel savings gal/veh-yr <sup>3</sup>				0.051		0.051		0.051		0.051		0.051		0.051		0.059		0.053

<sup>1</sup> based on mean plus one standard deviation for 2013 MY 2-day cert results on Tier 2 fuel

<sup>2</sup> 100 mg or 25% below T3 std whichever is greater

<sup>3</sup> (365 day per year)(1 gal per 5.6 lbs)(1 lb per 454g)(mg reduction/day)(1 g/1000 mg)(0.9 energy density effect); needs to be further multiplied by(15yr) (avg surv fraction for fleet)(gas price)

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*Canister honeycomb:* Current evaporative canisters use high working-capacity activated carbon, usually with multiple compartments, to optimize vapor loading and purging behavior. These canisters sometimes employ carbons of different working capacities within each chamber. Manufacturers may adjust the shapes and sizes of internal compartments, including design variations to include different grades of carbon in different areas to best manage rapid purge following engine starting, back purge during overnight parking, vapor loading at different loading rates, and vapor redistribution and migration while the vehicle is not operating. The biggest expected change to evaporative emission canisters is the addition of a secondary canister element, either attached to the canister body, or integral to it, in which a carbon with very low working capacity is available to capture diffusion emissions (also known as bleed emissions). This is commonly referred to as a canister scrubber. While this carbon element can hold only a few grams of hydrocarbon, it back purges easily and purges readily with a short amount of driving, so it is always ready to capture the small amount of hydrocarbon that escapes the body of the evaporative canister as a result of diffusion from vapor migration within the carbon bed. For purposes of this analysis, we expect that all vehicles covered by the rule use a canister scrubber. Slightly larger scrubbers are expected on vehicles with V-4 and V-6 engines, since they are expected to have less available purge for the primary canister than will V-8 engines. The scrubbers will vary in size, but a typical unit DMC is \$7.50-8.50. We expect that in most cases these will be built as an integral part of the current canister to avoid extra packaging costs. In some cases, dual tank HDGVs may employ two evaporative emission canisters.

*Engine/fuel system conversion:* To the extent that manufacturers use direct injection, there should be very little fuel vapor coming from the intake system. Any unburned fuel coming from the injectors would be preserved in the cylinder or released to the exhaust system and the catalyst. A small amount of crankcase vapor might remain, but this would likely not be enough to justify adding carbon to the intake system. As projected in our final rule RIA for the 2017-2025 GHG emissions, EPA projects a significant movement from port fuel injection (PFI) engines to gasoline direct injection (GDI) engines. This ranges from 60-100 percent of products for all categories except gasoline-powered trucks over 14,000 lbs GVWR. This reduces air induction systems emissions by 90 percent since the GDI uses a different fuel injection timing strategy than the PFI. This would not involve any additional cost for control of Tier 3 evaporative emissions.

*Air intake scrubbers:* Manufacturers have identified the engine's intake system as another source of evaporative emissions. These result from crankcase vapors and from unburned fuel from injectors, or sometimes from an injection event that occurred shortly before engine shutdown. One way to prevent these emissions is to add a device containing activated carbon to the air intake downstream of the air filter, typically in the form of reticulated foam coated with activated carbon. This device would have only a few grams of working capacity and would be designed to purge easily to ensure that the vapor storage is available any time the engine shuts down. This carbon insert would almost completely eliminate vapor emissions from the air intake system. This analysis projects that vehicles/engines not converting to GDI will use the air intake scrubber to address this source of emissions. The percentages by vehicle category are shown in Table 2-13 above. The intake scrubber DMC is approximately \$6.00 per vehicle.

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*Fuel-system architecture:* As discussed below, there may be the opportunity to reduce permeation emissions from some fuel lines. However, the bigger area of expected development with respect to fuel lines is to re-engineer whole systems to reduce the number of connections between fuel-system components and other fuel-line segments. While manufacturers have already made some changes in this direction, these systems may still involve more than the optimum number of connections and segments due to assembly and production considerations or other factors. Designing the fuel system more carefully to minimize connection points will limit possible paths for fuel vapors to escape. This would reduce emission rates and it should also improve system durability by eliminating potential failure points. A broader approach to addressing this source of emissions is to integrate designs and to move fuel-system components inside the fuel tank, which eliminates the concern for vapor emissions and permeation from those components and connections. Most of the costs associated with these upgrades lie in development and tooling. There may be some additional part costs, but the overall trend should ultimately allow for reduced costs from reducing the number of components and reducing assembly time. To the extent that fuel-system components are moved inside the fuel tank, there may be further cost savings since those components would no longer need to be made from low-permeation materials. DMC for these actions is about \$2.50

*Onboard Diagnostics (OBD):* EPA and CARB have similar but not identical OBD requirements for LDVs, LDTs, MDPVs, and HDGVs up to 14,000 lbs GVWR. Within the past five years CARB has revised their implementation scheme and upgraded requirements to improve the effectiveness of their systems in addressing potential exhaust and evaporative system performance issues in use. EPA regulations permit manufacturers to meet CARB's most recent requirements and to seek a Federal certificate based on meeting CARB's requirements. Certification based on meeting CARB's requirements and application of those OBD systems nationwide is common practice in the industry with only a few exceptions. EPA is adopting current CARB OBD certification, verification, and monitoring requirements. As part of our rule, we are including two new elements; (1) certification that the OBD evaporative system leak monitor is able to find a 0.020 inch leak and (2) a requirement that the OBD computer store information on when the full OBD leak monitoring protocol was last run successfully and the result of that assessment. Since current CARB OBD requirements are being met by manufacturers, additional costs are attributable to certification to the 0.020 inch leak detection requirement and software modification to retain information on the last successful run of the OBD evaporative system leak monitor. EPA estimates these two items to cost on average approximately \$0.10 (2011\$) per vehicle. These are reflected in indirect costs discussed below.

*Leak standard testing:* As part of the Tier 3 evaporative emission requirements EPA is proposing a vapor leak emission standard. EPA expects that many of the technologies and approaches for reducing evaporative emissions described above will assist in addressing potential vapor leak problems and that in most cases no specific additional measures would be needed. Nevertheless, there might be two additional cost areas. First would be certification testing. However, EPA is allowing certification requirements for the vapor leak emission standard to be met by written attestation rather than by testing since the certification vehicle would fail the hot soak plus diurnal evaporative emissions standard if it had a 0.02 inch leak. Manufacturers agree this is appropriate. Second, EPA is proposing to include assessment of the vapor leak emission standard within the in-use verification testing program (IUVP). However, we have structured the program to minimize additional costs. Testing will be required on all

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vehicles otherwise procured for exhaust emissions. All vehicles tested for exhaust emissions must also be tested for the leak emission standard. Thus, we generally expect multiple leak test results per group but in no case may there be no fewer than one test group representatives for each evaporative/refueling/leak family. Unless there are performance problems, no additional vehicle procurement costs are expected. Also, we are proposing to permit the manufacturer to use its current evaporative system leak monitoring OBD hardware to screen vehicles from IUVP testing for leaks and/or to use as an option to the proposed EPA test procedure if testing is needed. The additional costs for leak emission testing for IUVP (approximately \$0.10 (2011\$) per vehicle) are included in the indirect costs discussed below.

Taken together, these technologies applied to the fleet to the degree described in the paragraphs above result in an estimated DMC of \$10-15 per vehicle in 2011 dollars.

#### 2.4.2 DMCs of technologies which may be optimized if necessary to achieve further reductions

Chapter 1 of the RIA also identified four technology approaches which are in widespread use today but with some refinement and optimization could provide additional reductions. These are discussed below, but not included in the overall cost analysis. These technologies are likely to see limited application because in comparison to the technologies in Table 1-11 of Chapter 1 the emission reductions available (see Table 1-12 of Chapter 1) are small relative to the costs. If implemented, as can be seen in Table 2-13, the five approaches discussed above would provide more than enough reductions to meet the emission targets for the hot soak plus diurnal and canister bleed standards at certification even accounting for the non-fuel hydrocarbon effects. Thus, we are not projecting penetration rates for these technologies.

*Upgrade canister and improve purge:* Recent and projected engine design changes are increasing the challenge to maintain manifold vacuum for drawing purge air through the evaporative canister. Several different technology options would help to address this increasing challenge. Different grades of carbon and canister configurations can lead to a more effective canister purge for a given volume of air flowing over the canister. If employed, such strategies would cost \$2-4 per vehicle.

*Improve fuel tank barrier layer thickness and reduce pinch seam gaps:* Fuel tanks are already designed to limit permeation emissions. Fuel tanks are typically made of high-density polyethylene with an embedded barrier layer of ethyl vinyl alcohol (EvOH) representing about 1.8 percent of the average wall thickness. The EvOH layer is effective for reducing permeation emissions. Recent developments in production processes have led to improved barrier coverage around the ends of the tank where the molded plastic is pinch-welded to form a closed vessel, which is an important step in eliminating a permeation path through the wall of the fuel tank. Manufacturers could increase the EvOH barrier thickness to about 3 percent of the average wall thickness to provide a more uniform barrier layer, to provide better protection with ethanol-based fuels, and to improve permeation resistance generally. The incremental material cost for this thicker layer of EvOH comes to about \$3.50.

*Filler neck connection and materials upgrade:* Another area of potential evaporative emissions is the connection between the fill neck and the fuel tank. The challenge is to design a low-cost solution that is easily assembled and works for the demanding performance needs

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related to stiffness and flexibility. The best approach is likely either to use mating parts made from low-permeation materials, or to use conventional materials but cover this joint with material that acts as a barrier layer. Final designs to address this might vary widely. Technology to improve the permeation resistance of the fuel filler tube and the security of the connection to the fuel tank would cost \$4-6 per vehicle.

*Fuel line permeation:* Fuel lines in use today also are designed for low permeation rates. The biggest portion of fuel and vapor lines are made of metal, but that may still leave several feet of nonmetal fuel line on a vehicle. There may be development of new materials to further reduce permeation rates, but it is more likely that manufacturers will adjust the mix of existing types of plastic fuel lines, and perhaps use more metal fuel lines, to achieve the desired performance at the lowest possible price. This would likely vary significantly among vehicle models. As an industry average figure, we estimate upgrades involving \$1.60 of additional cost for materials with greater permeation resistance.

#### 2.4.3 ORVR for Complete HDGVs

*Onboard Refueling Vapor Recovery (ORVR):* Current EPA standards require vehicle-based control of refueling emissions for all complete LDVs and LDTs up to 10,000 lbs GVWR. We are extending EPA's refueling emission standard to complete heavy-duty gasoline vehicles (HDGVs) up to 14,000 lbs GVWR starting with the 2018 model year. Today these HDGVs are produced by three OEMs. Their chassis and fuel system configurations are very similar to their slightly lighter GVWR LDT counterparts, which are now covered by the refueling emission standard. Because annual sales of these 10,001-14,000 lb GVWR HDGVs is small relative to their similar lighter GVWR LDT counterparts, for uniformity of production and other cost savings reasons, manufacturers have installed ORVR on these vehicles since about 2006. However, they have not been certified since there were no emission control requirements to certify them against. We are including refueling emission control requirements for these vehicles but expect no additional costs beyond current practice. Beyond, this the refueling emission standards apply to all complete HDGVs regardless of their GVWR by the 2022MY. There are no complete HDGVs above 14,000 lbs GVWR today, but there have been in the past and if a future product emerges, this will be a requirement for the 2022 model year.

Table 2-14 presents the evaporative system costs discussed above along with how those have been weighted to arrive at evaporative system costs for the vehicle categories used throughout this cost analysis.

**Table 2-14 Evaporative Emission Control System DMC for Gasoline Vehicles (2011\$)**

Vehicle Type	DMC	Sales fraction	Tier 3 Cost analysis Vehicle category	Tier 3 Cost analysis DMC
LDV	\$13.15	100%	Passenger car	\$13.15
LDT1	\$12.37	17%	Light truck	\$12.00
LDT2	\$12.15	57%		
LDT3	\$11.47	17%		
LDT4	\$11.37	8%		
MDPV	\$11.27	1%		
LHDGV	\$9.75	100%	Class 2b & 3	\$9.75
HHDGV	\$15.50	100%	>14,000 pound GVWR	\$15.50

We consider these incremental costs to be applicable in MY2015 with flat learning applied thereafter. We consider evaporative emission controls to be a low complexity technology with near term factors applied through 2022 and long term thereafter. The resultant costs are shown in Table 2-15. Note that the values shown do not include phase-in rates. We do not show costs for diesel vehicles since none of those vehicles are expected to incur new evaporative emission control costs.

**Table 2-15 Evaporative Emission Control System Costs for Gasoline Vehicles (2011\$)**

Vehicle category	Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC	DMC	\$13	\$13	\$12	\$12	\$11	\$11	\$11	\$11	\$10	\$10	\$10
LT	DMC	\$12	\$11	\$11	\$11	\$10	\$10	\$10	\$10	\$10	\$9	\$9
Class 2b, 3	DMC	\$10	\$9	\$9	\$9	\$8	\$8	\$8	\$8	\$8	\$8	\$7
>14K HD	DMC	\$15	\$15	\$14	\$14	\$13	\$13	\$13	\$13	\$12	\$12	\$12
PC	IC	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$2	\$2	\$2
LT	IC	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2
Class 2b, 3	IC	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2
>14K HD	IC	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$3	\$3
PC	TC	\$16	\$15	\$15	\$14	\$14	\$14	\$14	\$13	\$13	\$13	\$12
LT	TC	\$14	\$14	\$14	\$13	\$13	\$13	\$12	\$12	\$12	\$11	\$11
Class 2b, 3	TC	\$12	\$11	\$11	\$11	\$10	\$10	\$10	\$10	\$9	\$9	\$9
>14K HD	TC	\$18	\$18	\$17	\$17	\$17	\$16	\$16	\$16	\$15	\$15	\$15

PC=passenger car; LT=light truck; DMC=direct manufacturing cost; IC=indirect cost; TC=total cost; 2015 & 2016 costs shown because the cost basis for the technology is 2015 where the learning factor=1.0; note that the costs shown do not include penetration rates so these costs represent technology costs, not package costs for packages of technologies expected to be applied to Tier 3 vehicles.

## 2.5 Vehicle Package Costs

The total costs (TC) of a given technology are the direct manufacturing costs (DMC) plus the indirect costs (IC). These costs change over time due to learning effects and different levels of indirect costs as discussed above. Here we present our estimated application or penetration rates for each technology and the subsequent average technology cost estimates by year for each

technology inclusive of those penetration rates. We then present our approach to developing package costs—a package being a group of individual technologies added to a given vehicle.

As stated above, we have developed our costs with respect to a given vehicle type and the type of engine with which it is equipped. Although the cost of achieving the Tier 3 standards will increase with both the size of the vehicle and the displacement of the engine we have concluded that the cost by engine type is consistent. The final cost per vehicle is the result of not only the cost per technology but also the application rate of that technology for each vehicle type. For example, while the cost of secondary air injection is the same, \$119 (2011\$) in MY2017, for both a V6 and V8 application, we anticipate that a lower percentage of V6 applications will require the technology compared to V8 applications. This technology penetration rate, or application rate, is the first step in developing our vehicle package costs.

Table 2-16 presents our estimates of application rates of each enabling technology by engine type to meet the Tier 3 standards. These rates are identical, with two exceptions, to the rates used in the proposal. The changes from the proposal are to the secondary air and the optimized thermal management technologies. For secondary air, we have used the same starting rate as used in the proposal, but are now ramping that rate downward in the later years of implementation. The secondary air application rates are shown in Table 2-17. We are using these application rates because we believe, based on comments from ICCT and post-proposal Tier 1 suppliers, that secondary air will follow a similar implementation schedule to past uses of that technology. In the past, secondary air has been added in the early years of implementation because it is a very effective and relatively easy to employ technology. As experience is gained, secondary air is often removed because it is a relatively expensive technology.

**Table 2-16 Technology Application Rates for MY2017 and later Passenger Cars and MY2018 and later Light Trucks and HD Vehicles**

Technology	Gasoline					Diesel
	I4	V6	V8	Class 2b, 3	>14K HD	All
Catalyst Loading	100%	100%	100%	100%	0%	0%
Optimized Close-coupled Catalyst	50%	60%	75%	0%	0%	0%
Hydrocarbon Adsorber	0%	0%	15%	0%	0%	0%
Evaporative Emissions Controls	100%	100%	100%	100%	100%	0%
Engine Calibration	100%	100%	100%	100%	0%	100%
Optimized Thermal Management	50%	40%	25%	25%	0%	25%
SCR Optimization	0%	0%	0%	0%	0%	100%

Note: 0% entries reflect the fact that the technology is not considered to be an enabler for compliance with the standards.

**Table 2-17 Technology Application Rates for Secondary Air Injection on Gasoline Vehicles**

Vehicle category	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC V6	25%	25%	25%	15%	15%	5%	5%	5%	5%
PC V8	75%	75%	75%	65%	65%	55%	55%	45%	45%
LT V6	0%	25%	25%	15%	15%	5%	5%	5%	5%
LT V8	0%	75%	75%	65%	65%	55%	55%	45%	45%

PC=passenger car; LT=light truck

MDPVs were included in the light-duty fleet as part of Tier 2. Given their current certification requirements for criteria pollutants, we have included the costs for MDPVs to meet the Tier 3 standards with the LT V8 cost estimates. We do not expect that the technologies required to meet the Tier 3 standards for MDPVs will be very different from those applied to LT V8s as in many cases there are identical powertrains and chassis between the LT and MDPV platforms.

The next step in developing vehicle package costs is to consider the phase-in rate of the standards. For example, the Tier 3 standards do not reach maximum stringency until the 2025 MY, ramping down from a presumed Tier 2 Bin 5 level in MY2016 to the final levels in MY2025. Manufacturers will be required to start the phase-in of Tier 3 standards on passenger cars in MY2017 and light trucks in MY2018. Based on the declining fleet averages for cars and trucks, we have apportioned our estimates for full compliance across of the phase-in years as a percentage of the final standard. Manufacturers will be required to move from a Tier 2 Bin 5 fleet average in MY2016 (for vehicles <6,000 lbs GVW) to the Tier 3 standards. This results in a significant step in stringency in MY2017. It is also important to note that manufacturers will have the opportunity in MYs 2015 and 2016 to earn Tier 3 credits by producing a fleet that is cleaner than the current Tier 2 requirements. While we expect that most manufacturers will earn credits, either by selling California vehicles as 50 state vehicles or by certifying existing vehicles to lower Tier 2 bins, we have not reflected these credits in our cost analysis.

The ramp down in standards can also be expressed as an increasing percentage of the fleet meeting the Tier 3 standards, moving from 0 percent compliance in MY2016 to 100 percent compliance in MY2025 (see Section IV of the preamble, which presents the standards and how they change by MY). This changing percentage of vehicles complying is treated as being equal in this analysis to the percentage of costs being incurred. Table 2-18 shows the percentage of vehicles complying with the new standards. Note that Table 2-18 is identical in content to the ramp down in standards used in the proposal.

**Table 2-18 Percentage of Vehicles Phasing-in Compliance with the Tier 3 Standards**

Vehicle Category	Standards	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC	Exhaust	57%	62%	68%	73%	78%	84%	89%	95%	100%
LT	Exhaust	0%	52%	59%	66%	73%	80%	87%	94%	100%
Class 2b	Exhaust	0%	54%	65%	77%	88%	100%	100%	100%	100%
Class 3	Exhaust	0%	47%	60%	73%	87%	100%	100%	100%	100%
PC	Evap	40%	60%	60%	80%	80%	100%	100%	100%	100%
LT	Evap	0%	60%	60%	80%	80%	100%	100%	100%	100%
HD	Evap	0%	60%	60%	80%	80%	100%	100%	100%	100%

PC=passenger car; LT=light truck; HD=Class 2b and 3 vehicles, and >14,000 pound gasoline vehicles.

The third step, and new for the final rule, is to consider the compliance rate in the reference case fleet—i.e., if some vehicles already comply with the Tier 3 standards, we do not need to add technology and costs to those vehicles. To estimate the reference case compliance rate, we looked at MY2013 compliance (the most recent full set of compliance data). Filtering these data to include only those certifications for federal Tier 2 compliance, and combining their certified NMOG and NOx emissions—Tier 2 vehicles are certified to separate NMOG and NOx standards, but we combined them as though they were combined standards as are the Tier 3 standards—we were able to determine that 14% of MY2013 passenger car and light truck certifications had combined NMOG+NOx emissions below the 30 mg level (i.e., the Tier 3 Bin 30 level). That percentage included 33% of passenger car I4 gasoline vehicles and 10% of passenger car V6 gasoline vehicles. These results are shown in Table 2-19.

**Table 2-19 Percentage of MY2013 Certifications with Certified NMOG+NOx Emissions at the Indicated Tier 3 Levels**

Vehicle Category	Fuel	Bin20	Bin30	Bin50	Bin70	Bin125	Bin160	>Bin160	% below Bin30
PC I4	gasoline	25%	7%	22%	37%	8%	0%	0%	33%
PC V6	gasoline	5%	4%	22%	46%	22%	0%	0%	10%
PC V8	gasoline	2%	2%	26%	41%	26%	3%	0%	3%
PC I4	Diesel	0%	0%	0%	100%	0%	0%	0%	0%
PC V6	Diesel	0%	0%	100%	0%	0%	0%	0%	0%
PC V8	Diesel	0%	0%	0%	0%	0%	0%	0%	0%
LT I4	gasoline	4%	4%	18%	36%	39%	0%	0%	7%
LT V6	gasoline	3%	4%	38%	31%	24%	0%	0%	7%
LT V8	gasoline	0%	1%	23%	34%	16%	18%	7%	1%
LT I4	Diesel	0%	0%	0%	100%	0%	0%	0%	0%
LT V6	Diesel	0%	0%	33%	67%	0%	0%	0%	0%
LT V8	Diesel	0%	0%	0%	0%	0%	0%	0%	0%
Total		10%	4%	25%	38%	17%	4%	2%	14%

Importantly, the percentages shown in Table 2-19 represent certified engine families, not vehicle sales, and they represent certified emission levels absent any compliance margin. We have chosen to address these two issues in the following ways. As regards the absence of

compliance margin—the amount below the standard to which vehicles are typically designed and certified as insurance against failing the standards in-use—we went the next step and considered only those certifications that met 70% of the Tier 3 Bin 30 combined NMOG+NOx levels. Doing this resulted in a total of 11% of the certifications with emissions below 70% of the Bin 30 levels.<sup>F</sup> This change also resulted in a reduction to 28% of passenger car I4 families and 6% of passenger car V6 families at 70% of the Bin 30 levels.

As for reconciling certified families with actual sales, we had no way of matching these certifications to actual sales since the full MY2013 sales were not yet available. We could simply assume that the percentage of engine families equates to the percentage of sales but, in an effort to be conservative in our cost estimates, we have chosen instead to assume only a 50% relationship. In other words, to be conservative, we have chosen to estimate that sales are represented by only half of the certified engine families. So, the 28% of passenger car I4 families with certified emissions below 70% of the Bin 30 level is taken to represent 14% of actual passenger car I4 sales. The resultant reference case sales percentages estimated to already comply with the Tier 3 Bin 30 average are shown in Table 2-20. Note that we have assumed that no HD vehicles are already at compliant emission levels in the reference case.

**Table 2-20 Reference Case Engine Families and Estimated Sales at or below 70% of the Bin 30 Standard**

Vehicle Category	Fuel	% of certified families below Bin30	% of certified families below 70% of Bin30	Estimated % of sales below 70% of Bin30
PC I4	gasoline	33%	28%	14%
PC V6	gasoline	10%	6%	3%
PC V8	gasoline	3%	2%	1%
PC I4	diesel	0%	0%	0%
PC V6	diesel	0%	0%	0%
PC V8	diesel	0%	0%	0%
LT I4	gasoline	7%	4%	2%
LT V6	gasoline	7%	3%	1%
LT V8	gasoline	1%	0%	0%
LT I4	diesel	0%	0%	0%
LT V6	diesel	0%	0%	0%
LT V8	diesel	0%	0%	0%
Total		14%	11%	5%

With each of these percentages—the technology application rate percentage; the phase-in rate of the standard; and the reference case sales percentage meeting Bin 30—we can then

<sup>F</sup> A compliance margin of just 70% of the actual standard could be considered too high by traditional measures where each criteria pollutant has a unique standard level. However, the combined nature of the Tier 3 NMOG+NOx standard makes traditional compliance margin goals too large and, some have argued, that even 70% in the context of Tier 3 may be too large. We prefer to be conservative and use 70% of the standard.

determine the contribution of each individual technology to the resultant package cost for each vehicle category. This is done by multiplying the total cost of each individual technology in a given year by its technology application rate for that year, then multiplying this product by the phase-in rate less reference case sales percentage. An example calculation is shown in Table 2-21 for optimized close coupled catalyst costs on I4 gasoline passenger cars.

**Table 2-21 Example Calculation: Contribution of Optimized Close Coupled Catalyst to the Package Cost for I4 Gasoline Passenger Car (dollar values in 2011\$)**

Item	Value	Source
Optimized close coupled catalyst Total Cost (TC) for MY2017	\$24	Table 2-8
Application rate to meet Tier 3	50%	Table 2-16
Standard phase-in percentage for MY2017	57%	Table 2-18
Reference case sales in compliance	14%	Table 2-20
Contribution to package cost	\$5 = (\$24)(50%)(57%-14%)	Table 2-22

Table 2-22 through Table 2-30 use this calculation approach to present the contribution of each technology cost to the resultant package cost. Table 2-31 and Table 2-32 present the final package costs for gasoline and diesel vehicles, respectively, which simply sum the appropriate costs shown in Table 2-22 through Table 2-30.

**Table 2-22 Contribution of Individual Technologies to Vehicle Package Costs – Gasoline Passenger Cars (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	I4	\$18	\$20	\$22	\$23	\$25	\$27	\$27	\$29	\$30
Optimized Close-coupled Catalyst	I4	\$5	\$6	\$6	\$7	\$7	\$7	\$8	\$8	\$8
Secondary Air Injection	I4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydrocarbon Adsorber	I4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	I4	\$4	\$7	\$6	\$9	\$9	\$11	\$11	\$11	\$11
Engine Calibration	I4	\$2	\$2	\$2	\$3	\$3	\$3	\$3	\$3	\$3
Optimized Thermal Management	I4	\$8	\$8	\$9	\$10	\$10	\$11	\$11	\$12	\$13
Catalyst Loading	V6	\$37	\$39	\$42	\$44	\$47	\$49	\$50	\$52	\$55
Optimized Close-coupled Catalyst	V6	\$15	\$16	\$18	\$19	\$20	\$21	\$21	\$22	\$23
Secondary Air Injection	V6	\$16	\$17	\$18	\$12	\$12	\$4	\$4	\$5	\$5
Hydrocarbon Adsorber	V6	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	V6	\$5	\$8	\$8	\$11	\$10	\$13	\$12	\$12	\$12
Engine Calibration	V6	\$3	\$3	\$3	\$3	\$3	\$3	\$4	\$4	\$4
Optimized Thermal Management	V6	\$8	\$8	\$9	\$9	\$10	\$10	\$11	\$11	\$11
Catalyst Loading	V8	\$57	\$61	\$64	\$68	\$72	\$75	\$77	\$80	\$83
Optimized Close-coupled Catalyst	V8	\$30	\$32	\$34	\$36	\$38	\$40	\$41	\$42	\$44
Secondary Air Injection	V8	\$50	\$53	\$57	\$52	\$55	\$49	\$50	\$42	\$44
Hydrocarbon Adsorber	V8	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2
Evaporative Emissions Controls	V8	\$6	\$9	\$8	\$11	\$11	\$13	\$13	\$12	\$12
Engine Calibration	V8	\$3	\$3	\$3	\$3	\$3	\$4	\$4	\$4	\$4
Optimized Thermal Management	V8	\$5	\$5	\$6	\$6	\$6	\$7	\$7	\$7	\$7

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-23 Contribution of Individual Technologies to Vehicle Package Costs – Gasoline Light-duty Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	I4	\$0	\$25	\$28	\$30	\$33	\$35	\$37	\$39	\$41
Optimized Close-coupled Catalyst	I4	\$0	\$6	\$6	\$7	\$8	\$8	\$9	\$9	\$10
Secondary Air Injection	I4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydrocarbon Adsorber	I4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	I4	\$0	\$8	\$7	\$10	\$10	\$12	\$11	\$11	\$11
Engine Calibration	I4	\$0	\$2	\$3	\$3	\$3	\$3	\$3	\$4	\$4
Optimized Thermal Management	I4	\$0	\$9	\$10	\$11	\$12	\$13	\$13	\$14	\$15
Catalyst Loading	V6	\$0	\$37	\$41	\$45	\$49	\$53	\$55	\$58	\$61
Optimized Close-coupled Catalyst	V6	\$0	\$14	\$16	\$17	\$19	\$20	\$21	\$22	\$23
Secondary Air Injection	V6	\$0	\$15	\$16	\$11	\$12	\$4	\$4	\$5	\$5
Hydrocarbon Adsorber	V6	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	V6	\$0	\$8	\$8	\$10	\$10	\$12	\$11	\$11	\$11
Engine Calibration	V6	\$0	\$2	\$3	\$3	\$3	\$3	\$3	\$4	\$4
Optimized Thermal Management	V6	\$0	\$7	\$8	\$9	\$9	\$10	\$10	\$11	\$12
Catalyst Loading	V8	\$0	\$55	\$61	\$66	\$72	\$78	\$81	\$86	\$90
Optimized Close-coupled Catalyst	V8	\$0	\$27	\$30	\$33	\$36	\$38	\$40	\$42	\$44
Secondary Air Injection	V8	\$0	\$45	\$50	\$47	\$52	\$47	\$49	\$42	\$44
Hydrocarbon Adsorber	V8	\$0	\$2	\$2	\$2	\$2	\$2	\$2	\$2	\$2
Evaporative Emissions Controls	V8	\$0	\$8	\$8	\$10	\$10	\$12	\$12	\$11	\$11
Engine Calibration	V8	\$0	\$2	\$3	\$3	\$3	\$3	\$4	\$4	\$4
Optimized Thermal Management	V8	\$0	\$5	\$5	\$5	\$6	\$6	\$7	\$7	\$7

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-24 Contribution of Individual Technologies to Vehicle Package Costs – Gasoline Heavy-duty Class 2b Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	All	\$0	\$31	\$37	\$42	\$48	\$53	\$51	\$50	\$49
Optimized Close-coupled Catalyst	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Secondary Air Injection	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydrocarbon Adsorber	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	All	\$0	\$6	\$6	\$8	\$8	\$10	\$9	\$9	\$9
Engine Calibration	All	\$0	\$2	\$3	\$3	\$4	\$4	\$4	\$4	\$4
Optimized Thermal Management	All	\$0	\$5	\$6	\$6	\$7	\$8	\$8	\$8	\$7

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-25 Contribution of Individual Technologies to Vehicle Package Costs – Gasoline Heavy-duty Class 3 Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	All	\$0	\$27	\$34	\$40	\$47	\$53	\$51	\$50	\$49
Optimized Close-coupled Catalyst	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Secondary Air Injection	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydrocarbon Adsorber	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	All	\$0	\$6	\$6	\$8	\$8	\$10	\$9	\$9	\$9
Engine Calibration	All	\$0	\$2	\$3	\$3	\$4	\$4	\$4	\$4	\$4
Optimized Thermal Management	All	\$0	\$4	\$5	\$6	\$7	\$8	\$8	\$8	\$7

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-26 Contribution of Individual Technologies to Vehicle Package Costs – >14,000 Pound HD Gasoline Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Optimized Close-coupled Catalyst	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Secondary Air Injection	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydrocarbon Adsorber	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Evaporative Emissions Controls	All	\$0	\$10	\$10	\$13	\$13	\$16	\$15	\$15	\$15
Engine Calibration	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Optimized Thermal Management	All	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-27 Contribution of Individual Technologies to Vehicle Package Costs – Diesel Passenger Cars (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	\$1	\$1	\$2	\$2	\$2	\$2	\$2	\$2	\$2
Optimized Thermal Management	All	\$5	\$5	\$6	\$6	\$6	\$7	\$7	\$7	\$7
SCR Optimization	All	\$34	\$36	\$38	\$40	\$43	\$45	\$45	\$47	\$49

**Table 2-28 Contribution of Individual Technologies to Vehicle Package Costs– Diesel Light-duty Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	\$0	\$1	\$1	\$1	\$2	\$2	\$2	\$2	\$2
Optimized Thermal Management	All	\$0	\$5	\$5	\$5	\$6	\$6	\$7	\$7	\$7
SCR Optimization	All	\$0	\$30	\$33	\$36	\$40	\$43	\$44	\$47	\$49

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-29 Contribution of Individual Technologies to Vehicle Package Costs– Diesel Heavy-duty Class 2b Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	\$0	\$1	\$1	\$2	\$2	\$2	\$2	\$2	\$2
Optimized Thermal Management	All	\$0	\$5	\$6	\$6	\$7	\$8	\$8	\$8	\$7
SCR Optimization	All	\$0	\$31	\$37	\$42	\$48	\$53	\$51	\$50	\$49

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-30 Contribution of Individual Technologies to Vehicle Package Costs– Diesel Heavy-duty Class 3 Trucks (2011\$)**

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	\$0	\$1	\$1	\$2	\$2	\$2	\$2	\$2	\$2
Optimized Thermal Management	All	\$0	\$4	\$5	\$6	\$7	\$8	\$8	\$8	\$7
SCR Optimization	All	\$0	\$27	\$34	\$40	\$47	\$53	\$51	\$50	\$49

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

The final package costs are simply the sum of the costs shown in each of Table 2-22 through Table 2-30. These results are shown in Table 2-31 for gasoline vehicles and Table 2-32 for diesel vehicles.

**Table 2-31 Vehicle Package Costs by Year for All Gasoline Vehicles (2011\$)**

Vehicle category	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	I4	\$37	\$43	\$46	\$51	\$54	\$60	\$60	\$63	\$65
Passenger car	V6	\$84	\$92	\$97	\$97	\$102	\$101	\$102	\$106	\$110
Passenger car	V8	\$152	\$165	\$174	\$177	\$187	\$189	\$192	\$190	\$197
Light-duty truck	I4	\$0	\$50	\$54	\$61	\$65	\$72	\$73	\$77	\$80
Light-duty truck	V6	\$0	\$83	\$91	\$94	\$101	\$102	\$105	\$111	\$116
Light-duty truck	V8	\$0	\$144	\$158	\$167	\$180	\$187	\$193	\$195	\$203
Class 2b		\$0	\$45	\$52	\$60	\$67	\$75	\$72	\$71	\$70
Class 3		\$0	\$40	\$48	\$58	\$66	\$75	\$72	\$71	\$70
>14,000 pound HD		\$0	\$10	\$10	\$13	\$13	\$16	\$15	\$15	\$15

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

**Table 2-32 Vehicle Package Costs by Year for All Diesel Vehicles (2011\$)**

Vehicle category	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	I4	\$40	\$43	\$46	\$48	\$51	\$53	\$54	\$56	\$59
Passenger car	V6	\$40	\$43	\$46	\$48	\$51	\$53	\$54	\$56	\$59
Passenger car	V8	\$40	\$43	\$46	\$48	\$51	\$53	\$54	\$56	\$59
Light-duty truck	I4	\$0	\$36	\$40	\$43	\$47	\$51	\$53	\$56	\$59
Light-duty truck	V6	\$0	\$36	\$40	\$43	\$47	\$51	\$53	\$56	\$59
Light-duty truck	V8	\$0	\$36	\$40	\$43	\$47	\$51	\$53	\$56	\$59
Class 2b	V8	\$0	\$37	\$44	\$50	\$57	\$63	\$61	\$60	\$59
Class 3	V8	\$0	\$32	\$40	\$48	\$56	\$63	\$61	\$60	\$59

Note: \$0 entries denote zero costs due to a 0 percent application rate (see Table 2-16) and/or compliance rate (see Table 2-18).

## 2.6 Operating Costs

New for the final rule are estimates of operating costs (fuel savings) associated with the new evaporative emission standards. The fuel that would have evaporated absent the new standards will ultimately be used to propel the vehicle, thus providing a savings to the consumer. This savings is very small but nonetheless real. We also considered other operating costs, such as maintenance costs and repair costs, but concluded that the nature of the Tier 3 compliance technologies will not result in any increases or decreases in existing operating costs.

In Chapter 1, we discussed at the length the new evaporative standards and the estimated reductions; hydrocarbon reductions achieved are converted to the fuel saved by each vehicle category using the equation in footnote 3 of Table 2-13. Those fuel savings in gallons/vehicle/year are shown in Table 2-33.

**Table 2-33 Fuel Savings per Vehicle per Year Associated with the New Evaporative Emission Standards**

Vehicle type	Gallons saved/vehicle/year	Sales fraction	Vehicle category	Tier 3 Cost analysis Gallons saved/vehicle/year
LDV	0.051	n/a	Passenger car	0.051
LDT1	0.051	17%	Light truck	0.050
LDT2	0.049	57%		
LDT3	0.051	17%		
LDT4	0.051	8%		
MDPV	0.051	1%		
LHDGV	0.059	n/a	Class 2b & 3	0.059
HHDGV	0.053	n/a	>14,000 pound GVWR	0.053

Tier 3 compliant vehicles will be expected to realize these fuel savings throughout their lifetimes. To estimate the lifetime fuel savings, we used the survival fractions shown in Table 2-34, the fuel prices shown in Table 2-35, and the evaporative emission standard phase-in rates shown in Table 2-18.

**Table 2-34 Vehicle Survival Fractions used in Operating Cost Estimates**

Vehicle age	PC	LT	HD
1	1.000	1.000	1.000
2	0.988	0.978	0.978
3	0.977	0.963	0.963
4	0.961	0.943	0.943
5	0.945	0.931	0.931
6	0.930	0.915	0.915
7	0.911	0.893	0.893
8	0.891	0.870	0.870
9	0.869	0.841	0.841
10	0.840	0.796	0.796
11	0.800	0.742	0.742
12	0.756	0.692	0.692
13	0.706	0.641	0.641
14	0.653	0.583	0.583
15	0.595	0.535	0.535
16	0.531	0.486	0.486
17	0.458	0.442	0.442
18	0.383	0.398	0.398
19	0.308	0.352	0.352
20	0.241	0.309	0.309
21	0.183	0.267	0.267
22	0.139	0.228	0.228
23	0.107	0.202	0.202
24	0.082	0.175	0.175
25	0.063	0.158	0.158
26	0.051	0.145	0.145
27	0.042	0.139	0.139
28	0.034	0.125	0.125
29	0.028	0.111	0.111
30	0.024	0.103	0.103
31	0.000	0.093	0.093
32	0.000	0.083	0.083
33	0.000	0.073	0.073
34	0.000	0.062	0.062
35	0.000	0.050	0.050
36	0.000	0.038	0.038
37	0.000	0.027	0.027
38	0.000	0.000	0.000
39	0.000	0.000	0.000
40	0.000	0.000	0.000

PC=passenger car; LT=light truck;  
HD=all Heavy-duty, including >14K  
pounds

Source: EPA's MOVES model . For  
more information regarding the  
MOVES model, see Chapter 7 of this  
RIA.

**Table 2-35 Gasoline Prices (2011\$)**

Calendar Year	Taxed price (\$/gal)	Untaxed price (\$/gal)
2017	\$3.15	\$2.74
2018	\$3.19	\$2.79
2019	\$3.25	\$2.85
2020	\$3.32	\$2.92
2021	\$3.38	\$2.98
2022	\$3.43	\$3.03
2023	\$3.45	\$3.06
2024	\$3.48	\$3.09
2025	\$3.49	\$3.10
2026	\$3.52	\$3.14
2027	\$3.55	\$3.17
2028	\$3.58	\$3.20
2029	\$3.63	\$3.25
2030	\$3.67	\$3.29
2031	\$3.71	\$3.33
2032	\$3.75	\$3.38
2033	\$3.82	\$3.44
2034	\$3.87	\$3.50
2035	\$3.94	\$3.57
2036	\$4.01	\$3.64
2037	\$4.08	\$3.71
2038	\$4.15	\$3.79
2039	\$4.23	\$3.87
2040	\$4.32	\$3.96

Source: Energy Information Administration, Annual Energy Outlook 2013, Table 59.  
Note that the 2040 prices were used for years beyond 2040 in the analysis.

Looking first at the gallons saved during the lifetime of Tier 3 vehicles, the results are shown in Table 2-36. Clearly, the fuel savings are small on a per vehicle basis, approaching 1 gallon per vehicle during the entire lifetime. Note that the fuel savings reach their maximum in MY2022 when the phase-in hits 100% and they remain at those levels thereafter. Importantly, the maximum lifetime savings would actually be realized by any vehicle meeting the new Tier 3 evaporative standards. The lower savings shown in the early years of implementation are the result of the phase-in. In other words, 40% of the MY2017 passenger cars would realize 0.783 gallons saved during their lifetimes while the remaining 60% would realize none since they would not be compliant with the new evaporative standards. The resultant savings for the average MY2017 passenger car would then be  $(40\%)(0.783) + (60\%)(0.0) = 0.313$  gallons. Nonetheless, while the savings per vehicle are small, they are real and when realized by millions of vehicles the total gallons saved becomes more meaningful.

**Table 2-36 Gallons of Gasoline Saved during the Lifetimes of Gasoline Vehicles sold in the indicated MY**

Vehicle category	MY 2017	MY 2018	MY 2019	MY 2020	MY 2021	MY 2022	MY 2023	MY 2024	MY 2025
PC	0.313	0.470	0.470	0.626	0.626	0.783	0.783	0.783	0.783
LT	0.000	0.491	0.491	0.655	0.655	0.819	0.819	0.819	0.819
Class 2b	0.000	0.585	0.585	0.779	0.779	0.974	0.974	0.974	0.974
Class 3	0.000	0.585	0.585	0.779	0.779	0.974	0.974	0.974	0.974
>14K HD	0.000	0.524	0.524	0.698	0.698	0.873	0.873	0.873	0.873

PC=passenger car; LT=light truck; HD=heavy-duty.

We can also look at these gasoline savings on a calendar year basis where, in calendar year 2017 only the MY2017 vehicles meeting the new evaporative standards will realize any fuel savings. As shown in Table 2-18 and Table 2-33, this means that only 40% of passenger cars will realize 0.051 gallons of fuel saved in the 2017 calendar year. But, with gasoline passenger car sales estimated at 6,184,804 in MY2017, the total gallons saved becomes a more meaningful number. These results are shown in Table 2-37.

**Table 2-37 Annual Gallons of Gasoline Saved**

Calendar Year	PC	LT	Class 2b	Class 3	>14K HD	Total
2017	124,985	0	0	0	0	124,985
2018	310,678	107,820	14,663	324	1,679	435,164
2019	498,358	213,383	29,055	642	3,341	744,779
2020	751,009	352,549	48,038	1,062	5,557	1,158,215
2021	1,002,378	487,226	66,546	1,471	7,728	1,565,350
2022	1,315,316	652,291	89,471	1,978	10,430	2,069,486
2023	1,625,192	812,105	112,044	2,478	13,089	2,564,908
2024	1,933,324	967,512	134,426	2,972	15,719	3,053,954
2025	2,239,897	1,118,389	156,504	3,461	18,318	3,536,569
2030	3,661,158	1,800,289	255,597	5,652	30,125	5,752,821

PC=passenger car; LT=light truck; HD=heavy-duty.

Using the gasoline prices shown in Table 2-35, we can determine the monetary savings associated with these fuel savings. These results are shown in Table 2-38 (using a 3% discount rate) and in Table 2-39 (using a 7% discount rate) for the lifetimes of all vehicles sold in each model year. Table 2-40 presents the annual monetized fuel savings.

**Table 2-38 Monetized Lifetime Fuel Savings of all Vehicles Sold in Each Model Year, Discounted at 3% to the 1<sup>st</sup> year of the Model Year (Millions of 2011\$)**

Vehicle category	MY 2017	MY 2018	MY 2019	MY 2020	MY 2021	MY 2022	MY 2023	MY 2024	MY 2025	Sum
PC	\$4.66	\$7.09	\$7.35	\$10.1	\$10.3	\$13.1	\$13.3	\$13.7	\$14.0	\$93.6
LT	\$0	\$4.22	\$4.29	\$5.76	\$5.77	\$7.17	\$7.16	\$7.19	\$7.24	\$48.8
Class 2b	\$0	\$0.574	\$0.584	\$0.786	\$0.793	\$0.99	\$1.01	\$1.03	\$1.05	\$6.82
Class 3	\$0	\$0.013	\$0.013	\$0.017	\$0.018	\$0.022	\$0.022	\$0.023	\$0.023	\$0.151
>14K HD	\$0	\$0.066	\$0.068	\$0.092	\$0.093	\$0.117	\$0.119	\$0.121	\$0.124	\$0.799
Sum	\$4.66	\$12.0	\$12.3	\$16.8	\$17.0	\$21.4	\$21.6	\$22.1	\$22.4	\$150

Fuel savings calculated with untaxed gasoline prices; PC=passenger car; LT=light truck; HD=heavy-duty.

**Table 2-39 Monetized Lifetime Fuel Savings of all Vehicles Sold in Each Model Year, Discounted at 7% to the 1<sup>st</sup> year of the Model Year (Millions of 2011\$)**

Vehicle category	MY 2017	MY 2018	MY 2019	MY 2020	MY 2021	MY 2022	MY 2023	MY 2024	MY 2025	Sum
PC	\$3.47	\$5.27	\$5.47	\$7.51	\$7.69	\$9.73	\$9.9	\$10.2	\$10.4	\$69.7
LT	\$0.000	\$3.05	\$3.10	\$4.17	\$4.17	\$5.18	\$5.18	\$5.20	\$5.24	\$35.3
Class 2b	\$0.000	\$0.415	\$0.422	\$0.568	\$0.573	\$0.719	\$0.730	\$0.747	\$0.763	\$4.94
Class 3	\$0.000	\$0.009	\$0.009	\$0.013	\$0.013	\$0.016	\$0.016	\$0.017	\$0.017	\$0.109
>14K HD	\$0.000	\$0.048	\$0.049	\$0.066	\$0.067	\$0.085	\$0.086	\$0.088	\$0.090	\$0.578
Sum	\$3.47	\$8.79	\$9.05	\$12.3	\$12.5	\$15.7	\$15.9	\$16.3	\$16.5	\$111

Fuel savings calculated with untaxed gasoline prices; PC=passenger car; LT=light truck; HD=heavy-duty.

**Table 2-40 Annual Monetized Fuel Savings (Millions of 2011\$)**

Calendar Year	PC	LT	Class 2b	Class 3	>14K HD	Total
2017	\$0.342	\$0.000	\$0.000	\$0.000	\$0.000	\$0.342
2018	\$0.866	\$0.301	\$0.041	\$0.001	\$0.005	\$1.21
2019	\$1.42	\$0.608	\$0.083	\$0.002	\$0.010	\$2.12
2020	\$2.19	\$1.030	\$0.140	\$0.003	\$0.016	\$3.38
2021	\$2.99	\$1.45	\$0.198	\$0.004	\$0.023	\$4.67
2022	\$3.99	\$1.98	\$0.271	\$0.006	\$0.032	\$6.28
2023	\$4.97	\$2.48	\$0.343	\$0.008	\$0.040	\$7.84
2024	\$5.97	\$2.99	\$0.415	\$0.009	\$0.049	\$9.43
2025	\$6.95	\$3.47	\$0.486	\$0.011	\$0.057	\$11.0
2030	\$12.0	\$5.92	\$0.841	\$0.019	\$0.099	\$18.9

Fuel savings calculated with untaxed gasoline prices; PC=passenger car; LT=light truck; HD=heavy-duty.

## 2.7 Vehicle Program Costs

With the package costs presented in Table 2-31 and Table 2-32 and the operating costs presented in Table 2-40, we can begin to develop vehicle program costs associated with the new Tier 3 standards. The vehicle program costs multiply package costs by appropriate vehicle sales per year to estimate the annual technology costs of the program. We then subtract from those annual technology costs the annual operating savings associated with the evaporative standards. We also include the annual PM facility costs as discussed below.

The first step to this is determining the projected sales of each vehicle category, or package, as presented in Table 2-31 and Table 2-32. To do this, we have started with the latest sales projections from our MOVES database which provides projected sales by passenger car, light truck, etc., and gasoline versus diesel. However, MOVES does not provide sales projections to the I4 versus V6 versus V8 level of granularity which we need for Tier 3 vehicle program costs.

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For a fleet mix breakout at the level needed, we are using the fleet mix projections stemming from OMEGA runs done in support of our recent GHG final rulemakings.<sup>13</sup> We began with the baseline database developed in support of the MY 2017-2025 GHG final rule.<sup>14</sup> That baseline database provides the fleet sales mix in the years 2017-2025 for each of the vehicle category/engine/fuel combinations listed in Table 2-31 and Table 2-32. However, that baseline database is not reflective of the MY 2012 to 2016 or the MY 2017-2025 GHG final rules which are expected to have an impact on the sales mix of the vehicle category/engine/fuel combinations largely due to an expectation that engines will be turbocharged and downsized to achieve better GHG performance while also maintaining vehicle performance and utility. This downsizing is expected to provide downward effects on overall Tier 3 costs since vehicles with smaller engines are expected to incur lower costs than vehicles with larger engines. Therefore, using the baseline database and the technology penetration rates expected from the MY 2017-2025 GHG final rule, we have developed a Tier 3 reference case fleet. This reference fleet is the fleet we have used in developing Tier 3 vehicle program costs. Note that the Tier 3 control case fleet and the reference case fleet are, in effect, one in the same since Tier 3 itself is not expected to have any impact on the car/truck fleet mix or the I4/V6/V8 fleet mix.

Note that this reference case fleet differs considerably from the reference case fleet used in the proposal. The proposal used a fleet mix representing a future fleet meeting the MY2016 GHG standards. That fleet mix had considerably less turbocharging and downsizing of engines since the MY2016 GHG standards were less stringent than the MY 2017-2025 standards represented in the final rule's reference case fleet.

Table 2-41 shows the baseline fleet mix—representing the best estimates of the future fleet absent any GHG rules—and Table 2-42 shows the Tier 3 reference fleet—representing the future fleet in the presence of the MY 2012-2016 and MY 2017-2025 GHG final rules. Table 2-43 shows projected sales of light-duty and heavy-duty vehicles excluding sales in California and other states that have adopted LEVIII.<sup>G</sup>

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<sup>G</sup> Vehicle sales in California and other states that have adopted LEVIII are estimated at 36% of the nationwide total.

**Table 2-41 Baseline Light-Duty Fleet Mix**

Vehicle category	Engine	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC	I4	G	37.8%	38.1%	38.4%	38.7%	38.9%	39.2%	39.7%	40.0%	40.4%
	I4	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V6	G	21.4%	21.7%	21.8%	22.0%	22.4%	22.3%	22.3%	22.5%	22.7%
	V6	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V8	G	3.2%	3.1%	3.2%	3.2%	3.2%	3.2%	3.2%	3.1%	3.1%
	V8	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LT	I4	G	4.4%	4.0%	3.9%	3.7%	3.6%	3.6%	3.6%	3.5%	3.5%
	I4	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V6	G	22.1%	23.4%	23.4%	23.4%	23.0%	23.2%	23.1%	23.0%	22.7%
	V6	D	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	V8	G	10.7%	9.3%	9.0%	8.6%	8.5%	8.2%	8.0%	7.5%	7.2%
	V8	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
EV			0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
PC	All	All	62.6%	63.2%	63.6%	64.2%	64.7%	64.9%	65.3%	65.9%	66.5%
LT	All	All	37.4%	36.8%	36.4%	35.8%	35.3%	35.1%	34.7%	34.1%	33.5%

PC=passenger car; LT=light truck; EV=electric vehicle; G=gasoline; D=diesel.

**Table 2-42 Tier 3 Reference Case Light-Duty Fleet Mix**

Vehicle category	Engine	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC	I4	G	49.8%	51.9%	53.9%	56.0%	58.0%	60.1%	60.8%	61.5%	62.2%
	I4	D	0.3%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
	V6	G	9.1%	7.7%	6.2%	4.8%	3.4%	1.9%	1.8%	1.6%	1.5%
	V6	D	0.8%	0.6%	0.5%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%
	V8	G	2.3%	2.2%	2.1%	2.1%	2.0%	1.9%	1.6%	1.3%	0.9%
	V8	D	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
LT	I4	G	19.1%	20.3%	21.4%	22.6%	23.7%	24.9%	26.0%	27.0%	28.1%
	I4	D	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V6	G	11.1%	10.0%	8.9%	7.7%	6.6%	5.5%	4.9%	4.3%	3.7%
	V6	D	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	V8	G	6.9%	6.4%	6.0%	5.5%	5.1%	4.7%	3.7%	2.7%	1.7%
	V8	D	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
EV			0.2%	0.3%	0.5%	0.6%	0.8%	0.9%	1.2%	1.5%	1.8%
PC	All	All	62.6%	63.1%	63.5%	64.0%	64.4%	64.9%	65.4%	65.9%	66.4%
LT	All	All	37.4%	36.9%	36.5%	36.0%	35.6%	35.1%	34.6%	34.1%	33.5%

PC=passenger car; LT=light truck; EV=electric vehicle; G=gasoline; D=diesel.

One very important piece of information shown in the above tables is the gasoline I4 share of the fleet mix—that share being 63% for passenger cars and 29% for light trucks. So, OMEGA projects that fully 92% of the light-duty fleet will be gasoline I4 by MY2025. With the exception of electric vehicles, gasoline I4 engines are the least costly of the vehicle categories at

achieving Tier 3 emission levels. This helps, in part, to explain the large reduction in program costs (presented below) in this final rule analysis relative to the proposal.

For heavy-duty Class 2b and 3, we expect no downsizing of engines or other changes to engines that might influence Tier 3 costs as a result of the MY 2014-2018 Heavy-duty GHG rule. Therefore, we are using the baseline fleet as the reference fleet for this analysis. However, we have updated the HD baseline fleet relative to the proposal using more recent MOVES data.

**Table 2-43 Projected Tier 3 Sales by Year<sup>a</sup>**

Vehicle Category	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025
PC I4	G	5,195,481	5,345,425	5,621,877	5,863,693	6,078,373	6,127,715	6,217,541	6,341,466	6,481,560
PC I4	D	22,542	16,732	11,301	5,685	0	0	0	0	0
PC V6	G	767,432	617,934	482,618	341,259	197,189	181,270	166,561	152,573	138,652
PC V6	D	65,042	48,787	33,640	17,961	2,080	1,852	1,637	1,427	1,217
PC V8	G	221,891	212,696	208,494	202,729	195,923	161,634	128,438	95,552	62,251
PC V8	D	14,440	10,718	7,239	3,642	0	0	0	0	0
LT I4	G	2,030,320	2,124,486	2,269,022	2,400,216	2,520,536	2,618,264	2,733,236	2,864,048	3,003,581
LT I4	D	0	0	0	0	0	0	0	0	0
LT V6	G	1,003,041	879,974	777,339	667,197	552,966	492,601	435,536	380,146	324,535
LT V6	D	11,155	9,982	9,041	8,017	6,947	6,342	5,779	5,241	4,705
LT V8	G	644,502	594,005	557,387	516,100	471,969	368,953	268,449	168,242	66,502
LT V8	D	11,102	8,301	5,688	2,985	247	223	202	181	160
EV		32,163	46,553	62,080	77,465	92,581	120,496	149,188	178,997	209,761
PC	All	6,318,991	6,298,846	6,427,249	6,512,434	6,566,146	6,595,482	6,668,409	6,777,644	6,903,720
LT	All	3,700,120	3,616,747	3,618,477	3,594,515	3,552,665	3,486,383	3,443,202	3,417,858	3,399,482
Light-duty	All	10,019,111	9,915,593	10,045,726	10,106,949	10,118,811	10,081,865	10,111,611	10,195,502	10,303,202
Class 2b	G	413,426	411,174	412,765	410,660	409,218	405,730	407,101	411,430	415,032
Class 2b	D	28,228	27,710	27,572	27,320	27,253	27,018	26,979	27,101	27,219
Class 3	G	9,142	9,092	9,127	9,081	9,049	8,972	9,002	9,098	9,177
Class 3	D	97,119	95,336	94,863	93,995	93,764	92,955	92,821	93,243	93,649
Class 2b	G	441,654	438,884	440,337	437,980	436,470	432,747	434,080	438,532	442,252
Class 3	D	106,261	104,428	103,990	103,076	102,812	101,926	101,823	102,341	102,826
>14K HD	G	53,101	52,557	53,216	53,508	53,558	53,349	53,505	53,952	54,514
Heavy-duty	All	601,015	595,869	597,544	594,563	592,841	588,023	589,408	594,824	599,592
LD + HD	All	10,620,126	10,511,462	10,643,270	10,701,513	10,711,652	10,669,888	10,701,019	10,790,326	10,902,793

PC=passenger car; LT=light truck; EV=electric vehicle; LD=light-duty; HD=heavy-duty; G=gasoline; D=diesel.

<sup>a</sup> Sales exclude vehicle sales in California and other states that have adopted LEVIII, or roughly 36% of the nationwide total; sales continue beyond 2025 but are not presented here.

Using these projected sales, we can calculate the annual costs of the Tier 3 vehicle program for each vehicle category/engine/fuel combination. We can then add the passenger car and light-duty truck results to get the costs for light-duty and add the Class 2b, 3 and >14,000 pound HD costs to get the costs for heavy-duty. We have done this separately for the exhaust and evaporative standards and then the combined standards. The results are shown in Table 2-45.

In addition to considering the costs associated with improving the emission control systems on vehicles, we also expect that manufacturers will be required to improve their capability to measure particulate matter (PM) at the levels being required. For additional information on the test procedure changes, see Section IV.H of the preamble.

We are using the same PM facility upgrade cost inputs as used in the proposal, except that we have updated those costs to 2011 dollars. To determine the appropriate costs for upgrading test facilities for PM measurement we used two sources of information: The first was the cost that the EPA incurred in upgrading its own PM measurement equipment, and the second was information provided by vehicle manufacturers reflecting estimates for upgrading their internal facilities. The cost estimates ranged from \$250,000 to \$500,000 per PM test site (both in 2010\$). We recognize that the number of sites that a manufacturer will require is dependent on the number of vehicle models it expects to develop and certify in a given model year. As stated in Section IV.A, we have limited the number of certifications required per model year to 25 percent of the represented durability groups, thereby potentially reducing the number of test sites that require upgrade. In addition, costs will vary by manufacturer depending on the state of their current test facilities.

Our estimated costs for each manufacturer are show in Table 2-44. With a certification responsibility of 25 percent of its given model year durability groups we believe that manufacturers with annual sales of 1 million units or less will require 2 facility upgrades at an average cost of \$375,000 (in 2010\$, or \$383,000 in 2011\$). For manufacturers with greater than 1 million units per year annual sales we believe that 4 facility upgrades may be required to meet the Tier 3 requirements.

**Table 2-44: PM Facility Costs Imposed by Tier 3 (2011\$)**

Annual Sales Volume	# of PM Sites to be upgraded	Cost per site	Weigh Room Costs	Facility Cost/Manufacturer	# of Manufacturers	Total Costs
<= 1 million	2	\$383,000		\$766,000	18	\$13,800,000
> 1 million	4			\$1,530,000	5	\$7,66,000
Fleet					23	\$21,400,000

Note that the number of manufacturers in the <= 1 million range has been reduced from 20 in the proposal to 18 in the final rule. This is because Chrysler, Fiat and Maserati are now treated as one manufacturer in the >1 million range rather than two in the <=1 million range (Fiat and Maserati) and one in the >1 million range (Chrysler).

We also anticipate that each manufacturer would hire a new full time employee to cover additional PM measurement-related work. We have estimated this employee to cost each manufacturer \$153,000 (2011\$) per year. With 23 manufacturers, the total cost would be

\$3,520,000 per year every year going forward. In contrast, the PM facility costs shown in Table 2-44 represent one-time costs we expect to be incurred in the year prior to implementation of the standards. These costs are shown in Table 2-45.

**Table 2-45 Undiscounted Annual Costs of the Tier 3 Vehicle Program (Millions of 2011\$)**

	Exhaust			Evaporative			Operating			Facility & staff	Total
	LD	HD	All	LD	HD	All	LD	HD	All		
2016	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$21.4	\$21.4
2017	\$268	\$0	\$268	\$25.5	\$0	\$25.5	\$0	\$0	\$0	\$3.52	\$297
2018	\$519	\$20.2	\$539	\$70.2	\$3.24	\$73.4	-\$1.17	-\$0.047	-\$1.22	\$3.52	\$615
2019	\$555	\$24.2	\$579	\$69.2	\$3.18	\$72.4	-\$2.03	-\$0.094	-\$2.12	\$3.52	\$653
2020	\$571	\$27.8	\$599	\$94.3	\$4.12	\$98.4	-\$3.22	-\$0.160	-\$3.38	\$3.52	\$697
2021	\$598	\$31.5	\$630	\$92.8	\$4.04	\$96.8	-\$4.44	-\$0.226	-\$4.67	\$3.52	\$725
2022	\$605	\$34.8	\$640	\$116	\$4.93	\$121	-\$5.96	-\$0.309	-\$6.27	\$3.52	\$758
2023	\$606	\$33.3	\$639	\$111	\$4.73	\$116	-\$7.45	-\$0.390	-\$7.84	\$3.52	\$751
2024	\$620	\$33.1	\$653	\$109	\$4.70	\$114	-\$8.95	-\$0.472	-\$9.42	\$3.52	\$761
2025	\$635	\$32.8	\$668	\$108	\$4.66	\$113	-\$10.4	-\$0.553	-\$11.0	\$3.52	\$773
2030	\$632	\$31.8	\$664	\$108	\$4.56	\$113	-\$18.0	-\$0.959	-\$19.0	\$3.52	\$761

Note: Costs shown include costs for the Tier 3 standards on vehicles sold outside California and other states that have adopted LEVIII; operating savings use untaxed gasoline prices.

By then sales weighting the exhaust and evaporative results by sales in each of the vehicle category/engine/fuel combinations, we can calculate the annual technology costs for passenger cars, light-duty trucks and heavy-duty trucks. We show these cost per vehicle results for the exhaust standards in Table 2-46, for the evaporative standards in Table 2-47 and for the combined exhaust and evaporative standards in Table 2-48. The costs shown in these three tables include all direct and indirect costs for new vehicle hardware (they exclude operating savings and PM facility costs). They also include the effects of learning, and the expected penetration rates and phase-ins of the Tier 3 standards.

**Table 2-46 Cost per Vehicle for the Tier 3 Exhaust Emission Standards (2011\$)**

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	\$42	\$45	\$47	\$48	\$50	\$52	\$52	\$54	\$55
Light-duty truck	\$0	\$65	\$70	\$72	\$76	\$76	\$75	\$75	\$75
All light-duty	\$27	\$52	\$55	\$56	\$59	\$60	\$60	\$61	\$62
Class 2b	\$0	\$38	\$45	\$52	\$59	\$65	\$63	\$62	\$60
Class 3	\$0	\$32	\$41	\$48	\$56	\$64	\$61	\$60	\$59
>14K HD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
All heavy-duty	\$0	\$34	\$40	\$47	\$53	\$59	\$57	\$56	\$55
All LD and HD	\$25	\$51	\$54	\$56	\$59	\$60	\$60	\$61	\$61

Note: Costs shown include costs for the Tier 3 standards on vehicles sold outside California and other states that have adopted LEVIII.

**Table 2-47 Cost per Vehicle for the Tier 3 Evaporative Emission Standards (2011\$)**

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	\$4	\$7	\$7	\$9	\$9	\$11	\$11	\$11	\$10
Light-duty truck	\$0	\$8	\$8	\$10	\$10	\$12	\$11	\$11	\$11
All light-duty	\$3	\$7	\$7	\$9	\$9	\$12	\$11	\$11	\$11
Class 2b	\$0	\$6	\$6	\$8	\$8	\$9	\$9	\$9	\$9
Class 3	\$0	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1
>14K HD	\$0	\$10	\$10	\$13	\$13	\$16	\$15	\$15	\$15
All heavy-duty	\$0	\$5	\$5	\$7	\$7	\$8	\$8	\$8	\$8
All LD and HD	\$2	\$7	\$7	\$9	\$9	\$11	\$11	\$11	\$10

Note: Costs shown include costs for the Tier 3 standards on vehicles sold outside California and other states that have adopted LEVIII.

**Table 2-48 Cost per Vehicle for the Combined Tier 3 Exhaust and Evaporative Emission Standards (2011\$)**

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	\$46	\$51	\$53	\$57	\$59	\$63	\$63	\$64	\$65
Light-duty truck	\$0	\$73	\$78	\$82	\$86	\$88	\$87	\$87	\$86
All light-duty	\$29	\$59	\$62	\$66	\$68	\$72	\$71	\$72	\$72
Class 2b	\$0	\$44	\$51	\$60	\$66	\$75	\$71	\$70	\$69
Class 3	\$0	\$33	\$41	\$49	\$57	\$65	\$62	\$61	\$60
>14K HD	\$0	\$10	\$10	\$13	\$13	\$16	\$15	\$15	\$15
All heavy-duty	\$0	\$39	\$46	\$54	\$60	\$68	\$65	\$64	\$62
All LD and HD	\$28	\$58	\$61	\$65	\$68	\$71	\$71	\$71	\$72

Note: Costs shown include costs for the Tier 3 standards on vehicles sold outside California and other states that have adopted LEVIII.

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## References

- <sup>1</sup> ICCT Comments in Response to the Tier 3 Proposed Rulemaking, Docket ID No. EPA-HQ-OAR-2011-0135-4304; Posada, Francisco, et. al., “Estimated Cost of Emission Control Technologies for Light-Duty Vehicles Part 1 – Gasoline,” SAE 2013-01-0534, 4/8/2013.
- <sup>2</sup> California Air Resources Board Initial Statement of Reasons, Public Hearing to Consider LEV III , December 7, 2011, Workshop Document (<http://www.arb.ca.gov/regact/2012/leviiiighg2012/leviiiighg2012.htm>), Document ID# EPA-HQ-OAR-2011-0135-0438.
- <sup>3</sup> “The Effects of Fuel Sulfur Level on Emissions from Tier 2 Vehicles in the In-Use Fleet,” EPA-420-D-13-003. Available in docket number EPA-HQ-OAR-2011-0135.
- <sup>4</sup> The 2012-2016 GHG final rule can be found at 75 FR 25374; the 2017-2025 GHG final rule can be found at 77 FR 62624.
- <sup>5</sup> RTI International. Automobile Industry Retail Price Equivalent and Indirect Cost Multipliers. February 2009. <http://www.epa.gov/otaq/ld-hwy/420r09003.pdf> ; Rogozhin, A., et al., “Using indirect cost multipliers to estimate the total cost of adding new technology in the automobile industry,” International Journal of Production Economics (2009), doi:10.1016/j.ijpe.2009.11.031. The peer review for the RTI report is at <http://www.epa.gov/otaq/ld-hwy/420r09004.pdf> .
- <sup>6</sup> “Joint Technical Support Document: Final Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards,” EPA-420-R-12-901, August 2012, Document ID# EPA-HQ-OAR-2011-0135-4948.
- <sup>7</sup> 75 FR 25324, 76 FR 57106, 77 FR 62624, 78 FR 29816.
- <sup>8</sup> Posada, Francisco, et. al., “Estimated Cost of Emission Control Technologies for Light-Duty Vehicles Part 1 – Gasoline,” SAE 2013-01-0534, 4/8/2013.
- <sup>9</sup> “Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements,” EPA420-R-00-026, December 2000; “Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines,” EPA420-R-04-007, May 2004; “Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression Ignition Engines Less than 30 Liters Per Cylinder,” EPA420-R-08-001, March 2008.
- <sup>10</sup> Ball, Douglas and David Moser, “Cold Start Calibration of Current PZEV Vehicles and the Impact of LEV-III Emission Regulations,” SAE 2012-01-1245, 4/16/2012.
- <sup>11</sup> See ICCT, Docket ID No. EPA-HQ-OAR-2011-0135-4304, at page 4 of 21; see MECA, Docket ID No. EPA-HQ-OAR-2011-0135-4675, at page 3 of 7; see CARB, Docket ID No. EPA-HQ-OAR-2011-0135-4621, at page 23.
- <sup>12</sup> See ICCT, Docket ID No. EPA-HQ-OAR-2011-0135-4304, at page 11 of 21; see MECA, Docket ID No. EPA-HQ-OAR-2011-0135-4675, at page 3 of 7.
- <sup>13</sup> OMEGA is the Optimization Model for reducing Emissions of Greenhouse gases from Automobiles. Information about OMEGA can be found at <http://www.epa.gov/otaq/climate/models.htm>.

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<sup>14</sup> See Chapter 1 of “Regulatory Impact Analysis: Final Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards,” EPA-420-R-12-016, August 2012.

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## Chapter 3 Establishing New Emission Test Fuel Parameters

In-use gasoline has changed considerably since EPA's emission test gasoline specifications were first set and last revised. Sulfur and benzene content have been reduced and, perhaps most visibly to consumers, gasoline containing 10 percent ethanol by volume (E10) has replaced non-oxygenated gasoline (E0) across the country. The relationship between emissions certification test fuel and in-use fuel is important in recognition of the fact that fuel properties can affect emission levels. Therefore, in revising specifications for emission test gasoline, it is important to have a thorough assessment of fuel available to the public.

We primarily used two sources of fuel property information to determine appropriate specifications for emissions test fuel. One was the Reformulated Gasoline and Anti-Dumping Batch Report data submitted to EPA (referred to in this section as batch data). Producers and importers of gasoline and related blendstocks must submit data to EPA for each batch of gasoline produced or imported. These data include batch volume as well as physical and chemical properties that can be used to determine whether the fuel is compliant with applicable standards and regulations. These reports are considered Confidential Business Information and thus only aggregated data is presented here.

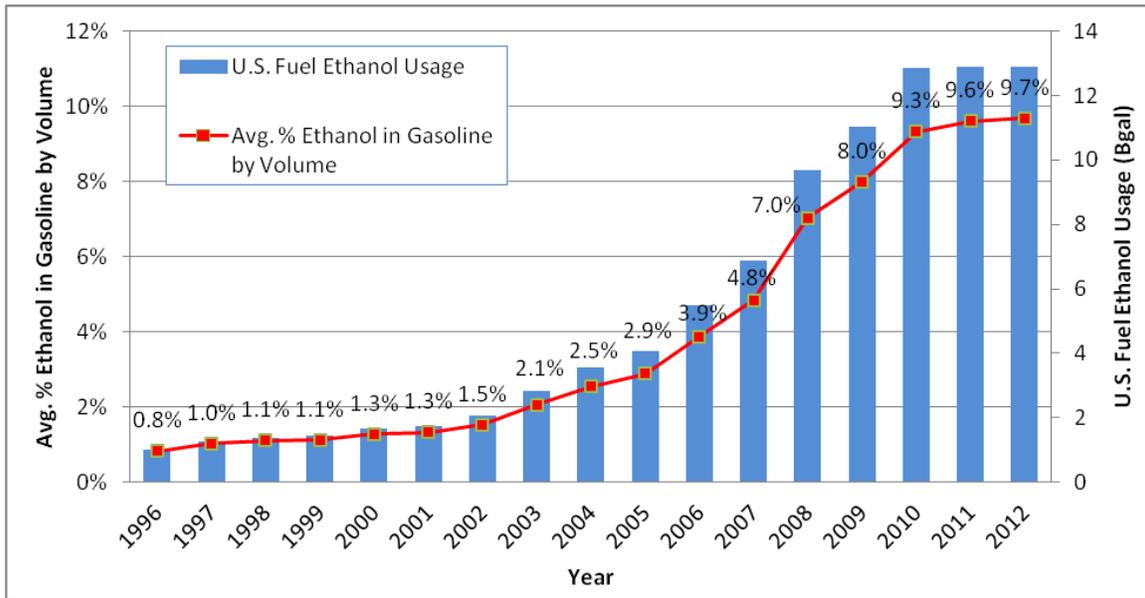
The second data source was the Alliance of Automobile Manufacturers (AAM) North American Fuel Survey. Each summer and winter, the AAM collects over 300 gasoline samples from retail stations in 29 major metropolitan areas in 23 states plus the District of Columbia. Areas currently sampled include: Albuquerque, NM; Atlanta, GA; Billings, MT; Boston, MA; Chicago, IL; Cleveland, OH; Dallas, Houston, and San Antonio, TX; Denver, CO; Detroit, MI; Fairbanks, AK; Kansas City and St. Louis, MO; Las Vegas, NV; Los Angeles and San Francisco, CA; Memphis, TN; Miami, FL; Minneapolis/St. Paul, MN; New Orleans, LA; New York, NY; Philadelphia and Pittsburgh, PA; Phoenix, AZ; Salt Lake City, UT; Seattle, WA; Washington, D.C.; and Watertown, SD. Although the AAM North American Fuel Survey does not represent all U.S. gasoline, it is designed to have good coverage of the U.S. market.

Note that this assessment focuses on fuel properties for summertime, regular grade, E10 gasoline since this is most relevant to the certification testing conditions and fuel specifications.

### 3.1 Assessment of Current Gasoline Properties

#### 3.1.1 Ethanol Content

According to the Energy Information Administration (EIA), ethanol is now blended into almost every gallon of U.S. gasoline, bringing the average gasoline ethanol content to 9.7 percent denatured ethanol by volume (vol%) as shown in Figure 3-1. Denaturant, generally a hydrocarbon blendstock such as natural gas liquids or low-octane gasoline components, is added at a rate of approximately 2 volume percent by the ethanol producer before shipping it to fuel terminals. (This is required to differentiate the product from beverage alcohol.)

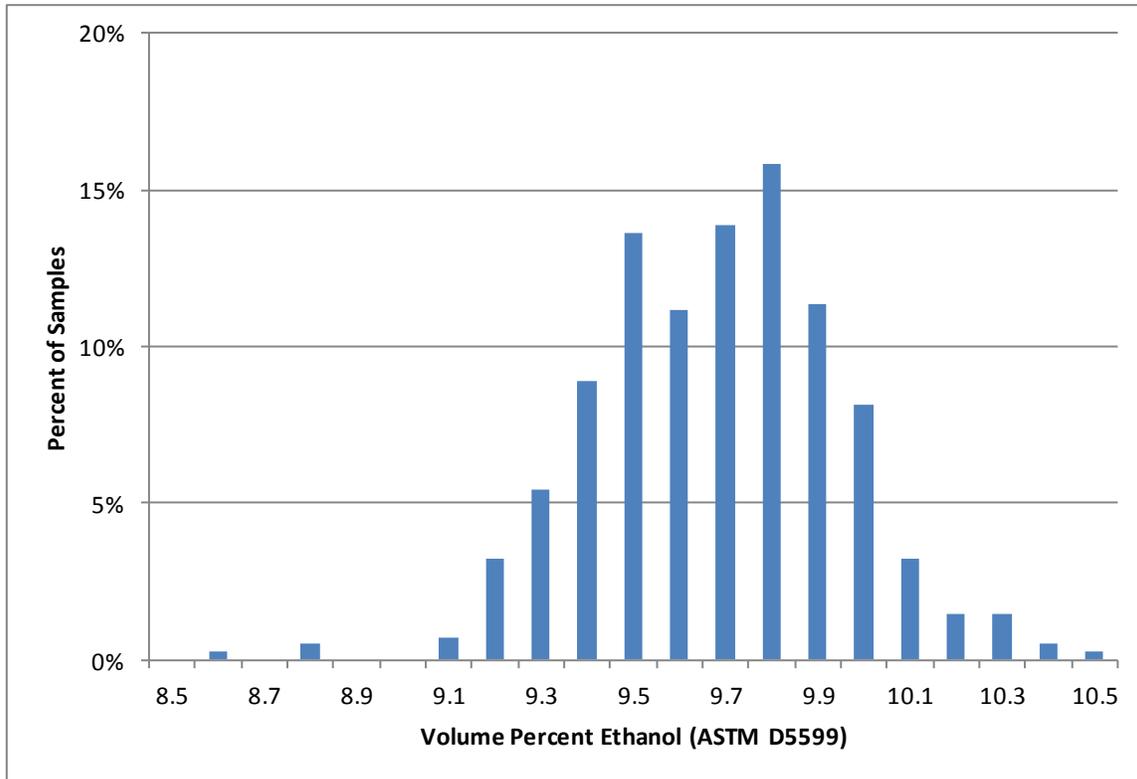


**Figure 3-1. Denatured Ethanol Content in U.S. Gasoline Over Time<sup>1</sup>**

The plot shows a rapid increase in ethanol content starting around 2002 and leveling out after 2010 as it approaches 10 percent volume (this average figure also includes a small amount of E85 use in Flex Fuel vehicles). While EPA has approved use of E15 in gasoline vehicles of model year 2001 and later, its use has not yet become widespread.<sup>A</sup>

Figure 3-2 shows the distribution of ethanol levels across 404 regular grade summer E10 gasoline samples collected by AAM in 2010 and 2011. These data suggest the range of ethanol blending in E10 is relatively narrow, with most samples falling between 9.3 and 10.0 volume percent (excluding denaturant). Higher and lower values in the data are likely due to test method uncertainty. Based on this information, an emission test fuel target of 9.8 volume percent ethanol (excluding denaturant) is appropriate.

<sup>A</sup> The E15 approval decision was published in 76 FR 4662 (January 26, 2011).

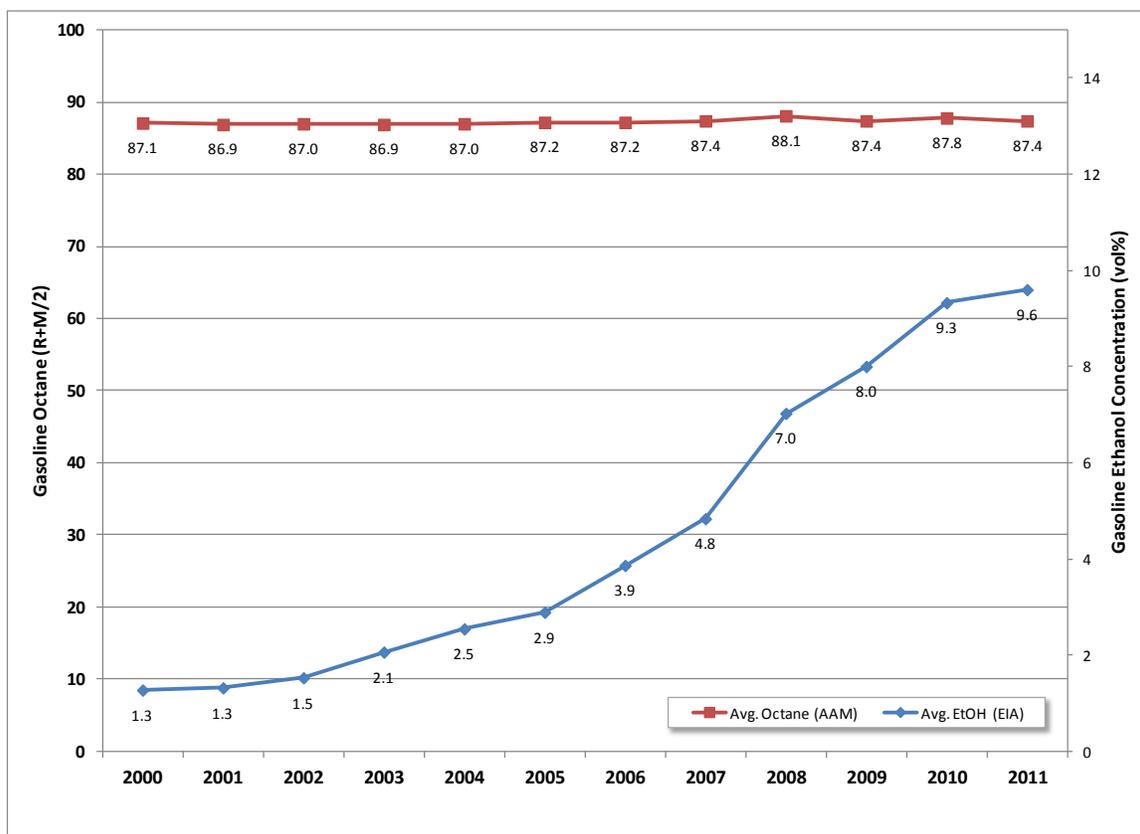


**Figure 3-2. Range of Ethanol in E10 Gasoline in 2010-11 AAM Summer Surveys**

### 3.1.2 Octane

U.S. gasoline must meet a minimum octane rating (also known as (R+M)/2 or anti-knock index, AKI) of 87 for regular grade in most parts of the country. Denatured fuel ethanol has a typical octane rating of 115 AKI, making it a high-octane blendstock. However, finished gasoline has not experienced an increase in octane due to increased ethanol blending. Given this situation, along with data presented in the next subsection, it is evident that many refiners have backed off on octane production at the refinery by reducing levels of aromatics and olefins. Producing these high-octane components at the refinery represents a significant cost to refiners, so they are able to reduce costs by taking advantage of ethanol’s octane value. We estimate that many refiners are currently producing 84-85 AKI blendstocks for 87 octane regular-grade gasoline and 88-89 AKI blendstocks for 91 octane premium-grade gasoline, such that the final E10 blends meet minimum octane requirements.

According to AAM summer fuel surveys, the average octane of finished regular grade gasoline has remained constant between 87-88 AKI over the past decade (refer to Figure 3-3) despite the increasing blend level of ethanol. According to EIA’s Petroleum Marketing Annual, regular grade gasoline represents over 85 percent of U.S. sales.<sup>2</sup> Accordingly, we believe the updated 87-88.4 (R+M)/2 test fuel specification is representative of regular grade in-use gasoline.



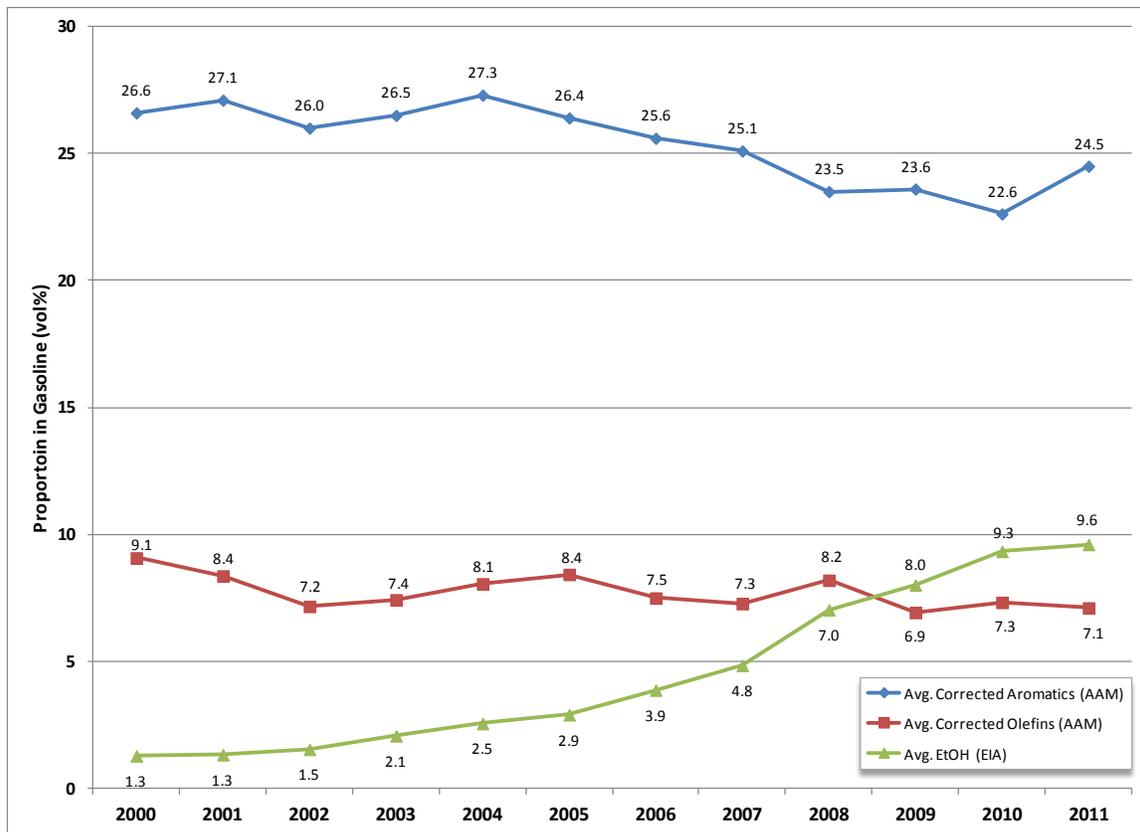
**Figure 3-3. Average Summer Regular Grade Octane and Ethanol Levels Over Time**

### 3.1.3 Total Aromatics and Total Olefins

The term olefin describes a hydrocarbon compound containing at least one unsaturated or double bond. Aromatics are a specific class of olefins that contain the benzene ring. When crude oil is distilled into various fractions according to boiling range, the fraction going into the gasoline pool, called straight run naphtha, contains primarily saturated hydrocarbons. Both olefins and aromatics have higher AKI values relative to saturates, and therefore increasing their proportions in the finished gasoline is an important method refiners use to meet required AKI targets.

Ethanol also has a high AKI value, and as it has become more ubiquitous as a blendstock, refiners are relying on it to an increasing extent to meet octane targets. The average aromatics, olefin, and ethanol levels by year for all summer gasoline are shown in Figure 3-4. Here we can see a general trend of aromatic and olefin levels declining as fuel ethanol content increased. Using 2010-11 AAM survey data, the average aromatics content of conventional regular grade E10 gasoline (172 samples) was 24.3 vol% and the average olefins content was 7.3 vol%. When interpreting these aromatics results as a basis for updating test fuel specifications, we considered

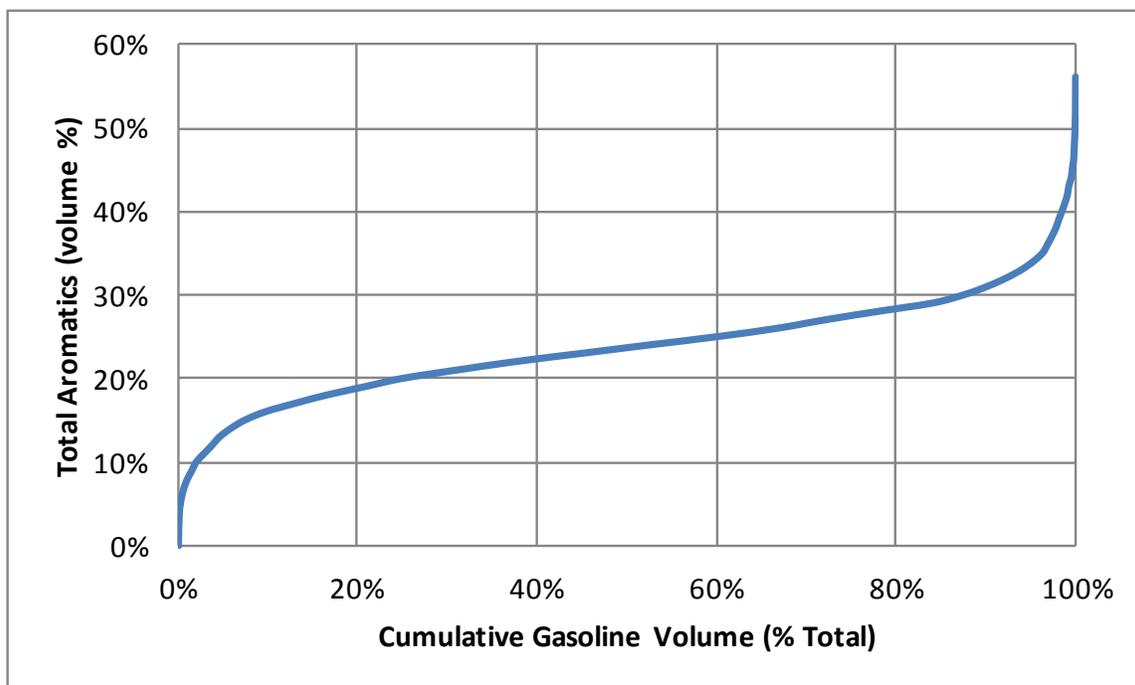
the fact that ASTM D1319 (used for the AAM surveys) gives a numerical value between 1-2 vol% higher than ASTM D5769 (specified for test fuel analysis) for the same fuel sample.<sup>B</sup>



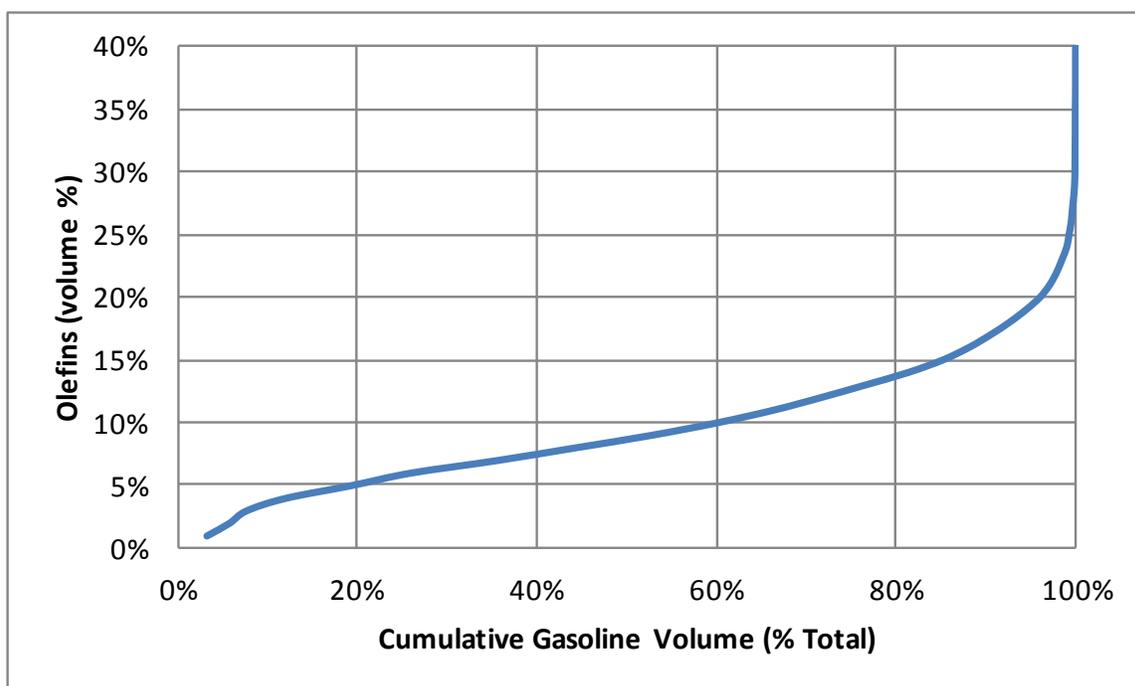
**Figure 3-4. Average Summer Gasoline Aromatics, Olefin and Ethanol Levels Over Time**

Although total aromatics and olefins have been reduced over the past decade, there continues to be variation on a batch-by-batch and geographic basis. Our refinery batch data for summer 2011 shows a range of gasoline aromatics levels from approximately 5 to 50 vol% with an average concentration of 24 vol% (Figure 3-5), and a range of olefin levels from 0 to 25 vol% with an average concentration of 11 vol% (Figure 3-6). The 2011 batch data shown in Figures 3-5 and 3-6 only reflects the effect of ethanol in reformulated gasoline that is match blended to account for it. It does not account for ethanol that may be blended into conventional gasoline after it leaves the refinery since existing gasoline regulations do not readily allow refiners to take advantage of ethanol properties in most compliance calculations. As a result, AAM and other gasoline surveys may show lower aromatics and olefins than what is suggested by the batch data.

<sup>B</sup> Information based on analysis of several recent ASTM cross-check datasets.



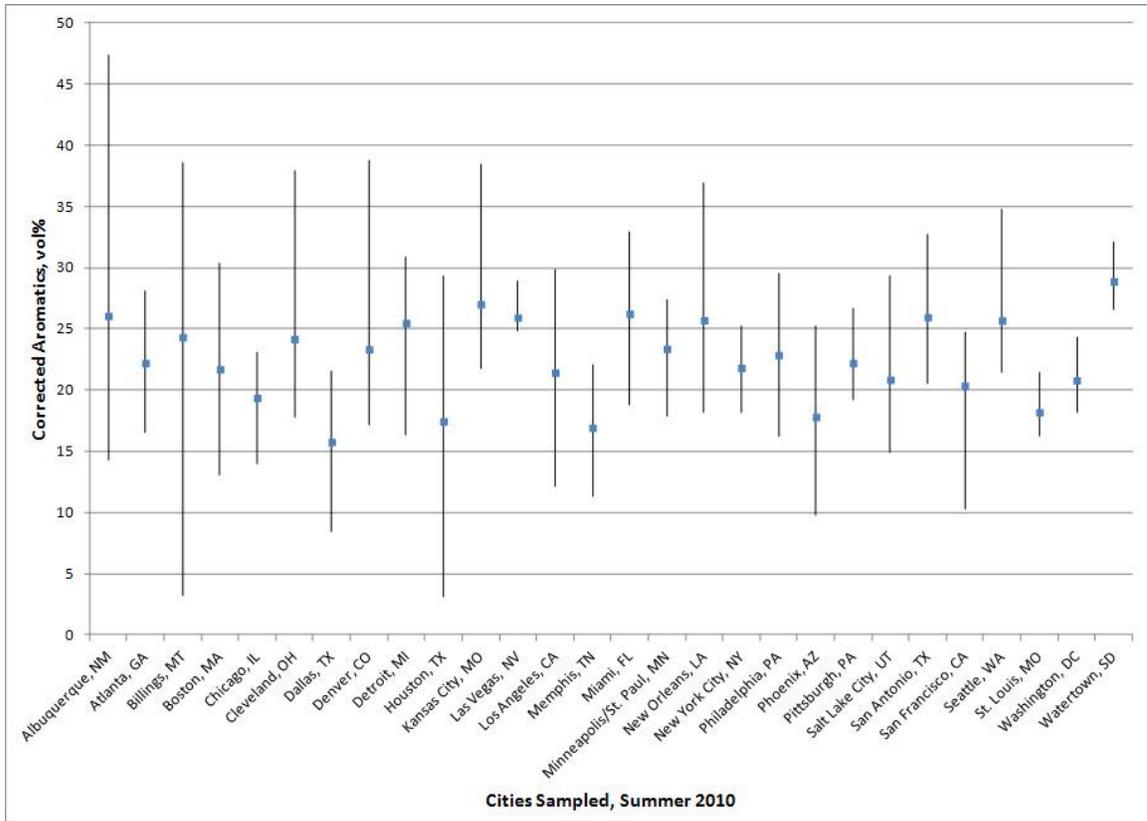
**Figure 3-5. Gasoline Aromatics Distribution Based on Summer 2011 Refinery Batch Data**



**Figure 3-6. Gasoline Olefins Distribution Based on Summer 2011 Refinery Batch Data**

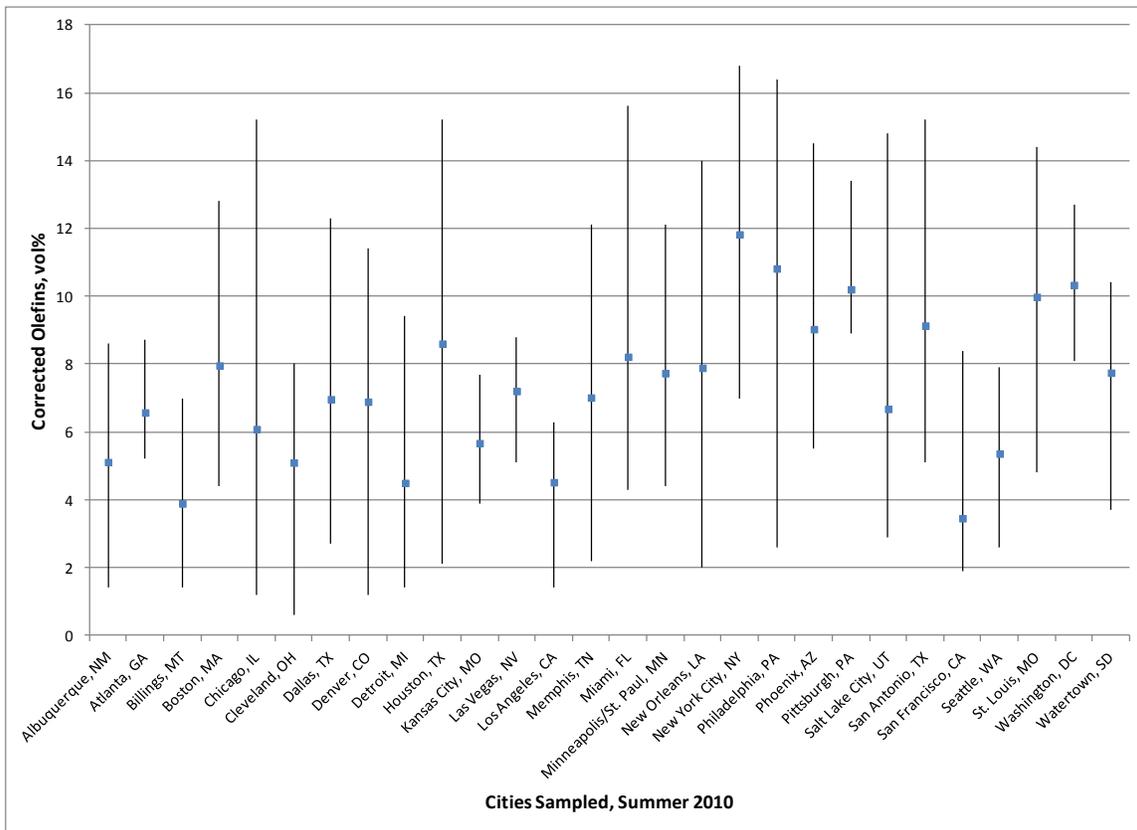
In the summer of 2010, according to the AAM North American Fuel Survey, measured in-use aromatics levels ranged from 3 to 47 vol% (Figure 3-7) while olefin levels ranged from

0.6 to 17 vol% (Figure 3-8). California tends to have lower, tighter in-use levels of aromatics and olefins as a result of their more stringent fuel regulations. As shown below, gasoline samples taken from Los Angeles and San Francisco had aromatics levels ranging from 10 to 30 vol% and olefin levels ranging from 1 to 8 vol%. Nevertheless, our updated emission test fuel specifications for aromatics and olefins still overlap with those established by the California Air Resources Board (CARB) for LEV III test fuel.<sup>C</sup>



**Figure 3-7. Range of Total Aromatics by AAM City Surveyed, Summer 2010**

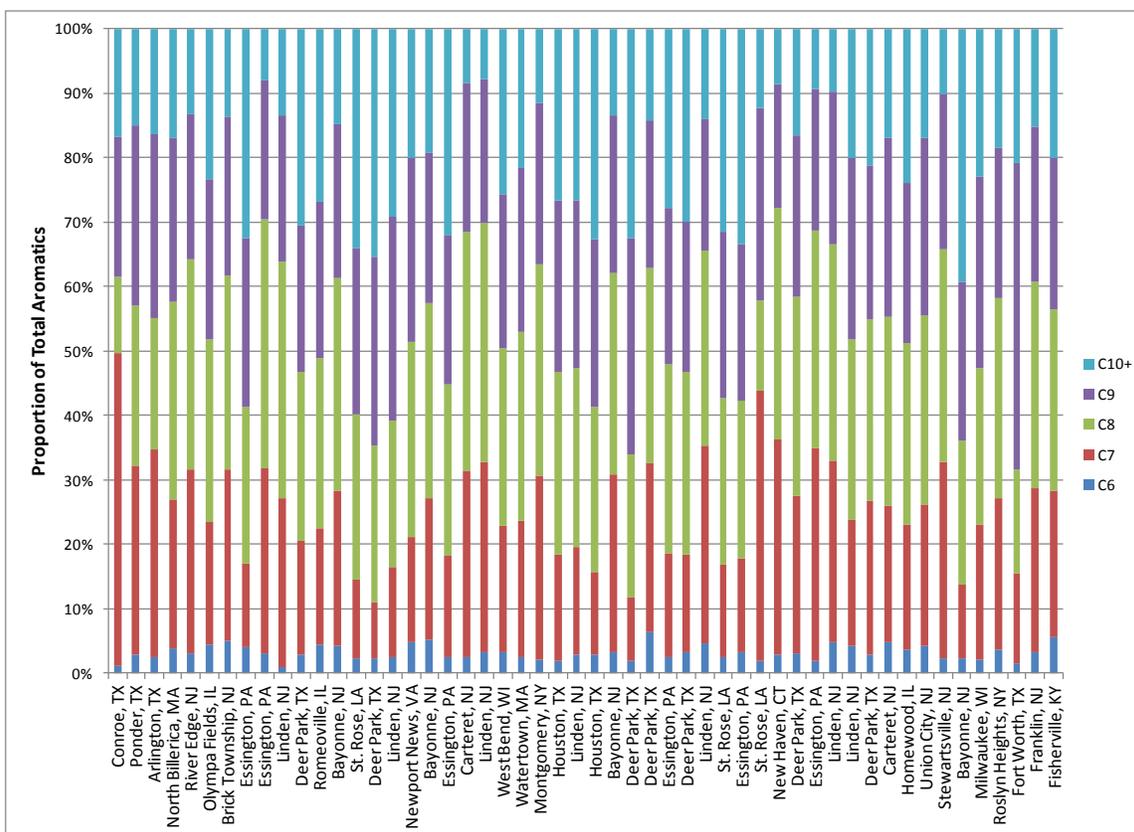
<sup>C</sup> California LEV III emission test procedures, including fuel specifications, are available at 13 CCR 1961.2.



**Figure 3-8. Range of Olefins by AAM City Surveyed, Summer 2010**

### 3.1.4 Aromatics Species

Gasoline speciation data performed by EPA and others shows a wide range of aromatic molecule configurations from benzene (C6, meaning it contains six carbon atoms), and toluene (C7), to larger more complicated C10+ aromatics. Between 2007 and 2011, EPA performed aromatic speciation analyses on 52 fuel samples from various locations throughout the country. Approximately 60 percent were RFG oversight samples (supplied by refiners as part of the RFG program) and the remainder were audit samples collected mostly from retail outlets as part of the City Surveys provision in the RFG program. Total aromatics ranged from 6 to 39 percent of gasoline by volume, but the relative proportions of molecular species by carbon number were relatively consistent across the samples (Figure 3-9).



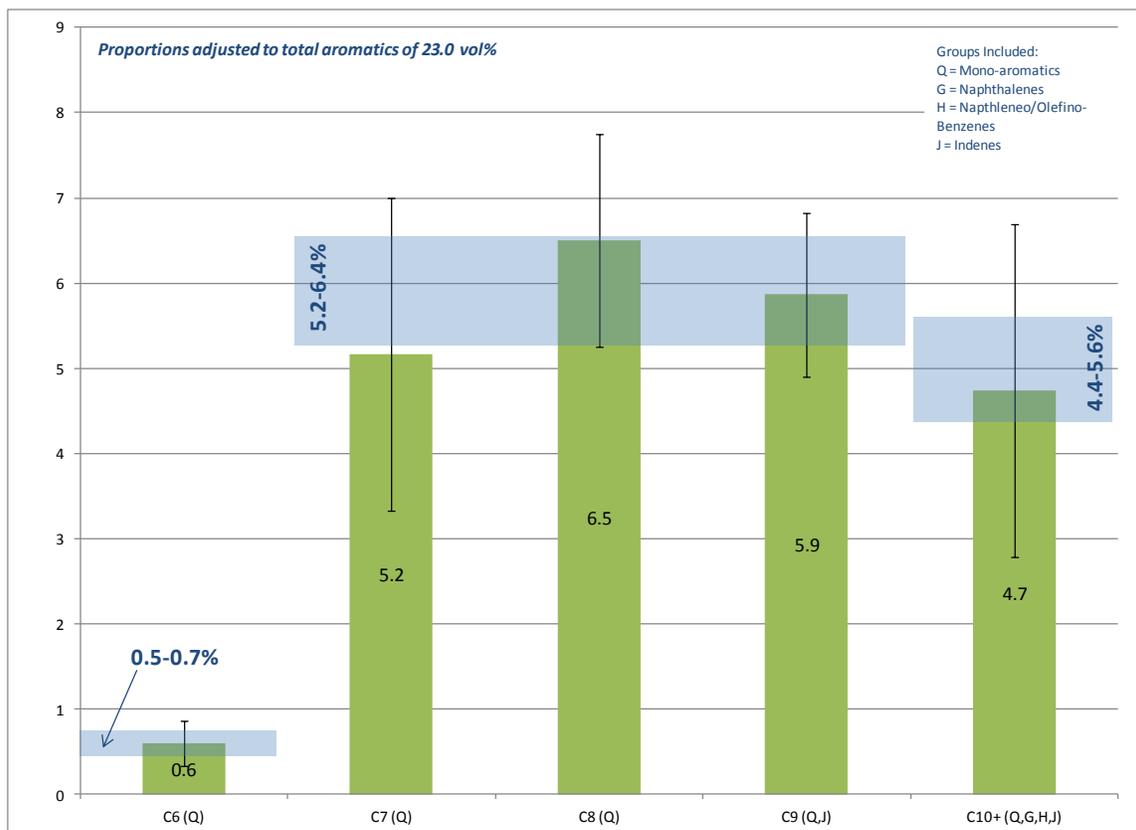
**Figure 3-9. Proportions of Aromatic Species by Carbon Number and Sample Location, Based on EPA Samples Taken Over 2007-2011**

The relative proportion of aromatics of varying molecular size is of interest in light of a growing number of studies showing the influence of higher-boiling aromatic compounds on particulate matter (PM) emissions from gasoline vehicles. A study published by the Japan Petroleum Energy Center (JPEC) found that PM mass emissions from a light-duty gasoline vehicle increased with increasing carbon number of aromatics in the gasoline.<sup>3</sup> Honda has published a “PM Index” that correlates PM emissions to the double bond equivalent (DBE) and vapor pressure (V.P) of the fuel components.<sup>4</sup> The PM index is a function of all the gasoline components (i) and their respective weight percent ( $Wt_i$ ) as shown in Equation 1. DBE is an indication of the number of double bonds and rings present in the molecule. For example, benzene ( $C_6H_6$ ) would have a DBE of four (three double bonds plus one ring) while naphthalene ( $C_{10}H_8$ ), would have a DBE of seven (five double bonds plus two rings). According to this model, gasoline containing a large fraction of low-volatility compounds with high DBE values is expected to produce greater PM emissions.

**Equation 1. Particulate Matter Index Calculation**

$$PM\ Index = \sum_{i=1}^n \left[ \frac{DBE_i + 1}{V.P(443K)_i} \times Wt_i \right]$$

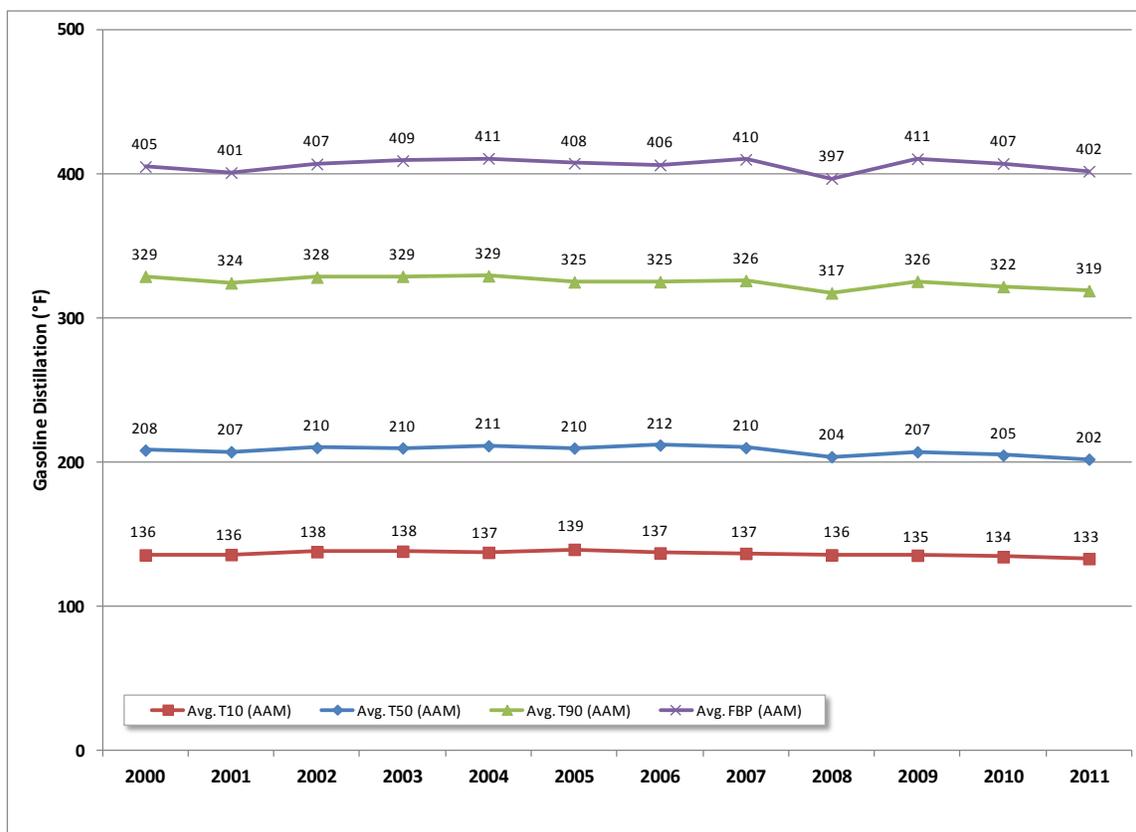
Since aromatics do not appear to be created equally in terms of the potential impact on vehicle PM emissions, we believe it is prudent that both the amount and distribution of aromatics in the updated emissions test fuel is representative of in-use fuel. Figure 3-10 shows averages and ranges of EPA aromatics speciation data with test fuel specification ranges shown in blue.



**Figure 3-10. Mean and Standard Deviation of Aromatics Speciation Data with Test Fuel Specification Ranges Shown in Blue**

### 3.1.5 Distillation Temperatures

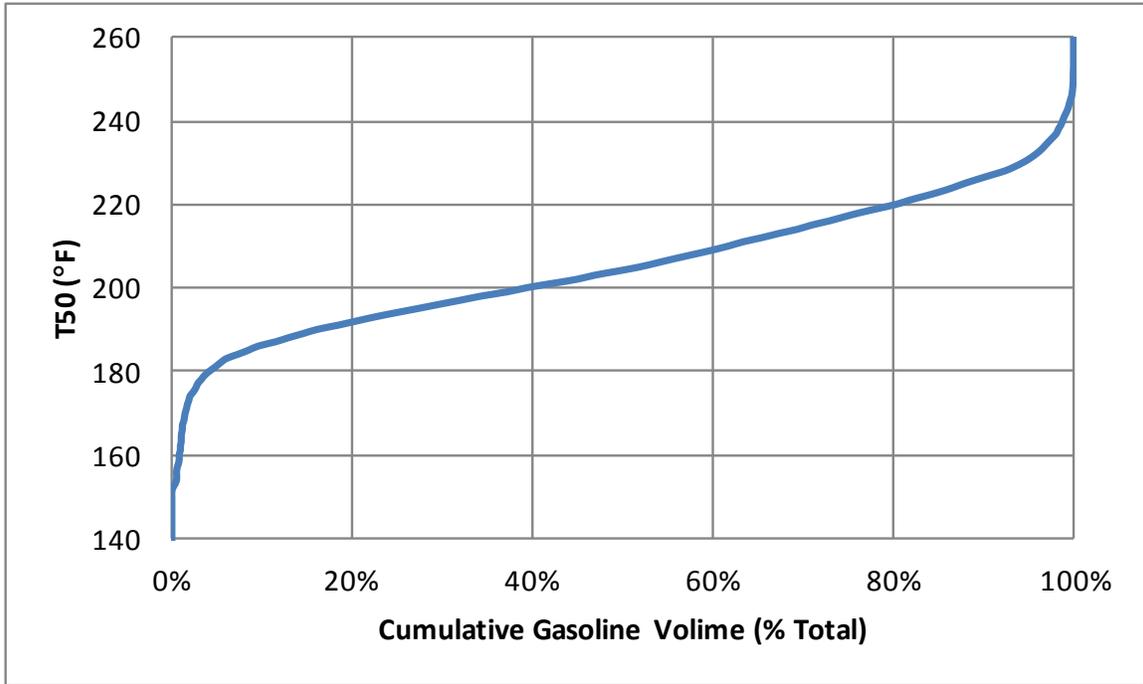
As shown below in Figure 3-11, AAM survey data suggests there has not been a large change in gasoline volatility curves for summer gasoline over the past decade as ethanol blending has increased. The T50 and T90 temperatures are treated in more detail in subsections below.



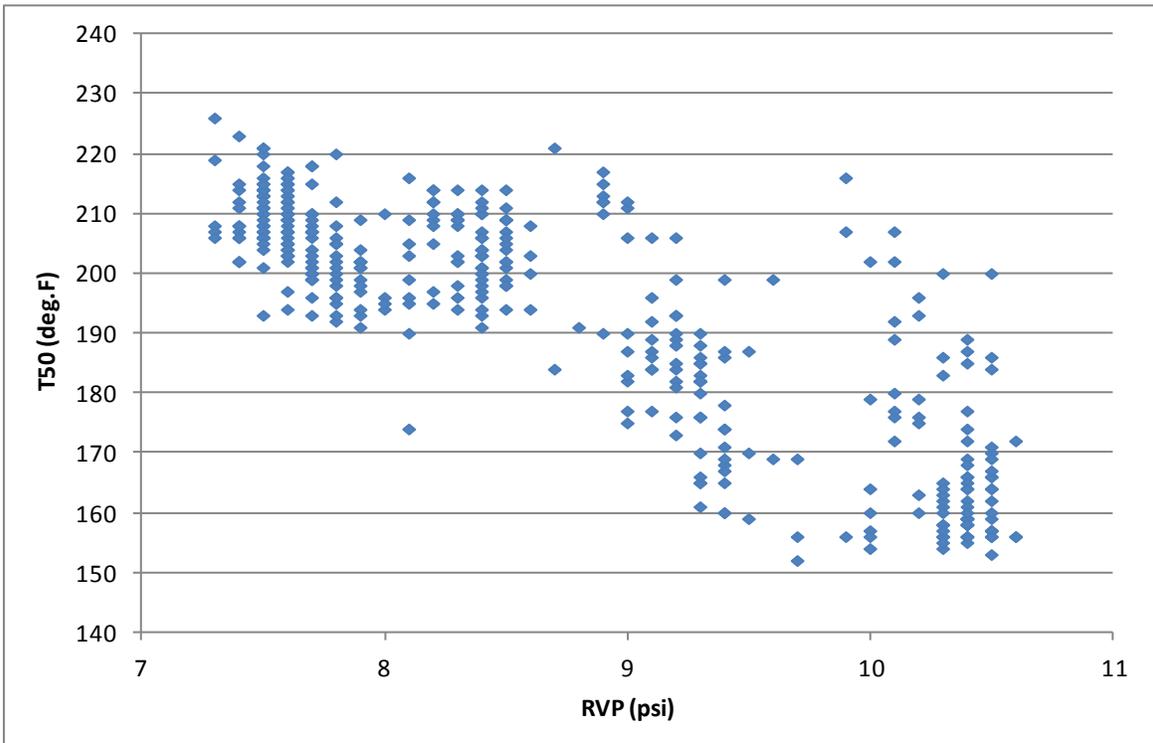
**Figure 3-11. Summer Gasoline Distillation Temperatures Over Time From AAM Surveys**

### 3.1.5.1 T50 analysis

Splash-blending 10 percent ethanol in an E0 base typically lowers T50 by several degrees relative to the base gasoline. Given that much of the refinery batch data for conventional gasoline in 2011 did not capture the property changes resulting from ethanol blending, we would expect the curve in Figure 3-12 to be shifted downward, putting it in closer agreement with the AAM survey data average of around 202°F as shown in Figure 3-11. The AAM survey data in Figure 3-13 shows that T50 varies widely in in-use fuel, from around 150°F to 220°F. Plotting T50 by RVP reveals that T50 values span a higher and narrower range in reformulated and volatility-control-area fuels (on the left, below about 8.5 psi) compared to conventional gasoline (above about 9 psi). Adopting a wide specification for test fuel to cover this whole range may have undesirable effects on consistency of vehicle test results between facilities and over time. Therefore, we have chosen a range of 190-210°F to represent both fuel types and maintain some overlap with CARB’s specification of 205-215°F.



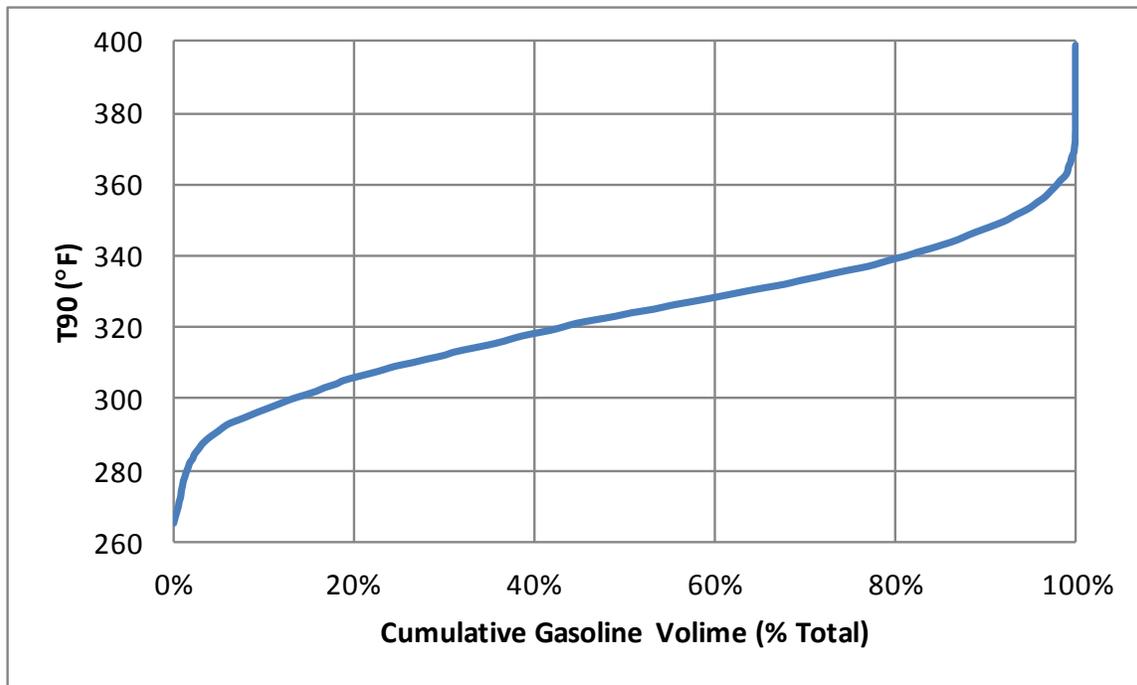
**Figure 3-12. Gasoline T50 Range Based on Summer 2011 Refinery Batch Data**



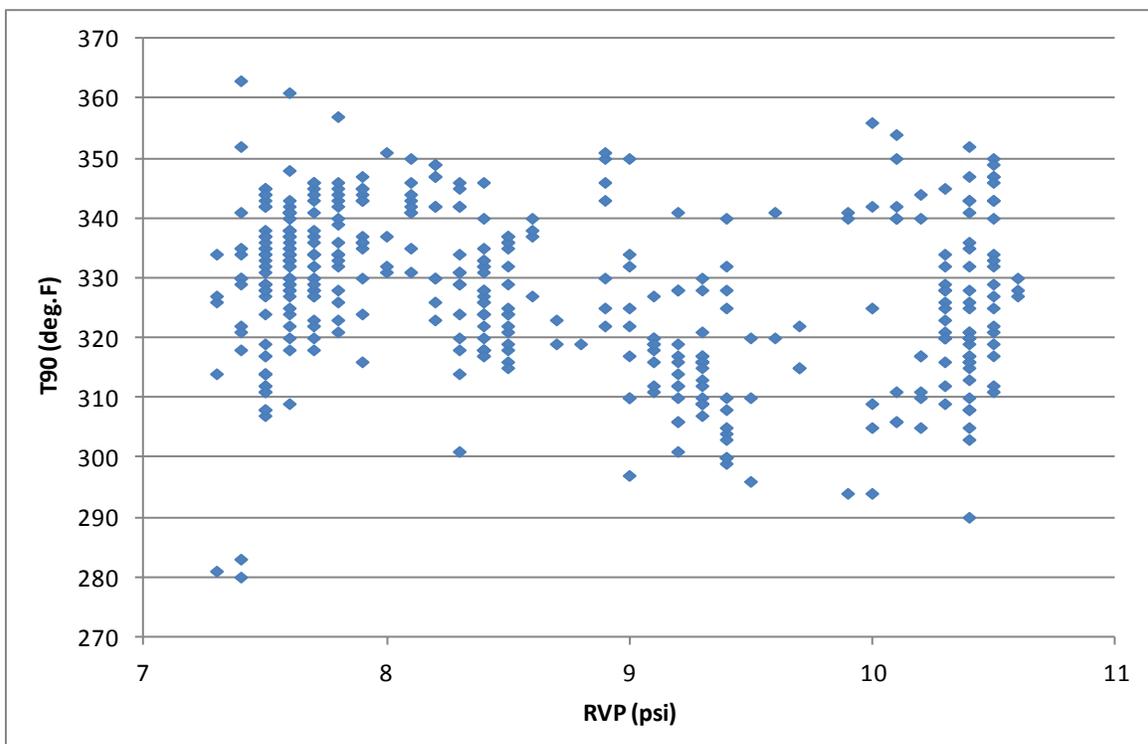
**Figure 3-13. T50 Range in 2010-11 Summer Gasoline as Reported in AAM Surveys**

### 3.1.5.2 T90 Analysis

To develop an understanding of the variation of T90 over the pool of gasoline produced or imported during the 2011 averaging period, we plotted T90 versus cumulative gasoline volume. Approximately 90% of the T90 data is linearly distributed along the center portion of the plot. The remaining 10% of the T90 data is comprised of outliers, with the lower and upper end of the temperature spectrum tailing off slightly. The volume-weighted average T90 was 325°F (see Figure 3-14). T90 is relatively insensitive to ethanol blending at the 10 percent level, and therefore we see good agreement between the batch and AAM datasets on average value. Figure 3-15 shows AAM T90 data plotted by RVP, where there appears to be much less influence difference between reformulated and conventional fuel pools. Based on this information, we set the test fuel specification range at 315-335°F.



**Figure 3-14. Gasoline T90 Range Based on Summer 2011 Refinery Batch Data**



**Figure 3-15. T90 Range in 2010-11 Summer Gasoline as Reported in AAM Surveys**

### 3.1.6 Sulfur and Benzene

Gasoline sulfur levels have declined significantly over the past decade under the Tier 2 gasoline program.<sup>D</sup> The phase-in period of those standards began in 2004 and continued until 2011, when all geographic and small refiner relief provisions ended. According to AAM summer fuel surveys, average gasoline sulfur has gone from over 150 ppm in 2000 to less than 30 ppm (the Tier 2 average standard) in 2012 (refer to Figure 3-16). Refinery batch reports for 2011 (refer to Figure 3-17) depict a volume-weighted average gasoline sulfur just below 30 ppm. Again, given that refinery certification data does not include all ethanol blended into conventional gasoline, the average sulfur content in-use is expected to be slightly lower, which is consistent with the AAM data.

After the phase-in of the Tier 3 sulfur limits, gasoline sulfur levels are required to fall to 10 ppm. Sulfur naturally occurs in crude oil and most refineries must spend money to install and operate units that remove it from gasoline. This sulfur byproduct of refining has little market value itself, so significant overcompliance with this standard is not expected. Accordingly, the updated test fuel sulfur specification is being set to a range of 8-11 ppm.

<sup>D</sup> The Tier 2 final rulemaking was published in 65 FR 6698 (February 10, 2000).

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Gasoline benzene levels have also fallen in recent years primarily due to the MSAT2 program, which enacted an annual average standard of 0.62 volume percent benzene across all gasoline effective January, 1, 2011.<sup>E</sup> According to AAM summer fuel surveys, average gasoline benzene content has declined from almost 1 vol% in 2006 to less than 0.7 vol% in 2011 (refer to Figure 3-16). This is in general agreement with refinery batch reports where volume-weighted average benzene was less than 0.6 vol% in summer 2011 (refer to Figure 3-18). Again, given that refinery certification data does not include all ethanol blended into conventional gasoline, it is reasonable that the average benzene content shown in the AAM data is a bit lower than suggested by the batch reports.

Some benzene naturally occurs in crude oil, but the majority that ends up in finished gasoline is produced during refinery operations intended to increase the total aromatics content to meet octane requirements. Therefore most refineries must spend money to install and operate units that remove benzene from certain blendstock streams before the finished gasoline is made. In some areas of the country (such as the Gulf Coast), benzene has significant value as a chemical feedstock and may be extracted from gasoline at a rate that is greater than would otherwise be required to meet fuel regulations. In most areas of the country, however, meeting the gasoline benzene limits is the sole driver of any reduction process, and therefore due to the averaging, banking, and trading provisions in the regulations we don't expect significant overcompliance on a nationwide basis. Therefore we believe an emissions test fuel benzene specification of 0.5-0.7 vol% is representative of in-use gasoline now and going forward. These benzene and sulfur specifications are consistent with CARB's LEV III specifications.

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<sup>E</sup> The MSAT 2 final rulemaking was published in 72 FR 8428 (February 26, 2007).

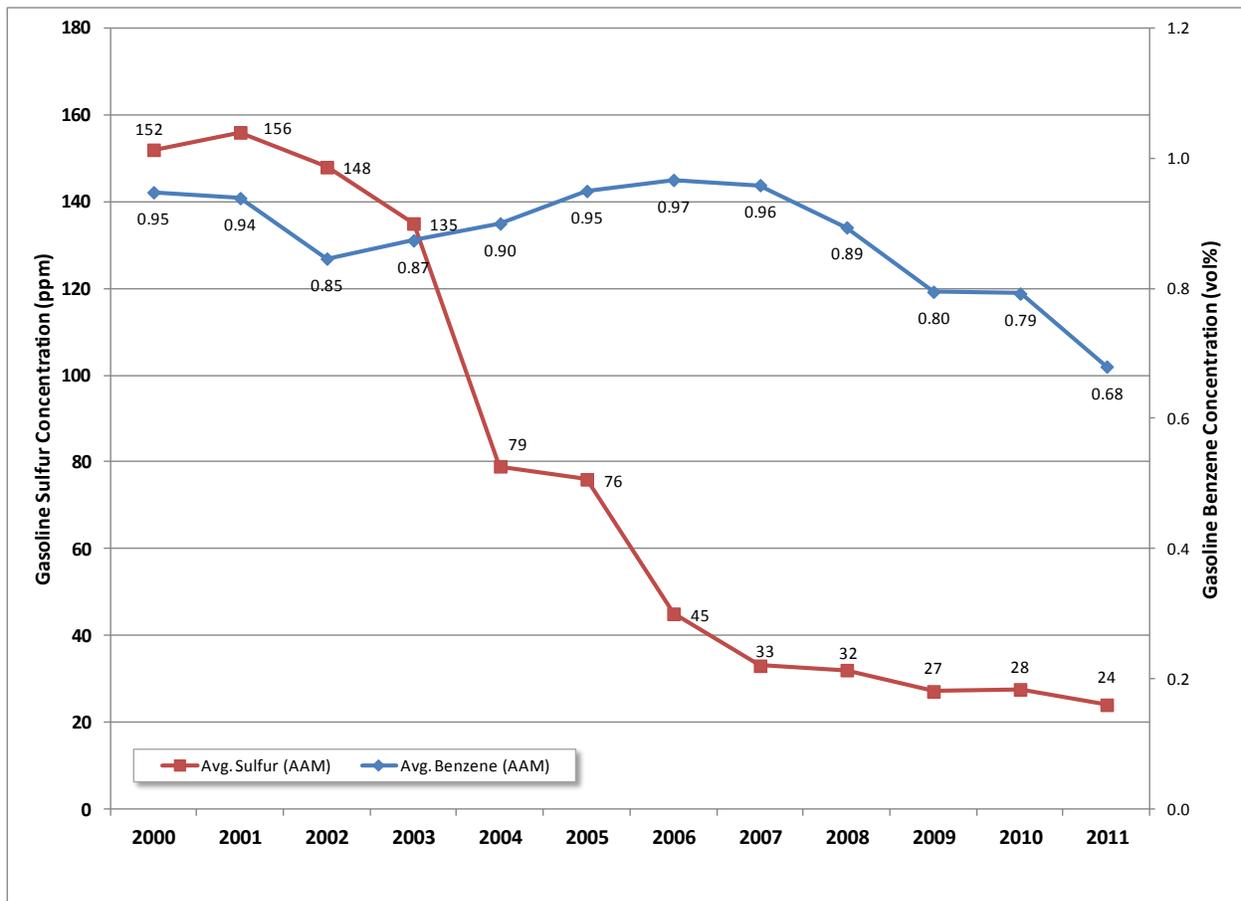
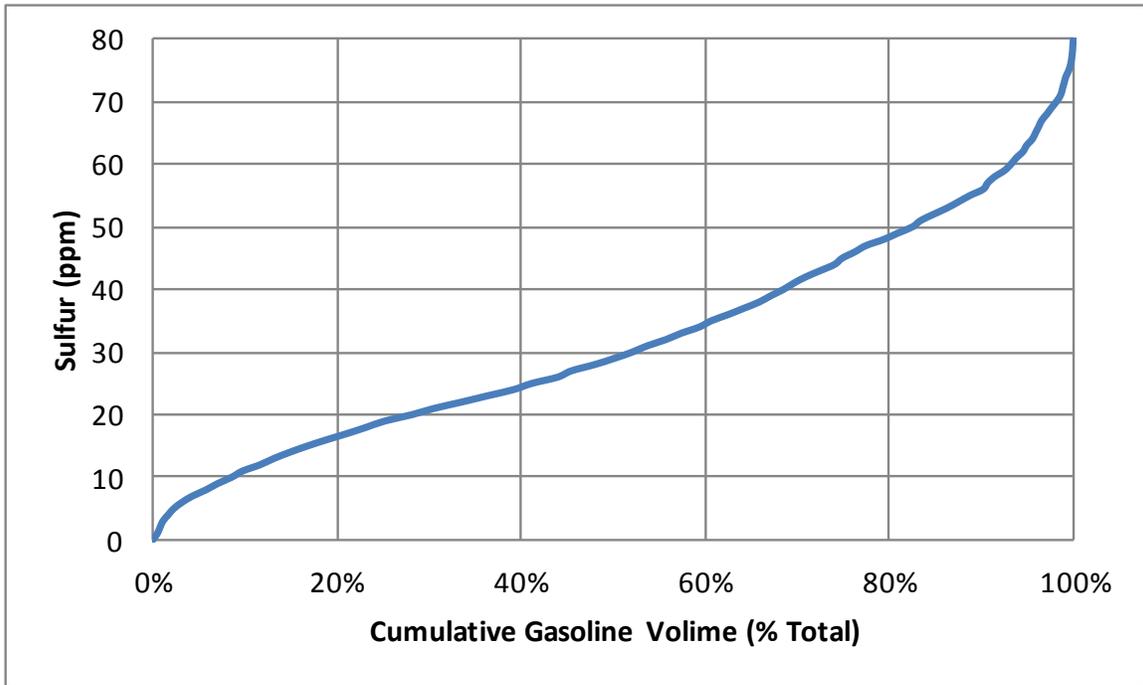
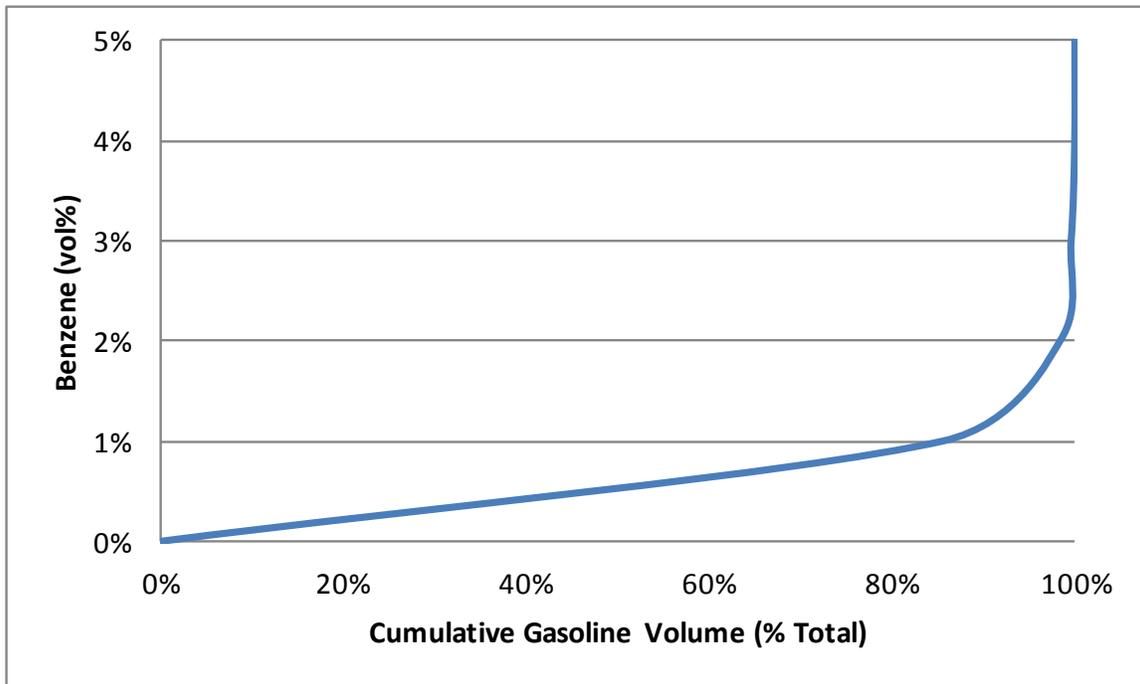


Figure 3-16. Average Summer Sulfur and Benzene Levels Over Time from AAM Surveys



**Figure 3-17. Gasoline Sulfur Based on Summer 2011 Refinery Batch Data**



**Figure 3-18. Gasoline Benzene Based on 2011 Refinery Batch Data**

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## **3.2 Gasoline Emission Test Fuel Specifications**

As explained in Section IV.F of the preamble, we are updating federal emission test fuel specifications to better match in-use fuel. The revised test fuel specifications apply for exhaust emissions testing, fuel economy/greenhouse gas testing, and emissions testing for non-exhaust emissions (evaporative, refueling, and leak detection testing). The revised gasoline specifications, found at §1065.710 and shown here in Table 3-1, apply to emissions testing of light-duty cars and trucks as well as heavy-duty gasoline vehicles certified on the chassis test, those subject to the Tier 3 standards. For information on how we arrived at the revised ASTM test procedures, refer to Section 3.3. Commercial gasoline or “street fuel” would continue to be used for service accumulation (durability fuel). This is consistent with CARB’s LEV III approach and should help limit the total number of test fuels that automakers need to manage.

**Table 3-1. Gasoline Emission Test Fuel Specifications**

Property	Unit	SPECIFICATION			Reference Procedure <sup>1</sup>
		General Testing	Low-Temperature Testing	High Altitude Testing	
Antiknock Index (R+M)/2	-	87.0 - 88.4 <sup>2</sup>		87.0 Minimum	ASTM D2699 and D2700
Sensitivity (R-M)	-	7.5 Minimum			ASTM D2699 and D2700
Dry Vapor Pressure Equivalent (DVPE) <sup>3,4</sup>	kPa (psi)	60.0-63.4 (8.7-9.2)	77.2-81.4 (11.2-11.8)	52.4-55.2 (7.6-8.0)	ASTM D5191
Distillation <sup>4</sup>	°C (°F)	49-60 (120-140)	43-54 (110-130)	49-60 (120-140)	ASTM D86
10% evaporated	°C (°F)	88-99 (190-210)			
50% evaporated	°C (°F)	157-168 (315-335)			
90% evaporated	°C (°F)	193-216 (380-420)			
Evaporated final boiling point	°C (°F)				
Residue	milliliter	2.0 Maximum			
Total Aromatic Hydrocarbons	volume %	21.0-25.0			ASTM D5769
C6 Aromatics (benzene)	volume %	0.5-0.7			
C7 Aromatics (toluene)	volume %	5.2-6.4			
C8 Aromatics	volume %	5.2-6.4			
C9 Aromatics	volume %	5.2-6.4			
C10+ Aromatics	volume %	4.4-5.6			
Olefins <sup>5</sup>	mass %	4.0-10.0			ASTM D6550
Ethanol blended	volume %	9.6-10.0			See §1065.710(b)(3)
Ethanol confirmatory <sup>6</sup>	volume %	9.4-10.2			ASTM D4815 or D5599
Total Content of Oxygenates Other than Ethanol <sup>6</sup>	volume %	0.1 Maximum			ASTM D4815 or D5599
Sulfur	mg/kg	8.0-11.0			ASTM D2622, D5453 or D7039
Lead	g/liter	0.0026 Maximum			ASTM D3237
Phosphorus	g/liter	0.0013 Maximum			ASTM D3231
Copper Corrosion	-	No. 1 Maximum			ASTM D130
Solvent-Washed Gum Content	mg/100 milliliter	3.0 Maximum			ASTM D381
Oxidation Stability	minute	1000 Minimum			ASTM D525

<sup>1</sup>ASTM procedures are incorporated by reference in §1065.1010. See §1065.701(d) for other allowed procedures.

<sup>2</sup>Octane specifications apply only for testing related to exhaust emissions. For engines or vehicles that require the use of premium fuel, as described in paragraph (d) of this section, the adjusted specification for antiknock index is a minimum value of 91.0; no maximum value applies. All other specifications apply for this high-octane fuel.

<sup>3</sup>Calculate dry vapor pressure equivalent, DVPE, based on the measured total vapor pressure,  $p_T$ , using the following equation:  $DVPE$  (kPa) =  $0.956 \cdot p_T - 2.39$  (or  $DVPE$  (psi) =  $0.956 \cdot p_T - 0.347$ ). DVPE is intended to be equivalent to Reid Vapor Pressure using a different test method.

<sup>4</sup>Parenthetical values are shown for informational purposes only.

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<sup>5</sup>The reference procedure prescribes measurement of olefin concentration in mass %. Multiply this result by 0.857 and round to the first decimal place to determine the olefin concentration in volume %.

<sup>6</sup>The reference procedure prescribes concentration measurements for ethanol and other oxygenates in mass %. Convert results to volume % as specified in Section 14.3 of ASTM D4815.

Along with updated emission test fuel parameters, we are adding specifications for distillation residue, total content of oxygenates other than ethanol, copper corrosion, solvent-washed gum content, and oxidation stability. These parameters, summarized in Table 3-1, are consistent with ASTM D-4814 gasoline specifications and CARB's LEV III test fuel requirements.

### 3.3 Changes to ASTM Test Methods

Many of the test methods specified in 40 CFR 86.113 for gasoline used in exhaust and evaporative emission testing have been retained in 40 CFR 1065.710 test fuel specification for ethanol-blended gasoline. However, some test methods have been replaced with methods deemed more appropriate, easier to use, or more precise. The following paragraphs highlight the new reference methods.

ASTM D323 "Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)" is not applicable to ethanol-blended gasoline. It is being replaced with an automated ASTM D5191 "Standard Test Method for Vapor Pressure of Petroleum Products (Mini Method)," which is appropriate for ethanol-blended gasoline.

ASTM D1319 "Standard Test Method for Hydrocarbon Types in Liquid Petroleum Products by Fluorescent Indicator Adsorption" is required by 40 CFR 86.113 for use in the measurement of aromatics and olefins. It is being replaced with ASTM D5769 "Standard Test Method for Determination of Benzene, Toluene, and Total Aromatics in Finished Gasolines by Gas Chromatography/Mass Spectrometry" and ASTM D6550 "Standard Test Method for Determination of Olefin Content of Gasolines by Supercritical-Fluid Chromatography." Method D5769 enables simultaneous determination of the total aromatic hydrocarbon content, carbon number-specific content, and benzene content and is already being used in reformulated gasoline applications. ASTM D1319 does not identify aromatics by carbon number, which is now required for the Tier 3 test fuel in 40 CFR 1065.710. In addition, ASTM D5769 and D6550 are more precise and less labor-intensive than ASTM D1319.

Measurement of oxygenates, including ethanol, is being updated to allow two methods that produce equivalent results: ASTM D4815, "Standard Test Method for Determination of MTBE, ETBE, TAME, DIPE, tertiary-Amyl Alcohol and C1 to C4 Alcohols in Gasoline by Gas Chromatography" and ASTM D5599, "Standard Test Method for Determination of Oxygenates in Gasoline by Gas Chromatography and Oxygen Selective Flame Ionization Detection".

For sulfur measurements, ASTM D1266 "Standard Test Method for Sulfur in Petroleum Products (Lamp Method)" is being replaced with three automated methods: ASTM D2622 "Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry", ASTM D5453 "Standard Test Method for Determination of Total

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Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence” and ASTM D7039 “Standard Test Method for Sulfur in Gasoline and Diesel Fuel by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry.” These three new methods are significantly less labor-intensive than ASTM D1266 and are widely used in the measurement of sulfur content in petroleum products.

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## References

<sup>1</sup> EIA, January 2012 Monthly Energy Review, Table 3.7a, Petroleum Consumption: Residential and Commercial Sectors; Table 3.7b, Petroleum Consumption: Industrial Sector; Table 3.7c, Petroleum Consumption: Transportation Sector, and Table 10.3, Fuel Ethanol Overview.

<sup>2</sup> EIA, Petroleum Marketing Annual 2009, Table 45, Prime Supplier Sales Volume of Motor Gasoline by Grade, Formulation, PAD District and State.

<sup>3</sup> Iizuka, Masashi, Advanced Technology and Research Institute (ATRI) and Japan Petroleum Energy Center (JPEC), *Effect of Fuel Properties on Emissions from Direct Injection Gasoline Vehicle*.

<sup>4</sup> Jetter, Jeff, Honda R&D America Inc., *Development of a Predictive Model for Gasoline Vehicle Particulate Matter Emissions*, SAE 2010-01-2115.



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components, referred to here as straight run naphtha, remain in the vapor phase until they exit the tower overhead, following which they are condensed and cooled and sent to the naphtha splitter.

#### Naphtha Splitter

The purpose of the naphtha splitter is to perform a distillation separation of straight run naphtha into light straight run naphtha and heavy straight run naphtha. The feed can be split between the C5's and C6's in order to assure the C6's and heavier are fed to the reformer.

#### Naphtha Hydrotreater

The purpose of the naphtha hydrotreater is to reduce the sulfur of light and heavy straight run streams before those streams are refined further by the isomerization and reformer units.

#### Isomerization Unit

The purpose of the isomerization unit is to convert the light naphtha from straight chain hydrocarbons to branched chain hydrocarbons, increasing the octane of this stream. The isomerate is sent to gasoline blending.

#### Reformer

The purpose of the reformer unit is to convert heavy straight run (C6 to C8 or C9 hydrocarbons) into aromatic and other higher octane compounds (benzene is one of the aromatic compounds produced), typically necessary to produce gasoline with sufficient octane. To protect the very expensive, precious metal catalyst used in reformers, heavy straight run naphtha must be hydrotreated first before it is fed to the reformer. As the reformer converts the feed hydrocarbons to aromatics, hydrogen and light gases are produced as byproducts. The liquid product, known as reformate, is sent directly to gasoline blending, or to aromatics extraction.

#### Aromatics Extraction Unit

The purpose of aromatics extraction is to separate the aromatic compounds from the rest of the hydrocarbons in reformate using chemical extraction with a solvent to concentrate the individual aromatic compounds, (mainly xylene and benzene) for sale to the chemicals market.

#### Vacuum Tower

The purpose of the vacuum distillation tower unit is to enable a refinery to produce more gasoline and diesel fuel out of a barrel of crude oil. It separates the vacuum gasoil (VGO), which is fed to the FCC unit, from the vacuum tower bottoms (VTB) which is sent to the coker, or in other refineries is made into asphalt. Because most sulfur contained in crude oil is contained in the heaviest part of crude oil, the VGO and VTB are very high in sulfur.

#### Fluidized Catalytic Cracker

The purpose of the fluidized catalytic cracker is to convert heavy hydrocarbons, which have very low value, to higher value lighter hydrocarbons. AGO and VGO are the usual feeds to

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a fluid catalytic cracker (FCC). The full boiling range cracked product leaves the reactor and is sent to a fractionator. The overhead includes propane, propylene, butane, butylene, fuel gas and FCC naphtha, which contains a significant amount of sulfur. There are two heavy streams; light cycle oil (LCO), which can be hydrotreated and blended into diesel fuel or hydrocracked into gasoline; and heavy cycle oil, sometimes called slurry oil, which can be used for refinery fuel. Very simple refineries do not have FCC units, and therefore, produce gasoline with very low in sulfur.

#### FCC Feed Hydrotreater or Mild Hydrocracker “A”

FCC feed hydrotreaters and mild hydrocrackers hydrotreat or mildly hydrocrack the feed to the FCC unit which provides two distinct benefits. First, by increasing the amount of hydrogen in the feed to the FCC unit, the FCC unit increases the conversion of the feed to high value light products, particularly FCC naphtha which increases the gasoline yield. Second, hydrotreating the feed removes some contaminants in the feed such as nitrogen and sulfur. Nitrogen in the feed negatively affects the FCC catalyst. Removing the sulfur in the feed helps in two ways. Some of the sulfur in the feed is released by the cracking process and results in high SO<sub>x</sub> emissions that would otherwise have to be controlled by scrubbers – the FCC feed hydrotreaters may prevent the need to add a scrubber. Also, FCC feed hydrotreaters remove sulfur which can allow a refinery to comply with gasoline sulfur standards.

#### FCC Posttreat Hydrotreater “B”

Posttreat hydrotreaters solely hydrotreat the naphtha that is produced by the FCC unit to reduce its sulfur level which enables compliance with gasoline sulfur standards. The FCC naphtha is high in olefins, which can be saturated by posttreat hydrotreaters, resulting in lower octane of the FCC naphtha. Vendor companies have developed posttreat hydrotreating technologies that minimize this octane loss.

#### Distillate Hydrotreater

The purpose of the distillate hydrotreater is to reduce the sulfur of distillate, which is also called diesel fuel.

#### Gas Plant

The purpose of the gas plant is to use a series of distillation towers to separate various light hydrocarbons for further processing in the alkylation or polymerization units or for sale.

#### Alkylation Unit

The purpose of the alkylation unit is to chemically react light hydrocarbons together to produce a high quality, heavy gasoline product. Alkylation uses sulfuric or hydrofluoric acid as catalysts to react butylene or propylene together with isobutane. Following the main reaction and product separation, the finished alkylate is sent to gasoline blending. Alkylate is low in RVP.

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## Polymerization Unit

The purpose of the polymerization unit is to react light hydrocarbons together to form a gasoline blendstock. A polymerization unit, often referred to as a “cat poly” is somewhat similar to an alkylation unit, in that both use light olefins to produce gasoline blendstocks. The feed is generally propylene and/or butylene from the gas plant. The product, called polygas is sent to gasoline blending.

## Coker Unit

The purpose of the coker unit is to process vacuum tower bottoms (VTB) to coke and to crack a portion to various lighter hydrocarbons. The hydrocarbons produced by the coker include cracked gases, coker naphtha, coker distillate and gas oil. The gas is fed to the gas plant, the naphtha to the naphtha hydrotreater after which the heavy coker naphtha is typically fed to the reformer, and the distillate either to distillate hydrotreating or to the hydrocracker.

## Hydrocracker

The purpose of the hydrocracker is to crack and “upgrade” the feedstock into higher value products. The feedstock to the hydrocracker is usually light cycle oil (LCO) and coker distillate, poor quality distillate blendstocks, which are upgraded to diesel fuel, or cracked to gasoline. Heavier hydrocarbons such as AGO and HVGO can be feedstocks as well.

A more complete description for naphtha hydrotreating is contained in Section 4.2.

## **4.2 Feasibility of Removing Sulfur from Gasoline**

The case that it is feasible to comply with the 10 ppm gasoline sulfur standard can be made in two ways. First, feasibility can be demonstrated because there are available technologies that are currently available to achieve significant reductions in gasoline sulfur. A discussion of these currently available technologies is contained below. Second, refiners in California are already meeting a 10 ppm average, and certain countries or other regions are currently complying with a 10 ppm gasoline sulfur cap standard. These two cases will be made below, but first we will review the source of sulfur in gasoline to understand how sulfur levels can be further reduced.

### 4.2.1 Source of Gasoline Sulfur

Sulfur is in gasoline because it naturally occurs in crude oil. Crude oil contains anywhere from fractions of a percent of sulfur, such as less than 500 ppm (0.05 weight percent) to as much as 30,000 ppm (3 percent). The average amount of sulfur in crude oil refined in the U.S. is about 14,000 ppm. Most of the sulfur in crude oil is in the heaviest part, or in the heaviest petroleum compounds, of the crude oil (outside of the gasoline boiling range). In the process of refining crude oil into finished products, such as gasoline, some of the heavy compounds are broken up, or cracked, into smaller compounds and the embedded sulfur can end up in gasoline. Thus, the

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refinery units which convert the heavy parts of crude oil into gasoline are the units most responsible for putting sulfur into gasoline.

The fluidized catalytic cracker (FCC) unit is a refinery processing unit that creates FCC naphtha, which is a high sulfur content gasoline blendstock. FCC naphtha contains from hundreds to several thousand parts per million of sulfur. The FCC unit cracks large carbon molecules into smaller ones and produces anywhere from 25 to 50 percent of the gasoline in those refineries with FCC units. Because the FCC unit makes a gasoline blendstock out of the heavier, higher sulfur-containing compounds, more than 95 percent of sulfur in gasoline blendstocks comes from streams produced in that unit. For compliance with the 30 ppm Tier 2 gasoline sulfur standard refiners reduced the sulfur content of the FCC naphtha. The impact of this action is described below in subsection 4.2.2.

Straight run naphtha is a gasoline blendstock which contains a moderate amount of sulfur. Straight run naphtha is the part of crude oil, which after distillation in the atmospheric crude oil tower, falls in the gasoline boiling range. The heaviest portion of straight run, which would have more sulfur, is normally desulfurized and reformed in the reformer (to improve its octane), so its contribution to the gasoline pool is virtually nil.<sup>A</sup> The light straight run naphtha, which contains the five-carbon hydrocarbons, contains on the order of 100 ppm sulfur and if this material is not hydrotreated and processed in an isomerization unit, it is blended directly into gasoline.

Another refinery unit which produces naphtha with a significant amount of sulfur is the coker unit. These units produce coke from the heaviest part of the crude oil. In the process of producing coke, a naphtha is produced that contains more than 3,000 ppm sulfur and many very unstable olefins. Because this stream is highly olefinic and unstable, refiners tend to hydrotreat coker naphtha. Coker naphtha is normally split into two different streams. The six- to nine-carbon hydrocarbons are hydrotreated along with the rest of the heavy naphtha and fed to the reformer. The five-carbon hydrocarbon part of coker naphtha is called light coker naphtha and usually contains on the order of several hundred parts per million sulfur. Light coker naphtha is usually hydrotreated along with the light straight run, and refined further in an isomerization unit if the refinery has one.

Other gasoline blendstocks contain little or no sulfur. Alkylate, which is produced from isobutene and butylenes that contain a small amount of sulfur, can end up with a small amount of sulfur. Most refineries have less than 15 ppm sulfur in this pool, however, some refineries which feed coker naphtha to the alkylate plant can have much more. On average, alkylate probably has about 10 ppm sulfur. One more gasoline blendstock with either very low or no sulfur is hydrocrackate, which is the naphtha produced by hydrocrackers. It is low in sulfur because the hydrocracking process removes the sulfur. Ethanol, which is eventually blended into gasoline usually has very little or no sulfur. However, the hydrocarbon used as a denaturant and blended with ethanol at 2 percent is usually natural gasoline, a C5 to C7 naphtha from natural gas

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<sup>A</sup> Sulfur interferes in the function of the precious metal catalyst used in the reforming process. As a result, refiners historically have desulfurized the heavy straight run naphtha feed to the reformer from several hundred ppm sulfur down to less than 1 ppm.

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processing, and it contains anywhere from a few parts per million to a couple hundred parts per million sulfur. After the denaturant is blended in, the denatured ethanol contains somewhere between 0 and 10 ppm sulfur. To meet current pipeline and California specifications, denatured ethanol must contain less than 10 ppm sulfur.

#### 4.2.2 Complying with the Current Tier 2 Gasoline Sulfur Standard

It is important to understand the steps that refiners took to comply with the 30 ppm Tier 2 gasoline sulfur standard because those capital investments and operational changes will play a major role in determining the steps that refiners take to comply with a more stringent gasoline sulfur standard.

The Tier 2 sulfur standard was promulgated February 10, 2000.<sup>2</sup> The sulfur standard requires that refiners reduce their annual average gasoline sulfur levels down to 30 ppm and each gallon of gasoline cannot exceed a per-gallon standard of 80 ppm. The sulfur standards were phased in from 2004 to 2006. The compliance deadline for western refiners (GPA) and small refiners were delayed until 2008. Some small refiners also had their gasoline sulfur deadlines extended through 2010 if they met the compliance deadline for the highway diesel fuel sulfur rule. As of January 1, 2011, all refineries are complying with the Tier 2 30 ppm sulfur standard.

A refinery's previous average gasoline sulfur level is an important factor which determined whether a refiner would need to make a substantial capital investment to meet the Tier 2 gasoline sulfur standards. We believe that refiners with low gasoline sulfur levels to begin with (i.e., gasoline sulfur levels lower than about 50 ppm) probably did not invest in expensive capital. These refineries have very low sulfur levels due to one or more of a number of possible reasons. For example, some of these refiners may not have certain refining units, such as either a FCC unit or a coker, which convert heavy boiling stocks to gasoline. As described above, these units push more sulfur into gasoline and their absence means much less sulfur in gasoline. Alternatively, these refiners may either use a very low sulfur (sweet) crude oil which can result in a low sulfur gasoline, or have already installed an FCC feed hydrotreater, which uses a heavier, higher sulfur (more sour) crude oil, to improve the operations of their refinery. As described above, this unit removes much of the sulfur from the heaviest portion of the heavy gas oil before it is converted into gasoline.

Of the refiners that already had low sulfur levels prior to Tier 2, the refineries with average sulfur levels below 30 ppm may not have had to do anything to meet the Tier 2 standards. On the other hand, refineries with sulfur levels above 30 ppm but below about 50 ppm, probably are meeting the 30 ppm sulfur standard by employing operational changes only and avoided making capital investments. Most refineries with gasoline sulfur levels below 50 ppm prior to the Tier 2 investments either do not have a FCC unit, or if they do, probably also have an FCC feed hydrotreating unit.

The vast majority of gasoline that was being produced prior to the inception of the Tier 2 program was by refineries with higher sulfur levels. These refiners had to either adapt some existing hydrotreating unit or install new capital equipment in these refineries to meet the Tier 2 gasoline sulfur standards. As stated above, the FCC unit is responsible for most of the sulfur in gasoline. Thus, investments for desulfurizing gasoline involved the FCC unit to maximize the sulfur reduction, and to minimize the cost of compliance with Tier 2. These desulfurization units

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were installed for treatment of either the gas oil feed to the FCC unit, or the gasoline blendstock that is produced by the FCC unit. Each method has advantages and disadvantages.

#### 4.2.2.1 Using FCC Feed Pretreat Hydrotreating to Comply with Tier 2

Some refiners installed FCC feed hydrotreaters (also known as pretreaters) at their refineries to comply with the Tier 2 gasoline sulfur standards. FCC pretreaters treat the vacuum gas oil, heavy coker gas oil and, in some cases, atmospheric residual feed to the FCC unit using a hydrotreater or a mild hydrocracker. These units are designed to operate at high pressures and temperatures to treat a number of contaminants in the feed. Besides sulfur, FCC pretreaters also reduce nitrogen and certain metals such as vanadium and nickel. These nonsulfur contaminants adversely affect the FCC catalyst, so the addition of this unit would improve the functioning of the unit. Also, because hydrotreating which occurs in the FCC pretreater reacts hydrogen in the feedstock, it increases the yield of the FCC unit, increasing the production of high profit-making products, such as gasoline and light olefins.<sup>3</sup> While FCC pretreaters provide yield benefits that offset the capital costs of adding this type of desulfurization, the costs are still high enough that many refiners would have a hard time justifying the installation of this sort of unit. For a medium to large refinery (i.e., 150,000-200,000 BPCD), the capital costs may exceed \$250 million. Because of the higher temperatures and pressures involved, utility costs are expensive relative to posttreat hydrotreating as explained below. Using FCC feed pretreating also allows refiners to switch to a heavier, more sour crude oil. These crude oils are less expensive per-barrel and can offset the increased utility cost of the FCC pretreater, providing that the combination of reduced crude oil costs and higher product revenues justify the switch. Another benefit for using FCC pretreaters is that the portion of the distillate pool that comes from the FCC unit would be partially hydrotreated as well. This distillate blendstock, termed light cycle oil, comprises a relatively small portion of the total distillate produced in the refinery (about 20 percent of on-road diesel comes from light cycle oil), and like FCC naphtha, light cycle oil contributes a larger portion of the total sulfur which ends up in distillate. Thus, FCC pretreaters would also help a refiner meet the 15 ppm highway and nonroad diesel fuel standards.

In terms of desulfurization capability, FCC pretreaters have different abilities to remove sulfur from the gas oil feed depending on the unit pressure. FCC pretreaters can be subdivided into high pressure units (1400 psi and above), medium pressure units (900 to 1400 psi), and low pressure units (under 900 psi). High pressure FCC pretreaters typically remove about 90 percent of the sulfur contained in the gas oil feedstock to the FCC unit, while low and medium pressure units typically remove 65 to 80 percent of the feed sulfur.<sup>4</sup> We are aware of at least 5 refineries in the U.S. that use high pressure FCC pretreaters. Because there is no posttreating at many of the refineries with FCC pretreaters, control of the feed to these units is a critical determining factor for how well the FCC pretreater will function as desulfurizers. If the feed becomes too heavy (due to a higher temperature endpoint), there would be a higher concentration of sulfur and other contaminants in the feed. To maintain the same sulfur level in the FCC naphtha, the FCC pretreater unit would have to be operated at a higher temperature which causes the catalyst to lose its effectiveness more quickly.<sup>5</sup>

FCC pretreaters improve desulfurization indirectly by improving the desulfurization performance of the FCC unit itself. When FCC units crack the vacuum gas oil into naphtha, about 90 percent of the sulfur is typically cracked out of the hydrocarbons converted to FCC

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naphtha (or the FCC naphtha contains only about 10 percent of the sulfur present in the feed) and is removed as hydrogen sulfide. When FCC pretreaters are used, the amount of sulfur in the feed, which ends up in the FCC naphtha, is only about 5 percent. This means that about 95 percent of the sulfur in the feed is removed from the FCC feed when it is cracked into FCC naphtha. This is due to the additional hydrogen in the pretreater, which reacts with the feed hydrocarbons. With more hydrogen molecules available in the feedstock after hydrotreatment, the FCC cracking reactions can react more hydrogen with the sulfur contained in the feed to produce more hydrogen sulfide.

For complying with Tier 2, refiners with existing pretreaters or those that installed high pressure FCC pretreaters were able to comply with the 30 ppm sulfur standard without the need to install a FCC naphtha hydrotreater. Refineries that had either a low pressure, or medium pressure FCC feed hydrotreater were generally less able to comply with the 30 ppm gasoline sulfur standard with the FCC hydrotreater by itself, and were more likely to also install an FCC posttreater.

#### 4.2.2.2 Using FCC Naphtha Posttreat Hydrotreating to Comply with Tier 2

A less capital intensive alternative for reducing FCC naphtha sulfur levels to comply with Tier 2 is FCC naphtha hydrotreating (also known as posttreaters). FCC posttreaters only treat the gasoline blendstock produced by the FCC unit. This unit is much smaller than an FCC pretreater because only about 50 to 60 percent of the feed to the FCC unit ends up as FCC naphtha, a gasoline blendstock. The unit is sometimes smaller still because some refiners which choose to use a fixed bed hydrotreater may only treat the heavier, higher sulfur portion of that stream with hydrotreating, and then treat the lighter fraction with another lower desulfurization cost technology. FCC posttreaters operate at lower temperatures and pressures than FCC pretreaters, which further reduces the capital and operating costs associated with this type of desulfurization equipment. Furthermore, because feed to the FCC unit has corrosive properties, FCC pretreaters use more corrosion-expensive metallurgy, which is not needed for posttreaters.<sup>6</sup> For a medium to large-sized refinery, the capital costs are on the order of \$70 million for a conventional FCC posttreater – about a third the cost of an FCC pretreater.

One disadvantage of this desulfurization method is that the octane value and/or some of the gasoline yield may be lost depending on the process used for desulfurization. Octane loss occurs by the saturation of high octane olefins which are produced by the FCC unit. Most of the olefins are contained in the lighter fraction of FCC naphtha.<sup>7</sup> Increased olefin saturation usually means higher hydrogen consumption. There can also be a loss in the gasoline yield caused by mild cracking that breaks some of the gasoline components into smaller fractions which are too light for blending into gasoline. If there is octane loss, the octane loss can be made up by increasing the feed to or the severity of the reformer, the aromatics production unit of the refinery, producing more alkylate, or purchasing high octane gasoline blendstocks (such as reformat) which is routinely trading between refineries. Sometimes vendors of FCC pretreater technologies design octane increasing capability into their designs, which is discussed below in the section about the individual posttreater technologies.

The loss of octane and gasoline yield caused by FCC posttreating is lower with technologies that were developed prior to the implementation of the Tier 2 program.<sup>8</sup> These

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processes are termed selective because they achieve the lower sulfur while preserving much of the octane and gasoline yield (they were designed specifically for treating FCC naphtha). Octane is preserved because the hydrotreating units and their catalysts are specially designed to avoid saturating olefins. These selective processes, or parts of these processes, usually operate at less severe conditions and result in less cracking and thus, preserve yield compared to conventional hydrotreating processes. The less severe conditions also lower the capital and operating costs for this process. The lower operating costs arise out of the reduced utility requirements (e.g., lower pressure). For example, because these processes are less severe, there is less saturation of olefins, which means that there is less hydrogen used. Less olefin saturation also translates into less octane loss, which would otherwise have to be made up by octane boosting processing units in the refinery. The lower capital and operating costs of these newer FCC posttreaters are important incentives for refiners to choose this desulfurization methodology over FCC pretreaters. For this reason, refiners chose to use the more recently developed FCC posttreaters technologies for meeting the 30 ppm Tier 2 gasoline sulfur standard.

Not saturating the olefins to preserve octane and limit hydrogen consumption provides a different challenge. During desulfurization, when the hydrogen sulfide is formed and there is a significant concentration of olefins present, the hydrogen sulfide compounds tend to react with the olefinic hydrocarbon compounds forming mercaptan sulfur compounds. This reaction is called “recombination” because the removed sulfur recombines with the olefinic hydrocarbons contained in the naphtha.<sup>9</sup> This is particularly a problem if the light cat naphtha is present in the hydrotreater because the highest concentration of olefins is in the light cat naphtha. The recombination reactions occur more readily if the hydrotreater is operated more severely (at a higher temperature) to increase the sulfur removal, and the feed to the hydrotreater is high in sulfur. However, while operating this type of hydrotreater more severely can result in the further removal of the original sulfur present in the hydrocarbons, it also can result in the formation of more recombination mercaptans that results in a “floor” reached for the amount of sulfur that can be removed from the hydrocarbons. This cycle of increased sulfur removal and simultaneous increase in recombination results in the saturation of more olefins and increases the consumption of hydrogen. There are a number of different vendor-specific technologies that each vendor may use to avoid or address recombination reactions as discussed below. It is important to note that the technologies employed to reduce recombination may require the addition of some capital costs which offsets some or perhaps all the capital cost savings due to the milder operating conditions of these selective hydrotreater technologies compared to nonselective hydrotreating.

One means to achieve high levels of desulfurization while avoiding much of the problem with recombination reactions is by using a two-stage hydrodesulfurization methodology. A two-stage unit has two desulfurization reactors, but instead of just adding additional reactor volume, the hydrocarbons exiting the first reactor are stripped of gaseous compounds (most importantly, the hydrogen sulfide is removed), injected with fresh hydrogen, and then hydrodesulfurized again in the second stage. Both reactors undergo modest desulfurization and hydrogen sulfide concentrations remain sufficiently low to avoid recombination reactions. The disadvantage of this approach is that the second stage incurs greater capital costs compared to single-stage configurations. Because Tier 2 was not too constraining, we believe that refiners installed few, if any, two-stage desulfurization units to comply with those gasoline sulfur standards.

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Whatever strategy chosen by the refiner to comply with Tier 2, a critical criterion was that the posttreater be capable of cycle lengths that match that of the FCC unit, which typically is 4 years. If the posttreater were to require a catalyst changeout before the FCC unit requires a shutdown, the refiner would either have to shutdown the FCC unit early to mirror that of the posttreater, or store the high sulfur FCC naphtha (this stream would be too high in sulfur to blend directly to gasoline under the Tier 2 80 ppm cap standard) until the posttreater was started up again and is able to hydrotreat the stored up high sulfur FCC naphtha.

We know of six FCC posttreater technologies that refiners used to comply with the Tier 2 gasoline sulfur standards. These are Axens (was IFP) Prime G and Prime G+, Exxon Scanning, CDTech's CDHydro and HDS, Sinopec's (was Phillips)S-Zorb and UOP's ISAL and Selectfining.

Axens Prime G+, Exxon Scanning and UOP's ISAL and Selectfining are all fixed bed desulfurization technologies. These processes are called fixed bed because the catalyst resides in a fixed bed reactor.<sup>10</sup> The high sulfur gasoline blendstock is heated to a high temperature (on the order of 600 degrees Fahrenheit) and pumped to a high pressure to maintain the stream as a liquid. It is then combined with hydrogen before it enters the reactor. The reactions occur within the bed of the catalyst. While the petroleum is in contact with the catalyst in the reaction vessel, the sulfur reacts with hydrogen and is converted to hydrogen sulfide. Also, depending on the process, some of the olefin compounds that are present in the cracked stream are saturated which increases the amount of octane lost and hydrogen consumed. After the reactor, the gaseous compounds, which include unreacted hydrogen, hydrogen sulfide, and any light end petroleum compounds which may have been produced in the reactor by cracking reactions, are separated from the liquid compounds by a gas/liquid separator. The hydrogen sulfide must be stripped out from the other compounds and then converted to elemental sulfur in a separate sulfur recovery unit. The recovered sulfur is then sold. If enough hydrogen is present, and it is economical to recover, it is separated from the remaining hydrocarbon stream and recycled. Otherwise, it is burned with light hydrocarbons as fuel gas.

Each of these fixed bed desulfurization technologies is somewhat different. Axens Prime G+ desulfurization process largely preserves olefins as its strategy for diminishing octane loss.<sup>11,12 13</sup> The Axens process employs a selective hydrogenation unit (SHU) as a first step. The role of this unit is to saturate the unstable diolefin hydrocarbons in a hydrogen rich environment, and react the light mercaptan and sulfide hydrocarbons together. The SRU also converts exterior olefins to interior olefins, which results in a small increase in octane. The mild operating conditions of the SHU tend to avoid the saturation of monoolefins. After exiting the SRU, the FCC naphtha is sent to a distillation column which separates the light FCC naphtha (typically comprising about one fourth of the total cat naphtha) from the heavy naphtha. Because the light sulfur compounds were reacted together and those compounds no longer fall within the light cat naphtha boiling range, the light cat naphtha is low in sulfur and can be blended directly into gasoline. The heavy cat naphtha which is naturally high in sulfur and which also contains the self-reacted light mercaptans and sulfides from the SHU, is sent to a fixed bed hydrotreater. The fixed bed hydrotreater contains both cobalt-molybdenum and nickel-molybdenum catalyst. An important way that Axens avoids recombination reactions is by separating the light sulfur compounds from the light naphtha and keeping the light naphtha out of the fixed bed hydrotreater. The desulfurized heavy cat naphtha is blended into the gasoline pool.

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If the feed to the Axens Prime G unit is very low in sulfur, a low capital investment option was available to the refiner by feeding the entire FCC naphtha stream to the hydrotreating reactor avoiding the SHU and splitter. This option trades lower capital cost with somewhat higher octane loss and hydrogen consumption. Because of the low severity of the hydrotreating reactor (low severity is possible because the lower amount of desulfurization that is occurring), the amount of octane loss and hydrogen consumption is modest. There are more than 180 Prime G+ units operating worldwide, and approximately 40 in the U.S.

The first step in Exxon's fixed bed Scanfining process is to mildly heat the full FCC naphtha and pass it through a small reaction vessel which reacts the diolefins to monoolefins.<sup>14 15 16 17 18 19</sup> The full FCC naphtha is then heated further, injected with hydrogen gas and sent to the fixed bed hydrotreating reactor, which is packed with a catalyst developed jointly between Exxon and Akzo Nobel (now Albermele). If the degree of desulfurization is relatively modest, the amount of recombination is low and the FCC naphtha is sent to gasoline blending. If, however, the degree of desulfurization is higher (due to FCC naphtha with a higher sulfur content), then there likely would be an excessive number of recombination reactions. In this case, Exxon recommends either one of two different technologies to address the recombination reactions. One technology is Zeromer. Zeromer is a fixed bed reactor vessel installed after the main fixed bed hydrotreater reactor that specifically designed to hydrodesulfurize the mercaptan sulfur from the FCC naphtha without saturating olefins.<sup>20</sup> Another technology Exxon developed, in conjunction with Merichem, is an extractive mercaptan removal technology named Exomer. The Exomer technology differs from other sulfur extraction technologies in that it is capable of extracting mercaptans from the entire FCC naphtha pool.<sup>21</sup> Like Zeromer, the Exomer technology would be an add-on technology installed after the Scanfining fixed bed reactor. There are 16 Scanfining units operating in the U.S.

UOP has licensed two FCC naphtha hydrotreating technologies. When Tier 2 was being phased-in, UOP was licensing a technology named ISAL developed by INTEVEP S.A.<sup>22 23</sup> The ISAL process is different from the other FCC naphtha hydrotreaters because instead of avoiding the saturation of olefins as sulfur is being hydrotreated out of FCC naphtha, the ISAL process completely saturates the olefins. To avoid a large octane loss, the ISAL process separates the olefin-rich, light cat naphtha from the heavy cat naphtha. The light cat naphtha is treated by an extractive desulfurization technology such as Merox which does not saturate olefins. Only the heavy cat naphtha is sent to the ISAL reactor. To offset the octane loss caused by the saturation of the olefins in the heavy cat naphtha as it is being desulfurized, the ISAL catalyst isomerizes and conducts some mild cracking and reforming of the heavy cat naphtha. One downside of the ISAL process is that, due to the complete saturation of olefins, the hydrogen consumption is higher relative to the selective hydrodesulfurization technologies that avoid saturating olefins.

UOP has since developed and licensed a FCC naphtha desulfurization technology called SelectFining.<sup>24</sup> SelectFining is a selective hydrodesulfurization technology that seeks to minimize olefin saturation to minimize both octane loss and hydrogen consumption. SelectFining treats the full FCC naphtha. The full range FCC naphtha is first sent to a diolefin saturating reactor before being sent to the SelectFining reactor. SelectFining relies on its catalyst design to selectively remove sulfur and prevent recombination reactions. UOP recommends a two-stage reactor setup for high levels of desulfurization.

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The next two FCC naphtha desulfurization technologies, CDTech and S-Zorb do not use fixed bed reactors, but very different technologies which are also very different from each other. Each will be discussed separately.

The CDTech process still uses the same type of catalyst used in fixed bed reactors. However, it also utilizes catalytic distillation.<sup>25,26,27</sup> Catalytic distillation is a technology which has been applied for a number of different purposes. CDTech is currently licensing the technology to produce MTBE and selective hydrogenation processes, including FCC naphtha desulfurization and benzene saturation. As the name implies, distillation and desulfurization, via catalyst, take place in the same vessel. This design feature saves the need to add a separate distillation column sometimes used with fixed bed hydrotreating. All refineries have a distillation column after the FCC unit (called the main fractionation column) that separates the FCC naphtha from the most volatile components (such as liquid petroleum gases), the distillate or diesel (light cycle oil), and the heavy ends or residual oil. However, if a refiner only wishes to treat a portion of the FCC naphtha, then a second distillation column would need to be added after the main FCC fractionation column to separate out the portion of the FCC naphtha that he wishes not to treat. With the CDTech process, the refiner can choose to treat either the entire pool or a portion of the pool, but choosing to treat a part of the pool, thus negating any need for an additional distillation column.

The most important portion of the CDTech desulfurization process is a set of two distillation columns loaded with desulfurization catalyst in a packed structure. The first vessel, called CDHydro, treats the lighter compounds of FCC gasoline and separates the heavier portion of the FCC naphtha for treatment in the second column. The second column, called CDHDS, removes the sulfur from the heavier compounds of FCC naphtha. All of the FCC naphtha is fed to the CDHydro column. The five- and six-carbon petroleum compounds boil off and head up through the catalyst mounted in the column, along with hydrogen which is also injected in the bottom of the column. The reactions in this column are unique in that the sulfur in the column is not hydrotreated to hydrogen sulfide, but they instead are reacted with dienes in the feed to form thioethers. Their higher boiling temperature causes the thioethers to fall to the bottom of the column. They join the heavier petroleum compounds at the bottom of the column and are sent to the CDHDS column. Because the pressure and temperature of the first column is much lower than conventional hydrotreating, saturation of olefins is reduced to very low levels. The olefin saturation which does occur is necessary to eliminate diolefins. Thus, little excess hydrogen is consumed. CDTech offers an option to refiners to put in an additional catalyst section in the CDHydro column to increase octane. This octane enhancing catalyst isomerizes some of the olefins, which increases the octane of this stream by about three octane numbers, and few of the olefins are saturated to degrade this octane gain. The seven-carbon and heavier petroleum compounds leave the bottom of the CDHydro unit and are fed into the CDHDS column. There, the heavier compounds head down the column and the lighter compounds head up. Both sections of the CDHDS column have catalyst loaded into them, which serve as hydrotreating reaction zones. Similar to how hydrogen is fed to the CDHydro column, hydrogen is fed to the bottom of the CDHDS column.

The temperature and pressure of the CDTech process columns are lower than fixed bed hydrotreating processes, particularly in the upper section of the distillation column, which is where most of the olefins end up. These operating conditions minimize yield and octane loss.

While the CDTech process is very different from conventional hydrotreating, the catalyst used for removing the sulfur compounds is the same. One important difference between the CDTech process and conventional hydrotreating is that CDTech mounts its catalyst in a unique support system, while conventional catalyst is usually dumped into the fixed bed reactor. CDTech has 13 CDHydro/CDHDS desulfurization units in operation in the U.S.

Phillips Petroleum Co. commercialized and licensed an adsorption desulfurization technology called S-Zorb, which it sold to SINOPEC in 2007.<sup>28 29</sup> S-Zorb uses a chemical adsorption process, instead of hydrotreating, as the principal methodology for the removal of sulfur from FCC naphtha. Adsorption has the benefit of operating at much lower pressure and temperatures, which lowers operating costs. S-Zorb, uses two separate columns and is constantly moving an adsorption catalyst from the reactor vessel to the regeneration column, and back again.<sup>30</sup> The untreated FCC naphtha and hydrogen are fed to the reaction vessel where the sulfur is catalytically removed from the petroleum compound and facilitated by the hydrogen present in the reactor. The catalyst, which begins to accumulate the removed sulfur, is transferred over to the regeneration column on a continual basis where the sulfur is removed from the catalyst using hydrogen as the scavenging compound. Then the hydrogen disulfide is converted to sulfur dioxide and sent to the sulfur recovery unit. Because the process still relies upon catalytic processing in the presence of hydrogen, there is some saturation of olefins, with a commensurate reduction in octane. Through a literature search, we believe that 7 S-Zorb desulfurization units were originally licensed for Tier 2. Other sources indicated that only 4 units are actually operating today.

We also conducted a literature search and asked both refiners and vendors to identify the FCC naphtha desulfurization technology that was installed at each refinery to enable compliance with Tier 2. A summary of the total number of units by vendor and technology type is summarized in Table 4-1.

**Table 4-1 Estimated Number of FCC Desulfurization Technologies Installed to comply with Tier 2 by Vendor Company or Technology**

Axens Prime G	Exxon Scanfining	CDTech	Sinopec S-Zorb	UOP ISAL UOP Selectfining	FCC Feed HT	No FCC Unit
40	16	15	4	2	17	14

#### 4.2.3 Meeting a 10 ppm Gasoline Sulfur Standard

To meet a 10 ppm average gasoline sulfur standard, we believe that the primary strategy that refiners would adopt would be to further reduce the sulfur level of FCC naphtha. There are three primary reasons why we believe this will be the primary strategy and therefore, used it for analyzing the compliance costs for Tier 3. The first reason is that FCC naphtha is by far the largest contributor of sulfur to the gasoline pool, by virtue of both its volume and sulfur content, even after refiner's use of hydrotreating to reduce the sulfur in the FCC naphtha to comply with Tier 2. Table 4-2 below summarizes the estimated average volumes and average sulfur levels for the primary blendstocks typically blended into gasoline for the current Tier 2 standards. By using the refinery-by-refinery model to model today's situation for the typical refinery, we estimate that the FCC naphtha contains about 75 ppm for the typical refinery complying with the

30 ppm Tier 2 sulfur standard and that gasoline blendstock typically contributes to about 34 percent of a refiner’s gasoline pool. Table 4-2 also summarizes the changes in gasoline blendstock sulfur levels we believe would occur when complying with the 10 ppm gasoline sulfur standard. Using the refinery-by-refinery model, we project that a 10 ppm gasoline sulfur standard can be met by a typical refinery by reducing the sulfur level of FCC naphtha from about 75 ppm to 25 ppm. We believe that virtually all refineries that have an FCC unit would not be able to comply with the proposed 10 ppm gasoline sulfur standard without further desulfurizing the FCC naphtha. The second reason is that both vendors and refiners have told us that this is the gasoline blendstock stream that they intend to address. Both vendors and refiners have explained to us that, for most refineries, existing FCC naphtha hydrotreaters can be retrofitted with only a modest capital cost to realize the sulfur reduction needed. Third, further reducing the sulfur of the FCC naphtha as the means to comply with Tier 3 is supported by other cost studies. When these studies assessed the costs for further reducing the sulfur levels of gasoline, they also focused further reducing the sulfur levels of the FCC naphtha. See the subsection at the end of Chapter 5 discussing these other cost studies.

**Table 4-2 Estimated Typical Gasoline Blendstock Volumes and Sulfur Levels after Tier 2 and Complying with a 10 ppm Sulfur Standard**

Gasoline Blendstock	30 ppm Tier 2 Gasoline Sulfur Standard		10 ppm Gasoline Sulfur Standard	
	Volume (Percent)	Sulfur (ppm)	Volume (Percent)	Sulfur (ppm)
FCC Naphtha	37	75	36	25
Reformate	23	0.5	22	0.5
Alkylate	13	10	13	10
Isomerate	3	0.5	3	0.5
Butane	4	5	4	5
Light Straight Run Naphtha and Natural Gas Liquids	5	15	5	5
Hydrocrackate	3	8	3	8
Ethanol	10	5	12.5	5
Coker Naphtha	2	1	2	1
Other Gasoline Blendstocks	1	10	1	1
Total/Sulfur Average	100	30	100	10

Reducing FCC naphtha from 75 ppm to 25 ppm would likely be accomplished in different ways depending on the desulfurizing technology and configuration used for Tier 2, and whether the current capital employed for lowering gasoline sulfur is severely taxed or not severely taxed. For purposes of this discussion, we will discuss the likely steps taken to comply with Tier 3 based on whether a refiner solely used an FCC pretreater or FCC postreater to comply with Tier 2. While we provided an example for a typical refinery needing to reduce its FCC naphtha from 75 ppm to 25 ppm to enable compliance with Tier 2, refineries that are not typical would have starting and ending sulfur levels that are different from this example. Despite these differences,

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we believe that every refinery can physically comply with a 10 ppm gasoline sulfur standard. This is because there are no technical difficulties removing sulfur from gasoline - the challenge is to comply while minimizing the cost of doing so, such as by minimizing the associated octane loss and by taking advantage of the flexibilities provided to comply. The cost analysis, reflecting the ability for refineries to comply through the use of the averaging banking and trading provisions is discussed in Chapter 5 of this RIA. Section 4.2.3.5 below also discusses the importance of the averaging, banking and trading program.

The one exception is the case where a refinery does not have an FCC unit. Refineries in this situation would likely already be producing gasoline which is 10 ppm or below. If such a refinery's gasoline is above 10 ppm, then the refiner would need to address one or more of several different gasoline blendstocks, including light straight run and natural gas liquids. Our discussion on treatment of other gasoline streams can be found in Section 4.2.3.3.

#### 4.2.3.1 Meeting 10 ppm if Refiners Used an FCC Feed Pretreater to Comply with Tier 2

Refiners that relied on an FCC pretreater to comply with Tier 2 at a refinery would likely only be able to achieve 10 ppm sulfur gasoline if its FCC pretreater is a high pressure unit.<sup>31 32</sup> This is because most refineries that have FCC pretreaters process sour crude oils and if the unit is a mid or low-pressure unit, the unit pressure would likely be too low to sufficiently desulfurize the FCC feed. This may be true even if the refiner added reactor volume to its existing low or medium pressure FCC pretreater, which does cause additional desulfurization. Mid and low pressure FCC pretreaters just cannot remove enough of the sulfur in the gas oil feed to the FCC unit to achieve adequately low sulfur levels in the FCC naphtha. If a refinery processes moderate to low sulfur crude oil and has a low to mid-pressure FCC pretreater, however, it may be able to achieve an adequate degree of desulfurization in the FCC naphtha to enable the refiner to reduce its gasoline sulfur down to 10 ppm. If a refinery cannot achieve a sufficient level of desulfurization with its current or revamped FCC pretreater to comply with a 10 ppm gasoline sulfur standard, then the refiner will have to install a grassroots FCC posttreater. Alternatively, refiners in this situation would be in the best situation to take advantage of the averaging, banking and trading program (ABT). Using the ABT provisions to its advantage, the refiner would achieve the most desulfurization that it can with its existing FCC pretreater (perhaps 20 ppm sulfur gasoline), and then would purchase credits to demonstrate the remainder of its compliance with the 10 ppm gasoline sulfur standard. Such a refiner would then avoid the need to install an expensive grassroots FCC posttreater.

While they are expensive to install, FCC pretreaters provide important operating cost advantages over posttreaters. An important advantage of FCC pretreating is that it occurs upstream of the FCC unit and therefore, does not jeopardize the octane value of the olefins produced in the FCC unit. Another advantage of the FCC pretreater is that it tends to increase the yield of naphtha from the FCC unit, which improves operating margins for the refinery with such a unit. Thus, refiners that are able to use FCC pretreaters to comply with the Tier 3 sulfur standard would likely yield a further return on any investment made, and offset some if not all of the increased operating costs incurred.

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A downside to solely relying on FCC pretreating to comply with Tier 3 is that a refinery has less operational flexibility. An FCC feed hydrotreater must be shutdown every one to three years to change out the catalyst, which is usually more often than when the FCC unit is shutdown. During the shutdown of the FCC pretreater, if the FCC unit remains operational a refiner has to figure out what to do with its high sulfur FCC naphtha (the refiner could blend up gasoline without FCC naphtha). For this reason, refiners that are complying with Tier 2 by solely relying on an FCC pretreater may choose to either install a grassroots posttreater instead to comply with Tier 3, or purchase credits.

The refiners most likely to rely on FCC pretreater to comply with Tier 3 are those with high pressure FCC pretreaters. As noted earlier, there are likely only 5 refineries have high pressure FCC pretreaters in the U.S. More refiners with FCC pretreaters may be able to comply with the Tier 3 standards using just their FCC pretreater, however, if they undercut the FCC naphtha into the diesel pool. The sulfur reduction in the FCC naphtha caused by undercutting would enable refiners to rely on lower pressure FCC pretreaters to comply with Tier 3, while also increasing diesel supply.

#### 4.2.3.2 Meeting 10 ppm if Refiners Used an FCC Posttreater to Comply with Tier 2

If a refiner installed an FCC posttreater to comply with the Tier 2 gasoline sulfur standard, there are several considerations about the current configuration of the posttreater which would affect how a refiner would use this unit to comply with a 10 ppm gasoline sulfur standard. EPA considered the issue of the degree of desulfurization the posttreater is currently facing. In doing so, EPA analyzed several examples to understand the types of revamps and associated investments that might occur for such refiners.

For the first example, if the refinery is refining a very sour (high sulfur) crude oil and the sulfur of the FCC naphtha exiting the FCC unit is 2,400 ppm, the posttreater is currently removing almost 97 percent of the feed sulfur. This assumes that the sulfur level of the FCC naphtha exiting the posttreater is 75 ppm, which is a very high level of desulfurization. When attempting to achieve further sulfur reduction in the FCC naphtha, the refiner must be concerned about the increased occurrence of recombination reactions and the potential for much more octane loss and hydrogen consumption. This refiner would strongly consider adding a second stage, which may actually reduce the level of recombination reactions and the octane loss currently experienced by the posttreater. Most of the vendors offer a second stage option. In the case of CDTech, they call the second reactor, added as part of its second stage, a polishing reactor. We contacted the desulfurization engineer at Sinopec who explained that these units could be turned up and that no additional capital investments would be needed (though there are additional operating costs). A Conoco-Phillips hydrotreating specialist we spoke to confirmed that this would be the strategy for their S-Zorb units. We also considered an additional option of the refiner is interested in improving its operating margins such as increased gasoline production, and has ample capital dollars to spend. Such a refiner could add an FCC feed hydrotreater to increase its yield of FCC naphtha, or a mild hydrocracker to increase its production of low sulfur distillate.

In contrast, if a refiner is processing a very sweet (low sulfur) crude oil, the sulfur level exiting the FCC unit may be as low as 300 ppm, and under Tier 2, the level of desulfurization

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necessary to bring that stream down to 70 ppm is about 81 percent which is a very modest level of desulfurization. Similarly, a refinery processing a moderately sour crude oil with a medium pressure FCC feed hydrotreater could be in a similar situation. The refineries in this situation could have a lot more capacity in their existing posttreaters to achieve lower sulfur without additional capital cost investments. However, many refiners in this situation which invested in an FCC posttreater for Tier 2 may have minimized their capital investments. For example, a refiner may have avoided the capital and operating cost of a splitter with its posttreater by hydrotreating the full range FCC naphtha. Therefore, the increased severity of the posttreater needed to achieve 20 ppm in the FCC naphtha to meet a 10 ppm gasoline sulfur standard might create a larger octane loss and higher hydrogen consumption than what the refinery could easily provide without a significant additional capital investment. In this case, the refiner can invest some capital in the posttreater to minimize the increase in octane loss and hydrogen consumption. For example a refiner with an Axens unit in this situation could add the SHU and a splitter. A refiner with a Scanfining unit in this situation wishing to minimize the octane loss and hydrogen consumption could add a Zeromer or an Exomer unit. Alternatively, if the refiner is processing a moderately sour crude oil and has a moderate pressure FCC feed hydrotreater, the refinery may choose instead to revamp the FCC feed hydrotreater for its operational benefits rather than revamp the posttreater.

We also considered a third example where a refiner with a posttreater has FCC gasoline exiting the FCC unit at 800 ppm. This is probably most typical of a refinery processing either crude oil containing an average amount of sulfur, or, perhaps a refinery refining a very sour crude oil but treating the vacuum gas oil with a low pressure FCC feed hydrotreater. The current FCC naphtha hydrotreater would be achieving about 90 percent desulfurization when producing FCC naphtha with 80 ppm sulfur. In looking to reduce the FCC naphtha down to 20 ppm to comply with a 10 ppm sulfur standard, such a refiner would not likely consider adding a second stage reactor. This is because avoiding both increased octane loss and hydrogen consumption for the additional increment of sulfur reduction would probably not justify the capital costs associated with a second stage reactor. Instead of a second stage reactor, a refiner could revamp the existing FCC posttreater with additional reactor volume, or add capital for addressing recombination reactions, both likely to be a lot less capital intensive than a second stage. A no investment option is possible for refiners in this situation, although the increase in octane loss and hydrogen consumption is likely to be significant.

The most important part of an FCC hydrotreater is likely the catalyst used in the unit. Due to continuing research, catalysts are constantly being developed which are more active, thus achieving greater desulfurization at a lower temperature, and minimizing octane loss and hydrogen consumption due to lower olefin saturation. When the Tier 2 naphtha desulfurizers were being put into service the most recent catalysts were likely used in those units. These catalysts can be changed when a posttreater is undergoing regular maintenance, and new and improved catalysts can be used to improve the desulfurization capacity of the unit. If refiners need to reduce their gasoline sulfur levels to 10 ppm gasoline, they would be expected to upgrade to the most recent catalyst to minimize their costs. Using the most active catalyst available would reduce the capital cost that would need to be incurred and reduce the hydrogen consumption and octane loss that would otherwise occur. We are aware of newer lines of more active catalysts being marketed by Axens and UOP. It is likely that since the time catalysts were

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loaded into FCC posttreaters to comply with Tier 2 all vendors are now offering improved hydrotreating catalysts.

#### 4.2.3.3 Desulfurizing Other Blendstocks

A more stringent gasoline sulfur standard could require refiners to address other gasoline streams with high enough in sulfur content to be a concern to the refiners when complying with Tier 3. This is because without addressing such gasoline streams, the refiner would have to reduce their FCC naphtha even lower in sulfur resulting in high per gallon costs at the lower sulfur levels. The gasoline streams that we have identified that could require additional desulfurization include light straight run naphtha and natural gas liquids.

Light straight run naphtha (LSR) is naturally occurring in the crude oil and is desulfurized at many refineries before it is sent to an isomerization unit. However, a number of refineries do not have isomerization units and therefore, some or perhaps many of these refineries may not be treating this stream today. Natural gas liquids (also termed pentanes plus) are naphtha streams sourced from natural gas wells, which are purchased by refiners, and blended into the gasoline pool. Depending on the source of the specific naphtha stream being purchased, these streams could vary widely in gasoline sulfur, ranging from a few ppm sulfur up to several hundred ppm sulfur.

Refiners have multiple options for addressing the sulfur levels of these various streams. The LSR and natural gas liquids can be hydrotreated in either the FCC posttreaters or the naphtha hydrotreaters. Because these naphtha streams do not have any olefins, there is essentially no octane loss and, therefore, hydrogen consumption is lower compared to hydrotreating FCC naphtha. Another way of treating these streams would be to use caustic extraction to extract the mercaptan sulfur from these streams. Since only the mercaptans are removed with the extraction technology, the final sulfur level would not be as low compared to desulfurization using hydrotreating. If the crude oil that is being refined by a particular refinery is low in sulfur, the refiner would likely only need to use extractive desulfurization to ensure that the sulfur in the LSR is adequately low under Tier 3. Finally, the refiner could choose to simply not purchase the natural gas liquids and sell the LSR on the open market as opposed to treating these streams. If a refiner decides to not treat the LSR or natural gas liquids, other refiners with excess capacity in their FCC posttreaters or naphtha hydrotreaters could purchase that volume, treat these streams and blend the volume into their gasoline pool.

For the NPRM, we did not know whether butane being blended by refiners still has high sulfur content and if refiners would need to treat it under Tier 3. We therefore assumed that some refiners might have to treat butane using extractive desulfurization licensed by UOP (Merox) or Merichem. A vendor we spoke to explained that almost all butane is being treated today using extractive desulfurization and the final sulfur level is under 5 ppm.

In summary, to comply with a 10 ppm gasoline sulfur standard, refiners have a range of options available to them that mostly involve reducing the sulfur content of the FCC naphtha. If a refinery has a high pressure FCC pretreater, the refiner may be able to turn up the hydrotreating severity of that unit. If a refinery has a low or medium pressure FCC pretreater and no posttreater, the refinery would likely need to either install a grassroots FCC posttreater to comply

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with a 10 ppm gasoline sulfur standard, or reduce sulfur as much as possible with its current capital and rely on the ABT program for the remainder. Refiners with FCC posttreaters have multiple options. If a refinery is short on octane and hydrogen, the refiner is likely to invest in capital (e.g., a second stage reactor) to avoid as much octane loss and hydrogen consumption as possible. However, if the refiner has a lot of excess octane and hydrogen, the refiner may choose to avoid any capital cost investments or only make small capital investments and tolerate the higher octane loss and hydrogen consumption by simply turning up the severity of its current FCC posttreater. Refineries with posttreaters could always invest in an FCC pretreater (hydrotreater or mild hydrocracker) to improve margins or produce more low sulfur diesel fuel. Finally, in blending up their gasoline, some refiners may still be blending in some produced or purchased gasoline blendstocks with high enough sulfur levels to be of concern when faced with the Tier 3 sulfur standard. Several options exist for addressing the sulfur in these gasoline blendstocks.

It should be noted that the preceding is EPA's best assessment of the steps refiners would have to take to comply with Tier 3. Refiners may choose to pursue alternative strategies that further other business objectives and also enable compliance with Tier 3 (e.g., installation of hydrocrackers, conversion of FCC feed hydrotreaters to mild hydrocrackers). It is not possible for EPA to project such alternative strategies on a refinery-by-refinery basis. While such alternative strategies may be triggered by or timed with actions to comply with Tier 3, they are not, and should not be, considered to be Tier 3 compliance actions.

#### 4.2.3.4 Demonstrated Compliance with a 10 ppm Gasoline Sulfur Standard

Currently, there are multiple cases of refiners complying with 10 ppm or lower gasoline sulfur programs. The State of California requires gasoline sold in the State to meet a 15 ppm gasoline sulfur standard on average and a 20 ppm cap (California gasoline's per-gallon sulfur cap dropped to 20 ppm on January 1, 2012). Furthermore, refiners can produce gasoline which varies in composition, provided that the California Predictive Emissions Model (which, like EPA's Complex Model, estimates vehicle emissions from fuels of varying composition) confirms that the proposed fuel formulation meets or exceeds the emissions reduction that would occur based on the default fuel requirements. California refineries are using the flexibility provided by the Predictive Model to surpass the prescriptive standards for gasoline sulfur and are producing gasoline which contains around 10 ppm sulfur on average. They are making this very low sulfur gasoline despite using Californian and Alaskan crude oils which are heavier and more sour than most other crude oils being used in the U.S. today. Thus, the experience in California demonstrates that commercial technologies already exist to permit refiners to produce very low sulfur gasoline.

Japan currently has a 10 ppm gasoline sulfur cap that took effect January 2008. Europe also has a 10 ppm sulfur cap that has been adopted by the 30 Member States that comprise the European Union (EU) and the European Free Trade Association (EFTA) as well as Albania and Bosnia-Herzegovina. Under a 10 ppm cap standard, the gasoline sulfur level likely averages about 5 ppm. Although gasoline in Japan and Europe is made from different crude oil sources and much of the heavier ends are cut into diesel fuel, these international fuel programs (along with California) provide evidence that advanced gasoline desulfurization technologies have been deployed and are readily available enable compliance with the proposed Tier 3 fuel program.

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#### 4.2.3.5 Improved Feasibility with the ABT Provisions

The averaging, banking and trading (ABT) and small refiner and small volume refinery aspects of the proposed Tier 3 gasoline sulfur program would ease the feasibility of compliance with the program. In the absence of the small refiner and small volume refinery provisions, all refineries would have to comply with the 10 ppm gasoline sulfur standard by January 1, 2017. Most refiners would have to make capital investments in their refineries to enable compliance with the 10 ppm gasoline sulfur standard by this date. These investments include revamped FCC pretreaters and posttreaters, and the installation of grassroots FCC posttreaters. As described above, reaching 10 ppm sulfur in the gasoline pool is feasible by each refinery. However, refiners assess the economic feasibility of their refineries differently depending on past and expected future economic performance. They therefore have different tolerances for making capital investments and absorbing increased operating costs. This is particularly true when gasoline demand is projected to be flat and renewable fuel blending is expected to increase. Refiners who own small refineries are concerned about the higher per-barrel costs for the capital installed at those small refineries.

The small refiner and small volume refinery provisions will delay compliance for these entities until January 1, 2020. Small refiners need more time because they have smaller engineering staffs that they can dedicate to oversee the necessary refinery changes, thus they are more likely to complete the necessary changes to their refineries later than large refiners. The banking provisions of the ABT program effectively phase in the sulfur standard over six years starting in 2014 through the end of 2019. The phase-in allows refiners to stagger their investments to their economic advantage. Refineries that are expected to incur the lowest costs for achieving lower gasoline sulfur levels can comply early and earn sulfur credits. These credits can then be used to demonstrate compliance starting in 2017 by refineries that are expected to incur higher costs for reducing their gasoline sulfur levels allowing those refineries to delay investments for lowering their gasoline sulfur. This phase-in of the gasoline sulfur standard will help spread out the various aspects of the construction process by the US refining industry complying with the sulfur standard including: the preliminary design demands on the vendor companies that license the desulfurization technology to refiners, the detailed design demands on the engineering companies that provide that service to refiners, the permitting demands on the states that must provide environmental permits to refiners, and the demands on the fabrication shops that construct the reactors and other major hardware which must be installed at refineries to realize the gasoline sulfur reductions. For more on how the proposed ABT provisions are expected to help with lead time, refer to Section 4.3.

Finally, the averaging provisions of the ABT program will provide additional flexibility and help to reduce the costs of the gasoline sulfur program. The averaging provisions will allow refiners to reduce the gasoline sulfur levels to under 10 ppm at their lower cost refineries and generate credits to sell to refiners who would purchase the credits for higher cost or financially challenged refineries.

#### 4.2.3.6 Implications of an Average Gasoline Sulfur Standard Less than 10 ppm

Although a more stringent sulfur standard than 10 ppm would increase the emission benefits of Tier 3, there are practical reasons for finalizing a 10 ppm annual average sulfur

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standard instead of a more stringent standard, e.g., 5 ppm or even a 10 ppm cap imposed in parts of Europe and in Japan. The lower the sulfur standard, the more costly it is for refiners to achieve the lower sulfur standard, and a 5 ppm average standard is much more costly than a 10 ppm average standard. We identified several reasons why the costs increase so much for more deeply desulfurizing the gasoline pool.

First, as desulfurization severity increases, the operating and capital costs associated with desulfurizing FCC naphtha also increases. FCC naphtha is very rich in high-octane olefins. As the severity of desulfurization increases, more olefins are saturated, further sacrificing the octane value of this stream and further increasing hydrogen consumption. Also, as desulfurization severity increases, there is an increase in the amount of the removed sulfur (in the form of hydrogen sulfide) which recombines with the olefins in the FCC naphtha, thus offsetting the principal desulfurization reactions. There are means to deal with the recombination reactions; however, this probably means either higher hydrogen consumption and octane loss, or greater capital investments. For example, the most expensive capital investment for an FCC posttreater is a two stage desulfurization unit. A sulfur standard less than 10 ppm would likely require more refiners to invest in a second stage for their FCC posttreater.

Second, as shown in Table 4-2, other refinery streams contain very modest amounts of sulfur, yet a 5 ppm sulfur standard would likely require desulfurization of some of these streams. Because refineries have different sulfur levels in their non-FCC streams based on their feedstock sulfur levels and their configurations, those with higher sulfur levels in other refinery streams may have to desulfurize additional streams. Each additional individual gasoline stream that requires desulfurization is incrementally a lot more expensive than addressing the sulfur from the FCC unit because more volume has to be processed. The amount of sulfur reduction is a lot lower, and the capital costs are higher on a per-barrel basis for lower volume gasoline blendstock streams.

Third, further desulfurization of gasoline down to 5 ppm essentially removes the flexibility offered by the 10 ppm gasoline sulfur standard with the ABT program. Each U.S. refinery is in a different position today, both technically and financially, relative to the other refineries. In general, they are configured to handle the different crude oils they process and turn their crude oil slate into a widely varying product slate to match their available markets. Those processing heavier, sour crudes would have a more challenging time reducing gasoline sulfur under the proposed Tier 3 program. Also, U.S. refineries vary greatly in size (atmospheric crude capacities range from less than 5,000 to more than 500,000 barrels per day) and thus have different economies of scale for adding capital to their refineries. As such, it is much easier for some refineries to get their sulfur levels below 10 ppm than for others to reach 10 ppm. This allows the ABT program to be used to reduce the cost of the proposed gasoline sulfur standard. If the gasoline sulfur standard were to be 5 ppm, the ability of refiners to average sulfur reductions across their refineries would likely end and thus, significantly increase the capital and operating costs while significantly reducing the desulfurization flexibility.

Our cost estimates for a 5 ppm average standard as compared to a 10 ppm average sulfur standard bears this out. We estimate the average cost for a 10 ppm gasoline sulfur standard (assuming nationwide credit trading) to be 0.65 ¢/gal compared to 1.27 ¢/gal for the 5 ppm standard. The cost per sulfur reduction (marginal cost) for the 10 ppm average standard is 0.65

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¢/gal for the 20 ppm sulfur reduction from Tier 2, which averages 0.045 ¢/gal for each ppm of sulfur reduction. The marginal cost for the 5 ppm standard is 0.49 ¢/gal for the 5 ppm sulfur difference from the 10 ppm average standard, which averages 0.098 ¢/gal per each ppm of sulfur reduction, which is over 2 times higher. Therefore, we believe that an annual average standard of 10 ppm at the refinery gate with an ABT program is reasonable and maximizes the amount of sulfur reduction and the associated emission reductions before the costs begin to steeply escalate.

We note that in most European countries and Japan, the gasoline sulfur level is capped at 10 ppm. We, however, are not considering a 10 ppm cap for the U.S. due to the increased cost and increased challenges of ensuring compliance for every batch of fuel. The cost estimates described above for 5 ppm do not capture any additional costs refiners might need to incur to deal with offspec batches of fuel that get produced. Therefore, we are finalizing a 10 ppm average sulfur standard coupled with 80 and 95 ppm caps at the refinery gate and downstream, respectively, similar to what currently exists under the Tier 2 program. We believe this is the most prudent approach for lowering in-use sulfur while maintaining flexibility considering cost and other factors. These per-gallon caps are important in the context of an average sulfur standard to provide an upper limit on the sulfur concentration that vehicles must be designed to tolerate. Since there are many opportunities for sulfur to be introduced into gasoline downstream of the refinery, these caps also limit downstream sulfur contamination and enable the enforcement of the gasoline sulfur standard in-use. For more on our consideration of downstream caps, refer to Section 4.2.4.2.

#### 4.2.4 Challenges with Lowering Today's Sulfur Caps

##### 4.2.4.1 Impacts of Lowering the 80 ppm Refinery Cap

We are maintaining the existing 80 ppm refinery gate cap standard in the final Tier 3 fuel standard. For the NPRM, we considered lowering this cap to either 50 ppm or 20 ppm. If we lowered the refinery cap standard to 20 ppm, then refiners would only be able to take advantage of very little of the averaging aspect of the ABT program. That is because, under a 20 ppm cap standard, we estimate that the maximum sulfur level that refineries could average is about 14 ppm sulfur. Thus, the compliance scenario if the cap standard were 20 ppm would essentially be the same as the non-ABT case we analyzed. In this case, refiners would have little of the flexibility offered by the ABT program.

If the cap standard were to be lowered to 50 ppm, the final compliance scenario under the Tier 3 fuels program would be somewhere between the ABT scenario that we analyzed and the non-ABT scenario that we analyzed (probably much closer to the ABT case). Under a 50 ppm cap standard, we estimate that the maximum average gasoline sulfur level that refineries could average is 35 ppm. Although EPA batch data shows 40 refineries that averaged between 35 and 80 ppm sulfur during 2011, our cost modeling shows only 8 of those would continue to average more than 35 ppm under a 10 ppm average standard and an 80 ppm cap. If the 80 ppm cap were to be reduced to 50 ppm, we project that those 8 refineries that averaging over 35 ppm would be forced to reduce their sulfur levels below 35 ppm regardless of their compliance costs. . Thus, the 10 ppm average standard reduced the number of refineries that average greater than 35 ppm sulfur from forty to eight.

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A more stringent cap would also affect refiners' ability to process high sulfur FCC naphtha when there is a short term shutdown of the FCC posttreater. If the FCC posttreater goes down, the refinery would likely continue operating the FCC unit and store up the high sulfur FCC naphtha. Since the FCC naphtha is too high in sulfur to blend directly with gasoline, the refinery would have to either sell the high sulfur FCC naphtha to other refiners, or hydrotreat the stored up FCC naphtha along with the ongoing hydrotreating of high sulfur FCC naphtha once the FCC posttreater was back online. If a stringent cap were in place, the refiner would have little room for short term production of higher sulfur gasoline if it was feeding a larger than normal quantity (stored and new production) of FCC naphtha to the FCC posttreater. A stringent sulfur cap may cause refiners to oversize the FCC posttreater and add additional FCC naphtha storage to ensure that, regardless of the higher feed volume needed to process the stored material, the FCC naphtha desulfurization unit could continue to desulfurize the FCC naphtha down to the required sulfur level to comply with the cap standard and ultimately the 10 ppm average standard. If the cap were to be lowered, a 50 ppm cap standard would continue to provide refiners with some flexibility while a 20 ppm cap would not. As shown in Section 4.4.2, refiners are currently taking full advantage of the flexibility offered by the 80 ppm cap standard offered under Tier 2.

#### 4.2.4.2 Downstream Sulfur Caps

The feasibility of complying with a downstream sulfur cap is dependent on the differential between the refinery/importer gate sulfur cap and the downstream cap. This differential must provide sufficient flexibility for worst-case situations when the potential sources of sulfur addition downstream of the refinery/importer compound in a single batch of gasoline that was introduced into the system at the refinery/importer gate sulfur cap.

We proposed, and are finalizing an 80 ppm refinery gate sulfur cap and 95 ppm downstream sulfur cap. These requirements are applicable under the current Tier 2 gasoline program. Therefore, under the Tier 3 program, we are maintaining the same 15 ppm differential between refinery gate and downstream sulfur caps that currently exists under the Tier 2 program. This 15 ppm differential has proven to be sufficient to accommodate the unavoidable addition of sulfur downstream of the refinery gate from contamination during distribution, the use of additives, and the disposition of transmix generated during distribution.

The downstream sulfur cap applies at all locations downstream of the refinery or importer gate including the gasoline produced by transmix processors and after the use of additives. The potential sources of sulfur addition downstream of the refinery/importer gate and issues associated with the feasibility of meeting the downstream sulfur cap are discussed in the following subsections.

##### 4.2.4.2.1 *Sulfur Addition Downstream of the Refinery and Importer Gate*

The sulfur content of gasoline can increase downstream of the refinery/importer due to contamination during distribution, the use of additives, and the disposition of transmix generated during distribution.

A small amount of sulfur contamination takes place during distribution as a result of the shipment of gasoline over long distances by pipeline and other modes due to the sharing of the

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same distribution assets with other higher-sulfur petroleum products, e.g., jet fuel. Steps can be taken to limit sulfur contamination. However, it is an unavoidable feature of the efficient multi-product distribution system in the U.S. We estimate that sulfur contamination of gasoline can be limited to a worst case maximum of 3 or 4 ppm in the future, even for the most involved and long-distance distribution pathways. Typical levels of sulfur contamination will likely be much lower given the removal of many sources of sulfur contamination in the fuel distribution system in recent years.

There were no direct regulatory controls on the sulfur content of gasoline additives under the Tier 2 program. The contribution to the sulfur content of finished gasoline from gasoline additives is accommodated in the differential between the refinery gate and downstream sulfur caps. The functional components of some gasoline additives such as silver corrosion inhibitors and demulsifiers are inherently high in sulfur content. However, the contribution to the overall sulfur content of the finished fuel is very limited. For example, silver corrosion inhibitors can contain as much as 30 percent sulfur but because of very low treatment rates can add only 0.17 ppm to the sulfur content of the finished fuel.<sup>33</sup> At seldom used highest treatment rates, the use of gasoline additives upstream of the consumer has the potential to add ~1 ppm to the sulfur content of the finished fuel. Aftermarket additives that are added directly into the vehicle fuel tank also have the potential to increase gasoline sulfur content. One particular aftermarket performance and anti-wear additive can contribute ~2 ppm sulfur to the treated fuel.<sup>B34</sup>

Transmix is a necessary byproduct of the multi-product refined product pipeline distribution system. Batches of different products are shipped in sequence in pipelines without any physical barrier between the batches. Transmix is produced when the mixture at the interface between two adjacent products cannot be cut into either batch. Transmix typically accumulates at the end of pipeline systems far from refineries. There are two methods of disposing of transmix. Most transmix is sent to transmix processing facilities for separation into saleable distillate and gasoline products through use of a simple distillation tower.

The other means of transmix disposal is for pipeline operators to blend small quantities directly into batches of gasoline during shipping. This typically takes place at remote pipeline locations where small volumes of transmix accumulate that would be difficult to consolidate and ship to transmix processors. Pipeline operators that blend transmix into the gasoline in their systems must ensure that the resulting gasoline meets all fuel quality specifications and the endpoint of the blended gasoline does not exceed 437 °F.<sup>C35</sup> This practice currently can add as much as 3 to 5 ppm to the sulfur content of gasoline although we believe that the contribution is typically less.

Transmix processing facilities do not handle sufficient volumes to support the installation of currently-available desulfurization units. Therefore, the sulfur content of the products they produce is predominantly governed by the sulfur content of the transmix they receive. In many cases, transmix contains jet fuel which can have a sulfur content as high as 3,000 ppm. Due to

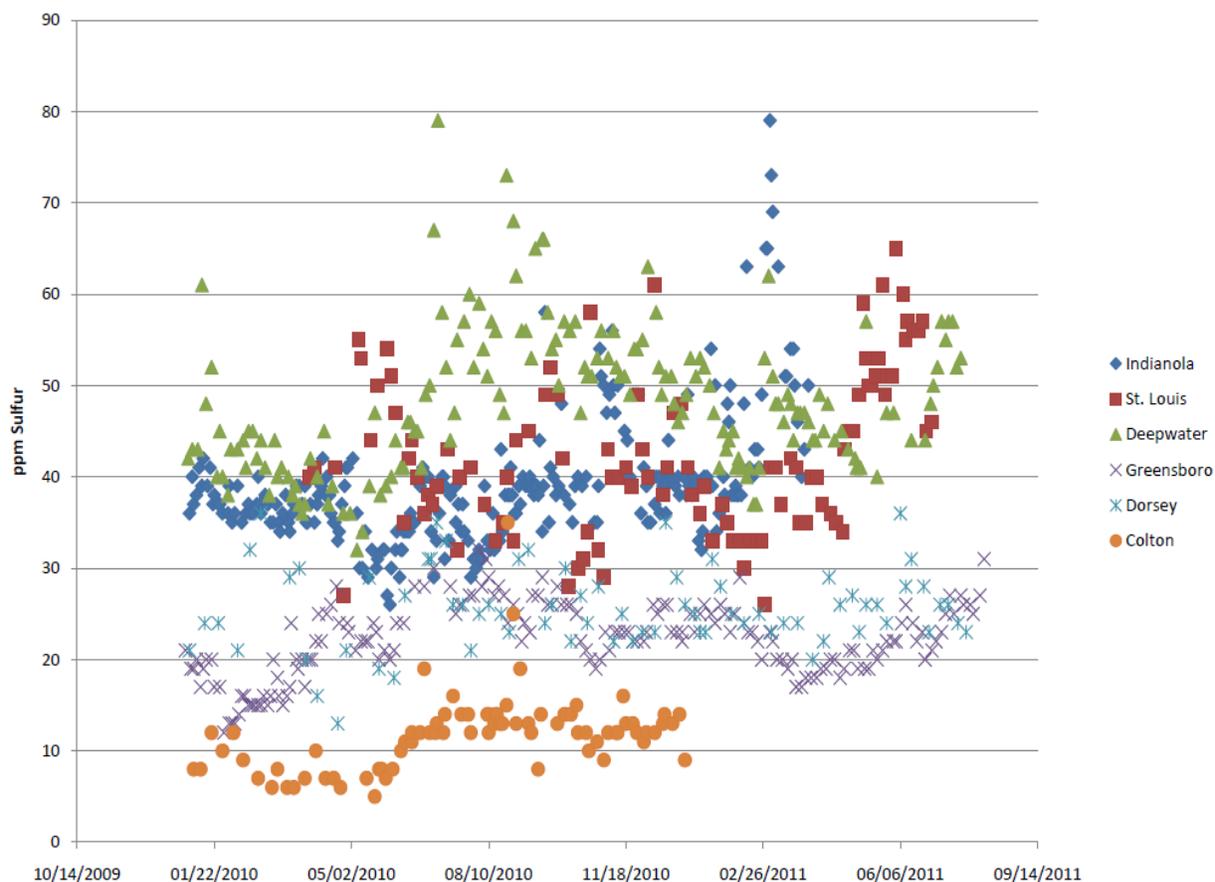
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<sup>B</sup> Aftermarket additives are defined as additives sold to vehicle operators for direct addition to vehicle fuel tanks.

<sup>C</sup> 437 F is the maximum endpoint allowed for gasoline in the ASTM International specification for gasoline in ASTM D4814.

the overlapping distillation characteristics of jet fuel and gasoline, it is unavoidable that some jet fuel in transmix will be present in the gasoline produced by transmix processors.

Transmix processors produce ~0.1 percent of all gasoline consumed in the U.S. The small volume of transmix-derived gasoline along with the fact that such gasoline is typically mixed with other gasoline before delivery to the end user, substantially limits the potential impact on gasoline sulfur levels. Furthermore, data provided by the largest operator of transmix processing facilities, shown in Figure 4-2, indicates that relatively few batches of the gasoline they produce approach 80 ppm sulfur.<sup>36</sup> Most batches are approximately 10 ppm above the current 30 ppm refinery sulfur average. We anticipate that this 10 ppm differential would likely continue under the 10 ppm refinery average sulfur standard.



**Figure 4-2 Kinder Morgan Transmix Gasoline Product Sulfur Levels**

*4.2.4.2.2 Maintaining the Current 15 ppm Differential Between the Refinery /Importer Gate and Downstream Sulfur Caps*

The 80 ppm refinery gate and 95 ppm downstream sulfur caps finalized today maintains the current 15 ppm differential between the refinery/importer gate sulfur cap and the downstream sulfur cap.

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The current 15 ppm differential was established under the Tier 2 program to accommodate the sulfur contamination during distribution, the sulfur contribution from transmix blending by pipeline operators, the sulfur contribution from the use of additives, and to enable compliant gasoline to be produced by transmix processors. Transmix processors need to produce gasoline sufficiently below the downstream sulfur cap to accommodate the addition of sulfur from the use of additives and contamination during further distribution. Experience under the Tier 2 program has shown that a 15 ppm differential is sufficient for downstream parties to ensure compliance with the downstream sulfur cap

Maintaining the current 95 ppm downstream sulfur cap with an 80 ppm refinery/importer gate sulfur cap under the Tier 3 program represents no change from current requirements. As a result, there will be no increased difficulty or additional costs associated with satisfying a 95 ppm downstream sulfur cap beyond those that were already incurred under the Tier 2 program. Furthermore, the reduction in the refinery average sulfur standard under the Tier 3 requirements may make it somewhat easier to comply with the downstream sulfur cap given that most gasoline produced would be at or near 10 ppm sulfur.

#### *4.2.4.2.3 Cap on Sulfur Contribution to Gasoline from the use of a Gasoline Additive*

The Tier 3 rule requires that each gasoline additive may add no more than 3 ppm sulfur to the sulfur content of gasoline when used at the maximum recommended treatment rate. All current gasoline additives are currently compliant with this requirement. Therefore, implementing this requirement will not place an additional burden on gasoline additive manufacturers. We are implementing this requirement to preclude the possibility that high sulfur blendstocks might be added to gasoline in the guise of a gasoline additive.

### **4.3 Sulfur Credits**

We conducted an analysis of 2012 Tier 2 Gasoline Sulfur Credit Banking and Allotment Generation Reports submitted to EPA by U.S. refineries to ascertain the availability of sulfur credits and the fluidity of the sulfur credit trading market. These reports must be submitted by producers and importers of gasoline destined for sale in the United States. Such facilities submit Credit Banking and Allotment Generation Reports for sulfur credits it possesses or possessed over a given year. This data is Confidential Business Information.

Sulfur credits must be used by the refiner that generated them or they can be transferred up to two times. These credits may be used at the refinery where they were generated, banked by a refiner for future use or use at another one of its refineries, or sold/transferred to another refiner. If a transferee does not use credits that they purchased, they may transfer them to another party; the second transferee must then use or bank the credits (i.e., they cannot be transferred again). Credits have a five-year life span from the year of generation. As such, 2007 credits expired at the end of 2012.

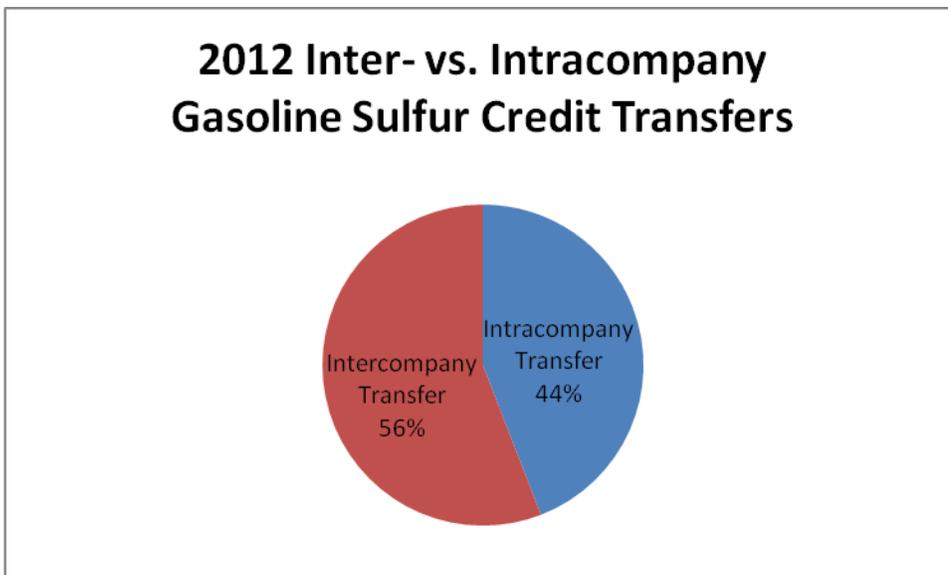
We performed several analyses of the data including: (a) the use of intercompany gasoline sulfur credit trading, (b) 2012 gasoline sulfur credit balances, (c) gasoline sulfur credit usage by age, and (d) the reduction of gasoline sulfur levels over time.

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The analysis revealed the number of gasoline sulfur credits banked by refiners as well as the extent to which gasoline sulfur credits are traded within a parent company (intra-company) and between competing parent companies (intercompany). These metrics, coupled with information on the gasoline sulfur credit usage and the reduction of gasoline sulfur levels over time under the current Tier 2 program, provides an indication of the ability and flexibility of refineries to rely on trading of credits for compliance with the Tier 3 standards being finalized today.

#### 4.3.1 Intra- and Inter-Company Trading

Our analysis found that approximately 44% of sulfur credits transacted in 2012 were transferred intra-company whereas approximately 56% of gasoline sulfur credits transacted were transferred between competing parent companies (Figure 4-3), suggesting the existence of a robust and fluid gasoline sulfur trading market.



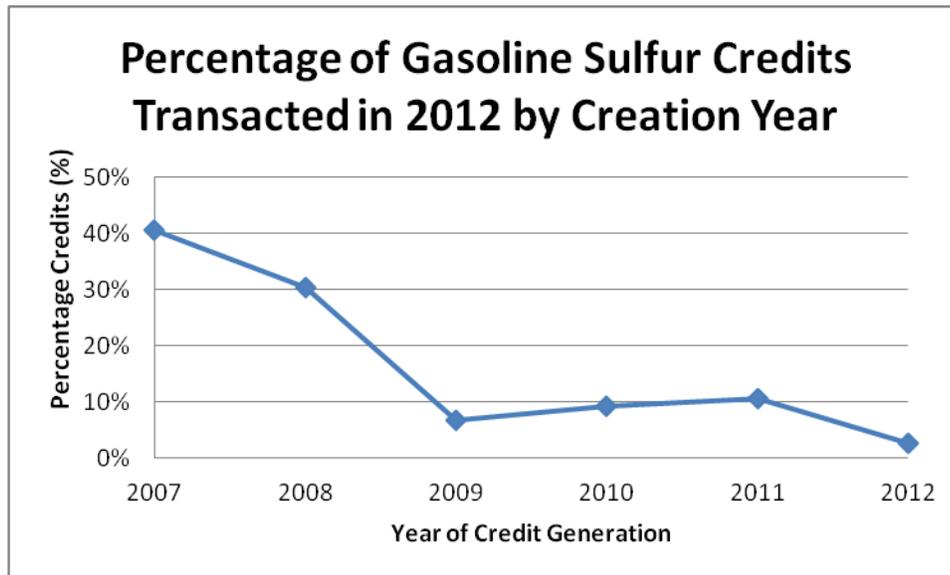
**Figure 4-3 2012 Inter- vs. Intra-company Gasoline Sulfur Credit Transfers**

#### 4.3.2 Tier 2 Sulfur Credit Analysis

Credits under the current Tier 2 program have a five year life, which means they could still be used in 2017. For the final Tier 3 program, we are allowing Tier 2 credits to be carried over for use in complying with Tier 3. As a result, we assessed gasoline sulfur credit availability for 2012. Our analysis of the number of sulfur credits generated and the number of sulfur credits used and transferred resulted in a difference of just under 400 billion ppm-gallon sulfur credits in 2012. This equates to 2-3 months of compliance with the 10 ppm Tier 3 standard. If refiners were to simply continue to accrue at this rate until 2017 without taking any additional actions to comply early with Tier 3, gasoline sulfur credits generated by refineries would afford approximately a one-year delay in implementation of the standard.

Of the gasoline sulfur credits transacted in 2012, 40% were generated in 2007, 30% were generated in 2008, 7% were generated in 2009, 9% were generated in 2010, 11% were generated

in 2011, and 3% were generated in 2012 (Figure 4-4). Thus, a refiner's willingness to trade gasoline sulfur credits varies with the time remaining until credits expire. Gasoline sulfur credits set to expire at the end of 2012 (i.e., credits generated in 2007) were traded thirteen times more often than sulfur credits generated in 2012, which expire at the end of 2017. Thus, having a finite credit life is helping to stimulate the robustness of the current credit trading market.

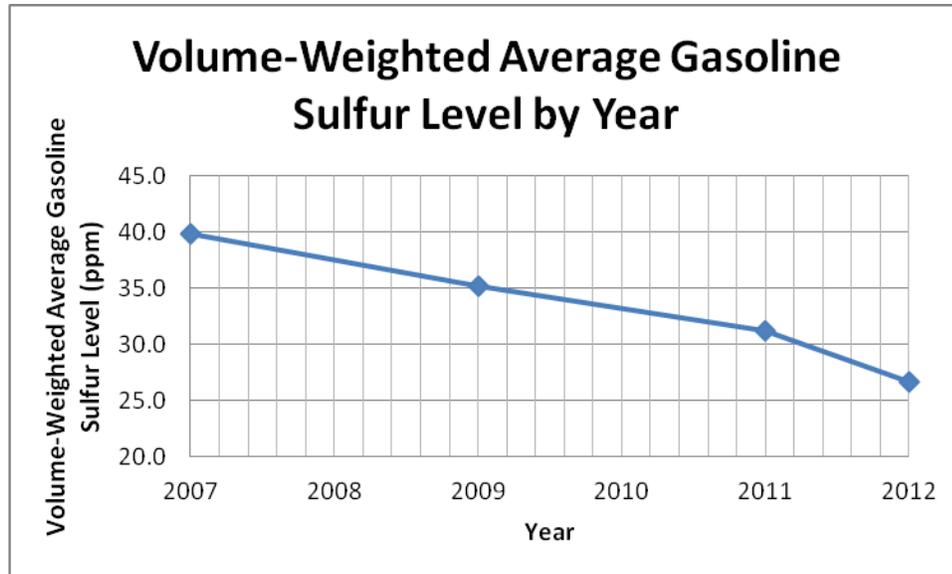


**Figure 4-4 Percentage 2012 Gasoline Sulfur Credits Transacted by Year of Generation**

#### **4.4 Sulfur Level Analysis**

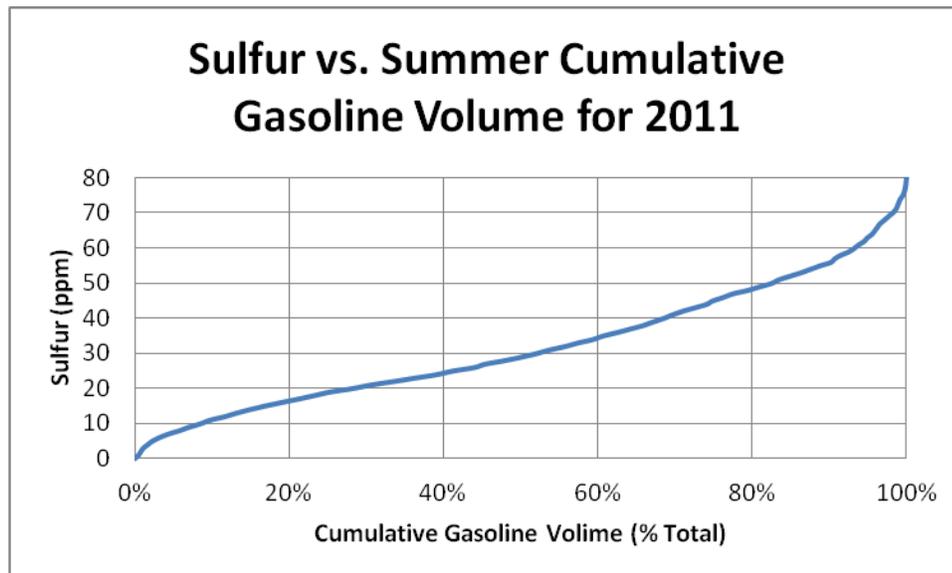
##### **4.4.1 Volume-Weighted Gasoline Sulfur**

The analysis also revealed that volume-weighted average gasoline sulfur levels have decreased steadily over the period for which we analyzed data. In 2007, the volume-weighted gasoline average sulfur concentration was 39.8 ppm, 35.2 ppm for 2009, 31.2 ppm for 2011, and 26.7 for 2012 (Figure 4-5). The steady decline over time was driven by the continued pressure of the Tier 2 standards. The last flexibilities in the program for a subset of small refiners ended in 2011. The additional drop in 2012, however, represents over-compliance with the Tier 2 30 ppm average standard.



**Figure 4-5 Volume-Weighted Average Gasoline Sulfur Level by Year**

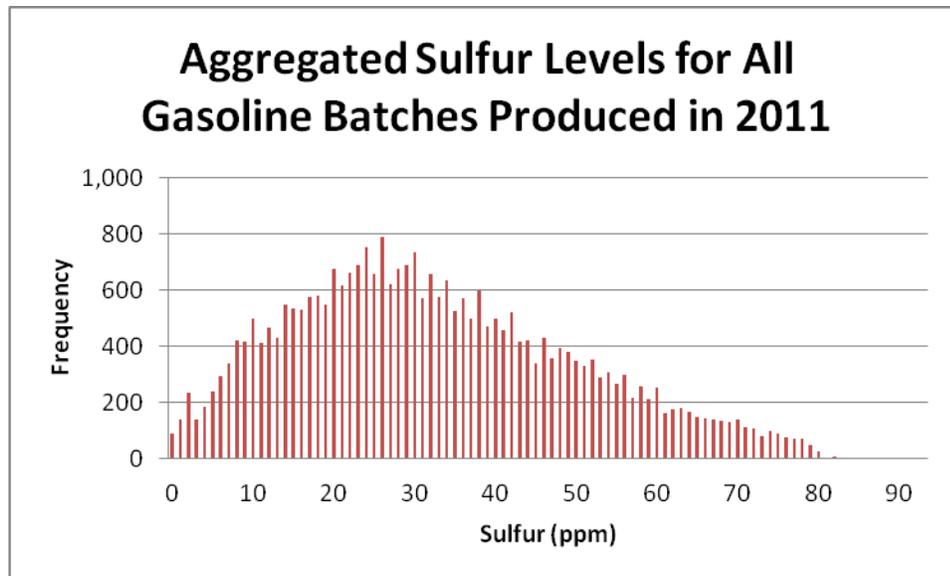
Sulfur levels by summer cumulative gasoline volume for 2011 are depicted in Figure 4-6.



**Figure 4-6 Sulfur Levels versus Summer Cumulative Gasoline Volume for 2011**

#### 4.4.2 Batch-to-Batch Sulfur Variability

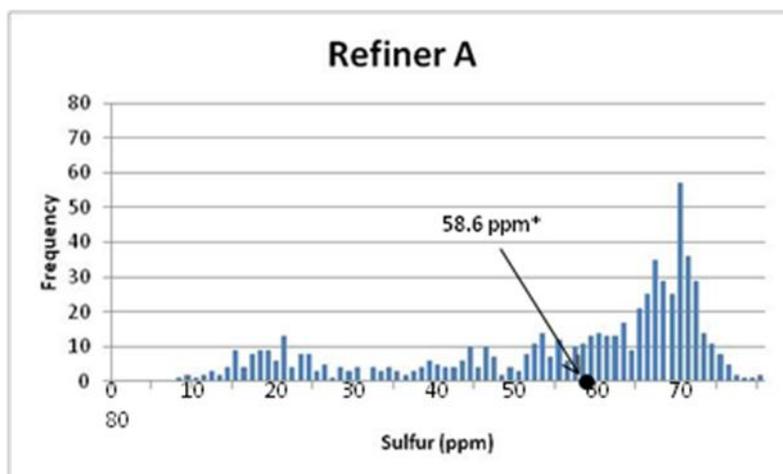
Our analysis also revealed the extent of batch-to-batch variability of gasoline sulfur. While such variability is suggested when examining the aggregated sulfur levels for all gasoline batches produced in a year, as in Figure 4-7, the implications of this variability is not clearly evident until gasoline sulfur is examined at the refiner-level.



**Figure 4-7 Aggregated Sulfur Levels for All Gasoline Batches Produced in 2011**

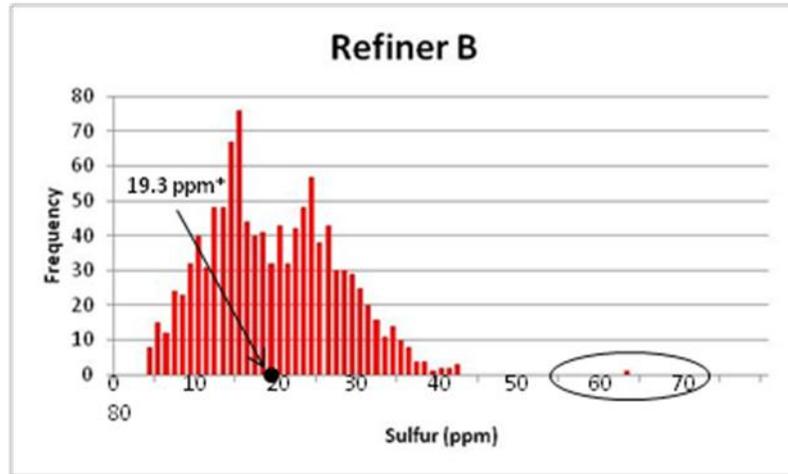
Average gasoline sulfur varies significantly between refiners as well as between gasoline batches produced by the same refiner, as can be seen in Figures 4-8a-d. These figures depict 2011 gasoline sulfur levels by batch frequency for four refineries from the analysis. In addition to providing insight into the volume-weighted average gasoline sulfur and the minimum and maximum gasoline sulfur, the figures also capture the broad distribution of sulfur levels and their skewness for gasoline batches produced by refiners.

For instance, the average gasoline sulfur for Refiner A (Figure 4-8a) is relatively high (58.6 ppm), with a broad range between minimum (8 ppm) and maximum (80 ppm). However, the data are negatively skewed, with most of the observations centered around 70 ppm – well-above the volume-weighted average – and, to a lesser extent, along a shallow tail to the left (with lower sulfur values). These lower values offset the higher observations centered about 70 ppm.



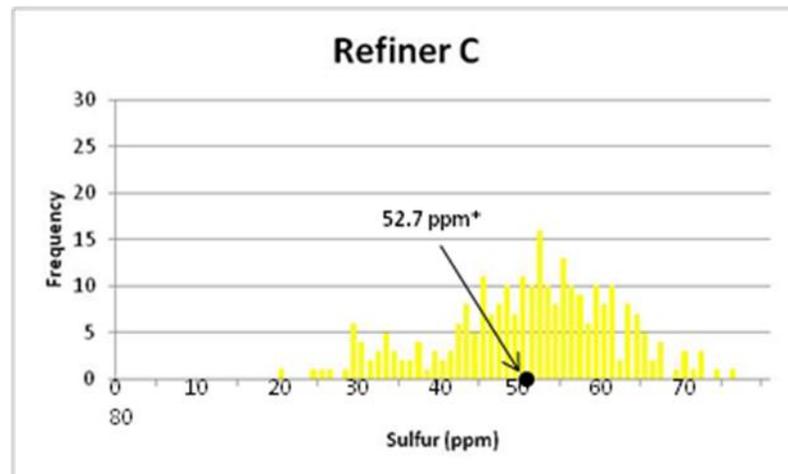
**Figure 4-8a Sulfur Concentration Versus Batch Frequency for Refiner A**

Average sulfur for Refiner B is considerably lower than Refiner A (19.3 ppm versus 58.6 ppm), and the data have a much smaller range (4 ppm minimum and 42 ppm maximum), with only a single higher observation at 63 ppm observation (Figure 4-8b). Unlike Refiner A, the gasoline sulfur for Refiner B is distributed bimodally about 15 and 25 ppm and is fairly symmetrical about the average of 19.3 ppm. The sulfur observations for Refiner B are not negatively skewed, as is the case for Refiner A.



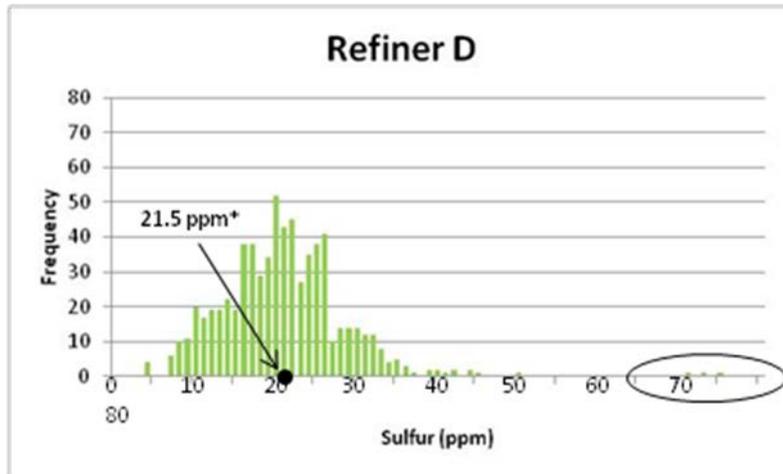
**Figure 4-8b Sulfur Concentration Versus Batch Frequency for Refiner B**

Like Refiner A, the volume-weighted average sulfur for Refiner C is relatively high (52.7 ppm), with a similarly broad range between minimum (20 ppm) and maximum (76 ppm) (Figure 4-8c). However, unlike Refiner A – which is negatively skewed – these data are largely symmetrical about the volume-weighted gasoline sulfur average.



**Figure 4-8c Sulfur Concentration Versus Batch Frequency for Refiner C**

Like Refiner B, the volume-weighted average sulfur for Refiner D is relatively low (21.5 ppm), with a similarly broad range between 4 ppm and 51 ppm, with just a few observations between 70-75 ppm (Figure 4-8d). And as with Refiner B, the data for Refiner D are largely distributed symmetrically about the volume-weighted sulfur average. See Table 4-3 for a summary of these parameters.



**Figure 4-8d Sulfur Concentration Versus Batch Frequency for Refiner D**

**Table 4-3 Summary of Statistics for Four Typical Refiners**

<b>Refiner</b>	<b>Sulfur Average</b>	<b>Sulfur Minimum</b>	<b>Sulfur Maximum</b>	<b>Sulfur (25<sup>th</sup>%)</b>	<b>Sulfur (75<sup>th</sup>%)</b>
Refiner A	58.6	8.0	80.0	44.0	70.0
Refiner B	19.3	4.0	63.0	13.0	25.0
Refiner C	52.7	20.0	76.0	45.0	58.0
Refiner D	21.5	4.0	75.0	16.0	26.0

Given the significant variability in batch-to-batch gasoline sulfur, the data suggest that a low sulfur average with a high sulfur cap allows refiners to minimize operating costs by providing flexibility to those refiners producing gasoline above the average standard while providing incentive to those refiners producing gasoline below the average standard.

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In addition, the data demonstrate the flexibility provided by a high cap to allow normally low sulfur gasoline-producing refiners to still market occasional higher sulfur batches of gasoline during abnormal operating conditions. Finally, the data show that the combination of an average standard with a higher cap allows refiners considerable batch-to-batch flexibility in producing individual batches of gasoline while still reducing the overall sulfur level.

#### **4.5 Lead Time Assessment**

We received a several comments in support of and against our proposed rule regarding feasibility assessment and lead time. Commenters in the refining industry generally stated that the amount of lead time proposed was not sufficient. These commenters noted concerns that the short lead time proposed would drive up costs as there would be unscheduled shut-downs to install and/or revamp equipment to meet the Tier 3 sulfur standard, and would not provide enough time for the permitting process. These commenters requested at least five years of lead time, and noted that EPA has historically provided at least four years of lead time in previous fuels rulemakings. Commenters in the auto industry, as well as states and non-governmental organizations (NGOs), encouraged us to finalize the rule as soon as possible and to retain the January 1, 2017 start date to harmonize our program with California's LEVIII program and to enable Tier 3 benefits as soon as possible. As discussed in more detail below, we believe the amount of lead time provided is sufficient, especially given the flexibilities being provided. A complete discussion on the comments received with regard to lead time can be found in Chapter 5 of the Summary and Analysis of Comments document.

While evaluating the merits of a national gasoline sulfur program to reduce emissions and enable future vehicle technologies, we also considered the refining industry's ability to reduce sulfur to 10 ppm on average by January 1, 2017 and the associated costs (for more on fuel costs, refer to Chapter 5). Based on information gathered from numerous stakeholder meetings and discussions with vendor companies that provide the gasoline desulfurization technologies both before and after the proposal, as well as the results from our refinery-by-refinery modeling, we believe it is technologically feasible at a reasonable cost for refiners to meet the sulfur standards in the lead time provided. A summary of our feasibility analysis is presented below.

##### **4.5.1 Employment Constraint Analysis**

As in prior rules, we also evaluated the capability of E&C industries to design and build gasoline hydrotreaters as well as performing routine maintenance. This includes an employment analysis. Two areas where it is important to consider the impact of the fuel sulfur standards are: 1) refiners' ability to procure design and construction services and 2) refiners' ability to obtain the capital necessary for the construction of new equipment required to meet the new quality specification. We evaluated the requirement for engineering design, and construction personnel, in a manner consistent with the Tier 2 analysis, particularly for three types of workers: front-end designers, detailed designers and construction workers, needed to implement the refinery changes. We developed estimates of the maximum number of each of these types of workers needed throughout the design and construction process and compared those figures to the number of personnel currently employed in these areas.

The number of person-hours necessary to design and build individual pieces of refinery equipment and the person-hours per piece of equipment were taken from Moncrief and Ragsdale<sup>37</sup>. Their paper summarizes analyses performed in support of a National Petroleum Council study of gasoline desulfurization, as well as other potential fuel quality changes. The design and construction factors for desulfurization equipment are summarized in Table 4-4.

**Table 4-4 Design and Construction Factors<sup>a</sup>**

<i>Gasoline Refiners</i>	
Number of New Pieces of Equipment per Refinery	60
Number of Revamped Pieces of Equipment per Refinery	15
<i>Job Hours Per Piece of New Equipment<sup>a</sup></i>	
Front End Design	300
Detailed Design	1,200
Direct and Indirect Construction	9,150

Note:

<sup>a</sup> Revamped equipment estimated to require half as many hours per piece of equipment

Refinery projects will differ in complexity and scope. Even if all refiners desired to complete their project by the same date, their projects would inevitably 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.

Applying the above factors, we projected the maximum number of personnel needed in any given month for each type of job. The results are shown in Table 4-5. In addition to total personnel required, the percentage of the U.S. workforce in these areas is also shown, assuming that half of all projects occur in the Gulf Coast in Table 4-5. Refineries are generally expected to not require the full 24-month period to complete scoping studies, process design, permitting, detailed engineering, field construction, and start-up/shakedown for revamping an existing FCC posttreater.

**Table 4-5 Maximum Monthly Demand for Personnel**

	Front-End Design	Detailed Engineering	Construction
<i>Tier 3 Gasoline Sulfur Program</i>			
Number of Workers	51	202	1,503
Percentage of Current Workforce <sup>a</sup>	3%	2%	1%

Note:

<sup>a</sup>Based on current employment in the U.S. Gulf Coast assuming half of all projects occur in the Gulf Coast

To meet the Tier 3 sulfur standards, refiners are expected to invest \$2.0 billion between 2014 and 2019 and utilize approximately 250 front-end design and engineering jobs and 1,500 construction jobs. The number of estimated jobs required is small relative to overall number available in the U.S. job market. As such, we believe that because of the ABT program with its flexibilities such as generous early credit generation period, that there is adequate lead time for refineries to obtain necessary permits, secure E&C resources, install new desulfurization equipment and make all necessary retrofits to meet the sulfur standards.

We conducted a refinery-by-refinery analysis to determine the impacts on refinery E&C demand of implementing the 10 ppm standard without an ABT program. The analysis suggests that a greater number of refineries would need to make investments in refinery apparatus and upgrades without an ABT program than would be required with an ABT program. This would result in a greater demand on the E&C industry. Moreover, the analysis also indicated that the demand upon the E&C industry would be spread over a shorter period than with the ABT case. In particular, our refinery-by-refinery analysis indicates that without an ABT program, 72 refineries would revamp existing pre- and posttreaters and 18 would install grassroots posttreaters in order to meet the Tier 3 sulfur standards. The remaining 18 refineries are either already in compliance with the 10 ppm standard or expected to comply with simple process changes. This is compared to 66 refineries that would revamp existing pre- and posttreaters and one refinery that would install grassroots posttreaters in order to meet the Tier 3 sulfur standards under an ABT program.

#### 4.5.2 Can Refiners Meet the January 1, 2017 Start Date?

An adequate amount of lead time is required for the implementation of any rulemaking. Depending on the level of effort required to comply, more or less lead time is also required. In the case of Tier 3, refiners need time to select the technology and the vendor that will provide the technology with which they will comply with the fuels standard. Next, they need time to arrange an engineering and construction (E & C) contractor which will design and oversee the construction of the refinery unit and the time needed to obtain the necessary permits and procure the necessary hardware. Next, refiners need time to construct the unit. Finally, the refiner needs time to make the necessary unit tie-ins of the unit with the rest of the refinery and then startup the unit.

This section explains that when taking into account the time to revamp existing FCC posttreater units or build grassroots posttreater units, tie-in the new or revamped units with the rest

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of the refinery and considering the flexibility offered by the ABT program, refiners will be able to comply with the Tier 3 program within the lead time provided.

#### 4.5.2.1 Time Required to Install Grassroots Units and Revamp Existing Units

The technologies for complying with Tier 3 are well known and well proven. As previously explained, refiners which complied with Tier 2 using FCC naphtha desulfurization technologies installed the following units, all of which were grassroots installations: Axens Prime G+, CDTech's CDHydro and CDHDS, UOP's ISAL, Sinopec's S-Zorb and Exxon's Scanfining. Prior to choosing a technology, refiners needed to evaluate each these different technologies and choose among them, all of which were largely untested at the time, which required us to provide more lead time for Tier 2. Since it has been 9 years since the Tier 2 sulfur standard began to be phased in, refiners now have direct experience with the installation and operation of these technologies and the vendor companies that license them and continue to support their installations onsite. This fact will allow refiners to reach a decision very quickly when complying with Tier 3, particularly, because in most cases the refiners will solely be revamping the units installed for Tier 2 when complying with Tier 3.

Based on our discussions with refiners, construction companies, vendor companies and from published literature, we estimated the time it takes to revamp existing posttreaters and install grassroots posttreaters. Revamping an existing posttreater is expected to require up to two years. Installing a grassroots posttreater is estimated to require three years. Figure 4-6 reflects these project completion times showing the various major intermediate steps for completing the projects.<sup>D</sup>

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<sup>D</sup> The timeline shows overlap between steps which reflect actions that can be taken to set up the following step while the previous step is being completed. For example, refines can establish the contract for the detailed engineering while the process design is being completed. Refiners can begin site preparation to prepare for construction before the detailed design is completed. Finally, refiners can test individual pieces of equipment as they are installed and while construction is ongoing to find problems that would streamline unit start-up and avoid delays

**Figure 4.6 Estimated Project Lead Time for Revamps and Grassroots Units**

		0-	3-	6-	9-	12-	15-	18-	21-	24-	27-	30-	33-
		6	9	12	15	18	21	24	27	30	33	36	
Revamp Pre- & Posttreaters	Scoping Studies	■	■	■									
	Process Design		■	■	■								
	Permitting			■	■	■	■						
	Detailed Engineering				■	■	■	■					
	Field Construction						■	■	■	■			
	Start-up / Shakedown							■	■	■	■		
Grassroots Posttreater	Scoping Studies	■	■	■									
	Process Design		■	■	■	■							
	Permitting			■	■	■	■						
	Detailed Engineering				■	■	■	■	■				
	Field Construction						■	■	■	■	■	■	
	Start-up / Shakedown								■	■	■	■	■

We believe that the revamping of posttreaters could take less time than what we estimate in Figure 4-6 because many of the Tier 3 revamps are expected to be very modest (e.g., change out a reboiler or heat exchanger). Since EPA held discussions with many refiners in 2011 about EPA’s plan to pursue additional sulfur control post-Tier 2 (Tier 3), refiners began the process of assessing how they would comply. The Tier 3 proposal was delayed for about a year and it is our understanding from recent discussions with vendor companies and some refiners that, during this time, many refiners began assessing how they intended to comply with Tier 3. Thus, many refiners likely have completed the scoping studies, which involves technology selection, and in the case of grassroots units, vendor selection as well (refiners with a particular posttreater technology in most cases are expected to simply revamp the same vendor’s technology, so there is no need to select a vendor). If refiners have already completed their scoping studies, we estimate that installation of the revamps or grassroots units would be about 3 months shorter than the 2 and 3 years, respectively, than we estimate in Figure 4-6.

These project timelines are reasonable in light of past industry experiences that show FCC posttreaters being installed in refineries in less time than what we estimate. At the Motiva refinery in Port Arthur, TX, a grassroots CDTech posttreater was designed, constructed and started up in less than 2 years.<sup>38</sup> At two refineries in Germany, two Prime G+ units were designed, constructed and started up – one of them in two years, and the other in 18 months.<sup>39</sup>

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As an extreme example, the \$3.6 billion dollar, 180 kbbbl/day crude oil expansion at Marathon's Garyville, LA refinery was designed, constructed and started up in less than 4 years.<sup>40</sup> This single project involved the construction of 10 major refinery units, and permitting required only 9 months. Since these may be best case examples, we continue to believe the projections provided above in Figure 4-6 are reasonable.

#### 4.5.2.2 Program Flexibility that Extends Lead Time

The final Tier 3 program includes an ABT program that would significantly help refiners comply with the January 1, 2017 start date. There are three provisions of the ABT program which helps with respect to leadtime.

The ABT program allows for ongoing intra-company and inter-company trading nationwide. This will allow some refineries to over-comply with the 10 ppm gasoline sulfur standard (in our analysis, we modeled these refineries bringing their gasoline down to 5 ppm), allowing other refineries that would otherwise need to install grassroots units to not invest and purchase credits instead. This aspect of the ABT program is very important because our analysis estimates that only one refinery would need to install a grassroots hydrotreater whereas without the ABT provisions, there could be as many as 20 grassroots units. This one aspect has important implications for leadtime because as discussed in the previous subsection, revamps require two years or less whereas grassroots FCC postreater units require approximately three years to install. We are convinced that this aspect of the ABT program will be utilized to the maximum extent possible because refineries revamping their postreaters in lieu of installing grassroots postreaters results in the most cost-effective mechanism for meeting the 10 ppm annual average standard.

An important question is whether refiners will not invest in a grassroots unit trusting that the credits will be freely available. For the NPRM, we conservatively assumed that refiners would only rely on credits if they could generate them internal to the company. As discussed in Section 4.4, we assessed how the sulfur credits were being traded under Tier 2 and we found that over half the sulfur credits were freely traded between companies (as opposed to only being used within companies), and many single-refinery companies had sulfur levels above 30 ppm (single-refinery companies must purchase credits from other companies). Because we set up the Tier 3 credit trading program to work just like the Tier 2 credit trading program, we are confident that there will be widespread trading within and between refining companies which means that few grassroots units will be need to be built for Tier 3.

A second aspect of the ABT program that helps with leadtime is the provision for generating early sulfur credits and banking them for later use. This provision allows refineries to reduce their gasoline sulfur to less than 30 ppm prior to January 1, 2017 and bank the credits for later use. Based on comments that we received on the proposed rule, we are allowing Tier 2 credits which are generated during the years 2012 and 2013 to also be used to show compliance for Tier 3. This effectively extends the early credit generation period for Tier 3 to encompass the years 2012 to 2016, which is 5 years. Analyzing the 2012 gasoline quality data that refiners reported to EPA, we found that gasoline sulfur levels in the U.S. averaged 26.7 ppm. Thus, refiners have already begun overcomplying with Tier 2 by 3.3 ppm, and are therefore already generating early credits for Tier 3. If refiners do nothing more but continue to overcomply with

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Tier 2 by 3.3 ppm over the 5 years of early credit generation, refiners will have generated enough credits to delay the completion of their capital projects by more than one year. Furthermore since those credits generated in 2012 and 2013 will expire in 2017 and 2018 respectively, refiners will have an incentive to either use them themselves or trade them in 2017 and 2018. Thus refiners that may need to count on them to delay their capital investment are likely to be able to have access to them.

We believe that refiners will generate a lot more early credits with their existing gasoline sulfur control units than the 3.3 ppm we observed in 2012. As we discussed in our cost analysis, to produce more diesel fuel in response to a greater demand for diesel fuel relative to gasoline, refiners are undercutting the swingcut portion of FCC naphtha at their refineries.<sup>E</sup> This action to shift what historically was blended into the gasoline pool to the diesel fuel pool, also dramatically reduces the sulfur content of the gasoline pool. If the entire swingcut portion of FCC naphtha is undercut to the diesel fuel pool, the amount of sulfur in the gasoline pool is reduced by about 50 percent. Our cost analysis estimates that at almost one quarter of U.S. refineries, refiners are fully undercutting the FCC naphtha to diesel fuel today. At many other refineries, our cost analysis estimates that refiners are partially undercutting their FCC naphtha. These refineries will be able to reduce the sulfur of their gasoline well below their current levels and generate a large number of early credits for Tier 3. Even for the subset of refineries where FCC naphtha is not being undercut, refiners can assess how much activity or catalyst life is left in its FCC posttreater catalyst and compare this time with the time to the next turnaround when the FCC posttreater catalyst is scheduled to be replaced. If there is spare catalyst life, the refiner could elect to increase the severity of their postreaters to reduce their gasoline sulfur levels to under 30 ppm. With this strategy, the refiner would generate early sulfur credits. Also, when the refiner replaces the catalyst in its Tier 2 posttreater, it can elect to do so with a more active catalyst which would allow the refinery to produce gasoline at sulfur levels below 30 ppm and generate more early credits for Tier 3.

Based on the early actions refiners are either already taking, or could take, to reduce their gasoline sulfur levels, we believe that refiners would be able to reduce their gasoline sulfur to as low as 20 ppm, on average, without making any capital investments. By averaging 20 ppm for 2.5 years prior to 2017, refiners would be able to delay completion of all capital investments for Tier 3 until mid 2019. If we add the 3.3 ppm of credits during 2012, 2013 and first part of 2014, refiners would be able to delay completion of all capital investments in Tier 3 until 2020. Thus, the early credit provisions in-effect can provide nearly 6 years of leadtime for full compliance with the fuels program. This will allow ample time for refiners to complete their investment and schedule their tie-ins during normal shutdown activities. It effectively provides even more lead time than 5 years that the refining industry requested in their comments. The delay in the program implementation will also help to distribute the demand on the E & C industry over more years ensuring that the E & C industry would not be overwhelmed. Thus, the Tier 3 program with a very flexible ABT program provides ample leadtime.

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<sup>E</sup> The term swingcut means that this portion of the FCC product pool can be blended into gasoline or diesel fuel while still meeting the fuel quality specifications for either fuel regardless of where this swingcut is blended.

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A third aspect of the Tier 3 ABT provisions which helps with leadtime is that small refiners and small volume refineries (i.e., refineries processing less than or equal to 75,000 net barrels per day of crude oil) are exempted from complying with the 10 ppm average sulfur standard until 2020. This provides an estimated 36 refineries, of the total 108 refineries, nearly 6 years of lead time; again more than the 5 years that the refining industry requested in their comments. As a group, we believe that these refiners and refineries are disproportionately impacted when it comes to their cost of compliance and ability to rationalize investment costs in today's gasoline market. Giving these refiners and refineries additional lead time provides more time to invest in desulfurization technology, take advantage of advancements in technology, develop confidence in a Tier 3 credit market as a means of compliance, and avoid competition for capital, engineering, and construction resources with the larger refineries. The small refiner and small volume refinery exemption until 2020 reduces the number of refineries which will need to make a significant capital investment to comply with Tier 3 prior to 2020 to a total of 49 non-small refineries (48 revamps and 1 grassroots unit), thus 15 refineries could wait to take action until 2020 (see Table 4-8 below). The provisions for small refiners and small volume refineries are discussed in more detail in Section V.E.1 of the preamble. Although the small refiners and small volume refineries are not required to comply with Tier 3 until 2020, they can still generate early credits (from January 1, 2017 through December 31, 2019) relative to 30 ppm for sale to other small refiners/small volume refineries, and relative to 10 ppm for sale to non-small refiners. Such credits generated relative to 10 ppm could provide another pool of early credits for Tier 3.

In summary, the ABT program provides ample flexibility for complying with Tier 3. The averaging provisions will allow refiners that only need to revamp their Tier 2 posttreaters to overcomply and generate credits which will allow refineries that otherwise need to install grassroots units to comply solely through the purchasing of credits. The banking provisions, which allow refiners to generate early credits, effectively delays investments for compliance to potentially as late as the year 2020. Finally, the small refiner and small refinery provisions delay compliance for approximately 30 refiners until 2020. The provisions also allow them to generate and sell credits during this period if they so choose. All these ABT provisions effectively address the leadtime concerns. Furthermore, were we to shift the start date back another 2 years as the refinery industry suggests in their comments, it would provide nearly 8 years of leadtime for refinery changes that require just 2 or 3 years to complete. Refiners would not have to even begin taking action for Tier 3 for a couple of years. Given that the lead time and associated programmatic flexibility we are finalizing is sufficient to allow industry to readily comply; we do not expect that a delay in the start date of the fuel standards would change the cost of compliance discussed in Chapter 5. Any further delay in the program start date would simply delay the actions to comply. Furthermore, delaying the start of the program would forego significant emissions, air quality, and health benefits.

#### 4.5.2.3 Impact of Turnaround Timing

In their comments to the proposed Tier 3 rulemaking, the oil industry stated that the time it takes to comply with the proposed 10 ppm gasoline sulfur standard must include the time it takes to tie-in the revamps and grassroots units. The oil industry suggested that the leadtime for Tier 3 be increased to 5 years to allow for refiners to make their investments needed to comply with Tier 3 and tie-in those new investments. We agree that the need to make tie-ins must be

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considered when assessing the feasibility of leadtime, and even when we factor the time needed to do so, our analysis shows that refiners can comply with Tier 3 with the leadtime provided. This is true because the final rule effectively provides nearly 6 years of leadtime to complete capital projects, as described above, and also because the capital projects do not have to be completed prior to installing the necessary tie-ins for new Tier 3 units.

When a refiner builds a grassroots unit or some sort of revamp that involves a new reactor or perhaps an added distillation column, the new vessels and associated equipment must be “tied-in” to the rest of the refinery. The tie-in usually involves connecting a pipe from the existing unit to the new unit installed. However, a pipe cannot simply be added while the refinery is operating. Instead, the refiner will add the necessary pipe for making the tie-in when the refinery is shutdown for regular maintenance. The revamp or grassroots unit does not have to be started up at that time. Instead, the connection pipe just needs to be added and blocked off with a sealing-type valve and a blind flange (essentially a flat piece of steel) is bolted on as a precaution against a leaky valve. This is a very simple process that would take several pipefitters a half a day of work to complete including completing all the necessary safety protocols.<sup>F</sup> Once this piping has been added, the refiner can restart its refinery. Then when the refiner is ready to complete the tie-in to the completed revamp or grassroots unit, the refiner would remove the blind flange and connect a pipe that connects the existing part of the refinery to the newly installed grassroots postreater unit or revamp postreater subunit. This last step can either occur when the refinery is shutdown or still operating. At that point the refiner would only need to open the block valve to complete the tie-in of the grassroots unit or revamp to the existing refinery. One refiner who owns a number of refineries informed us that it installed the tie-ins for a possible Tier 3 rule when it installed its Tier 2 units.

On its webpage, the American Petroleum Institute (API) reports that the average time between major turnarounds is 4 years when the U.S. refineries perform maintenance on the FCC unit.<sup>41</sup> An Energy Information Administration (EIA) study makes a similar finding, which is that refiners target 3 – 5 years, or 4 years on average, between refinery turnarounds.<sup>42</sup> This means that on average, 25% of U.S. refineries shutdown to perform maintenance on its FCC units each year. Most often, refiners conduct maintenance turnarounds on their refineries during the spring when the demand for gasoline and diesel fuel is at their lowest. The EIA study also found that over 25% of the time refiners need to conduct turnarounds earlier than targeted because a maintenance issue forces the earlier turnaround. However, the EIA study did not estimate how much earlier the turnaround occurred so it was not possible to estimate an actual average turnaround schedule, which is likely less than 4 years.

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<sup>F</sup> Since most refiners have already completed their scoping studies with the vendor companies which license the desulfurization technologies, they likely already understand what steps would need to be taken to tie-in their revamps and grassroots units with their existing refinery. Installation of tie-ins is relatively simple refinery change that can be engineered and installed in a short period of time. For this reason, we believe that refiners can begin making their tie-ins as soon as the spring of 2014,

<sup>G</sup> This analysis is focused on the projected emissions increase (step 1) and the net emissions increase calculation (step 2). Even if a project results in a significant emissions increase, the source may be able to demonstrate that the net emissions increase is insignificant and thus the project does not constitute a major modification.

If refiners reduce their gasoline sulfur to 20 ppm immediately after the Tier 3 rule is finalized, as we anticipate they are capable of, then the substantial number of early credits generated would allow refiners to delay their unit start-ups sufficiently for refiners to not only make the tie-ins, but even complete their capital projects as necessary. However, we also conducted another analysis which assesses the ability of refiners to comply with Tier 3 if they generate no or few early credits. Using the estimate that turnarounds are scheduled at refineries every 4 years and the output from our refinery-by-refinery model, we analyzed how the need for refiners to tie in the new revamps and grassroots units affects the ability for refiners to comply with the Tier 3 program start date. Our refinery-by-refinery cost model projects how refiners will comply with the 10 ppm average gasoline sulfur standard at their refineries while minimizing the costs for doing so under the ABT program. Our modeling projects that the ABT program will result in a preference of revamps over grassroots units, and refiners desulfurizing their gasoline to 5 ppm at some refineries and generating credits that would allow refiners to not reduce the sulfur at other refineries requiring grassroots units. Also, small refiner and refinery provisions delay the Tier 3 start date for the refineries covered by these provisions until the year 2020. Table 4-6 summarizes our estimate for the numbers of refineries which will need to comply in 2017 and also in 2020, when the Tier 3 gasoline sulfur program is fully phased-in.

**Table 4-6 Summary of Investment Types in 2017 and 2020 Assuming no Early Credit Use**

		Grassroots Units	Revamps	No Investments
Refineries Complying in 2017	10 ppm	0	31	19
	5 ppm	1	21	
Small Refiners/Refineries Complying in 2020	10 ppm	0	8	21
	5 ppm	0	7	
Total	10 ppm	0	39	40
	5 ppm	1	28	

Table 4-6 shows that to comply in 2017 without the use of early credits, 1 grassroots unit will be installed and 54 existing postreaters will be revamped to comply with the 10 ppm gasoline sulfur standard. Table 4-6 shows that some refineries would overcomply with the 10 ppm gasoline sulfur standard by producing gasoline which contains 5 ppm sulfur and generate credits which would be purchased by refiners to show compliance because it would be more expensive at their refineries to reduce their gasoline sulfur to 10 ppm. Thus, 19 refineries will

not need to reduce their gasoline sulfur to comply in 2017 because they purchase credits instead. Thirty six small refineries and refineries owned by small refiners will not need to invest for 2017 because they don't need to comply until 2020.

With an estimate of the number of revamps and grassroots units needed for 2017, we can superimpose the tie-in timing that we believe would occur as refiners comply. Since the Tier rule was finalized by early 2014, we believe that refiners will begin to make their Tier 3 tie-ins starting in the spring of 2014. Thus, refiners will have the years of 2014, 2015 and 2016 to make their tie-ins during a regularly scheduled refinery turnaround, thus roughly three-quarters of the tie-ins could occur before the January 1, 2017 compliance date. The other quarter of revamped refineries would need to wait until the spring of 2017 to make their tie-ins. For the one grassroots unit, the tie in could be made anytime during the years from 2014 to 2017, but because we project that a grassroots unit requires three years until unit start-up, we project that the grassroots unit would start-up in the spring of 2017. Table 4-7 summarizes the unit startup timeline that accounts for the need for refiners to tie-in their revamped or grassroots units. Since we do not have data for when individual refineries are shutting down their FCC units and existing posttreaters, we conducted a simple averaged analysis which assumes that each of the refineries is producing the same volume of gasoline and that each refinery earns credits for a year of compliance. To avoid confusion with how credits are generated under Tier 2, we call these compliance units (one compliance unit is equal to one refinery earning 20 ppm (30 minus 10 ppm) credits or purchasing credits for one year).

**Table 4-7 Example Case of Compliance Unit Balance for Tier 3**

	Revamps installed 2 years after T3 Published (April 2016)	Program Start Jan. 1, 2017	Tie-ins made so that Revamps can start-up - 4 Months after Program Start (April 2017)	Grassroots units start up 16 Months after Program Start (April 2017)	Total Compliance Units <sup>a</sup>
# Revamps	39		13		
# Grassroots				1	
Compliance Unit Balance <sup>a</sup>	26		-4.3	-0.33	21.4

<sup>a</sup> Compliance units are a simplified representation for credits, whereas one refinery's compliance with Tier 3 (producing 5 or 10 ppm gasoline instead of 30 ppm gasoline) represents one compliance unit for each year of compliance.

Table 4-7 shows that 39 of the total 52 revamps will have completed their tie-ins during the years 2014, 2015 and 2016 and will have the ability to start up immediately upon completion of construction of their revamped Tier 3 units. The startup of these revamps is estimated to be at the end of April 2016, about two years after Tier 3 is published. We believe that this is a

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conservative assumption because many revamps will not require the full two years to design, construct and start up. For example, we don't discount the time required to complete these projects due to the fact that most refiners already completed their scoping studies before Tier 3 was finalized. Even with this conservative set of assumptions, these refineries are estimated to generate 26 compliance units – 26 compliance units are generated because those 39 refineries are operating for two thirds of a year (May through December) before the compliance date of January 1, 2017. For the other 13 revamps and the one grassroots unit, they are assumed to start up at the end of April of 2017, which is one third of a year after the official program start date which would require the purchase of about 5 compliance units. The 26 compliance units generated greatly exceed the 5 compliance units needed to be purchased by the revamped and grassroots refineries estimated to start-up after January 1, 2017. It is important to point out that we did not assume any generation of early compliance units (early credits) in this analysis, thus no compliance units were created from 2012 through 2016, except for the revamps which started up in early 2016.

While many refiners likely could begin to make their tie-ins in 2014, which would likely be before they have completed their finished design, many other refiners could also wait until 2015 before they start to do so. We also assessed the leadtime feasibility if we assume that tie-ins don't begin until the spring of 2015, thus tie-ins are made in the spring of 2015, 2016, 2017 and 2018. Table 4-10 shows the number of refineries which would start up in the spring of each year based both on the time to construct the revamps and the grassroots unit and taking into account when the tie-ins are estimated to occur. Case 1 of Table 4-8 assumes that no early compliance units (early credits) are generated by refiners. Case 2 shows the compliance unit balance for Tier 3 if US refineries (including all the refineries not investing for 2017) average just 1 ppm lower sulfur starting in 2012, generating early compliance units over those 5 years. Case 3 shows the compliance unit balance for Tier 3 assuming that US refiners will average 3 ppm lower sulfur starting in 2012 (data provided by refiners to EPA shows that the US refining industry averaged 26.7 ppm sulfur in 2012, which is greater than 3 ppm lower than what the 30 ppm Tier 2 sulfur program requires). This analysis in Table 4-8 is really a business as usual case. Case 4 that we conducted assumed that all refineries average 27 ppm from 2012 until mid-2014, and 20 ppm from mid-2014 until they start up, therefore generating 3 and 10 ppm worth of compliance units, respectively.

**Table 4-8 Example Cases of Compliance Unit Balances for Tier 3**

	Early Compliance Units <sup>a</sup> 2012 - 2016	Revamps installed 2 years after T3 Published (April 2016)	Tie-ins made so that Revamps can start-up (April 2017) <sup>b</sup>	Grassroots and Revamp units start up (April 2018) <sup>b</sup>	Total Compliance Units <sup>a</sup>
# Revamps		26	13	13	
# Grassroots				1	
Case 1 Compliance Unit <sup>a</sup> Balance (no early credits)		17.3	-4.3	-20	-7.0
Case 2 Compliance Unit <sup>a</sup> Balance (1 ppm early credit)	27	16.5	-4.1	-17.7	21.7
Case 3 Compliance Unit <sup>a</sup> Balance (3 ppm early credits)	81	14.7	-3.7	-15.9	76.1
Case 4 Compliance Unit <sup>a</sup> Balance (3/10 ppm early credits)	175.5	8.7	-2.2	-9.3	172.7

a Compliance units are a simplified representation for credits, whereas one refinery's compliance with Tier 3 (producing 5 or 10 ppm gasoline instead of 30 ppm gasoline) represents one compliance unit for each year of compliance.

b The reason why the values in these columns are decreasing as early credit increase is due to the fact that the sulfur level declines below 30 ppm reducing the number of compliance units needing to be purchased

As shown in the upper row in Table 4-8, we conservatively assume no early compliance units are generated in Case 1 other than the start-up of the 26 revamps in early 2016. This case shows that the 17.3 early compliance units generated by the revamps which start up in April of 2016 are insufficient to supply the 24.3 needed compliance units. To show how easy it would be to satisfy the demand for purchasing compliance units, Case 2 shows the compliance unit balance if we assume that all US refineries generate early compliance units by reducing their

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gasoline sulfur by only 1 ppm starting in 2012 (the gasoline they are producing is 29 ppm instead of 30 ppm). For this Case, the very modest additional compliance unit generation that occurs from 1 ppm of early credit generation (added to the revamps which start up in the spring of 2016) easily shifts the compliance units balance to a positive balance because the 43.5 early compliance units generated exceeds the 21.8 compliance units demanded. Case 3 assumes that refiners produce gasoline which averages 27 ppm sulfur, slightly higher than the level already being achieved in 2012. For this partial compliance case the 95.6 compliance units generated exceeds the 19.6 compliance units demanded by a large margin. Case 4, which assumes that refineries average 27 ppm until mid-2014 and 20 ppm afterwards, shows that the 184 compliance units generated exceed the 11.5 compliance units demanded by about a factor of seventeen. These analyses demonstrate that if the US refining industry generates a very modest number of early credits, that there is ample leadtime for refiners to comply with Tier 3.

#### 4.5.2.4 Hardship

While we project that there will be plenty of credits available to allow refiners to complete their capital investments and tie in the new or revamped unit to the rest of their refinery, we provide another option to refiners as a safety valve in case there is a shortfall of credits. In the case where a refiner cannot complete its project by January 1, 2017 and credits are not available or are prohibitively expensive, the refiner may file a hardship waiver. Details about our hardship provisions can be found in Section 5.E.2 of the preamble.

#### 4.5.3 Permitting Analysis

To meet the Tier 3 standards, it will be necessary for some U.S. refineries to install new equipment and/or modify existing equipment and processes resulting in increased emissions of some regulated air pollutants. Refinery projects designed to meet the new fuel standards could trigger preconstruction air permitting requirements under the Clean Air Act and the EPA's New Source Review (NSR) regulations.

EPA has updated our refinery-by-refinery assessment of the physical and operational changes that are likely to be needed to allow each active refinery in the U.S. to produce gasoline that complies with the final Tier 3 fuel specifications. We have also assessed the likely effects of those changes on refinery emissions. This updated assessment is described in more detail below. Using this updated assessment, we were able to update our understanding of the potential scope of the major NSR permitting requirements refiners might face under the final Tier 3 program. In general, our assessment indicates that only a small number of refineries will likely need to make modifications of a type and size that would trigger the need for a PSD or nonattainment NSR permit.

In our updated analysis, we adjusted several inputs to reflect the existence of a nationwide average, banking, and trading (ABT) program and refined our estimates regarding the physical and operational changes that will be required at each refinery. The modifications at a given refinery could include revamps to existing FCC pre- or post-treatment unit(s) or the installation of a new grassroots post-treatment unit for sulfur reduction. Based on the updated projections of refinery-specific changes, we re-estimated the increased demand for energy (i.e., fuel to generate process heat, steam, and electricity), hydrogen, and sulfur recovery associated

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with meeting the final Tier 3 standards. Having received no comments suggesting that they should be changed, we re-applied the representative industry emission factors for NAAQS pollutants, their precursors, and GHGs for each emitting process and combined them with estimates of incremental activity to estimate the emissions changes at each equipment unit (or group of similar units) at each refinery.

Resulting emissions increases were compared to pollutant-specific “major modification” permitting thresholds under the NSR regulations, including Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NA NSR), as applicable. Refineries projected to trigger PSD and/or NA NSR for specific regulated NSR pollutants were identified.

In summary, the permitting analysis results support the conclusion that NSR permitting impacts associated with the final Tier 3 fuel standards are limited, with only 3 refineries projected to trigger PSD and/or NA NSR for criteria pollutants and an additional 6 refineries projected to trigger PSD for GHGs only under the worst case impact scenario.

In comparison, for the Tier 2 program, EPA expected the need for NAAQS-related NSR permits might be widespread among refineries. For the final Tier 3 gasoline sulfur standard, however, only about 3 refineries would need air permits that address NAAQS pollutants.

This number could be lower if these refineries apply emission controls, such as selective catalytic reduction (SCR) for NO<sub>x</sub>, to reduce the emission increases below the significance level. For refineries that do need a major source NSR permit for NAAQS pollutants, the permitting process is expected to take 9 - 12 months. For an in depth assessment of stationary source implications, refer to Section V.K of the preamble.

#### 4.5.3.1 Calculation Approach

A “major modification” is a physical change or change in the method of operation that results in a significant emissions increase and a significant net emissions increase.<sup>G</sup> In accordance with the major NSR applicability procedures contained in the federal regulations, the calculation approach for determining whether a significant emissions increase will occur depends upon the type of emissions units involved in the project. Three different tests can potentially apply: (1) the actual-to-projected-actual test for projects that involve only existing emissions units, (2) the actual-to-potential test for projects that only involve construction of new emissions unit(s) and (3) the hybrid test for projects that involve multiple types of emissions units. Under the hybrid test, the appropriate calculation is performed by emissions unit depending on new vs. existing unit status. The terms “existing emissions unit” and “new emissions unit” are defined in

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<sup>G</sup> This analysis is focused on the projected emissions increase (step 1) and the net emissions increase calculation (step 2). Even if a project results in a significant emissions increase, the source may be able to demonstrate that the net emissions increase is insignificant and thus the project does not constitute a major modification.

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the regulations. “Replacement units” meeting specified criteria are treated as existing emissions units for the purpose of calculating emissions increases.<sup>H</sup>

The actual-to-projected-actual test involves calculating baseline actual emissions and projected actual emissions for each emissions unit affected by a project and calculating the project emissions increase as the sum of the differences between projected actual emissions and baseline actual emissions for each unit. The definition of projected actual emissions provides that the owner or operator shall exclude, in calculating the increase from a particular emissions unit, that portion of the unit’s emissions following the project that the unit could have accommodated in the selected baseline actual emissions period and that are also unrelated to the project, including any increased utilization due to demand growth. The actual-to-potential test compares the potential to emit of a unit with the baseline actual emissions and does not provide for the exclusion of any emissions in calculating the increase. For new emissions units other than those qualifying as replacement units, baseline actual emissions are zero.

Because individual refinery project details were not available for this analysis, EPA used a simplified approach to approximate the results from the application of the actual-to-projected-actual and/or or actual-to-potential tests for affected units at each source. The approach relied upon estimates of incremental energy, hydrogen and sulfur recovery demands associated with meeting the final Tier 3 fuel standards and the application of scaling factors to adjust from base year to projected maximum annual rates and design rates for existing and new units, respectively. Representative industry emission factors were identified for each affected emissions unit category (i.e., process heaters/boilers, hydrogen plants and sulfur recovery units) and emissions increases were calculated as the product of the production or activity data (e.g., MMBtu energy demand) and corresponding emission factors (e.g., lb/MMBtu). The activity data and emission factors used in the analysis are discussed in further detail below.

#### Activity Data

EPA performed a refinery-by-refinery analysis of process and equipment changes likely to be implemented to meet the final Tier 3 fuel standards and from this analysis generated refinery-specific estimates of energy demand, hydrogen demand and increased sulfur recovery unit (SRU) loading for 108 U.S. refineries. Energy demand includes fuel needed to generate process heat, steam and electricity. Hydrogen demand is associated with increased hydrotreating of post-fluid catalytic cracking (FCC) naphtha and light straight run (LSR) streams, which may involve new or revamped hydrotreater units. Increased SRU loading results from the increased fuel desulfurization and associated H<sub>2</sub>S generation.

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<sup>H</sup> The actual-to-projected actual test was adopted in the federal regulations as part of the 2002 NSR Reform rulemaking. At this time, the Reform Rule provisions are available to sources in a large majority of state/local jurisdictions either by delegation or adoption into state/local rules (most of which are SIP approved). There may be isolated cases where, at the time that Tier 3 projects are being evaluated for NSR applicability, Reform Rule applicability procedures are not available. For the purpose of this analysis, it was assumed that the federal NSR applicability procedures were available for all affected sources because: 1) this is the case for most refineries presently, and 2) the analysis is sufficiently conservative such that applying alternative applicability calculations is not expected to significantly affect the overall conclusions.

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In our updated analysis, we adjusted the analysis performed prior to the NPRM to reflect a nationwide average, banking, and trading (ABT) program which is being finalized and refined our estimates regarding the physical and operational changes that will be required at each refinery. To estimate the Tier 3 emissions impacts, it was first necessary to establish the production volumes of the units that would be affected by the standards. A “normal operating” case reflecting calendar year volumes was developed using refinery-specific actual base-year (2011) production data and production-normalized impact data (e.g., MMBtu per 1000 bbl gasoline production and MMscf hydrogen per 1000 bbl gasoline production). Normal operating production rates were then scaled up to reflect maximum annual capacity utilization rates and further adjusted using “overdesign” factors in certain cases as summarized below. This scaling was done under the assumption that, for the purpose of determining NSR applicability, each refinery would project emissions based on the maximum achievable production rate for existing units and would use design capacity to calculate potential to emit for new units. It was not tied to any particular assumption about overall gasoline demand.

- For refineries projected to meet Tier 3 sulfur specifications by revamping existing hydrotreater units, demands were scaled up to 92 percent of the refinery’s maximum design production. If a particular refinery ran its FCC at a utilization level above 92 percent in the base year, it was assumed that that refinery was already operating at its annual capacity and no adjustment was made.
- For refineries projected to meet Tier 3 standards by installing new FCC post treatment units (post-treaters), the same scale-up approach documented above for revamps was applied, and an additional overdesign factor of 15 percent was applied to represent a maximum stream day capacity.
- For refineries projected to install new LSR treating units, the same approach was applied as documented above for new FCC post-treaters.
- For SRUs, the additional sulfur loading was calculated based on the incremental sulfur reduction required to meet the proposed standards and the scaled-up production estimates documented above for FCC revamps.

From the scaled utility demand data, low and high impact cases were designed for estimating emissions increases under each scenario as follows.

- Low case: Each refiner buys its additional hydrogen, high octane blendstocks and electricity externally.
- High case: Each refiner generates the required additional hydrogen, high octane blendstocks and electricity internally.

The low case represents external sourcing of some of the energy and chemical demand associated with meeting the proposed standards, meaning that emissions associated with these activities do not occur from the refinery itself and are not accounted for in determining NSR applicability. The high case represents internal production of all required energy and chemical demand, meaning that these impacts do occur at the refinery itself and are accounted for in determining NSR applicability.

## Emission Factors

The emission factors used to estimate Tier 3 projected emissions increases are documented in Table 4-9.

**Table 4-9 Emission Factors**

Unit	Pollutant	EF	Units	Reference
Heaters & Boilers	NO <sub>x</sub>	0.040	lb/MMBtu	Assumed average for new/modified units equipped with ultra-low NO <sub>x</sub> burners; consistent with NSPS subpart Ja for natural draft heaters (40 CFR 60.102a).
	SO <sub>2</sub>	0.012	lb/MMBtu	Calculated based on 8 ppmv annual average SO <sub>2</sub> limit in NSPS subpart Ja (40 CFR 60.102a).
	CO	0.040	lb/MMBtu	Recent BACT determinations – burner design and good combustion practices.
	VOC	0.0055	lb/MMBtu	AP-42 Chapter 1.4.
	PM <sub>10</sub>	0.0075	lb/MMBtu	AP-42 Chapter 1.4.
	PM <sub>2.5</sub>	0.0075	lb/MMBtu	AP-42 Chapter 1.4.
	H <sub>2</sub> SO <sub>4</sub>	0.0004	lb/MMBtu	Assumes 2% oxidation of SO <sub>2</sub> to SO <sub>3</sub> (non-SCR).
	CO <sub>2</sub> e	130.6	lb/MMBtu	40 CFR 98 Tables C-1, C-2 (CO <sub>2</sub> EF for fuel gas; CH <sub>4</sub> & N <sub>2</sub> O EFs for petroleum).
H <sub>2</sub> Plant	CO <sub>2</sub>	25.0	tons/MMscf H <sub>2</sub>	Bonaquist, Dante. Analysis of CO <sub>2</sub> Emissions, Reductions, and Capture for Large-Scale Hydrogen Production Plants, White Paper. Praxair, Oct. 2010. (Available in docket).
SRU	NO <sub>x</sub>	0.271	lb/ton S	Calculated industry average EF based on 2005 NEI.
	SO <sub>2</sub>	3.792	lb/ton S	Calculated industry average EF based on 2005 NEI.
	CO	0.882	lb/ton S	Calculated industry average EF based on 2005 NEI.
	VOC	0.039	lb/ton S	Calculated industry average EF based on 2005 NEI.
	PM <sub>10</sub>	0.020	lb/ton S	Calculated industry average EF based on 2005 NEI.
	PM <sub>2.5</sub>	0.017	lb/ton S	Calculated industry average EF based on 2005 NEI.
	H <sub>2</sub> SO <sub>4</sub>	0.290	lb/ton S	Calculated as 5% of SO <sub>2</sub> EF corrected for mol. wt.
	CO <sub>2</sub>	806.9	lb/ton S	Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases. EPA OAR, Sept. 8, 2008, p. 11. (Available in docket).

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### Pollutants Evaluated

The regulated NSR pollutants identified in the table above were determined to have some probability of triggering major NSR as a result of projects designed to meet the final Tier 3 fuel standards. Certain other regulated NSR pollutants, including total reduced sulfur (TRS), H<sub>2</sub>S and reduced sulfur compounds (RSC) may be emitted at very low rates from potentially affected refinery units, but were determined to have little or no probability of exceeding significant emission rate thresholds. Therefore, these pollutants were not included in the quantitative analysis.

### Heaters and Boilers

The emission factors selected for refinery process heaters and boilers represent combustion emissions from refinery fuel gas (RFG) and/or natural gas. The worst case (higher emitting fuel) was assumed where fuel-specific factors were available. For NO<sub>x</sub>, an emission factor of 0.040 lb/MMBtu was selected to represent average emissions from new and modified refinery process heaters and boilers. In most cases, emissions at this level are achievable using ultra-low NO<sub>x</sub> burners and without the addition of add-on controls such as selective catalytic reduction (SCR). With the use of SCR, emissions substantially below this level, on the order of 0.01 lb/MMBtu or less are achievable. An SO<sub>2</sub> emission factor of 0.012 lb/MMBtu was calculated based on the NSPS subpart Ja annual average SO<sub>2</sub> limit of 8 ppmv for fuel gas combustion units. A CO emission factor of 0.040 lb/MMBtu was selected based on recent BACT determinations that represent burner design and good combustion practices.<sup>1</sup> VOC and PM emission factors are based on EPA AP-42 Chapter 1.4: Natural Gas Combustion and are consistent with permit precedent for refinery heaters.<sup>1</sup> For sulfuric acid mist, it was conservatively assumed that 2 percent of SO<sub>2</sub> emissions oxidize to SO<sub>3</sub> and then condense to form H<sub>2</sub>SO<sub>4</sub>. A GHG emission factor of 130.6 lb/MMBtu CO<sub>2</sub> equivalent (CO<sub>2</sub>e) was calculated as the sum of CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emission factors reported in 40 CFR 98 (EPA GHG Reporting Rule, Subpart C) for fuel gas multiplied by their respective global warming potentials.

### Hydrogen Plants

In addition to emissions associated with process heat, hydrogen production by steam methane reforming (SMR) generates CO<sub>2</sub> emissions as a byproduct. The selected CO<sub>2</sub> emission factor of 25 lb/MMscf H<sub>2</sub> is based on data from Praxair, a major hydrogen plant engineering and design firm and hydrogen supplier to the refining industry in the U.S.

### Sulfur Recovery Units

Emissions from SRUs can vary significantly depending on design and upstream variables, making published emission factors inappropriate in general. To account for this variability, EPA derived industry average emission factors for most pollutants based on total

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<sup>1</sup> Based on a review of recent BACT determinations documented in the EPA RACT/ BACT/ LAER Clearinghouse available at: <http://cfpub.epa.gov/RBLC/index.cfm?action=Home.Home>

<sup>J</sup> Available at: <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf>

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refinery SRU emissions reported in the 2005 National Emissions Inventory (NEI) database combined with sulfur plant production data from the U.S. Energy Information Administration (EIA). For sulfuric acid mist, it was conservatively assumed that 5 percent of SO<sub>2</sub> emissions oxidize to SO<sub>3</sub> and then condense to form H<sub>2</sub>SO<sub>4</sub>. For GHGs, a CO<sub>2</sub> emission factor from the EPA Technical Support Document for the proposed GHG Reporting Rule for the petroleum refining sector was used.

#### Attainment Status

The attainment status of each refinery location for ozone and PM (PM<sub>2.5</sub> and PM<sub>10</sub>) was determined using nonattainment area designation information from the EPA Green Book website as of November 1, 2013 supplemented by information in relevant notices for final redesignation actions that were not yet reflected on the website.<sup>K</sup> Based on the attainment status and classification (for ozone nonattainment areas), NA NSR and PSD triggers were resolved for each refinery. For serious and severe ozone nonattainment areas, or areas required to maintain NSR program requirements consistent with those designations under the prior 1-hour ozone standard as a result of the “anti-backsliding” policy, major modification thresholds of 25 tons per were assumed for the precursors NO<sub>x</sub> and VOC, versus 40 tons per year in attainment areas and areas classified as marginal or moderate nonattainment.<sup>L</sup>

#### 4.5.3.2 NSR Applicability Results

The results of the Tier 3 projected NSR applicability analysis are summarized below for the lowest and highest NSR impact scenario/case combinations. In total, 108 refineries determined to be potentially affected by the final standards were included in the analysis.

##### No ABT Scenario; Low Case

- 4 refineries trigger PSD and/or NA NSR
- 2 of the 4 refineries trigger PSD and/or NA NSR for criteria pollutant(s)
- 2 of the 4 refineries only trigger PSD for GHGs

##### Primary ABT Scenario; High Case

- 9 refineries trigger PSD and/or NA NSR
- 3 of the 9 refineries trigger PSD and/or NA NSR for criteria pollutant(s)
- 6 of the 9 refineries only trigger PSD for GHGs

The pollutants driving major NSR applicability are GHGs and NO<sub>x</sub>. None of the other pollutants evaluated, including SO<sub>2</sub>, CO, VOC, PM<sub>2.5</sub> and PM<sub>10</sub> and H<sub>2</sub>SO<sub>4</sub>, exceeded major

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<sup>K</sup> Available at: <http://www.epa.gov/oaqps001/greenbk/>

<sup>L</sup> The significant emission rate (SER) threshold in severe ozone nonattainment areas is 25 tpy of NO<sub>x</sub> and VOC. While the SER in serious nonattainment areas is 40 tpy of NO<sub>x</sub> and VOC, increases in both serious and severe nonattainment areas are also affected by CAA §182(c)(6), which limits aggregated NO<sub>x</sub> and VOC emissions over a five-year period to less than 25 tpy to avoid major NSR. For the purpose of this analysis, a SER of 25 tpy for NO<sub>x</sub> and VOC was conservatively assumed for both serious and severe ozone nonattainment areas.

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modification thresholds at any refinery. It should also be noted that in several cases, emissions increases shown to trigger NSR were very close to the respective thresholds, indicating that there would likely be opportunities to design these projects in such a way to avoid NSR applicability, at least for some pollutants.

### **Example Calculations**

The following example calculations illustrate the approach used to determine NSR applicability on a refinery-by-refinery basis. The calculations are based on hypothetical Tier 3 project impacts.

#### Assumptions

- Refinery located in an area designated as attainment/unclassifiable for all criteria pollutants (PSD area)
- Incremental demand estimates reflect “high case” assumptions, i.e., hydrogen and electrical power demand generated internally

#### Tier 3 Incremental Refinery Demand Estimates:

Total energy demand: 1,500,000 MMBtu/yr

Hydrogen demand: 400 MMscf/yr

SRU production: 150 tons S/yr

#### Emissions Increase - NO<sub>x</sub>:

$[(1,500,000 \text{ MMBtu/yr}) \times (0.040 \text{ lb/MMBtu}) + (150 \text{ tons S/yr}) \times (0.271 \text{ lb/ton})] \times (1 \text{ ton}/2,000 \text{ lb}) = 30.0 \text{ tons NO}_x/\text{yr}$

*The applicable significant emission rate threshold for NO<sub>x</sub> is 40 tpy; therefore, the project does not trigger PSD for NO<sub>x</sub>.*

#### Emissions Increase - PM<sub>2.5</sub>:

$[(1,500,000 \text{ MMBtu/yr}) \times (0.0075 \text{ lb/MMBtu}) + (150 \text{ tons S/yr}) \times (0.017 \text{ lb/ton})] \times (1 \text{ ton}/2,000 \text{ lb}) = 5.63 \text{ tons PM}_{2.5}/\text{yr}$

*The applicable significant emission rate threshold for PM<sub>2.5</sub> is 10 tpy; therefore, the project does not trigger PSD for PM<sub>2.5</sub>.*

#### Emissions Increase - GHGs (CO<sub>2</sub>e):

$[(1,500,000 \text{ MMBtu/yr}) \times (130.6 \text{ lb/MMBtu}) + (150 \text{ tons S/yr}) \times (806.9 \text{ lb/ton})] \times (1 \text{ ton}/2,000 \text{ lb}) + (400 \text{ MMscf H}_2/\text{yr}) \times (25 \text{ tons/MMscf}) = 108,011 \text{ tons CO}_2\text{e/yr}$

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*The applicable “subject to regulation” threshold for GHGs is 75,000 tpy CO<sub>2</sub>e and the applicable significant emission rate threshold is any increase on a mass basis; therefore, the project triggers PSD for GHGs.*

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## Chapter 5 Fuel Program Costs

### 5.1 Methodology

This chapter provides a summary of the methodology used and the results obtained from our cost analyses of the final Tier 3 gasoline sulfur control program. We start by summarizing the refinery models used for our analysis. We then describe our detailed methodology for estimating the sulfur control costs for our proposed sulfur program followed by the results. Finally, we discuss and compare the results of several other cost analyses.

#### 5.1.1 Overview

When we began our planning for estimating the cost of additional reductions in gasoline sulfur, we considered two different options. One option for estimating the costs would be to utilize a linear programming (LP) model, while the second option would be to develop a refinery-by-refinery cost model. While the LP refinery models are necessary and appropriate for many analyses, they also have several important limitations of relevance here. When used to model the cost of nationwide fuel control programs on the entire refining industry, LP models are usually used to model groups of refineries in geographic regions called Petroleum Administration for Defense Districts (PADDs). The LP refinery model averages the costs over the refineries represented in the PADDs; however, the technology chosen by the refinery model would normally be the lowest cost technology found by the refinery model. This may represent an unreasonable choice of technologies for individual refineries because of how refineries are configured and based on the sulfur control technologies installed for compliance with the Tier 2 gasoline sulfur program. While the choice of technologies can be limited based on an approximate analysis of what mix of technologies would best suit the group of refineries modeled in each PADD, this would only provide an approximate estimate of the cost incurred. Based on the quality of input data to these LP models and the assumptions made for complying with a regulatory requirement, LP refinery models may overestimate or underestimate the program costs. For example, an LP refinery model would not be a sensible tool for estimating the credit averaging and trading between refineries. This could be partially overcome by iterating between PADD refinery model runs, thus estimating the number of credits traded between PADDs and estimating the level of sulfur control in each PADD. However, the need to make multiple runs per PADD for each case, coupled with the need to run multiple control cases for different sulfur standards, would be very time consuming, costly and still would only result in approximate estimates of the sulfur levels achieved and the cost incurred.

For this reason, EPA developed a refinery-by-refinery cost model which models the capability for each refinery to revamp existing or install new sulfur control technologies available to them to reduce their gasoline sulfur levels. Rather than start from scratch, we started from a refinery-by-refinery cost model developed by APT (Mathpro) for EPA to estimate the cost of benzene control under MSAT2. However, instead of using the representations of benzene control technology contained in the model, we obtained information about gasoline desulfurization and represented the cost of this desulfurization in the refinery-by-refinery cost model.

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We believe the refinery-by-refinery cost model best estimates the cost of individual refineries, especially when considering an averaging, banking and trading (ABT) program and therefore is the best analysis tool for estimating nationwide costs. However, certain inputs necessary for estimating costs. Because some refinery-specific information is not publicly available, it was necessary to find another way to estimate certain inputs necessary for estimating costs with the refinery-by-refinery model. The inputs and outputs from LP refinery cost modeling provide this needed information and it was utilized in the refinery-by-refinery cost model. The information from LP refinery modeling used in the refinery-by-refinery cost model is described in Section 5.1.2, and in more detail in other Sections below.

Since the refinery-by-refinery cost model contains confidential business information for each refinery, we could not publish the model or present some of the details of the model here. Therefore, to ensure its viability, the refinery-by-refinery cost model that we developed for the proposed rule was subjected to peer reviews by two refinery industry consultants (involving a total of three peer reviewers). Our review of most of the suggested changes recommended by the initial set of peer reviewers suggested that there would be little to no change in our desulfurization cost estimate (some of the changes would increase the estimated costs, while others would reduce the estimated costs). Also, after modifying the modeling to respond to this first round of peer review comments, we then went on to make a number of additional model improvements to support the final rule. This additional work was then put through a second round of peer review that was used to modify the modeling for this FRM. The peer review comments and our assessment of the peer review comments are contained in reports submitted to the docket.<sup>1 2 3 4</sup>

The refinery-by-refinery cost model focuses on reducing sulfur from the FCC naphtha because of its high sulfur content. To comply with the 30-ppm Tier 2 sulfur control program, most refiners installed FCC naphtha hydrotreaters (referred to as FCC posttreaters) or FCC feed hydrotreaters (referred to as FCC pretreaters) to reduce that unit's sulfur contribution to their gasoline pool. If refiners installed an FCC posttreater under Tier 2, we modeled refiners revamping those units. However, if refiners relied on FCC pretreaters to comply with Tier 2, we assumed that grassroots FCC posttreaters would have to be installed at those refineries to reduce its gasoline pool down to 10 ppm. However, since adding grassroots FCC posttreaters is relatively expensive for the amount of sulfur reduction obtained, the ABT analysis we conducted avoided almost all of these types of investments. Refineries with both pre and posttreaters today could achieve further gasoline sulfur reductions less than 10 ppm (we used 5 ppm) at a relatively low incremental cost and sell the credits to those refiners who are operating refineries which would otherwise be faced with grassroots posttreater investments. In addition to addressing the sulfur in the FCC naphtha, we believe that at some refineries, refiners may need to reduce the sulfur in light straight run (LSR) naphtha.

To better understand the desulfurization costs, we evaluated several alternative gasoline sulfur control scenarios or cases besides the primary final rule cost analysis. For a 10-ppm average sulfur standard, also we assessed the costs based on each refinery achieving the 10-ppm standard with no averaging among refineries and another with only intra-company transfers of sulfur credits. To provide credits for averaging and trading under the 10-ppm average standard, we evaluated refiners reducing their gasoline sulfur down to 5 ppm. Since we had estimated costs for each refinery to get to 5 ppm sulfur, we also report out the cost for a 5 ppm average

gasoline sulfur standard assuming no averaging between refineries (at an average of 5 ppm, the opportunity to comply through credit transfers would be limited). Although we considered reducing the 80 ppm cap standard, we do not provide any cost assessment for lowering the 80 ppm cap standard, nor do we estimate sulfur control costs which include a lower cap standard. These different scenarios are summarized in Table 5-1.

**Table 5-1 Sulfur Control Cases Evaluated for the Final Rule**

Description	Sulfur Standard	ABT Credit Trading	Cap Standard
Final Rule Fuels Program	10ppm	Nationwide	80 ppm
Limited Credit Trading (Proposed rule)	10 ppm	Intra-company	80 ppm
No Credit Trading	10 ppm	None	80 ppm
Stringent Sulfur Standard	5 ppm	None	80 ppm

We made a series of improvements to the cost analysis since we completed the proposed rule cost analysis. Some of the improvements were made to address the comments of the peer reviewers. Others were conceived and incorporated to further improve the robustness of the refinery modeling work by incorporating more data which we believe allowed us to better model each individual refinery. The following describes the most important improvements that we made to the refinery-by-refinery cost model:

We updated the EIA data for individual refineries in the refinery-by-refinery cost model from 2009 to 2011. The data that we updated included crude oil sulfur content and API gravity, refinery-specific throughput volumes for the atmospheric crude tower, the FCC unit, cokers and hydrocrackers. We also incorporated new refinery-specific data into the refinery cost model which includes purchases and sales of pentanes plus (natural gas liquids or NGLs), and sales into the petrochemical market.

Refinery blendstock volumes for the reformer, alkylation unit, isomerization unit, and the naphtha hydrotreater are now based on actual throughput volume data from the Office of Air Quality Planning and Standards (OAQPS). OAQPS requested, and the Office of Management and Budget (OMB) approved, the collection of refinery operations data by OAQPS from refiners which included throughput data for many refinery units. The data collected by OAQPS was for the year 2010. We obtained that data and entered it into the refinery-by-refinery model and this new data provides us with a much clearer picture of how these units are being utilized in individual refineries and provides us with a much more robust modeling tool. Previously we were using projected PADD-average use estimates by an LP refinery modeling run made by Mathpro for the MSAT2 cost analysis. A very important outcome of using this actual unit throughput data is that we removed the uncertainty associated with the volumes of gasoline blendstocks which make up each refinery's gasoline pool. Since we better understand the volumes of these gasoline blendstocks, we can much better deduce certain other practices that refiners may be using, such as undercutting their heavy naphtha streams into the jet and diesel pools which will likely have implications for complying with Tier 3.

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We attempted to better match each refinery's gasoline production in the refinery-by-refinery cost model to actual refinery gasoline production volume as reported to EPA. In trying to match individual refinery gasoline volumes, we estimated if the practice of undercutting FCC naphtha and heavy naphtha is being practiced. Since we often had excess gasoline blendstock material, we also estimated hydrocracker operation (naphtha, intermediate, or diesel modes) as a means to match gasoline volumes. More often than not, heavy naphtha volumes tend to exceed reformer throughput volumes, so for those refineries that have excessive gasoline volumes we assume that the excessive heavy naphtha volume is sold. For refineries with insufficient gasoline volume, this excess volume is assumed to be blended into gasoline (but not reformed).

We updated the refinery-by-refinery model with 2012 refinery capacity data, and included some 2013 and later data for announced expansions. Based on the comments of one peer reviewer, we focused on including the expansions of the refineries recently modified to process more tar sands from Canada. Because we incorporated the refinery expansions that involved processing more tar sands, we needed to not only process more volume, but we needed to adjust the quality of crude oil processed by the refinery to represent the heavier tar sands.

The volume of light and heavy straight run naphtha are based on the API gravity of the crude oil slate being refined by each refinery. This replaces the previous method of relying on similar correlation for the average quality of crude oil refined in each PADD.

We developed a means to adjust desulfurization costs to account for the cases when a refinery's modeled desulfurization situation differed from the typical case for which the vendors provided us information. For example, for reducing a refinery's gasoline sulfur from 30 ppm to 10 ppm, the refiner would typically need to reduce its FCC naphtha from 75 to 25 ppm. Depending on the amount of FCC naphtha blended into its gasoline, the amount of sulfur control that the refiner would need to achieve in its FCC naphtha could be larger or smaller than this. We linearly adjusted the desulfurization cost to account for the variances from the typical case. However, where the level of desulfurization required exceeded 96% and 99% for single stage and double stage units, respectively, we assumed an exponential increase in hydrogen demand and octane loss. If we did not make this adjustment, we would be underestimating the cost for those refineries which must achieve a very steep rate of desulfurization.

We incorporated in our refinery-by-refinery cost model refiner actions that they took for complying with the Mobile Source Air Toxics rulemaking to reduce the content of benzene in their gasoline. This affected the volume of benzene precursors sent to the reformer or the volume of benzene extracted from the gasoline pool.

We obtained more information from vendors of gasoline desulfurization equipment and included this information in the final rule cost analysis. We increased the offsite factor for the vendor costs to 0.35 based on discussions with engineering companies.<sup>5</sup>

In the refinery-by-refinery cost model, we updated utility (natural gas and electricity) cost projections to be based on AEO 2013, the most recent projections available at the time that we were conducting the final rule cost analysis.

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We updated the octane costs used in the refinery-by-refinery model. To do so we improved, updated and reran the LP refinery model for octane costs, As part of the LP refinery analysis, we updated our analysis of the changes in gasoline qualities associated with gasoline sulfur control. The LP refinery model incorporated improvements in how the model blends up reformat.<sup>A</sup>

The several errors that the peer reviewers found in the version of the refinery-by-refinery model that was used for the proposed rule have been corrected. These errors had an insignificant impact on the costs of the Tier 3 program.

Since we made a series of new modifications to the refinery-by-refinery cost model, we had the refinery-by-refinery cost model peer reviewed again by three peer reviewers. The following describes the most important improvements that we made to the refinery-by-refinery cost model based on the second round of peer reviews:

Two peer reviewers commented that inside battery and outside battery limit costs that we estimated do not reflect extra costs which could be incurred. Such excess costs could include adding pilings for foundations at construction sites with poor soil, adding a control room for operations control, adding a storage tank, and long pipeline runs in the case that the Tier 3 unit needs to be placed an abnormally long distance from associated refinery units. To account for such cost add-ons, we applied a 20% contingency factor.

One peer reviewer commented that some FCC feed pretreaters are too small to hydrotreat the entire FCC feed, yet our cost analysis assumed that that the entire FCC feed was being hydrotreated. We adjusted the sulfur level of the feed and the output of FCC units in the cases where the FCC pretreaters were relative small in throughput capacity and could only treat a part of the FCC feed.

One peer reviewer commented that we only accounted for the sulfur content of vacuum gas oil and not very high sulfur light coker gas oil which also is fed to FCC units. For those refineries with cokers, we increased the sulfur content of the feed to the FCC pretreater or FCC unit to account for refining light coker gas oil in addition to vacuum gas oil.

One peer reviewer commented that the volumetric yield loss from the reformer was based on too low of severity and that many reformers are operating at a higher severity than that which would cause a higher yield loss. We developed a methodology for estimating reformer severity which resulted in higher average reformer severity.

One peer reviewer commented that the regression that we developed for estimating light straight run volume from crude oil had a poor fit. The peer reviewer provided a regression based on much more crude assays with a much better fit of the data and we used that regression to estimate light straight run volume for each refinery.

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<sup>A</sup> The refinery model now estimates reformat distillation properties, including RVP, based on actual feed qualities. Before the improvements, the refinery model estimated a fixed set of reformat distillation properties based on a typical set of feed qualities.

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We discuss how we applied these changes to our refinery-by-refinery cost model in the following sections and a more complete discussion of the peer review comments and our response to them are contained in our response document to the peer review comments.

### 5.1.2 LP Refinery Modeling Methodology and Results

Although we used the refinery-by-refinery cost model to estimate gasoline desulfurization costs, certain input information was needed. Without access to detailed refinery-specific information, we relied on outputs from our LP refinery modeling for some important inputs. Perhaps the most important input is the cost for making up the octane loss that occurs with desulfurization. In addition, certain refinery operations information from the LP refinery model was used for estimating the volume of gasoline produced in the refinery-by-refinery model, including the utilization factors of individual refinery units, and the percentage that straight run naphtha, FCC naphtha and hydrocrackate comprises of the feed volume of their respective units.

LP refinery models are detailed mathematical representations of refineries. They are used by individual refining companies to project how best to operate their refineries. They are also used by government agencies, such as EPA and DOE, as well as by refining industry associations and individual companies, to estimate the cost and supply impacts of fuel quality changes. LP refinery models have been used for these purposes for decades and a certain protocol has been established to conduct these studies.

Refinery modeling output from the Haverly GRTMPS refinery model was used in the refinery-by-refinery cost analysis. The primary reason for using recent LP refinery modeling analysis was to estimate the cost of making up the octane loss associated with desulfurization as well as estimate how gasoline qualities would be affected by the octane recovery to feed into the emissions inventory impact analysis discussed in Chapter 7. The cost of octane has decreased due to expected increased use of ethanol under the RFS2 rulemaking, making historical octane cost data of limited usefulness.

The first step in conducting an LP refinery modeling analysis was the development of a base case. The base case is a refinery modeling case that calibrates the refinery model based on actual refinery unit capacity and input and output data. The base year for this study was the year 2004 for the Haverly model. Because much of the information available for establishing the base case is only available for PADDs of refineries, the LP refinery modeling was conducted on a PADD-wide basis. Refinery capacity information for 2012 from the Energy Information Administration (EIA) was aggregated by PADD and entered into the LP refinery model. The feedstock volumes, including crude oil and gasoline blendstocks, were obtained from the EIA and entered into each PADD's model. Similarly, product volumes such as gasoline, jet fuel, and diesel fuel were obtained from EIA and entered into the cost model. The environmental and ASTM fuel quality constraints in effect in the base year were imposed on the products. This includes the Reformulated Gasoline program and the 500-ppm highway diesel fuel sulfur standard, and the first year of the Tier 2 gasoline sulfur standard. This information was input into the LP refinery cost model for each PADD and each PADD model was run to model the U.S. refinery industry for the base year. The gasoline quality for each PADD refinery model was then compared to the actual gasoline quality for conventional and reformulated gasoline which is

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available from the RFG database. Each model was calibrated to closely approximate the gasoline quality of each PADD.

The second step in modeling is the development of a reference case. The purpose of the reference case is to model the refining industry operations and cost in a future year, which is the year that the control program is modeled to be in effect (serving as a point of reference to the control cases for estimating costs and other impacts). The reference years for the Haverly refinery modeling were 2018 and 2030 for the control cases that we ran. The reference cases were created by starting with the base case for each PADD and adjusting each base case to model the future year, accounting for the changes between the two years.

Two different types of adjustments were made to the base case refinery models to enable modeling the refining industry for the reference case. First, the refinery model needed to reflect future product volumes and energy prices which are projected year-by-year by EIA in its Annual Energy Outlook (AEO). For the 2018 and 2030 Haverly LP refinery modeling cases, we relied on the early release of the AEO 2013 (the later actual AEO 2013 was not yet available). The projected U.S. refinery production was entered into the reference case version of the LP refinery model. The utility and crude oil and other feedstock prices which are projected by EIA for 2018 and 2030 were also entered into the refinery model, as well as the estimated product prices which were based on the forecasted product prices.

The second adjustment made to model the reference cases was the application of fuel quality changes. Environmental programs which have been implemented or which will largely be implemented by the time that the prospective fuels control program would take effect were modeled in the reference case. These fuel quality changes include limits such as the 30-ppm average gasoline sulfur standard, 15-ppm caps on highway and nonroad diesel fuel and the MSAT2 benzene control program, in addition to the environmental programs which were already being modeled in the base case. This also included the fact that California gasoline was already averaging 10 ppm sulfur or less as a result of prior changes to their predictive model used for gasoline certification, well in advance of their 20 ppm cap on gasoline sulfur taking effect. As a result, our Tier 3 gasoline standards are not proposed to apply in California. Thus, for this analysis we only assumed further sulfur control on gasoline volumes produced by California refineries for distribution outside of California. Also, the implementation of EPA's Act included a de facto ban on MTBE by rescinding the RFG oxygenate requirement. The RFS2 renewable fuels volumes were modeled for 2030 based on the projections made by the Energy Information Administration (EIA) in its 2013 early release of the Annual Energy Outlook (AEO). For the 2030 reference case, we modeled 14.4 billion gallons of corn and cellulosic ethanol, and 8.3 billion gallons of renewable diesel and biodiesel. As discussed below, for the 2018 case, which was used for modeling octane costs, we modeled all gasoline containing 10 volume percent ethanol and a small volume of E85.

The third step in conducting the LP refinery modeling was to run the control cases. The control cases are created by applying a specific fuel control standard to each PADD reference case. To single out a specific cost or other impact, the sole difference between the control case and the reference case is the parameter change being studied.

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One control case was run to model the octane loss associated with desulfurizing gasoline using 2018 as the year of analysis. Since we solely wanted to identify the cost of recovering lost octane for the refinery-by-refinery modeling, this case was run by reducing the octane value of the FCC naphtha by one octane number, and this was the sole change relative to the reference case. The control case was run with capital costs evaluated at a 15 percent rate of return on investment (ROI) after taxes.<sup>B</sup> This case was run with E10 and a small volume of E85, and we substituted 2013 natural gas liquid prices (ethane, propane and butane) which are much lower compared to the historical price relationship from previous years. The lower natural gas prices increases the octane cost provided by the reformer since the reformer produces natural gas liquids as byproducts. The octane cost estimated by the LP cost model is \$0.31/octane number-barrel (0.74 c/octane number-gallon) as summarized in Table 5-39 in the appendix and the related tables numbered 5-41 through 5-49. Because the octane loss associated with a specific sulfur control technology may be lower or higher than 1 octane number, we scaled the octane cost based on the relative estimated octane loss on the FCC naphtha (i.e., a ½ octane loss of the FCC naphtha was estimated to cost \$0.155/octane number-barrel).

The oil industry and one of the peer reviewers commented that we should use the wholesale price difference between premium and regular gasoline grades to develop an octane cost. Using this method, they estimated that the cost of octane would be \$1/octane number-barrel. We believe that the premium minus regular grade pricing method for estimating octane cost overstates the cost of making up lost octane in the FCC naphtha pool. Premium grade gasoline is produced in smaller batches than regular grade and must be handled specially and separately to avoid compromising its octane content. For example, when shipping premium gasoline in pipelines, the interface between premium and regular grades of gasoline must be downgraded into the regular grade gasoline to ensure that premium gasoline's high octane content is not compromised – this downgrading increases the production cost of premium gasoline. Furthermore, the pricing between regular and premium grades of gasoline tends to reflect higher profit margins on premium fuel.

However, it was further analysis of our LP refinery modeling work which provided the most significant reason why the price differentials between premium and regular grade gasoline overstates the cost of octane when the octane loss is in fact occurring in the FCC naphtha. While the octane cost for making up octane loss in the FCC naphtha is \$31/octane number-barrel from the LP model, the octane cost determined by the premium-regular grade differential using the LP model is \$0.50/octane number-barrel, which is 60 percent higher (see Table 5-40). We believe that the LP refinery model is estimating a higher octane cost for the premium-regular grade differential because of the cost of producing premium gasoline, which is 6 octane numbers higher than the regular grade. And yet, the LP model is not capturing the additional cost inflating factors mentioned above such as smaller tankage, special handling and distribution and profit. Our conclusion from this analysis is that the premium-regular grade price differential is a poor indicator of the cost of making up the small amount of lost octane in FCC naphtha for

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<sup>B</sup> Normally we conduct the refinery modeling assuming an after-tax 15% ROI and adjust the costs to reflect a before-tax 7% ROI to report the costs. However, in this case because the new capital investments were so minimal, we omitted the capital cost amortization adjustment because its effect on costs was judged to be negligible.

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desulfurization and by using it would overstate the cost. Despite our confidence in the octane cost that we generated, we recognize the need to quantify the impacts on our costs if octane costs are indeed higher than what we estimated, so in Section 5.2 where we present the Tier 3 fuel cost, we provide a sensitivity cost estimate assuming that octane costs are \$0.50/octane number-barrel. A table in an appendix at the end of this chapter summarizes the data output from the refinery modeling from which we calculated the octane cost for use in the refinery-by-refinery cost model. Other output from the LP refinery modeling are also summarized in tables contained in the appendix.

Another peer reviewer also evaluated octane cost and concluded that while recent octane costs using premium minus regular grade price differences were in the \$1/octane number barrel range, modeled future octane costs for 2015 and 2020 were appreciably lower. This peer reviewer's estimate for future octane costs could be much lower and provided a range of \$0.25 - \$0.5/octane number-barrel. The octane cost that we are using is right in the middle of the projected octane cost projected by this peer reviewer and our octane cost sensitivity is at the high end of this range.

We also conducted LP refinery modeling to estimate how the addition of ethanol affects gasoline quality which allowed us to establish a reference case for our air quality analysis. This refinery modeling is described, and the resultant projected changes in gasoline quality are summarized, in Chapter 7 in subsection 7.1.3.

### 5.1.3 Summary of Refinery-by-Refinery Model Methodology

The purpose of the refinery-by-refinery cost model is to project how each refinery would reduce the sulfur in its gasoline pool to 10 ppm or lower and to estimate the cost for doing so. To do this we created a U.S. refining industry refinery-by-refinery spreadsheet cost model using refinery-specific unit operations information. This spreadsheet cost model also allowed us to model how costs would be affected by the ABT provisions.

The building of the refinery-by-refinery model consisted of two major steps. The first step was to estimate baseline operating conditions for each refinery. This involves estimating the volumes and sulfur levels of the gasoline blendstocks that comprise each refinery's gasoline. We chose to use information from 2010 and 2011 for modeling the baseline operating conditions for the refineries as it was the latest years for which we had data for refiner operations and yields. Additionally, EIA projections indicated that gasoline demand is expected to be essentially flat between 2011 and when the Tier 3 sulfur control program takes effect, alleviating the need to adjust refinery operating throughputs and yields for future changes in gasoline demand.<sup>6</sup> As a final adjustment to our estimated gasoline volumes and sulfur levels, we calibrated the model to actual refinery gasoline volume and sulfur levels to ensure our model's accuracy.

A critical step in characterizing refinery operations was to estimate the FCC naphtha volume, the sulfur level of the FCC naphtha, and the amount of sulfur reduction needed in FCC naphtha to meet a 10-ppm sulfur standard at each refinery. We also incorporated in our refinery-by-refinery model the impacts that FCC pretreaters have on FCC naphtha yields and sulfur levels, as well as the impact of refinery-specific crude oil sulfur levels on FCC naphtha yields. Similarly, we also used the refinery-by-refinery cost model to estimate the volume levels of light

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straight run naphtha (LSR) and natural gas liquids (NGL) that may require additional hydrotreating.

The second step involved applying the various sulfur control technologies to each refinery as necessary to meet the 10-ppm sulfur standard. We expect that the majority of the sulfur reductions necessary to comply with a 10-ppm gasoline sulfur standard will come from reducing the sulfur level in their FCC naphtha. We first identified the sulfur control technology used by refiners at each refinery for complying with Tier 2. We then obtained information from vendors of FCC naphtha desulfurizing equipment for revamping or adding new capital as the basis for complying with additional gasoline sulfur control. Furthermore, we used our refinery-by-refinery model to estimate the extent that refiners will need to add additional LSR/NGL hydrotreating capacity at their refineries.

This allowed us to generate a cost estimate for the sulfur control technology in each refinery. The capital costs for installing the sulfur control technologies in each refinery were evaluated based on a before-tax, 7 percent return on investment (ROI). In the following sections, we present the various steps that were used in this refinery-by-refinery modeling analysis.

#### 5.1.3.1 Estimating Individual Refinery Gasoline Blendstock Volumes

To effectively model sulfur control costs for each refinery in our refinery-by-refinery cost model, it was necessary to understand the sulfur levels and volumes of the various blendstocks which make up each refinery's gasoline. Each refinery blends up its gasoline pool from the various gasoline blendstocks that are produced from the refinery units installed at each refinery. However, information on the volumes and sulfur levels of each gasoline blendstock produced by each refinery is not publicly available, so it was necessary to seek other sources of information. Fortunately, instead of solely relying on refinery unit capacity data to estimate unit operations, we were able to obtain individual refinery unit throughput volumes for most of the refinery units. From the Energy Information Administration (EIA), we obtained actual year 2011 refinery specific throughput volumes for the crude, FCC, cokers and hydrocracking units. For other refinery units, including the alkylation unit, reformer isomerization unit and naphtha hydrotreater, we obtained throughput data from the Office of Air Quality and Standards (OAQPS). We used this information to estimate the extent that each refinery process unit is utilized, followed by a unit-specific analysis for estimating how the respective refinery unit produces material for blending into gasoline. After the unit-by-unit estimates were completed, we performed a check for each refinery by comparing our estimated gasoline volumes with reported gasoline volumes for each refinery, using refinery gasoline production volumes that refiners report to EPA and made further appropriate adjustments to our refinery-by-refinery model.

##### 5.1.3.1.1 *Principal Refinery Unit Throughput Volumes*

To estimate the production volumes for each of the refinery's gasoline blendstocks, we obtained average unit throughput volumes from EIA and from the Office of Air Quality Planning and Standards (OAQPS), a sister office at the EPA. With this information, the refinery-by-refinery model effectively models each refinery's gasoline blendstock yields. Our use of this information significantly improved our model's ability to estimate FCC naphtha, as well as other

gasoline blendstocks that each refinery makes. The FCC, coker and hydrocracker unit throughputs versus actual capacity (capacity utilization) that we obtained from EIA for each domestic refinery are aggregated and presented on a PADD-average basis in Table 5-2. We also present the actual throughput volume aggregated by PADD in Table 5-3. This data is presented on a PADD-average basis to protect refinery confidential business information (CBI).

**Table 5-2 Process Capacity Utilization<sup>a</sup>**

	Crude Throughput	FCC Throughput	Coker Throughput	Hydrocracker Throughput
Total U.S.	0.827	0.797	0.803	0.827
PADD 1 <sup>b</sup>	0.722	0.750	0.474	0.434
PADD 2	0.840	0.763	0.838	0.782
PADD 3	0.847	0.821	0.813	0.860
PADDs 4/5 excluding California	0.762	0.777	0.739	0.774

<sup>a</sup>Actual unit throughput rates as a fraction of maximum unit capacity on a PADD basis

**Table 5-3 2011 EIA Refinery Unit Throughputs (1,000 BPSD)**

	Crude	FCC Units	Coker	Hydrocracker
PADD 1	906	419	<3 <sup>a</sup>	<3 <sup>a</sup>
PADD 2	3,427	998	512	239
PADD 3	7,893	2,572	1,326	985
PADDs 4/5 excluding California	1,362	282	124	99

<sup>a</sup> Since there are less than three refiners in this PADD with these units, the data was not reported to protect CBI information.

In the model, we also adjusted the refinery capacity information to account for refinery expansions or refinery shutdowns that we were aware of and are scheduled to occur over the next several years. Refinery expansions include those announced for WRB Refinery in Wood River Illinois Motiva in Port Arthur, TX, Valero in Port Arthur, TX, Tesoro in Mandan, ND, Holly Frontier in Woods Cross, UT and BP in Whiting, IN. For these expansions, there is limited public data on which of the specific process unit capacities would be increased, though each expansion project has information on the crude unit capacity increase. Since the data was limited, we increased all of the existing individual process unit capacities by the fractional increase in crude oil unit capacity at each of the expanding refineries. Refineries that we believe are permanently shutdown in PADD 1 were removed from our analysis but, consistent with recent import/export trends, PADD 3 refineries or European gasoline likely would supply any lost capacity to PADD 1 as a result of this lost production. PADD 1 refineries that were presumed to be permanently shutdown are; Giant refinery located in Yorktown, Virginia, the Sunoco refineries in Westville, New Jersey, the Sunoco refinery in Markus Hook (was part of the Philadelphia complex), and the Hovensa refinery on St. Croix of the Virgin Islands

The next step was to calculate actual unit throughput rates for the other refinery processes that produce gasoline blendstocks. These units include alkylation, dimerization, polymerization, isomerization, naphtha reforming. All of the feedstocks for these processes are primarily

supplied by the crude and FCC Units. We used OAQPS throughput data for Alkylation and Isomerization units, while Poly/Dimersol units were assumed to run at full capacity. Additionally, there were seven refiners that did not have alkylation throughput charge rates in the OAPQS data. Since it is likely that refiners are using the alkylation units at these refineries, in response to peer reviewer comments, we assumed that the alkylation units were being used at the same utilization rate as the FCC unit at those refineries. Since the throughput data for alkylation units is for the production volume, alkylate volume was the same as the throughput volume. The results of the capacity utilizations of these downstream units are aggregated summarized on a PADD-average basis in Table 5-4.

**Table 5-4 Other Unit Process Capacity Utilization<sup>a</sup>**

	Reformer Throughput	Alkylation Throughput	Isomerization Throughput	Poly/Dimersol Throughput
PADD 1	0.499	0.597	0.960	1.000
PADD 2	0.580	0.727	0.651	1.000
PADD 3	0.599	0.800	0.443	1.000
PADDs 4/5 excluding California	0.609	0.691	0.730	1.000

<sup>a</sup> Actual unit throughput rates as a fraction of maximum unit capacity on a PADD basis

With these inputs the refinery-by-refinery model now contained estimates of the feedstock charge rates for all of the gasoline blendstock producing units. However, for some units, estimating refinery unit capacity and capacity utilization may does not translate directly into the gasoline blendstock volume produced by a specific refinery unit. This is because some refinery units may also produce products other than gasoline blendstock. Additionally, some processes have volume loss of feedstock due to process reactions and conversions that take place that increase or decrease the density and therefore the volume of products. To take this into account, a gasoline fraction yield factor has to be applied for some of the processes to convert the process charge rate into the yield of gasoline blendstocks. The crude, the FCC, the coker and hydrocracker units all produce some naphtha from its feed, and we needed to estimate the naphtha volume. We will discuss how we estimated the FCC naphtha here separate from the other units because the FCC naphtha is usually kept separate from the other naphtha streams until it is blended into the gasoline pool. We will discuss the contribution of the crude, coker and hydrocracker units to naphtha when we present how we estimate light naphtha and heavy naphtha volume below.

#### 5.1.3.1.2 FCC Naphtha Volume

The FCC unit produces significant volumes of naphtha, a gasoline blendstock. The conversion percentage to naphtha is affected by the severity of the operation of the FCC unit. As shown in Table 5-5, an initial estimate was made for the portion of FCC feedstock converted to naphtha. This initial estimate ranged from 53 to 57 percent depending on the PADD and was estimated based on a year 2018 refinery modeling run output using the Haverly LP refinery model.

**Table 5-5 FCC Naphtha Fraction of Feed**

	FCC Units Average
PADD 1	0.543
PADD 2	0.574
PADD 3	0.572
PADDs 4/5 excluding California	0.535

While having an initial estimate is useful, the range among individual refineries can be quite large, but we didn't have access to refinery-specific data for this. However, we were able to take steps to use the data that we did have access to better estimate each refinery's FCC naphtha production. There is expected to be differences in FCC naphtha production between refineries with and without FCC pretreaters. Thus, as the first step we took to better estimate FCC naphtha production from each refinery's FCC unit, we differentiated between refineries that have an FCC feedstock pretreater and those that do not. We also quantified the gasoline blendstock fraction yield for FCC units that have both feed pretreater and posttreater units. Per comments from the peer review of our model, we limited the amount of FCC feedstock that could be pretreated at a few refineries that did not have enough capacity to pretreat all of their FCC feedstock. Historically, refiners have installed FCC feed pretreaters for economic reasons, as pretreaters increase FCC unit conversion to a high value gasoline blendstock while decreasing the production of low value light cycle oil and residual material. FCC feed pretreaters also have the benefit of reducing sulfur from the FCC feedstocks, resulting in the production of lower sulfur FCC naphtha and ultimately lower sulfur gasoline. In developing our refinery-by-refinery model, we quantified the impact that FCC feed pretreating and posttreating has on FCC naphtha yields and sulfur levels based on our evaluation of information we received from technology vendors. The results of this analysis are shown in Table 5-6.

**Table 5-6 FCC Unit Gasoline Blendstock Fraction Yields**

	Average of All FCC Units	FCC Units with No Pretreater	FCC Units with a Pretreater Only	FCC Units with a Pretreater and Posttreater
PADD 1	0.543	0.532	NA	0.588
PADD 2	0.574	0.547	0.650	0.605
PADD 3	0.572	0.551	0.650	0.608
PADD 4/5 excluding California	0.535	0.523	0.608	0.574

The volume of FCC naphtha is affected in other ways by how refiners operate their refineries. One way that FCC naphtha volume is affected is if they choose to produce increased volumes of propylene.<sup>7 8 9 10</sup> Propylene is a valuable feedstock chemical used for the production of polypropylene. All FCC units produce some propylene, however, if refiners opt to use a particular catalyst additive called ZSM-5, the FCC unit cracks even more heavier hydrocarbons (primarily C6 and C7 hydrocarbons) to light olefins and more propylene is produced. The extent that more olefins are produced depends on the amount of ZSM-5 which is added to the FCC unit. We obtained refinery-specific data from EIA for the volume of propylene sales by each refinery. We compared the propylene sales data to the volume of propylene expected to be produced by

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FCC units which do not use the ZSM-5 catalyst, and if the propylene sales volume exceeded the expected propylene production volume, we assumed that ZSM-5 catalyst is being used. The reason why this is important is that as the propylene production increases, the volume of FCC naphtha decreases, which lowers the fuel volume needing to be desulfurized. It also reduces the severity of desulfurization because FCC naphtha comprises a smaller percentage of the gasoline pool and the FCC naphtha would not need to be desulfurized to as low a level to meet the same gasoline sulfur target.

The two critical criteria for implementing this propylene-related adjustment to FCC naphtha volume are the point at which higher propylene production fractions of the FCC naphtha indicates the use of ZSM-5, and the rate at which FCC naphtha production volume decreases relative to the rate that propylene production volume increases. For the former criterion, we used the recommendation made by a peer reviewer, who consulted refiners on the use of ZSM-5. The peer reviewer recommended that we use 8.5 percent as the point at which the propylene production indicated the use of ZSM-5 catalyst.<sup>11</sup> Thus, when propylene sales by a refinery exceed 8.5 percent of the FCC naphtha volume, we apply an adjustment to lower the FCC naphtha volume. For the second criterion which estimates how much to adjust the FCC naphtha volume as propylene production exceeds 8.5 percent, we used information from the Jacobs data base which models the use of a ZSM-5 catalyst. The Jacobs database estimates that for every 1 percent increase in propylene volume above 8.5 percent, there is a reduction of 1.4 percent in FCC naphtha. After implementing this adjustment, the production volume of FCC naphtha was reduced in 22 refineries from a range of 0 to 10 percent, and the volume weighted average was 2.9 percent.

Another way that refiner decisions impact FCC naphtha volume is if the refiner elects to undercut its FCC naphtha to the light cycle oil (diesel fuel) pool in response to relatively higher demand for diesel fuel. Diesel fuel demand is increasing in the US and US refiners are also exporting more diesel fuel. At the same time gasoline demand is decreasing in the US and US refiners tend not to export as much gasoline. This trend is expected to continue in the future based on Energy Information Administration's (EIA's) projections in its Annual Energy Outlook. Table 5-7 summarizes both the historical and projected demand in petroleum and renewable fuels.

**Table 5-7 Historical and Projected US Petroleum and Renewable Fuels Demand  
(billion gallons)**

	<b>2009</b>	<b>2012</b>	<b>2018</b>	<b>2030</b>
Total Gasoline	132.8	134.6	130.9	112.5
Total Diesel	53.9	57.8	66.6	68.7
Total Jet	20.2	21.1	22.9	24.5
Ethanol	11	13	16	22
Biodiesel/Renewable Diesel	0.3	1	3.84	8.34
Refinery Gasoline	121.8	121.6	114.9	90.5
Refinery Distillate (Jet + Diesel)	73.8	77.9	85.7	84.9
Distillate/Gasoline Ratio	0.606	0.641	0.746	0.938

Table 5-7 summarizes historical and future total demand for gasoline, diesel and jet fuel including renewable fuels and that which refiners produce after renewable fuels are subtracted out (refineries don't produce these fuels). Refinery gasoline production was essentially flat from 2009 to 2012, but after 2012, it is expected to decline. Conversely, refinery distillate production has been increasing and it is expected to increase further in the future. Thus, the changing refinery production profile, when expressed as a ratio of distillate production (jet and diesel fuel) to gasoline production, is expected to increase from 0.61 to 0.94 during the period from 2009 to 2030. As a point of comparison, Europe demands much more diesel fuel than gasoline, and its ratio of distillate to gasoline demand is currently over 2.0.

If this trend towards lower relative gasoline demand continues, refiners will continue to change how they refine crude oil into gasoline and diesel fuel. One way that refiners are expected to respond to this trend is by undercutting the FCC naphtha to the diesel fuel pool. The refinery unit information that we obtained from OAQPS has allowed us to better calibrate our model to how refiners are operating their refineries. Despite the improved modeling of US refineries, we frequently found that refinery gasoline production exceeded their actual gasoline production volume as reported to EPA. One refiner which operates multiple refineries shared with us that they use FCC naphtha undercutting as a means to rebalance its gasoline and diesel fuel production volumes. One vendor of FCC naphtha desulfurization shared with us that refiners are indeed undercutting FCC naphtha into diesel fuel at many refineries, particularly in the wintertime. Finally, the peer reviewers shared that undercutting FCC naphtha to diesel fuel is a commonly used practice by refiners. As a verification that undercutting of FCC naphtha is occurring, we compared the T90 value of US gasoline produced in 2011 versus 2004. We found that the volume-weighted average T90 of US gasoline was 323F in 2011 compared to 333F in 2004. Thus, the gasoline pool is getting lighter which supports our premise that undercutting of FCC naphtha is occurring. Therefore, we used undercutting of FCC naphtha in our refinery-by-refinery model as a means to help balance the modeled gasoline volume with actual gasoline volume. The practice of undercutting is important because if the FCC naphtha swingcut is fully cut into the diesel fuel pool, an estimated 16% of FCC naphtha volume, and more importantly, half of the FCC naphtha sulfur would be shifted to the diesel fuel pool.<sup>12 13</sup> It is important to note that we do not project that this is a strategy that refiners will adopt for complying with Tier

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3, but instead refiners will pursue undercutting FCC naphtha as a means to improve its day-to-day refinery margins independent of Tier 3.

We used output from the LP refinery model to guide us in assumptions for undercutting the heavy gasoline streams in the refinery-by-refinery model. The LP refinery model estimates that US refineries undercut the heavy naphtha (heavy naphtha is the feedstock for the reformer) swingcut by 84% in 2009 and projects that 100% will be undercut in 2018. Conversely, the LP model estimates that refineries undercut 22% of the FCC naphtha swingcut in 2009 and will undercut 68% of the FCC naphtha swingcut in 2018. This information from our LP model suggests that the economics favor undercutting the heavy naphtha to jet fuel over undercutting FCC naphtha to diesel fuel. For this reason, we chose to undercut the heavy naphtha to jet as a first step to match the model's gasoline production volumes with actual gasoline volumes (to the extent that reformer throughput volume allows it) before we resorted to undercutting FCC naphtha. After applying FCC naphtha undercutting to further balance the gasoline volume in the refinery-by-refinery model, we ended up undercutting 34% of the FCC naphtha swingcut to diesel fuel. There is general agreement between the LP refinery model and our refinery-by-refinery model since the undercutting in the refinery-by-refinery model is in the range of 22% to 68% undercutting which represents the undercutting between 2009 and 2018. While the LP model projects that refiners will be undercutting a larger portion of the FCC naphtha to diesel fuel in the future, we did not attempt to account for any cost reduction associated with further undercutting of FCC naphtha to diesel fuel, so we are likely being conservative with this aspect of our cost analysis. We present a sensitivity case for the potential savings due to full undercutting of the FCC naphtha in subsection 5.2.

#### *5.1.3.1.3 Poly Gas and Alkylate*

For the polymerization and alkylation units the throughput volume from the OAQPS data base was used for these units for each refinery. Since this volume represents the output from these units, no adjustments to the volumes were necessary

#### *5.1.3.1.4 Heavy Naphtha and Reformate*

A series of steps were taken in the refinery-by-refinery model to effectively estimate the volume of heavy naphtha which, for the most part, serves as the feed to the reformer. The heavy naphtha volume was estimated from the volume of three components of heavy naphtha, including heavy straight run naphtha, heavy coker naphtha, and heavy hydrocrackate. The feed to the reformer was based on OAQPS throughput data, which often did not match the heavy naphtha volume. With the use of actual unit throughput volume, it removed a lot of uncertainty about how refiners are actually operating their reformers. Having good estimates of both the volume of heavy naphtha and feed to the reformer allowed us to better estimate the total volume of heavy naphtha sent to the reformer and volume of heavy naphtha which is likely blended straight to gasoline, instead of being sent to the reformer, or undercut to the jet and kerosene pool. An additional step was added to estimate the fate of benzene precursors based on refiners' actions they took to comply with the Mobile Source Air Toxics (MSAT2) 0.62 volume percent benzene standard. The aggregated summary of refinery action on MSAT2 (we used refinery specific information which is confidential business information) can be found in a report entitled

Summary and Analysis of the 2011 Gasoline Benzene Pre-Compliance Reports on EPA's webpage ([www.epa.gov/otaq/regs/toxics](http://www.epa.gov/otaq/regs/toxics)).

Heavy straight run naphtha comes from the distillation of crude oil in the atmospheric crude oil tower. The heavy straight run naphtha volume was estimated for each refinery by applying the results of a regression analysis of API gravity versus heavy straight run naphtha volume based on the assays of 13 crude oils. Table 5-8 summarizes the regression equations used for each cut of heavy straight run naphtha, and also provides a regression based on the total volume of HSR naphtha.

**Table 5-8 Values from Regression Analysis Used to Estimate Heavy Straight Run Naphtha Volume**

	x- variable	Intercept	r2
All HSR	0.0090	-0.106	0.88
160/220	0.0031	-0.0448	0.81
220/285	0.0035	-0.0484	0.83
285/350	0.0023	-0.0131	0.85
350/400	0.0014	0.0027	0.75

Based on a regression of crude quality (API gravity) versus crude assays, we were able to estimate the fraction of crude oil that is heavy straight run. The volume of heavy straight run naphtha ranges from about 7 to 36 percent of the crude oil input depending on crude oil quality processed by the refinery, and whether or not the refinery may be undercutting the heaviest part of this stream into the jet or diesel fuel pool. To demonstrate the results of the regression analysis, the volume of the various portions of heavy straight run naphtha are estimated for two different API gravities representing two hypothetical crude oils in Table 5-9. The two API gravities chosen to represent light and heavy crude oils were 20 and 35, respectively.

**Table 5-9 Estimated heavy straight run naphtha volume cuts at two API Gravities**

Crude Oil fraction for specific distillation cuts (Temperature F)	API Gravity	
	20	35
160/220	0.017	0.064
220/285	0.023	0.076
285/350	0.033	0.068
350/400	0.031	0.052

The information in Table 5-9 shows that lighter crude oils (API gravity 35) contain a larger amount of heavy naphtha than heavier crude oils. An important reason why we chose to conduct our regression analysis for separate heavy naphtha cutpoints was to capture how, as the API gravity changes, the fraction of each heavy naphtha cutpoint varies. For example, the 350/400 swingcut cutpoint comprises about 30% of the heavy naphtha volume for the 20 API crude oil, but only 20% of the of the heavy naphtha volume for the 35 API crude oil.

The volume of heavy coker naphtha was estimated based on fractions of coker unit feed from information in the Jacobs data base that we use with the Haverly refinery cost model. For the 160/220, 220/350 and 350/400 distillation cuts, the fractions of coker feed are 0.022, 0.097 and 0.033, respectively. While cokers can produce somewhat lower and higher amounts of naphtha depending on how the coker units are being operated, we believe that these fractions are about average. Because the feed volumes to the cokers are actual throughput volumes from EIA data, the volume of coker naphtha that we estimate at each refinery is likely to be reasonably accurate.

The volume of heavy hydrocrackate was also estimated based on information in the Jacobs data base as well as from a peer reviewer, depending on feedstock type. We estimated different production profiles depending on the feed type. Standalone hydrocrackers which process gas oil are very flexible units capable of producing a range of gasoline and diesel fuel production volumes. We incorporated the range of gasoline production volumes in our refinery-by-refinery model to represent this flexibility. One important reason why we included this range of gasoline production volume is to help balance the gasoline volume produced at each refinery. Our refinery-by-refinery model estimates lower and higher gasoline volumes than actual gasoline

production, and differences in hydrocracker naphtha production volumes, based on how hydrocrackers are operated, is likely one reason why our model is not matching actual refinery gasoline production volume. We also model the heavy naphtha production volume when hydrocrackers are used to process residual fuel. When processing residual fuel, the naphtha production profile is more predictable for residual fuel hydrocrackers and the conversion to naphtha tends to be much lower. The last type of hydrocracker that we modeled is an FCC feed hydrotreater which is converted over to a mild hydrocracker. This may increasingly be an approach used by refiners to increase their distillate to gasoline ratio. In doing so, it would also aid Tier 3 sulfur control. However, since we had no data with which to estimate which refiners might convert their FCC feed hydrotreaters to mild hydrocrackers, we did not assume this in our cost analysis, but only show the potential impact in a sensitivity analysis discussed in section 5.2. The fraction of feed to the hydrocracker which is produced as heavy naphtha is summarized in the Table 5-10 for each type of hydrocracker that we modeled.

**Table 5-10 Summary of Heavy Naphtha Production by Hydrocracker Type and Operating Mode**

Naphtha cut (F)	Hydrocracking of Gas Oil – Operating Modes			Resid	Gas Oil
	Naphtha	Middle	Diesel		
49/200*	0.42	0.23	0.06	0.03	0.02
200/285	0.21	0.15	0.08	0.04	0.03
285/400	0.16	0.23	0.17	0.09	0.07

\* The naphtha cutpoint data for hydrocrackers included the light hydrocrackate cut (49/160) along with the light portion of the heavy naphtha cut.

The heavy naphtha distillation cutpoints were sometimes different depending on the source of the heavy naphtha. For example, the heaviest naphtha cut for the hydrocracker is 285/400, while the heaviest naphtha cut for the heavy straight run naphtha is 350/400. It was necessary to create a consistent set of cutpoints before we could combine the various streams from different units, so we normalized the cutpoints to create four distinct heavy naphtha volumes. The cutpoints for the heavy naphtha volumes are 160/200, 200/285, 285/340 and 340/400. The cutpoints were either adopted from the Jacobs data base, or specified to satisfy a certain need. The benzene precursor fraction was established as 160/200, (changed from 160/180 used in the NPRM) based on benzene precursor boiling point information provided by a peer reviewer. The swingcut was established as 340/400 (changed from 350/400 used in the NPRM) to capture the ability for jet fuel or kerosene to accommodate the lighter blendstocks and still meet the flashpoint specifications. In cases when a heavy naphtha cutpoint provided does

not match the cutpoints we are using, we adjusted the volume using a simple reapportionment based on the temperature range that the cutpoint represents. Using the heaviest naphtha cut produced by the hydrocracker as an example, to convert 285/400 to 285/340 and 340/400, the volume was apportioned  $(340-285)/(400-285)$ , or 48% for the lighter cut, and 52% for the heavier portion.

Refiners must comply with MSAT2 benzene standard which requires refiners to reduce their gasoline to an average of 0.62 volume percent benzene. How refiners comply with MSAT2 determines the fate of the 160/200 heavy naphtha volume. Depending on what happens with the volume, it can affect our estimated refinery gasoline volume. In their compliance report to EPA, refiners indicated how that they would comply with MSAT2 benzene standard listing one of several possible actions. These actions can be divided into two categories; those who would route the benzene precursors to the reformer and those who would not. A second point of interest is whether the benzene precursor stream or the benzene-rich reformat stream is blended into the refinery's gasoline pool or not, which makes a difference in terms of matching a refinery's gasoline production volume. Table 5-11 summarizes the refinery options for the benzene precursors or the benzene-rich reformat stream.

**Table 5-11 Summary of Refiner Actions for Complying with MSAT2**

Fate of Benzene Precursors	Keep in Gasoline Pool	Do not Keep in Gasoline Pool
Do not Route to Reformer	<ol style="list-style-type: none"> <li>1) Send to Isom unit</li> <li>2) Route around Reformer</li> <li>3) Send to Benzene Saturation unit</li> </ol>	Send Benzene Precursors to another Refinery
Route to Reformer	<ol style="list-style-type: none"> <li>1) Reform and Extract</li> <li>2) Benzene Alkylation</li> </ol>	Send Benzene-Rich Reformat to another Refinery or Petrochemical Plant

The options for compliance with MSAT2 are: continue to reform the benzene precursor cut and extract the benzene, routing the benzene precursors around the reformer to a benzene saturation unit, route the benzene precursors around the reformer to an isomerization unit, and finally, exporting the 160/200 substream. In the case of exporting the 160/200 substream, it is not clear whether the stream would be exported before or after being reformed. So we used a reformer balance, as described below, to estimate whether this stream is reformed or not before being exported. Table 5-12 summarizes refiner plans for complying with MSAT2.

**Table 5-12 Refinery MSAT2 Compliance Plans**

	MSAT2 Compliance Plans				
	Extraction	Route Around Reformer to Gasoline	Isomerization	Export	Benzene Saturation
Number of Refineries	15	39	16	16	10

The reformate volume is based on throughput volume from data we obtained from OAQPS. The reformer throughput volume is the volume of heavy naphtha which is fed to the reformer. The OAQPS reformer throughput data shows that on average, US refiners are operating their reformers at 69% of capacity, with some reformers operating at full capacity while others are shutdown (this usually is one train of multiple reformer trains at larger refineries). Consistent with our LP refinery modeling results, refiners are operating their reformers at a much lower throughput volume than capacity due to the much increased blending of ethanol which is very high in octane. Furthermore, demand for premium gasoline has diminished in recent years, which also has reduced the demand from octane-producing units such as the reformer.

The reformer throughput volume usually did not match the heavy naphtha volume that we estimated for each refinery, which we expected because throughput volume was so low relative to reformer capacity. While there was a very good match between the heavy naphtha volume and the reformer throughput for 22 refineries, for the rest of the refineries there was a discrepancy. While 13 refineries did not have sufficient heavy naphtha volume to match the reformer throughput volume, it was far more common for the heavy naphtha volume to exceed reformer throughput volume, even after accounting for refiners' plans for complying with MSAT2. The most likely reason why refiners were not feeding all the heavy naphtha to the reformer is because refiners are undercutting the 340/400 heavy naphtha swingcut to the jet pool. When the heavy naphtha volume exceeded the reformer throughput volume and our model estimated a larger gasoline volume than actual, we assumed that the refinery is undercutting the heavy naphtha swingcut to the jet pool. Based on our criteria for undercutting the heavy naphtha, our model estimates that about one third of the heavy naphtha swingcut is being undercut to the jet pool. If after assuming that the refinery is undercutting the heavy naphtha swingcut and the refinery's heavy naphtha volume still exceeds the reformer throughput volume, we assumed that the refinery is routing a portion of the heavy naphtha around the reformer and blending it straight to gasoline. Alternatively, we assume that the heavy naphtha stream which is not being reformed is being exported from the refinery if the model's gasoline production is exceeding actual gasoline production.

The volume of reformate produced by the reformer is not the same as the feed volume to the reformer because of the cracking and volume shrinkage which occurs due to the reforming reactions. Furthermore, the change in volume that occurs in the reformer is dependent on the severity of the reformer. Reformer severity is measured by the research octane number (RON) of the reformate, which can vary between 90 to 105. As the severity of the reformer increases, the volume of the product reformate decreases as a fraction of the feed. This relationship also varies depending on the type of reformer. Table 5-13 summarizes the estimated volume shrinkage for different reformers operating at different operating severities.

**Table 5-13 Reformate Production Fraction of Feed for Different Reformer Severities**

Severity	Reformer Type and Fraction of Feed Volume that Reformate Volume Represents		
	Semi Regen	Cyclic	Continuous
90	0.87	0.87	0.895
95	0.845	0.845	0.87
100	0.78	0.78	0.805

The volume of reformate is clearly dependent on the severity that a refiner is operating its reformer. Unfortunately, there is no available data on the severity at which refinery reformers are operating, so we developed a means to estimate it. Our assumption is that reformer severity is dependent on the number of octane increasing units that a refinery has and whether the refinery has an aromatics plant. If a refinery has an aromatics plant (refiners would likely want to maximize aromatics production if they have an aromatics plant), or if the refinery does not have an isomerization unit nor an alkylation plant (if the sole octane producing unit in a refinery is a reformer, then the refiner would likely need to operate it at high severity to provide sufficient octane), then we assume that a refinery's reformer is operating at 100 severity. If a refinery has either an alkylation plant or an isomerization unit and no aromatics plant, then we assume the refinery's reformer is operating at 95 severity. However, if a refinery has both an alkylation and isomerization unit and no aromatics plant, then we assume that the refinery's reformer is operating at 90 severity. Based on our assumptions for estimating reformer severity, the reformers at 14 refineries are operating at 90 severity, the reformers at 66 refineries are operating at 95 severity, and the reformers at 27 refineries are operating at 100 severity. Once we assigned a severity to each refinery's reformer and knowing the type of reformer each refinery has (based on information from the Oil and Gas Journal), we determined the fraction that the product reformate is of the throughput volume as summarized in Table 5-13.

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#### 5.1.3.1.5 *Light Naphtha*

The light straight run naphtha (LSR), light coker naphtha, light hydrocrackate and pentanes plus (natural gas liquids) all are light naphtha streams which are principally comprised of five- and six-carbon hydrocarbons which boil in the range from 49 F to 160 F. The LSR comes directly from crude oil and the pentanes plus (natural gas liquids or NGL) come from natural gas wells, while light coker naphtha and light hydrocrackate come from the coker and hydrocracker units, respectively.

The volume of LSR for each refinery was based on a regression analysis of volume of LSR versus API gravity for the crude oil that it processes. Crude oil assays contain crude API gravity numbers along with the corresponding LSR yields fraction for the crude oils, which enables someone to develop a correlation between crude API and LSR yield. During the peer review of our model, one of the peer reviewers provided a regression analysis of the LSR versus crude oil API gravity using a large number of crude oil assays. For the final rule we adopted the equation recommended by the peer reviewer. The resulting equation is:  $LSR\ Yield = 2E-06 X^3 - 8E-5X^2 + 0.0022X + 0.0001$ , with X being crude API gravity number. This equation has a predictive R<sup>2</sup> value of 0.8197 for estimating the percentage of LSR from Crude API gravity. By utilizing data obtained from EIA for each refinery's average annual crude oil API number, we were then able to estimate each refiner's LSR yield fraction. Our regression analysis estimates that the percentage of LSR in crude oil varies from 2 and one half percent, for heavy crude oils, to over 8 percent for light crude oils.

The NGL that refiners purchase comes from natural gas wells after it has been separated and cleaned up at natural gas processing plants. Refiners report to EIA this volume of NGL that they purchase at each refinery and we obtained and entered this data into our refinery-by-refinery model and added this volume to the rest of the light naphtha assuming that it all boils in the temperature range of 49 F to 160 F.

The volume of light naphtha produced by the coker unit is estimated based on data from the Jacobs data base. That data base estimates that light coker naphtha comprises 2.1 percent of the feed volume to the coker unit. While the coker units may produce a somewhat higher or lower percentage of light naphtha than what we estimated, we believe that this percentage is average for coker units in general.

The volume of light naphtha from hydrocrackers is estimated based on naphtha production estimates for hydrocrackers operating in different modes as described above in Section 5.1.3.1.4. In that Section, we present the volume of lightest cut of the heavy naphtha produced by hydrocrackers, and that cut also contains the volume of light naphtha. To calculate the volume of light naphtha from that cut, we used a simple ratio of the distillation cut points. The light naphtha portion of the 49/200 cut is calculated to be  $(160-49)/(200-49)$ , or 74 percent of that volume fraction provided for that cut.

For modeling purposes, the light naphtha (LSR, light coker naphtha and light hydrocrackate) were split into a five carbon stream and a six carbon stream. This split was necessary to facilitate matching the RVP of the gasoline produced by the refinery, as described in subsection X that discusses matching refinery gasoline volume. These five and six carbon

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streams have several possible fates in each refinery. If a refinery has an isomerization unit, which converts straight chain hydrocarbons to branched chain hydrocarbons for its octane benefit, these streams could be fed to that unit. If a refinery does not have an isomerization unit, or that unit is capacity limited, the five and six carbon hydrocarbons are blended directly into gasoline, unless removing five carbon hydrocarbons is necessary to control RVP.

The volume of C5 and C6 hydrocarbons fed to a refinery's isomerization unit was based on its throughput volume in 2010 from OAQPS data. To ease the task of balancing RVP, the six carbon stream was sent to the isomerization unit first and then the five carbon stream sent to the isomerization unit to satisfy the throughput volume. Any leftover volume was blended straight to gasoline, unless some 5 carbon hydrocarbons needed to be removed to balance RVP. For the isomerization units in 6 refineries, the Oil and Gas Journal specifies that these are only C5 isomerization units. For these isomerization units, we modeled that these isomerization units were solely being fed C5s. The volume of isomerate is estimated to be 98.5 percent of the feed to the isomerization unit (there is 1.5 percent volume loss in the isomerization unit).

#### *5.1.3.1.6 Other Purchased Blendstocks*

Some additional gasoline blendstocks are purchased and blended into the gasoline pool and we attempt to account for this. The gasoline blendstocks typically purchased include ethanol and butane. Gasoline quality data reported by refiners to us contains the percentage of ethanol blended into each refinery's RFG, but does not contain the amount of ethanol that is blended into the conventional gasoline pool at the refinery, and it certainly does not contain the ethanol blended into gasoline at terminals. In the 2011 gasoline quality database, the ethanol volumes only averaged 3.3 percent of US refinery gasoline production, which would result in an over estimation of our refinery and program costs if we did not account for the rest of the ethanol. To capture the impact of the blended ethanol, we added ethanol into each refinery's gasoline pool until the total ethanol blended into each refinery's gasoline reached 10 percent. .

To estimate the butane volumes in our refinery-by-refinery model we used an RVP balance equation. This equation states that the product of the overall RVP and volume of a refinery's annual gasoline pool is equal to the sum of the product of the RVP and volumes of the non-butane components plus the product of the RVP and the volume of the butane blendstocks. We raised each of the RVP values to an exponent to capture the true impact of hydrocarbon's volatility. The value of the exponent that we used is 1.15 which is the value recommended by vendors and consultants. This equation can be rearranged to solve for the volume of butane blendstocks as shown in Equation 5-1 below.

### Equation 5-1 RVP Butane Balance Equation

$$\text{Butane} = D * (A^{1.15} - B^{1.15}) / (C^{1.15} - A^{1.15})$$

Where:

Butane = Volume of Butane added in each refinery in BPSD

A = Blended gasoline RVP average

B = Non-butane blendstock RVP average

C = Butane RVP

D = Volume of gasoline produced

The gasoline production volumes and RVP of the blended gasoline are reported to EPA by refiners for each refinery and were used for the A and D terms in Equation 5-1. For the butane stream, our LP refinery modeling shows that this stream is comprised predominantly of normal butane. We assumed that only normal butane would be blended into gasoline in our refinery modeling analysis. The non-butane blendstock RVP was estimated by multiplying each individual gasoline blendstock RVP times the gasoline blendstocks volume fraction of each refineries gasoline pool (CG and RFG) using 2011 ethanol volumes and taking the sum of all of these values. The RVP value for each of these streams is shown in Table 5-14 below. With this information we were then able to estimate the volume of butane added to the gasoline blendstock at each refinery. The annual volumes of butane added by refineries on a PADD level are listed in Table 5-15. The volume of butane blended into gasoline at each individual refinery varies based on the annual average gasoline RVP that the refinery produces (the RVP of CG and RFG gasoline are volume weighted together), as well the variance in gasoline blendstock streams that a particular refinery uses to produce CG and RFG gasoline.

**Table 5-14 PADD Average RVP's of Gasoline Blendstocks**

	PADD 1	PADD 2	PADD 3	PADD's 4/5 <sup>a</sup>
LSR	12.0	12.0	12.0	12.0
Heavy Naphtha	3.0	3.0	3.0	3.0
Reformate[update]	4.5	6.6	5.0	6.2
FCC Naphtha	4.6	4.6	4.6	4.6
Isomerase C5	13.0	13.0	13.0	13.0
Isomerase C6	7.2	7.2	7.2	7.2
NGL	12.6	12.6	12.6	12.6
Polymerization Gasoline	2.8	2.8	2.8	2.8
Alkylate, C4	3.2	3.2	3.2	3.2
Dimersol	5.8	5.8	5.8	5.8
Ethanol <sup>b</sup>	13.5	10.713.5	10.713.5	10.713.5

<sup>a</sup> Excluding California data

<sup>b</sup> Ethanol's RVP was established by taking ethanol's blending RVP of 20 to the root of 1.15

**Table 5-15 PADD Average Gasoline Data**

	PADD 1	PADD 2	PADD 3	PADD's 4/5 <sup>a</sup>
Non-butane blendstock RVP (B), psi	6.4	6.3	5.7	6.3
Gasoline Pool Volume (D), BPSD	738.2	1744	3487.8	500.3
Volume Butane Added, BPSD	21.4	95.1	143.1	25.7
Blended Gasoline RVP average (A), psi	9.4	10.38	9.31	10.2

<sup>a</sup> Excluding California data

#### 5.1.3.1.7 *Calibrating the Blendstock Volumes in the Refinery-By-Refinery Model*

As we discussed earlier, we took steps to balance each refinery's gasoline production volume in the refinery-by-refinery model against actual gasoline volume production reported by refiners to EPA. We estimated each refinery's gasoline volume by estimating the volume of each gasoline blendstock which comprises gasoline. Because we used individual refinery unit throughput volumes to estimate the gasoline blendstock volume for each refinery unit, we believe that we employed a robust methodology for estimating gasoline volume. However, the modeled gasoline volume for most refineries was higher than their actual gasoline volume. Thus, it was necessary to identify and make additional adjustments that would better match refiners' gasoline production.

We adjusted gasoline volume based on certain inputs and outputs that we identified. EIA collects data on natural gas liquid (termed pentanes plus) purchases for each refinery and we added the 2011 volume to each refinery. We entered the information of refinery actions for complying with the MSAT2 gasoline benzene standard in the refinery model. The MSAT2 actions which involved exports from the refinery, which included extraction of benzene, or exports of benzene precursors or the benzene-rich reformate, and these impact gasoline volume. We also adjusted for gasoline exports from Gulf Coast refineries. We did not have refinery-specific data on Gulf Coast exports, so we apportioned the 428 thousand barrel per day exports (EIA data) from Gulf Coast refineries by each Gulf Coast refinery's overproduction of gasoline.

While the throughput volume fairly well defines the gasoline blendstock volumes for most refinery units, we needed to estimate the gasoline blendstock volume for others. Hydrocrackers can be operated in different modes that preferentially produce naphtha or distillate fuel. While we did not know which mode each refinery operates its hydrocrackers, when the modeled gasoline volume for a refinery with a hydrocracker was too high relative to its actual gasoline production, we assumed that the refinery was operating its hydrocracker in distillate maximization mode. Or, when the modeled gasoline volume for a refinery with a hydrocracker was too low, we assumed that the hydrocracker was being operated in naphtha mode. We also assumed a middle mode for hydrocrackers when the modeled gasoline volume for refinery with a hydrocracker was close to matching its actual gasoline volume.

Another gasoline blendstock volume which we adjusted was heavy naphtha from the atmospheric crude distillation unit, the hydrocracker and the coker that would otherwise be feed to the reformer. Refiners have the option of feeding the heaviest portion of this heavy naphtha

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stream to the reformer or cutting it into the distillate pool. For any refinery, we only cut this heaviest portion of the heavy naphtha pool into distillate fuel if the volume of heavy naphtha exceeded the reformer throughput volume and the modeled gasoline volume exceeded the actual gasoline volume for that refinery. There were times when the heavy naphtha volume was insufficient compared to the reformer throughput volume, so we assumed that unfinished oils which are purchases that are made by refineries are

The last refinery's unit production volume that we adjusted is the FCC unit and we did so in several different ways. The production of FCC naphtha from the FCC unit is affected by whether the feed to the FCC unit is hydrotreated with an FCC pretreater – FCC units produce greater naphtha when the feed is hydrotreated. As a percentage of feed, the FCC naphtha volume varied from 53.5 to 65%. Another adjustment we made was to adjust for refinery use of a propylene increasing catalyst named ZSM-5. When maximizing propylene production, the ZSM-5 reduces FCC naphtha volume. We identified 21 refineries which we estimate are using the ZSM-5 catalyst. The last volume adjustment we made to FCC naphtha was to undercut the heaviest portion of the FCC naphtha, called the swingcut. This volume is called the swingcut because it can either be blended into the gasoline pool or the distillate pool. We only undercut the FCC naphtha to distillate fuel if the modeled refinery volume exceeded the actual refinery volume. In the refinery-by-refinery model, some or all of the FCC naphtha swingcut was being undercut to distillate fuel at 45 out of the total 108 refineries that we modeled.

After having completed these steps that we took to balance the modeled gasoline volume against actual gasoline production volume, the modeled gasoline volume for many refineries did match actual gasoline production volume. However, for many refineries the modeled refinery gasoline volume did not match the actual gasoline production volume. We reviewed the modeling for the refineries whose modeled gasoline volume did not match actual gasoline volume and we were able to identify several reasons why there were discrepancies. First, the refineries which we modeled as tar sands refineries were short of gasoline relative to actual gasoline volume. This is because tar sands are so heavy that they contain very little naphtha. Another group of refineries with a volume discrepancy have aromatics extraction units and they tend to have insufficient heavy naphtha feed for the reformer. We believe that the volume discrepancy exists because these refineries purchase heavy naphtha for feeding to their reformers for making additional aromatics for their aromatics plants, but we do not have data for heavy naphtha purchase (the only category that may reflect this is unfinished oils, but the volumes did not match the heavy naphtha shortfall in many of these cases. To avoid improperly modeling refinery costs because of our inability to accurately model refinery gasoline volume, we used actual refinery gasoline production volume in the year 2011 for refinery gasoline volume instead of the modeled gasoline volume estimated by the refinery-by-refinery model.

#### 5.1.3.2 Refinery Blendstock Sulfur Levels

After determining the volume of each gasoline blendstock stream, we next estimated the sulfur level of each of the gasoline blendstocks for our modeling analysis using information we collected from literature reviews and discussions with refinery consultants and technology providers. We also considered the blendstock sulfur levels estimated for the MSAT2 rule and the estimates derived from our refinery-by-refinery model to estimate the sulfur levels of the blendstock streams. Establishing these sulfur levels is important as this sets a baseline for the

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refinery-by-refinery model that represents our estimate for the current operations of each refinery. This allowed us to project what changes refiners would have to make in their refineries to comply with the Tier 3 standards, and project the new investments and operating costs associated with these changes. The following section contains further details on how the sulfur content of each of the blendstocks was estimated. The results of this analysis can be found in Table 5-9 at the end of this section.

The first stream we considered was the butanes that are used as a gasoline blendstock. The butanes used as gasoline blendstock within a refinery come from a variety of sources. Much of the butane used as a gasoline blendstock is distilled from the crude oil or other blendstock streams within the refinery. Refiners remove the butanes from crude oil and sometimes gasoline blendstocks which contain some butane (i.e., FCC naphtha, hydrocrackate) and then blend them back into the gasoline up to the RVP or vapor/liquid limit applicable to the gasoline market that the gasoline is being sold into. During the summer months refiners usually have excess butane which cannot be blended into the gasoline pool because of the tighter RVP standards. Many refiners store the excess butanes and then blend them back into gasoline in the winter months when the volatility limits for gasoline are less stringent. Other sources of butanes used as gasoline blendstocks are natural gas processors and crude oil drilling operations. The butanes from these sources are produced in downstream units which separate the various hydrocarbon components. Some of these downstream units “sweeten” or desulfurize the butanes using an extractive desulfurization unit prior to shipping them in pipelines or selling them directly to refiners. The sweetening process reacts the hydrocarbon mercaptan compounds to disulfide compounds reducing their odor and corrosivity. The sweetening process, however, does not lower the sulfur level. If the source natural gas well is very high in sulfur, the operator may need to use an extractive treatment technology which actually removes the sulfur from the butane stream. If the purchased butanes are not treated, then refiners treat the butanes. This treatment generally lowers the sulfur level of the butanes to under 5ppm. Purchased butanes that are blended into gasoline have a sulfur limit of 30 ppm and those that are shipped through pipelines, regardless of their end use, have a limit of 140 ppm. Furthermore, many refiners have extractive desMerex units on site that are capable of removing sulfur from butanes that are either purchased or generated internally from refinery units. For dimersol, and poly gas blendstock streams, we used the same sulfur levels that we estimated for our MSAT2 rulemaking. The sulfur levels for these streams are inherently low due to the dynamics of process reactions in the dimersol and polymerization units. Furthermore, it is unlikely that refiners have altered these processes in their refineries since our analysis for the MSAT2 rule was completed.

Alkylate blendstocks usually have a small amount of sulfur, usually less than 15 ppm. The primary source of sulfur in alkylate is the sulfuric acid that is used as a catalyst in the alkylation process. Finished product coalescers and knockout drums are used by refiners to remove impurities, including sulfuric compounds, from the alkylate product as it leaves the alkylation unit. This separation is imperfect, and a small quantity of the sulfuric compounds which remain in the alkylate account for the majority of its sulfur content. Prior to the enactment of the Tier 2 standards, the alkylate produced by most refineries contained 10 to 25 ppm sulfur which assumes that there was some carryover of sulfuric compounds into the alkylate. Based on our discussions with gasoline desulfurization technology vendors, however, refiners have installed new acid coalescers and knock out drums in recent years. These new units improved the removal of residual sulfuric compounds and can produce an alkylate blendstock with a 5-ppm

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sulfur level. This adjustment by refiners seems to be a low cost method for reducing the sulfur content of alkylate. For our refinery-by-refinery baseline analysis, we assumed that refiners have already installed improved acid knockout drums and are currently producing alkylate which averages 10 ppm sulfur. We also assumed that Hydrofluoric Acid (HF) alkylation processes had the same alkylate yield per feedstock throughput as a sulfuric acid alkylation unit in our refinery by refinery model. We assumed that the sulfur level of alkylate from an HF units also averages 10 ppm sulfur, even though HF processing units use hydrofluoric acid as the processing catalyst, instead of using sulfuric acid.

The coker unit produces a gasoline blendstock with a significant amount of sulfur. These units convert the heavy portion of crude oil, called residuals, into gasoline and diesel blendstocks through the use of heat and pressure. The gasoline blendstock produced by the coker can contain more than 3,000 ppm sulfur. This stream is normally split into two different streams. The stream which contains the six to nine carbon hydrocarbons is processed in the naphtha hydrotreater, which reduces the sulfur level of this blendstock to below 1 ppm. This stream is then routed to the reformer for octane improvement. The five and six carbon hydrocarbon portion of coker naphtha is called light coker naphtha and usually contains on the order of several hundred ppm sulfur. Because of the instability of this stream due to its high olefin content, it is generally processed by the naphtha hydrotreater and sent to the isomerization unit if the refinery has one. After being processed in the hydrotreater, the sulfur content of this stream is reduced to approximately 1 ppm. If a refinery does not have an isomerization unit, we assume that light coker naphtha is already being desulfurized due to the unstable and very high sulfur levels of this naphtha stream. These treating pathways were assumed for each refinery in the refinery-by-refinery baseline analysis.

Straight run naphtha is a gasoline blendstock which contains a moderate amount of sulfur. Straight run naphtha is the product stream from the atmospheric crude oil tower with a boiling point that falls within the boiling range of gasoline. The heaviest portion of straight run naphtha is higher in sulfur relative to the lighter portion of the straight run naphtha. The heavy portion of straight run naphtha is normally hydrotreated in the naphtha hydrotreater before being reformed by the reformer in order to improve its octane before being blended into gasoline. After this processing, the reformate has a sulfur level of less than 1 ppm. The light straight run naphtha (LSR) contains the five and part of the six carbon hydrocarbons and can range from zero to hundreds of parts per million sulfur before any extractive desulfurization or hydrotreating. LSR that is routed as feedstock to isomerization units has its sulfur lowered to 1 ppm by hydrotreating in the naphtha hydrotreater. This hydrotreating is necessary to allow this material to be processed in the isomerization unit, as the catalysts in these units require low sulfur feedstocks to function properly. Some refiners, however, do not have isomerization units or they produce LSR volumes that are greater than the capacity of their isomerization units. For many of these cases, refiners can treat LSR using sulfur extraction which, in most cases, reduces the sulfur level of LSR to well under 10 ppm sulfur. Even cases where there is insufficient capacity in the isomerization units it may be desirable for refiners to hydrotreat as much of the LSR as possible since it is more cost-effective to reduce the sulfur content of the LSR than the FCC naphtha. Refiners can either hydrotreat this volume of LSR in the naphtha hydrotreaters or in FCC naphtha posttreaters. After considering the volume of LSR which is already being hydrotreated or treated with extractive desulfurization, we assume that LSR contains 5 ppm sulfur.

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Natural Gas Liquids (NGL) have a composition that is similar to LSR, as it is comprised primarily of pentanes and hexanes. NGLs are produced from natural gas processors and crude oil drilling operations and the sulfur content of the NGLs can vary depending on its source, although we estimate that this stream ranges from zero to about 100ppm sulfur. While some of the NGLs are treated to remove sulfur by the NGL producers before being purchased by the refineries we did not have sufficient information to be able to determine the extent to which this treatment is occurring. At most, if not all refineries, refiners are extracting the sulfur from NGLs to prevent their gasoline from having odor issues due to the mercaptans which may be present in NGLs. Extraction is likely to reduce the total sulfur content of NGLs to low levels. For the control case in our refinery-by-refinery model we assumed that NGL liquids are being treated in a similar manner as LSR.

We also assumed that all ethanol blended into gasoline has a sulfur content of 5 ppm. Ethanol produced at ethanol plants should naturally have a negligible amount of sulfur. Before being sold, however, a denaturant is added to the ethanol. This denaturant most commonly used is natural gasoline, a C5 to C7 naphtha produced during natural gas processing. Natural gasoline has a sulfur content that ranges anywhere from a few parts per million to a couple hundred parts per million sulfur. We conservatively assumed that the natural gasoline used as an ethanol denaturant is not hydrotreated and has an average sulfur level of 250 ppm. Ethanol contains 2 percent denaturant, which results in denatured ethanol having a sulfur level of 5 ppm.

After determining the sulfur level for each of the gasoline blendstock streams as discussed above we can use this information, along with the gasoline production volumes and sulfur levels for the United States in 2011, to determine the sulfur level of the FCC naphtha stream on a national average basis. To do this we used the following equation, referred to as Equation 5-2 hereafter:

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$$\text{FCC Naphtha Sulfur ppm} = [(A*B) - (C*D+E*F+G*H+I*J+K*L+M*N+O*P+Q*R+S*T)] / Z$$

Where:

A = Refinery Total Gasoline Yield, BPSD

B = Refinery Total Gasoline Sulfur level, ppm

C = Butane to Gasoline, BPSD

D = Butane Sulfur, ppm

E = Alkylate BPSD

F = Alkylate Sulfur, ppm

G= Reformate BPSD

H= Reformate Sulfur, ppm

I = Coker Naphtha, BPSD

J = Coker Naphtha Sulfur, ppm

K= Hydro-crackate BPSD

L= Hydro-crackate Sulfur, ppm

M= Light Straight Run (LSR) and Natural Gas Liquids (NGL), BPSD

N =LSR and NGL Sulfur, ppm

O= Dimersol, BPSD

P= Dimersol Sulfur, ppm

Q= Polymerization BPSD

R= Polymerization Sulfur, ppm

S= Ethanol, BPSD

T = Ethanol Sulfur, ppm

Z= FCC Gasoline Yield, BPSD

### **Equation 5-2 Calculating FCC Naphtha Sulfur Content for Refinery-By-Refinery Model**

We used this equation to assess two cases; a baseline case where the 30 ppm Tier 2 sulfur standards were fully implemented and a control case that reflects the 10 ppm Tier 3 sulfur standards. The only terms in Equation 5-2 that change between the two cases are the national average sulfur level and the sulfur levels of the LSR, NGL, and FCC naphtha streams. The national average sulfur levels for the two cases were set at the sulfur limits under the Tier 2 and Tier 3 programs -- 30 ppm and 10 ppm, respectively. For the baseline case we assumed that the sulfur level of the LSR stream is 15 ppm. This reflects our assessment of how these streams are currently being handled as discussed earlier in this section. We estimate that 66 percent of the volume of NGL and LSR are hydrotreated before being blended into gasoline and have a very low sulfur content of approximately 1 ppm. Another 25 percent of LSR is being treated by extractive desulfurization and is low in sulfur, likely in the 0 to 10 ppm range. The remaining 10 percent is untreated and has a sulfur content of approximately 100 ppm.

For the Tier 3 control case we assumed that all of the NGLs and LSR were either A) hydrotreated or treated with extractive desulfurization and therefore had an average sulfur content of 5 ppm, or B) the refinery would comply by purchasing credits and their LSR would remain at its Tier 2 levels. This information allowed us to solve Equation 5-2 for the FCC naphtha content. The resulting FCC naphtha sulfur numbers, along with our estimation of the gasoline blendstock sulfur levels and percent of total gasoline volume made up by each blendstock are shown in Table 5-16.

**Table 5-16 Sulfur Levels for Gasoline Blendstocks in the Refinery-By-Refinery Model**

Gasoline Blendstocks	Baseline Tier 2 Case		Proposed Tier 3 Case Year 2017		Proposed Tier 3 Case Year 2030	
	Percent of Total Volume	Sulfur Levels 30 ppm	Percent of Total Volume	Sulfur Levels 10 ppm	Percent of Total Volume	Sulfur Levels 10 ppm
FCC Naphtha	37.2	80 <sup>a</sup>	36.0	21 <sup>a</sup>	35.0	21 <sup>a</sup>
Reformate	22.5	0.5	21.8	0.5	21.2	0.5
Alkylate	12.7	10	12.5	10	12.1	10
Isomerate	3.2	0.5	3.1	0.5	3.1	0.5
Butane	4.0	5	4.0	5	3.8	5
Light Straight Run Naphtha (LSR) and Natural gas Liquids (NGL)	5.2	15	4.9	5	4.8	5
Hydrocrackate	3.0	8	2.9	8	2.8	8
Ethanol	9.9	5	12.5	5	15	5
Coker Naphtha	2.2	0.5	2.1	0.5	2.0	0.5
Other Gasoline Blendstocks	0.2	10	0.2	10	0.2	10
Total/Sulfur Average	100	30	100	10	100	10

<sup>a</sup>These values are calculated using Equation 5-2; all other sulfur levels are assumed.

The numbers in the table above represent national averages. While this is useful information, it is insufficient for us to be able to model the implications of the proposed Tier 3 standards for an individual refinery. Each refinery has a unique combination of processing units that will determine the cost and operational changes necessary for that refiner to comply with our proposed sulfur limit. While each of these processing units may impact the cost for refiners to lower the sulfur content of the gasoline they produce we believe these costs will be dominated by the units responsible for the desulfurization of the FCC naphtha, and to a lesser extent the NGLs and LSR. This is because these are the only streams we anticipate would see significant sulfur reduction under the proposed Tier 3 sulfur standards. The units that are used to desulfurize these streams include the FCC unit pre- and posttreaters and the naphtha hydrotreaters. It is important, therefore, to have a good understanding of which of these units are in place in each refinery, as well as the type and capacity of these units, in order to allow us to most accurately estimate the cost of the Tier 3 sulfur standards to the refining industry. We used the above FCC naphtha sulfur balance information as the basis of our vendor request for refiner modifications to FCC posttreaters under Tier 3. However, for the vendor requests, we used a preliminary model, where the FCC naphtha levels under Tier 2 averaged 75 ppm, while FCC naphtha levels under Tier 3 averaged 25 ppm for 10-ppm sulfur gasoline, representing a 50 ppm sulfur reduction, close to the

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same delta presented in the table above.<sup>c</sup> The following section discusses our assessment of the desulfurization equipment currently being used in refineries.

### 5.1.3.3 Assessment Existing Desulfurization Equipment at Refineries

Since the desulfurization cost of the Tier 3 program is largely impacted by the cost of lowering sulfur in FCC gasoline, it is important to understand what refiners are already doing to lower the sulfur content of the FCC gasoline blendstock to meet the Tier 2 sulfur standards. This was important to our analysis of the cost for each individual refiner to reduce the sulfur content of their gasoline to meet the proposed Tier 3 sulfur standard. Refiners that already have an FCC pretreater or posttreater can revamp these units for a lower cost than installing grass roots units. It was also important to determine which refineries have an FCC feed pretreater, since these units increase the refineries FCC conversion and production of FCC naphtha and also lower the sulfur level of the FCC naphtha. To compile this information we analyzed capacity information for FCC naphtha pretreaters and posttreaters for each refinery listed in the OGJ, EIA and OAQPS database sets. If one of the databases showed that a refinery had FCC pretreating and/or post-treating capacity, while the other did not, we assumed that the refinery did have the units listed with a capacity as reported. Our OAQPS database had approximately six refiners that have FCC post treaters, and that were not listed in either the EIA or OGJ data sets. We assumed that these refiners had an existing posttreater. For refineries that have FCC naphtha posttreaters we next determined which vendor's FCC naphtha desulfurization technology is installed in each refinery. To do this we conducted a public database search using OGJ, company web postings and, other refinery publications. To supplement this data we also had extensive discussions with many refiners who provided us with information on the type and capacity of the desulfurization technology currently installed in their refineries, as well as how their operations might be adjusted to meet the new Tier 3 sulfur standards. The various FCC naphtha desulfurization technologies that we identified as currently being used by refiners are CD Tech's Cd Hydro and CDHDS, Axens Prime G and Prime G+, UOP's ISAL and Selectfining, Exxon's Scanfining I or II and Sinopec's S-Zorb. For refineries for which we could not find or obtain information on the type of desulfurization they were using, Axens was chosen as the default as they have the largest market share of desulfurization units in the U.S. To confirm the accuracy of our work we reviewed our assessments with one of the main technology vendors. Our desulfurization technology selection assumptions were adjusted based on feedback from the vendor. The aggregated results of this assessment are summarized in Table 5-17.

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<sup>c</sup> Because the technology vendors provided us with cost data only for the increment of reducing FCC naphtha sulfur content from 75 ppm to 25 ppm and in some cases from 75 ppm to 10 ppm, we modeled all refineries, regardless of their current sulfur level, using the same technology costs. In reality, those with finished gasoline sulfur levels higher than 30 ppm would have slightly higher costs and those with finished gasoline sulfur levels lower than 30 ppm would have slightly lower costs. We are trying to obtain additional information that would enable us to adjust our cost analysis to reflect actual refinery starting sulfur levels.

**Table 5-17 Posttreater Technologies Used By Refineries**

	CD Tech	IFP/Axens	Scanfining	UOP ISAL	S-Zorb
Refiners with Existing Posttreater	15	38	15	2	5

The next step of our analysis was to determine which refineries use FCC feed hydrotreating technology (pretreaters) in addition to post-treating units. FCC feed hydrotreating was primarily installed at refineries not as a sulfur control technology but because of the economic benefits that can be obtained from hydro-treating FCC feed. Hydrotreating the FCC feed increases the crackability of this stream by saturating the components with hydrogen resulting in a higher paraffin content in the feed stream. Hydrotreating also removes FCC feed impurities such as nitrogen, metals, con-carbon and sulfur, which improve FCC unit catalyst effects. An additional benefit of FCC feed pretreating is that it reduces the sulfur content of the FCC feedstock by 70 to 90 percent, resulting in the production of FCC naphtha with lower sulfur levels than what would be produced using FCC feed that is not hydrotreated.

Our analysis indicates that approximately 54 refiners are currently using FCC feed pretreaters. Of the 54 refineries with pretreaters, 35 also have FCC posttreaters installed to comply with the Tier 2 gasoline sulfur standard. The technologies used by these 35 refineries are shown in Table 5-18. FCC naphtha produced from an FCC pretreater operating at standard severity generally produces a gasoline with a sulfur content that exceeds the Tier 2 standards. According to information from vendors, the average FCC naphtha sulfur level of refineries with an FCC feed pretreater operating at standard conditions without a posttreater ranges from 200 to 500 ppm. Further reductions in the sulfur level of the FCC naphtha are possible using only an FCC pretreater by operating the pretreater at a higher severity or higher pressure (if the unit is designed to do so). This appears to be the case for the 19 refineries using only FCC pretreaters to comply with the current Tier2 sulfur standard. These high pressure FCC pretreating units were designed to be able to run at a high severity to further increase the crackability of the FCC feed and therefore increase the conversion rate of the FCC unit. These more severe conditions also further reduce the sulfur level of the FCC naphtha. The naphtha produced from these units operating with high severity or high pressure has an average sulfur content ranging from 75 to 100 ppm, allowing these refineries to produce gasoline that meets the Tier 2 sulfur standards. Operating FCC pretreaters at the high severities necessary to meet the Tier 2 standards, however, also results in increased operating cost, as the pretreater requires more frequent catalyst changeouts, consumes more hydrogen, and operates higher temperatures than pretreaters operating under standard conditions.

**Table 5-18 Technologies Used By Refiners with FCC Pre and Posttreaters**

	CD Tech	IFP/Axens	Scanfining	UOP ISAL	S-Zorb
Refiners with FCC Pretreater and Naphtha Posttreater	9	17	6	1	2

Our analysis also showed that there are several refineries that have an FCC unit but have installed neither an FCC naphtha posttreater nor an FCC feed pretreater. These are small refineries, or refineries that produce a refinery gate gasoline with a sulfur level below the Tier 2 cap of 80 ppm sulfur, but above the 30-ppm average. These refiners are relying on buying or

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sharing sulfur credits from other refineries that are over-complying with Tier 2 and make gasoline with a sulfur level less than 30 ppm.

Finally, some refineries do not have an FCC unit and therefore have not installed FCC postreaters to comply with the Tier 2 sulfur standards. These refiners primarily use reformat, alkylate, LSR, butanes, and pentanes to make gasoline. Since these blendstocks all have low sulfur content this allows refiners to produce gasoline with a low enough sulfur content to meet the Tier 2 sulfur standards.

A summary of the number refineries which fall into differing categories of how they are complying with Tier 2 is shown in Table 5-19.

**Table 5-19 Refinery FCC Naphtha Desulfurization Unit Characterization**

FCC Treatment Units Installed	Number of Refineries
No FCC Unit	14
FCC Unit, No Pretreater or Postreater	4
FCC Unit With Postreater Only	42
FCC Unit With Pretreater Only	16
FCC Unit With Pretreater and Postreater	35

#### 5.1.3.4 Estimate of FCC Naphtha Sulfur Levels

After we had determined the desulfurization technology in place at each refinery, we sought to calculate the sulfur content of the FCC naphtha, which is the feedstock for FCC postreaters. It is important to understand the sulfur level of FCC naphtha because it helps to determine the extent that existing FCC postreaters are operating at their maximum hydrotreating capacity and how refiners might invest to comply with Tier 3. Some refineries may have excess capacity in their FCC naphtha pretreater or postreaters that would allow them to produce gasoline that would meet the proposed Tier 3 standards without having to revamp existing units or add grass roots units. These refineries will have much lower cost impacts than refineries that have to make more significant capital investments. To estimate the sulfur of the FCC naphtha we must start upstream of the FCC unit and first understand the sulfur level of the crude oil which is the source for the vacuum gas oil that serves as the feedstock for the FCC units.

The sulfur level of the FCC feedstock is dependent on several items; 1) the sulfur level of the crude oil being processed by the refinery, 2) whether or not a refinery has a coker unit and 3) whether or not the refinery has an FCC feed pretreater. In refineries, the crude unit directly supplies heavy atmospheric gas oils (HGO) and vacuum gas oils (VGO) streams, which are the bulk of material used as FCC feedstock in most refineries. The sulfur level of these two streams can be estimated using a regression correlation that is based on the actual crude unit sulfur level and actual VGO sulfur level from crude assays. The peer reviewers agreed that our calculations were adequate for estimating the FCC feed sulfur levels of HGO/VGO feedstocks based on crude sulfur levels. However, if a refinery has a coker unit, the FCC unit will also likely use heavy coker gas oil (HCGO) as a feedstock. A peer reviewer pointed out to us that the sulfur level of HCGO is usually much higher than HGO and VGO, since coker units use heavy residual stocks

as feedstock. As such, the sulfur level of HCGO cannot be estimated from the same correlation used for HGO and VGO. As a result, for our final rule analysis we adjusted the FCC feed sulfur levels higher to account for the refining of higher sulfur HCGO in FCC units.

To arrive at each refiner’s FCC feed sulfur level, we determined the blended FCC feedstock sulfur value based on the volumes and sulfur levels we estimate for HGO/VGO and HCGO, as describe below.

The first step in determining the sulfur level of the FCC feedstock was to input the crude sulfur level for each refinery into our refinery-by-refinery model. For this, we obtained confidential business information (CBI) from EIA on the annual average crude sulfur levels that each refinery processed in 2011. This data, which is reported to EIA for each refinery, was used as the baseline crude sulfur level in our refinery-by-refinery analysis. Using this data, we then determined what each refiner’s HGO/VGO feed sulfur level would be, using a regression correlation we built from data on crude sulfur levels and FCC feedstock material, as discussed below.

The boiling point range that we assumed for VGO also contained some residual material, representing FCC feed with residual content. This was done to reflect the imperfect distillation cuts in crude towers and that some refiners use small amounts of residual material as FCC feedstock. The balance of the residual material, however, was excluded from the feed to FCCs since this material makes a poor feedstock due to its high aromatics, metals and concarbon content. Each of these materials negatively affects the FCC gasoline conversion yields. Most refiners today do not directly use residuals as feedstock to their FCC units, but instead send them to be processed in coker units or use the residual material for fuel oil and asphalt production. The boiling point ranges that we used for HGO and VGO are listed Table 5-20.

**Table 5-20 Boiling Ranges of FCC Feedstocks from the Crude Unit**

	TBP Initial	TBP Final
Heavy Atmospheric Gas Oil (HGO)	600°F	800°F
Vacuum Gas Oil (VGO) <sup>a</sup>	800°F	1,000°F

<sup>a</sup> Contains some residual material

For our FCC HGO/VGO feed sulfur regression, we used various crude oil assays that we obtained from Jacobs Engineering. We used data from five specific crude types, including West Texas intermediate, Bonny Light, Saudi Heavy, Alaskan North Slope, and Mayan, and three blended crude assays. The equation for this regression, along with the estimated FCC feed sulfur contents for various crude oils are shown in Equation 5-3 and Table 5-21.

**Equation 5-3 FCC HGO/VGO Feed Sulfur Content Based on Crude Sulfur Content**

$$\text{FCC Feed Sulfur Weight Percent} = (\text{Crude Sulfur Weight Percent})^{0.8} * 1.1858 + 0.0409$$

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**Table 5-21 FCC HGO/VGO Feedstock Sulfur For Various Crude Sulfur Levels**

Crude Sulfur Level (Weight %)	FCC HGO/VGO Feed Sulfur Level (Weight %)
0.11%	0.24%
0.28%	0.47%
0.85%	1.08%
1.3%	1.50%
1.4%	1.59%
1.6%	1.77%
2.8%	2.74%
3.04%	2.93%

If a refiner did not have a coker unit, we used the above method to estimate the FCC feedstock sulfur level prior to any FCC feed pretreating. However, for refiners with a coker unit, we had to adjust the above numbers higher to account for the levels of sulfur from HCGO.

For refiners with a coker unit, the HCGO yield from the coker unit was set at 25% of the feedstock, based on yield estimated from one of the peer reviewers. The sulfur level of HCGO was set to be equal to the feedstock sulfur level of vacuum residual bottoms (VTB), which is used as feedstock to the coker unit. The VTB sulfur level was assumed to be 2.2 times the refiners EIA crude sulfur level, based on correlations recommended by the peer reviewer. Using this approach, we estimated the HCGO volume and sulfur level that is used as FCC feedstock in refineries with coker units. Then, the HGO/VGO volume of feedstock was determined by subtracting any HCGO from the total EIA FCC feedstock volume that the refiner used as charge in 2011. The resulting HCGO and HGO/VGO feedstocks were then volume averaged with the corresponding sulfur levels to determine the final FCC feedstock sulfur level for the refiner. This resulted in a modest rise in FCC unit feedstock sulfur levels from our NPRM analysis approach. Table 5-22 shows the FCC feedstock sulfur results, using this methodology.

**Table 5-22 PADD Average Effects of HCGO on FCC feed sulfur levels**

PADD	FCC Feed not adjusted for HCGO, wt. % sulfur	FCC Feed adjusted for HCGO, wt. % sulfur
1	1.15	1.21
2	1.46	1.59
3	1.52	1.70
4 & 5, excluding California	1.30	1.35
California	1.54	1.54
National Average	1.44	1.54

With FCC feed sulfur estimated, the next step in our analysis was to consider the impact of pretreaters on the FCC feed sulfur levels for refineries that have these units. There are several factors that must be considered to determine the impact of the pretreaters on the FCC sulfur level, including the pressure at which the unit operates, the severity at which it is run, and whether or not the FCC naphtha will be posttreated.

To inform our understanding of how FCC pretreaters operate, we obtained guidance from technology and catalyst providers. From these discussions we learned that the capability for FCC pretreaters to remove sulfur from the gas oil feed varies significantly depending on the pressure at which the unit operates. FCC pretreaters can generally be subdivided into high pressure units (1400 psi and above), medium pressure units (900 to 1,400 psi), and low pressure units (below 900 psi). High pressure FCC pretreaters are capable of removing about 90 percent of the sulfur contained in the gas oil feedstock to the FCC unit, while low and medium pressure units are capable of removing 65 to 80 percent of the feed sulfur. Information we received from the vendors also indicated that refiners with both a pretreater and a posttreater are typically producing FCC naphtha that ranges from 200 to 450 ppm before being processed by the posttreater. Having a posttreater allows these refineries to not have to operate their pretreaters at a high severity for compliance with the 30 ppm Tier 2 sulfur standard since the sulfur will further be reduced to levels necessary to meet the applicable standards in the posttreater. For a subset of these refineries, the pretreater is undersized and not able to pretreat the entire FCC feed charge volume. In response to peer reviewer comments, we therefore, limited the amount of FCC feed that was processed for several refineries based on their unit capacity. Refineries with only a pretreater are making lower sulfur FCC naphtha in the 75 to 100 ppm range, according to vendor estimates. With this information we used our refinery-by-refinery model to estimate the pretreater desulfurization rates required to get FCC naphtha sulfur levels within the ranges specified. We estimated that FCC units with a pretreater and a naphtha posttreater are operating their pretreaters at a severity which results in a 76 percent desulfurization of the FCC feed stream. This number represents the national average. While the actual severity at which the

pretreating units are run varies on a refinery-by-refinery basis this average was used in our modeling for all refineries with both pretreating and posttreating units due to a lack of refinery-specific information. For FCC units with a feed pretreater but no posttreater we calculated the FCC naphtha sulfur level required to make a refinery gate gasoline that meets the Tier 2 standard. To do this calculation we used the gasoline yields from our refinery-by-refinery model along with the gasoline blendstock sulfur levels discussed in subsection 5.1.3.2 and shown in Table 5-16. These calculations showed that refiners with FCC feed pretreating units, but no posttreaters, need to produce FCC naphtha that averages about 85 ppm on a national level. This sulfur level corresponded to these refiners operating their pretreaters at a severity that results in a reduction of sulfur in the FCC feed stream of approximately 91-92 percent. This number is close to the estimate we received from the vendors for this category of refineries and therefore was used in our refinery-by-refinery model to determine the FCC feed sulfur level for refiners with pretreaters.

After we have calculated the sulfur level of the FCC feed we had to then take into consideration the impact the FCC unit itself has on the sulfur level of the FCC naphtha. We reviewed several literature sources<sup>14,15</sup> and found that the FCC naphtha sulfur level can be estimated by dividing the FCC feed sulfur level by 20 for refineries with an FCC feed pretreating unit. For refineries without an FCC feed pretreater, the FCC naphtha sulfur levels can be calculated by dividing the desulfurized FCC feed sulfur level by 10. In these cases the effect of the FCC unit itself on the sulfur level of the FCC naphtha is lower, as the FCC feed has already been through a desulfurization process. These factors, when combined with the sulfur levels of the FCC streams as discussed above, allow us to calculate on a refinery-by-refinery basis the sulfur level of the FCC naphtha before any post-treating operations. The results of this analysis are summarized in Table 5-23.

**Table 5-23 FCC Naphtha Sulfur Levels for Various Refinery Configurations**

	PADD 1	PADD 2	PADD 3	PADD 4/5
No Pretreater or Posttreater	N.A. <sup>a</sup>	<3 <sup>b</sup>	<3 <sup>b</sup>	<3 <sup>b</sup>
Pretreater Only	N.A. <sup>a</sup>	79	52	61
Posttreater Only	1119	1233	556	1039
Pretreater and Posttreater	45	<3 <sup>b</sup>	601	293

<sup>a</sup> N.A. – not applicable, no units of this type in the PADD

<sup>b</sup> Since there are less than three refiners in this PADD with the described configuration, the data was removed to protect potential CBI concerns.

An additional adjustment to the FCC naphtha sulfur levels was made because of undercutting of the FCC naphtha into the diesel fuel pool. If in the refinery-by-refinery model we estimated that a refinery is fully undercutting its FCC naphtha to the diesel fuel pool, the sulfur level of the FCC naphtha was reduced to half of what it would be without undercutting. If the amount of FCC undercutting was somewhere between none and all of the swingcut being undercut to diesel fuel, we proportionally adjusted the FCC naphtha sulfur level. For example, if in the refinery-by-refinery model we estimated that half of the FCC naphtha swingcut was being undercut, we estimated that the FCC naphtha sulfur level is 75 percent of what the FCC naphtha sulfur level would be without undercutting.

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This information, along with the information described in previous sections (e.g., gasoline blendstock volumes and sulfur levels, desulfurization equipment currently in place at refineries, and crude oil sulfur levels) allowed us to conduct the best analysis for the baseline case for our refinery-by-refinery model. This baseline case reflects what we believe the current operating conditions are at each refinery, including any modifications they have made to meet the Tier 2 sulfur standards. The next step of our analysis was to project what further changes, either to operations, adding new equipment or revamping existing units, each refiner would have to make to meet the proposed Tier 3 standards. After these changes are estimated, we can then estimate the cost associated with each of these changes, and ultimately the cost of the program.

#### 5.1.3.5 Cost Inputs for the Sulfur Control Technologies

After we determined the sulfur levels of the gasoline blendstocks for each refinery and the sulfur levels that these blendstocks would have to achieve to meet the Tier 3 sulfur standards, the next step in our refinery-by-refinery analysis was to project the changes to refinery units and unit operations each refinery would have to make to comply with the Tier 3 sulfur standard. One step refiners would take to further reduce gasoline sulfur levels would be to desulfurize the light straight run and natural gas liquids. The costs to reduce the sulfur content of these streams is relatively low and would therefore be a cost-effective way to further reduce the sulfur content of the finished gasoline. In addition, because ethanol tends to be a relatively low sulfur blendstock (assumed to be 5 ppm in our refinery-by-refinery model), increasing the amount of ethanol in the gasoline pool lowers the overall sulfur content of the gasoline. For the NPRM analysis, we projected that 50 percent of all gasoline produced by refiners in 2017 would contain 15 percent ethanol and that it would be almost entirely E15 by 2030. However, for our final rule analysis we are basing our ethanol use on AEO2013, which assumes widespread E10 use with very little E15 use and a small amount of E85 use. Reducing the sulfur content of the LSR and NGL streams and taking advantage of ethanol blending, however, would fall far short in enabling refiners to comply with the Tier 3 gasoline sulfur standards. Refineries with an FCC unit would still have to reduce the sulfur content of their FCC naphtha blendstock to meet the Tier 3 standards.

For each refinery we considered two cases. In the first case each refinery had to meet the Tier 3 gasoline sulfur standard of 10 ppm. To meet this standard, as discussed in Section 5.1.3.2, we estimated that they would have to reduce the sulfur level of their FCC naphtha stream from 75 to 25 ppm. We also considered a case where each refinery would reduce the sulfur level of their gasoline to 5 ppm. This information was used to help us determine which refineries might reduce the sulfur level of their gasoline below our proposed 10-ppm standard to generate credits for our ABT scenarios summarized in Table 5-1 and discussed in Section 5.2.1.

Our refinery-by-refinery model assumed that reducing the sulfur content of the FCC naphtha to 25 ppm and 10 ppm for the two cases discussed above would require that each refinery that produces FCC naphtha have an FCC naphtha posttreater. For companies that already have an FCC naphtha posttreater we assumed that all that would be necessary to meet the Tier 3 sulfur standards was to revamp their existing FCC posttreating units. We received cost information from several vendors for revamping FCC posttreating units and assumed a revamp cost for each refinery in line with the cost projections quoted by the vendor of the technology already in place in their refinery. We assumed that refineries with FCC units that currently do

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not have an FCC posttreater would have no choice other than to add a new grass roots FCC posttreating unit. We ultimately only received cost information from one vendor for the cost of adding a new grass roots FCC posttreating unit that fit the sulfur reduction requirements of the proposed Tier 3 program. We therefore assumed the cost for each refinery that would need to add a new FCC post-treating unit would be in line with this estimate. More details on the costs used in our refinery-by-refinery model for the desulfurization of LSR and NGL, as well as the new FCC post-treating units and revamps, can be found in the following sections.

#### *5.1.3.5.1 Cost to Revamp Existing FCC Naphtha Postreaters*

To estimate the cost for revamping existing FCC posttreating units or for adding new posttreating capacity, we contacted several technology vendors for cost estimates and reviewed literature, including cost information provided for the Tier 2 rulemaking. Because no two refineries are exactly the same, the cost for new FCC posttreater units or revamps to existing units will vary significantly from refinery to refinery. Some of the factors that have the most significant impact on the cost of FCC postreaters are the technology that the refiner used to comply with Tier 2, the volume of FCC naphtha, the sulfur content of the FCC unit feed and the level of desulfurization in the existing posttreater, and the location of the refinery. Based on feedback from vendors we considered three categories of FCC postreaters based on whether the FCC naphtha (the feed for the existing Tier 2 posttreater) contained low (0 – 400 ppm) medium (400 – 1,200 ppm) or high (>1,200 ppm) levels of sulfur.

For revamp postreaters, we asked the vendors to evaluate desulfurizing FCC naphtha from a Tier 2 sulfur level of 75 ppm, down to 25 and 10 ppm, for Tier 3 finished gasoline sulfur levels of 10 and 5 ppm, respectively. This corresponds to a delta FCC naphtha sulfur reduction of 50 ppm (75 ppm minus 25 ppm) for the 10 ppm standard, and 65 ppm (75-10 ppm) for the 5 ppm level. For new standalone Tier 3 post treaters, we asked the vendors to evaluate a FCC naphtha sulfur reduction from a Tier 2 sulfur level of 100 ppm, down to levels of 25 and 10 ppm, (reductions of 75 and 90 ppm), for the 10 and 5 ppm finished gasoline levels, respectively. For our FRM analysis, we applied the vendor cost estimates based on these sulfur ranges, to the sulfur reductions needed for every refinery. Since each refinery has a specific FCC naphtha sulfur reduction level needed for the Tier 3 standards, we adjusted the vendor cost estimates, so as to apply them to each refinery's particular FCC naphtha sulfur level reduction amount that was needed for Tier 3. We applied the vendor cost estimates to each refiners FCC naphtha sulfur reduction level needed for Tier3, by assuming that the vendors estimate scale linearly for octane and hydrogen for sulfur reduction levels that are less than 96 percent of the FCC naphtha Tier 2 sulfur levels. As such, the vendor cost estimates for octane and hydrogen were scaled based on the relative increase or decrease in a refiners FCC naphtha sulfur level, versus the 50 and 65 ppm sulfur delta used in the vendor estimates for a 10 and 5 ppm standard. All of the other vendor cost estimates, such as capital cost, steam, electricity usage etc, were assumed to not vary from what was supplied by the vendors. This cost adjustment was applied to all of the vendor estimates for new and revamp FCC Naphtha post treaters. The starting (Tier 2 ) FCC naphtha sulfur level for each refiner was determined based on our modeling of the volumes and sulfur levels of each of the gasoline blendstocks that the refinery uses to produce finished gasoline.

We obtained information from several technology providers for the revamp costs of existing FCC postreaters. One of the technology providers, however, declined to provide us with

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information applicable for Tier 3 sulfur control; they merely provided us with historical information for controlling sulfur from pre-Tier 2 uncontrolled sulfur levels. As a result, their capital and operating costs were extraordinarily high relative to the rest of the cost information we received from the other technology providers that was specific to Tier 3. In addition, the information they provided did not contain sufficient detail to enable us to adjust it to be of relevance for Tier 3. Given the magnitude of their cost estimate, we also believe it is likely that their cost estimate represented not only a grass roots FCC posttreater, but also significant refinery investment in other refinery processes such as FCC feed pretreating, coker unit expansion, etc. Thus, we were unable to use this information to estimate the revamp costs for FCC post treating for the refineries that employ that company's technology, and our peer reviewers concurred. The other technology providers submitted information applicable to Tier 3, but not necessarily covering all of the scenarios refineries would experience. Therefore, as discussed below, we used and adjusted the information we were provided as necessary to apply it across all the refineries. Some of the submitted information only had cost information for our medium sulfur (400 – 1,200 ppm) FCC feed case. Another technology provider did not provide cost estimates for producing FCC naphtha with a sulfur level of 25 ppm, corresponding to a finished gasoline with 10 ppm sulfur, therefore, we needed to interpolate their cost information. Because the cost information provided by the technology providers was labeled CBI, this cost information cannot be listed individually, however we aggregated the cost information we received for FCC posttreater revamps to meet 10 ppm and 5 ppm sulfur levels in gasoline. The aggregated information is summarized in 5-25 and 5-26.

One of the vendors we contacted for a cost estimate for FCC naphtha desulfurization technology provided information for several potential FCC posttreater revamp cases. The first case was a no capital costs case where refiners made no equipment modifications, but rather solely made operational changes using their existing equipment installed for Tier 2. The second case we requested was one where refiners would incur only minor capital costs and was intended to be used for analyzing program options with moderate octane costs. The third case we requested was one where refiners were willing to incur greater capital costs in order to minimize operating costs and octane loss. The majority of the vendors only supplied cost estimates for the third case, which included adding an additional catalyst reactor bed to the existing FCC posttreater unit (i.e. revamping their existing FCC posttreater). This addition of catalyst reactor bed ensures that refiners will be able to run their existing FCC posttreater at 4 to 5 year catalyst cycle lengths, which is a critical feature for FCC unit operations.

The costs for the FCC posttreater revamps submitted by one of the vendors, however showed that for low (0 – 400 ppm) and medium (400 – 1,200 ppm) sulfur FCC naphtha sulfur levels, the second case, with low capital costs, resulted in the lowest cents per gallon costs for meeting the proposed 10-ppm Tier 3 standards. According to this vendor, these cases also had a 4 to 5 year catalyst cycle length, equivalent to the higher capital cost cases even though a second stage reactor was not required. We therefore assumed that refineries using this vendor's technology would choose the minor capital cost pathway for meeting the 10-ppm Tier 3 standard when they had low or medium sulfur levels in their FCC feed. The high capital cost cases for producing gasoline to meet a 5 ppm sulfur standard from low and medium sulfur FCC feeds were found to have the lowest cost on a cents per gallon basis and were therefore selected by our model for these cases.

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One vendor only submitted information for posttreater revamp cost estimates for FCC naphtha in the 400 – 1,200 ppm sulfur category that produced a 5 ppm sulfur gasoline. In our refinery-by-refinery model, however, we had multiple refineries with FCC feed sulfur levels in the 0 – 400 and >1,200 ppm categories that use this vendor’s posttreating technology. In order to apply this vendor’s cost estimate to cases of low (0 – 400 ppm) and high (>1,200 ppm) sulfur feed categories we adjusted this vendors 400 – 1,200 ppm posttreater revamp cost based on the cost differentials between the three FCC naphtha sulfur levels in the other vendors’ revamp estimates. We similarly derived a posttreater revamp cost estimate to produce a 10 ppm gasoline for this vendor using cost differentials between the 10 and 5 ppm cases from other vendors. For refineries currently employing technology by other vendors for which we had no specific cost information, we used an average of all of the vendors’ estimates to represent FCC posttreater revamp costs for refiners using this particular technology in our refinery-by-refiner model.

After we had determined cost estimates for the FCC posttreater revamps based on information from the vendors the next step was to scale these costs based on the size of the FCC posttreating unit present in each refinery. The vendor estimates submitted for revamp costs were based on various FCC posttreater design volumes ranging from 10,000 BPSD to 45,000 BPSD depending on the base unit size used by the vendor. To determine how to apply these vendor costs to each refinery, we first calculated each refinery’s maximum FCC naphtha production. The maximum production was derived by assuming each refiner runs their FCC unit at its maximum nameplate throughput capacity (barrels per stream day) with the FCC naphtha yield rates discussed in Section 5.1.3.1.2. After sizing the FCC posttreater that would be required for each refinery we then scaled the costs given by the vendors using the six-tenths rule as shown in Equation 5-4. This is a “rule of thumb” cost estimating tool commonly used for cost estimating by the refining and petrochemical industries for estimating the cost of a process unit based on a similar unit of differing size.

$$\text{Cost to Revamp an FCC Unit} = A * (B/C)^{0.6}$$

Where:

A = Cost Estimate Received from the Vendor

B = Size of the FCC Unit in the Refinery

C = Size of the FCC Unit in the Vendor’s Estimate

#### **Equation 5-4 Six-Tenths Rule for Estimating Capital Cost**

We also adjusted the costs submitted by the technology providers based on the location of each refinery. We assumed that each vendor’s estimate was based on revamping an FCC posttreater in PADD 3 (Gulf Coast), which is the lowest cost region for installing new capital in refineries. The cost for refineries that are not located in PADD 3 were adjusted upwards based on a ratio of the cost of refinery capital projects in the PADD in which they are located relative to PADD 3. An additional factor was applied to account for the “offsite” costs that are incurred when installing new capital in refineries. When vendors provide a cost estimate for their technology, this estimated cost is called the inside battery limits (ISBL) cost and it is solely for the immediate unit of interest. However, refiners may need to install peripheral capital to support the new unit, such as electrical switchgear, a control room, storage for feed, intermediate or unit products, and longer than anticipated pipeline runs – these costs are usually considered Outside battery limit (OSBL) costs, or offsite costs. In some cases, OSBL costs may include

hydrogen and sulfur plant costs, although, for our analysis, we separately estimated the cost for providing additional hydrogen and for processing the removed sulfur and included this cost in our cost analysis. Based on feedback from our peer reviewers, for the FRM analysis, we increased the grassroots and revamp offsite cost factors for desulfurization units significantly to 1.35.

To reflect the capital costs in the per-gallon costs, we amortize the capital costs over the volume of gasoline produced. The Office of Management and Budget (OMB) set guidelines how this is to be done. The capital costs are to be amortized assuming a before-tax 7 percent return on investment (ROI), which OMB believes reflects the societal cost of complying with environmental regulations. Using this criterion, we derived a capital amortization factor which is 0.11. Thus, the aggregate capital costs are multiplied times the capital amortization factor to derive a yearly capital cost charge. Also in the OMB guidelines, OMB stated that the program costs should be estimated based on how the industry would assess costs to achieve a payback on capital invested. For a capital payback cost analysis, we assessed costs assuming an after-tax 10 percent ROI. For the capital payback cost analysis, we derived a capital amortization factor which is 0.16. The other relevant factors we used in deriving the capital cost amortization factors are: a 10 year depreciation life, a 15 year economic life and 39 percent federal and tax rate.

These cost factors, as well as the utility prices that we used in our refinery-by-refinery cost model, are shown in Table 5-24:

**Table 5-24 Cost Factors for Various PADDs**

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 <sup>a</sup>
Capital Cost Factor	1.5	1.3	1.0	1.4	1.2
Natural Gas (\$/MMBTU)	8.91	7.77	6.31	6.78	7.69
Electricity (¢/kW-hr)	8.66	6.17	5.87	5.36	8.83
Steam (\$/1,000 lb)	20.56	17.89	14.23	17.03	17.24
Offsite Capital Cost Factor – New Units	1.35	1.35	1.35	1.35	1.35
Offsite Capital Cost Factor – Unit Revamps	1.35	1.35	1.35	1.35	1.35
Capital Amortization Factor Before Tax 7% ROI	0.11	0.11	0.11	0.11	0.11
Capital Amortization Factor After Tax 10% ROI	0.16	0.16	0.16	0.16	0.16

<sup>a</sup> Excluding California

The volume-weighted cost estimates for revamping FCC posttreaters across the entire refining industry as calculated by our refinery-by-refinery model are shown in Table 5-25 and Table 5-26. These costs are aggregated cost estimates for the FCC revamp costs used in our refinery-by-refinery model. In our model, we paired vendor cost data with refineries that are already using that particular vendor’s technology for their FCC posttreating units. We further tailored the information provided by the vendors to match the specific refinery configuration to the extent possible. We assumed that the data provided by the vendors includes the cost for

complying with the applicable stationary emission standards and that any incidental costs for permitting, if necessary, are negligible and covered by the offsite factor. The information that we received from the vendors and the individual refinery capital costs, however, cannot be shown due to CBI concerns.

**Table 5-25 Revamp Cost for a 30,000 BPSD FCC Postreater for 10-ppm Standard**

FCC Feed Sulfur Level <sup>a</sup>	0 – 400 ppm	400 – 1,200 ppm	>1,200 ppm	Volume Weighted Average <sup>b</sup>
Capital Cost (\$/B ISBL)	294	214	592	334
Hydrogen (scf/bbl)	46.3	51.3	58.5	42.0
Fuel Gas (kBTU/bbl)	8.5	7.6	3.1	5.3
Electricity (kWh/bbl)	0.10	0.12	0.51	0.17
Octane Loss (R+M)/2	0.68	1.00	0.93	0.77
Olefin Decrease (vol%)	2.44	2.57	1.31	1.89
Catalyst Cost (\$/B)	0.02	0.03	0.02	0.02
Steam (lb/bbl)	6.23	6.96	19.86	6.25

<sup>a</sup> \$/B = dollars per barrel, scf/bbl = standard cubic feet per barrel; kBTU/bbl = thousand BTU per barrel; kWh/bbl = kilowatt-hours per barrel; (R+M)/2 = (research octane + motor octane)/2; vol% = volume percent; \$/B = dollars per barrel; lb/bbl = pounds of steam per barrel of feed.

<sup>b</sup> Of the refineries that are expected to revamp their FCC naphtha hydrotreater for the no ABT case, 28 have FCC naphtha sulfur levels in the 0 – 400 ppm range, 30 have FCC naphtha sulfur levels in the 400 – 1200 ppm range and 17 have FCC naphtha sulfur levels greater than 1200 ppm.

**Table 5-26 Revamp Cost for a 30,000 BPSD FCC Postreater for 5 ppm Standard<sup>a</sup>**

FCC Feed Sulfur Level	0 – 400 ppm	400 – 1,200 ppm	>1,200 ppm	Volume Weighted Average
Capital Cost (\$/B ISBL)	470	530	652	487
Hydrogen (scf/bbl)	39.3	64.9	55.3	45.69
Fuel Gas (KBTU/bbl)	13.36	3.07	4.45	5.53
Electricity (kWh/bbl)	0.23	0.47	0.51	0.33
Octane Loss (R+M)/2	0.97	1.10	1.04	0.94
Olefin Decrease	1.45	2.46	2.12	1.82
Catalyst Cost (\$/B)	0.02	0.03	0.02	0.02
Steam (lb/bbl)	29.17	6.96	19.86	12.71

<sup>a</sup> Assumes every refinery is complying with a 5 ppm gasoline sulfur standard

We also found that there were 16 refineries that had an existing FCC postreaters that were not sized large enough to process their maximum FCC naphtha production volume. For these refineries we assigned additional capital costs to debottleneck the existing first stage reactor in order to increase the postreater capacity so that it could accommodate maximum FCC naphtha production. For each refinery with an existing unit that could not process more than 70 percent of our estimate of a refiner’s maximum FCC naphtha production we added capital costs to revamp and expand the first stage to increase its capacity to allow the postreater to process 100 percent of its maximum FCC naphtha rate. For the capital costs for this debottlenecking we used 35 percent of the cost of a new grass roots unit (discussed below) for the volume of the expansion. We once again used the six-tenths rule to adjust the capital cost for the volume

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expansion needed versus the cost for the 30,000 BPSD grass roots treater used for technology vendor estimates.

#### *5.1.3.5.2 Cost for Grassroots FCC Posttreaters*

While all refineries that already have FCC posttreaters should be able to meet the Tier 3 standards by revamping their existing posttreaters, refineries that do not currently have an FCC posttreater would have to add a grass roots FCC posttreater. To determine the cost of building grass roots FCC posttreating units at a refinery we similarly requested cost estimates from vendors. Only one of the vendors that supplied FCC posttreating equipment submitted information on the cost of a grass roots FCC posttreating unit for desulfurizing FCC naphtha with a feed sulfur content of 100 ppm. Based on the calculation methodology shown in Equation 5-2, we estimate that refineries that require a grass roots posttreater will already have an FCC feed sulfur level that averages between 85 and 100 ppm as these refineries already have FCC feed pretreaters. The other grassroots vendor estimate we received, as well as those we received for Tier 2, represented a grass roots posttreater with an FCC feed sulfur content of about 800 ppm. These estimates were deemed to be not representative of the costs to refineries that would be installing grass roots posttreating units as the capital, hydrogen, and other operating costs would be much higher for an FCC feed sulfur of 800 ppm vs. 100 ppm. We did not consider this other vendor's cost estimate for a grass roots posttreater and therefore relied on a single vendor's cost estimate for grass roots FCC posttreating units for the Tier 3 program. In our FRM analysis we expanded our analysis for the vendor's cost estimate of a new standalone unit by incorporating additional cost information from other vendors and literature sources on new units. Based on this other information, the cost estimate we obtained for a new Tier 3 unit, seemed reasonable relative to the other cost data that we have for higher levels of desulfurization.

The vendor estimate submitted for a grass roots posttreater was based on a posttreater with a capacity of 30,000 BPSD capable of producing an FCC naphtha with a sulfur level of 10 ppm, corresponding to a gasoline sulfur level of 5 ppm. To scale the cost submitted by the technology vendor to be applicable to a specific refinery, we used a similar methodology to that which was used for posttreater revamps. We first determined the appropriate size for each unit based on each refiners maximum FCC naphtha production rate. We then used the six-tenths rule (Equation 5-4) to scale the cost reported by the vendor up or down as appropriate based on the relative volume of the grass roots unit required by the refinery and the size on which the vendor's cost estimate was based. We once again assumed that the capital cost from the technology vendor was representative of a refinery in PADD 3 complying with the applicable stationary emission standards. We then adjusted the cost based on the cost of refinery capital projects in the PADD in which they are located relative to PADD 3. Finally, we used a new unit offsite adjustment factor listed in Table 5-24 to estimate the final cost of a grass roots FCC posttreater for each refinery. The costs to produce FCC naphtha with a sulfur level of 25 ppm (corresponding to a 10-ppm gasoline) were estimated based on the grass roots posttreater unit that makes FCC naphtha for the 5-ppm standard. These costs are summarized in Table 5-27 and Table 5-28 below.

**Table 5-27**  
**Cost for a 30,000 BPSD Grass Roots FCC Posttreater for 10-ppm Standard**

FCC Feed Sulfur Level	100 ppm
Capital Cost (\$/B ISBL)	1500
Hydrogen (scf/bbl)	94.2
Fuel Gas (KBTU/bbl)	7.5
Electricity (kWh/bbl)	1.06
Octane Loss (R+M)/2	0.83
Olefin Decrease	4.02
Catalyst Cost (\$/B)	0.04
Steam (lb/bbl)	20.0

**Table 5-28**  
**Cost for a 30,000 BPSD Grass Roots FCC Posttreater for 5-ppm Standard**

FCC Feed Sulfur Level	100 ppm
Capital Cost (\$/B ISBL)	1500
Hydrogen (scf/bbl)	113
Fuel Gas (kBTU/bbl)	9
Electricity (kWh/bbl)	1.06
Octane Loss (R+M)/2	1.00
Olefin Decrease	5.15
Catalyst Cost (\$/B)	0.04
Steam (lb/bbl)	20.0

*5.1.3.5.3 Adjustments to Vendor Costs for Atypical Levels of Desulfurization*

The information that we obtained from the vendors estimated the desulfurization cost for a typical refinery which is reducing its gasoline sulfur from 30 ppm to 10 ppm, or 5 ppm. Since the refiner would need to reduce the sulfur in its FCC naphtha, we estimated that for a typical refinery, the refiner would need to reduce its FCC naphtha by 50 ppm for 10 ppm gasoline, or reduce its FCC naphtha by 65 ppm for 5 ppm gasoline. However, even if every refinery were reducing its gasoline sulfur from 30 ppm to 10 or 5 ppm, because FCC naphtha comprises a different fraction of the gasoline pool, refineries would need to desulfurize their FCC naphtha different amounts. Added to this, under Tier 2, US refineries produce gasoline which ranges from well under 10 ppm and up to the cap at 80 ppm. Thus, to best model the cost for each refinery, we needed to develop a strategy for adjusting the desulfurization cost to capture the cost for desulfurizing FCC naphtha different increments than the 50 or 65 ppm that the vendor data is based on.

We reviewed desulfurization curves from desulfurization vendors for desulfurizing FCC naphtha. The curves show that the octane loss for desulfurizing FCC naphtha is fairly linear when the desulfurization severity is below a certain point. Thus, if a particular vendor estimated a 0.5 octane number loss for a 50 ppm sulfur reduction in the FCC naphtha, we assumed that if a particular refinery would require a 100 ppm sulfur reduction, then the octane loss would be 1

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octane number. Similarly, if that refinery would only require a 25 ppm reduction in the FCC naphtha, then the octane number loss would be 0.25 octane numbers. Since hydrogen is consumed to saturate the olefins that leads to the octane loss, we scaled hydrogen in the same manner. We, however, didn't scale utility demands, but rather assumed that the estimated utility demands are the same regardless of the change in sulfur required.

Above a certain desulfurization severity point, the octane loss seems to increase in an exponential manner, and if we did not account for this we would be underestimating the desulfurization cost for some refineries. The point at which that occurs seems to depend on the capital investment made to hydrotreat the FCC naphtha. For example, if a refinery has a one stage reactor and it uses distillation to separate the light FCC naphtha, the cost curves suggest that the octane loss for this hydrotreater would begin to increase exponentially when the percent desulfurization exceeds 93 – 96%. For complying with Tier 3, we assume that many revamps fall into this category. Alternatively, FCC posttreaters which are two stage units do not seem to reach the point where the octane loss begins to increase exponentially until the percent desulfurization is in the high 90s, such as 98% or 99%. We asked one of the hydrodesulfurization vendors which licenses an FCC posttreating technology where to draw the line between linear and nonlinear octane loss, and the vendor suggested at 99% desulfurization and we used that value in our cost model.

#### *5.1.3.5.4 Light Straight Run and Natural Gas Liquids Desulfurization Costs*

Another action refiners may need to take to reduce the sulfur content of their gasoline is to desulfurize their light straight run naphtha (LSR) and natural gas liquids (NGL) blendstocks. While these blendstocks have lower sulfur contents than the FCC naphtha, in some cases, the sulfur levels may still be too high and it would be cheaper to desulfurize than FCC naphtha for refineries that are not already treating these streams. Many refineries have been desulfurizing some or all of these blendstocks using extraction desulfurization technologies, such as Merox or Merichem, due to the very strong odor of the mercaptans. The extraction desulfurization technologies can usually reduce the sulfur levels of LSR and NGL by about 2/3rds by removing most of the mercaptans. One third of the sulfur is not removable by these technologies either because the sulfur compounds are thiophenes or are heavier mercaptans, which cannot be extracted using these technologies. If refiners find that they need to resort to hydrotreating because the sulfur levels are too high, they may be able to use existing excess hydrotreating capacity in their naphtha hydrotreaters or FCC naphtha posttreaters. Additionally, as opposed to hydrotreating FCC naphtha which contains olefins, the LSR and NGL blendstocks contain no olefins and therefore, hydrotreating them does not result in octane loss and has a lower hydrogen consumption. The combination of the potential for using excess capacity in existing units and low operating costs result in the relatively low desulfurization costs for the LSR and NGL blendstocks. From our discussions with refiners, several refineries indicated that they would install new standalone hydrotreaters for processing LSR and NGL blendstocks, though it is unclear which other refineries will have to add equipment to desulfurize LSR and NGL. To determine the cost to desulfurize the LSR and NGL blendstocks we first had to determine the volume of blendstock that requires desulfurization. Our determination of the quantity of LSR and NGL used as gasoline blendstock at each refinery is discussed in Section 5.1.3.1.5. From this total we then subtracted the volume of LSR processed in the isomerization unit. Because the

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isomerization units require a low sulfur feedstock we assume that refiners with isomerization units are treating all the light straight run naphtha in the naphtha hydrotreater. Refiners likely determine how they desulfurize their naphtha depending on whether they have an isomerization unit. If a refinery has an isomerization unit, the refiner likely hydrotreats the straight run naphtha before sending the stream to a splitter, after which the heavy straight run naphtha is sent to the reformer while the light straight run naphtha is sent to the isomerization unit. If a refinery does not have an isomerization unit, the refiner likely sends the straight run naphtha to the splitter and afterwards, the heavy straight run naphtha is sent to the naphtha hydrotreater before it is reformed, while the light straight run naphtha is blended directly into the gasoline pool.

We also evaluated the likely sulfur level of LSR associated with crude sulfur level. Table 5-29 summarizes the name of the crude oil, the total sulfur level and sulfur level of the LSR from a crude assay (or in the case of Bakken and Eagle Ford fracked crude oil, data was provided by a peer reviewer), and the expected sulfur level of the LSR after using extractive desulfurization.

**Table 5-29 Sulfur of LSR associated with Crude Sulfur Level**

Crude Oil Name	Crude Oil Sulfur Level (wt%)	LSR Sulfur Level (ppm)	LSR Sulfur Level after Extracting Sulfur (ppm)
Alaskan North Slope	1.04	26	9
Kern River	1.1	330	109
Ecuador Export	1.0	10	3
Saudi Heavy	2.82	6	2
Saudi Light	1.8	200	66
Saudi Medium	2.32	108	36
West Texas Intermediate	0.28	0	0
Bonny Light	0.11	48	16
Bow River	2.96	65	21
Cabinda	0.1	5	2
Maya	3.04	50	17
Canadian Interprov.	0.37	0	0
West Texas Sour	1.57	1510	498
Bakken	0.15	4	1
Eagle Ford Light	0.01	1	0
Eagle Ford Heavy	0.12	10	4

Table 5-29 shows that lower sulfur crude oils tend to have very low sulfur LSR when extractive desulfurization is factored in. In fact, for crude oils with less than 1 percent sulfur, there is only one crude oil where the LSR contains more than 5 ppm sulfur after extractive desulfurization is accounted for, and that is Bonny Light. However, imported light crude oils such as Bonny Light (which is imported from Nigeria) are likely being displaced by domestically fracked crude oils such as Bakken or Eagle Ford, the LSR of which is very low in sulfur. Based on this data, we assumed that refiners would solely rely on extractive desulfurization for

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desulfurizing their LSR under Tier 3 if the crude sulfur being refined at their refineries was below 1 percent sulfur.

The next step in our assessment of the desulfurization costs of the LSR and NGL blendstocks was to estimate the extent to which higher sulfur LSR (refineries with crude oil sulfur levels above 1 percent and without an isomerization unit) is already being treated at refineries to meet the existing Tier 2 sulfur standards. Based on our discussion with refining consultants, vendors and refiners, it appears that in response to the Tier 2 standards refiners have altered their operations to use excess capacity in their FCC naphtha posttreaters and naphtha hydrotreaters to reduce the sulfur content of LSR and NGL blendstocks. Since information on the extent to which these streams are currently being hydrotreated is not publicly available we estimated these volumes using the capacities of the FCC posttreaters and reformer feed hydrotreaters under normal refiner crude throughputs and yields from the refinery-by-refinery model.

We evaluated each refinery's capacity to hydrotreat LSR and NGL using existing equipment by first determining the volume that can be processed in their naphtha hydrotreaters. We compared the throughput volume of each refinery's naphtha hydrotreater with the calendar-day capacity of that unit. The difference between the two represented the available capacity of that unit. If a refinery had insufficient excess capacity in their naphtha hydrotreater to treat all of the LSR and NGL volumes we next determined if there was excess capacity in that refinery's FCC posttreater. We allowed LSR and NGL to be processed using excess FCC posttreating capacity in refineries where the capacity of the FCC posttreater exceeds 120 percent of that required to process a refinery's maximum FCC naphtha yield as determined by the refinery-by-refinery model. Several refiners had excess FCC posttreating capacity available for the treating of LSR or NGL feedstocks, as the capacity of most FCC posttreaters was less than 120 percent of the maximum FCC naphtha production rate. We assumed that refiners are currently using any excess hydrotreating capacity in their naphtha hydrotreating and FCC posttreating units to desulfurize LSR and NGL in response to the Tier 2 sulfur standards.

If a refinery did not have sufficient excess hydrotreating capacity for all of the LSR and NGL in these units we assumed the refinery would have to either revamp their existing equipment or add new hydrotreating capacity. If the additional capacity needed at any given refinery exceeded the existing naphtha hydrotreater capacity by less than 30 percent we assumed the necessary capacity could be added by revamping the existing unit. If, however, the additional capacity required exceeded the existing reformer feed hydrotreater capacity by more than 30 percent we assumed the refinery would install a new stand-alone hydrotreater to desulfurize the excess LSR and NGL. Based on available capacity in our refinery-by-refinery model and 2010 and 2011 refinery unit throughput data, we estimated that refiners are already hydrotreating 66 percent of the LSR and NGL that are directly blended into gasoline (excluding LSR processed in the isomerization units). The results of this assessment are shown in Table 5-30.

**Table 5-30 Refineries Adding Hydrotreating Capacity for LSR and NGL**

	New Hydrotreater (No FCC Unit)	New Hydrotreater (with FCC Unit)	Revamped Hydrotreater (No FCC Unit)	Revamped Hydrotreater (with FCC Unit)
Number of Refineries	4	11	1	7

We conservatively evaluated the capital cost required for hydrotreater revamps and new units by assuming that refiners will size their hydrotreater equipment needs to treat all production volumes of LSR and NGL based on each refinery's maximum crude run rate. The operating costs used in our refinery-by-refinery model, however, are based on LSR and NGL blendstock volumes from the model's yields based on 2011 operational crude throughputs and crude oil quality as discussed in Section 5.1.3.1.5. Sizing the equipment this way allows each refiner to have excess hydrotreater capacity utilization, which is beneficial in the event of process unit shutdowns and to reprocess blendstocks from abnormal operations.

Our estimate for the cost of adding a new hydrotreater at a refinery was obtained from Gary and Handwork's Petroleum Refining Technology and Economics, page 182-183, Curve C, Table 9.1, 30,000 BSD unit. The capital cost for a grass roots hydrotreater listed by this source was for a hydrotreater with a capacity of 30,000 BPSD and was based on 1999 dollars. We multiplied this cost by 1.534 to determine the equivalent cost in 2010 dollars based on the relative increase in the Nelson Refining Construction index from 1999 to 2010 (listed as 1497 and 2296 respectively). We used the six-tenths rule to scale the capital cost listed in Petroleum Refining Technology and Economics to those of differing capacities based on relative size of the desired unit. We assumed a hydrogen consumption of 40 SCF/Bbl for the processing of LSR and NGL blendstocks which we obtained from the Jacobs Refining LP modeling database for naphtha hydrotreating as this information was not presented in the literature source. For refineries that only required a revamp of existing units we assumed a capital cost equivalent to 40 percent of the cost of a new hydrotreating unit of equal size. We assumed equivalent operating costs for new hydrotreating units and revamped units. The capital and operating costs for these hydrotreating units that were used in our model is shown in Table 5-31.

**Table 5-31 Capital and Operating Costs for LSR and NGL Hydrotreaters**

	New Hydrotreating Units	Revamped Hydrotreating Units
Capital (\$/BBL ISBL)	1380	550
Hydrogen (SCF/BBL)	40	40
Fuel Gas (kBTU/BBL)	100	100
Electricity (kWh/BBL)	2.0	2.0
Octane Loss (R+M)/2	0.0	0.0
Change in Olefins (vol%)	0.0	0.0
Steam (lb/BBL)	6.0	6.0
Catalyst Cost (\$/BBL)	0.03	0.03

#### 5.1.3.5.5 Using FCC Pretreaters to Comply with Tier 3

##### 5.1.3.5.5.1 FCC Pretreater Sulfur Control Cost

We also assessed the cost of utilizing an existing FCC pretreater to comply with Tier 3. To understand the feasibility and estimate the cost for using FCC pretreaters to comply with Tier 3, we conducted a literature survey and spoke to vendors and refiners. In our literature search and conversation with vendors, we found that the feasibility and cost for using current FCC pretreaters for complying with Tier 3 is dependent on many factors. These factors include the pressure of the FCC pretreater, the current turnaround schedule of the unit, the price of natural gas used to produce hydrogen for the unit, the crude oil sulfur level which determines the sulfur level of the gas oil feed, the percent desulfurization that must be achieved to comply with Tier 3, the refiner's future product marketing plans, and whether the refiner is willing to spend capital dollars to revamp the existing unit. Since we don't know the response to these issues that we identified, we found it useful to conduct several different cost assessments to estimate the costs for a range of situations that different refiners may be in with their FCC pretreaters.

FCC pretreaters hydrotreat the gas oil which boils in the range of 690F to 1000F. FCC pretreaters enable greater production of FCC naphtha by the FCC unit by saturating aromatic compounds in the gas oil. These saturated aromatic compounds can be cracked more easily which allows the FCC unit to produce more FCC naphtha. Even before the Tier 2 gasoline standards were put in place, many refiners installed FCC pretreaters to increase the production of FCC naphtha. To comply with Tier 2, more refiners installed FCC pretreaters, not only because the refinery was able to comply with Tier 2 by hydrotreating the feed to the FCC unit, but also because refiners were able to realize a return on investment by producing more FCC naphtha (increase gasoline production). FCC pretreaters also improve the quality of the light cycle oil, a diesel fuel blendstock, which is produced by the FCC unit.

Some refiners who installed FCC pretreaters for Tier 2 installed repurposed reactors which were originally installed for other purposes and these can affect a refiner's ability to comply with Tier 3. For example, refiners installed hydrotreaters to hydrotreat residual fuel, but found that the hydrotreating catalyst is quickly diminished by the high metal content in residual fuel. Refiners then reused the very high pressure (2000+ psi) reactors as their FCC pretreaters. Other refiners repurposed diesel fuel hydrotreaters as FCC hydrotreaters and put in higher pressure diesel hydrotreaters when the diesel fuel sulfur standards took effect. The repurposed

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diesel fuel hydrotreaters were likely low pressure (i.e. 600 pound per square inch (psi)) units. While refiners constructing a grassroots FCC pretreater would target a 3 to 4 year cycle length and a higher pressure unit (i.e. 1400 psi), if a refiner instead repurposed an existing reactor for its FCC pretreater, the cycle lengths of its FCC pretreater may be shorter, and the unit's pressure could be lower pressure, than desired. As we discuss in section 4.2.3.1, refiners with low pressure FCC hydrotreaters are likely limited in their ability to use those units for complying with Tier 3. If refiners are currently experiencing short cycle lengths with their FCC pretreaters, the cost and inconvenience of even shorter cycle lengths would likely deter any refiner from using existing FCC pretreaters to comply with Tier 3 without adding additional reactor volume.

In conducting our cost analysis, we based our cost analysis on a refinery which is solely using an FCC pretreater today to comply with Tier 2. We assume that this unit currently requires a turnaround every two years. From EIA data for that refinery, the throughput to the FCC pretreater is 75,000 bbl/day and the total gasoline volume is a little more than over twice that volume. Our refinery-by-refinery model estimates that this refinery is achieving about 92% desulfurization of the FCC feed, which allows the refinery to reduce its FCC naphtha to about 80 ppm. To comply with Tier 3, the refinery would need to achieve about 98% desulfurization of its FCC feed to comply with Tier 3.

We analyzed three different pathways that the refiner could take if it were to solely rely on its FCC pretreater to further reduce the sulfur of the feed to its FCC unit to comply with Tier 3. In the first case (Case 1), the refiner solely increases the severity of its FCC pretreater, by raising the temperature of the reactor, which further reduces the sulfur of the FCC naphtha. In this case we assume that the unit is capable of further saturating aromatics and creating additional yield benefits. However, for this first case, the cycle length of the FCC pretreater shortens from 2 years to 1 year, so the refiner would have to replace the catalyst in the FCC pretreater every year instead of every two years.

In the second case (Case 2), the refiner revamps the FCC pretreater by adding a second reactor, which effectively doubles the reactor volume. This allows the refinery to comply with Tier 3, achieve additional yield benefits and still maintain a two year cycle length with its FCC pretreater.

In the third case (Case 3), we assume no additional investments (like Case 1), but in this case the refinery is assumed to have a lower pressure FCC pretreater and the FCC pretreater has reached its poly-aromatics saturation maximum. Thus, while the FCC pretreater is able to achieve the desired desulfurization, it does not realize additional yield benefits.

The cost factors for increasing the severity or revamping an existing FCC pretreater (for all three cases) are from a National Petrochemical and Refiners Association (NPRO) Annual Meeting technical report.<sup>16</sup> The report includes yield estimates, hydrogen demands and a capital cost for adding additional reactor volume for 90%, 98% and 99% desulfurization. We estimate that the refinery we are studying is desulfurizing its FCC naphtha by 92% and we estimate that it must desulfurize its FCC naphtha at 98% to comply with Tier 3 (produce 10 ppm gasoline). Thus, we used the differences between 90% HDS and 98% HDS in our cost analysis. Table 5-32 summarizes the changes in yield, hydrogen consumption and capital costs for operating an FCC pretreater at a higher desulfurization level.

**Table 5-32 Yield Changes and Other Impacts of Higher Severity FCC Pretreating**

	90% HDS	98% HDS	Difference
H <sub>2</sub> S (wt%)	0.1	0.0	-0.1
C <sub>2</sub> (wt%)	3.5	3.2	-0.3
C <sub>3</sub> -C <sub>4</sub> (wt%)	17.6	18.7	1.1
Full Range FCC naphtha (wt%)	51.5	52.5	1.0
LCO (wt%)	15.7	15.0	-0.7
CSO (wt%)	6.6	5.9	-0.7
Coke (wt%)	5.0	4.7	-0.3
Total	100	100	-
Naphtha Sulfur (ppm)	225	55	170
LCO sulfur (ppm)	3400	900	-2500
LCO cetane index	25.7	26.4	0.7
Hydrogen Addition (wt%)	0.51	0.74	0.23
Capital Cost	61.8	70.3	8.5

To estimate the cost impacts of operating the FCC pretreater at a higher level of desulfurization, it was necessary to estimate the costs for the changes in yield, the increased hydrogen demand, the cost of additional capital. We used the component cost values for ethane, propane and butane, FCC naphtha, light cycle oil (LCO), and cycle slurry oil (CSO) from our LP refinery model for the year 2018. The value of hydrogen is from our LP model based on natural gas which averages \$7.1 per million BTU. The hydrotreating catalyst is estimated to cost \$244 per barrel per stream day. These cost factors are summarized in Table 5-33.

**Table 5-33 Economic Value of Yield Components, Hydrogen and Catalyst**

FCC Product or Reactant	Value
C2 (\$/bbl FCC)	9.2
C3-C4 (\$/bbl FCC)	66.5
Full Range FCC naphtha (\$/bbl)	115.6
LCO (\$/bbl)	122
CSO (\$/bbl)	87
Hydrogen (\$/KSCF) based on natural gas at 7.1 \$/mmbtu	4.1

The economic value of the FCC unit yield changes for the three cases is estimated by converting the weight percent percentages to volume percent, multiplying each times the FCC unit feed, which is 75,000 bbl/day and then multiplying the resulting yield changes in barrels per day by the respective economic value of each hydrocarbon product in dollars per barrel. The hydrogen is calculated in a similar way. We estimate that the hydrogen consumption corresponds to about 300 standard cubic feet per barrel of feed. We multiplied this times \$4.1 per thousand standard cubic feet. The capital costs were inflated from 1999 dollars to 2011 dollars using Nelson-Farrar inflation index, which increased the capital costs by a factor of 1.63. We applied a 20% contingency factor and a 35% offsite factor. Finally, the costs were scaled using the sixth-tenths rule to estimate the cost for the refinery unit processing 75,000 bbl/day.

For Cases 1 and 3, we estimate that the FCC pretreater must be shutdown every year instead of every two years. Based on information shared to us by one vendor for a 35,000 barrel per day unit, the lost production due to the shutdown is estimated to cost \$150,000/day for 5 weeks, the catalyst is estimated to cost \$5 million to fill the reactor, and an additional \$1.5 million cost is added to represent the maintenance cost during the shutdown. To estimate the cost for a 75,000 bbl/day unit these costs were scaled by a factor of 75,000 over 35,000. The catalyst cost is also used for Case 2 for filling the added reactor volume.

Table 5-34 contains the results of the cost analysis for each of the three cases analyzed.

**Table 5-34 Cost for Different FCC Pretreater Scenarios for Complying with Tier 3**

	Case 1 Higher Severity	Case 2 Revamp	Case 3 Higher Severity at Aromatics Peak Saturation
Yield Cost (\$/bbl)	-1.1	-1.1	0
Catalyst and Turnaround Cost (\$/bbl FCC feed)	0.47	0.23	0.47
Hydrogen Cost (\$/bbl FCC feed)	1.2	1.2	1.2
Capital Cost (\$/bbl FCC feed)	-	0.18	-
Fixed Cost (\$/bbl FCC feed)	-	0.11	-
Total Cost FCC Feed (\$/bbl)	0.59	0.64	1.7
Total Cost All Gasoline (\$/bbl)	0.27	0.29	0.77
Total Cost All Gasoline (c/gal)	0.65	0.71	1.8

Our analyses of the three different cases summarized in Table 5-34 shows that achieving additional yield gain is an important factor for achieving further sulfur control at a low cost. For the cases which assume additional yield gain, we estimate a cost of about 0.3 dollars per barrel, or about 0.7 cents per gallon when the costs are amortized over the refinery's entire gasoline pool. The estimated total capital cost for the revamp case is \$44 million. For the case which assumes no additional yield gain, our estimated cost is about 1.8 cents per gallon. These costs may be overstated somewhat because we are not accounting for the further desulfurization and cetane improvements of the light cycle oil, which is a diesel fuel blendstock. We estimate that if this refinery were to install a grassroots FCC posttreater for complying with Tier 3 instead of its FCC pretreater, the grassroots posttreater is estimated to cost 1.45 c/gal and need to invest \$109 million in capital. Thus, our cost analysis estimates that if a refinery were to revamp its FCC pretreater or simply turn up the severity of its FCC pretreater and expect to achieve additional yield benefits in addition to lower FCC naphtha sulfur levels, then it would do so based on costs, as opposed to installing a grassroots FCC posttreater.

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*5.1.3.5.5.2 Would Refiners use FCC Pretreaters to Comply with Tier 3?*

The decision to rely solely on FCC pretreating to comply with Tier 3 is more complicated than simple economics. If the refinery solely relies on an FCC pretreater to comply with Tier 3, the refinery will not gain the operational flexibility of having both an FCC pretreater and postreater would provide (if one of those units suffers an emergency shutdown, the other unit would allow the refiner to continue to use the FCC unit to blend up its gasoline and still comply with the cap standard). If the refiner were to revamp its FCC pretreater, it would roughly maintain the operational flexibility that it currently experiences under Tier 2, although it would be somewhat lower due to the higher desulfurization that would have to be maintained and the more stringent sulfur standard that the refiner would have to comply with. If a refiner chooses to solely increase the severity of its FCC pretreater for complying with Tier 3, which would reduce the cycle length of its FCC pretreater, the refiner would have lower operational flexibility since the unit would need to shutdown more frequently.

Refiners may have sacrificed some of their operational flexibility when complying with Tier 2 by turning up the severity of its FCC pretreater, and therefore may already be experiencing shorter turnaround times with its FCC pretreaters than desired. If this is the case, then when investing for Tier 3 the refiner may choose to add additional reactor volume when revamping its pretreater to lengthen the FCC pretreater turnaround times. This additional investment would be justified if the refiner would offset the increased capital costs by lower turnaround costs. This same investment strategy could occur if the refiner intends on installing a grassroots postreater. The refiner would design the postreater to take over some of the pretreater's desulfurization duty which would allow for lengthening the turnaround times for the FCC pretreater.

Another consideration of refiners contemplating relying solely on FCC pretreating to comply with Tier 3 is the coke make on the FCC catalyst and how it would affect the FCC unit operations. As shown in Table 5-32, coke make in the FCC unit decreases as the percent desulfurization by the FCC pretreater increases. As the amount of coke which forms on FCC catalyst decreases, there would be less heat created in the FCC unit regenerator. The lower heat generation in the FCC regenerator can apparently be addressed by increasing the catalyst flow between the reactor and regenerator, but if the catalyst control valve must be opened too much to control the FCC temperature balance, an FCC control issue can develop which potentially could cause operational problems that would force a shutdown of the FCC unit. To counter this, the refiner may have to operate their FCC pretreater at the poly aromatics saturation maximum temperature to preserve coke make. However, in operating in maximum poly aromatics saturation mode, the refinery would not realize the yield gains and would face higher desulfurization costs.

One more consideration that refiners could have about relying on FCC pretreaters for complying with Tier 3 is the price of natural gas, which essentially determines the production cost for producing hydrogen. FCC pretreaters demand a lot of hydrogen and low natural gas prices support a desulfurization strategy that uses FCC pretreating. We are aware that several US liquid natural gas (LNG) export projects have been approved to export natural gas to the rest of the world. Although natural gas prices are projected to stay low, if refiners are concerned that

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increased exports of natural gas from the US could cause US natural gas prices to double or even triple, which is roughly what the rest of the world pays for natural gas, it would significantly increase the cost of FCC pretreating compared to FCC posttreating. This could cause refiners to choose to add an FCC posttreater instead.

One more strategy that a refiner could pursue would be to convert the FCC pretreater to a mild hydrocracker. This strategy involves a lot more investment to allow for fractionating the product after the hydrocracking reactor. For two reasons, the potential level of hydrocracking is often limited. First, the FCC unit requires on the order of 50 percent of its maximum capacity to permit the unit to operate. If the FCC pretreater were to be converted over to a high conversion hydrocracker, there may not be sufficient feed for the FCC unit. Second, many FCC pretreaters are not sufficiently high in pressure to permit its conversion to a high conversion hydrocracker. We believe that the increased demand for diesel fuel will already cause refiners to convert their FCC pretreaters over to mild hydrocrackers, so we did not pursue this as part of a Tier 3 strategy, although we did include a sensitivity case for which we estimated the compliance cost to Tier 3 assuming lower feed rates to FCC units if FCC pretreaters are converted over to mild hydrocrackers.

Based on the low estimated cost for Case 1 and Case 2 that we evaluated for relying on FCC pretreaters to comply with Tier 3, we could have included FCC pretreater modifications in our cost analysis for Tier 3. For several different reasons we decided not to. First, we assessed the use of credits under Tier 2 and found that the sulfur credits are freely traded between refining companies. When we assumed nationwide credit trading, the ABT program effectively eliminated most of the need to install grassroots posttreaters which would be installed at these refineries currently using FCC pretreating for Tier 2 and are thus the candidates for using FCC pretreaters to comply with Tier 3. Thus, even if we included options for using existing FCC pretreaters to comply with Tier 3, it may not actually be the most economical option available to these refiners given the flexibility of the ABT program.

A second reason why we did not include in our cost estimates the revamp of existing FCC pretreaters for complying with Tier 3 is the uncertainty of how each pretreater is operated today and how it would operate when complying with Tier 3. We don't know the current turnaround schedule for each refinery's FCC pretreater, nor do we know their operating pressure, thus, we don't know how these units would operate at higher severity, nor if refiners would add reactor volume or just increase their severity. We also don't know what the coke-make is on the FCC catalyst at these refineries that rely on FCC pretreaters for Tier 2 and how a refiner would operate its FCC pretreater if insufficient coke-make would be an issue when operating its FCC unit when relying on an FCC pretreater to comply with Tier 3. Furthermore, as discussed above, adding a posttreater would provide additional compliance flexibility. For these reasons, we did not include FCC pretreating as an option for complying with Tier 3 in our cost modeling. While we did not model any refineries revamping their existing FCC pretreaters to comply with Tier 3, there may nevertheless be some for whom it may be commercially advantageous. If so, this would tend to lower the overall costs of the Tier 3 standards compared to our cost analysis described in sections 5.1 and 5.2.

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## 5.2 Estimated Tier 3 Sulfur Control Costs

### 5.2.1 Final Fuel Program Cost Results

We used the refinery-by-refinery cost model to estimate the costs of the 10 ppm average standard being adopted in this final rule. The Tier 3 fuels program maintains the 80 ppm cap sulfur control standard that was put in place under the Tier 2 sulfur program. In general, the cost model indicates that further desulfurizing the FCC naphtha will be the most cost-effective means for achieving sulfur control. We accounted for additional costs to refiners for desulfurizing their LSR naphtha, for those refineries where we estimate that the LSR naphtha is not being desulfurized today and found that it likely needs to be. In addition to analyzing the cost of the final Tier 3 fuels program, we also assessed the cost of other possible gasoline sulfur standards that we considered for the proposed rulemaking. The cost information for these other gasoline sulfur standards that we analyzed is summarized in subsection 5.2.2.

As described in Section V.D of the preamble and Chapter 4, we are also adopting an ABT program that is designed to ease the overall burden on the industry while still achieving the 10-ppm annual average sulfur standard for the nation as a whole. Under the ABT program, refineries that can reduce sulfur below 10 ppm at a relatively low cost can generate credits which can then be acquired by refiners for the refineries at which the cost of attaining the 10-ppm sulfur standard would be higher. These credits can be traded among refineries within the same company, or between refiners and importers nationwide. The net effect of this credit trading would be to reduce the overall cost of the program. The extent to which the ABT provisions reduce the cost of the Tier 3 program depends on the extent that the ABT program is used by refiners. Since we were not sure about the extent that credits were traded under Tier 2 when we conducted the cost analysis for the NPRM we conservatively assumed for the NPRM cost analysis that refiners would only volume-average sulfur levels among their refineries, and not trade credits between refining companies. However, for the final rule cost analysis we evaluated the credit trading that was occurring under Tier 2. We found that 56% of credits were in fact being traded between refining companies under Tier 2, with the balance being used within refining companies. This demonstrated that credit trading was freely occurring between refining companies, supporting the conclusion that credit trading would occur nationwide among refineries under Tier 3. We therefore assumed nationwide credit trading for our final rule.

To estimate the impact that the ABT program could have on nationwide average fuel costs, we began with the refinery-by-refinery costs for sulfur reductions down to either 10 ppm or 5 ppm. We then determined the lowest cost option among three alternatives for each refinery:

1. The refinery reduces its sulfur to 10 ppm.
2. The refinery reduces its sulfur to 5 ppm and generates credits for the increment between 10 ppm and 5 ppm.
3. The refinery does not lower sulfur, but instead relies on the purchase of credits to comply with the 10-ppm standard.

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A fourth category applied to refineries whose average gasoline sulfur levels are already below 10 ppm (their refineries don't have FCC units). All such refineries were assumed to generate credits for the increment between 10 ppm and their current sulfur level.

Our methodology was unable to consider a fifth category where a refinery may utilize less expensive capital and operational changes to reduce their sulfur levels partially below Tier 2 levels and rely on purchasing credits only for the remainder. Such opportunities are likely to exist at most refineries, but such refinery specific information is not available to us. As a result, refineries in the third category are modeled to simply remain at Tier 2 sulfur levels and incur no capital or operating cost.

To simplify the modeling of how an ABT program might operate, we focused on the circumstances that refineries would face in the longer term, specifically after 2020. This approach meant that the ABT program modeling did not consider the impact on gasoline sulfur levels of delayed compliance for small refiners and small volume refineries, nor did it consider the generation and use of any early sulfur credits. Moreover, our ABT modeling considered only gasoline sold for use outside of California, and only gasoline produced by domestic refineries (not importers).

To model credit trading in our cost analysis, we first establish an estimated cost for each refinery for reducing its gasoline sulfur down to 10 ppm and to 5 ppm. Next we ranked the sulfur control strategies for all the refineries in order from lowest to highest sulfur control cost per gallon of gasoline and estimated the impact of their projected sulfur control strategies on refinery sulfur levels using only one cost (either 10 or 5 ppm) for any one refinery. The model then follows this ranking, starting with the lowest-cost refineries, and adds refineries and their associated control technologies one-by-one until the projected national average gasoline sulfur level reaches 10 ppm. This modeling strategy projects the sulfur control technology that will be used by each refinery, as well as identifies those refineries that are expected to generate credits and those that are expected to use credits in lieu of investing in sulfur control. The sum of the costs of the refineries expected to invest in further sulfur control provides the projected overall cost of the program.

Based on the results of our cost analysis, we estimate that for the US refining industry to achieve a 10-ppm average level with the full benefit of nationwide credit trading, the final sulfur control program would cost on average 0.65 cents per gallon when it is fully phased in, assuming that capital investments are amortized at a seven percent return on investment before taxes and expressed in 2011 dollars. Refiners would be expected to make \$2.025 billion in capital investments to achieve this sulfur reduction. These capital investments are expected to be made over the 6 years that the Tier 3 program is expected to be phased in, which would spread out the capital costs to average about \$330 million per year.

Our cost assessment is likely conservative. The capital cost estimate is based on vendor data which assumes that refiners are hydrotreating full range FCC naphtha. If refiners are indeed undercutting their FCC naphtha at many refineries (and more will be doing so in the future), many refiners would likely not need to make any capital changes. This is because the FCC posttreaters were designed when refiners were maximizing their gasoline production and hydrotreating full range FCC naphtha. When undercutting the FCC naphtha to the diesel pool,

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refiners are cutting out about 16% of the FCC naphtha volume, but more importantly, they are cutting out about half of the sulfur. Thus, if a refiner was able to produce 30 ppm gasoline, after fully undercutting their FCC naphtha into the diesel pool, they would likely be able to produce 15 ppm sulfur gasoline using their existing Tier 2 posttreater. They could then use a more active catalyst which likely would enable the refinery to achieve 10 ppm gasoline without any capital changes to their FCC posttreaters. If all refiners were undercutting their FCC naphtha and are able to comply with Tier 3 without any capital additions to their FCC posttreaters, the cost of the program would decrease to about 0.4 c/gal.

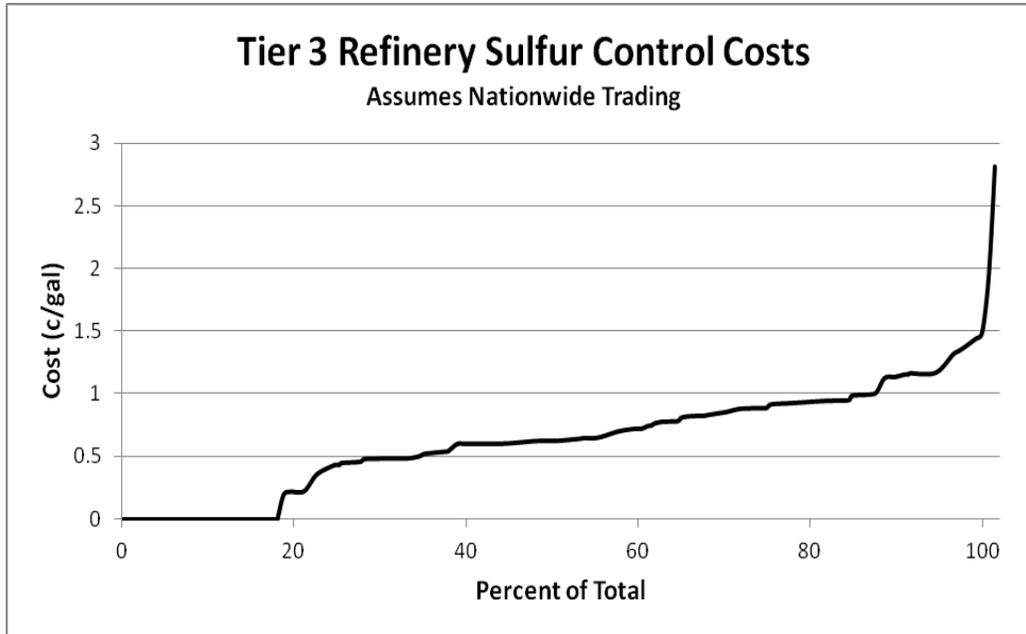
Another way that our modeling could be conservative is that refiners are slowly converting their FCC pretreaters over to mild hydrocrackers to produce more diesel fuel, which is in higher demand. We don't know the extent that this is happening, and our current analysis assumes that none of the FCC pretreaters have been converted over to mild hydrocrackers. However, a cost sensitivity analysis that we conducted with our refinery model estimates that if all the FCC pretreaters were converted over to mild hydrocrackers, costs of the Tier 3 program would decrease to 0.55 c/gal, assuming nationwide credit trading. If we combined the cost reduction of undercutting with the mild hydrocracking, the Tier 3 costs would be lower than either of two cost sensitivities which were conducted independently.

We also received some comments by API and two of the peer reviewers about our octane costs. We will not include all the discussion here about octane costs because we do so in detail in the response to peer review comments. While we are comfortable with the octane costs that we used, we did conduct a sensitivity at a higher octane cost (\$0.5/per octane number barrel instead of \$0.31/octane number-barrel that we used). At the higher octane cost of \$0.5/octane number barrel, the Tier 3 sulfur control costs increases from 0.65 c/gal to 0.73 c/gal.

We also estimated annual aggregate costs, including the amortized capital costs, associated with the new fuel standard.<sup>D</sup> When the 10-ppm gasoline sulfur standard is fully phased in 2020, we estimate that the sulfur standard would cost \$790 million in that year. Figure 5-1 shows the distribution of refinery costs over the accumulated gasoline volume for the fully phased in 10 ppm sulfur standard.

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<sup>D</sup> The aggregate annual costs is the estimated per-gallon cost multiplied by the total projected gasoline volume in that year.



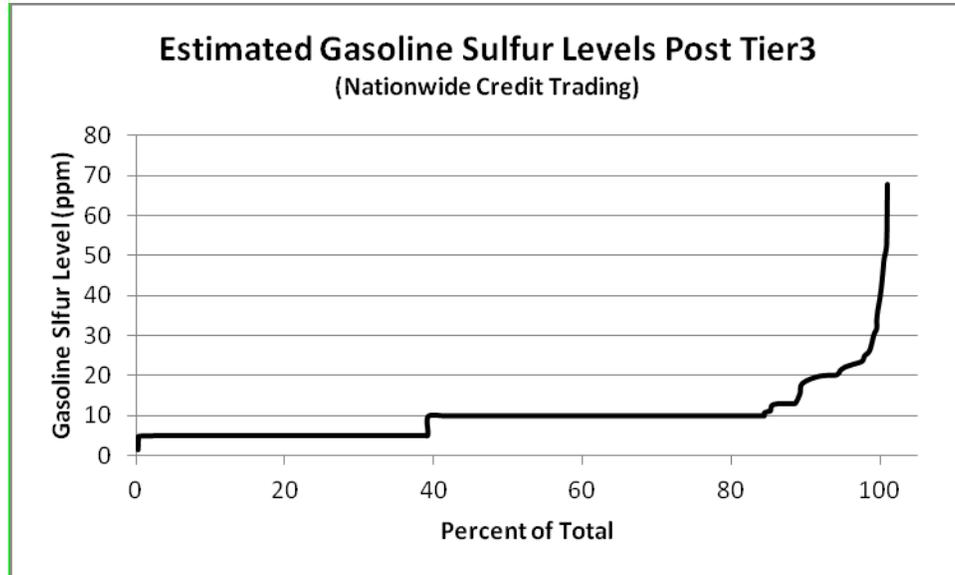
**Figure 5-1 Tier 3 Sulfur Control Costs**

Figure 5-1 shows that for almost 20 percent of the gasoline pool, refineries will not incur any cost under Tier 3, either because these refineries are already very low in sulfur because they don't have FCC units, or because the refineries are purchasing credits.<sup>E</sup> For another 10 percent of the gasoline pool, the refinery costs are in the 0 – 0.5 cent/gal range. For the next 55 percent of the gasoline pool, the refinery costs are in the 0.5 – 1.0 c/gal range. For the last 15 percent of the gasoline pool, the refinery costs range from 1.0 to 2.1 c/gal for revamps, with the exception of one refinery at 2.8 c/gal representing the cost for the sole grassroots unit which our modeling estimates would need to be installed. All other refiners that may otherwise need to install a grassroots hydrotreater were able to do so more cheaply through the purchase of credits.

In addition to assessing the Tier 3 program costs on a societal cost basis which amortizes the capital costs on a before-tax 7 percent ROI, we also assessed the program costs based on how industry would assess costs to achieve a payback on the capital invested, which amortizes capital costs on an after-tax 10 percent ROI. When the capital costs are amortized assuming an after-tax 10 percent ROI, the per-gallon costs of the final Tier 3 fuels program increases to 0.75 cents per gallon.

Figure 5-2 summarizes our estimated US gasoline sulfur levels over the accumulated gasoline volume post Tier 3.

<sup>E</sup> Refineries purchasing credits will incur a cost for the purchase of the credit, but since we don't know what the price of a credit will be, we allocate all the cost for complying with Tier 3 solely on the refineries adding capital and incurring operating costs to comply with Tier 3.



**Figure 5-2 Estimated US Gasoline Sulfur Levels Post Tier 3**

Figure 5-2 shows that over 80 percent of the gasoline pool would predominately be either 5 or 10 ppm representing the two sulfur levels to which we assumed that refiners would desulfurize their gasoline pool. For the rest of the gasoline pool, the refineries are clearly purchasing credits and their sulfur levels range from 10 to nearly 70 ppm. As discussed earlier, lacking more detailed refinery-specific information, for these refineries we assumed that they take no action to reduce their gasoline sulfur below their Tier 2 levels. In reality these refineries are likely to take some very cost-effective steps to partially reduce their gasoline sulfur and not rely solely on credits to demonstrate compliance with Tier 3. Were we able to model such refinery changes, it would only serve to further lower our projected costs.

### 5.2.2 Cost of Alternative Fuel Program Standards and Alternative ABT Program Assumptions

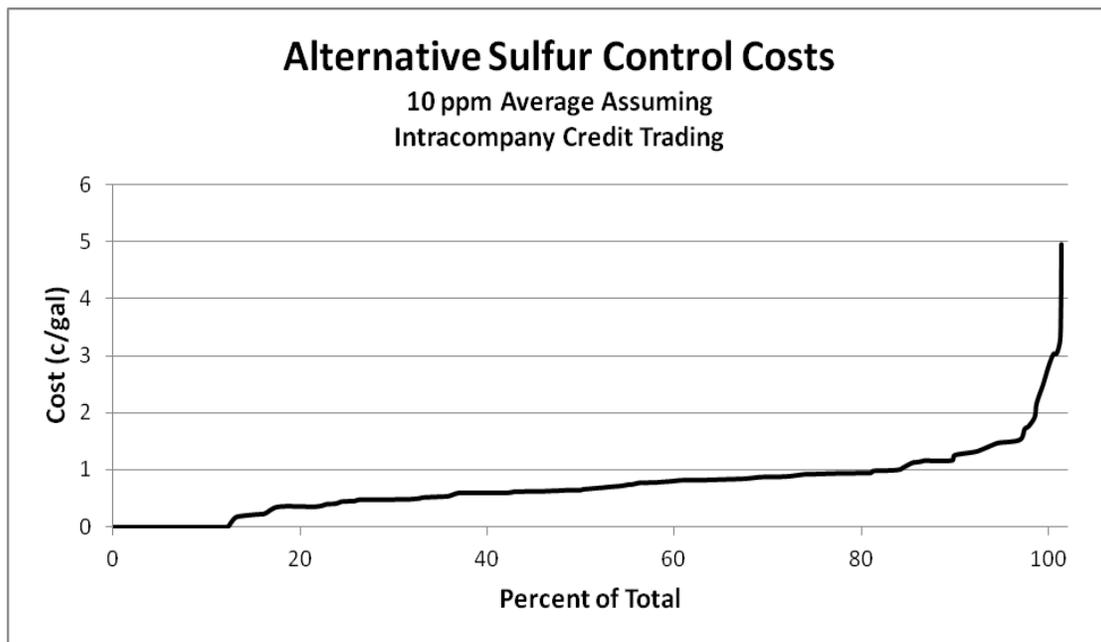
In addition to analyzing the cost of the finalized sulfur control program, we also provide other gasoline sulfur control cost estimates. In one case we analyzed the cost of the final rule program, but assumed that refiners don't continue to trade credits as freely as they are doing under Tier 2, but only trade credits within companies (intracompany) instead. For other cost estimates we assessed the cost of 10 ppm but with no ABT program and the cost of a 5 ppm sulfur standard with no ABT program. In no case did we assess the cost of a more stringent cap standard, but continued to assume that the sulfur cap remained at 80 ppm.

#### 5.2.2.1 10 ppm Average Assuming Only Intracompany Credit Trading

Based on the results of our cost analysis, we estimate that for the US refining industry to achieve a 10-ppm average level with only the benefit of intracompany credit trading, the final sulfur control program would cost on average 0.75 cents per gallon when it is fully phased in, assuming that capital investments are amortized at a seven percent return on investment before

taxes and expressed in 2011 dollars. Refiners would be expected to make \$2.190 billion in capital investments to achieve this sulfur reduction.

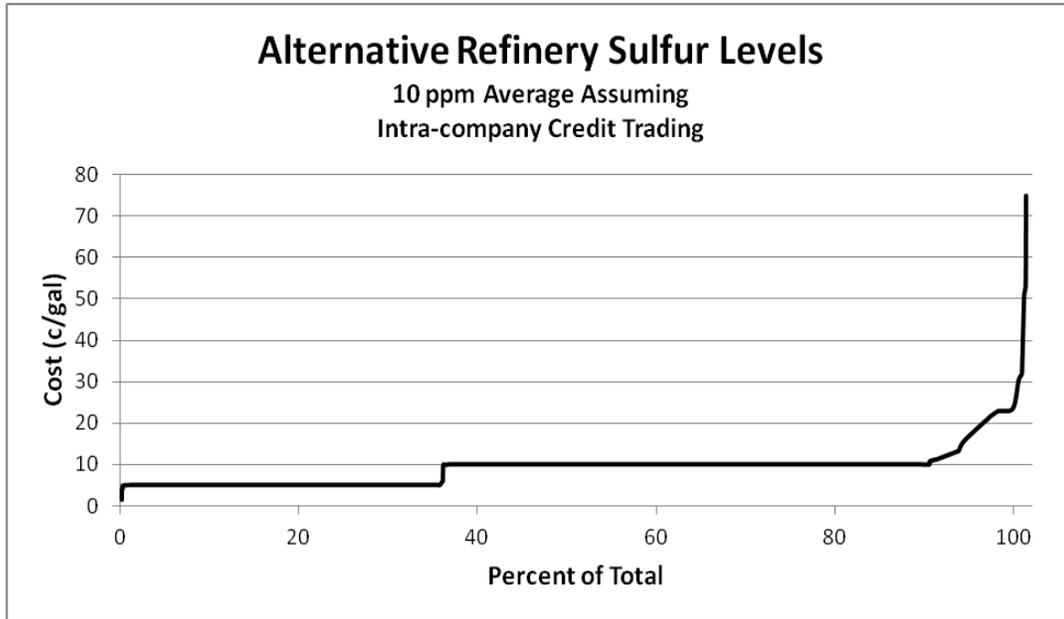
We also estimated annual aggregate costs, including the amortized capital costs, associated with the new fuel standard. When the 10 ppm gasoline sulfur standard is fully phased in 2020, we estimate that the sulfur standard would cost \$910 million in that year. Figure 5-3 shows the distribution of refinery costs over the accumulated gasoline volume for the fully phased-in 10 ppm sulfur standard which assumes that sulfur credits were solely traded within refining companies.



**Figure 5-3 Alternative Sulfur Control Costs - 10 ppm Average Assuming Intracompany Credit Trading**

Figure 5-3 shows that for about 15 percent of the gasoline pool, refineries would not incur any cost, either because these refineries are already very low in sulfur because they don't have FCC units, or because the refineries are purchasing credits. For the next 65 percent of the gasoline pool, the refinery costs are in the 0 – 1.0 c/gal range. For the last 20 percent of the gasoline pool, the refinery costs range from 1.0 to 5 c/gal. While the average cost increased by just 0.1 cents per gallon compared to the cost based on nationwide trading, the upper end of this range is nearly twice that of the maximum cost for nationwide trading. This emphasizes the benefits to the program that result from nationwide trading.

Figure 5-4 summarizes our estimated US gasoline sulfur levels over the accumulated gasoline volume post Tier 3.



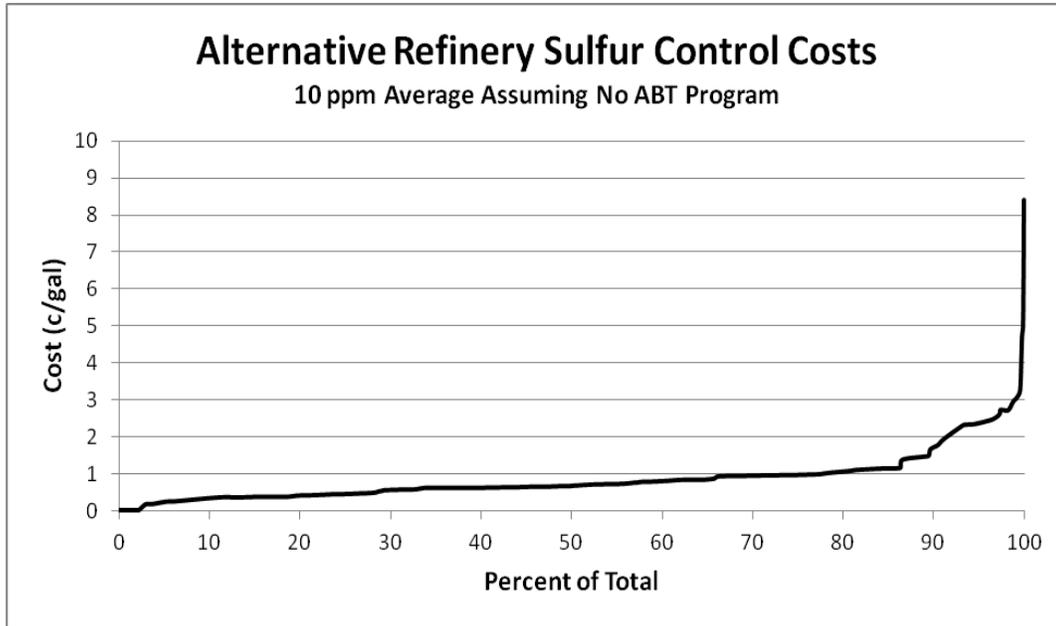
**Figure 5-4 Alternative US Gasoline Sulfur Levels - 10 ppm Average Assuming Intracompany Credit Trading**

Figure 5-4 shows that for about 90 percent of the gasoline pool would predominately be either 5 or 10 ppm representing the two sulfur levels to which we assumed that refiners would desulfurize their gasoline pool. For the rest of the gasoline pool, the refineries are clearly purchasing credits and their sulfur levels range from 10 to nearly 70 ppm. As discussed earlier, lacking more detailed refinery-specific information, for these refineries we assumed that they take no action to reduce their gasoline sulfur below their Tier 2 levels. In reality these refineries would likely to take some very cost-effective steps to partially reduce their gasoline sulfur and not rely solely on credits to demonstrate compliance with Tier 3.

#### 5.2.2.2 10 ppm Average Assuming No ABT program

Based on the results of our cost analysis, we estimate that for the US refining industry to achieve a 10-ppm average level but with no benefit of credit trading, the final sulfur control program would cost on average 0.87 cents per gallon when it is fully phased-in, and with capital investments at a seven percent return on investment before taxes and expressed in 2011 dollars. Refiners would be expected to make \$2.990 billion in capital investments to achieve this sulfur reduction.

We also estimated annual aggregate costs, including the amortized capital costs, associated with the new fuel standard. When the 10 ppm gasoline sulfur standard is fully phased in 2020, we estimate that the sulfur standard would cost \$1060 million in that year. Figure 5-5 shows the distribution of refinery costs over the accumulated gasoline volume for the fully phased in 10 ppm sulfur standard.



**Figure 5-5 Tier 3 Sulfur Control Costs**

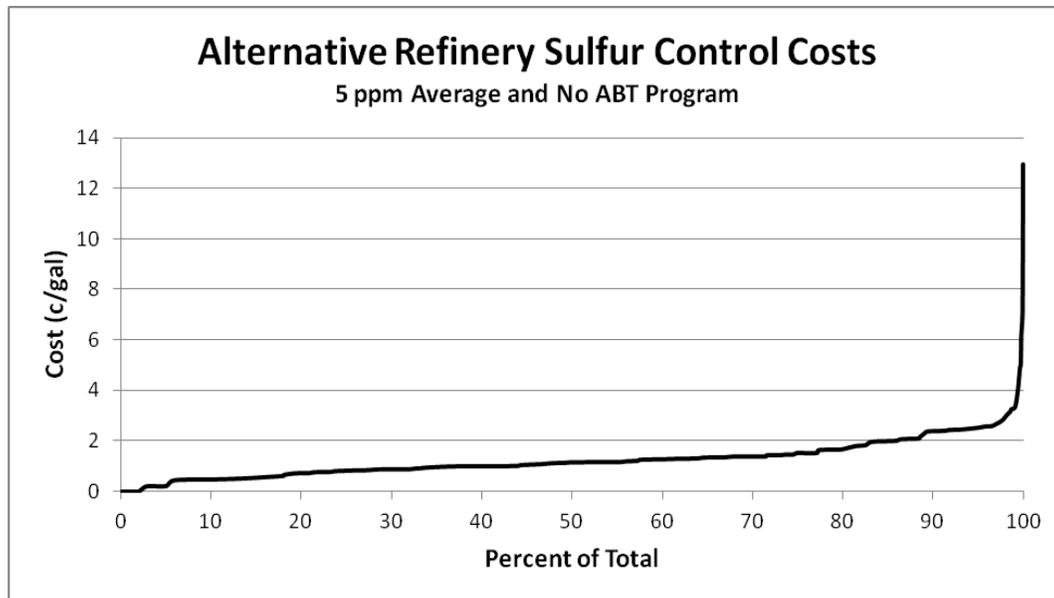
Figure 5-5 shows that for a small fraction of the gasoline pool, refineries would not incur any cost under Tier 3, because these refineries are already very low in sulfur because they don't have FCC units. For about 80 percent of the gasoline pool, the refinery costs are in the 0 – 1 cent/gal range. For the next 55 percent of the gasoline pool, the refinery costs are in the 0.5 – 1.0 c/gal range. For the last 20 percent of the gasoline pool, the refinery costs range from 1.0 to 8.5 c/gal. All other refiners that may otherwise need to install a grassroots hydrotreater were able to do so more cheaply through the purchase of credits. While the average cost increased by just 0.22 cents per gallon compared to the cost based on nationwide trading, the upper end of this range is about three times higher than that of the maximum cost for nationwide trading. This emphasizes the benefits to the program that result from nationwide trading. This cost scenario most closely parallels that conducted by Baker & O'Brien for API as discussed below in Section 5.3, given the stringent per-gallon cap they assumed. This serves to emphasize the cost benefits provided by a flexible nationwide ABT program.

#### 5.2.2.3 5 ppm Average Assuming No ABT program

Based on the results of our cost analysis, we estimate that for the US refining industry to achieve a 10-ppm average level with the full benefit of nationwide credit trading, the final sulfur control program would cost on average 1.28 cents per gallon when it is fully phased in, assuming that capital investments are amortized at a seven percent return on investment before taxes and expressed in 2011 dollars. Refiners would be expected to make \$3810 million in capital investments to achieve this sulfur reduction.

We also estimated annual aggregate costs, including the amortized capital costs, associated with the new fuel standard. When the 10-ppm gasoline sulfur standard would be fully phased in 2020, we estimate that the sulfur standard would cost \$1555 million in that year.

Figure 5-6 shows the distribution of refinery costs over the accumulated gasoline volume for the fully phased in 10 ppm sulfur standard.



**Figure 5-6 Alternative Sulfur Control Costs – 5 ppm Average and no ABT Program**

Figure 5-6 shows that for a small fraction of the gasoline pool, refineries would not incur any cost, because these refineries would already be very low in sulfur because they don't have FCC units. For another 80 percent of the gasoline pool, the refinery costs are in the 0 – 1.0 cent/gal range. For the last 20 percent of the gasoline pool, the refinery costs range from 1.0 to 13 c/gal.

#### 5.2.2.4 Estimated Cost of a 50 ppm Sulfur Cap Standard

For the NPRM, we co-proposed a 50 ppm sulfur cap along with the current 80 ppm cap already in place under the Tier 2 regulations. In doing so, we assumed, based on feedback from some refiners, that a 50 ppm cap would not increase the cost of compliance with Tier 3. However, we received comments on this assumption from API and other commenters suggesting that lowering the sulfur cap might considerably increase the cost of Tier 3 gasoline sulfur control. To support their comments, they provided a study they commissioned by Turner, Mason and Company (TMC) as discussed further below.

In response to the comments provided, for the FRM we estimated the cost of a potential 50 ppm refinery gate sulfur cap standard relative to the current 80 ppm cap standard. We identified two potential cost impacts of lowering the cap standard to 50 ppm: 1) some refineries that could maintain their sulfur levels at higher levels under Tier 3 with a 80 ppm cap standard would have to reduce their gasoline sulfur levels under a 50 ppm cap, and 2) some refineries may need to invest in additional tankage to store high sulfur FCC naphtha if the FCC pretreater or posttreater has operational problems or needs to shutdown.

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If the refinery gate cap standard were to be reduced from 80 ppm sulfur to 50 ppm, we estimate that refineries which otherwise might avoid capital investment by purchasing credits and continuing to produce gasoline above an average of 35 ppm under Tier 3 with an 80 ppm cap would need to make a capital investment to avoid having batches of gasoline exceed the 50 ppm cap on a regular basis. Refiners cannot produce gasoline which averages the same as the cap standard because of the variability in gasoline blendstock and gasoline batch-to-batch sulfur content (see Section 4.42). Based on our evaluation of refinery gasoline sulfur levels under the Tier 2 program, we found that the average sulfur level for refineries is at or below 70% of the cap standard, with the exception of only two refineries. This appears to be about the level necessary for most refineries to operate with adequate flexibility. Seventy percent of a 50 ppm cap would translate into a maximum average sulfur production level of 35 ppm for refineries. Of the 40 refineries which average greater than 35 ppm under Tier 2, our refinery modeling for Tier 3 estimates that 8 refineries would continue to average above 35 ppm sulfur when the Tier 3 sulfur standard is fully phased in under the 80 ppm cap standard. For the purpose of estimating the cost of the 50 ppm cap standard we assume that these 8 refineries would then need to make capital investments to reduce their gasoline sulfur levels. Because our refinery modeling could not model partial sulfur reductions in gasoline (i.e., reducing gasoline sulfur from 55 to 35 ppm), we estimated that these 8 refineries would reduce their gasoline sulfur levels to 10 ppm. To avoid overcomplying with Tier 3, other refineries would then not invest as much which would maintain the industry average of 10 ppm sulfur. After modeling these changes in our refinery model, we estimate that complying with Tier 3 with a more stringent cap of 50 ppm increases the average cost by 0.02 c/gal and increases the overall capital costs at refineries by \$135MM.

The second factor we identified that would increase refinery costs is the potential need to add storage at refineries to store high sulfur FCC naphtha, or other high sulfur naphtha, in the event that a refinery's gasoline hydrotreater (pretreater or posttreater) were to require emergency maintenance. This volume of storage is not intended to store all the FCC naphtha to enable a full turnaround of the FCC pretreater or posttreater. Instead, it would: 1) provide short-term storage for a modest fix to either of these units, 2) permit the refiner to make arrangements for storing or selling the FCC naphtha elsewhere until the inoperable hydrotreating unit could be made operational, or 3) allow for an orderly shutdown the FCC unit. Based on data that TMC collected on behalf of API from a survey of refiners, refiners today have on average 4.6 days worth of storage for unhydrotreated FCC naphtha to comply with the current Tier 2 standards (an average of 30 ppm and a cap of 80 ppm). The affect of a lower cap with Tier 3 would be slight. As we describe in Section 5.1.3.2, a Tier 3 refinery's FCC naphtha is typically 21 ppm assuming that FCC naphtha comprises 35% of the refinery's gasoline pool. However if a refinery's FCC pretreater or posttreater needs to be taken off line, the refinery's FCC naphtha sulfur level could increase to hundreds or even thousands of ppm. Assuming that the refinery's FCC naphtha is 1000 ppm when the pretreater or posttreater is down, the refiner would only be able to blend less than 1% FCC naphtha in its gasoline under either an 80 ppm or a 50 ppm cap, so the cap should not fundamentally change the refinery's situation when the cap standard is at 80 or 50 ppm. Either way the refiner needs to find a home for the high sulfur FCC naphtha and they are currently doing so with an average of 4.6 days worth of storage. Nevertheless, it is possible that some refineries may need to increase their storage capacity for unhydrotreated FCC naphtha in response to a lower sulfur cap.

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We conservatively estimated potential storage need increases with a 50 ppm cap by evaluating which refineries might experience lower ratio of cap to average sulfur level under Tier 3 compared to Tier 2, and therefore have a need for increases storage capacity. To estimate which refineries might need more storage we used our modeling results to look at each refinery's situation before and after Tier 3. For example, one refinery's average sulfur level is 29 ppm under Tier 2 and our modeling assumed that this refinery would remain at 29 ppm and purchase credits under Tier 3. Under Tier 3 the refinery's cap to average sulfur level would be 1.6 (compared to 2.6 under Tier 2). This refinery could experience a greater need for storing high sulfur FCC naphtha batches than under Tier 2. On the other hand, if a refinery reduces its gasoline sulfur under Tier 3 from 30 ppm to 10 or 5 ppm, the refinery's cap to average sulfur level would be higher under Tier 3 than Tier 2 (assuming a 50 ppm cap standard) and the refinery is less likely to need FCC naphtha storage under Tier 3 than under Tier 2. We project that after complying with Tier 3 and with a 50 ppm refinery gate standard, 17 refineries would be projected to experience lower ratio of cap to average sulfur level under Tier 3 than under Tier 2

To estimate the potential tankage costs, we assumed that these 17 refineries have no FCC storage capacity today and would need to add the full 4.6 days worth. For each of the 17 refineries, we calculated the volume of FCC naphtha that may be needed to be stored based on the maximum FCC naphtha volume capable of being produced (at maximum FCC throughput rates) with the FCC unit operating full time over those 4.6 days. We estimated the cost of petroleum storage to be \$25/bbl for a 250,000 barrel storage tank, which is based on a cost estimate we obtained from the Independent Fuel Terminal Association for a gasoline storage tank. We applied a 20% contingency factor and a 20% offsite factor to estimate a total installed cost. We adjusted this cost to reflect the cost for the appropriate-sized storage tank for each refinery using the six-tenths rule (see equation 5-4). Based on the capital cost for adding the storage capacity at each of these refineries, we estimated the fixed costs assuming that they comprise 6.7% of the capital costs. The total of capital and fixed costs, averaged over the entire US gasoline production volume is 0.02 cents per gallon, and the capital costs for this storage are \$95 million.

Combining the above cost estimates, we estimate that reducing the cap standard from 80 to 50 ppm could increase the total compliance cost for Tier 3 compliance cost by 0.04 cents per gallon, thus, increasing Tier 3 estimated costs from 0.65 to 0.69 cents per gallon. The estimated total capital cost increase for a 50 ppm cap standard is \$230 million, thus increasing Tier 3 estimated capital costs from \$2.025 billion to \$2.26 billion.

In their comments on our proposal, the American Petroleum Institute provided a report which discussed the costs and other impacts that might result from a more stringent gasoline sulfur cap standard. The comments were in the form of a report analyzed and written by the Turner, Mason and Company (TMC) wherein they principally report the results of a survey of refiners that they conducted to ascertain their compliance approach and potential compliance costs with more stringent gasoline sulfur caps of 60, 40, 30, and 20 ppm as compared to the current 80 ppm cap. The survey was comprised of a series of multiple choice questions. While the TMC study did not look specifically at the implications of the proposed 50 ppm cap standard, one could look at the responses for the 40 and 60 ppm cap standard and interpolate to get a good sense of what the study would show for a 50 ppm cap standard. Apparently, 6 refiners responded to the survey and TMC estimated that these refiners operate 30% of the operating

refineries and produce 44% of the gasoline produced in the U.S. Thus, the respondents were primarily large refining companies which own multiple refineries. TMC then extrapolated the results from these 6 refiners to the remaining 38 U.S. refiners to estimate the overall impact. A summary of the API estimated cost and other impacts is summarized in Table 5-35. We calculated a per-gallon cost by amortizing the capital costs over the volume of gasoline that API used in its cost study assuming a before tax 7% return on investment (specified by the Office of Management and Budget). The estimated per-gallon costs are also summarized in Table 5-35.

**Table 5-35 API Estimated Cost and Supply Impacts**

	80	60	40	30	20
Capital Cost (\$MM)	-	1768	3390	5533	6090
Per-Gallon Cost (c/gal)	-	0.17	0.33	0.54	0.60
Gasoline Supply Loss (Kbbl/day)	12	43	63	108	129

The TMC survey results can be placed into five different categories associated with lower cap standards: 1) how refiners would comply with the Tier 3 average sulfur standard, 2) how refiners would react to an outage of a FCC naphtha desulfurization unit (FCC pretreater or posttreater), 3) how refiners would react to a loss of low sulfur blendstocks, 4) what the projected increase in capital costs would be for tighter cap standards, and 5) what the loss in gasoline production volume would be. Many of the survey results are presented in the report as a series of pluses (from 1 to 4) or a single minus instead of presenting the raw survey results. Presumably, one plus indicates a modest tendency to undertake an action and increasing numbers of pluses indicates a greater tendency to undertake an action, while a single minus sign indicates very little or no tendency to undertake an action.

With respect to the first survey category, when complying with the 10 ppm average standard, the TMC refiner survey found that as the cap standard was decreased refiners would rely less and less on FCC pretreating as the sole means for desulfurizing FCC naphtha, and therefore would rely on both combined pre and posttreating (at a 20 ppm cap, the report seems to conclude that every refinery which solely relies on FCC pretreating today to lower its gasoline sulfur would install an FCC posttreater). This survey result in TMC's study for API is inconsistent with the cost study Baker & O'Brien performed for API. In that study, which assumed a 20 ppm cap standard, refiners were assumed to rely on revamped FCC pretreaters for complying with the 10 ppm average standard. In our cost analysis discussed in section 5.1.3.5, we conservatively assumed that the only option considered by refineries which are complying with Tier 2 by only using FCC pretreating is to put in a grassroots FCC posttreater to comply with Tier 3. Thus, our cost analysis of the 10 ppm average and 80 ppm cap standard may already include some of the costs of a tighter cap standard. Furthermore, there are several California refineries, already governed by a 20 ppm cap standard, that solely use FCC pretreating to comply with the California gasoline sulfur standard. Thus, it does not appear that decreasing the cap would necessarily force FCC posttreating versus FCC pretreating.

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With respect to the first survey category, the survey also found that refiners are more likely to reduce the endpoint of FCC naphtha and add treatment of other blendstocks as the cap standard is lowered. Reducing the endpoint of gasoline is likely an important factor driving the gasoline supply results from the TMC study. However, our LP refinery modeling projects that refineries will already be extensively undercutting FCC naphtha when the Tier 3 program is implemented in order to maximize distillate production and profits. Thus, we believe that this will be occurring in the baseline with or without Tier 3.

With respect to the second survey category, (how refiners would react to an outage of a FCC naphtha desulfurization unit with lower cap standards), the refiner survey found that refiners would predominantly idle or significantly reduce feed rate to the FCC unit, regardless of the stringency of the cap standard. The second most important strategy that refiners would use would be to store high sulfur components, and that this strategy would increase as the cap tightens. Other strategies that increased as the cap was lowered included purchasing low-sulfur components, selling high sulfur components and/or exporting high-sulfur gasoline, reducing the endpoint of FCC naphtha, and reducing crude oil feed rate. One other strategy identified for that subset of refineries with both a pretreater and a posttreater or multiple postreaters today was to simply operate the nonshutdown hydrotreating unit more severely. The refiner survey results supports the analysis that we conducted above, which is to add storage capacity to allow additional storing of high sulfur FCC naphtha. The refiner then has time to deal with the very high sulfur FCC naphtha stream through reprocessing, selling, blending, exporting, etc.

With respect to the third survey category (loss of low sulfur blendstocks), the refiner survey found that refiners would take a number of actions. The most common response was to store high sulfur components, although idling or significantly reducing the feed rate to the FCC unit was also common. Other responses were to increase the severity of the FCC pre or posttreater, sell high sulfur components or export high sulfur gasoline. We believe that this issue is predominantly about an emergency shutdown of the naphtha hydrotreater which facilitates the production of reformate, isomerate, and low-sulfur, light straight run naphtha. Both the reformer and isomerization units require near zero sulfur gasoline to function, and if the naphtha hydrotreater undergoes an emergency shutdown, then the feedstock to the reformer and isomerization units must be stopped and those units would need to be shutdown as well. Since straight-run naphtha is high in sulfur, it likely cannot be blended straight to gasoline without exceeding the sulfur cap standard. This is a situation that exists today, and due to the very high sulfur of untreated FCC naphtha, this situation is little impacted by the level of the cap. Perhaps in limited situations if a refinery was refining a sweet crude oil, the refinery may be able to blend some of the heavy straight run naphtha into its gasoline pool and still meet the sulfur cap without hydrotreating it if the cap was not too stringent. However, this would be further limited by the need to meet the octane requirements for the gasoline. Provided that the refiner put in emergency storage for FCC naphtha, this storage could also be used for heavy straight run naphtha since it is unlikely that the naphtha hydrotreater would need to be shutdown at the same time that an FCC pre or posttreater would need to be shutdown. As a result, there should really be no additional impact or cost associated with this issue that isn't already captured under survey category 2.

With respect to the fourth survey category (estimated capital costs for lower caps), the survey results, TMC extrapolated to the industry as a whole, estimated the impact of the cap

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standards would be \$1.8 billion for a 60 ppm cap standard, \$3.4 billion for a 40 ppm cap standard, \$5.5 billion for a 30 ppm cap standard, and \$6.1 billion for a 20 ppm cap standard. Thus, for complying with a 50 ppm cap standard, the TMC refiner survey estimates a capital cost of about \$2.5 billion, which is about one order of magnitude higher than our estimate. Because these values are solely responses to a survey questionnaire, and no justification or support for these values was provided in the report, it is difficult to identify the basis for the reported costs. It is difficult to reconcile these results with our own. There is no connection made in the report between the responses to the other survey questions discussed above, and the potential capital costs. As discussed above, there are several other survey results which would have an impact on capital costs that we believe are inappropriate to attribute to a declining cap standard, but the report doesn't provide any means to assess this in the context of capital costs. Part of the discrepancy between the survey results and our own may simply be due to confusion with the refiner responses to the survey. The survey asked refiners what the costs would be for complying with the various hypothetical cap standards, but the survey did not specify whether the refiner should report their capital cost estimate on a refinery basis or company basis. Thus, it is possible that TMC assumed that the refiner responses for a capital cost estimate were on a refinery basis and multiplied the values by the number of refineries that each refiner has, when in fact the refiner may have responded on a company basis. No discussion is provided to help the reader understand how this potential confusion may have been resolved by TMC.

The last survey category discussed in the TMC report is the potential gasoline production loss during turnarounds associated with tighter cap standards. The TMC report estimated that the 80 ppm cap standard would already be responsible for 12 thousand barrels per day (kbbbl/day) of gasoline production loss. As the cap is lowered to 60 ppm the report estimates this gasoline production loss increases to 43 kbbbl/day, if the cap is lowered to 40 ppm the projected loss increases to 63 kbbbl/day, at a 30 ppm cap standard the loss increases to 108 kbbbl/day and a 20 ppm cap standard is projected to cause a loss of 129 kbbbl/day of gasoline production. Interpolating between 60 and 40 ppm, the projected gasoline production loss for a 50 ppm cap is 53 kbbbl/day. Thus, decreasing the cap standard from 80 to 50 ppm is projected by TMC to increase the gasoline production loss by 41 kbbbl/day. Of the 8452 kbbbl/day of gasoline consumed in the US, this projected gasoline production loss represents 0.5%. Similar to our observation of estimated capital costs, there is no connection made in the report between the responses to the other survey questions discussed above and the potential gasoline production loss. Furthermore, as discussed above, there are several other survey results which would have an impact on gasoline production that we believe are inappropriate to attribute to a declining cap standard, but the report doesn't provide any means to assess this in the context of gasoline production impacts. A portion of this projected gasoline production loss is a short term loss and once the affected units are restarted, high sulfur intermediate refinery streams (such as FCC naphtha) would be hydrotreated with the excess capacity available in the respective hydrotreating units and would eventually be blended into the gasoline pool. Thus, the projected net gasoline production loss would be much less than the 0.5% reported by TMC for a 50 ppm cap standard.

### **5.3 Other Cost Studies**

Other cost studies were recently conducted to estimate the cost of additional reduction in gasoline sulfur. We evaluated each of these studies and compare them to our own cost analysis.

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### 5.3.1 International Council for Clean Transportation Cost Study

The International Council for Clean Transportation (ICCT) retained Mathpro in October 2011 to study the cost of a 10 ppm average gasoline sulfur standard as well as a 1 psi reduction in RVP.<sup>17</sup> Since the lower RVP standard was modeled as a separate step from the low sulfur standard, we were able to isolate the gasoline sulfur reduction costs from the low RVP costs.

ICCT's estimated cost for a 10 ppm average gasoline sulfur standard is 0.8 cents per gallon which reflects the capital costs amortized assuming a before-tax 7 percent rate of return on investment (to be consistent with our analysis). This cost reflects an assumption that the capital cost for revamps of FCC posttreaters is 30 percent of the capital costs for a grassroots FCC posttreater. Mathpro also analyzed costs assuming that the capital cost for revamps of FCC posttreaters are 50 percent of a grassroots FCC posttreaters, which is 1.1 cents per gallon. ICCT's cost estimate for complying with a 10 ppm average gasoline sulfur standard is very close to ours.

### 5.3.2 The Alliance Cost Study

In 2008 The Alliance retained Mathpro to use its LP refinery cost model to estimate the costs of what they termed National Clean Gasoline (NCG) in PADDs 1, 2 and 3 (generally speaking, this is the part of the U.S. east of the Rocky Mountains).<sup>18</sup> Achieving NCG would entail reducing gasoline sulfur to 5 ppm under a 10-ppm cap standard and the reduction of gasoline RVP to 7 psi. For the low-RVP standard, a 1-psi waiver was allowed for conventional gasoline, but not for current low-RVP areas. The study also evaluated two sensitivity cases which increases the stringency of the distillation index (DI) from 1250 to 1200. The Alliance study also evaluated crude oil price as a second sensitivity case, evaluating crude oil prices at \$51 /bbl and \$125/bbl.

The Alliance studied three different cases. The first case applied the 10 ppm sulfur cap to RFG. The second case applied the 10 ppm sulfur cap and the 7.0-psi low-RVP standard to RFG as well as 7.0- and 7.8-psi low-RVP gasoline. The third case applies the 10 ppm sulfur cap and 7.0-psi RVP standard to all RFG and CG. Of these three cases, the first case is most relevant because applying the fuels changes to RFG solely applies the 10 ppm sulfur cap to RFG and does not involve any changes in RVP. However, the 10 ppm sulfur cap standard studied by the Alliance is still 5 ppm more stringent than the 10 ppm average standard that we are proposing.

The Alliance cost estimate for Case 1 is 1.6 cents per gallon for RFG in PADDs 1, 2 and 3. This cost estimate is based on amortizing the capital costs on a 10 percent after-tax return on investment (ROI). We adjusted the cost estimate to amortize the capital costs based on a before tax 7 percent ROI and adjusted the costs to 2010 dollars which increases the costs to 1.75 cents per gallon. The 1.75 ¢/gal cost estimate is based on a crude oil price of \$51/bbl. The Alliance estimated the cost of a 10 ppm sulfur cap standard on RFG assuming that crude oil is priced at \$125/bbl. At the \$125/bbl crude oil price, the Alliance study estimates that it costs 2.50 ¢/gal to require that RFG comply with a 10-ppm sulfur cap standard. Adjusting the Alliance costs to reflect a 7 percent before tax ROI and 2010 dollars increases the Alliance costs based on a \$125/bbl crude oil price to 2.69 ¢/gal.

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For our cost analysis we analyzed the cost of sulfur control assuming that crude oil is priced at \$91.8/bbl. We can interpolate between the Alliance costs based on \$51 and \$125 per barrel crude oil prices, which results in a single cost which is 2.3 cents per gallon. We also estimated a cost for refiners lowering their gasoline sulfur to 5 ppm using the refinery-by-refinery cost model and our cost is 1.28 ¢/gal.

### 5.3.3 API Cost Study

In response to the Alliance study, API retained Baker & O'Brien (BOB) in 2010 to study the cost of additional gasoline sulfur control and RVP control using a refinery-by-refinery cost approach with BOB's Prism model.<sup>19</sup> The Prism model is largely a spreadsheet cost model with blending optimization. The primary case analyzed by the API study is the cost of reducing gasoline sulfur to an average of 10 ppm and reducing gasoline RVP to 7.0 psi without a 1-psi waiver for blending 10 percent ethanol. The study also analyzed three other sensitivity cases: 1) a 5-ppm average gasoline sulfur standard with 7 psi RVP limit on conventional gasoline without a 1-psi waiver; 2) a 10 ppm average gasoline sulfur standard and a 7.8-psi RVP limit on conventional gasoline without a 1-psi waiver; and 3) a 10 ppm average gasoline sulfur standard with a 7.8-psi RVP limit on all conventional gasoline with a 1-psi waiver.

In an addendum to its fuels study report released in 2011, API contracted with Baker & O'Brien to study a sensitivity case 4, which is a sulfur only case, using its PRISM refinery model. From our understanding of the study, the study parameters seemed to be about the same as the original study, except that API solely studied a 10 ppm average gasoline sulfur standard (not including any RVP control), the same sulfur standard that we are proposing. However, API also assumed that a 20 ppm cap standard would also be in place which would effectively not allow the application of an averaging, banking and trading (ABT) program to optimize refinery investments and minimize overall costs.

API made a series of conclusions based on the study. Perhaps the most important difference with the original study is that API concluded that not a single refinery would shut down as a result of the proposed 10 ppm gasoline sulfur control standard, even though API did not study the flexibilities of an ABT program and used excessively high capital costs for a grassroots FCC posttreater (see below). Like the original study, API did not report average costs, but reported only the marginal costs for the cost study. Marginal costs reflect the cost of the program to the refinery or refineries which would incur the highest costs, assuming that the highest cost refineries would set the price (or in this case, the price increase) of gasoline. The report concluded that marginal costs after the imposition of a 10 ppm gasoline sulfur program would increase the price of gasoline by 6 to 9 cents per gallon in most markets. API did not define how its statement "in most markets" would apply to the US gasoline supply. API also did not provide any justification why it assumed that the refineries that would experience the highest desulfurization cost under Tier 3 would also be the same refineries which set the gasoline price in their gasoline markets today.

Although API did not provide an average gasoline desulfurization cost in its report, we could calculate an average cost based on the gasoline volume and total annual costs provided. The total cost reported in the report for the 10 ppm average gasoline sulfur standard is \$2390MM/yr and the non-California gasoline volume is 7343 thousand barrels per day. This

results in an average per-gallon desulfurization cost of \$0.89/bbl or 2.12 c/gal. The difference between the average cost and marginal cost (price increase) that API is projecting is profit. API is projecting that the oil industry would profit from 10 ppm low sulfur standard by the roughly 4 to 7 cents per gallon difference between the average cost and the two marginal price values. That per-gallon profit translates into \$4 to \$8 billion dollars per year in profit.

The average cost of the 10 ppm average gasoline sulfur standard was calculated using API's methodology for amortizing capital investments. To facilitate a fairer comparison between the API cost study and our cost study, we adjusted the API costs to be on a similar basis as our costs. We adjusted the API costs to reflect a before-tax 7 percent return on investment (ROI) for capital invested for the hydrotreaters and hydrogen plants instead of the after-tax 10 percent ROI used by API. This lowered the API estimated costs from 2.12 c/gal to 1.58 c/gal. API's 1.58 cents per gallon cost is still higher than our 0.89 c/gal cost with an ABT program that assumes intercompany trading of credits, and higher than our 0.97 c/gal for the case which assumes no ABT program. Thus comparing "apples-to-apples" to the extent possible, API's 1.58 c/gal estimated cost for complying with a 10 ppm average gasoline sulfur standard compares very favorably with our own cost estimates, and not at all near the 25 c/gal value that was sometimes quoted from the first API study. The remaining cost difference between our estimated costs and those by API are the capital cost assumptions that API used, as discussed below. While little detail is provided by API about what hardware comprises their desulfurization units, the inside battery limits (ISBL) and total capital costs for the FCC posttreaters and FCC pretreaters are provided in API's report. API's FCC pretreaters capital costs are consistent with the capital costs that we have used for this unit. However, the FCC posttreater costs used by API are much higher than what we used and have been used in the past by others. API's capital cost for a grassroots FCC posttreater is \$228 million for a 35,000 bbl/day unit, or \$6540 per/bbl per day. API's capital cost includes the outside battery limit (OSBL) costs. In contrast, the ISBL capital cost that we used for a grassroots FCC posttreater is \$1500/bbl-day for a 30,000 bbl/day grassroots unit, which increases to \$2440/bbl/day when the offsite costs and a 20% contingency are added on. Thus, the API capital costs are more than 2 ½ times higher than the capital costs that we are using for a grassroots FCC posttreater. To check our capital costs, we found other capital cost estimates to which we could compare our costs. Table 5-36 contains a cost comparison of ISBL and OSBL FCC posttreater capital costs for a grassroots unit.

**Table 5-36 Capital Cost Comparison**

Technology	EPA (Tier 3)	Mathpro (ICCT)	Jacobs	API
ISBL Capital Cost (\$/bbl/day)	1500	-	2440	-
ISBL and OSBL Capital Cost (\$/bbl/day)	2430	1800	3538	6540

Table 5-36 shows that, compared to the average of the rest of the capital cost estimates, the API capital cost for FCC posttreater is about 2 ½ times higher. Compared to the next highest

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cost estimate, which is the FCC postreater capital cost from the Jacobs data base in the Haverly refinery cost model that we use,<sup>F</sup> the API capital costs are almost two times higher.

An important distinction must be made with respect to the severity of desulfurization for the capital cost comparison made in 5-32. For complying with the Tier 2 gasoline sulfur standard (Jacobs), a typical refinery would have installed an FCC postreater to desulfurize the FCC naphtha from about 800 ppm down to about 75 ppm, a 725 ppm, or a 91 percent sulfur reduction. In the case of a grassroots postreater that would be installed for Tier 3, the postreater would treat FCC naphtha already low in sulfur due to the pretreater installed before the FCC unit (these refineries are currently complying with Tier 2 using an FCC pretreater). Thus, the new grassroots FCC postreater would only have to reduce the FCC naphtha from 100 ppm to 25 ppm, a much smaller 75 ppm or 75 percent sulfur reduction. A grassroots FCC postreater installed for Tier 2 would typically remove 10 times more sulfur than one installed for Tier 3. This is important because a significant portion of the FCC postreater capital cost is devoted to avoiding the recombination reactions which occur when hydrogen sulfide concentrations are high and react with the olefins contained in the FCC naphtha. Thus, a grassroots FCC postreater installed for Tier 3 would be expected to be significantly lower in capital cost compared to a Tier 2 FCC postreater. API's costs are based solely on Tier 2 compliance costs, which is one reason why their costs are so high. API obtained either estimated installation costs or actual installation costs (API did not specify) for FCC postreaters for installation in 5 different refineries for complying with the Tier 2 30 ppm gasoline sulfur standard. The postreater capital cost information which reflected cost information from the years 2003 to 2005 was adjusted upward to reflect mid-year 2009 capital costs using the Nelson-Farrar index and normalized to reflect a 35 thousand barrel per day unit. This resulted in an average ISBL cost of \$144.5 million for installing a Tier 2 compliant FCC postreater. After discussing this capital cost estimate with several refiners who built several of the units in recent years, those refiners felt that the estimated capital costs that API had calculated were too low, and one refiner thought that the estimated capital costs should be doubled. Based on the information provided by that one refiner, API doubled its estimated capital costs for a 35K bbl/day FCC postreater to \$228.8 million.

Another way to assess the API capital cost for the FCC postreaters is to compare it to the FCC pretreater cost that API is using. FCC pretreaters are much higher pressure units and use more expensive metallurgy than FCC postreaters and, for these two reasons, are much more expensive than FCC postreaters on a per-barrel basis. However, API's FCC postreater capital costs are about 50 percent more expensive than its FCC pretreater capital costs, which is inconsistent with the design requirements of the units. API acknowledged this inconsistency, but did not take steps to correct it.

API's estimated range of capital cost for revamping an FCC postreater is also higher than our range of capital cost for revamping an FCC postreater, when assessing the revamped costs as a percentage of the capital cost for a grassroots unit. API estimates that revamping an FCC

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<sup>F</sup> The installed capital cost for an FCC postreater from the Jacobs data base was adjusted to current year dollars. This estimated installed capital cost is several years old and may not represent Jacobs current cost estimate for a FCC postreater.

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postreater would cost 30 to 70 percent of the capital cost for a grassroots FCC unit. Our capital cost estimate for revamping FCC naphtha postreaters range from 17 to 50 percent of the capital cost for a grassroots FCC postreater, however, most of the revamps are estimated to cost at the lower end of that range.

As discussed above, an important reason why API's projected capital costs for complying with Tier 3 are so high is that API assumed a 20 ppm cap standard in addition to the 10 ppm average standard that it studied. The 20 ppm cap standard eliminates the possibility of realizing the cost savings of an ABT program. After we proposed the Tier 3 rule, API presented to EPA, in its comments on the proposed rulemaking, its estimate for the cost of finalizing a more stringent cap standard. The study, which was contracted to the Turner, Mason & Company, estimated that a 20 ppm cap standard would increase the capital cost of complying with a 10 ppm average standard by \$6.1 billion. If we subtract the \$6.1 billion in capital costs attributed to the 20 ppm cap standard from the \$9.8 billion in total capital costs from API's Addendum report which estimated the cost of complying with Tier 3, and adjust the fixed operating costs accordingly, the API estimated average cost (not marginal cost) for complying with Tier 3 decreases to 0.97 c/gal. In addition to the questionable capital costs assumed for FCC postreaters as discussed above, this information from API on its estimated cost of complying with a 20 ppm cap standard helps to answer an important question of why the API estimated average cost was still higher than the other studies after other cost adjustments were made. This final adjustment to the API costs makes the estimated API costs for complying with Tier 3 right in line with the other cost studies. This adjusted API cost, however, still does not include the cost saving aspects of credit averaging and trading since the API analysis assumed that each refinery meets the 10 ppm average sulfur standard. Thus, to compare this most recent cost adjustment of API costs to our cost study, our 0.87 c/gal cost for no ABT program would be the most appropriate cost for comparison (see section 5.2.2 for alternative costs). The adjusted API cost and our cost are only 0.1 c/gal different.

#### 5.3.4 Emissions Control Technology Association Cost Study

The Emissions Control Technology Association (ECTA) retained personnel within Navigant Economics to study the costs of a 10 ppm average gasoline sulfur standard and assess the ICCT and API cost studies.<sup>20</sup> The authors made a number of conclusions. After reviewing both the ICCT and API studies, the authors found that a primary difference in estimated costs between the two studies was the capital costs. The authors contacted vendor companies that license FCC postreater technologies and surveyed the companies to find out what the capital costs are for a FCC postreater. As a result of the survey, the report authors concluded that API's capital costs were too high, and those used in the ICCT study were about right. The authors found that Baker & O'Brien has a history of exaggerating the economic impacts of EPA rules, citing the costs and other impacts of its analysis of the 2007 on-highway heavy-duty proposed rulemaking. The authors concluded that the impact of a 10 ppm gasoline sulfur standard on the average refining cost would likely be closer to the 1 cent per gallon estimate by the ICCT study. Furthermore, the report's authors also pointed out that the marginal cost analysis conducted by API did not consider the proposed averaging banking and trading (ABT) program that we were expected to propose, which would reduce the marginal costs of the Tier 3 proposed rule.

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## 5.4 Projected Energy Impacts and Impacts on Permitting

Our refinery-by-refinery model was also used to determine the impact the Tier 3 standards would have on the energy related CO<sub>2</sub> emissions and permitting of existing refineries. While the Tier 3 proposal will reduce emissions from vehicles, the addition of grass roots units and revamping of existing units which we project will happen as a result of the Tier 3 sulfur standards are likely to result in some increased emissions of regulated air pollutants at refineries. Refinery projects designed to meet the new fuel standards could trigger preconstruction air permitting requirements under the Clean Air Act and EPA's New Source Review (NSR) regulations. To address this concern, we used our refinery-by-refinery model to estimate the likely process and equipment changes that may be required to meet the Tier 3 gasoline standards. This information was submitted to EPA's Office of Air Quality Planning and Standards (OAQPS) to provide the inputs that are necessary for the modeling and analysis of the refinery emissions and permitting impacts of the Tier 3 fuel standards.

Using our refinery-by-refinery model we generated refinery-specific estimates of the increased energy and hydrogen demands that we estimate will result from the proposed Tier 3 standards. We also estimated the increase in sulfur plant recovery unit (SRU) loading/operations for the 110 U.S. refineries that we modeled in our analysis. Energy demand includes fuel that is needed to generate refinery process heat, steam and electricity. Hydrogen demand is associated with increased hydrotreating of Fluid Catalytic Cracking (FCC) naphtha and light straight run (LSR) streams. Increased SRU loading results from the increased fuel desulfurization and associated H<sub>2</sub>S generation. All of these incremental demands will be referred to as "demands" in the following sections. We used our refinery-by-refinery model to calculate the increase in these various demands for several scenarios where sulfur averaging, banking, and trading (ABT) was not allowed and each refinery had to meet the 10ppm standard, as well as scenarios that allowed ABT between refineries owned by the same parent company to minimize the cost of compliance with the Tier 3 standards.

### 5.4.1 Emissions Impacts of Different Production Volumes

In addition to considering scenarios with and without ABT we also considered the impacts on emissions and permitting of different gasoline production volumes for each refinery. In the first case, called the normal case, we considered the incremental demands for each refinery assuming no change in gasoline production volume. We also considered a case, called the maximum demand case, where each refinery maximized gasoline production based on currently existing refinery capacity and equipment.

#### 5.4.1.1 Normal Case

The normal case was estimated using each refinery's predicted yields of FCC naphtha and LSR from our refinery-by-refinery model, along with each refinery's total gasoline production volume from EPA's RFG database. For each refinery the refinery-by-refinery model generated specific Tier 3 demands for hydrogen, steam, fuel gas and electricity based on the desulfurization technology used by each refinery for any FCC posttreating and LSR hydrotreating. To determine the FCC posttreating demands the model considers each refinery's volume of FCC naphtha under normal operations, the FCC naphtha sulfur level at the refinery

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prior to posttreating, and the process requirements of the FCC posttreater technology used by that refinery. The demands are calculated by multiplying the FCC naphtha volume by the demands from the use of the associated FCC posttreating technology. Table 5-20 through Table 5-23 show the FCC posttreater technology demand averages as applied to refineries on a national basis for the 5 and 10 ppm gasoline sulfur standards. Note that the demands vary significantly with the FCC naphtha sulfur level prior to posttreating.

Similarly, the normal case demands for any LSR blendstocks that require additional hydrotreating as a result of the Tier 3 standards were determined based on each refinery's yield of LSR blendstock under normal operations and the demands for the additional LSR hydrotreating. These demands are discussed in section 5.1.3.1.2. The normal case demands for FCC posttreating and LSR hydrotreating were then summed to determine the increase in energy and hydrogen demand. To determine the additional sulfur removed from gasoline we first calculated the difference between the current gasoline sulfur level of the gasoline produced at each refinery according to their compliance reports to EPA and the proposed Tier 3 standard. This difference was multiplied by the refinery's gasoline production volume and divided by the number of days of operation to calculate the additional sulfur removal level at each refinery. This sulfur removal information was then used to determine the increase in SRU loading on a fractional basis by dividing the additional sulfur removal as a result of the Tier 3 standards (in tons of sulfur per day) by the refineries SRU process capacity.

#### 5.4.1.2 Maximum Case

We also considered a second demand case, called the maximum case, in which we calculated the demands that result from the Tier 3 standards if each refinery maximizes gasoline production based on currently existing refinery capacity. For this case we first determined each refiners FCC unit process capacity utilization rate in the normal case. The annual FCC unit feedstock charge rate for each refinery as reported in the 2011 EIA data was divided by the FCC unit design capacity as reported in the Oil and Gas Journal (OGJ) to calculate the capacity utilization rate for the normal case. These normal capacity utilization rates were then scaled up to reflect maximum capacity utilization rates, and further adjusted using an overdesign factor.

For refineries projected to meet the proposed Tier 3 standards by revamping existing FCC posttreating units we assumed that their maximum gasoline production rate was equal to the rate produced running the FCC unit at 92% of the refinery's maximum FCC design capacity. There were several refineries that are currently operating their FCC unit greater than a 92% capacity utilization rate. We assumed that these refineries were already operating at their maximum annual capacity utilization rate. For the refinery projected to install a new FCC posttreater, we similarly assumed that the new unit would be scaled to process the output of the FCC unit operating with a 92% utilization rate. For the new FCC posttreater, however, we increased the results by 15% as an overdesign factor and adjusted the results accordingly. A similar sizing approach was taken for refineries we projected would revamp or add new LSR hydrotreating capacity to comply with the proposed Tier 3 standards.

The results represent a "maximum" annual gasoline production case for each refinery under the Tier 3 standards based on each refiners FCC unit design capacity. These cases represent a scenario where each refinery's emissions based on the maximum achievable annual

production rate for their existing processing units. These cases reflect each refiner’s potential emissions impacts as a result of the proposed Tier 3 standards, relative to the existing Tier 2 standards, when operating at maximum FCC rates as opposed to normal operation more indicative of national gasoline demand.

#### 5.4.2 Refinery Demand Sourcing

After determining the increased demands for each refinery as a result of the proposed Tier 3 regulations we next developed cases for each refinery demand scenario that represented different options for sourcing these demands. Some refiners may choose to produce all of the required hydrogen and electricity. Others may choose to purchase some or all of the hydrogen and electricity that they would need to comply with the Tier 3 standards from external suppliers. These decisions have a significant impact on the emissions and permitting impacts of the proposed Tier 3 regulations. In order to bound all possible scenarios we considered both high and low impact cases for each refinery demand scenario. In the high impact scenarios we assume that each refinery produces all of the required hydrogen, and electricity needs. In the low impact scenarios we assume that all the necessary hydrogen and electricity are purchased from an external supplier.

In both cases we assumed that fuel gas demands would increase to meet the increased thermal demands at the refinery. In the high impact scenarios the refinery’s fuel gas needs would be further increased to produce the needed hydrogen and electricity. We consulted literature sources to determine the conversion factors from MBTU fuel gas to 1,000 standard cubic feet (scf) of hydrogen<sup>21</sup> and 1,000 pounds of steam<sup>22</sup> that are typical for refineries. We also assumed a standard conversion efficiency from fuel gas to electricity for our modeling. For hydrogen needs, in our emissions analysis, we presumed that fuel gas used to make hydrogen would only generate CO2 emissions, as we presumed that the conversion process was efficient. Fuel gas used as process energy needs in the hydrogen production process, however, we projected would emit the full range of emissions. All of the fuel gas demand estimates are shown in Table 5-37.

**Table 5-37 Fuel Gas Required to Produce Hydrotreater Utilities**

Utility	Fuel Gas Required (M BTU)
Hydrogen Process Energy (1,000 SCF)	140
Hydrogen Process Feed Needs (1,000 SCF)	248
Steam (1,000 lbs)	1530
Electricity (1 kWh)	5.1

We assumed that refiners would not need any additional energy needs to make up for lost octane, because our LP refinery modeling estimates that the utility demands associated with recovering the octane debit from Tier 3 was inconsequential. Refiners are expected to use reformers and other high octane processes, such as alkylation units, to cover any octane debit in FCC naphtha, by making minor shifts in operations which apparently does not impact utility

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demands. Also, in some cases lost octane could be recovered by purchasing high octane blendstocks which would result in no fuel gas or electricity demand increases at the refinery.

#### 5.4.3 Refinery Energy Demand Impacts

Using our refinery-by-refinery model, along with the technology vendor data for new and revamped FCC posttreating and LSR hydrotreating data (shown in Table 5-25 through Table 5-28 and Table 5-31), we were able to calculate the increases in refinery energy demands as a result of our proposed Tier 3 regulations for each of the various scenarios outlined in the previous sections. This information is summarized in Table 5-38 below. The refineries have been identified by randomly assigned numbers to protect confidential business information (CBI).

This information was submitted to our sister office, OAQPS, to serve as the basis for their emissions and permitting analysis of the Tier 3 regulations. Based on the updated refinery analysis, EPA determined that under the final Tier 3 gasoline sulfur standard, which includes national ABT, 9 refineries are projected to trigger New Source Review (NSR). This equates to approximately 8% of the 108 refineries. Of these 9 refineries, only 3 are projected to trigger permitting for both a NAAQS-related pollutants and GHGs while an additional 6 refineries are projected to require PSD permits addressing only GHG emissions. A technical memorandum describing the OAQPS analysis and results is in the public docket for this final rule.<sup>23</sup>

**Table 5-38 Tier 3 Maximum Refinery Energy, Hydrogen and Sulfur Plant Demand Increases for ABT Case**

Refinery Number	Demand Estimates					
	Fuel Gas Demands (Million BTU/Yr)			Sulfur Plant Production		Hydrogen
	Low Case	High Case	High Case Plus CO2 for Hydrogen	Sulfur Production Increase (Tons Sulfur/Day)	Sulfur Plant Capacity Increase (Percent of Existing Facility)	Hydrogen Demand Increase (million scf/year)
1	55,766	239,291	555,121	0.50	0.07	1529
2	494,692	579,106	690,241	0.44	0.04	462
3	0	0	0	0.00	0.00	0
4	50,404	125,517	252,794	0.04	0.08	501
5	0	0	0	0.00	0.00	0
6	125,277	344,410	561,788	0.88	No Data	867
7	140,263	215,618	345,295	0.30	0.09	524
8	1,152,149	1,403,863	1,743,848	0.86	0.12	1686
9	0	0	0	0.00	0.00	0
10	498,770	1,088,552	1,989,386	0.08	0.06	3638
11	0	0	0	0.00	0.00	0
12	512,053	618,649	766,760	0.68	0.18	595
13	32,553	113,349	210,888	0.25	0.21	394
14	181,259	259,280	370,586	0.45	0.10	450

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
15	0	0	0	0.00	0.00	0
16	184,692	279,786	443,434	0.05	0.03	661
17	0	0	0	0.00	0.00	0
18	592,842	464,226	485,068	0.27	0.50	88
19	579,988	721,733	918,750	0.26	0.26	811
20	2,169,093	2,506,050	2,863,334	0.78	0.09	1441
21	0	0	0	0.00	0.00	0
22	29,522	115,563	169,530	0.56	0.04	217
23	127,534	358,933	594,542	2.20	0.00	0
24	53,024	129,662	259,460	0.41	0.28	536
25	0	0	0	0.00	0.00	0
26	0	0	0	0.00	0.00	0
27	19,972	81,398	123,448	0.25	0.11	167
28	1,040,992	1,309,416	1,716,105	0.30	0.06	1633
29	0	0	0	0.00	0.00	0
30	0	0	0	0.00	0.00	0

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
31	0	0	0	0.00	0.00	0
32	0	0	0	0.00	0.00	0
33	0	0	0	0.00	0.00	0
34	24,527	64,717	102,608	0.10	0.06	153
35	0	0	0	0.00	0.00	0
36	0			0.00	0.00	0
37	0	0	0	0.00	0.00	
38	50,152	200,906	396,393	0.88	0.41	786
39	76,080	158,367	202,974	0.28	0.07	180
40	90,268	142,703	232,938	0.12	0.09	364
41	25,536	53,123	99,593	0.01	0.05	188
42	22,695	71,902	127,645	0.27	0.22	186
43	724,372	929,979	1,225,219	0.40	0.04	1187
44	597,780	803,621	1,157,854	0.60	0.04	1307
45	0	0	0	0.00	0.00	0
46	21,128	32,402	51,803	0.07	0.69	78

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
47	1,421,831	1,530,970	1,643,335	0.47	0.12	454
48	99,075	113,173	122,179	0.56	0.19	0
49	0	0	0	0.00	0.04	0
50	43,263	81,700	146,144	0.31	0.03	249
51	0	0	0	0.00	0.00	0
52	33,128	118,783	223,948	0.31	0.09	425
53	0	0	0	0.00	0.00	0
54	0	0	0	0.00	0.00	0
55	0	0	0	0.00	0.00	0
56	1,433,373	1,661,638	1,955,563	0.77	0.04	1172
57	124,488	152,511	192,146	0.16	No Data	165
58	0	0	0	0.00	0.00	0
59	868,124	1,123,388	1,492,456	0.59	0.09	1366
60	62,323	101,795	169,723	0.14	0.70	331
61	0	0	0	0.00	0.00	0
62	634,584	760,395	933,119	0.34	0.14	605

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
63	0	0	0	0.00	0.00	0
64	177,667	249,774	359,493	0.27	0.63	443
65	666,474	766,007	891,308	0.52	0.05	502
66	0	0	0	0.00	0.00	0
67	276,071	504,649	834,842	0.37	0.09	1170
68	173,066	242,782	362,756	0.37	0.91	435
69	0	0	0	0.00	0.00	0
70	0	0	0	0.00	0.00	0
71	358,243	508,962	768,333	0.63	0.07	976
72	18,780	78,287	180,693	0.13	0.10	0
73	396,525	470,283	569,854	0.42	0.26	400
74	71,768	210,552	357,881	0.18	0.01	595
75	96,393	185,026	325,957	0.24	0.05	297
76	0	0	0	0.00	0.04	0
77	0	0	0	0.00	0.00	0
78	0	0	0	0.00	0.00	0

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
79	581,482	734,018	956,397	0.73	0.09	895
80	34,842	87,838	177,666	0.19	0.06	663
81	70,820	90,336	119,036	0.15	0.09	113
82	0	0	0	0.00	0.00	0
83	144,344	489,552	899,581	0.56	0.07	1653
84	30,605	51,089	86,339	0.11	0.90	142
85	0	0	0	0.00	0.00	0
86	48,840	109,034	210,697	0.36	0.03	381
87	0	0	0	0.00	0.00	0
88	0	0	0	0.00	0.00	0
89	454,267	689,362	1,093,938	0.23	0.06	1708
90	0	0	0	0.00	0.00	0
91	221,368	386,207	669,879	0.34	No Data	1001
92	48,475	98,562	182,847	0.18	0.02	310
93	0	0	0	0.00	0.00	0
94	60,159	130,128	248,169	0.28	0.15	476

Refinery Number	Demand Estimates					
	Fuel Gas Demands			Sulfur Plant Production		Hydrogen
	(Million BTU/Yr)			Sulfur	Sulfur Plant	Hydrogen
95	22,121	71,369	127,917	0.14	0.22	237
96	31,063	182,172	442,216	0.39	0.73	822
97	0	0	0	0.00	0.00	0
98	0	0	0	0.00	0.00	0
99	64,964	99,342	158,505	0.09	0.05	238
100	16,472	33,132	61,154	0.08	No Data	119
101	145,657	151,780	158,099	0.16	4.32	25
102	0	0	0	0.00	0.00	0
103	0	0	0	0.00	0.00	0
104	37,609	122,658	221,067	0.17	0.13	397
105	57,350	100,794	173,298	0.15	0.01	0
106	96,148	164,991	283,464	0.17	No Data	403
107	23,486	86,923	195,167	0.19	0.16	437
108	18,721	63,065	115,508	0.10	0.21	212

<sup>a</sup> The refinery did not have published information on the capacity of the existing sulfur plant.

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## **5.5 Fuel Quality Requirements for Denatured Fuel Ethanol**

### **5.5.1 Costs for Producers and Importers of Denatured Fuel Ethanol**

The State of California's has a long-standing 10 ppm sulfur requirement for denatured fuel ethanol (DFE). Do to logistical issues associated with maintaining a separate DFE pool that complies with California requirements, all DFE manufacturers currently produce California compliant DFE. Therefore, we expect that there will be only minimal additional costs to DFE producers as a result of the Tier 3 program associated with new recordkeeping and product transfer document requirements as discussed in the Information Collection Request (ICR) for the Tier 3 rule.

### **5.5.2 Costs for Producers and Distributors of Ethanol Denaturants**

Suppliers of denaturants for use in manufacturing denatured fuel ethanol (DFE) are already accustomed to providing product with a sulfur content that is consistent with a 10 ppm sulfur cap for DFE as discussed in Chapter 5.4.1. Denaturant manufacturers will be required to maintain per batch test records on the denaturants they produce to demonstrate that the sulfur content does not exceed 200 ppm. As discussed in Section V of the preamble to the Tier 3 final rule, that addition of denaturant with sulfur content of 200 ppm would result in DFE with a sulfur content of 10 ppm when blended at 5 volume percent into neat ethanol. As is current practice today, we anticipate that ethanol manufacturers will negotiate what specific sulfur level they require from denaturant manufacturers to facilitate with compliance with the 10 ppm sulfur cap for DFE considering what level of compliance margin a given manufacturer feels is necessary. We understand that ethanol manufacturers often currently require denaturant manufacturers to provide a product with a sulfur content of 120 ppm or less in order to ensure that DFE that contains 5 volume percent denaturant can comply with California's 10 ppm sulfur cap for DFE. Therefore, we expect that there will be no additional processing costs to manufacture denaturant for use in the manufacture of DFE meting the Tier 3 program 10 ppm sulfur cap.

As discussed in the Information Collection Request (ICR) for the Tier 3 rule, there will only be minimal additional costs to ethanol denaturant producers and importers to comply with the Tier 3 requirements associated with the registration, maintenance of denaturant testing records, and generation of product transfer documents (PTDs). There will also be minimal additional costs for distributors of ethanol denaturants associated with maintaining ethanol denaturant product transfer documents.

## **5.6 Gasoline Additives**

The Tier 3 rule requires that manufacturers of gasoline additives used downstream of the refinery at less than 1 volume percent must limit the sulfur contribution to the finished gasoline from the use of their additive to less than 3 ppm when the additive is used at the maximum recommended treatment rate. All current gasoline additives contribute less than 3 ppm to the sulfur content of the finished fuel when used at the maximum recommended treatment rate (with 3 ppm being the extreme). Normal additive production quality control practices already have had to consider the sulfur contribution of the additive to finished gasoline as a result of the Tier 2 gasoline sulfur program. Therefore, the Tier 3 requirements will not necessitate the

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reformulation of any gasoline additives or additional additive production quality testing. The maximum recommended treatment rate is already stated on product transfer document or packaging for the additive. Hence, no changes will be needed to the product transfer documents for gasoline additives. The only additional burden for additive manufacturers will be to retain production quality control records for 5 years and make these available to EPA upon request. Therefore, the Tier 3 program requirements will not result in significant additional costs to gasoline additive manufacturers.

### **5.7 Downstream Pentane Blending**

The Tier 3 program provisions that will facilitate the blending of pentane into previously certified gasoline at terminals will provide additional flexibility to industry. The associated requirements are described in Section VI.A. of the preamble to the Tier 3 final rule. We expect that the cost savings in reduced gasoline costs from downstream pentane blending will substantially outweigh the associated compliance costs. Industry will only take advantage of the pentane blending provisions, and be subject to the associated compliance costs, the extent that there is a substantial cost motive to do so. Therefore, we are not assessing any costs associated with the Tier 3 pentane blending provisions. In addition, pentane blending will likely be used in place of the butane blending already allowed. Consequently, there would be no new increase in the amount of testing and recordkeeping.

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## Appendix A

### Linear Program Refinery Modeling Tables

**Table 5-39 – Summary of LP Refinery Modeling Output Information and the Resulting Cost of Octane Used in the Refinery-by-Refinery Cost Model**

(Cost of Recovering 1 Octane Number Loss in FCC Naphtha, no E15 in Gasoline Pool and Low NGL Prices)

		US Total	PADD 1	PADD 2	PADD 3	PADD 4/5
Control Case	Summer	374463	32827	93577	221108	26951
FCC naphtha volume (thousand bbls)	Winter	425601	53282	116134	218249	37936
	Annual	800,064				
Objective Function (thousand dollars)	Reference Case	-118884419				
	Control Case	-118634411				
Change in Obj Funct		-250.008				
Cost		0.312	\$ /octane-bbl			
		0.744	c /octane-gal			

**Table 5-40 – Summary of LP Refinery Model Estimated Regular and Premium Marginal Production Costs and the Calculated Cost of Octane - Not Used in Refinery Cost Analysis**

(No E15 in Gasoline Pool and Low NGL Prices)

		Octane Number	Marginal Price		Cost Difference			
		(R+M)/2	Premium	Regular	c/gal	\$/bbl		
Summer	PADD 1	93	264.36	254.27	10.09	4.2378		
	PADD 2	93	261.71	253.49	8.22	3.4524		
	PADD 3	93	262.31	252.23	10.08	4.2336		
	PADD 4/5 OC	91.5	259.72	251.99	7.73	3.2466		
Winter	PADD 1	93	248.17	243.06	5.11	2.1462		
	PADD 2	93	221.55	218.09	3.46	1.4532		
	PADD 3	93	249.58	244.47	5.11	2.1462		
	PADD 4/5 OC	91.5	243.63	240.07	3.56	1.4952		
Annual Average							\$/ON-bbl	c/ON-gal
	PADD 1					3.192	0.532	1.266667
	PADD 2					2.4528	0.4088	0.973333
	PADD 3					3.1899	0.53165	1.265833
	PADD 4/5 OC					2.3709	0.526867	1.254444
US							0.495089	1.178783

**Table 5-41 – PADDs 1 and 2 – Modeled Refinery Purchase Volumes for Reference and Low Octane LP Refinery Modeling Cases (thousand bbl/day)**

	PADD 1						PADD 2					
	Summer			Winter			Summer			Winter		
	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.
PADD Crude	1,058	1,022	-36	1,728	1,728	0	2,903	2,924	21	4,245	4,246	1
GTL Naphtha	0	0	0	0	0	0	0	0	0	0	0	0
GTL Diesel	0	0	0	0	0	0	0	0	0	0	0	0
VGO HS	0	0	0	0	0	0	0	0	0	0	0	0
VGO LS	115	170	54	76	76	0	90	90	0	1	1	0
HS AR (A960)	0	0	0	0	0	0	0	0	0	0	0	0
LS AR (Alg)	47	66	19	0	0	0	0	0	0	0	0	0
Normal Butane	7	3	-4	166	165	-1	23	31	8	200	200	0
Isobutane	12	12	0	16	16	0	57	53	-4	56	56	0
MTBE	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol - E10	311	310	0	295	295	0	238	238	0	231	231	0
Ethanol - E15	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol - E85	21	21	0	20	20	0	16	16	0	15	15	0
Reformer Feed	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (FOE)	73	74	1	100	99	-1	201	198	-3	219	220	2
Hydrogen (MSCF)	0	0	0	0	0	0	0	0	0	0	0	0
Pentanes Plus	0	0	0	0	0	0	238	214	-24	0	0	0
Import CBOB 10% Reg	0	4	4	0	2	2	0	6	6	0	3	3
Import CBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0
Import RBOB 10% Reg	0	1	1	0	2	2	0	0	0	0	0	0
Import RBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0
Import Alkylate	0	0	0	0	0	0	0	0	0	0	0	0
Import Raffinate	25	25	0	50	50	0	0	0	0	0	0	0
Import Reformate	0	0	0	0	0	0	0	0	0	0	0	0
Import FCC Naphtha	0	0	0	0	0	0	0	0	0	0	0	0
Import Lt Naphtha	0	0	0	0	0	0	0	0	0	0	0	0
Import Hvy Naph	81	53	-28	0	0	0	0	0	0	0	0	0
Transfer Lt Naphtha	0	22	22	0	0	0	0	22	22	0	0	0
Transfer Reformate	0	68	68	0	0	0	0	0	0	0	0	0
Transfer Alkylate	0	23	23	0	0	0	0	0	0	0	0	0
Transfer FCC Naphtha	0	0	0	0	0	0	0	29	29	0	0	0
Transfer Raffinate	0	0	0	0	0	0	0	88	88	0	0	0
Transfer CBOB 10% Reg	0	1,508	1,508	0	1,254	1,254	0	116	116	0	0	0
Transfer CBOB 10% Prem	0	197	197	0	144	144	0	0	0	0	0	0
Transfer RBOB 10% Reg	0	260	260	0	275	275	0	0	0	0	0	0
Transfer RBOB 10% Prem	0	104	104	0	87	87	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0	0	0	0	0	0
Isooctene	0	0	0	0	0	0	0	0	0	0	0	0

**Table 5-42 – PADDs 3, 4 and 5 non-California - Modeled Refinery Purchase Volumes for Reference and Low Octane LP Refinery Modeling Cases (thousand bbl/day)**

	PADD 3						PADD 4/5 nonCA						US Total					
	Summer			Winter			Summer			Winter			Summer			Winter		
	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.
PADD Crude	7,408	7,409	1	6,368	6,377	9	1,437	1,425	-12	1,452	1,441	-12	12,806	12,781	-25	13,794	13,792	-2
GTL Naphtha	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GTL Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VGO HS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VGO LS	0	0	0	0	0	0	0	0	0	0	0	0	205	260	54	77	77	0
HS AR (A960)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LS AR (Alg)	750	750	0	750	750	0	0	0	0	0	0	0	797	816	19	750	750	0
Normal Butane	37	34	-2	216	216	0	24	24	0	77	75	-2	90	92	2	659	656	-3
Isobutane	0	0	0	0	0	0	6	7	1	3	3	1	75	72	-3	75	75	1
MTBE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol - E10	142	142	0	137	137	0	80	80	0	76	76	0	771	770	0	739	739	0
Ethanol - E15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol - E85	10	10	0	9	9	0	5	5	0	5	5	0	51	51	0	49	49	0
Reformer Feed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (FOE)	627	626	-1	607	606	-1	96	95	-1	100	99	-2	996	992	-4	1026	1024	-2
Hydrogen (MSCF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pentanes Plus	250	250	0	0	0	0	60	60	0	0	13	13	548	524	-24	0	13	13
Import CBOB 10% Reg	0	0	0	0	0	0	2	2	0	1	1	0	2	12	10	1	7	6
Import CBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import RBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	2	2
Import RBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import Alkylate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import Raffinate	0	0	0	0	0	0	10	10	0	0	0	0	35	35	0	50	50	0
Import Reformate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import FCC Naphtha	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import Lt Naphtha	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import Hvy Naph	100	100	0	0	0	0	0	0	0	0	0	0	181	153	-28	0	0	0
Transfer Lt Naphtha	0	0	0	0	0	0	0	0	0	0	0	0	0	44	44	0	0	0
Transfer Reformate	0	0	0	0	0	0	0	0	0	0	0	0	0	68	68	0	0	0
Transfer Alkylate	0	0	0	0	0	0	0	0	0	0	0	0	0	23	23	0	0	0
Transfer FCC Naphtha	0	0	0	0	0	0	0	0	0	0	0	0	0	29	29	0	0	0
Transfer Raffinate	0	0	0	0	0	0	0	0	0	0	0	0	0	88	88	0	0	0
Transfer CBOB 10% Reg	0	0	0	0	0	0	50	60	11	0	0	0	50	1684	1634	0	1254	1254
Transfer CBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0	0	197	197	0	144	144
Transfer RBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0	0	260	260	0	275	275
Transfer RBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0	0	104	104	0	87	87
Isocutane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Isocutene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

**Table 5-43 – PADDs 1 and 2 – Modeled Refinery Sale Volumes for Reference and Low Octane Cases (thousand bbl/day)**

	PADD 1						PADD 2					
	Summer			Winter			Summer			Winter		
	Ref	Control	Dif.									
Propane	13	14	2	21	22	1	49	50	1	58	58	0
Propylene	25	25	0	25	25	0	40	40	0	40	40	0
Normal Butane	0	0	0	0	0	0	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0	0	0	0	0	0	0
PC Naphtha	25	25	0	16	16	0	50	50	0	40	40	0
PC Gasoil	0	0	0	0	0	0	0	0	0	1,031	1,031	0
CG Reg	0	0	0	0	0	0	0	0	0	0	0	0
CG Prem	0	0	0	0	0	0	0	0	0	0	0	0
CG E10 Reg	1,669	1,669	0	1,562	1,562	0	1,785	1,785	0	1,721	1,721	0
CG E10 Prem	219	217	-2	168	168	0	227	227	0	219	219	0
RFG E10 Reg	1,072	1,072	0	1,057	1,057	0	302	302	0	305	305	0
RFG E10 Prem	115	115	0	139	139	0	38	38	0	39	39	0
CG E15 Reg	0	0	0	0	0	0	0	0	0	0	0	0
RFG E15 Reg	0	0	0	0	0	0	0	0	0	0	0	0
E85 to CG	17	17	0	16	16	0	18	18	0	17	17	0
E85 to RFG	11	11	0	11	11	0	3	3	0	3	3	0
Transfer CBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0
Transfer CBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0
Transfer RBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0
Transfer RBOB 10% Prem	0	0	0	0	0	0	0	0	0	0	0	0
Export CBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0
Export RBOB 10% Reg	0	0	0	0	0	0	0	0	0	0	0	0
Jet/Kero A (450ppm)	70	70	0	70	70	0	189	189	0	185	185	0
X-Fer Diesel Rundown to St	0	0	0	0	0	0	0	0	0	0	0	0
HSD Gr 76 (0.2%)	0	0	0	0	0	0	0	0	0	0	0	0
LSD Gr 74 (.05%)	0	0	0	0	0	0	0	0	0	0	0	0
ULSD (15 ppm)	469	469	0	820	820	0	767	752	-15	680	680	0
CARB Diesel	0	0	0	0	0	0	0	0	0	0	0	0
X-Fer C5's to Storage	0	0	0	0	0	0	0	0	0	0	0	0
1% Residual Fuel	0	0	0	0	0	0	0	0	0	0	0	0
Residual Fuel	30	30	0	50	50	0	39	39	0	39	39	0
Slurry	0	0	0	40	40	0	80	78	-2	97	97	0
Asphalt & Wax	118	118	0	73	73	0	210	210	0	210	210	0
Gasoil	0	0	0	0	0	0	10	10	0	8	8	0
Lubes	19	19	0	19	19	0	8	8	0	8	8	0
Benzene	2	2	0	2	2	0	19	19	0	22	22	0
Toluene	0	0	0	0	0	0	0	0	0	0	0	0
Xylenes	0	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Raffinate	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Alkylate	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Reformate	0	0	0	0	0	0	0	0	0	0	0	0
Transfer FCC naphtha	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Lt Naphtha	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Blendstock	0	0	0	0	0	0	0	0	0	0	0	0
Sulfur (STons)	5	5	0	8	8	0	20	21	0	26	26	0
Coke (STon)	6	5	-1	42	42	0	41	41	-1	95	95	0

**Table 5-44 – PADDs 3, 4 and 5 non-California – Modeled Refinery Sale Volumes for Reference and Low Octane Cases (thousand bbl/day)**

	PADD 3						PADD 4/5 nonCA						US Total					
	Summer			Winter			Summer			Winter			Summer			Winter		
	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.	Ref	Control	Dif.
Propane	101	103	2	69	70	1	17	17	0	17	17	0	179	184	4	164	167	2
Propylene	250	250	0	250	250	0	15	15	0	15	15	0	330	330	0	330	330	0
Normal Butane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Isobutane	4	0	-4	0	0	0	0	0	0	0	0	0	4	0	-4	0	0	0
PC Naphtha	550	550	0	433	433	0	0	0	0	0	0	0	625	625	0	489	489	0
PC Gasoil	158	158	0	158	158	0	0	0	0	0	0	0	158	158	0	1189	1189	0
CG Reg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CG Prem	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CG E10 Reg	968	968	0	930	930	0	686	686	0	650	650	0	5108	5108	0	4862	4862	0
CG E10 Prem	74	74	0	71	71	0	107	107	0	101	101	0	627	625	-2	559	559	0
RFG E10 Reg	334	334	0	325	325	0	0	0	0	0	0	0	1708	1708	0	1687	1687	0
RFG E10 Prem	33	33	0	31	32	1	0	0	0	0	0	0	187	187	0	208	210	1
CG E15 Reg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RFG E15 Reg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E85 to CG	10	10	0	9	9	0	7	7	0	6	6	0	51	51	0	49	49	0
E85 to RFG	3	3	0	3	3	0	0	0	0	0	0	0	17	17	0	17	17	0
Transfer CBOB 10% Reg	1,718	1,684	-33	1,251	1,254	4	0	0	0	0	0	0	1718	1684	-33	1251	1254	4
Transfer CBOB 10% Prem	198	197	-2	144	144	0	0	0	0	0	0	0	198	197	-2	144	144	0
Transfer RBOB 10% Reg	259	260	1	242	275	34	0	0	0	0	0	0	259	260	1	242	275	34
Transfer RBOB 10% Prem	104	104	-1	120	87	-34	0	0	0	0	0	0	104	104	-1	120	87	-34
Export CBOB 10% Reg	7	12	4	7	7	0	0	0	0	0	0	0	7	12	4	7	7	0
Export RBOB 10% Reg	1	1	0	2	2	0	0	0	0	0	0	0	1	1	0	2	2	0
Jet/Kero A (450ppm)	895	895	0	819	819	0	233	233	0	236	236	0	1387	1387	0	1310	1310	0
X-Fer Diesel Rundown to S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HSD Gr 76 (0.2%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSD Gr 74 (.05%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ULSD (15 ppm)	2,119	2,135	15	2,091	2,091	0	518	517	-1	513	513	0	3874	3873	-1	4104	4104	0
CARB Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
X-Fer C5's to Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1% Residual Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual Fuel	125	125	0	125	125	0	39	37	-1	33	32	-1	233	231	-1	247	246	-1
Slurry	157	157	0	102	102	1	20	20	0	20	20	0	257	256	-2	259	260	1
Asphalt & Wax	250	250	0	250	250	0	30	30	0	30	30	0	608	608	0	563	563	0
Gasoil	0	0	0	0	0	0	0	0	0	0	0	0	10	10	0	8	8	0
Lubes	158	158	0	158	158	0	0	0	0	0	0	0	184	184	0	184	184	0
Benzene	51	51	0	50	50	0	0	0	0	0	0	0	72	72	0	74	74	0
Toluene	34	34	0	34	35	0	0	0	0	0	0	0	34	34	0	34	35	0
Xylenes	8	8	0	8	8	0	0	0	0	0	0	0	8	8	0	8	8	0
Cumene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transfer Raffinate	90	89	-1	1	1	0	0	0	0	0	0	0	90	89	-1	1	1	0
Transfer Alkylate	120	83	-37	1	1	0	0	0	0	0	0	0	120	83	-37	1	1	0
Transfer Reformate	63	68	5	0	0	0	0	0	0	0	0	0	63	68	5	0	0	0
Transfer FCC naphtha	0	29	29	0	0	0	0	0	0	0	0	0	29	29	0	0	0	0
Transfer Lt Naphtha	5	22	17	0	0	0	0	0	0	0	0	0	5	22	17	0	0	0
Transfer Blendstock	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sulfur (STons)	64	64	0	55	55	0	10	10	0	11	11	0	99	100	1	99	99	0
Coke (STon)	237	237	0	173	174	0	44	43	0	44	43	0	328	326	-2	354	354	0

**Table 5-45 - PADD 1 Modeled Refinery Unit Throughput Volumes for Reference and Low Octane Cases (Thousand bbl/day)**

PADD 1 Refinery Units	Actual Capacity in 2012	2018 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,250	1,058	1,728	1,022	1,728	-36	0
Vacuum Tower	560	454	731	442	731	-11	0
Sats Gas Plant	0	52	64	51	66	0	2
Unsats Gas Plant	0	123	151	142	151	19	0
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	494	467	550	535	550	68	0
FCC Splitter	0	257	298	296	298	39	0
Hydrocracker	44	44	49	44	49	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	82	25	172	21	172	-4	0
Visbreaker	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	3	21	3	21	0	0
CRU Reformer	239	102	124	101	162	-1	39
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	11	11	11	11	0	0
C4 Isomerization	18	16	16	16	16	0	0
C5/C6 Isomerization	9	9	0	9	0	0	0
HF Alkylation	49	44	44	44	44	0	0
H2SO4 Alkylation	34	51	65	58	66	7	1
Dimersol	0	0	0	0	0	0	0
Cat Poly	6	1	6	6	6	5	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	585	454	807	454	807	0	0
DHT 2nd RCT - Total	0	416	746	416	746	0	0
DHT Arom Saturation	0	0	0	0	0	0	0
NHT - Total Fd	371	175	316	170	316	-5	0
CGH - Generic	211	152	152	152	152	0	0
CGH - Olefin Sat'n	211	0	0	0	0	0	0
FCCU Fd HDT	44	40	40	40	40	0	0
LSR Splitter	0	49	87	47	87	-2	0
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	6	1	6	1	0	0
Reformate Splitter	0	19	3	19	3	0	0
SDA	33	5	15	5	15	0	0
MTBE	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	113	493	695	519	673	25	-23
Lube Unit	58	53	53	53	53	0	0
Sulfur Plant	1	1	1	1	1	0	0
Mercox Jet	0	0	0	0	0	0	0
Mercox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	4	4	4	4	4	0	0
BTX Reformer - Extract feed	9	9	9	9	9	0	0
Toluene Dealkylation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

**Table 5-46 - PADD 2 Modeled Refinery Unit Throughput Volumes for Reference and Low Octane Cases (Thousand bbl/day)**

PADD 2 Refinery Units	Actual Capacity in 2012	2018 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	4,005	2,903	4,245	2,924	4,246	21	1
Vacuum Tower	1,707	1,229	1,840	1,221	1,841	-8	0
Sats Gas Plant	0	138	144	141	144	3	0
Unsats Gas Plant	0	301	330	296	330	-6	0
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	1,314	1,066	1,134	1,047	1,134	-19	0
FCC Splitter	0	616	649	603	649	-12	0
Hydrocracker	307	276	276	276	276	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	508	168	388	166	388	-3	0
Visbreaker	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	20	47	20	47	0	0
CRU Reformer	859	428	550	483	550	55	0
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	100	127	100	127	0	0
C4 Isomerization	28	25	25	25	25	0	0
C5/C6 Isomerization	178	153	118	156	150	2	32
HF Alkylation	175	157	150	157	157	0	7
H2SO4 Alkylation	98	104	104	97	97	-6	-6
Dimersol	3	0	3	0	3	0	0
Cat Poly	5	0	8	0	9	0	1
Isooctane	0	0	0	0	0	0	0
DHT - Total	1,526	789	633	770	634	-19	0
DHT 2nd RCT - Total	0	588	441	572	441	-16	0
DHT Arom Saturation	6	0	0	0	0	0	0
NHT - Total Fd	1,324	620	965	677	966	57	0
CGH - Generic	511	318	232	312	232	-6	0
CGH - Olefin Sat'n	511	0	0	0	0	0	0
FCCU Fd HDT	576	518	518	518	518	0	0
LSR Splitter	0	57	85	59	86	3	1
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	1	1	1	1	0	0
Reformate Splitter	0	3	3	3	3	0	0
SDA	54	54	54	54	54	0	0
MTBE	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	956	1,170	1,171	1,108	1,176	-62	5
Lube Unit	25	23	23	23	23	0	0
Sulfur Plant	8	4	5	4	5	0	0
Merox Jet	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	43	37	43	37	43	0	0
BTX Reformer - Extract feed	80	80	80	80	80	0	0
Toluene Dealkylation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

**Table 5-47 - PADD 3 Modeled Throughput Volumes for Refinery Units for Reference and Low Octane Cases (Thousand bbl/day)**

PADD 3 Refinery Units	Actual Capacity in 2012	2018 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	9,567	7,408	6,368	7,409	6,377	1	9
Vacuum Tower	4,778	3,382	2,882	3,383	2,885	1	4
Sats Gas Plant	0	424	366	428	369	4	3
Unsats Gas Plant	0	843	736	848	738	5	3
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	3,120	2,736	2,089	2,736	2,097	0	9
FCC Splitter	0	1,515	1,109	1,511	1,114	-4	4
Hydrocracker	1,029	1,037	1,037	1,037	1,037	0	0
H-Oil Unit	0	110	110	110	110	0	0
Delayed Coker	1,604	859	629	859	631	0	2
Visbreaker	51	46	46	46	46	0	0
Thermal Naphtha Splitter	0	104	77	104	77	0	0
CRU Reformer	1,665	909	725	945	750	36	25
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	256	256	256	256	0	0
C4 Isomerization	95	86	70	86	71	0	1
C5/C6 Isomerization	323	0	0	13	0	13	0
HF Alkylation	297	267	190	267	186	0	-4
H2SO4 Alkylation	311	280	280	287	287	7	7
Dimersol	19	0	0	0	0	0	0
Cat Poly	22	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	4,339	2,230	2,107	2,246	2,106	17	0
DHT 2nd RCT - Total	0	1,643	1,643	1,659	1,643	16	0
DHT Arom Saturation	4	0	0	0	0	0	0
NHT - Total Fd	2,677	1,078	888	1,080	909	2	20
CGH - Generic	1,613	690	396	673	398	-18	1
CGH - Olefin Sat'n	1,613	0	0	0	0	0	0
FCCU Fd HDT	1,822	1,640	1,640	1,640	1,640	0	0
LSR Splitter	0	1	1	1	1	0	0
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	10	1	10	1	0	0
Reformate Splitter	0	30	3	30	3	0	0
SDA	433	389	389	389	389	0	0
MTBE	28	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	2,004	4,287	4,301	4,282	4,286	-5	-15
Lube Unit	530	440	440	440	440	0	0
Sulfur Plant	27	13	11	13	11	0	0
Mercox Jet	0	0	0	0	0	0	0
Mercox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	93	93	93	93	93	0	0
BTX Reformer - Extract feed	204	204	204	204	204	0	0
Toluene Dealkylation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

**Table 5-48 - PADD 4 and 5 non-California Modeled Throughput Volumes for Refinery Units for Reference and Low Octane Cases (Thousand bbl/day)**

PADD 4 and 5 nonCA Refinery Units	Actual Capacity in 2012	2018 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,791	1,437	1,452	1,425	1,441	-12	-12
Vacuum Tower	637	647	650	642	645	-5	-5
Sats Gas Plant	0	64	68	62	67	-1	-1
Unsats Gas Plant	0	104	105	103	104	-1	-1
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	368	376	376	374	374	-3	-3
FCC Splitter	0	146	147	143	145	-2	-2
Hydrocracker	128	130	146	130	146	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	173	154	155	152	153	-2	-2
Visbreaker	56	0	0	0	0	0	0
Thermal Naphtha Splitter	0	18	18	18	18	0	0
CRU Reformer	0	92	95	98	106	6	11
SRU Reformer	273	0	0	0	0	0	0
BTX Reformer	0	0	0	0	0	0	0
C4 Isomerization	26	23	23	23	23	0	0
C5/C6 Isomerization	45	41	0	41	0	0	0
HF Alkylation	39	39	39	39	39	0	0
H2SO4 Alkylation	47	48	48	47	47	-1	-1
Dimersol	1	0	0	0	0	0	0
Cat Poly	10	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	584	557	559	551	553	-6	-6
DHT 2nd RCT - Total	0	404	404	398	398	-6	-6
DHT Arom Saturation	0	0	0	0	0	0	0
NHT - Total Fd	391	297	300	295	297	-3	-3
CGH - Generic	132	107	107	107	107	0	0
CGH - Olefin Sat'n	132	0	0	0	0	0	0
FCCU Fd HDT	121	109	109	109	109	0	0
LSR Splitter	0	100	100	100	100	0	0
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	1	10	1	8	0	-2
Reformate Splitter	0	3	30	3	24	0	-6
SDA	58	58	58	58	58	0	0
MTBE	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	518	679	722	665	704	-14	-17
Lube Unit	0	0	0	0	0	0	0
Sulfur Plant	2	2	2	2	2	0	0
Merox Jet	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	0	0	0	0	0	0	0
BTX Reformer - Extract feed	0	0	0	0	0	0	0
Toluene Dealkylation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

**Table 5-49 – PADDs 1-4 and 5 non-California Modeled Throughput Volumes for Refinery Units for Reference and Low Octane Cases (Thousand bbl/day)**

PADDs 1 -4 and 5 nonCA Refinery Units	Actual Capacity in 2012	2018 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	16,613	12,806	13,794	12,781	13,792	-25	-2
Vacuum Tower	7,683	5,712	6,103	5,688	6,102	-24	-1
Sats Gas Plant	0	677	642	682	647	5	4
Unsats Gas Plant	0	1,371	1,321	1,389	1,323	18	2
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	5,296	4,646	4,149	4,692	4,155	46	6
FCC Splitter	0	2,533	2,203	2,554	2,206	21	2
Hydrocracker	1,508	1,488	1,508	1,488	1,508	0	0
H-Oil Unit	0	110	110	110	110	0	0
Delayed Coker	2,366	1,207	1,344	1,198	1,344	-9	0
Visbreaker	107	46	46	46	46	0	0
Thermal Naphtha Splitter	0	145	162	144	162	-1	0
CRU Reformer	2,763	1,532	1,494	1,627	1,568	95	75
SRU Reformer	273	0	0	0	0	0	0
BTX Reformer	0	367	394	368	394	0	0
C4 Isomerization	168	151	135	151	136	0	1
C5/C6 Isomerization	556	203	118	218	150	15	32
HF Alkylation	560	508	424	508	426	0	3
H2SO4 Alkylation	490	483	497	490	498	7	0
Dimersol	23	0	4	0	4	0	0
Cat Poly	43	2	14	6	15	5	1
Isooctane	0	0	0	0	0	0	0
DHT - Total	7,034	4,030	4,106	4,021	4,100	-9	-6
DHT 2nd RCT - Total	0	3,052	3,234	3,045	3,228	-6	-6
DHT Arom Saturation	10	0	0	0	0	0	0
NHT - Total Fd	4,763	2,170	2,469	2,222	2,487	52	18
CGH - Generic	2,467	1,267	887	1,244	888	-24	2
CGH - Olefin Sat'n	2,467	0	0	0	0	0	0
FCCU Fd HDT	2,564	2,308	2,308	2,308	2,308	0	0
LSR Splitter	0	206	273	207	274	1	1
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	18	13	18	11	0	-2
Reformate Splitter	0	55	39	55	33	0	-6
SDA	577	506	516	506	516	0	0
MTBE	28	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	3,591	6,630	6,889	6,574	6,839	-56	-50
Lube Unit	614	515	515	515	515	0	0
Sulfur Plant	38	20	20	20	20	0	0
Mercox Jet	0	0	0	0	0	0	0
Mercox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	140	135	140	135	140	0	0
BTX Reformer - Extract feed	293	293	293	293	293	0	0
Toluene Dealkylation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

**Table 5-50 - PADD 1 - Gasoline Qualities Estimated by LP Refinery Modeling for Reference and Octane Recovery Cases**

PADD 1	2018 Reference Case						2018 minus 1ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	5.00	5.00	5.00	4.92	4.87	4.90	5.01	4.99	5.00	4.92	4.87	4.90
Density (lb/bbl)	259	261	260	255	254	255	260	261	260	255	254	255
Sulfur (ppm)	26	26	26	15	18	16	25	25	25	15	18	16
% at 200	57	54	56	60	62	61	56	54	56	60	62	61
% at 300	83	86	84	87	90	88	83	86	84	87	90	88
RVP (psi)	9.1	7.0	8.3	13.0	13.0	13.0	9.1	7.0	8.3	13.0	13.0	13.0
T10 (F)	125	139	131	100	101	101	125	139	131	100	101	101
T50 (F)	186	192	188	179	176	178	187	191	189	179	176	178
T90 (F)	328	316	323	310	300	306	329	316	324	310	300	306
Driveability	1067	1093	1077	991	974	984	1072	1092	1080	991	974	984
Vapor Lock	132	144	137	110	110	110	132	144	137	110	110	110
Aromatics (vol%)	21.8	18.7	20.6	17.6	16.1	17.0	23.2	18.9	21.5	17.6	16.1	17.0
Benzene (vol%)	0.61	0.59	0.60	0.61	0.63	0.62	0.61	0.61	0.61	0.61	0.63	0.62
Olefins (vol%)	10.8	8.7	9.9	10.7	9.6	10.2	10.1	8.9	9.6	10.7	9.6	10.2
Alcohol (vol%)	11.5	11.6	11.5	11.5	11.5	11.5	11.5	11.6	11.5	11.5	11.5	11.5
Oxygen (wt%)	4.27	4.29	4.28	4.34	4.35	4.34	4.27	4.29	4.28	4.34	4.35	4.34
Volume (Kbbl/day)	1,864,595	1,241,809	3,106,404	1,745,324	1,181,174	2,926,498	1,864,595	1,241,809	3,106,404	1,745,324	1,181,174	2,926,498

**Table 5-51 - PADD 2 - Gasoline Qualities Estimated by LP Refinery Modeling for Reference and Octane Recovery Cases**

PADD 2	2018 Reference Case						2018 minus 1ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.93	4.99	4.94	4.86	4.87	4.86	4.93	4.99	4.94	4.86	4.87	4.86
Density (lb/bbl)	259	260	259	257	257	257	259	259	259	257	257	257
Sulfur (ppm)	26	14	24	23	26	23	26	12	24	23	26	23
% at 200	60	57	60	62	62	62	61	57	60	62	62	62
% at 300	86	85	86	87	88	87	86	85	86	87	88	87
RVP (psi)	9.2	7.0	8.9	12.7	12.7	12.7	9.2	7.0	8.9	12.7	12.7	12.7
T10 (F)	125	139	127	103	102	103	125	139	127	103	102	103
T50 (F)	178	186	180	176	175	176	178	186	179	176	175	176
T90 (F)	317	321	318	311	309	311	317	321	318	311	309	311
Driveability	1033	1081	1040	986	982	985	1032	1079	1039	986	982	985
Vapor Lock	130	143	132	110	110	110	130	143	132	110	110	110
Aromatics (vol%)	21.5	20.6	21.4	19.9	18.7	19.8	21.6	20.3	21.4	19.9	18.7	19.8
Benzene (vol%)	0.64	0.68	0.64	0.55	0.67	0.57	0.61	0.67	0.62	0.55	0.67	0.57
Olefins (vol%)	8.1	4.8	7.6	9.2	10.6	9.4	8.5	4.9	7.9	9.2	10.6	9.4
Alcohol (vol%)	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Oxygen (wt%)	4.33	4.31	4.32	4.35	4.35	4.35	4.33	4.32	4.33	4.35	4.35	4.35
Volume (Kbbl/day)	2,068,931	349,978	2,418,909	1,959,358	346,825	2,306,183	2,068,931	349,978	2,418,909	1,959,358	346,825	2,306,183

**Table 5-52 - PADD 3 - Gasoline Qualities Estimated by LP Refinery Modeling for Reference and Octane Recovery Cases**

PADD 3	2018 Reference Case						2018 minus 10N in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	5.01	5.07	5.02	4.98	5.05	5.00	5.02	5.03	5.02	4.98	5.05	5.00
Density (lb/bbl)	259	260	260	257	257	257	260	260	260	257	257	257
Sulfur (ppm)	26	11	22	15	9	14	25	20	24	15	9	14
% at 200	58	55	57	59	52	57	58	57	58	59	52	57
% at 300	83	83	83	85	80	84	83	84	83	85	80	84
RVP (psi)	9.0	7.0	8.5	11.1	11.2	11.1	9.0	7.0	8.5	11.1	11.2	11.1
T10 (F)	125	139	129	112	112	112	126	139	129	112	112	112
T50 (F)	183	190	185	181	195	185	184	186	184	181	195	185
T90 (F)	330	330	330	318	341	324	331	326	330	318	341	324
Driveability	1061	1100	1072	1025	1087	1041	1065	1086	1071	1025	1087	1041
Vapor Lock	132	143	135	120	121	120	132	143	135	120	121	120
Aromatics (vol%)	22.2	19.3	21.5	19.0	18.0	18.7	23.5	19.8	22.5	19.0	18.0	18.7
Benzene (vol%)	0.61	0.51	0.59	0.62	0.36	0.55	0.62	0.67	0.63	0.62	0.36	0.55
Olefins (vol%)	10.8	4.4	9.1	11.2	1.7	8.7	10.2	6.6	9.2	11.2	1.7	8.7
Alcohol (vol%)	11.5	11.6	11.5	11.5	11.5	11.5	11.5	11.6	11.5	11.5	11.5	11.5
Oxygen (wt%)	4.27	4.32	4.28	4.30	4.31	4.30	4.26	4.32	4.27	4.30	4.31	4.30
Volume (Kbbl/day)	1,051,761	378,078	1,429,839	1,010,516	352,882	1,363,398	1,051,761	378,078	1,429,839	1,010,516	352,882	1,363,398

**Table 5-53 - PADD 4 and 5 non-California - Gasoline Qualities Estimated by LP Refinery Modeling for Reference and Octane Recovery Cases**

PADD 4/5 nonCA	2018 Reference Case						2018 minus 10N in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.90	0.00	4.90	4.87	0.00	4.87	4.90	0.00	4.90	4.87	0.00	4.87
Density (lb/bbl)	259	0	259	256	0	256	259	0	259	256	0	256
Sulfur (ppm)	22	0	22	28	0	28	20	0	20	28	0	28
% at 200	65	0	65	67	0	67	65	0	65	67	0	67
% at 300	93	0	93	93	0	93	93	0	93	93	0	93
RVP (psi)	9.3	0.0	9.3	12.6	0.0	12.6	9.3	0.0	9.3	12.6	0.0	12.6
T10 (F)	124	0	124	102	0	102	123	0	123	102	0	102
T50 (F)	170	0	170	165	0	165	170	0	170	165	0	165
T90 (F)	286	0	286	282	0	282	286	0	286	282	0	282
Driveability	978	0	978	926	0	926	978	0	978	926	0	926
Vapor Lock	129	0	129	110	0	110	129	0	129	110	0	110
Aromatics (vol%)	16.1	0.0	16.1	14.4	0.0	14.4	15.9	0.0	15.9	14.4	0.0	14.4
Benzene (vol%)	1.16	0.00	1.16	0.43	0.00	0.43	1.11	0.00	1.11	0.43	0.00	0.43
Olefins (vol%)	7.5	0.0	7.5	7.7	0.0	7.7	7.6	0.0	7.6	7.7	0.0	7.7
Alcohol (vol%)	11.6	0.0	11.6	11.6	0.0	11.6	11.6	0.0	11.6	11.6	0.0	11.6
Oxygen (wt%)	4.33	0.00	4.33	4.37	0.00	4.37	4.33	0.00	4.33	4.37	0.00	4.37
Volume (Kbbl/day)	801,247	0	801,247	758,461	0	758,461	801,247	0	801,247	758,461	0	758,461

**Table 5-54 - PADD 1 Gasoline Qualities Estimated by LP Refinery Modeling for Reference, E10 and E15 Cases**

Gasoline Qualities and Volume for PADD 1	2005 in 2030						E10						E15					
	Summer			Winter			Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	
Energy (MMBTU/bbl)	4.90	5.06	5.10	4.99	4.96	5.02	5.07	5.05	5.06	5.02	4.94	4.98	4.99	4.92	4.96	4.92	4.89	
Density (lb/bbl)	252.86	260.41	259.87	253.26	255.50	255.32	258.49	261.05	259.52	255.89	256.26	256.05	260.93	259.32	260.27	256.64	255.49	
Sulfur (ppm)	28.00	23.67	23.47	2.91	14.71	14.35	10.57	23.33	15.71	2.49	15.98	8.24	20.99	27.59	23.71	25.86	25.40	
% at 200	62.51	53.59	48.71	45.27	61.47	54.10	56.09	54.08	55.28	55.40	62.22	58.30	63.01	62.44	62.77	64.96	65.14	
% at 300	95.61	85.52	84.11	80.77	88.89	85.91	85.30	86.18	85.65	83.29	89.53	85.94	86.70	87.83	87.17	86.82	87.94	
RVP (psi)	8.40	7.00	7.76	13.95	12.96	12.38	9.40	7.00	8.43	13.17	12.96	13.08	8.40	7.00	7.82	12.68	12.85	
T10 (F)	128.15	139.22	134.25	98.33	101.74	105.33	123.48	138.75	129.63	99.94	101.49	100.60	129.78	138.64	133.43	102.09	102.18	
T50 (F)	174.28	192.49	202.45	209.47	176.41	191.45	187.38	191.49	189.04	188.80	174.87	182.86	173.26	174.42	173.73	169.28	168.91	
T90 (F)	272.12	317.99	324.41	339.58	302.70	316.22	318.99	315.01	317.39	328.14	299.79	316.06	312.62	307.52	310.52	312.10	307.01	
Driveability	987.19	1097.88	1126.11	1104.02	977.92	1041.25	1059.49	1092.27	1072.69	1036.80	970.86	1008.71	1020.79	1034.48	1026.43	968.09	962.01	
Vapor Lock	135.42	144.26	141.40	109.71	109.71	114.91	129.82	144.30	135.65	109.71	109.71	109.71	133.09	141.91	136.72	109.71	109.71	
Aromatics (vol%)	10.11	18.99	23.77	24.31	18.93	22.55	20.75	18.79	19.96	20.23	19.34	19.85	20.25	14.09	17.71	17.13	14.46	
Benzene (vol%)	0.72	0.58	0.67	0.92	0.59	0.65	0.52	0.58	0.54	0.54	0.59	0.56	0.76	0.90	0.81	0.50	0.45	
Olefins (vol%)	19.67	8.00	14.36	4.67	10.28	13.74	10.02	11.98	10.81	7.51	14.52	10.50	11.33	6.33	9.27	10.23	5.57	
Alcohol (vol%)	0.00	10.00	4.16	0.00	10.00	4.36	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	
Oxygen (wt%)	0.00	3.70	1.54	0.00	3.77	1.64	3.73	3.69	3.71	3.77	3.76	3.76	5.54	5.58	5.56	5.63	5.66	
Volumes (kbb/day)	21,942	1,111,857	2,671,322	160,860	1,121,901	2,574,564	1,681,574	1,134,711	2,816,285	1,504,982	1,116,727	2,621,709	1,754,900	1,229,826	2,984,726	1,570,606	1,165,422	

**Table 5-55 - PADD 2 Gasoline Qualities Estimated by LP Refinery Modeling for Reference, E10 and E15 Cases**

Gasoline Qualities and Volume for PADD 2	2005 in 2030						E10						E15					
	Summer			Winter			Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	
Energy (MMBTU/bbl)	4.91	5.02	4.93	5.02	4.75	4.97	4.92	5.02	4.94	4.89	4.85	4.89	4.92	4.91	4.92	4.87	4.77	
Density (lb/bbl)	256.73	260.54	257.33	256.45	252.44	255.79	257.04	260.49	257.61	258.44	256.94	258.19	259.31	259.23	259.30	260.25	256.17	
Sulfur (ppm)	25.00	19.56	24.15	25.31	24.84	25.24	24.87	21.47	24.31	23.87	22.21	23.60	28.00	28.00	28.00	28.00	25.11	
% at 200	60.99	54.39	59.95	49.26	71.10	52.81	60.45	54.40	59.45	57.80	60.38	58.22	64.60	64.60	64.60	63.37	70.07	
% at 300	89.09	85.63	88.54	82.83	94.01	84.65	88.51	85.71	88.05	85.60	87.22	85.86	87.92	89.19	88.12	84.75	89.69	
RVP (psi)	9.45	7.00	9.07	13.31	12.27	13.14	9.49	7.00	9.08	12.92	12.79	12.89	8.60	7.00	8.35	12.54	12.28	
T10 (F)	122.71	138.63	125.21	99.77	104.71	100.57	122.52	138.57	125.18	101.33	102.02	101.44	128.27	138.10	129.81	103.86	104.79	
T50 (F)	177.38	190.84	179.49	201.32	156.74	194.08	178.48	190.82	180.52	183.88	178.63	183.03	170.00	170.00	170.00	172.52	158.84	
T90 (F)	301.79	317.48	304.25	330.22	279.39	321.97	304.39	317.12	306.50	317.64	310.25	316.44	307.11	301.30	306.20	321.48	299.07	
Driveability	1012.88	1091.45	1025.20	1073.68	902.57	1045.90	1018.23	1091.08	1030.28	1014.05	992.49	1010.55	1003.99	1014.21	1005.59	987.23	927.90	
Vapor Lock	128.45	143.42	130.80	110.29	110.29	110.29	128.34	143.45	130.84	110.29	110.29	110.29	131.67	140.71	133.09	110.29	110.29	
Aromatics (vol%)	17.74	20.00	18.09	27.75	14.77	25.65	18.28	20.00	18.56	21.33	19.82	21.08	18.08	15.28	17.64	22.09	16.01	
Benzene (vol%)	0.54	0.58	0.55	0.51	0.58	0.52	0.52	0.58	0.53	0.51	0.55	0.51	0.55	0.75	0.58	0.64	0.77	
Olefins (vol%)	8.92	7.09	8.63	11.80	9.37	11.40	8.89	7.39	8.64	11.07	10.30	10.94	8.37	7.31	8.20	11.03	11.17	
Alcohol (vol%)	9.59	10.00	9.65	0.00	10.00	1.62	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	
Oxygen (wt%)	3.60	3.70	3.62	0.00	3.82	0.62	3.75	3.70	3.74	3.73	3.75	3.73	5.58	5.58	5.58	5.56	5.64	
Volumes (kbbbl/day)	1,396,446	259,727	1,656,173	1,327,820	257,387	1,585,207	1,357,780	269,081	1,626,861	1,375,643	266,657	1,642,300	1,509,824	280,814	1,790,638	1,435,628	278,286	

**Table 5-56 - PADD 3 Gasoline Qualities Estimated by LP Refinery Modeling for Reference, E10 and E15 Cases**

Gasoline Qualities and Volume for PADD 3	2005 in 2030						E10						E15					
	Summer			Winter			Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	
Energy (MMBTU/bbl)	5.11	5.11	5.09	5.09	5.14	5.10	5.08	5.08	5.08	5.07	5.03	5.06	5.00	5.06	5.02	4.98	4.96	
Density (lb/bbl)	258.93	259.59	258.38	255.87	256.01	255.89	258.77	260.62	259.30	257.06	256.33	256.88	261.39	260.17	261.06	258.99	257.57	
Sulfur (ppm)	16.95	15.87	9.56	10.97	3.52	9.93	10.43	22.45	13.92	2.76	3.63	2.98	19.78	2.97	15.21	26.77	23.50	
% at 200	49.43	50.15	54.62	49.84	54.67	50.51	55.79	51.98	54.68	53.98	57.96	54.99	61.63	58.43	60.76	61.19	58.11	
% at 300	83.78	82.02	84.24	83.31	83.96	83.40	85.08	83.50	84.62	83.18	86.25	83.96	85.50	84.06	85.11	84.40	82.11	
RVP (psi)	8.69	7.00	8.66	11.56	11.26	11.52	9.30	7.00	8.63	11.32	11.20	11.29	8.30	7.00	7.95	10.93	11.02	
T10 (F)	128.38	139.25	128.72	110.21	112.14	110.48	124.17	138.64	128.37	111.20	111.55	111.29	130.62	139.16	132.94	113.41	113.18	
T50 (F)	200.97	199.51	190.37	200.14	190.27	198.76	188.00	195.78	190.25	191.68	183.56	189.61	176.08	182.61	177.85	176.97	183.26	
T90 (F)	325.92	333.93	323.80	328.03	325.07	327.61	320.01	327.19	322.09	328.64	314.67	325.08	318.09	324.65	319.87	323.09	333.51	
Driveability	1113.37	1132.80	1079.32	1085.66	1056.08	1081.53	1063.17	1115.94	1078.47	1063.44	1027.57	1054.32	1035.20	1073.07	1045.49	1018.21	1045.60	
Vapor Lock	135.62	144.29	133.75	120.07	120.07	120.07	130.38	144.24	134.40	120.07	120.07	120.07	133.83	141.55	135.93	120.07	120.07	
Aromatics (vol%)	25.49	20.00	21.81	24.00	18.98	23.30	21.19	19.79	20.78	19.75	18.28	19.38	21.42	18.70	20.68	19.00	17.29	
Benzene (vol%)	0.65	0.47	0.51	0.61	0.44	0.58	0.53	0.58	0.54	0.48	0.58	0.50	0.77	0.56	0.71	0.53	0.52	
Olefins (vol%)	13.68	1.02	4.34	12.32	2.95	11.01	9.94	8.68	9.58	7.88	11.95	8.91	10.15	1.52	7.81	10.03	1.29	
Alcohol (vol%)	3.92	10.00	10.00	3.18	10.00	4.13	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	
Oxygen (wt%)	1.46	3.71	3.72	1.20	3.77	1.56	3.73	3.70	3.72	3.75	3.76	3.75	5.53	5.56	5.54	5.58	5.61	
Volumes (kbb/day)	2,528,524	378,805	1,369,806	2,378,941	385,854	1,472,992	960,985	392,446	1,353,431	1,126,292	384,074	1,510,366	1,097,387	409,559	1,506,946	1,175,404	400,822	

**Table 5-57 - PADD 4 and 5 non-California - Gasoline Qualities Estimated by LP Refinery Modeling for Reference, E10 and E15 Cases**

Gasoline Qualities and Volume for PADDs 4 & 5 nonCA	2005 in 2030						E10						E15					
	Summer			Winter			Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	
Energy (MMBTU/bbl)	5.14	0.00	5.14	5.01	0.00	5.01	5.03	0.00	5.03	4.92	0.00	4.92	4.95	0.00	4.95	4.85	0.00	
Density (lb/bbl)	256.88	0.00	256.88	253.37	0.00	253.37	258.60	0.00	258.60	255.69	0.00	255.69	260.83	0.00	260.83	256.55	0.00	
Sulfur (ppm)	9.72	0.00	9.72	10.69	0.00	10.69	9.89	0.00	9.89	7.91	0.00	7.91	22.12	0.00	22.12	24.71	0.00	
% at 200	57.05	0.00	57.05	59.49	0.00	59.49	62.45	0.00	62.45	66.88	0.00	66.88	64.60	0.00	64.60	72.87	0.00	
% at 300	95.31	0.00	95.31	95.16	0.00	95.16	93.21	0.00	93.21	95.94	0.00	95.94	90.13	0.00	90.13	96.24	0.00	
RVP (psi)	8.60	0.00	8.60	12.79	0.00	12.79	9.49	0.00	9.49	12.49	0.00	12.49	8.60	0.00	8.60	12.22	0.00	
T10 (F)	130.48	0.00	130.48	102.91	0.00	102.91	122.47	0.00	122.47	103.82	0.00	103.82	127.64	0.00	127.64	104.41	0.00	
T50 (F)	185.42	0.00	185.42	180.44	0.00	180.44	174.40	0.00	174.40	165.36	0.00	165.36	170.00	0.00	170.00	153.13	0.00	
T90 (F)	273.51	0.00	273.51	274.16	0.00	274.16	283.04	0.00	283.04	270.62	0.00	270.62	297.06	0.00	297.06	269.29	0.00	
Driveability	1015.94	0.00	1015.94	961.79	0.00	961.79	985.09	0.00	985.09	917.05	0.00	917.05	994.89	0.00	994.89	882.72	0.00	
Vapor Lock	133.90	0.00	133.90	110.58	0.00	110.58	127.89	0.00	127.89	110.29	0.00	110.29	132.21	0.00	132.21	110.29	0.00	
Aromatics (vol%)	22.25	0.00	22.25	20.98	0.00	20.98	18.78	0.00	18.78	16.27	0.00	16.27	17.63	0.00	17.63	13.40	0.00	
Benzene (vol%)	1.30	0.00	1.30	0.94	0.00	0.94	0.34	0.00	0.34	0.65	0.00	0.65	0.42	0.00	0.42	0.27	0.00	
Olefins (vol%)	7.90	0.00	7.90	7.88	0.00	7.88	6.36	0.00	6.36	6.72	0.00	6.72	6.41	0.00	6.41	6.26	0.00	
Alcohol (vol%)	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.00	10.00	10.00	0.00	10.00	15.00	0.00	15.00	15.00	0.00	
Oxygen (wt%)	0.00	0.00	0.00	0.00	0.00	0.00	3.73	0.00	3.73	3.77	0.00	3.77	5.54	0.00	5.54	5.64	0.00	
Volumes (kbbbl/day)	544,754	0	544,754	578,168	0	578,168	529,671	0	529,671	598,991	0	598,991	552,767	0	552,767	625,110	0	

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## Chapter 6 Health and Environmental Effects Associated with Exposure to Criteria and Toxic Pollutants

### 6.1 Health Effects of Criteria and Toxic Pollutants

Motor vehicles emit pollutants that contribute to ambient concentrations of ozone, PM, NO<sub>2</sub>, SO<sub>2</sub>, CO, and air toxics. A discussion of the health effects of these pollutants is included in this section of the RIA. Children may be more vulnerable to air pollution and other environmental exposures than adults because their bodily systems are still developing, they breathe more in proportion to their body size than adults and their behavior can expose them more to chemicals than adults. Early lifestages (e.g., children) are thought to be more susceptible to tumor development than adults when exposed to carcinogenic chemicals that act through a mutagenic mode of action.<sup>1</sup>

#### 6.1.1 Particulate Matter

##### 6.1.1.1 Background

Particulate matter (PM) is a highly complex mixture of solid particles and liquid droplets distributed among numerous atmospheric gases which interact with solid and liquid phases. Particles range in size from those smaller than 1 nanometer (10<sup>-9</sup> meter) to over 100 micrometer (µm, or 10<sup>-6</sup> meter) in diameter (for reference, a typical strand of human hair is 70 µm in diameter and a grain of salt is about 100 µm). Atmospheric particles can be grouped into several classes according to their aerodynamic and physical sizes, including ultrafine particles (<0.1 µm), accumulation mode or 'fine' particles (< 1 to 3 µm), and coarse particles (>1 to 3 µm). For regulatory purposes, fine particles are measured as PM<sub>2.5</sub> and inhalable or thoracic coarse particles are measured as PM<sub>10-2.5</sub>, corresponding to their size (diameter) range in micrometers. The EPA currently has standards that measure PM<sub>2.5</sub> and PM<sub>10</sub>.<sup>2</sup>

Particles span many sizes and shapes and may consist of hundreds of different chemicals. Particles are emitted directly from sources and are also formed through atmospheric chemical reactions; the former are often referred to as "primary" particles, and the latter as "secondary" particles. Particle concentration and composition varies by time of year and location, and in addition to differences in source emissions, is affected by several weather-related factors, such as temperature, clouds, humidity, and wind. A further layer of complexity comes from particles' ability to shift between solid/liquid and gaseous phases, which is influenced by concentration and meteorology, especially temperature.

Fine particles are produced primarily by combustion processes and by transformations of gaseous emissions (e.g., sulfur oxides (SO<sub>x</sub>), nitrogen oxides (NO<sub>x</sub>) and volatile organic compounds (VOCs)) in the atmosphere. The chemical and physical properties of PM<sub>2.5</sub> may vary greatly with time, region, meteorology and source category. Thus, PM<sub>2.5</sub> may include a complex mixture of different components including sulfates, nitrates, organic compounds, elemental carbon and metal compounds. These particles can remain in the atmosphere for days to weeks and travel through the atmosphere hundreds to thousands of kilometers.<sup>3</sup>

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#### 6.1.1.2 Health Effects of PM

Scientific studies show ambient PM is associated with a broad range of health effects. These health effects are discussed in detail in the December 2009 Integrated Science Assessment for Particulate Matter (PM ISA).<sup>4</sup> The PM ISA summarizes health effects evidence associated with both short- and long-term exposures to PM<sub>2.5</sub>, PM<sub>10-2.5</sub>, and ultrafine particles. The PM ISA concludes that human exposures to ambient PM<sub>2.5</sub> concentrations are associated with a number of adverse health effects and characterizes the weight of evidence for these health outcomes.<sup>5</sup> The discussion below highlights the PM ISA's conclusions pertaining to health effects associated with both short- and long-term PM exposures. Further discussion of health effects associated with PM<sub>2.5</sub> can also be found in the rulemaking documents for the most recent review of the PM NAAQS completed in 2012.<sup>6,7</sup>

The EPA concludes that a causal relationship exists between both long- and short-term exposures to PM<sub>2.5</sub> and premature mortality and cardiovascular effects and a likely causal relationship exists between long- and short-term PM<sub>2.5</sub> exposures and respiratory effects. Further, there is evidence suggestive of a causal relationship between long-term PM<sub>2.5</sub> exposures and other health effects, including developmental and reproductive effects (e.g., low birth weight, infant mortality) and carcinogenic, mutagenic, and genotoxic effects (e.g., lung cancer mortality).<sup>8</sup>

As summarized in the Final PM NAAQS rule, and discussed extensively in the 2009 PM ISA, the scientific evidence available since the completion of the 2006 PM NAAQS review significantly strengthens the link between long- and short-term exposure to PM<sub>2.5</sub> and premature mortality, while providing indications that the magnitude of the PM<sub>2.5</sub>-mortality association with long-term exposures may be larger than previously estimated.<sup>9,10</sup> The strongest evidence comes from recent studies investigating long-term exposure to PM<sub>2.5</sub> and cardiovascular-related mortality. The evidence supporting a causal relationship between long-term PM<sub>2.5</sub> exposure and mortality also includes consideration of new studies that demonstrated an improvement in community health following reductions in ambient fine particles.<sup>11</sup>

Several studies evaluated in the 2009 PM ISA have examined the association between cardiovascular effects and long-term PM<sub>2.5</sub> exposures in multi-city studies conducted in the U.S. and Europe. While studies were not available in the 2006 PM NAAQS review with regard to long-term exposure and cardiovascular-related morbidity, studies published since then have provided new evidence linking long-term exposure to PM<sub>2.5</sub> with an array of cardiovascular effects such as heart attacks, congestive heart failure, stroke, and mortality. This evidence is coherent with studies of short-term exposure to PM<sub>2.5</sub> that have observed associations with a continuum of effects ranging from subtle changes in indicators of cardiovascular health to serious clinical events, such as increased hospitalizations and emergency department visits due to cardiovascular disease and cardiovascular mortality.<sup>12</sup>

As detailed in the 2009 PM ISA, extended analyses of studies available in the 2006 PM NAAQS review as well as epidemiological studies conducted in the U.S. and abroad published since then provide stronger evidence of respiratory-related morbidity effects associated with long-term PM<sub>2.5</sub> exposure. The strongest evidence for respiratory-related effects is from studies that evaluated decrements in lung function growth (in children), increased respiratory symptoms,

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and asthma development. The strongest evidence from short-term PM<sub>2.5</sub> exposure studies has been observed for increased respiratory-related emergency department visits and hospital admissions for chronic obstructive pulmonary disease (COPD) and respiratory infections.<sup>13</sup>

The body of scientific evidence detailed in the 2009 PM ISA is still limited with respect to associations between long-term PM<sub>2.5</sub> exposures and developmental and reproductive effects as well as cancer, mutagenic, and genotoxic effects, but is somewhat expanded from the 2006 review. The strongest evidence for an association between PM<sub>2.5</sub> and developmental and reproductive effects comes from epidemiological studies of low birth weight and infant mortality, especially due to respiratory causes during the post-neonatal period (i.e., 1 month to 12 months of age). With regard to cancer effects, “[m]ultiple epidemiologic studies have shown a consistent positive association between PM<sub>2.5</sub> and lung cancer mortality, but studies have generally not reported associations between PM<sub>2.5</sub> and lung cancer incidence.”<sup>14,15</sup>

Specific groups within the general population are at increased risk for experiencing adverse health effects related to PM exposures.<sup>16,17,18,19</sup> The evidence detailed in the 2009 PM ISA expands our understanding of previously identified at-risk populations and lifestages (i.e., children, older adults, and individuals with pre-existing heart and lung disease) and supports the identification of additional at-risk populations (e.g., persons with lower socioeconomic status, genetic differences). Additionally, there is emerging, though still limited, evidence for additional potentially at-risk populations and lifestages, such as those with diabetes, people who are obese, pregnant women, and the developing fetus.<sup>20</sup>

For PM<sub>10-2.5</sub>, the 2009 PM ISA concluded that available evidence was suggestive of a causal relationship between short-term exposures to PM<sub>10-2.5</sub> and cardiovascular effects (e.g., hospital admissions and ED visits, changes in cardiovascular function), respiratory effects (e.g., ED visits and hospital admissions, increase in markers of pulmonary inflammation), and premature mortality. Data were inadequate to draw conclusions regarding the relationships between long-term exposure to PM<sub>10-2.5</sub> and various health effects.<sup>21,22,23</sup>

For ultrafine particles, the 2009 PM ISA concluded that the evidence was suggestive of a causal relationship between short-term exposures and cardiovascular effects, including changes in heart rhythm and vasomotor function (the ability of blood vessels to expand and contract). It also concluded that there was evidence suggestive of a causal relationship between short-term exposure to ultrafine particles and respiratory effects, including lung function and pulmonary inflammation, with limited and inconsistent evidence for increases in ED visits and hospital admissions. Data were inadequate to draw conclusions regarding the relationship between short-term exposure to ultrafine particle and additional health effects including premature mortality as well as long-term exposure to ultrafine particles and all health outcomes evaluated.<sup>24,25</sup>

## 6.1.2 Ozone

### 6.1.2.1 Background

Ground-level ozone pollution is typically formed through reactions involving VOCs and NO<sub>x</sub> in the lower atmosphere in the presence of sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources such as highway and nonroad

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motor vehicles and engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller area sources.

The science of ozone formation, transport, and accumulation is complex. Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions, many of which 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 result in more ozone than typically occurs on a single high-temperature day. Ozone and its precursors can be transported hundreds of miles downwind of precursor emissions, resulting in elevated ozone levels even in areas with low VOC or NO<sub>x</sub> emissions.

The highest levels of ozone are produced when both VOC and NO<sub>x</sub> emissions are present in significant quantities on clear summer days. Relatively small amounts of NO<sub>x</sub> enable ozone to form rapidly when VOC levels are relatively high, but ozone production is quickly limited by removal of the NO<sub>x</sub>. Under these conditions NO<sub>x</sub> reductions are highly effective in reducing ozone while VOC reductions have little effect. Such conditions are called “NO<sub>x</sub>-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 NO<sub>x</sub>-limited.

Ozone concentrations in an area also can be lowered by the reaction of nitric oxide (NO) with ozone, forming nitrogen dioxide (NO<sub>2</sub>). As the air moves downwind and the cycle continues, the NO<sub>2</sub> forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of NO<sub>x</sub>, VOC, and ozone, all of which change with time and location. When NO<sub>x</sub> levels are relatively high and VOC levels relatively low, NO<sub>x</sub> 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 NO<sub>x</sub> reductions can actually increase local ozone under certain circumstances. Even in VOC-limited urban areas, NO<sub>x</sub> reductions are not expected to increase ozone levels if the NO<sub>x</sub> reductions are sufficiently large. Rural areas are usually NO<sub>x</sub>-limited, due to the relatively large amounts of biogenic VOC emissions in such areas. Urban areas can be either VOC- or NO<sub>x</sub>-limited, or a mixture of both, in which ozone levels exhibit moderate sensitivity to changes in either pollutant.

#### 6.1.2.2 Health Effects of Ozone

This section provides a summary of the health effects associated with exposure to ambient concentrations of ozone.<sup>26</sup> The information in this section is based on the information and conclusions in the February 2013 Integrated Science Assessment for Ozone (Ozone ISA) prepared by EPA’s Office of Research and Development (ORD).<sup>27</sup> The Ozone ISA concludes that human exposures to ambient concentrations of ozone are associated with a number of adverse health effects and characterizes the weight of evidence for these health effects.<sup>28</sup> The discussion below highlights the Ozone ISA’s conclusions pertaining to health effects associated with both short-term and long-term periods of exposure to ozone.

For short-term exposure to ozone, the Ozone ISA concludes that respiratory effects, including lung function decrements, pulmonary inflammation, exacerbation of asthma, respiratory-related hospital admissions, and mortality, are causally associated with ozone

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exposure. It also concludes that cardiovascular effects, including decreased cardiac function and increased vascular disease, and total mortality are likely to be causally associated with short-term exposure to ozone and that evidence is suggestive of a causal relationship between central nervous system effects and short-term exposure to ozone.

For long-term exposure to ozone, the Ozone ISA concludes that respiratory effects, including new onset asthma, pulmonary inflammation and injury, are likely to be a causally related with ozone exposure. The Ozone ISA characterizes the evidence as suggestive of a causal relationship for associations between long-term ozone exposure and cardiovascular effects, reproductive and developmental effects, central nervous system effects and total mortality. The evidence is inadequate to infer a causal relationship between chronic ozone exposure and increased risk of lung cancer.

Finally, interindividual variation in human responses to ozone exposure can result in some groups being at increased risk for detrimental effects in response to exposure. The Ozone ISA identified several groups that are at increased risk for ozone-related health effects. These groups are people with asthma, children and older adults, individuals with reduced intake of certain nutrients (i.e., Vitamins C and E), outdoor workers, and individuals having certain genetic variants related to oxidative metabolism or inflammation. Ozone exposure during childhood can have lasting effects through adulthood. Such effects include altered function of the respiratory and immune systems. Children absorb higher doses (normalized to lung surface area) of ambient ozone, compared to adults, due to their increased time spent outdoors, higher ventilation rates relative to body size, and a tendency to breathe a greater fraction of air through the mouth. Children also have a higher asthma prevalence compared to adults. Additional children's vulnerability and susceptibility factors are listed in Section XII.G of the preamble.

### 6.1.3 Nitrogen Oxides and Sulfur Oxides

#### 6.1.3.1 Background

Sulfur dioxide (SO<sub>2</sub>), a member of the sulfur oxide (SO<sub>x</sub>) family of gases, is formed from burning fuels containing sulfur (e.g., coal or oil), extracting gasoline from oil, or extracting metals from ore. Nitrogen dioxide (NO<sub>2</sub>) is a member of the nitrogen oxide (NO<sub>x</sub>) family of gases. Most NO<sub>2</sub> is formed in the air through the oxidation of nitric oxide (NO) emitted when fuel is burned at a high temperature. SO<sub>2</sub> and NO<sub>2</sub> and their gas phase oxidation products can dissolve in water droplets and further oxidize to form sulfuric and nitric acid which react with ammonia to form sulfates and nitrates, both of which are important components of ambient PM. The health effects of ambient PM are discussed in Section 6.1.1.2. NO<sub>x</sub> along with VOCs are the two major precursors of ozone. The health effects of ozone are covered in Section 6.1.2.2.

#### 6.1.3.2 Health Effects of Sulfur Oxides

This section provides an overview of the health effects associated with SO<sub>2</sub>. Additional information on the health effects of SO<sub>2</sub> can be found in the 2008 Integrated Science Assessment for Sulfur Oxides (SO<sub>2</sub> ISA).<sup>29</sup> Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the U.S. EPA has concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO<sub>2</sub>. The immediate

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effect of SO<sub>2</sub> on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO<sub>2</sub> likely resulting from preexisting inflammation associated with this disease. In addition to those with asthma (both children and adults), potentially sensitive groups include all children and the elderly. In laboratory studies involving controlled human exposures to SO<sub>2</sub>, respiratory effects have consistently been observed following 5-10 min exposures at SO<sub>2</sub> concentrations  $\geq$  0.4 ppm in asthmatics engaged in moderate to heavy levels of exercise, with more limited evidence of respiratory effects among exercising asthmatics exposed to concentrations as low as 0.2-0.3 ppm. A clear concentration-response relationship has been demonstrated in these studies following exposures to SO<sub>2</sub> at concentrations between 0.2 and 1.0 ppm, both in terms of increasing severity of respiratory symptoms and decrements in lung function, as well as the percentage of asthmatics adversely affected.

In epidemiologic studies, respiratory effects have been observed in areas where the mean 24-hour SO<sub>2</sub> levels range from 1 to 30 ppb, with maximum 1 to 24-hour average SO<sub>2</sub> values ranging from 12 to 75 ppb. Important new multicity studies and several other studies have found an association between 24-hour average ambient SO<sub>2</sub> concentrations and respiratory symptoms in children, particularly those with asthma. Generally consistent associations also have been observed between ambient SO<sub>2</sub> concentrations and emergency department visits and hospitalizations for all respiratory causes, particularly among children and older adults ( $\geq$  65 years), and for asthma. A limited subset of epidemiologic studies has examined potential confounding by copollutants using multipollutant regression models. These analyses indicate that although copollutant adjustment has varying degrees of influence on the SO<sub>2</sub> effect estimates, the effect of SO<sub>2</sub> on respiratory health outcomes appears to be generally robust and independent of the effects of gaseous and particulate copollutants, suggesting that the observed effects of SO<sub>2</sub> on respiratory endpoints occur independent of the effects of other ambient air pollutants.

Consistent associations between short-term exposure to SO<sub>2</sub> and mortality have been observed in epidemiologic studies, with larger effect estimates reported for respiratory mortality than for cardiovascular mortality. While this finding is consistent with the demonstrated effects of SO<sub>2</sub> on respiratory morbidity, uncertainty remains with respect to the interpretation of these associations due to potential confounding by various copollutants. The U.S. EPA has therefore concluded that the overall evidence is suggestive of a causal relationship between short-term exposure to SO<sub>2</sub> and mortality. Significant associations between short-term exposure to SO<sub>2</sub> and emergency department visits and hospital admissions for cardiovascular diseases have also been reported. However, these findings have been inconsistent across studies and do not provide adequate evidence to infer a causal relationship between SO<sub>2</sub> exposure and cardiovascular morbidity.

#### 6.1.3.3 Health Effects of Nitrogen Oxides

The most recent review of the health effects of oxides of nitrogen completed by the EPA can be found in the 2008 Integrated Science Assessment for Nitrogen Oxides (NO<sub>x</sub> ISA).<sup>30</sup> The EPA concluded that the findings of epidemiologic, controlled human exposure, and animal toxicological studies provide evidence that is sufficient to infer a likely causal relationship between respiratory effects and short-term NO<sub>2</sub> exposure. The 2008 NO<sub>x</sub> ISA concluded that the strongest evidence for such a relationship comes from epidemiologic studies of respiratory

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effects including increased respiratory symptoms, emergency department visits, and hospital admissions. Based on both short- and long-term exposure studies, the 2008 NO<sub>x</sub> ISA concluded that individuals with preexisting pulmonary conditions (e.g., asthma or COPD), children, and older adults are potentially at greater risk of NO<sub>2</sub>-related respiratory effects. Based on findings from controlled human exposure studies, the 2008 NO<sub>x</sub> ISA also drew two broad conclusions regarding airway responsiveness following NO<sub>2</sub> exposure. First, the NO<sub>x</sub> ISA concluded that NO<sub>2</sub> exposure may enhance the sensitivity to allergen-induced decrements in lung function and increase the allergen-induced airway inflammatory response following 30-minute exposures of asthmatic adults to NO<sub>2</sub> concentrations as low as 260 ppb. Second, exposure to NO<sub>2</sub> has been found to enhance the inherent responsiveness of the airway to subsequent nonspecific challenges in controlled human exposure studies of healthy and asthmatic adults. Small but statistically significant increases in nonspecific airway hyperresponsiveness were reported for asthmatic adults following 30-minute exposures to 200-300 ppb NO<sub>2</sub> and following 1-hour exposures of asthmatics to 100 ppb NO<sub>2</sub>. Enhanced airway responsiveness could have important clinical implications for asthmatics since transient increases in airway responsiveness following NO<sub>2</sub> exposure have the potential to increase symptoms and worsen asthma control. Together, the epidemiologic and experimental data sets form a plausible, consistent, and coherent description of a relationship between NO<sub>2</sub> exposures and an array of adverse health effects that range from the onset of respiratory symptoms to hospital admission.

In evaluating a broader range of health effects, the 2008 NO<sub>x</sub> ISA concluded evidence was “suggestive but not sufficient to infer a causal relationship” between short-term NO<sub>2</sub> exposure and premature mortality and between long-term NO<sub>2</sub> exposure and respiratory effects. The latter was based largely on associations observed between long-term NO<sub>2</sub> exposure and decreases in lung function growth in children. Furthermore, the 2008 NO<sub>x</sub> ISA concluded that evidence was “inadequate to infer the presence or absence of a causal relationship” between short-term NO<sub>2</sub> exposure and cardiovascular effects as well as between long-term NO<sub>2</sub> exposure and cardiovascular effects, reproductive and developmental effects, premature mortality, and cancer.<sup>31</sup> The conclusions for these health effect categories were informed by uncertainties in the evidence base such as the independent effects of NO<sub>2</sub> exposure within the broader mixture of traffic-related pollutants, limited evidence from experimental studies, and/or an overall limited literature base.

#### 6.1.4 Health Effects of Carbon Monoxide

Information on the health effects of carbon monoxide (CO) can be found in the January 2010 Integrated Science Assessment for Carbon Monoxide (CO ISA).<sup>32</sup> The CO ISA concludes that ambient concentrations of CO are associated with a number of adverse health effects.<sup>33</sup> This section provides a summary of the health effects associated with exposure to ambient concentrations of CO.<sup>34</sup>

Controlled human exposure studies of subjects with coronary artery disease show a decrease in the time to onset of exercise-induced angina (chest pain) and electrocardiogram changes following CO exposure. In addition, epidemiologic studies show associations between short-term CO exposure and cardiovascular morbidity, particularly increased emergency room visits and hospital admissions for coronary heart disease (including ischemic heart disease, myocardial infarction, and angina). Some epidemiologic evidence is also available for increased

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hospital admissions and emergency room visits for congestive heart failure and cardiovascular disease as a whole. The CO ISA concludes that a causal relationship is likely to exist between short-term exposures to CO and cardiovascular morbidity. It also concludes that available data are inadequate to conclude that a causal relationship exists between long-term exposures to CO and cardiovascular morbidity.

Animal studies show various neurological effects with in-utero CO exposure. Controlled human exposure studies report central nervous system and behavioral effects following low-level CO exposures, although the findings have not been consistent across all studies. The CO ISA concludes the evidence is suggestive of a causal relationship with both short- and long-term exposure to CO and central nervous system effects.

A number of studies cited in the CO ISA have evaluated the role of CO exposure in birth outcomes such as preterm birth or cardiac birth defects. The epidemiologic studies provide limited evidence of a CO-induced effect on preterm births and birth defects, with weak evidence for a decrease in birth weight. Animal toxicological studies have found perinatal CO exposure to affect birth weight, as well as other developmental outcomes. The CO ISA concludes the evidence is suggestive of a causal relationship between long-term exposures to CO and developmental effects and birth outcomes.

Epidemiologic studies provide evidence of associations between ambient CO concentrations and respiratory morbidity such as changes in pulmonary function, respiratory symptoms, and hospital admissions. A limited number of epidemiologic studies considered copollutants such as ozone, SO<sub>2</sub>, and PM in two-pollutant models and found that CO risk estimates were generally robust, although this limited evidence makes it difficult to disentangle effects attributed to CO itself from those of the larger complex air pollution mixture. Controlled human exposure studies have not extensively evaluated the effect of CO on respiratory morbidity. Animal studies at levels of 50-100 ppm CO show preliminary evidence of altered pulmonary vascular remodeling and oxidative injury. The CO ISA concludes that the evidence is suggestive of a causal relationship between short-term CO exposure and respiratory morbidity, and inadequate to conclude that a causal relationship exists between long-term exposure and respiratory morbidity.

Finally, the CO ISA concludes that the epidemiologic evidence is suggestive of a causal relationship between short-term concentrations of CO and mortality. Epidemiologic studies provide evidence of an association between short-term exposure to CO and mortality, but limited evidence is available to evaluate cause-specific mortality outcomes associated with CO exposure. In addition, the attenuation of CO risk estimates which was often observed in copollutant models contributes to the uncertainty as to whether CO is acting alone or as an indicator for other combustion-related pollutants. The CO ISA also concludes that there is not likely to be a causal relationship between relevant long-term exposures to CO and mortality.

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## 6.1.5 Health Effects of Air Toxics

### 6.1.5.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.<sup>35,36,37</sup> EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. EPA's IRIS documentation for benzene also lists a range of  $2.2 \times 10^{-6}$  to  $7.8 \times 10^{-6}$  as the unit risk estimate (URE) for benzene.<sup>38,39</sup> The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.<sup>40,41</sup>

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.<sup>42,43</sup> The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.<sup>44,45</sup> EPA's inhalation reference concentration (RfC) for benzene is  $30 \mu\text{g}/\text{m}^3$ . The RfC is based on suppressed absolute lymphocyte counts seen in humans under occupational exposure conditions. In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.<sup>46,47,48,49</sup> EPA's IRIS program has not yet evaluated these new data. EPA does not currently have an acute reference concentration for benzene. The Agency for Toxic Substances and Disease Registry (ATSDR) Minimal Risk Level (MRL) for acute exposure to benzene is  $29 \mu\text{g}/\text{m}^3$  for 1-14 days exposure.<sup>50,51</sup>

### 6.1.5.2 1,3-Butadiene

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.<sup>52,53</sup> The IARC has determined that 1,3-butadiene is a human carcinogen and the U.S. DHHS has characterized 1,3-butadiene as a known human carcinogen.<sup>54,55,56</sup> There are numerous studies consistently demonstrating that 1,3-butadiene is metabolized into genotoxic metabolites by experimental animals and humans. The specific mechanisms of 1,3-butadiene-induced carcinogenesis are unknown; however, the scientific evidence strongly suggests that the carcinogenic effects are mediated by genotoxic metabolites. Animal data suggest that females may be more sensitive than males for cancer effects associated with 1,3-butadiene exposure; there are insufficient data in humans from which to draw conclusions about sensitive subpopulations. The URE for 1,3-butadiene is  $3 \times 10^{-5}$  per  $\mu\text{g}/\text{m}^3$ .<sup>57</sup> 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.<sup>58</sup> Based on this critical effect and the benchmark concentration methodology, an RfC for chronic health effects was calculated at 0.9 ppb (approximately  $2 \mu\text{g}/\text{m}^3$ ).

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#### 6.1.5.3 Ethanol

EPA is planning to develop an assessment of the health effects of exposure to ethanol, a compound which is not currently listed on EPA's IRIS database. Extensive health effects data are available for ingestion of ethanol, while data on inhalation exposure effects are sparse. In developing the assessment, EPA is evaluating pharmacokinetic models as a means of extrapolating across species (animal to human) and across exposure routes (oral to inhalation) to better characterize the health hazards and dose-response relationships for low levels of ethanol exposure in the environment.

#### 6.1.5.4 Formaldehyde

In 1991, EPA concluded that formaldehyde is a carcinogen based on nasal tumors in animal bioassays.<sup>59</sup> An Inhalation Unit Risk for cancer and a Reference Dose for oral noncancer effects were developed by the Agency and posted on the Integrated Risk Information System (IRIS) database. Since that time, the National Toxicology Program (NTP) and International Agency for Research on Cancer (IARC) have concluded that formaldehyde is a known human carcinogen.<sup>60,61,62</sup>

The conclusions by IARC and NTP reflect the results of epidemiologic research published since 1991 in combination with previous animal, human and mechanistic evidence. Research conducted by the National Cancer Institute reported an increased risk of nasopharyngeal cancer and specific lymphohematopoietic malignancies among workers exposed to formaldehyde.<sup>63,64,65</sup> A National Institute of Occupational Safety and Health study of garment workers also reported increased risk of death due to leukemia among workers exposed to formaldehyde.<sup>66</sup> Extended follow-up of a cohort of British chemical workers did not report evidence of an increase in nasopharyngeal or lymphohematopoietic cancers, but a continuing statistically significant excess in lung cancers was reported.<sup>67</sup> Finally, a study of embalmers reported formaldehyde exposures to be associated with an increased risk of myeloid leukemia but not brain cancer.<sup>68</sup>

Health effects of formaldehyde in addition to cancer were reviewed by the Agency for Toxic Substances and Disease Registry in 1999<sup>69</sup> and supplemented in 2010,<sup>70</sup> and by the World Health Organization.<sup>71</sup> These organizations reviewed the literature concerning effects on the eyes and respiratory system, the primary point of contact for inhaled formaldehyde, including sensory irritation of eyes and respiratory tract, pulmonary function, nasal histopathology, and immune system effects. In addition, research on reproductive and developmental effects and neurological effects were discussed.

EPA released a draft Toxicological Review of Formaldehyde – Inhalation Assessment through the IRIS program for peer review by the National Research Council (NRC) and public comment in June 2010.<sup>72</sup> The draft assessment reviewed more recent research from animal and human studies on cancer and other health effects. The NRC released their review report in April 2011<sup>73</sup> ([http://www.nap.edu/catalog.php?record\\_id=13142](http://www.nap.edu/catalog.php?record_id=13142)). The EPA is currently revising the draft assessment in response to this review.

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#### 6.1.5.5 Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.<sup>74</sup> The URE in IRIS for acetaldehyde is  $2.2 \times 10^{-6}$  per  $\mu\text{g}/\text{m}^3$ .<sup>75</sup> Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 12<sup>th</sup> Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.<sup>76,77</sup> EPA is currently conducting a reassessment of cancer risk from inhalation exposure to acetaldehyde.

The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.<sup>78</sup> In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.<sup>79,80</sup> Data from these studies were used by EPA to develop an inhalation reference concentration of  $9 \mu\text{g}/\text{m}^3$ . Some asthmatics have been shown to be a sensitive subpopulation to decrements in functional expiratory volume (FEV1 test) and bronchoconstriction upon acetaldehyde inhalation.<sup>81</sup> The agency is currently conducting a reassessment of the health hazards from inhalation exposure to acetaldehyde.

#### 6.1.5.6 Acrolein

EPA most recently evaluated the toxicological and health effects literature related to acrolein in 2003 and concluded that the human carcinogenic potential of acrolein could not be determined because the available data were inadequate. No information was available on the carcinogenic effects of acrolein in humans and the animal data provided inadequate evidence of carcinogenicity.<sup>82</sup> The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.<sup>83</sup>

Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein.<sup>84</sup> The Agency has developed an RfC for acrolein of  $0.02 \mu\text{g}/\text{m}^3$  and an RfD of  $0.5 \mu\text{g}/\text{kg}\text{-day}$ .<sup>85</sup> EPA is considering updating the acrolein assessment with data that have become available since the 2003 assessment was completed.

Acrolein is extremely acrid and irritating to humans when inhaled, with acute exposure resulting in upper respiratory tract irritation, mucus hypersecretion and congestion. 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.<sup>86</sup> These data and additional studies regarding acute effects of human exposure to acrolein are summarized in EPA's 2003 IRIS Human Health Assessment for acrolein.<sup>87</sup> Studies in humans indicate that levels as low as 0.09 ppm ( $0.21 \text{ mg}/\text{m}^3$ ) for five minutes may elicit subjective complaints of eye irritation with increasing concentrations leading to more extensive eye, nose and respiratory symptoms. Acute exposures in animal studies report bronchial hyper-responsiveness. Based on animal data (more pronounced respiratory irritancy in mice with allergic airway disease in comparison to non-diseased mice<sup>88</sup>) and demonstration of similar effects in humans (e.g., reduction in respiratory rate), individuals with compromised respiratory function (e.g., emphysema, asthma) are expected to be at increased risk of developing adverse responses to strong respiratory irritants such as acrolein. EPA does not currently have an acute

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reference concentration for acrolein. The available health effect reference values for acrolein have been summarized by EPA and include an ATSDR MRL for acute exposure to acrolein of 7  $\mu\text{g}/\text{m}^3$  for 1-14 days exposure; and Reference Exposure Level (REL) values from the California Office of Environmental Health Hazard Assessment (OEHHA) for one-hour and 8-hour exposures of 2.5  $\mu\text{g}/\text{m}^3$  and 0.7  $\mu\text{g}/\text{m}^3$ , respectively.<sup>89</sup>

#### 6.1.5.7 PAN

PAN (peroxy acetyl nitrate) has not been evaluated by EPA's IRIS program. Information regarding the potential carcinogenicity of PAN is limited. As noted in the EPA air quality criteria document for ozone and related photochemical oxidants, cytogenetic studies indicate that PAN is not a potent mutagen, clastogen (a compound that can cause breaks in chromosomes), or DNA-damaging agent in mammalian cells either in vivo or in vitro. Some studies suggest that PAN may be a weak bacterial mutagen at concentrations much higher than exist in present urban atmospheres.<sup>90</sup>

Effects of ground-level smog causing intense eye irritation have been attributed to photochemical oxidants, including PAN.<sup>91</sup> Animal toxicological information on the inhalation effects of the non-ozone oxidants has been limited to a few studies on PAN. Acute exposure to levels of PAN can cause changes in lung morphology, behavioral modifications, weight loss, and susceptibility to pulmonary infections. Human exposure studies indicate minor pulmonary function effects at high PAN concentrations, but large inter-individual variability precludes definitive conclusions.<sup>92</sup>

#### 6.1.5.8 Polycyclic Organic Matter

The term polycyclic organic matter (POM) defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). One of these compounds, naphthalene, is discussed separately below. POM compounds are formed primarily from combustion and are present in the atmosphere in gas and particulate form. Cancer is the major concern from exposure to POM. Epidemiologic studies have reported an increase in lung cancer in humans exposed to diesel exhaust, coke oven emissions, roofing tar emissions, and cigarette smoke; all of these mixtures contain POM compounds.<sup>93,94</sup> Animal studies have reported respiratory tract tumors from inhalation exposure to benzo[a]pyrene and alimentary tract and liver tumors from oral exposure to benzo[a]pyrene.<sup>95</sup> In 1997 EPA classified seven PAHs (benzo[a]pyrene, benz[a]anthracene, chrysene, benzo[b]fluoranthene, benzo[k]fluoranthene, dibenz[a,h]anthracene, and indeno[1,2,3-cd]pyrene) as Group B2, probable human carcinogens.<sup>96</sup> Since that time, studies have found that maternal exposures to PAHs in a population of pregnant women were associated with several adverse birth outcomes, including low birth weight and reduced length at birth, as well as impaired cognitive development in preschool children (3 years of age).<sup>97,98</sup> These and similar studies are being evaluated as a part of the ongoing IRIS assessment of health effects associated with exposure to benzo[a]pyrene.

#### 6.1.5.9 Naphthalene

Naphthalene is found in small quantities in gasoline and diesel fuels. Naphthalene emissions have been measured in larger quantities in both gasoline and diesel exhaust compared

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with evaporative emissions from mobile sources, indicating it is primarily a product of combustion. Acute (short-term) exposure of humans to naphthalene by inhalation, ingestion, or dermal contact is associated with hemolytic anemia and damage to the liver and the nervous system.<sup>99</sup> Chronic (long term) exposure of workers and rodents to naphthalene has been reported to cause cataracts and retinal damage.<sup>100</sup> EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.<sup>101</sup> The draft reassessment completed external peer review.<sup>102</sup> Based on external peer review comments received, a revised draft assessment that considers all routes of exposure, as well as cancer and noncancer effects, is under development. The external review draft does not represent official agency opinion and was released solely for the purposes of external peer review and public comment. The National Toxicology Program listed naphthalene as "reasonably anticipated to be a human carcinogen" in 2004 on the basis of bioassays reporting clear evidence of carcinogenicity in rats and some evidence of carcinogenicity in mice.<sup>103</sup> California EPA has released a new risk assessment for naphthalene, and the IARC has reevaluated naphthalene and re-classified it as Group 2B: possibly carcinogenic to humans.<sup>104</sup>

Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.<sup>105</sup> The current EPA IRIS assessment includes noncancer data on hyperplasia and metaplasia in nasal tissue that form the basis of the inhalation RfC of 3  $\mu\text{g}/\text{m}^3$ .<sup>106</sup> The ATSDR MRL for acute exposure to naphthalene is 0.6 mg/kg/day.

#### 6.1.5.10 Other Air Toxics

In addition to the compounds described above, other compounds in gaseous hydrocarbon and PM emissions from vehicles will be affected by this proposal. Mobile source air toxic compounds that would potentially be impacted include ethylbenzene, propionaldehyde, toluene, and xylene. Information regarding the health effects of these compounds can be found in EPA's IRIS database.<sup>107</sup>

#### 6.1.6 Traffic-associated health effects

In addition to health concerns resulting from specific air pollutants, a large number of studies have examined the health status of populations near major roadways. These studies frequently have employed exposure metrics that are not specific to individual pollutants, but rather reflect the large number of different pollutants found in elevation near major roads.

In this section of the RIA, information on health effects associated with air quality near major roads or traffic in general is summarized. Generally, the section makes use of publications that systematically review literature on a given health topic. In particular, this section makes frequent reference of a report of by the Health Effects Institute (HEI) Panel on the Health Effects of Traffic-Related Air Pollution, published in 2010 as a review of relevant studies.<sup>108,109</sup> Other systematic reviews of relevant literature are cited where appropriate.

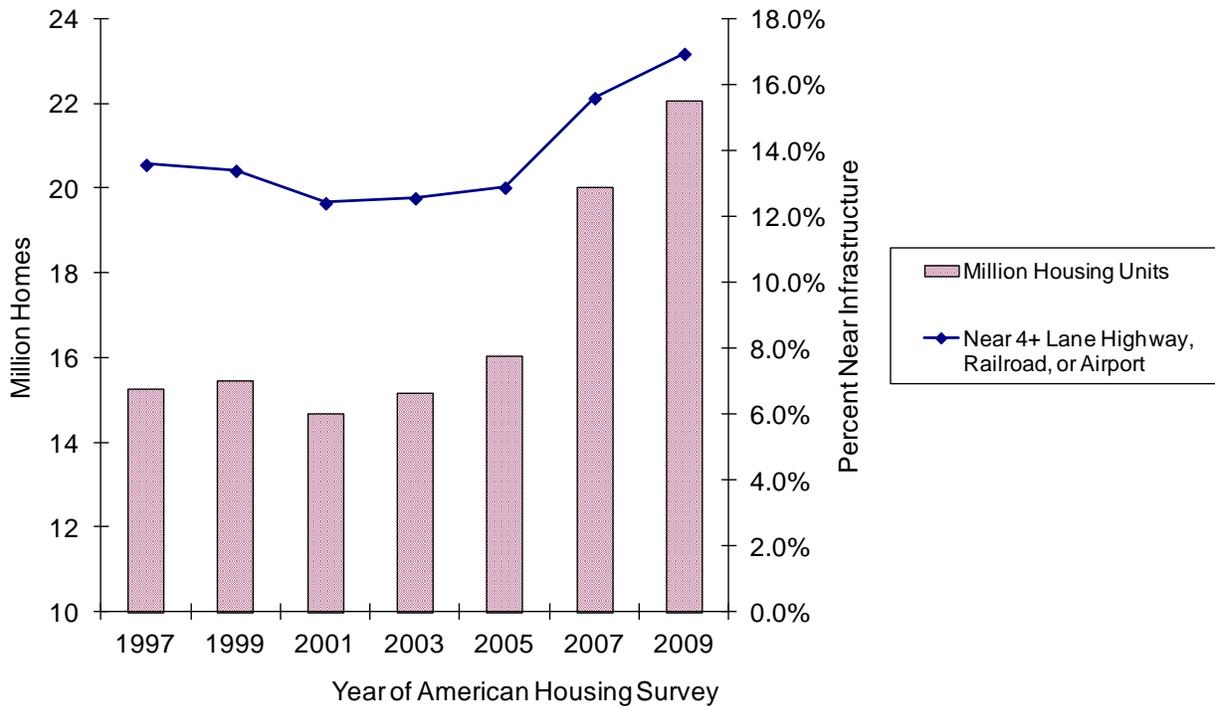
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#### 6.1.6.1 Populations near major roads

Numerous studies have estimated the size and demographics of populations that live near major roads. Other studies have estimated the number of schools near major roads, and the populations of students in such schools.

Every two years, the U.S. Census Bureau's American Housing Survey (AHS) has reported whether housing units are within 300 feet of an "airport, railroad, or highway with four or more lanes." The 2009 survey reports that over 22 million homes, or 17 percent of all housing units in the U.S., were located in such areas. Assuming that populations and housing units are in the same locations, this corresponds to a population of more than 50 million U.S. residents in close proximity to high-traffic roadways or other transportation sources. According to the Central Intelligence Agency's World Factbook, in 2010, the United States had 6,506,204 km of roadways, 224,792 km of railways, and 15,079 airports. As such, highways represent the overwhelming majority of transportation facilities described by this factor in the AHS.

The AHS reports are published every two years, and until 2011 recorded whether homes were located near highways with four or more lanes, railroads, or airports. As such, trends in the AHS can be reported to describe whether a greater or lesser proportion of homes are located near major roads over time. Figure 6-1 depicts trends in the number and proportion of homes located near major transportation sources, which generally indicate large roadways. As the figure indicates, since 2005, there has been a substantial increase in the number and percentage of homes located near major transportation sources. As such, the population in close proximity to these sources, which may be affected by near-road air quality and health concerns, appears to have increased over time.



**Figure 6-1 Trends in Populations Near Large Highways, Railroads, and Airports**

Furthermore, according to data from the 2008 American Time Use Survey (ATUS), conducted by the Bureau of Labor Statistics (BTS), Americans spend more than an hour traveling each day, on average.<sup>110</sup> Although the ATUS does not indicate their mode of travel, the majority of trips undertaken nationally is by motor vehicle.<sup>111</sup> As such, daily travel activity brings nearly all residents into a high-exposure microenvironment for part of the day.

#### 6.1.6.2 Premature mortality

The HEI panel report concluded that evidence linking traffic-associated air pollution with premature mortality from all causes was “suggestive but not sufficient” to infer a causal relationship. This conclusion was based largely on several long-term studies that “qualitatively” examined whether or not someone was exposed to traffic-associated air pollution. In addition, based on several short-term studies of exposure, the panel concluded that there was evidence that there was “suggestive but not sufficient” evidence to infer a causal relation between traffic-related exposure and cardiovascular mortality.

#### 6.1.6.3 Cardiovascular effects

##### 6.1.6.3.1 Cardiac physiology

Exposure to traffic-associated pollutants has been associated with changes in cardiac physiology, including cardiac function. One common measure of cardiac function is heart rate

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variability (HRV), an indicator of the heart's ability to respond to variations in stress, reflecting the nervous system's ability to regulate the heart.<sup>112</sup> Reduced HRV is associated with adverse cardiovascular events, such as myocardial infarction, in heart disease patients. The HEI panel concluded that available evidence provides evidence for a causal association between exposure to traffic-related pollutants and reduced control of HRV by the nervous system. Overall, the panel concluded that the evidence was "suggestive but not sufficient" to infer a causal relation between traffic-related pollutants and cardiac function. Studies suggest that the HRV changes from traffic-related air pollution result in changes to heart rhythms, which can lead to arrhythmia.<sup>113,114</sup>

#### 6.1.6.3.2 *Heart attack and atherosclerosis*

The HEI panel concluded that epidemiologic evidence of the association between traffic-related pollutants and heart attacks and atherosclerosis was "suggestive but not sufficient" to infer a causal association. In addition, the panel concluded that the toxicology studies they reviewed provided "suggestive evidence that exposure to traffic emissions, including ambient and laboratory-generated [PM] and diesel- and gasoline-engine exhaust, alters cardiovascular function." The panel noted there are few studies of human volunteers exposed to real-world traffic mixture, which were not entirely consistent. The panel notes that the studies provide consistent evidence for exposure to PM and impaired cardiovascular responses. In addition to the HEI study, several other reviews of available evidence conclude that there is evidence supporting a causal association between traffic-related air pollution and cardiovascular disease.<sup>115</sup>

A number of mechanisms for cardiovascular disease are highlighted in the HEI and AHA report, including modified blood vessel endothelial function (e.g., the ability to dilate), atherosclerosis, and oxidative stress. The HEI review cites "two well executed studies" in which hospitalization for acute myocardial infarction (i.e., heart attack) were associated with traffic exposures and a prospective study finding higher rates of arterial hardening and coronary heart disease near traffic.

#### 6.1.6.4 Respiratory effects

##### 6.1.6.4.1 *Asthma*

Pediatric asthma and asthma symptoms are the effects that have been evaluated by the largest number of studies in the epidemiologic literature on the topic. In general, studies consistently show effects of residential or school exposure to traffic and asthma symptoms, and the effects are frequently statistically significant. Studies have employed both short-term and long-term exposure metrics, and a range of different respiratory measures. HEI Special Report 17 (HEI Panel on the Health Effects of Traffic-Related Air Pollution, 2010) concluded that there is sufficient evidence for a causal association between exposure to traffic-related air pollution and exacerbation of asthma symptoms in children.

While there is general consistency in studies examining asthma incidence in children, the available studies employ different definitions of asthma (e.g., self-reported vs. hospital records), methods of exposure assessment, and population age ranges. As such, the overall evidence,

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while supportive of an association between traffic exposure and new onset asthma, are less consistent than for asthma symptoms. The HEI report determined that there is “sufficient” or “suggestive” evidence of a causal relationship between exposure to traffic-related air pollution and incident (new onset) asthma in children (HEI Panel on the Health Effects of Traffic-Related Air Pollution, 2010). A recent meta-analysis of studies on incident asthma and air pollution in general, based on studies dominated by traffic-linked exposure metrics, also concluded that available evidence that exposures is consistent with a effect of exposure on asthma incidence (Anderson et al., 2011). The study reported excess main risk estimates for different pollutants ranging from 7-16 percent per 10  $\mu\text{g}/\text{m}^3$  of long-term exposure (random effects models). Other qualitative reviews (Salam et al., 2008; Braback and Forsberg, 2009) conclude that available evidence is consistent with the hypothesis that traffic-associated air pollutants are associated with incident asthma.

#### *6.1.6.4.2 Chronic obstructive pulmonary disease (COPD)*

The HEI panel reviewed available studies examining COPD in the context of traffic-associated air pollution. Because of how the panel selected studies for inclusion in review, there were only two studies that they used to review the available evidence. Both studies reported some positive associations, but not for all traffic metrics. The small number of studies and lack of consistency across traffic metrics led the panel to conclude that there is insufficient evidence for traffic-associated air pollution causing COPD.

#### *6.1.6.4.3 Allergy*

There are numerous human and animal experimental studies that provides strongly suggestive evidence that traffic-related air pollutants can enhance allergic responses to common allergens.<sup>116,117,118</sup> However, in its review of 16 epidemiologic studies that address traffic-related air pollution’s effect on allergies, the HEI expert panel (HEI, 2010) reported that only two such studies showed consistently positive associations. As a result, despite the strong experimental evidence, the panel concluded that there is “inadequate/insufficient” evidence of an association between allergy and traffic-associated air pollution. As noted above, the HEI panel considered toxicological evidence only based on whether or not they provide mechanistic support for observations and inferences derived from epidemiology.

#### *6.1.6.4.4 Lung function*

There are numerous measurements of breathing (spirometry) that indicate the presence or degree of airway disease, such as asthma and chronic obstructive pulmonary disease (COPD). Forced vital capacity (FVC) is measured when a patient maximally fills their lungs and then blows their hardest in completely exhaling. The peak expiratory flow (PEF) is the maximum air flow achievable during exhalation. The forced expiratory volume in the first second of exhalation is referred to as FEV<sub>1</sub>. FEV<sub>1</sub> and PEF reflect the function of the large airways. FVC and FEV<sub>1</sub>, along with their ratio (FVC/FEV<sub>1</sub>) are used to classify airway obstruction in asthma and COPD. Measurements of air flow at various times during forced exhalation, such as 25 percent, 50 percent, and 75 percent, are also used. The flow at 75 percent of forced exhalation (FEF<sub>75</sub>) reflects the status of small airways, which asthma and COPD affect.

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The HEI panel concluded that the available literature suggests that long-term exposure to traffic-related air pollution is associated with reduced lung function in adolescents and young adults and that lung function is lower in populations in areas with high traffic-related air pollutant levels. However, the panel noted the difficulty of disentangling traffic-specific exposures from urban air pollution in general. The studies reviewed that were more specifically oriented toward traffic were not consistent in their findings. As a result, the panel found that the evidence linking lung function and traffic exposure is “inadequate and insufficient” to infer a causal relationship.

#### 6.1.6.5 Reproductive and developmental effects

Several studies have reported associations between traffic-related air pollution and adverse birth outcomes, such as preterm birth and low birth weight. At the time of the HEI review, the panel concluded that evidence for adverse birth outcomes being causally associated with traffic-related exposures was “inadequate and insufficient.” Only four studies met the panel’s inclusion criteria, and had limited geographic coverage. One study provided evidence of small but consistently increased risks using multiple exposure metrics. No studies were at the time available that examined traffic-specific exposures and congenital abnormalities. Since then, several studies investigating birth outcomes have been published, but no new systematic reviews. One new meta-analysis of air pollution and congenital abnormalities has been published, though none of the reviewed studies includes traffic-specific exposure information.

The HEI panel also reviewed toxicological studies of traffic-related air pollutants and fertility. While numerous studies examining animal or human exposure and sperm count have been published, the panel concluded that the generally high exposure concentrations employed in the studies limited the applicability to typical ambient concentrations. Because there was no overlap in the effects studied by epidemiology and toxicology studies, no synthesis review of the combined literature was undertaken.

Since the HEI panel’s publication, a systematic review and meta-analysis of air pollution and congenital abnormalities was published.<sup>119</sup> In that review, only one study directly included nearby traffic in its exposure analysis. As such, there are so systematic reviews that specifically address traffic’s impact on congenital abnormalities.

#### 6.1.6.6 Cancer

##### 6.1.6.6.1 *Childhood cancer*

A number of studies examining various types of childhood cancer have been published with mixed results. The HEI panel concluded that the available epidemiologic evidence was “inadequate and insufficient” to infer a causal relationship between traffic-related air pollution and childhood cancer. An earlier review article on the topic noted that studies reporting positive effects tended to be small, while those with null effects tended to be larger, suggesting the potential for publication bias in the available literature.<sup>120</sup>

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#### 6.1.6.6.2 *Adult cancer*

Several studies have examined the risk of adult lung cancers in relation to exposure to traffic-related air pollutants. The HEI panel evaluated four such studies, and rated the available evidence as “inadequate and insufficient” to infer a causal relation for non-occupational lung cancer.

#### 6.1.6.7 Neurological effects

The HEI panel found that current toxicologic and epidemiologic literature on the neurotoxicity of traffic-related air pollution was inadequate for their evaluation. The panel noted that there were a number of toxicologic studies of traffic-associated pollutants, but found them to have diverse exposure protocols, animal models, and endpoints, making them unsuitable for systematic evaluation.

## 6.2 Environmental Effects of Criteria and Toxic Pollutants

### 6.2.1 Visibility Degradation

Visibility can be defined as the degree to which the atmosphere is transparent to visible light.<sup>121</sup> Visibility impairment is caused by light scattering and absorption by suspended particles and gases. Visibility is important because it has direct significance to people’s enjoyment of daily activities in all parts of the country. Individuals value good visibility for the well-being it provides them directly, where they live and work, and in places where they enjoy recreational opportunities. Visibility is also highly valued in significant natural areas, such as national parks and wilderness areas, and special emphasis is given to protecting visibility in these areas. For more information on visibility see the final 2009 PM ISA.<sup>122</sup>

EPA is working to address visibility impairment. In 1999, EPA finalized the regional haze program (64 FR 35714) to protect the visibility in Mandatory Class I Federal areas. There are 156 national parks, forests and wilderness areas categorized as Mandatory Class I Federal areas (62 FR 38680-38681, July 18, 1997). These areas are defined in CAA section 162 as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977. Figure 6-2 shows the location of the 156 Mandatory Class I Federal areas.



**Figure 6-2 Mandatory Class I Federal Areas in the U.S.**

EPA has also concluded that  $PM_{2.5}$  causes adverse effects on visibility in other areas that are not protected by the Regional Haze Rule, depending on  $PM_{2.5}$  concentrations and other factors that control their visibility impact effectiveness such as dry chemical composition and relative humidity (i.e., an indicator of the water composition of the particles). EPA revised the  $PM_{2.5}$  standards in December 2012 and established a target level of protection that is expected to be met through attainment of the existing secondary standards for  $PM_{2.5}$ .

#### 6.2.1.1 Visibility Monitoring

In conjunction with the U.S. National Park Service, the U.S. Forest Service, other Federal land managers, and State organizations in the U.S., the U.S. EPA has supported visibility monitoring in national parks and wilderness areas since 1988. The monitoring network was originally established at 20 sites, but it has now been expanded to 110 sites that represent all but one of the 156 Mandatory Federal Class I areas across the country (see Figure 6-2). This long-term visibility monitoring network is known as IMPROVE (Interagency Monitoring of Protected Visual Environments).

IMPROVE provides direct measurement of fine particles that contribute to visibility impairment. The IMPROVE network employs aerosol measurements at all sites, and optical and scene measurements at some of the sites. Aerosol measurements are taken for  $PM_{10}$  and  $PM_{2.5}$  mass, and for key constituents of  $PM_{2.5}$ , such as sulfate, nitrate, organic and elemental carbon (OC and EC), soil dust, and several other elements. Measurements for specific aerosol constituents are used to calculate "reconstructed" aerosol light extinction by multiplying the mass for each constituent by its empirically-derived scattering and/or absorption efficiency, with adjustment for the relative humidity. Knowledge of the main constituents of a site's light extinction "budget" is critical for source apportionment and control strategy development. In

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addition to this indirect method of assessing light extinction, there are optical measurements which directly measure light extinction or its components. Such measurements are made principally with either a nephelometer to measure light scattering, some sites also include an aethalometer for light absorption, or at a few sites using a transmissometer, which measures total light extinction. Scene characteristics are typically recorded using digital or video photography and are used to determine the quality of visibility conditions (such as effects on color and contrast) associated with specific levels of light extinction as measured under both direct and aerosol-related methods. Directly measured light extinction is used under the IMPROVE protocol to cross check that the aerosol-derived light extinction levels are reasonable in establishing current visibility conditions. Aerosol-derived light extinction is used to document spatial and temporal trends and to determine how changes in atmospheric constituents would affect future visibility conditions.

Annual average visibility conditions (reflecting light extinction due to both anthropogenic and non-anthropogenic sources) vary regionally across the U.S. Visibility is typically worse in the summer months and the rural East generally has higher levels of impairment than remote sites in the West. Figures 9-9 through 9-11 in the PM ISA detail the percent contributions to particulate light extinction for ammonium nitrate and sulfate, EC and OC, and coarse mass and fine soil, by season.<sup>123</sup>

## 6.2.2 Particulate Matter Deposition

Particulate matter contributes to adverse effects on vegetation and ecosystems, and to soiling and materials damage. These welfare effects result predominately from exposure to excess amounts of specific chemical species, regardless of their source or predominant form (particle, gas or liquid). The following characterizations of the nature of these environmental effects are based on information contained in the 2009 PM ISA and the 2005 PM Staff Paper as well as the 2008 Integrated Science Assessment for Oxides of Nitrogen and Sulfur- Ecological Criteria (secondary NO<sub>x</sub>/SO<sub>x</sub> ISA).<sup>124,125,126</sup>

### 6.2.2.1 Deposition of Nitrogen and Sulfur

Nitrogen and sulfur interactions in the environment are highly complex. Both nitrogen and sulfur are essential, and sometimes limiting, nutrients needed for growth and productivity of ecosystem components (e.g. algae, plants). In terrestrial and aquatic ecosystems excesses of nitrogen or sulfur can lead to acidification and nutrient enrichment.<sup>127</sup>

The process of acidification affects both freshwater aquatic and terrestrial ecosystems. Acid deposition causes acidification of sensitive surface waters. The effects of acid deposition on aquatic systems depend largely upon the ability of the ecosystem to neutralize the additional acid. As acidity increases, aluminum leached from soils, flows into lakes and streams and can be toxic to both terrestrial and aquatic biota. The lower pH concentrations and higher aluminum levels resulting from acidification make it difficult for some fish and other aquatic organisms to survive, grow, and reproduce. Research on effects of acid deposition on forest ecosystems has come to focus increasingly on the biogeochemical processes that affect uptake, retention, and cycling of nutrients within these ecosystems. Decreases in available base cations from soils are at least partly attributable to acid deposition. Base cation depletion is a cause for concern

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because of the role these ions play in acid neutralization, and because calcium, magnesium and potassium are essential nutrients for plant growth and physiology. Changes in the relative proportions of these nutrients, especially in comparison with aluminum concentrations, have been associated with declining forest health.

At current ambient levels, risks to vegetation from short-term exposures to dry deposited particulate nitrate or sulfate are low. However, when found in acid or acidifying deposition, such particles do have the potential to cause direct leaf injury. Specifically, the responses of forest trees to acid precipitation (rain, snow) include accelerated weathering of leaf cuticular surfaces, increased permeability of leaf surfaces to toxic materials, water, and disease agents; increased leaching of nutrients from foliage; and altered reproductive processes—all which serve to weaken trees so that they are more susceptible to other stresses (e.g., extreme weather, pests, pathogens). Acid deposition with levels of acidity associated with the leaf effects described above are currently found in some locations in the eastern U.S.<sup>128</sup> Even higher concentrations of acidity can be present in occult depositions (e.g., fog, mist or clouds) which more frequently impacts higher elevations. Thus, the risk of leaf injury occurring from acid deposition in some areas of the eastern U.S. is high. Nitrogen deposition has also been shown to impact ecosystems in the western U.S. For example, a study conducted in the Columbia River Gorge National Scenic Area (CRGNSA), located along a portion of the Oregon/Washington border, indicates that lichen communities in the CRGNSA have shifted to a higher proportion of nitrophilous species and the nitrogen content of lichen tissue is elevated.<sup>129</sup> Lichens are sensitive indicators of nitrogen deposition effects to terrestrial ecosystems and the lichen studies in the Columbia River Gorge clearly show that ecological effects from air pollution are occurring.

Some of the most significant detrimental effects associated with excess nitrogen deposition are those associated with a condition known as nitrogen saturation. Nitrogen saturation is the condition in which nitrogen inputs from atmospheric deposition and other sources exceed the biological requirements of the ecosystem. The effects associated with nitrogen saturation include: (1) decreased productivity, increased mortality, and/or shifts in plant community composition, often leading to decreased biodiversity in many natural habitats wherever atmospheric reactive nitrogen deposition increases significantly above background and critical thresholds are exceeded; (2) leaching of excess nitrate and associated base cations from soils into streams, lakes, and rivers, and mobilization of soil aluminum; and (3) fluctuation of ecosystem processes such as nutrient and energy cycles through changes in the functioning and species composition of beneficial soil organisms.<sup>130</sup>

In the U.S. numerous forests now show severe symptoms of nitrogen saturation. These forests include: the northern hardwoods and mixed conifer forests in the Adirondack and Catskill Mountains of New York; the red spruce forests at Whitetop Mountain, Virginia, and Great Smoky Mountains National Park, North Carolina; mixed hardwood watersheds at Fernow Experimental Forest in West Virginia; American beech forests in Great Smoky Mountains National Park, Tennessee; mixed conifer forests and chaparral watersheds in southern California and the southwestern Sierra Nevada in Central California; the alpine tundra/subalpine conifer forests of the Colorado Front Range; and red alder forests in the Cascade Mountains in Washington.

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Excess nutrient inputs into aquatic ecosystems (i.e. streams, rivers, lakes, estuaries or oceans) either from direct atmospheric deposition, surface runoff, or leaching from nitrogen saturated soils into ground or surface waters can contribute to conditions of severe water oxygen depletion; eutrophication and algae blooms; altered fish distributions, catches, and physiological states; loss of biodiversity; habitat degradation; and increases in the incidence of disease.

Atmospheric deposition of nitrogen is a significant source of total nitrogen to many estuaries in the United States. The amount of nitrogen entering estuaries that is ultimately attributable to atmospheric deposition is not well-defined. On an annual basis, atmospheric nitrogen deposition may contribute significantly to the total nitrogen load, depending on the size and location of the watershed. In addition, episodic nitrogen inputs, which may be ecologically important, may play a more important role than indicated by the annual average concentrations. Estuaries in the U.S. that suffer from nitrogen enrichment often experience a condition known as eutrophication. Symptoms of eutrophication include changes in the dominant species of phytoplankton, low levels of oxygen in the water column, fish and shellfish kills, outbreaks of toxic alga, and other population changes which can cascade throughout the food web. In addition, increased phytoplankton growth in the water column and on surfaces can attenuate light causing declines in submerged aquatic vegetation, which serves as an important habitat for many estuarine fish and shellfish species.

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 a National Oceanic and Atmospheric Administration 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.<sup>131</sup>

#### 6.2.2.2 Deposition of Heavy Metals

Heavy metals, including cadmium, copper, lead, chromium, mercury, nickel and zinc, have the greatest potential for impacting forest growth.<sup>132</sup> Investigation of trace metals near roadways and industrial facilities indicate that a substantial load of heavy metals can accumulate on vegetative surfaces. Copper, zinc, and nickel have been documented to cause direct toxicity to vegetation under field conditions. Trace metals are associated with ambient PM, however little research has been conducted on the effects associated with mixtures of contaminants. While metals typically exhibit low solubility, limiting their bioavailability and direct toxicity, chemical transformations of metal compounds occur in the environment, particularly in the presence of acidic or other oxidizing species. These chemical changes influence the mobility and toxicity of metals in the environment. Once taken up into plant tissue, a metal compound can undergo chemical changes, exert toxic effects on the plant itself, accumulate and be passed along to herbivores or can re-enter the soil and further cycle in the environment. Although there has been no direct evidence of a physiological association between tree injury and heavy metal exposures, heavy metals have been implicated because of similarities between metal deposition patterns and forest decline. This hypothesized relationship/correlation was further explored in

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high elevation forests in the northeastern U.S. These studies measured levels of a group of intracellular compounds found in plants that bind with metals and are produced by plants as a response to sublethal concentrations of heavy metals. These studies indicated a systematic and significant increase in concentrations of these compounds associated with the extent of tree injury. These data strongly imply that metal stress causes tree injury and contributes to forest decline in the northeastern United States.<sup>133</sup> Contamination of plant leaves by heavy metals can lead to elevated soil levels. Trace metals absorbed into the plant frequently bind to the leaf tissue, and then are lost when the leaf drops. As the fallen leaves decompose, the heavy metals are transferred into the soil.<sup>134,135</sup> Upon entering the soil environment, PM pollutants can alter ecological processes of energy flow and nutrient cycling, inhibit nutrient uptake, change ecosystem structure, and affect ecosystem biodiversity. Many of the most important effects occur in the soil. The soil environment is one of the most dynamic sites of biological interaction in nature. It is inhabited by microbial communities of bacteria, fungi, and actinomycetes. These organisms are essential participants in the nutrient cycles that make elements available for plant uptake. Changes in the soil environment that influence the role of the bacteria and fungi in nutrient cycling determine plant and ultimately ecosystem response.<sup>136</sup>

The environmental sources and cycling of mercury are currently of particular concern due to the bioaccumulation and biomagnification of this metal in aquatic ecosystems and the potent toxic nature of mercury in the forms in which it is ingested by people and other animals. Mercury is unusual compared with other metals in that it largely partitions into the gas phase (in elemental form), and therefore has a longer residence time in the atmosphere than a metal found predominantly in the particle phase. This property enables mercury to travel far from the primary source before being deposited and accumulating in the aquatic ecosystem. The major source of mercury in the Great Lakes is from atmospheric deposition, accounting for approximately eighty percent of the mercury in Lake Michigan.<sup>137,138</sup> Over fifty percent of the mercury in the Chesapeake Bay has been attributed to atmospheric deposition.<sup>139</sup> Overall, the National Science and Technology Council identifies atmospheric deposition as the primary source of mercury to aquatic systems.<sup>140</sup> Forty-four states have issued health advisories for the consumption of fish contaminated by mercury; however, most of these advisories are issued in areas without a mercury point source.

Elevated levels of zinc and lead have been identified in streambed sediments, and these elevated levels have been correlated with population density and motor vehicle use.<sup>141,142,143</sup> Zinc and nickel have also been identified in urban water and soils. In addition, platinum, palladium, and rhodium, metals found in the catalysts of modern motor vehicles, have been measured at elevated levels along roadsides.<sup>144</sup> Plant uptake of platinum has been observed at these locations.

### 6.2.2.3 Deposition of Polycyclic Organic Matter

Polycyclic organic matter (POM) is a byproduct of incomplete combustion and consists of organic compounds with more than one benzene ring and a boiling point greater than or equal to 100 degrees centigrade.<sup>145</sup> Polycyclic aromatic hydrocarbons (PAHs) are a class of POM that contains compounds which are known or suspected carcinogens.

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Major sources of PAHs include mobile sources. PAHs in the environment may be present as a gas or adsorbed onto airborne particulate matter. Since the majority of PAHs are adsorbed onto particles less than 1.0  $\mu\text{m}$  in diameter, long range transport is possible. However, studies have shown that PAH compounds adsorbed onto diesel exhaust particulate and exposed to ozone have half lives of 0.5 to 1.0 hours.<sup>146</sup>

Since PAHs are insoluble, the compounds generally are particle reactive and accumulate in sediments. Atmospheric deposition of particles is believed to be the major source of PAHs to the sediments of Lake Michigan.<sup>147,148</sup> Analyses of PAH deposition in Chesapeake and Galveston Bay indicate that dry deposition and gas exchange from the atmosphere to the surface water predominate.<sup>149,150</sup> Sediment concentrations of PAHs are high enough in some segments of Tampa Bay to pose an environmental health threat. EPA funded a study to better characterize the sources and loading rates for PAHs into Tampa Bay.<sup>151</sup> PAHs that enter a water body through gas exchange likely partition into organic rich particles and can be biologically recycled, while dry deposition of aerosols containing PAHs tend to be more resistant to biological recycling.<sup>152</sup> Thus, dry deposition is likely the main pathway for PAH concentrations in sediments while gas/water exchange at the surface may lead to PAH distribution into the food web, leading to increased health risk concerns.

Trends in PAH deposition levels are difficult to discern because of highly variable ambient air concentrations, lack of consistency in monitoring methods, and the significant influence of local sources on deposition levels.<sup>153</sup> Van Metre et al. noted PAH concentrations in urban reservoir sediments have increased by 200-300 percent over the last forty years and correlate with increases in automobile use.<sup>154</sup>

Cousins et al. estimate that more than ninety percent of semi-volatile organic compound (SVOC) emissions in the United Kingdom deposit on soil.<sup>155</sup> An analysis of PAH concentrations near a Czechoslovakian roadway indicated that concentrations were thirty times greater than background.<sup>156</sup>

#### 6.2.2.4 Materials Damage and Soiling

The effects of the deposition of atmospheric pollution, including ambient PM, on materials are related to both physical damage and impaired aesthetic qualities. The deposition of PM (especially sulfates and nitrates) can physically affect materials, adding to the effects of natural weathering processes, by potentially promoting or accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Only chemically active fine particles or hygroscopic coarse particles contribute to these physical effects. In addition, the deposition of ambient PM can reduce the aesthetic appeal of buildings and culturally important articles through soiling. Particles consisting primarily of carbonaceous compounds cause soiling of commonly used building materials and culturally important items such as statues and works of art.

### 6.2.3 Plant and Ecosystem Effects of Ozone

The welfare effects of ozone can be observed across a variety of scales, i.e., subcellular, cellular, leaf, whole plant, population and ecosystem. Ozone effects that begin at small spatial

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scales, such as the leaf of an individual plant, when they occur at sufficient magnitudes (or to a sufficient degree) can result in effects being propagated along a continuum to larger and larger spatial scales. For example, effects at the individual plant level, such as altered rates of leaf gas exchange, growth and reproduction can, when widespread, result in broad changes in ecosystems, such as productivity, carbon storage, water cycling, nutrient cycling, and community composition.

Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure.<sup>157</sup> In those sensitive species<sup>158</sup>, effects from repeated exposure to ozone throughout the growing season of the plant tend to accumulate, so that even low concentrations experienced for a longer duration have the potential to create chronic stress on vegetation.<sup>159</sup> Ozone damage to sensitive species includes impaired photosynthesis and visible injury to leaves. The impairment of photosynthesis, the process by which the plant makes carbohydrates (its source of energy and food), can lead to reduced crop yields, timber production, and plant productivity and growth. Impaired photosynthesis can also lead to a reduction in root growth and carbohydrate storage below ground, resulting in other, more subtle plant and ecosystems impacts.<sup>160</sup> These latter impacts include increased susceptibility of plants to insect attack, disease, harsh weather, interspecies competition and overall decreased plant vigor. The adverse effects of ozone on areas with sensitive species could potentially lead to species shifts and loss from the affected ecosystems<sup>161</sup>, resulting in a loss or reduction in associated ecosystem goods and services. Additionally, visible ozone injury to leaves can result in a loss of aesthetic value in areas of special scenic significance like national parks and wilderness areas and reduced use of sensitive ornamentals in landscaping.<sup>162</sup>

The Integrated Science Assessment (ISA) for Ozone presents more detailed information on how ozone effects vegetation and ecosystems.<sup>163</sup> The ISA concludes that ambient concentrations of ozone are associated with a number of adverse welfare effects and characterizes the weight of evidence for different effects associated with ozone.<sup>164</sup> The ISA concludes that visible foliar injury effects on vegetation, reduced vegetation growth, reduced productivity in terrestrial ecosystems, reduced yield and quality of agricultural crops, and alteration of below-ground biogeochemical cycles are causally associated with exposure to ozone. It also concludes that reduced carbon sequestration in terrestrial ecosystems, alteration of terrestrial ecosystem water cycling, and alteration of terrestrial community composition are likely to be causally associated with exposure to ozone.

#### 6.2.4 Environmental Effects of Air Toxics

Emissions from producing, transporting and combusting fuel contribute to ambient levels of pollutants that contribute to adverse effects on vegetation. Volatile organic compounds (VOCs), some of which are considered air toxics, have long been suspected to play a role in vegetation damage.<sup>165</sup> In laboratory experiments, a wide range of tolerance to VOCs has been observed.<sup>166</sup> Decreases in harvested seed pod weight have been reported for the more sensitive plants, and some studies have reported effects on seed germination, flowering and fruit ripening. Effects of individual VOCs or their role in conjunction with other stressors (e.g., acidification, drought, temperature extremes) have not been well studied. In a recent study of a mixture of VOCs including ethanol and toluene on herbaceous plants, significant effects on seed production, leaf water content and photosynthetic efficiency were reported for some plant species.<sup>167</sup>

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Research suggests an adverse impact of vehicle exhaust on plants, which has in some cases been attributed to aromatic compounds and in other cases to nitrogen oxides.<sup>168,169,170</sup> The impacts of VOCs on plant reproduction may have long-term implications for biodiversity and survival of native species near major roadways. Most of the studies of the impacts of VOCs on vegetation have focused on short-term exposure and few studies have focused on long-term effects of VOCs on vegetation and the potential for metabolites of these compounds to affect herbivores or insects.

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- <sup>2</sup> Regulatory definitions of PM size fractions, and information on reference and equivalent methods for measuring PM in ambient air, are provided in 40 CFR Parts 50, 53, and 58. With regard to national ambient air quality standards (NAAQS) which provide protection against health and welfare effects, the 24-hour PM<sub>10</sub> standard provides protection against effects associated with short-term exposure to thoracic coarse particles (i.e., PM<sub>10-2.5</sub>).
- <sup>3</sup> U.S. EPA (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F, 2009.
- <sup>4</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F.
- <sup>5</sup> The causal framework draws upon the assessment and integration of evidence from across epidemiological, controlled human exposure, and toxicological studies, and the related uncertainties that ultimately influence our understanding of the evidence. This framework employs a five-level hierarchy that classifies the overall weight of evidence and causality using the following categorizations: causal relationship, likely to be causal relationship, suggestive of a causal relationship, inadequate to infer a causal relationship, and not likely to be a causal relationship (U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F, Table 1–3).
- <sup>6</sup> 78 FR 3086 (January 15, 2013) pages 3103-3104.
- <sup>7</sup> 77 FR 38890 (June 29, 2012) pages 38906-38911.
- <sup>8</sup> These causal inferences are based not only on the more expansive epidemiological evidence available in this review but also reflect consideration of important progress that has been made to advance our understanding of a number of potential biologic modes of action or pathways for PM-related cardiovascular and respiratory effects (U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F, chapter 5).
- <sup>9</sup> 78 FR 3086 (January 15, 2013) pages 3103-3104.
- <sup>10</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F, chapter 6 (section 6.5) and chapter 7 (Section 7.6).
- <sup>11</sup> 78 FR 3103 (January 15, 2013).
- <sup>12</sup> 78 FR 3103 (January 15, 2013).
- <sup>13</sup> 78 FR 3103-3104 (January 15, 2013).
- <sup>14</sup> 78 FR 3104 (January 15, 2013).
- <sup>15</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. pg 2-13.
- <sup>16</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. Chapter 8 and Chapter 2.
- <sup>17</sup> 77 FR 38890,(June 29, 2012) page 38910.
- <sup>18</sup> 78 FR 3086 (January 15, 2013) page 3104.
- <sup>19</sup> U.S. EPA. (2011). Policy Assessment for the Review of the PM NAAQS. U.S. Environmental Protection Agency, Washington, DC, EPA/452/R-11-003. section 2.2.1.
- <sup>20</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. Chapter 8 and Chapter 2 (Section 2.4.1).

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- <sup>21</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. Section 2.3.4 and Table 2-6.
- <sup>22</sup> 78 FR 3167-8 (January 15, 2013).
- <sup>23</sup> 77 FR 38947-51 (June 29, 2012).
- <sup>24</sup> U.S. EPA. (2009). Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. Section 2.3.5 and Table 2-6.
- <sup>25</sup> 78 FR 3121 (January 15, 2013).
- <sup>26</sup> Human exposure to ozone varies over time due to changes in ambient ozone concentration and because people move between locations which have notable different ozone concentrations. Also, the amount of ozone delivered to the lung is not only influenced by the ambient concentrations but also by the individuals breathing route and rate.
- <sup>27</sup> U.S. EPA. Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-10/076F, 2013. The ISA is available at <http://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=247492#Download>.
- <sup>28</sup> The ISA evaluates evidence and draws conclusions on the causal relationship between relevant pollutant exposures and health effects, assigning one of five “weight of evidence” determinations: causal relationship, likely to be a causal relationship, suggestive of a causal relationship, inadequate to infer a causal relationship, and not likely to be a causal relationship. For more information on these levels of evidence, please refer to Table II in the Preamble of the ISA.
- <sup>29</sup> U.S. EPA (2008). *Integrated Science Assessment (ISA) for Sulfur Oxides – Health Criteria* (Final Report). EPA/600/R-08/047F. Washington, DC; U.S.EPA. Retrieved on March 19, 2009 from <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=198843>.
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## Chapter 7 Impacts of the Rule on Emissions and Air Quality

This chapter presents the overall emissions and air quality impacts of the Tier 3 standards. Section 7.1 describes the national impacts on criteria and toxic emissions resulting from the Tier 3 program. Section 7.2 describes the air quality effects of the emission reductions. Because the air quality analysis requires emission inventories with greater geographical resolution than the national average inventories, the emission inventories described in the two sections were developed separately, as described in each portion of this chapter. Section 7.3 discusses the impact of the program on greenhouse gas emissions.

### 7.1 Criteria and Toxic Pollutant Emission Impacts

#### 7.1.1 Overview

This section presents the projected national emission impacts of Tier 3 standards on criteria and toxic air pollutants for selected calendar years, and the methodology used to estimate these reductions. The Tier 3 fuel and vehicle standards will directly reduce emissions of nitrogen oxides (NO<sub>x</sub>) (including nitrogen dioxide (NO<sub>2</sub>)), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM<sub>2.5</sub>), air toxics, and sulfur dioxide (SO<sub>2</sub>). The implementation of lower sulfur gasoline will reduce criteria and air toxic emissions from the existing gasoline-powered vehicle fleet, and cause some reductions in SO<sub>2</sub> emissions from the nonroad gasoline sector. The largest reductions come immediately following the implementation of the fuel standard, as a significant share of overall emissions are produced by Tier 2 and older vehicles. To reflect these early reductions, we present the emission reductions in calendar year 2018, near the beginning of the fuel program.

The vehicle standards will reduce emissions as the cleaner cars and trucks begin to enter the fleet in model year 2017 and model year 2018, respectively. The magnitude of reduction will grow as the contribution of these vehicles to fleet emissions becomes more prominent – to reflect this, we are also presenting emission reductions in calendar year 2030, when 70 percent of the miles travelled are from vehicles that meet the fully phased-in Tier 3 standards. Furthermore, 2030 is a standard out-year for evaluation; it is used for air quality modeling in this rule as well as recent EPA rules. However, the full impact of the vehicle program will be realized after 2030. For this reason, we are also presenting emissions reductions in calendar year 2050, when the fleet will have fully turned over to the vehicles meeting the fully phased-in Tier 3 standards. As explained in Section 7.2, air quality modeling was done only for 2018 and 2030.

Emission impacts presented in this section are estimated on an annual basis, for all 50 U.S. states plus the District of Columbia, Puerto Rico and the U.S. Virgin Islands. The reductions from onroad sources were estimated using an updated version of EPA's Motor Vehicle Emission Simulator (MOVES) model, as described in detail in Section 7.1.3; and the NONROAD model for offroad sources. Reductions were estimated compared to a reference case that assumed an average gasoline sulfur level of 30 ppm (10 ppm in California) and continuation

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of the Tier 2 vehicle program indefinitely, with the exception of California and Section 177 states that have adopted the LEV III program. For those states, adoption of LEV III was included in the reference case.<sup>A</sup>

The emission inventory methodology applied to generate these national estimates does differ from the methodology used to generate the finely resolved emission inventories needed for the air quality modeling, leading to some differences in absolute estimates of tons reduced between the two analyses. These differences are discussed in Section 7.2.1.1.

### 7.1.2 Scenarios Modeled

We analyzed emission impacts of the Tier 3 vehicle emissions and fuel standards by comparing projected emissions for future years without the Tier 3 rule (reference scenario) to projected emissions for future years with the Tier 3 standards in place (control scenario). Table 7-1 below presents an overview of the reference and control scenarios for calendar years 2018 and 2030. Both scenarios reflect the renewable fuel volumes and market fractions projected by the Annual Energy Outlook 2013 Report.<sup>1</sup> We thus refer to this renewable fuel level as “AEO 2013”.

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<sup>A</sup> These states include Connecticut, Delaware, Maryland, Maine, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Washington, and Vermont.

**Table 7-1 Overview of Reference and Control Scenarios**

	Reference Scenario	Control Scenario
2018	Renewable Fuels: AEO 2013 <sup>a</sup> 17.5 B gallons renewable fuels (18.3 B ethanol-equivalent gallons): 16.0 B gallons ethanol: E10 <sup>b</sup> , E15 <sup>c</sup> , E85 <sup>d</sup>  Fuel Sulfur Level: 30 ppm (10 ppm California)  Fleet: <sup>e</sup> 96 percent Tier 2 and older vehicles 4 percent LEV III vehicles	Renewable Fuels: AEO 2013 <sup>a</sup> 17.5 B gallons renewable fuels (18.3 B ethanol-equivalent gallons): 16.0 B gallons ethanol: E10 <sup>b</sup> , E15 <sup>c</sup> , E85 <sup>d</sup>  Fuel Sulfur Level: 10 ppm  Fleet: <sup>e</sup> 86 percent Tier 2 and older vehicles 14 percent Tier 3/LEV III vehicles
2030	Renewable Fuels: AEO 2013 <sup>a</sup> 17.6 B gallons renewable fuels (18.6 B ethanol-equivalent gallons): 15.3 B gallons ethanol: E10 <sup>b</sup> , E15 <sup>c</sup> , E85 <sup>d</sup>  Fuel Sulfur Level: 30 ppm (10 ppm California)  Fleet: <sup>e</sup> 76 percent Tier 2 and older vehicles 24 percent LEV III vehicles	Renewable Fuels: AEO 2013 <sup>a</sup> 17.6 B gallons renewable fuels (18.6 B ethanol-equivalent gallons): 15.3 B gallons ethanol: E10 <sup>b</sup> , E15 <sup>c</sup> , E85 <sup>d</sup>  Fuel Sulfur Level: 10 ppm  Fleet: <sup>e</sup> 21 percent Tier 2 and older vehicles 79 percent Tier 3/LEV III vehicles

<sup>a</sup> U.S. Energy Information Administration, Annual Energy Outlook 2013 (April 15, 2013)

<sup>b</sup> Gasoline containing 10 percent ethanol by volume

<sup>c</sup> Gasoline containing 15 percent ethanol by volume

<sup>d</sup> Gasoline containing up to 85 percent ethanol by volume (74 percent nominal used in this analysis)

<sup>e</sup> Fraction of the vehicle population

Our reference scenarios assumed an average fuel sulfur level of 30 ppm in accordance with the Tier 2 gasoline sulfur standards. Under the Tier 3 program, federal gasoline will contain no more than 10 ppm sulfur on an annual average basis by January 1, 2017 (Section V of the preamble), and we therefore assumed a nationwide fuel sulfur level of 10 ppm for both future year control cases. A more detailed description of our fuel inputs and assumptions for this analysis can be found in Section 7.1.3.2.

We assumed a continuation of the existing Tier 2 standards for model years 2017 and later in modeling emissions for our reference scenario, with the exception of California and Section 177 states that have adopted the LEV III program. Our Tier 3 control scenario modeled the suite of exhaust and evaporative emission standards for light-duty vehicles (LDVs), light duty trucks (LDTs: 1-4), medium passenger vehicles (MDPVs) and large pick-ups and vans (Class 2b and 3 trucks) described in Section IV of the preamble, including:

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- Fleet average Federal Test Procedure (FTP) NMOG+NO<sub>x</sub> standards of 30 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2025 for the light-duty fleet under 6,000 lbs. GVWR and phasing in from MYs 2018 to 2025 for the light-duty fleet over 6,000 lbs. GVWR, and MDPVs
  - Fleet average Supplemental Federal Test Procedure (SFTP) NMOG+NO<sub>x</sub> standards of 50 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2025 for the light-duty fleet under 6,000 lbs. GVWR and phasing in from MYs 2018 to 2025 for the light-duty fleet over 6,000 lbs. GVWR, and MDPVs
  - Per-vehicle FTP PM standard of 3 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2022 for the light-duty fleet under 6,000 lbs. GVWR and phasing in from MYs 2018 to 2022 for the light-duty fleet over 6,000 lbs. GVWR, and MDPVs
  - Per-vehicle US06-only PM standard of 10 mg/mi for LDVs, LDTs and MDPVs through MY2021 and of 6 mg/mi for MY2022 and later model years
  - New standards for Class 2b and 3 trucks phasing in by MY 2022 including NMOG+NO<sub>x</sub> declining fleet average, and more stringent PM standards
  - More stringent evaporative emission standards for diurnal plus hot soak emissions, a new canister bleed test and emission standard, and new requirements addressing evaporative leaks on in-use vehicles.
  - New refueling emission control requirements for all complete HDGVs equal to or less than 14,000 lbs GVWR (i.e., Class 2b/3 HDGVs), starting in the 2018 model year, and for all larger HDGVs by the 2022 model year

The Tier 3 standards will reduce onroad criteria and toxic emissions, and to a much smaller extent, nonroad SO<sub>2</sub> emissions, but will not affect upstream, refueling or portable fuel container criteria or toxic emissions. The methodology for estimating emission impacts and the results for onroad and nonroad emissions are described in Section 7.1.3 and Section 7.1.4, respectively.

Implementation of the Tier 3 standards is aligned with the model year 2017-2025 Light-Duty GHG standards<sup>2</sup> to achieve significant criteria pollutant and GHG emissions reductions while providing regulatory certainty and compliance efficiency to the auto and oil industries. Accordingly, the analyses for the Tier 3 rule include the final LD GHG standards in both the reference and control scenarios, and thus account for their impacts on the future vehicle fleet and future fuel consumption.

The analysis described here accounts for the following national onroad rules:

- Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, February 10, 2000)

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- Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, January 18, 2001)
  - Mobile Source Air Toxics Rule (72 FR 8428, February 26, 2007)
  - Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program (75 FR 14670, March 26, 2010)
  - Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards for 2012-2016 (75 FR 25324, May 7, 2010)
  - Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (76 FR 57106, September 15, 2011)
  - 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards (77 FR 62623, October 15, 2012)

In addition, the modeling accounts for state and local rules including local fuel standards, Inspection/Maintenance programs, Stage II refueling controls, the National Low Emission Vehicle Program (NLEV), and the Ozone Transport Commission (OTC) LEV Program. Furthermore, the Tier 3 emissions modeling for both the national inventory and air quality analysis includes California's LEV III program and its associated emission reductions from both California and the states that adopted the LEV III program, in the baseline scenario. See the Tier 3 emissions modeling TSD for more detail.

### 7.1.3 Onroad Emissions

#### 7.1.3.1 Methodology Overview

EPA's official model for use in estimating mobile source emissions is known as the Motor Vehicle Emission Simulator (MOVES), with the most recent version approved for use in State Implementation Plan (SIP) and transportation conformity analyses being MOVES2010b.<sup>3</sup> A version of MOVES2010b, updated specifically for this analysis, was used to estimate emissions of criteria and air toxic emissions from on-road gasoline and diesel vehicles for the entire U.S. for the reference and control scenarios described in Section 7.1.2 above, for calendar years 2018, 2030, and 2050.<sup>B</sup>

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<sup>B</sup> The MOVES updates are reflected in a version of the MOVES model code (October 2, 2012 Version F) and concurrently updated versions of the MOVES default database; October 2, 2012 Version K\_truncatedGFRE for the inventory runs for the air quality modeling and October 2, 2012 Version L\_truncatedGFREIM for the national inventory runs (see Section 7.2.1.1 for details). Both the code and the databases are available in the Tier 3 docket. As these updates are still draft, these code and/or databases are not approved for official use in SIP and conformity analyses.

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The MOVES model updates affecting reference and control case emissions were extensive, and are documented in a separate memorandum to the Tier 3 docket.<sup>4</sup> Updates made to MOVES2010b for this analysis primarily incorporated major new research in four areas. The first involves fuel effects on exhaust emissions from Tier 2 vehicles. The second involves improvements in estimation of evaporative emissions from all vehicles, including Tier 2 vehicles. The third involves accounting for the effects of fuel sulfur level on exhaust emissions. The fourth involves estimating the exhaust emissions from vehicles using E85 fuel (gasoline containing up to 85 percent ethanol by volume). Other than sulfur, these changes had more bearing on updating the reference case emissions than on the projected reductions from the Tier 3 standards.

The effects of changes in fuel properties on exhaust emissions of Tier 2 vehicles, which comprise the majority of the fleet by 2018, were assessed through the results of the EPA Act Phase-3 Program.<sup>5</sup> Specific fuel properties addressed include ethanol level, aromatics, distillation properties, and volatility (Reid Vapor Pressure, or RVP). Methods used to account for the effects of these properties in inventory modeling are described in a separate memorandum to the docket.<sup>6</sup> Improvements in estimating and projecting evaporative emissions are described in this document (see Section 7.1.3.3.7). Finally, because the updates to fuel sulfur effects are critical for estimating the reductions from the Tier 3 program, they are also presented in detail in Section 7.1.3.4.

In addition to fuel effects, we also improved emission estimates in other areas. The sulfate, sulfur dioxide, organic carbon and elemental carbon emission rates for 2007-and-later heavy-duty diesel vehicles were updated to include information from a recent study that examined the composition of particulate emissions from advanced diesel engines.<sup>7</sup> HC, CO and NO<sub>x</sub> start and running emission rates for light heavy-duty gasoline vehicles were updated to fix an error in these rates for 2007-and-later emissions, and we repaired errors in the MOVES2010b emission rates for NH<sub>3</sub>, NO and NO<sub>2</sub>.<sup>C,8</sup>

The MOVES version used for this analysis also includes an added capability to model many hazardous air pollutants. And, additional changes were made to the MOVES2010b model to facilitate the large number of parallel runs that needed to be done to complete the Tier 3 air quality modeling inventories. These changes are also detailed in the docket memo for the proposed rule addressing MOVES updates<sup>9</sup>.

In addition to the model updates needed to incorporate new research, a set of custom inputs were developed to allow MOVES to model the reference and control scenarios. Some of these inputs were required to reflect regional variations in fuels for both the reference and control scenarios, as discussed in detail in Section 7.1.3.2. Other inputs were required to model the vehicle program for exhaust and evaporative emissions, discussed in Section 7.1.3.3.

The national emission inventories presented in this section were developed with a simpler and quicker method than we used for the air quality modeling. The abbreviated approach makes

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<sup>C</sup> The changes to the NO and NO<sub>2</sub> rates did not impact the total NO<sub>x</sub> emissions, but facilitated the output of separate results for nitric oxide and nitrogen dioxide.

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the analysis easier for stakeholders and other commenters to replicate. National emission inventories were developed using the pre-aggregation feature of MOVES at the state level. For all pollutants, the default pre-aggregation level of ‘hour’ was selected, which condenses the county-level temperatures into a single state average temperature by hour of the day. While the model and many of the inputs are identical for the emission inventory modeling performed for the air quality analysis, the pre-aggregation approach is coarser than the approach described in Section 7.2 used to develop the gridded/hourly emission inventories needed for air quality modeling. In addition to the difference in temperature resolution (state average vs. gridded hourly temperature), the national emission inventory analysis also used information contained in the MOVES2010b default database for fleet age distributions, activity inputs (e.g., speeds), temperatures, emission standards, and inspection/maintenance programs. In contrast, as discussed in Section 7.2, the air quality modeling inventory methodology used the data supplied by state and regional modelers for many of these inputs, and employed hourly meteorological data. Both the national emission inventories and the air quality modeling inventory accounted for the state adoption of California LEV III standards, as well as previous LEV programs, in the modeling baseline. The future year projections of vehicle population and vehicle miles travelled were updated to reflect the latest estimates from the Department of Energy’s Annual Energy Outlook (AEO2013).

To assure that adequate temperature resolution was incorporated into the national emission inventory processes, MOVES was run separately for January and July, and annual emissions were extrapolated (for all pollutants except PM) by scaling up each month by a factor of 5.88. For PM, to offset the disproportionate effect of the colder temperature January results, a scaling factor of 4.3 was applied to January and 7.5 to July; these factors were determined based on analysis of annual PM emissions during modeling for the RFS2 rule.<sup>10</sup> The updated MOVES version, and all inputs and outputs that produced the results presented in Section 7.1.5 of this Chapter, are contained in the Tier 3 rulemaking docket.

#### 7.1.3.2 Fuel Inputs

Estimating national emission inventories required translation of the reference and control fuel scenarios presented in Table 7-1 into a discrete set of fuels (defined by RVP, sulfur content, ethanol level, aromatics content, olefin content, T50 and T90), and the market share of these fuels, by month and county. These data were converted into “fuel supply” database tables used by MOVES to estimate emission inventories. Even for the state-level emission inventories calculated at a pre-aggregated level, these county-level fuel supply tables are retained to develop composite emissions that reflect the market share of the entire set of fuels that define the U.S. fuel pool. The crux of estimating emission impacts for the Tier 3 fuel program was the development of fuel supply database tables that reflected the difference between the reference and control scenarios, discussed in the following sections.

In order to further simplify the final analysis, provide more consistent results for future efforts, and create additional data for renewable volume sensitivity, we elected to use projections found in the Annual Energy Outlook 2013 report<sup>1</sup> for our primary case. This report provided the basis for our analysis with conventional fuel volumes, as well as renewable fuel volumes and flex fuel vehicle usage year by year. In some years, the volume and usage differ significantly from the analysis found in the proposal (based on the RFS2 “mid-ethanol” full compliance case).

Comparisons between our final analysis and the analysis completed in the proposal can be found in the following subsection below.

#### 7.1.3.2.1 AEO Fuel Volume Analysis

The Annual Energy Outlook 2013 report provided the basis for the fuel volumes used in this analysis. The AEO2013 report contains updated effects on fuel volumes from programs not included in the analysis for the proposal, most notably the latest light duty greenhouse gas standards<sup>2</sup>. The inclusion of that rulemaking significantly reduces the overall volume of fuel used as compared to the volume found in the proposal. The AEO2013 projections also show a lower volume of renewable fuel used, and coupled with the reduced fuel volumes, show an increasing fraction at which renewable fuel would have to be blended into the supply as compared to volumes found in the RFS2 rulemaking as well as the NPRM modeling. A comparison between the volumes used for the final analysis and the proposal can be found in Table 7-2, below:

**Table 7-2 Comparison of NPRM Fuel Volume with FRM Fuel Volume**

(Million gallons)	<b>NPRM 2017</b>	<b>FRM 2018</b>	<b>NPRM 2030</b>	<b>FRM 2030</b>
Total Fuel Volume	144.9	129.6	148.3	113.5
Ethanol Volume	21.6	15.2	30.5	14.6
E10 Volume	84.5	100.7	1.7	68.4
E15 Volume	60.0	27.5	146.6	43.4
E85 (as E74) Volume	0.4 <sup>a</sup>	1.4	0.0	1.7

<sup>a</sup> This small volume of E85 fuel was not modeled in the NPRM 2017 version

The AEO2013 report shows that due to the increase in renewable fuel blending levels, E85 must be included in the fuel supply for the final analysis as compared to the NPRM. E85 fueling rates were derived from the AEO2013 report on flex fuel vehicle sales and E85 fuel volume, and can be found in Table 7-3, below. This table describes the fraction of the gasoline vehicle population that is flex-fuel capable, the fraction of E85 in the overall gasoline fuel pool, and finally the fraction of refueling events where flex-fuel capable vehicles fill with E85 fuel.

**Table 7-3 FFV Population, E85 Fuel Volume and Overall FFV E85 Usage Rates**

	<b>2018</b>	<b>2030</b>
FFV Pop. % (of gasoline vehicles)	6.9%	8.1%
E85 Vol % (of gasoline fuel volume)	1.0%	1.5%
Overall E85 Usage by FFVs %	15.3%	18.9%

Updates in modeling technique have allowed us to vary ethanol blending penetration by region, with data provided by the AEO2013 report. These regional rates vary between 63% - 83% for E10 penetration and 17% - 37% for E15 penetration in 2018 and between 45% - 78% for E10 penetration and 22% - 55% for E15 penetration in 2030. The remainder of fuel was E85, with no E0 included in the on-road fuel supply. The non-road/off-road fuel supply was assumed to be 100 percent E10. For more information regarding non-road modeling, please see Section

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7.1.4. A breakdown of ethanol penetration by region can be found in subsection 7.1.3.2.7, Table 7-7.

*7.1.3.2.2 Baseline and Reference Case*

Since the platform for air quality modeling is based on 2007, a baseline fuel supply was needed for that year. The regional fuel supply approach was applied using Alliance fuel survey data as well as the EPA refinery compliance data for the year 2007, as described in the subsection 7.1.3.2.4.

Reference cases in the years 2018 and 2030 were required for the final analysis. These reference cases were also created following the regional fuel supply approach using Alliance fuel survey data as well as the EPA refinery compliance data from the years 2011 and 2012 as the most up-to-date surrogate for fuel properties in those years. Additionally, these fuel supplies were further corrected to provide consistent results region to region when compared to the control cases. These corrections are as follows below:

Benzene and sulfur levels for all counties were corrected to properly reflect the introduction of the Control of Hazardous Air Pollutants from Mobile Sources (MSAT2) (2007) rule and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (1999). Benzene corrections were made by Petroleum Administration Defense Districts (PADD) following results from the MSAT2 analysis of downstream benzene levels. No other fuel property changes were found to change significantly with a change in benzene levels. Benzene levels by PADD follow in Table 7-4 below:

**Table 7-4 MSAT2 Downstream Fuel Benzene Levels**

<b>PADD</b>	<b>CG</b>	<b>RFG</b>
1	0.61	0.54
2	0.63	0.60
3	0.63	0.54
4	0.86	N/A
5	0.65	0.61
CA	N/A	0.62

Sulfur corrections were made to all counties based on the default sulfur level found in the 2007 baseline fuel supply. Counties with a sulfur level higher than 30 ppm were reduced to 30 ppm to reflect the gasoline sulfur standards of the Tier 2 rule (counties subjected to lower fuel sulfur standards, such as in California, were not changed). Refinery modeling showed that there is an effect on aromatics level when sulfur is reduced. Corrections to the aromatics level based on refinery modeling for counties with reduced sulfur level were made as follows:

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1) A “high sulfur” aromatics level was determined using the following equation:

$$\text{high sulfur aromatics level} = \left( \frac{1}{\text{sulfur level}} * 0.479 \right) + 24.60$$

**Equation 7-1 Aromatics Level from Initial Sulfur Concentration**

- 2) A “low sulfur” aromatics level was determined using the same equation, substituting 30ppm for the initial sulfur level of the county
- 3) An aromatics delta was calculated by subtracting the “low sulfur” aromatics level from the “high sulfur” aromatics level
- 4) This aromatics delta was applied as a correction for sulfur reduction to the original aromatics level for the county as appearing in the 2007 fuel supply

Diesel fuel sulfur levels were also adjusted to 15ppm to reflect low sulfur diesel levels. There were no other changes to the 2018 and 2030 reference cases. For detailed fuel property information by region for the reference case, please refer to the subsection 7.1.3.2.7, Table 7-9.

*7.1.3.2.3 Control Case*

The Tier 3 control fuel scenarios for the years 2018 and 2030 used the fuel supplies constructed for the 2018 and 2030 reference cases described in the previous section as a foundation. To develop the control scenario fuel supplies, we modified the reference case fuel supplies to reflect the sulfur program in the Tier 3 control case by reducing sulfur from 30 ppm to 10 ppm for all gasoline. Changes in other fuel properties resulting from sulfur control were determined by refinery modeling and reflected in the control case, such as an increase in aromatics and decrease in olefins and distillation properties, as shown in Table 7-13. These changes were made to every county with fuel exceeding a sulfur level of 10ppm. Please note, the impacts to other fuel properties due to sulfur reduction are significantly lower in the final analysis than what was used for the proposal. Updated refinery modeling results have reduced the impact on these other fuel properties, which is properly reflected in the final analysis fuel supplies. For more information regarding refinery modeling adjustments, please refer to subsection 7.1.3.2.9.

The result of this effort was two additional alternate fuel supply databases tables for use in MOVES, reflecting the control case fuel supplies in 2018 and 2030; these tables were used for the development of the final national emissions inventory as well as the inventory used for air quality modeling.

*7.1.3.2.4 Regional Fuel Supply*

In addition to simplifying the fuel volumes, we also made an effort to simplify the county-level fuel properties within the MOVES fuel supply for the final analysis. Many counties in the previous analysis contained unique fuel properties not associated with neighboring

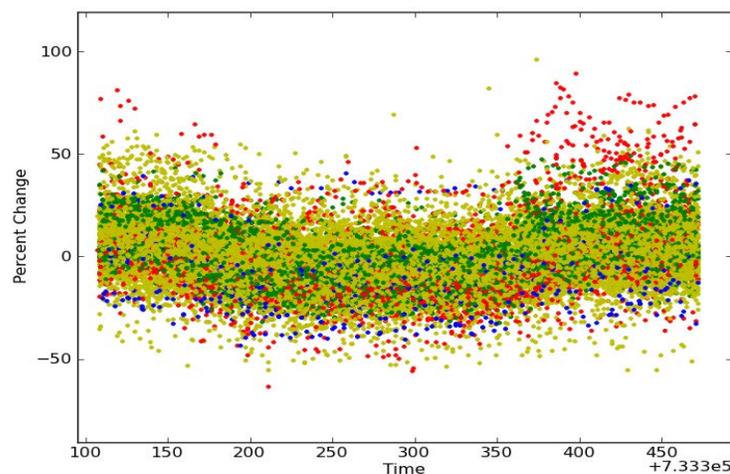
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counties or pipeline locations based on fuel survey data performed in those individual counties. We did not feel that it was appropriate to continue this approach for the final analysis, and developed new fuel properties based on averages of these survey data as well as data provided to us at the refinery gate as part of EPA fuel compliance. We believe this average data by region provides a more consistent and maintainable basis for this final analysis as well as future analyses. Details regarding this regional fuels approach can be found in the following subsections, 7.1.3.2.5 – 7.1.3.2.6.

#### *7.1.3.2.5 Rationale for Updating MOVES Fuel Supply County Level Properties*

The fuel supplies used in the proposal analysis as well as the default version of MOVES are based on single-point county data on a small number of cities. Fuel survey data has tended to include large deviation depending on when fuel was sampled, which batch of fuel the sample was pulled from, which blend of fuel was being sampled, and/or when the station was refueled. Depending on which batch of fuel was at a station during sampling and testing, properties could dramatically impact the result in one city versus another. Updating this data would also result in potentially wide swings in assumed fuel properties for that area, when in reality the average fuel for that location had not changed. As a result, the single point county data are not very useful for creating national fuel supplies. Refer to Figure 7-1 below, for an example of deviation in fuel batch parameters for E200 through a one year period. Note while there is an overall trend in fuel property variation throughout the year, which is expected, there is also a deviation of up to 50% in some cases.

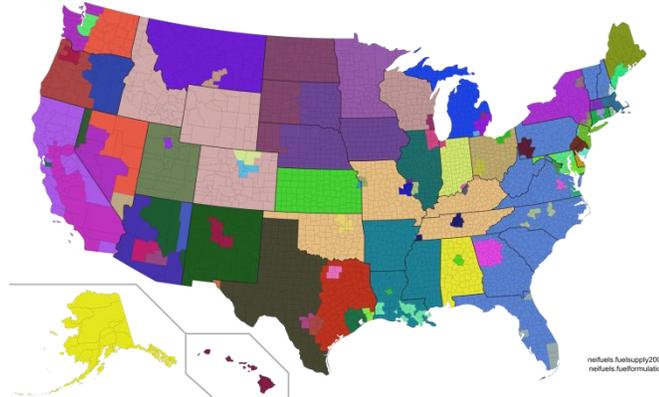
**Figure 7-1 Fuel Property Batch Variation Throughout One Year**



As a result, the use of this survey data city-by-city has led to a fuel supply contained in the default version of MOVES, as well as the proposal analysis, that includes many variations of fuel properties in a non-contiguous fashion, often with little application to fuel distribution or overall properties. Without aggregation of the data, the fuel supply became very large, and less

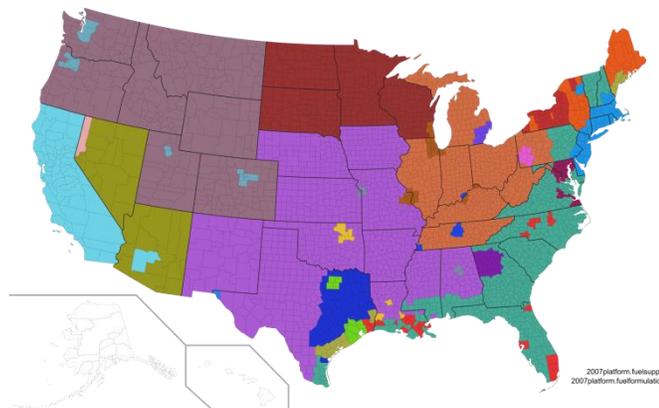
representative of our actual knowledge of fuel property variation overall. For example, the fuel supply used in the proposal analysis contained approximately 425 various fuel formulations, spread over the country in a way not representative of distribution networks, natural borders, and state/regional programs. Please see Figure 7-2, below, for a detailed layout of the proposal fuel supply:

**Figure 7-2 National Map of Unique Fuel Properties Used in Proposal**



With a new method aggregating fuel survey data, as well as incorporating refinery batch-by-batch fuel compliance data, a more representative fuel supply was created for the final analysis. This new version of the fuel supply better accounts for fuel production and distribution networks, natural borders, and regional/state/local variations in fuel policy. Reducing the number of fuel formulations in the supply also increased our confidence that the fuels in a particular region represent fuel being used in that region; rather than being based on samples taken in a particular city or small set of cities. The new regional fuel supply method created approximately 45 fuel formulations. Please see Figure 7-3, below, for a detailed layout of the regional fuel supply used in the final analysis:

**Figure 7-3 National Map of Unique Fuel Properties Using Regional Fuels Approach**



7.1.3.2.6 Fuel Regions

There are eleven general fuel regions used in the new regional fuel supply approach. Table 7-5 identifies and briefly describes each region as used in the MOVES fuel supply database. Please see Figure 7-3, above, for an illustration of these fuel regions on a national map.

**Table 7-5 Description of Fuel Regions**

<b>Region ID#</b>	<b>Region Name</b>	<b>Description</b>
<b>1</b>	<b>East Coast</b>	East coast states up to Appalachians, Florida, and gulf coast region
<b>2</b>	<b>Midwest</b>	Midwest states up to Appalachians (not including Wisconsin), Tennessee, Kentucky
<b>3</b>	<b>South</b>	Southern states not including gulf coast, Nebraska, Iowa
<b>4</b>	<b>North</b>	North and South Dakota, Minnesota, Wisconsin
<b>5</b>	<b>Rocky Mts</b>	Pacific northwest, Rocky mountain states, Utah
<b>6</b>	<b>CA/NV/AR</b>	California, Nevada, Arizona NOT using RFG
<b>11</b>	<b>East Coast RFG</b>	East coast states and regions using RFG fuel or under a controlled fuel program
<b>12</b>	<b>MD/VA</b>	Maryland and Virginia regions using RFG fuel or under a controlled fuel program
<b>13</b>	<b>Texas RFG</b>	Texas regions using RFG fuel or under a controlled fuel program
<b>14</b>	<b>Midwest RFG</b>	Midwest regions using RFG fuel or under a controlled fuel program
<b>15</b>	<b>California</b>	California using California fuel, Nevada and Arizona regions using California Fuel

7.1.3.2.7 Fuel Properties by Region

The following subsection contains tables detailing fuel properties by region for the final analysis 2007 baseline, 2018 and 2030 reference cases, and the 2018 and 2030 control cases.

Fuel properties in Table 7-8, Table 7-9 and Table 7-10 below are for conventional gasoline only. To derive E10 and E15 properties, please refer to Table 7-6, below, for the adjustment factors used.

**Table 7-6 Ethanol Blending Adjustments for Conventional Gasoline Properties Within Fuel Regions**

ETHANOL ADJUSTMENT FACTORS (from E0 to EXX)										
FUEL	DESCRIPTION	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90
E10 S	E10 Summer Fuel	1.00		-2.02	-0.46		3.11	0.39	-6.34	-1.77
E10 W	E10 Winter Fuel	1.00		-3.65	-2.07		4.88	0.54	-9.96	-2.45
E15 S	E15 Summer Fuel			-3.36	-1.64		9.24	0.91	-18.86	-4.14
E15 W	E15 Winter Fuel			-5.69	-3.27		11.11	1.01	-22.67	-4.59

**Table 7-7 Non - Flex Fuel Ethanol Fuel Blending Levels by Region<sup>1</sup>**

REGION	2018		2030	
	E10	E15	E10	E15
1 East Coast	0.834	0.166	0.628	0.372
2 Midwest	0.722	0.278	0.592	0.408
3 South	0.746	0.254	0.447	0.553
4 North	0.632	0.368	0.544	0.456
5 Rocky Mts	0.817	0.183	0.686	0.314
6 CA/NV/AR	0.822	0.178	0.780	0.220
11 East Coast RFG	0.834	0.166	0.628	0.372
12 MD / VA RFG	0.834	0.166	0.628	0.372
13 Texas RFG	0.746	0.254	0.447	0.553
14 Midwest RFG	0.722	0.278	0.592	0.408
15 California	0.000	1.000	0.000	1.000

<sup>1</sup> This table does not include the contribution of fuel blending due to flex fuel (E85) usage. For flex fuel blending levels, please refer to Table 7-3

**Table 7-8 2007 Baseline Case Fuel Properties by Region**

REGION		SUMMER									WINTER								
		RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90
1	East Coast	8.70	34.66	27.60	12.78	1.004	44.06	80.22	214.9	337.6	11.31	34.27	24.68	12.71	0.915	48.52	82.52	202.4	330.8
2	Midwest	8.70	42.00	28.52	9.95	1.540	47.87	81.24	211.5	339.6	11.84	35.77	25.51	9.36	1.495	52.03	84.02	198.7	239.2
3	South	8.70	78.88	28.55	9.02	1.689	45.56	84.71	211.3	318.2	10.85	80.44	26.47	8.55	1.661	48.78	86.80	205.3	312.5
4	North	8.70	37.92	24.53	8.65	1.211	49.17	82.23	201.2	333.7	12.55	32.90	21.67	8.67	1.081	52.49	85.06	195.2	322.3
5	Rocky Mts	8.70	65.06	28.17	9.67	1.765	46.03	85.26	207.9	318.3	11.75	57.50	25.76	9.50	1.737	50.41	86.84	199.5	311.4
6	CA/NV/AR	8.70	78.88	28.55	9.02	1.689	45.56	84.71	211.3	318.2	10.85	80.44	26.47	8.55	1.661	48.78	86.80	205.3	312.5
11	East Coast RFG	6.90	33.12	21.69	11.61	0.641	50.26	84.97	196.2	322.7	11.31	33.12	21.69	11.61	0.641	55.82	87.18	184.9	312.7
12	MD / VA RFG	6.91	35.10	20.11	11.76	0.626	50.35	83.84	195.4	331.1	11.31	35.10	20.11	11.76	0.626	55.89	86.04	184.1	321.1
13	Texas RFG	6.92	30.12	16.65	11.12	0.533	50.58	85.05	196.1	329.0	10.85	30.12	16.65	11.12	0.533	55.53	87.02	186.0	320.1
14	Midwest RFG	7.06	32.12	17.13	7.85	0.774	50.98	85.24	193.2	326.7	11.84	32.12	17.13	7.85	0.774	57.00	87.63	180.9	315.8
15	California	7.06	9.00	21.98	4.44	0.530	44.52	88.81	211.0	303.0	11.84	9.00	21.98	4.44	0.530	50.54	91.20	198.5	292.0

**Table 7-9 Reference Case Fuel Properties by Region**

REGION		SUMMER									WINTER								
		RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90
1	East Coast	8.70	30.00	22.89	13.19	0.610	45.78	80.81	208.4	339.4	10.82	30.00	21.19	12.36	0.610	50.32	83.58	199.2	326.8
2	Midwest	8.70	30.00	25.40	7.13	0.630	47.65	82.32	204.6	332.5	11.96	30.00	22.40	7.12	0.630	52.93	85.12	193.8	319.8
3	South	8.70	30.00	26.82	10.75	0.630	45.34	84.65	209.3	321.9	10.36	30.00	24.92	9.69	0.630	48.93	86.92	202.0	311.6
4	North	8.70	30.00	24.28	8.18	0.860	47.20	81.13	205.5	337.9	12.92	30.00	20.79	8.42	0.860	51.33	83.74	197.1	326.0
5	Rocky Mts	8.70	30.00	27.41	8.13	0.650	45.24	84.64	209.5	322.0	11.61	30.00	25.12	8.00	0.650	49.73	86.46	200.4	313.7
6	CA/NV/AR	8.70	30.00	26.82	10.75	0.650	45.34	84.65	209.3	321.9	10.36	30.00	24.92	9.69	0.650	48.93	86.92	202.0	311.6
11	East Coast RFG	6.90	30.00	21.69	11.61	0.540	50.26	84.97	199.3	320.5	11.31	30.00	21.69	11.61	0.540	55.82	87.18	187.9	310.4
12	MD / VA RFG	6.90	30.00	20.11	11.76	0.540	50.35	83.84	199.1	325.6	11.31	30.00	20.11	11.76	0.540	55.89	86.04	187.8	315.6
13	Texas RFG	6.90	30.00	16.65	11.12	0.540	50.58	85.05	198.6	320.1	10.85	30.00	16.65	11.12	0.540	55.53	87.02	188.5	311.2
14	Midwest RFG	6.90	30.00	17.13	7.85	0.600	50.98	85.24	197.8	319.2	11.84	30.00	17.13	7.85	0.600	57.00	87.63	185.5	308.4
15	California	6.90	9.00	21.98	4.44	0.530	44.52	88.81	211.0	303.0	11.84	9.00	21.98	4.44	0.530	50.54	91.20	198.5	292.0

**Table 7-10 Control Case Fuel Properties by Region**

REGION	SUMMER									WINTER								
	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90
1 East Coast	8.70	10.00	22.91	12.39	0.610	45.78	80.78	208.4	339.5	10.82	10.00	21.28	11.40	0.610	50.23	83.50	199.3	327.1
2 Midwest	8.70	10.00	25.42	7.13	0.630	47.65	82.29	204.6	332.6	11.96	10.00	22.49	6.16	0.630	52.84	85.04	194.0	320.1
3 South	8.70	10.00	26.84	10.75	0.630	45.34	84.62	209.3	322.0	10.36	10.00	25.01	8.73	0.630	48.84	86.84	202.2	312.0
4 North	8.70	10.00	24.30	8.18	0.860	47.20	81.10	205.5	338.0	12.92	10.00	20.88	7.46	0.860	51.24	83.66	197.3	326.4
5 Rocky Mts	8.70	10.00	27.43	8.13	0.650	45.24	84.61	209.5	322.1	11.61	10.00	25.21	7.04	0.650	49.64	86.38	200.6	314.0
6 CA/NV/AR	8.70	10.00	26.84	10.75	0.650	45.34	84.62	209.3	322.0	10.36	10.00	25.01	8.73	0.650	48.84	86.84	202.2	312.0
11 East Coast RFG	6.90	10.00	21.71	11.61	0.540	50.26	84.94	199.3	320.6	11.31	10.00	21.78	10.65	0.540	55.73	87.10	188.1	310.8
12 MD / VA RFG	6.90	10.00	20.13	11.76	0.540	50.35	83.81	199.1	325.7	11.31	10.00	20.20	10.80	0.540	55.80	85.96	188.0	316.0
13 Texas RFG	6.90	10.00	16.67	11.12	0.540	50.58	85.02	198.6	320.2	10.85	10.00	16.74	10.16	0.540	55.44	86.94	188.7	311.5
14 Midwest RFG	6.90	10.00	17.15	7.85	0.600	50.98	85.21	197.8	319.4	11.84	10.00	17.22	6.89	0.600	56.91	87.55	185.7	308.7
15 California	6.90	9.00	21.98	4.44	0.530	44.52	88.81	211.0	303.0	11.84	9.00	21.98	4.44	0.530	50.54	91.20	198.5	292.0

*7.1.3.2.8 Boutique Fuels*

The new regional fuel supply used for the final analysis also contains fuel formulations for counties or regions using local fuel controls, also referred to as “boutique fuels”. These fuel controls are usually expressed in additional control on RVP and/or ethanol blending levels. Table 7-11 presents the fuel property adjustments due to RVP control used in the final analysis.

**Table 7-11 RVP Adjustment Factors for Boutique Fuel Areas Within Fuel Regions**

RVP ADJUSTMENT FACTORS (per PSI)										
FUEL	DESCRIPTION	RVP	SULF	AROM	OLEF	BENZ	E200	E300	T50	T90
per PSI	boutique fuel adj	-1.00					-1.26	-0.50	2.57	2.27

In addition to the properties listed above, a small change in aromatics and olefins was found to be associated with changes to RVP in boutique fuel areas. After additional refinery modeling, effects to these properties were not found to be significant and were excluded from the analysis.

*7.1.3.2.9 Application of Refinery Modeling*

It was necessary to estimate the gasoline qualities and changes in gasoline quality to estimate the emissions impact of the Tier 3 program. This was conducted in two separate steps – the first step estimated the impact of blending in more ethanol, the second step for estimating desulfurization on gasoline qualities.

For estimating ethanol’s impact on gasoline qualities, it was necessary to establish a base case for refinery modeling, for which we chose the year 2005. However, we revised the base case from what actually occurred in 2005, by replacing the content of MTBE blended into

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gasoline in 2005 with 5.55 billion gallons of ethanol. Next, we established a reference case and the sole differences that we modeled between the 2005 revised base case and the 2030 reference case were the gasoline and other refinery product volumes (which change with changing demand), and product pricing (which changes based on forecasted changes in crude oil prices). Finally, we then modeled two control cases which reflect different ethanol volumes, one with 100 percent E10 and the other with 100 percent E15.<sup>D</sup> This allowed us to estimate the impacts of the two different amounts of ethanol on gasoline qualities. These two ethanol control cases were also modeled in 2030. The changes in gasoline quality are summarized in Table 7-12. For estimating how ethanol affects gasoline quality, we solely used the national average change in gasoline qualities and applied those changes for all E10 or E15 gasoline.

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<sup>D</sup> Because E85 is blended up with the same gasoline blendstock which comprises E10 or E15, there was no need to estimate separate gasoline qualities for the gasoline blendstock which is used for E85.

**Table 7-12 Difference in Gasoline Qualities between the 2030 E10 and E15 Control Cases with the 2030 Reference Case**

2030 (E10)				2030 (E15)			
		Refinery Modeling				Refinery Modeling	
		Summer	Winter			Summer	Winter
PADD 1	E200	6.57	4.21	PADD 1	E200	14.07	10.94
	E300	1.54	0.03		E300	3.06	1.38
	RVP	0.67	0.70		RVP	0.06	0.37
	Aromatics	-3.81	-2.70		Aromatics	-6.06	-6.55
	Olefins	-3.55	-3.24		Olefins	-5.09	-5.49
PADD 2	E200	-0.50	5.41	PADD 2	E200	4.65	11.65
	E300	-0.49	1.22		E300	-0.43	0.91
	RVP	0.01	-0.24		RVP	-0.72	-0.65
	Aromatics	0.47	-4.56		Aromatics	-0.45	-4.54
	Olefins	0.01	-0.46		Olefins	-0.43	-0.35
PADD 3	E200	0.06	4.48	PADD 3	E200	6.13	9.89
	E300	0.37	0.56		E300	0.86	0.41
	RVP	-0.03	-0.23		RVP	-0.72	-0.57
	Aromatics	-1.03	-3.92		Aromatics	-1.13	-4.73
	Olefins	5.23	-2.09		Olefins	3.47	-3.20
PADD 4/5	E200	5.40	7.39	PADD 4/5	E200	7.55	13.38
	E300	-2.10	0.78		E300	-5.18	1.07
	RVP	0.89	-0.30		RVP	0.00	-0.58
	Aromatics	-3.48	-4.71		Aromatics	-4.62	-7.58
	Olefins	-1.54	-1.17		Olefins	-1.49	-1.62
US avg minus CA	E200	3.11	4.88	US avg minus CA	E200	9.24	11.11
	E300	0.39	0.54		E300	0.91	1.01
	RVP	0.35	0.15		RVP	-0.33	-0.20
	Aromatics	-2.02	-3.65		Aromatics	-3.36	-5.69
	Olefins	-0.46	-2.07		Olefins	-1.64	-3.27

The second step for estimating gasoline qualities was to model the impact of desulfurization on gasoline qualities. The total impact of desulfurization on gasoline qualities is comprised of the reduction in gasoline sulfur, the associated reduction in olefins and the impacts of recovering the lost octane. The sulfur reduction is fixed by the standard and the olefins reduction is a function of the selectivity of the desulfurization technologies. We reviewed the information that we had obtained for the gasoline desulfurization technologies and estimated that desulfurizing gasoline from 30 ppm to 10 ppm would result in a 1 percent reduction in olefin level. Since we estimated the cost of making up lost octane using the LP refinery model, we used that case for estimating the impact of octane recovery on gasoline qualities. The gasoline

qualities for the reference case and the control case that we developed reflect a 1 octane number loss in the FCC naphtha pool. However, we estimate that the gasoline desulfurization equipment that refiners will use to comply with Tier 3 will only cause about a one half octane number reduction in the gasoline pool, so we reduce the gasoline quality changes by half. The difference in gasoline qualities between the reference and control cases reflecting a one half reduction in octane number is summarized in Table 7-13. Because of the tendency for the LP refinery model to shift gasoline blendstocks around resulting in odd gasoline quality changes in individual PADDs, we solely used the national average change in gasoline qualities and applied those changes for all gasoline for the emissions analysis.

**Table 7-13 Differences in Gasoline Qualities between the Control and Reference Cases**

Change in Gasoline Quality for 1/2 Octane Number Decrease			
		Summer	Winter
PADD 1	E200	-0.11	-0.04
	E300	-0.12	-0.09
	RVP	0.00	0.00
	Aromatics	0.02	0.18
	Olefins	0.20	0.11
PADD 2	E200	-0.10	-0.10
	E300	-0.10	-0.03
	RVP	0.00	0.01
	Aromatics	0.01	-0.03
	Olefins	0.17	-0.01
PADD 3	E200	0.38	-0.22
	E300	0.29	-0.16
	RVP	0.00	0.01
	Aromatics	-0.02	0.11
	Olefins	0.36	-0.03
PADD 4/5	E200	0.00	-0.02
	E300	-0.02	-0.06
	RVP	0.00	0.00
	Aromatics	0.11	0.10
	Olefins	0.01	0.00
US avg minus CA	E200	0.00	-0.09
	E300	-0.03	-0.08
	RVP	0.00	0.01
	Aromatics	0.02	0.09
	Olefins	0.20	0.04

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### 7.1.3.3 Vehicle Program Inputs

Modeling the controls introduced by the Tier 3 vehicle program required the development of a set of alternate MOVES database tables to reflect each aspect of the Tier 3 program. These database tables included:

- Gaseous exhaust emission rates (HC/CO/NO<sub>x</sub>) for light-duty cars, trucks, and light-heavy trucks (gas and diesel) to reflect the Tier 3 FTP and US06 standards and their phase-in.
- Elemental carbon (EC) and organic carbon (OC) exhaust emission rates for light-duty cars, trucks, and light-heavy-duty trucks (gas and diesel) to reflect the Tier 3 FTP and US06 PM standards and phase-in.
- Evaporative hydrocarbon emission rates for the permeation process to reflect the diurnal test standard, certification fuel, and phase-in.
- Leak prevalence rates for tank vapor and liquid leaks to reflect requirements for evaporative leak detection.

The development of these alternative inputs is discussed below by pollutant, fuel and vehicle regulatory class.

#### *7.1.3.3.1 Gasoline Light-Duty HC/CO/NO<sub>x</sub> Exhaust*

Emission rates for gaseous pollutants (HC/CO/NO<sub>x</sub>) in MOVES are contained in a database table (EmissionRateByAge). Rates are expressed in terms of mass per time (g/hr), distinguished by emission process (start and running), fuel type (gas and diesel), vehicle regulatory class (LDV, LDT, Light HD, etc.), model year, age, and operating mode (power/speed for running, engine soak time for start). Developing these rates for Tier 3 vehicles required accounting for expected changes in each of these dimensions.

The development of emission rates representing implementation of the Tier 3 standards followed the same procedures used to develop rates for the National LEV (NLEV, covering model years 2001-2003) and Tier 2 standards (covering model years 2004 and later) in the default MOVES database, as described in the documentation for light-duty exhaust emission rates for MOVES2010 (known as the “MOVES Light-Duty report”).<sup>11</sup> However, specific modifications were made to represent the introduction of Tier 3 standards, summarized below. Where no modifications to methods were made, we will refer the reader to the appropriate section of the MOVES2010 report. In particular, see Section 1.3.4.

MOVES emission rates are estimated by standard level, model year, age, and vehicle regulatory class. There are separate rates for areas with Inspection/Maintenance programs (I/M) and those without. Developing the rates involves six steps, listed below.

1. *Project average Federal Test Procedure (FTP) results* by standard level and vehicle regulatory class. As in the development of the default MOVES2010 database (outlined in the

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Light Duty Report), we made use of data measured on the FTP cycle in the course of EPA's In-use Verification Program (IUVP) to project emissions under the standards. For Tier 3, we developed estimates of FTP results for Tier 3 vehicles based on IUVP data from vehicles certified to Tier 2 Bin 2 and 3 standards, including cycle composites, "cold-start" emissions" (Bag1 minus Bag3) and "hot-running" emissions (FTP Bag 2 and US06).

2. *Develop phase-in assumptions* for model years (MY) 2017 – 2031, by standard level, vehicle class and model year, including phase-in assumptions representing the introduction of Tier 3 standards. Note that for purposes of inventory modeling for the FRM, the onset of the Tier 3 phase-in was delayed from 2017 to 2018 for truck classes with gross vehicle weight ratings > 6,000 lb (LDT3 and LDT4). For LDV, LDT1 and LDT2, the phase-in begins in 2017, as in the inventory modeling for the NPRM.

3. *Merge FTP results and Phase-in assumptions.* For running emissions, calculate weighted ratios of FTP and US06 emissions in each model year relative to those for cars (LDV) in MY2000, which represent Tier 1 LDV.

4. *Estimate Emissions by Operating Mode.* Calculate emissions by operating mode in each model year by multiplying the MY2000 emission rates by the weighted ratio for each model year. We assume that the emissions control at high power (outside ranges of speed and acceleration covered by Bag 2 of the FTP) is not as effective as at lower power (within the range of speed and acceleration covered by Bag 2).

5. *Apply Deterioration* to estimate emissions for three additional age groups (4-5, 6-7 and 8-9). We assume that Tier 3 vehicles will deteriorate similarly to other vehicles, when viewed in logarithmic terms, but we modified deterioration to represent a useful life of 150,000 miles, as opposed to a useful life of 120,000 miles, which was assumed for Tier 2 and NLEV vehicles. This is the outcome of applying ln-linear deterioration to the rates developed in steps 1-4. For the remaining three groups (10-14, 15-19 and 20+), emissions are assumed to stabilize as described in the MOVES2010 report.

6. *Estimate non-I/M reference rates.* The rates in steps 1-6 represent rates under a reference inspection/maintenance (I/M) program. Corresponding non-I/M rates are calculated by applying the ratios applied to the Tier 1 and pre-Tier 1 rates.

Each of these six steps is described in more detail below. Additional information is available in a separate memo available in the docket.<sup>12</sup>

#### *7.1.3.3.1.1 Average FTP Results (Step 1) (Standard)*

Our projected emissions for Tier 3 vehicles are driven by the NMOG+NO<sub>x</sub> standard, set at 30 mg/mi. However, because MOVES models NO<sub>x</sub> and THC emissions separately, we apportioned the aggregate standard into NMOG and NO<sub>x</sub> components, which we will refer to as the "effective standards" for each pollutant. For purposes of apportionment, we assumed that NMOG control would pose a greater technical challenge than NO<sub>x</sub> control. Accordingly, we assumed "effective standards" for NMOG and NO<sub>x</sub> would be 20 mg/mi and 10 mg/mi, respectively. To implement this assumption, we further assumed that for NO<sub>x</sub>, vehicles would be

effectively brought into Bin 2, and that for NMOG, vehicles would be brought to a level between Bin 2 and Bin 3, but closer to Bin 2.

In addition, MOVES models start and running processes separately. It is therefore necessary to translate the composite standard into start and running components. One component represents a “cold start” on the FTP cycle, represented as “Bag1 minus Bag3” emissions. A second component represents “hot-running” emissions, represented by the hot-running phase of the FTP (Bag 2). A third component represents emissions on the US06 cycle, representing emissions at high speed and power.

Estimated FTP and US06 emissions levels for hydrocarbons (NMOG and NMHC) are shown in Table 7-14, for several Tier 2 Bins and for Tier 3. Values for all standards except Tier 3 are identical to those used to develop rates in the default database. The values for Tier 3 are calculated as a weighted average of those for Bins 2 and 3, using Equation 7-2.

$$T3 = 0.775 \cdot B2 + 0.225 \cdot B3$$

**Equation 7-2**

**Table 7-14 Hydrocarbons (HC): Useful-Life FTP Standards and Associated Cold-Start and Hot-Running Results on the FTP and US06 Cycles.**

Bin	Useful-life Standard (mg/mi)	FTP Composite <sup>a</sup> (mg/mi)	FTP Cold Start <sup>a</sup> (mg)	FTP hot Running <sup>a</sup> (Bag 2) (mg/mi)	US06 <sup>b</sup> (mg/mi)
8	125	41.3	591	3.56	35.8
5	90	35.5	534	2.63	35.8
4	70	24.8	383	2.28	35.8
3	55	21.5	329	1.74	35.8
2	10	5.6	87	0.42	2.6
Tier 3 <sup>c</sup>	20	9.2	142	0.7	10.0

<sup>a</sup> Values represent “non-methane organic gases” (NMOG).

<sup>b</sup> Values represent “non-methane hydrocarbons” (NMHC).

<sup>c</sup> Values for Tier 3 calculated using Equation 7-2.

Under a general assumption that CO standards are not forcing, but that CO emissions tend to track NMOG emissions, corresponding values for CO were calculated in the same manner, and are presented in Table 7-15.

**Table 7-15 CO: Useful-Life FTP Standards and Associated Cold-Start and Hot-Running Results on the FTP and US06 Cycles.**

Bin	Useful-life Standard (mg/mi)	FTP Composite (mg/mi)	Cold Start (mg)	FTP hot Running (Bag 2) (mg/mi)	US06 (mg/mi)
8	4,200	861	6,680	451	2,895
5	4,200	606	5,510	238	2,895
4	4,200	537	5,500	201	2,895
3	2,100	463	3,470	119	2,895
2	2,100	235	1,620	70	948
Tier 3 <sup>a</sup>	2,100	286	2,040	81	1,390

<sup>a</sup> Values for Tier 3 calculated using Equation 7-2.

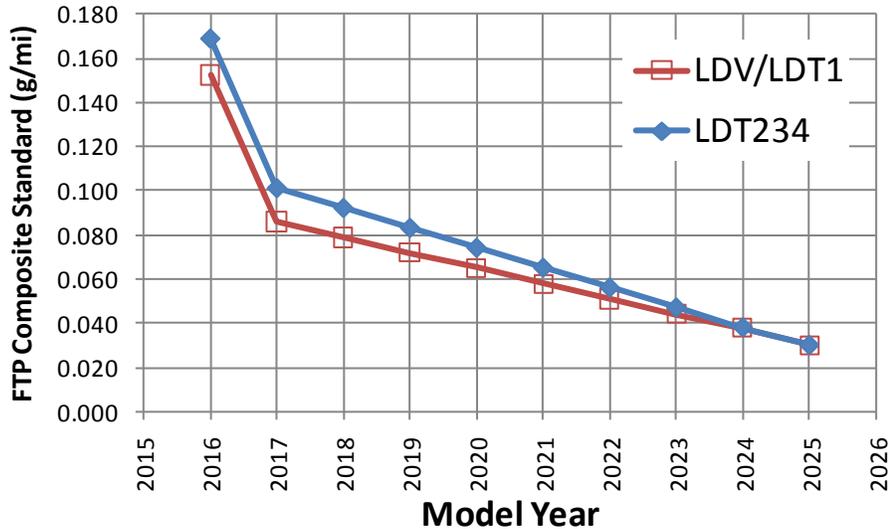
Corresponding results for NO<sub>x</sub> are presented in Table 7-16. In contrast to HC and CO, the values for Tier 2 Bin 2 were adopted for Tier 3, as the FTP composite of 5.5 mg/mi suggests that Bin 2 vehicles can meet the “effective standard” of 10 mg/mi with a reasonable compliance margin.

**Table 7-16 NO<sub>x</sub>: Useful-Life FTP Standards and Associated Cold-Start and Hot-Running Results on the FTP and US06 Cycles.**

Bin	Useful-life Standard (mg/mi)	FTP Composite (mg/mi)	Cold Start (mg)	FTP hot Running (Bag 2) (mg/mi)	US06 (mg/mi)
8	200	64.2	418	35.1	61.3
5	70	21.2	165	8.2	45.9
4	40	8.7	90	4.7	30.6
3	30	5.7	71	3.8	30.6
2	20	5.5	67	0.4	18.4
Tier 3	10	5.5	67	0.4	18.4

*7.1.3.3.1.2 Develop Phase-In Assumptions (Step 2)*

We designed phase-in assumptions so as to project compliance with the Tier 3 fleet average NMOG+NO<sub>x</sub> requirements. The requirements are illustrated in Figure 7-4. The phase-in begins in model year 2017 and ends in model year 2025. Note the sharp drop in emissions at the outset of the Tier 3 phase-in, also that the truck standards (LDT2,3,4) are slightly higher than the lighter vehicles’ (LDV-T1). After 2017, the reduction in the fleet average is linear. The fleet averages for cars and trucks no longer differ at the completion of the phase-in.



**Figure 7-4 NMOG+NO<sub>x</sub> FTP Fleet Average Requirements during Phase-In of the Tier 3 Exhaust Emissions Standards for Light-Duty Vehicles.**

*7.1.3.3.1.3 Merge Cycle Results and Phase-In Assumptions (Step 3)*

The goal of this step is to calculate weighted averages of the FTP (cold-start and hot-running) results for all standards in each model year, with the emissions results weighted by applicable phase-in fractions. We do this step for each vehicle class separately, then weight the four truck classes together using a set of fractions also derived from the weighted sales estimates.

Start and running emissions in each model year are simply calculated as weighted averages of the emissions estimates and the phase-in fractions. The resulting weighted start estimates are used directly to represent cold-start emissions for young vehicles in each model year (ages 0-3). For running emissions, however, the averages are not used directly; rather, each is expressed as a ratio to the corresponding Tier 1 value.

*7.1.3.3.1.4 Estimate Emissions by Operating Mode (Step 4)*

To project emissions for the 2016-and-later vehicles, we divided the operating modes for running exhaust into two groups. These groups represent the ranges of speed and power covered by the hot-running phase (Bag 2) of the FTP cycle (< ~20 kW/Mg), and the ranges covered by the SFTP standards (primarily the US06 cycle). For convenience, we refer to these two regions as “the hot-running FTP region” and “US06 region,” respectively (See Figure 7-5).

To estimate emissions by operating mode, the approach was to multiply the emission rates for MY 2000, representing Tier 1, by a specific ratio for each model year from 2017 to 2025, to represent emissions for that model year.

To estimate rates for the US06 modes, we followed a procedure similar to that for the “FTP” modes, but using the “US06” columns in Table 7-14 through Table 7-16. For HC and CO, we used Equation 7-2, as before. For NO<sub>x</sub>, we applied the Bin-2 values. Figure 7-6 and

Figure 7-7 show application of the ratios to the FTP and US06 operating modes in model years 2010, 2017, and 2025, representing fully phased-in Tier 2 standards, an interim year during the Tier 3 phase-in, and the fully phased-in Tier 3 standards, respectively. Figure 7-6 displays the information on linear scale, highlighting the differences at the higher operating modes, while Figure 7-7 shows the same information on a logarithmic scale, illustrating the patterns for the lower operating modes.

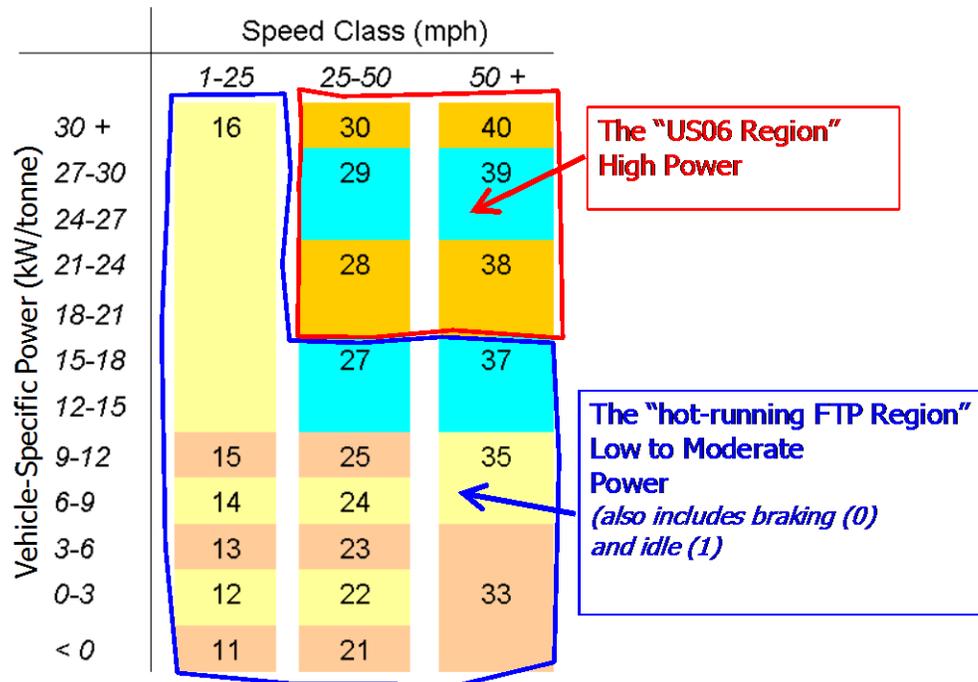
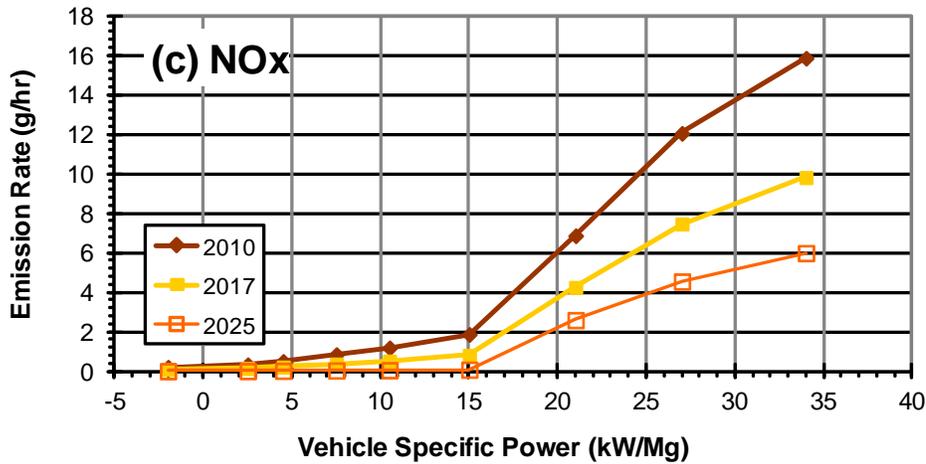
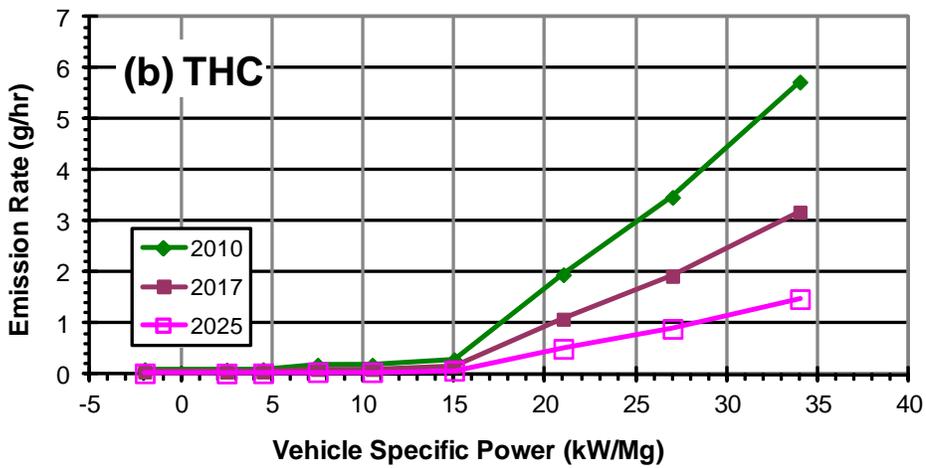
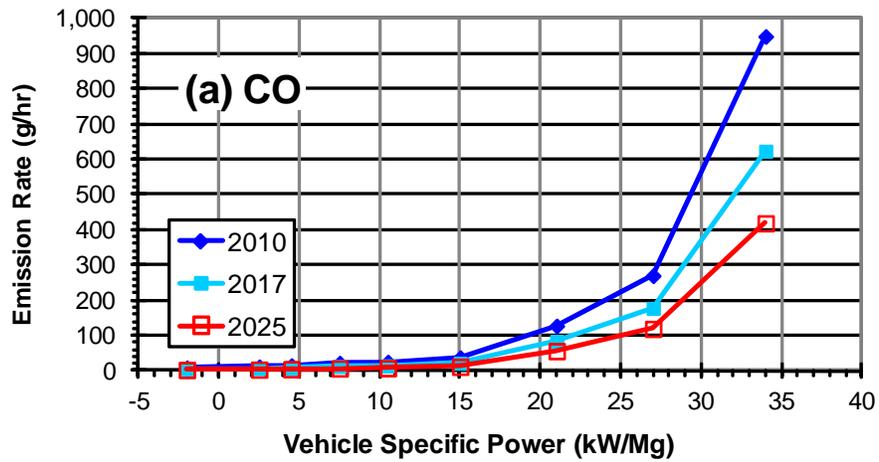
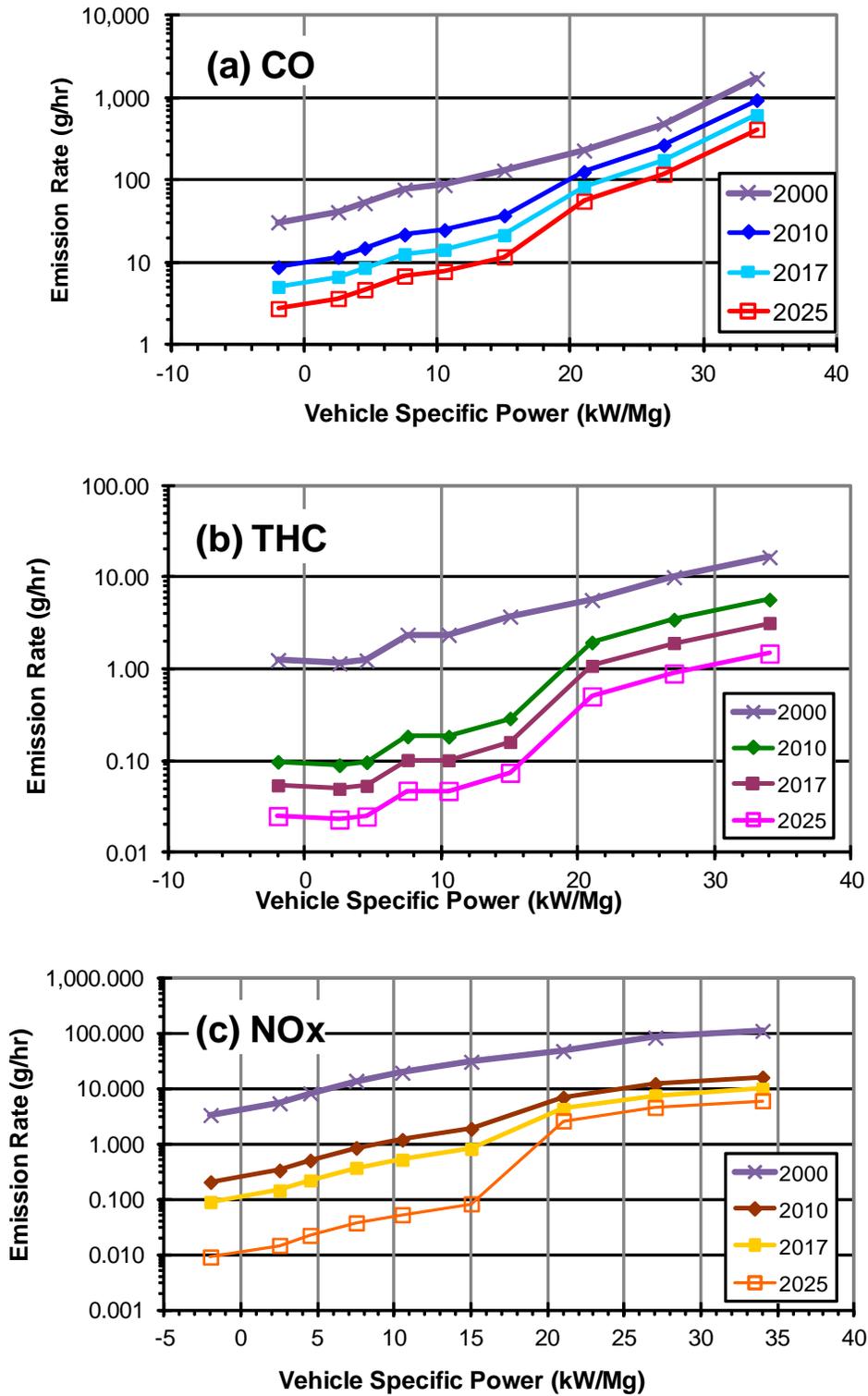


Figure 7-5 Operating modes for running Exhaust Emissions, divided broadly into “hot-running FTP” and “US06” regions.



**Figure 7-6 Projected Emission Rates for Cars in Operating modes 21-30, vs. VSP, in ageGroup 0-3 years, for three model years, for (a) CO, (b) THC and (c) NO<sub>x</sub> (LINEAR SCALE).**



**Figure 7-7 Projected Emission Rates for Cars in Operating modes 21-30, vs. VSP, in ageGroup 0-3 years, for Four Model Years, for (a) CO, (b) THC and (c) NO<sub>x</sub> (LOGARITHMIC SCALE).**

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#### *7.1.3.3.1.5 Apply Deterioration (Step 5)*

Based on our extensive emissions analysis during MOVES2010 development, we assumed that deterioration for different technologies was best represented by a multiplicative model, in which different technologies, represented by successive model-year groups, showed similar deterioration in relative terms but markedly different deterioration in absolute terms. We implemented this approach by translating emissions for the 0-3 age group, as calculated above, into natural logarithms and applying uniform logarithmic age trends to all model-year groups. We derived logarithmic deterioration slopes for Tier 1 vehicles (MY 1996-98) and applied them to Tier 2 vehicles. In this process we applied the same logarithmic slope to each operating mode, which is an extension of the multiplicative deterioration assumption.

For vehicles manufactured after the onset of the Tier 3 phase-in, the deterioration assumptions were modified to represent an extension of the full useful life (FUL) from 120,000 mi to 150,000 mi. Thus, the inventory modeling assumes a standard of 30 mg/mi NMOG+NOx and a 150,000 mi useful life. However, under the final rule, manufacturers will retain the option of certifying some engine test groups to a somewhat lower standard with a 120,000 mi useful life. Over the useful life of vehicles, we assume that the two options (higher standard with longer useful life, lower standard with shorter useful life) will yield approximately equivalent deterioration trends. Therefore, no attempt was made to represent both options in the inventory modeling.

Note that we did not extrapolate the logarithmic deterioration trend beyond the 8-9 year age group, as we know that emissions tend to stabilize beyond this age, while the ln-linear emissions model would project an increasingly steep and unrealistic exponential emissions trend. For the 10-14, 15-19 and 20+ age groups, the “stabilization of emissions with age” was estimated as for MOVES2010 (MOVES Light Duty report, section 1.3.3.7).

#### *7.1.3.3.1.6 Estimate Non-I/M References (Step 6)*

Completion of the preceding steps provided a set of rates representing I/M reference rates for MY 2016-2025. As a final step, we estimated non-I/M reference rates by applying the same ratios used in MOVES2010 (section 1.3.3.6).

#### *7.1.3.3.1.7 Start Emissions*

The values for “Cold Start” shown in Tables 8-4 through 6 above were used to represent cold-start emissions for the various standard levels. These are designated as opModeID=108 in the emissionRateByAge table; emission rates for starts following shorter soak periods were developed by applying standard soak curves (found in the MOVES Light Duty report) to the updated cold start rates. Deterioration was applied to start emissions, using the same approach as used for developing MOVES2010 base rates discussed in the MOVES Light Duty report. Start deterioration is expressed relative to deterioration for running emissions.

7.1.3.3.1.8 Final Estimates of Composite FTP and US06

In producing emission inventory estimates, MOVES combines emission rates with activity patterns derived from surveys of in-use vehicles. These emissions do not necessarily correlate directly with the test procedures used for compliance; for example, in-use activity shows that more miles are driven per start event than assumed on the FTP. Likewise, the US06 cycle is focused on compliance, and represents a relatively small portion of in-use driving. However, to give a relative sense of the changes projected by the Tier 3 standards, emissions can be constructed for FTP composite and US06 from MOVES emission rates for the Tier 2 (labeled as MY2010) and Tier 3 (labeled as MY 2025) cases. These are shown in Figures 7-5 through 7-8 below. Note that the Tier 3 rates shown below are for the MOVES base fuel of 30 ppm. In modeling the control scenarios on 10 ppm, these emission rates were further lowered by the sulfur reductions outlined in Section 7.1.3.4.1.

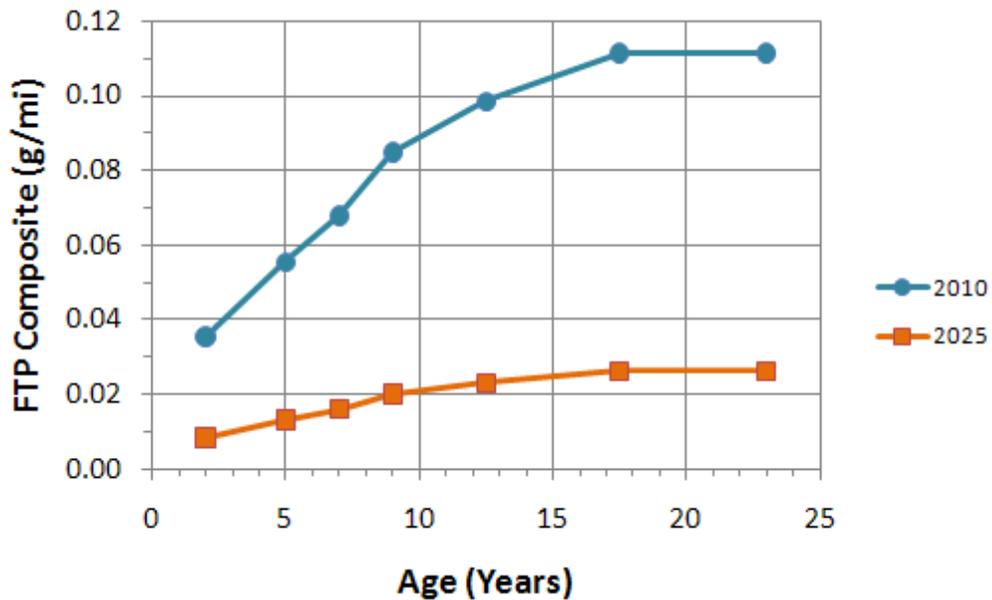


Figure 7-8 FTP Composite NO<sub>x</sub> emissions for reference (2010) and Tier 3 (2025) constructed from MOVES rates

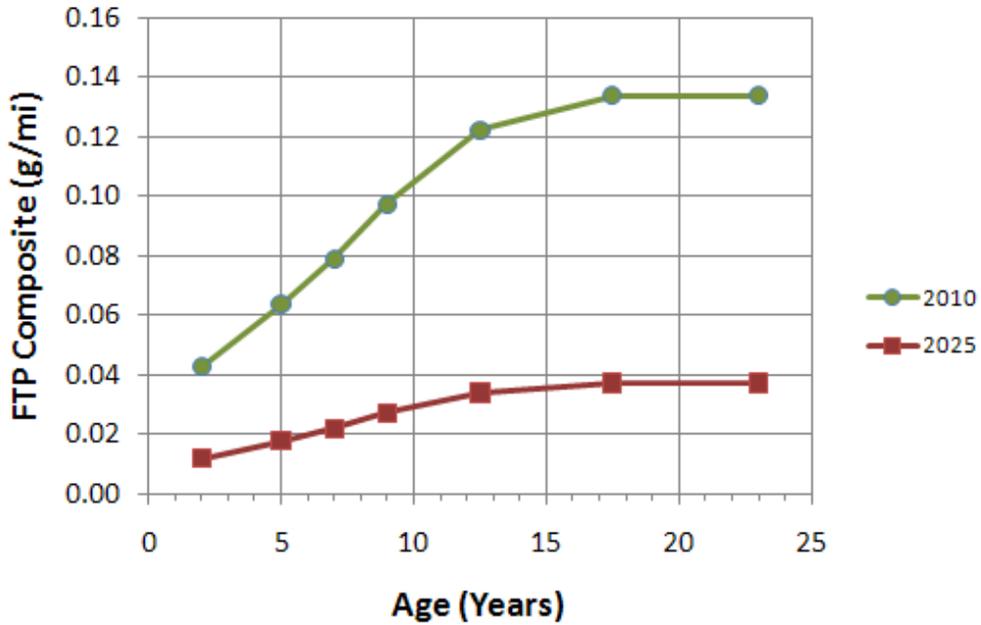


Figure 7-6 FTP Composite THC emissions constructed from MOVES rates

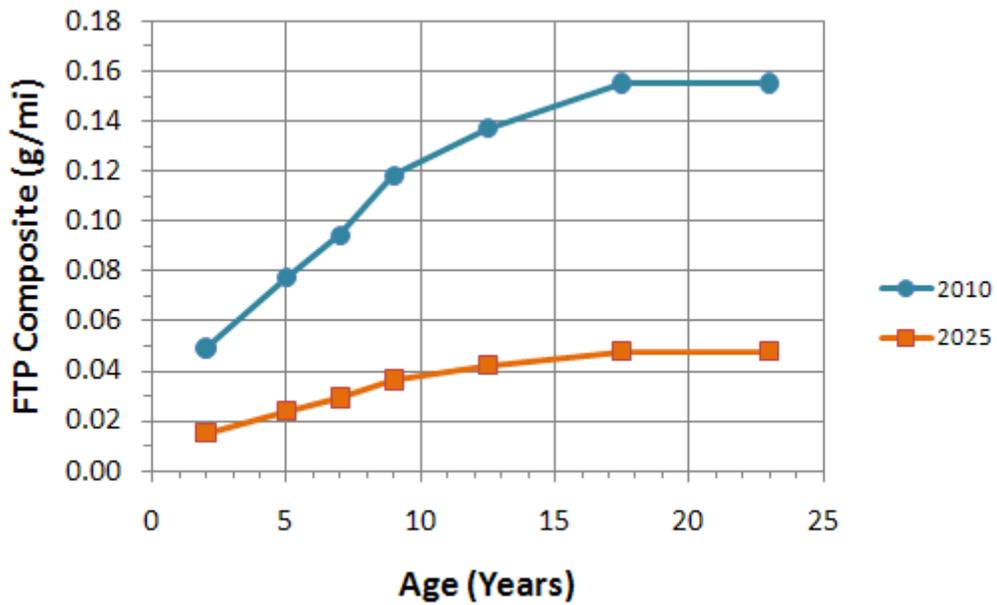
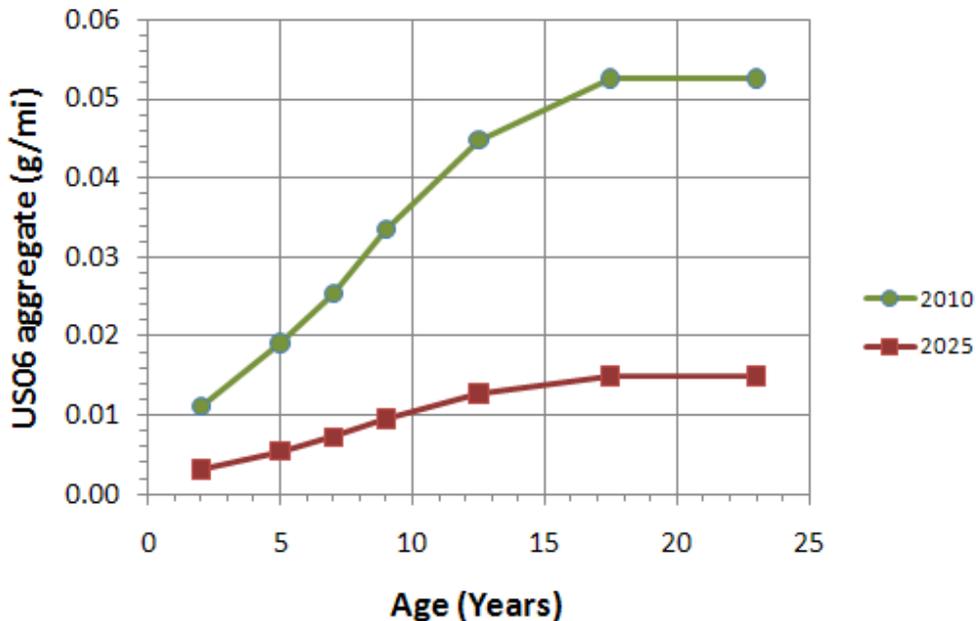


Figure 7-7 US06 NO<sub>x</sub> emissions constructed from MOVES rates



**Figure 7-8 US06 THC emissions constructed from MOVES rates**

#### 7.1.3.3.2 Diesel LD HC/CO/NO<sub>x</sub> Exhaust

Emission rates representing light-duty diesel vehicles under Tier 3 standards were calculated identically to those representing gasoline vehicles, with the exception that the “effective standards” were set differently. Again, diesel vehicles are projected to meet the same NMOG+NO<sub>x</sub> standard as gasoline vehicles (30 mg/mi). However, for diesel vehicles, we assumed that light-duty vehicles would meet Bin-2 standards following completion of the phase in. Accordingly, the “effective standards” for NMOG and NO<sub>x</sub> were set at 10 and 20 mg/mi, respectively. As mentioned, all remaining steps were conducted as described in Section 7.1.3.3.1 above. As a result of the different effective standards, however, the ratios and other numeric results specific to diesel vehicles vary slightly from their counterparts for gasoline vehicles.

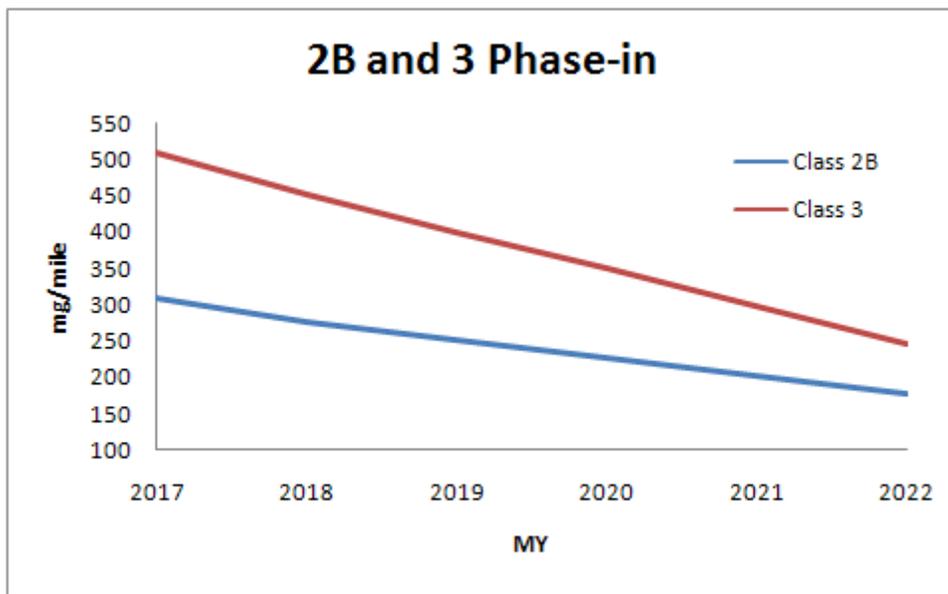
#### 7.1.3.3.3 Gasoline Medium-duty HC/CO/NO<sub>x</sub>

The Tier 3 program will affect not only light-duty vehicles (below 8,500 pounds GVWR), but also chassis-certified vehicles between 8,500 and 14,000 pounds GVWR. This class of vehicles is referred to “light-heavy-duty” or “medium-duty” vehicles. In MOVES, these vehicles are designated as regulatory class 41. This regulatory class comprises several types of vehicles, including engine-certified trucks, Class 2b and Class 3 heavy trucks, and medium-duty passenger vehicles (MDPV), which are not regulated under the medium-duty standards considered here. As described in the reference-case medium-duty updates to MOVES,<sup>13</sup> we assumed that during this timeframe, engine-certified vehicles and medium-duty passenger vehicles (MDPV) comprise five percent and fifteen percent of the regulatory class, respectively, with the remainder composed of Class 2b and 3 trucks.

**Table 7-17 Population Percentage**

Category	Fraction of RegClass 41 (%)
Engine-certified	5.0
MDPV	15
Class 2b	60
Class 3	20

The Class 2b and Class 3 vehicle program was modeled to begin in model year 2018 and fully phase in during the 2022 model year (Figure 7-9). This projection yields an aggregate standard of 0.178 g/mile NMOG+NO<sub>x</sub> for Class 2b vehicles and 0.247 gram/mile for Class 3 vehicles in 2022.



**Figure 7-9 Class 2B and 3 Standard Phase-in**

To represent mean emissions on the FTP for this regulatory class, we combined the Tier 3 phase-in for Class 2b and 3 vehicles with the existing emission standards for MDPV and engine-certified vehicles that comprise MOVES regulatory class 41. For this analysis, we assumed that MDPVs met the Tier 3 SULEV 30 standard, and that engine certified vehicles would perform at 1.2 times their standard on the chassis FTP.<sup>14</sup> Calculated using the fractions in Table 7-17, the weighted average of the Class 2b, Class 3, MDPV, and engine standards is 0.181 for model year 2022.

To account for the real-world performance of these vehicles, we related this average to that for Tier 2 light-duty vehicles, for which we have a substantial volume of data from EPA's in-use verification program. Using the same approaches used for developing the Tier 2 and Tier 3 light duty emission rates (see Section 7.1.3.3.1), we modeled MOVES Regulatory Class 41 in

2022 as 90 percent Bin 5 and 10 percent Bin 8 vehicles.<sup>E</sup> For the phase-in years 2017-2021, we calculated interim emission rates for each year as a weighted average of the Tier 3 rates and the existing MOVES rates for regulatory class 41 (in MY 2016), such that the appropriate weighted composite was calculated each year as shown in Table 7-18.

**Table 7-18 Phase-in of MD Tier 3 Rates**

Model Year	Tier 3 Rate	Current Rate (MY2016)	Composite Standard (g/mile)
2017	34%	66%	0.33
2018	49%	51%	0.29
2019	62%	38%	0.26
2020	75%	25%	0.24
2021	87%	13%	0.21
2022	100%	0%	0.18

The CO standards for MD vehicles are less stringent than those for Tier 2 Bin 5 and Bin 8 vehicles. For Bin 5 and Bin 8 vehicles, the CO standard is 4.2 g/mile. For engine certified vehicles, the standard is approximately 17.3 grams per mile (14.4 g/hp-hr multiplied by 1.2),<sup>15</sup> and for the Tier 3 MD vehicles, the standard ranges from 4.2 to 7.3 g/mile. Using the same phase-in fractions as for NMOG+NO<sub>x</sub>, we calculated an aggregate CO standard of 4.4 grams/mile in 2022, which is 5.5 percent higher than the Tier 2 Bin 5/8 standards. To compensate for the lower CO emissions in the Tier 2 vehicles that were used to develop the Tier 3 MD emission rates, we multiplied the running CO rates by 1.1 and the start CO rates by 1.05.

As for light-duty vehicles, deterioration was modeled to represent a 150,000 mile useful life. The same methodology was used for light-duty and medium-duty vehicles.

#### *7.1.3.3.4 Diesel Medium-Duty HC/CO/NO<sub>x</sub>*

For medium-duty (MD) diesel vehicles, the emission rates currently in MOVES imply levels on the FTP substantially below the Tier 3 HC and CO standards. When MOVES is used to generate a simulated FTP estimate for NMHC, the model calculates a rate of approximately 0.05 grams per mile, while the simulated FTP estimate for CO is less than 1 gram/mile. Consequently, we assumed no HC and CO emission benefits from Tier 3 standards on MD diesel vehicles.

By contrast, we estimate that the Tier 3 NO<sub>x</sub> standard will produce a reduction in diesel Class 2b and Class 3 NO<sub>x</sub> emissions. Because data on current NO<sub>x</sub> emissions are limited, as there is little in-use data on MY 2010 and 2011 vehicles which use selective catalytic reduction as a NO<sub>x</sub> control strategy, we used a proportional approach to estimate the Tier 3 effect, reducing NO<sub>x</sub> in proportion to the change in the emission standard. Because emission standards

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<sup>E</sup> By basing the data on light duty vehicles, it is possible that we are misstating the emission profile of these larger vehicles, but as emissions decrease, it is also possible that the emission profile for the larger vehicles will more closely resemble that of light duty vehicles.

tend to impact start and running emissions differently, we applied a greater portion of the reduction to running emissions and a smaller reduction to start emissions. These reductions were phased-in over the same schedule as for gasoline vehicles, as detailed in Table 7-19. Also, to account for the change in “useful life”, we duplicated the Tier 3 age 0-3 NO<sub>x</sub> rates to the 4-5 year age-group.

**Table 7-19 Phase-in of MD Diesel Tier 3 NO<sub>x</sub> Rates**

Model Year	Tier 3 Phase In	Reduction in NO <sub>x</sub> Running Emission Rate	Reduction in NO <sub>x</sub> Start Emission Rate
2017	20%	12%	5%
2018	38%	23%	9%
2019	54%	33%	12%
2020	69%	42%	16%
2021	85%	52%	19%
2022	100%	61%	23%

*7.1.3.3.5 Gasoline Particulate Matter (PM<sub>2.5</sub>)*

Tier 3 will introduce standards for emissions of primary particulate matter (PM) for light-duty vehicles. For the Federal Test Procedure (FTP), a full-useful life (FUL) standard of 3.0 mg/mi will apply. Additionally, for the US06, a standard of 10.0 mg/mi during the PM phase-in and a final standard of 6.0 mg/mile<sup>F</sup> will apply to vehicles with GVWR up to 8,500 lbs, as well as medium-duty passenger vehicles (MDPV). Additionally, the full useful life (FUL) for most vehicles will be increased from 120,000 to 150,000 miles under the Tier 3 rule. These standards are targeting several processes that contribute to particulate matter in light-duty gasoline vehicles: cold starts, high-power and high load operation, and deterioration of engine and emission control technology over the life of the vehicle.

As mentioned in the preamble, most current new light-duty vehicles are effectively in compliance with the 3.0 mg/mile standard (Section 1.5.1.1). The MOVES model includes strong deterioration of light-duty gasoline emissions based on data collected in the Kansas City Vehicle Emissions Study<sup>16</sup>, which causes predictions of fleet-average Tier 2 light-duty gasoline vehicles to exceed the proposed 3 mg/mile standard after only 3-4 years of operation. We anticipate that the Tier 3 PM standards will force continual improvement on fleet-wide PM emissions in several ways. First, the rule will require reductions in emissions from the light-duty vehicles that currently exceed the Tier 3 standard. Second, we expect that vehicle manufacturers will decrease PM emissions in order to increase their compliance margin, which will help vehicles meet the increased durability requirements for those test groups certified to the extended useful life of 150,000 miles. Third, we expect that manufacturers will lower US06 PM emissions in a similar fashion in order to meet the respective standards. And finally, the Tier 3 standards will prevent

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<sup>F</sup> The US06 PM standard will be 10 mg/mi starting and MY 2017 through MY 2021. After MY 2021, the US06 PM standard will drop to 6 mg/mi.

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the backsliding of PM emissions from new vehicles with new technologies. The technologies and techniques that manufacturers require to meet these standards are described in Chapter 1 of this RIA.

To reflect the above projections, the emission rates in MOVES were modified in the following ways. The light-duty PM<sub>2.5</sub> emission rates were reduced such that future vehicles (when new) will meet the Tier 3 standards with a compliance margin of approximately 50 percent. MOVES estimates that current vehicles, within the first 3 years of use, emit PM<sub>2.5</sub> on the FTP at 2.72 mg/mile (cars), and 3.08 mg/mile (light trucks). To achieve a 50 percent compliance margin with the fully-phased in Tier 3 rule, we estimated a reduction of 50 percent to the Tier 3 standards. The reductions are applied:

- Uniformly to cars and trucks,
- Uniformly across start and running processes,
- Uniformly across all operating modes (including the ones that cover US06 type driving)

The reductions in the PM<sub>2.5</sub> emissions over the model years reflect the phase-in of the Tier 3 PM<sub>2.5</sub> standards. The phase-in begins in 2017 for cars, and in 2018 for light trucks. By 2021, the emission rates (described above) are fully phased-in for light-duty vehicles. Table 7-20 includes the estimated FTP and US06 PM<sub>2.5</sub> for new (undeteriorated) vehicles, by model year. As shown in the table, the reductions in PM<sub>2.5</sub> yield compliance margins of more than 45 percent for both the FTP and US06 standards.

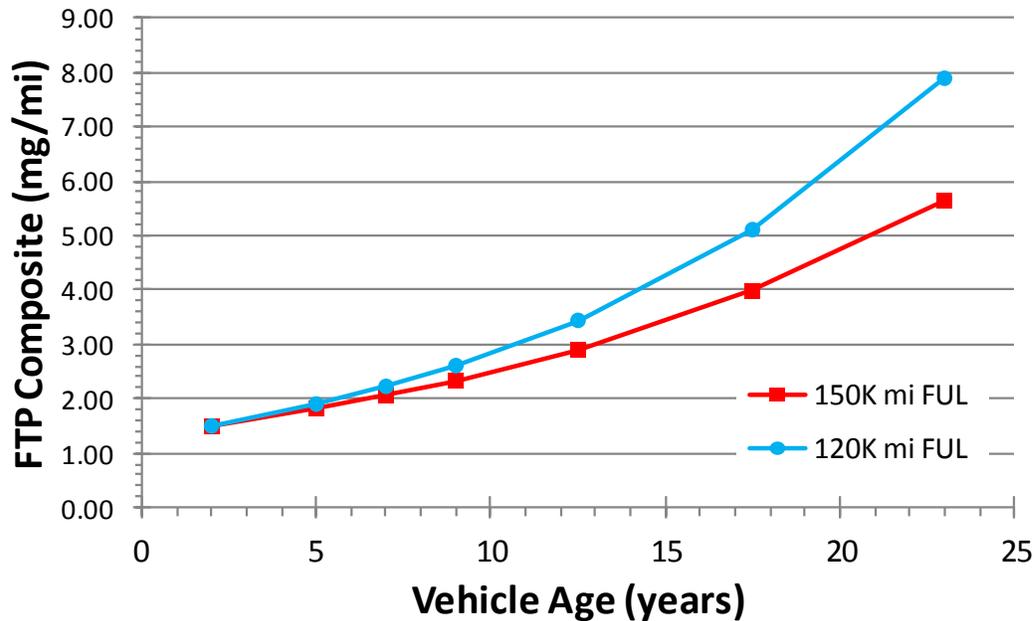
**Table 7-20 Trends in PM<sub>2.5</sub> Emissions on the FTP and US06 Cycles, by Model Year, Reflecting the Phase-in of the Tier 3 Standards**

Model Year	Tier 3 phase-in		FTP (mg/mile)		US06 (mg/mile)	
	Car	Truck	Car	Truck	Car	Truck
2011	0%	0%	2.72	3.08	2.94	4.85
2012	0%	0%	2.72	3.08	2.94	4.85
2013	0%	0%	2.72	3.08	2.94	4.85
2014	0%	0%	2.72	3.08	2.94	4.85
2015	0%	0%	2.72	3.08	2.94	4.85
2016	0%	0%	2.72	3.08	2.94	4.85
2017	10%	0%	2.59	3.08	2.79	4.85
2018	20%	20%	2.45	2.77	2.64	4.36
2019	40%	40%	2.18	2.46	2.35	3.88
2020	70%	70%	1.77	2.00	1.91	3.15
2021	100%	100%	1.36	1.54	1.47	2.42
2022	100%	100%	1.36	1.54	1.47	2.42
2023	100%	100%	1.36	1.54	1.47	2.42
2024	100%	100%	1.36	1.54	1.47	2.42
2025	100%	100%	1.36	1.54	1.47	2.42

PM<sub>2.5</sub> emissions of the vehicle fleet deteriorate with age, due to wear and failure of engine and emission control systems on some vehicles. The deterioration of the fleet-average PM<sub>2.5</sub> emission rates increase logarithmically with age as documented in the MOVES report<sup>10</sup>. The emissions trend reflecting the durability associated with a FUL of 120,000 mi is shown in Figure 7-10. The deterioration is applied multiplicatively to rates for “young” vehicles in the 0-3 yr ageGroup.

For vehicles manufactured after the onset of the Tier 3, the deterioration assumptions were modified to represent an extension of the full useful life (FUL) from 120,000 mi to 150,000 mi. To model this assumption, we adjusted the deterioration trend such that emissions levels were shifted to a point in age (or miles) that is 25% later (the value of 1.25 was calculated as the ratio of the extended FUL to the previous FUL, or 150/120). For example, under the 120K assumption, the fleet-average PM<sub>2.5</sub> emission rate reaches 10 mg/mile after 14 years. Under the 150K scenario, the fleet-average PM<sub>2.5</sub> emission rate does not reach 10 mg/mile until after  $14 * 1.25 = 17.5$  years.

Thus, the inventory modeling assumes a standard of 3.0 mg/mi and a 150,000 mi useful life. However, under the final rule, manufacturers will retain the option of certifying some engine test groups to a somewhat lower standard with a 120,000 mi useful life. Over the useful life of vehicles, we assume that the two options (higher standard with longer useful life, lower standard with shorter useful life) will yield approximately equivalent emissions trends over the life of the vehicles. Therefore, no attempt was made to represent both options in the inventory modeling.



**Figure 7-10 Deterioration Trends for PM<sub>2.5</sub>, for Full Useful Lives of 120,000 and 150,000 miles**

The discussion to this point has concerned total particulate (PM<sub>2.5</sub>). It is important to note that the rates stored in the emissionRateByAge table in MOVES do not represent PM<sub>2.5</sub> but rather organic and elemental carbon components, OC<sub>2.5</sub> and EC<sub>2.5</sub>, respectively. In the table, these components are identified as pollutantID = 111 and 112 respectively. Starting with OC and EC rates in the default database for MY 2016, the reductions described in Table 7-20 are applied equally to OC and EC rates to generate corresponding rates under the Tier 3 standards.

#### 7.1.3.3.6 Diesel PM

The Tier 3 controls were modeled as having no impact on light-duty diesel PM emissions. Although light-duty diesels are subject to the same Tier 3 PM standards as light-duty gasoline vehicles, all light-duty diesels are equipped with diesel particulate filters (DPF). The application of a DPF results in diesel PM emissions being very close to the cleanest gasoline vehicles in operation today. As a result the application of the Tier 3 PM standards to diesel vehicles will not result in a change in diesel PM emissions.

#### 7.1.3.3.7 Evaporative Emissions

The Tier 3 evaporative program requires lower emissions on the hot soak plus diurnal test procedure on 9 RVP E10 certification fuel and strengthens in-use performance through a new leak standard and OBD requirements for detection of vapor leaks. The new standards are projected to result in significant reductions in evaporative hydrocarbon emissions. For this analysis, tighter evaporative emission standards in conjunction with 9 RVP E10 certification fuel are expected to reduce evaporative permeation emissions and fuel system venting, since the Tier 3 evaporative emission standards are aimed at not allowing any vented vapor emissions during

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the test. Moreover, the new requirements addressing leaks are expected to reduce the prevalence (frequency rate) of fuel system vapor and liquid leaks.<sup>G</sup> The discussion below focuses on reducing evaporative emissions by improving the permeation resistance of fuel tanks and vapor lines and improved fuel system designs to reduce leaks. However, as mentioned above, and discussed in Chapter 1, there are a variety of technologies manufacturers could use to achieve the required reductions (including those which address vapor venting, permeation and leaks) and manufacturers are likely to use the technologies they expect to get the largest reductions for the lowest cost whether they be from reductions in fuel venting emissions, permeation, or leaks. Furthermore, some technologies will be effective in achieving emission reductions against more than one standard. For example, the canister honeycomb will help to meet the canister bleed and Tier 3 hot soak plus diurnal standards and any measure to reduce leaks will help to meet the leak standard and the hot soak plus diurnal standard. The technology choice is up to the manufacturer, but we expect that the technologies used will to varying degrees address all three basic emission types.

#### *7.1.3.3.7.1 Permeation Improvements*

Permeation emissions include fuel vapors that escape from a vehicle through micro pores in the various fuel system components and materials. Tier 3 will reduce the allowable emissions from this process. Light duty vehicles will see a reduction of about 50 percent from Tier 2 levels.

The Tier 2 permeation rate in MOVES is 0.0102 g/hour on E0 fuel. Analysis of the impact of ethanol on permeation emissions conducted as part of the RFS2 final rule, and included in MOVES2010, suggests that the use of E10 as Tier 3 certification test fuel will effectively double permeation emissions over the test procedure. Therefore, the combination of lowering the vehicle standard and certifying on a fuel with higher propensity to permeate must be accounted for in Tier 3 permeation rates.

The Tier 3 emission rate in MOVES is developed by estimating permeation emissions over one day of diurnal activity (65F-105F) on an ethanol-containing fuel and applying reductions in the base rate over time. The total permeation emissions for the day should equal about 75 percent of the standard (~0.225g) as the other 25 percent of the standard can be attributed to the Hot Soak portion of the certification test. The result is a Tier 3 permeation rate of 0.0026g/hour (a 75 percent reduction from the Tier 2 rate).

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<sup>G</sup> One of the updates to MOVES for this analysis was to enable direct input of the leak prevalence rates.

**Table 7-21 Tier 3 Permeation Rates**

Model Year	Tier 3 Phase-in	Permeation (g/hr)
Tier 2	0%	0.0102
2016_2017	40%	0.0072
2018_2019	60%	0.0056
2020_2021	80%	0.0041
2022	100%	0.0026

*7.1.3.3.7.2 Reduced frequency of vapor leaks*

EPA, in conjunction with the state of Colorado and the Coordinating Research Council, undertook multiple research programs to help quantify the prevalence of evaporative system leaks in the real world, and the emissions they cause.<sup>17,18,19</sup> The evaporative leak provisions grew from this work, informing the emission inventory contribution of evaporative leaks, and the level of reductions possible from an in-use program focused on reducing the incidence of these leaks. To establish the reference case, the frequency of evaporative system leaks were estimated from the prevalence of high evaporative emission vehicles in the Colorado field study.

The impact of the Tier 3 evaporative emissions standards are quantified from MOVES, which has been updated based on the new data collected. We expect that emissions reductions will come from the reduction in the incidence rate of vapor leaks.

The vapor leak frequency estimates are generated from the high evaporative emissions field study in Colorado during the summer of 2009.<sup>17</sup> In that study, it was found that, compared to the 1981-1995 model years pre-enhanced evaporative emissions vehicles, the vapor leak frequency dropped significantly with the onset of the enhanced evaporative emissions standards in 1996. The new standards did not explicitly require the measurement of vapor leaks through OBD leak detection, but the standards encouraged changes in the materials and connections in the fuel systems resulting in approximately 70 percent less vapor leaks. The upgraded materials and connections for the following Tier 2 standards are estimated to have reduced vapor leak rates another 33 percent.

We expect that manufacturers will again respond to the Tier 3 standards by making further improvements, such as changes in materials and connections in order to reduce the amount of fuel permeation and vapor leaks and will address canister bleed emissions. These changes plus design enhancements (see Chapter 1, Section 1.6.1 “Tier 3 Evaporative Emissions/Leak Control Technology Approaches” for more details) can be expected to further reduce the amount of vapor leaks by one third, similar to the effect of Tier 2.

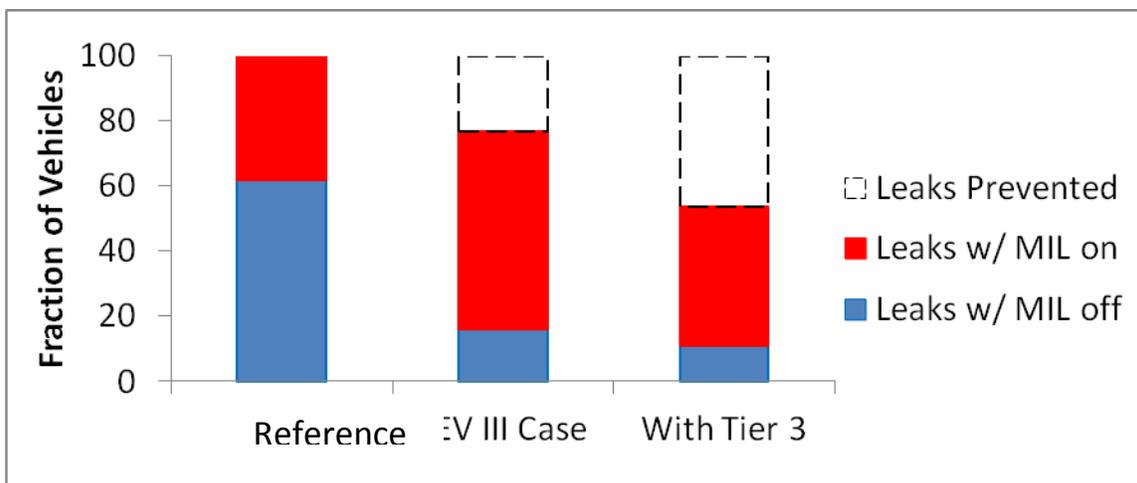
Tier 3 also includes provisions for an in-use measurement program that will explicitly detect the remaining vapor leaks. The in-use leak standard will be enforced in the In-Use Vehicle Program (IUVP) at different points in the vehicle’s useful life. Tier 3 also imposes more stringent requirements for evaporative on-board diagnostics (OBD) including a change in the vapor leak check from a 0.040” equivalent diameter orifice in the current federal leak detection

requirement to 0.020”, as well as other more stringent readiness requirements which are already in place for implementation in the State of California.

The analysis from the high evaporative emission field studies in Colorado (2008-2010) found that evaporative OBD was only 30-50 percent effective in detecting vapor leaks.<sup>20</sup> The improvements to evaporative OBD in the Tier 3 rule are estimated to increase OBD vapor leak detection to 80 percent effectiveness.

Based on the analysis as described above, the leak standard is therefore estimated to result in an additional one third less evaporative vapor leaks. The prediction of an overall two thirds reduction in vapor leaks is not unreasonable, considering the observed impact of the 1996 enhanced evap rule. Modeling details can be found in a separate memo to the docket.<sup>21</sup>

The leak prevalence rates in MOVES utilize observations that the State of Colorado found in a follow-up study in 2010. Leaking vehicles were recruited in the Denver area to the Colorado Tech Center and Laboratory to determine pre and post repair emissions. In this study they found that approximately 70 percent of the evaporative leaks detected were due to the deterioration of the evaporative and/or fuel system e.g. problems like corroded fuel lines, filler neck, cracked hoses, etc. that could be repaired or improved with design and materials. The other 30 percent were due to issues beyond the manufacturers’ control, such as improper maintenance or missing gas caps.



**Figure 7-10 Vapor Leak Control Assumed for 100 Leaking Vehicles**

The Reference case in Figure 7-10 assumes 40 percent OBD effectiveness with 95 percent OBD readiness, resulting in 38 out of 100 MILs due to leaks turned on (the red portion of first bar in above figure). This 40 percent OBD effectiveness is based on the analysis comparing the evaporative system leak OBD DTCs to the portable SHED hot soak emissions in the high evaporative emissions field studies in Denver (2008-2010), 30-50 percent of the time. For the LEV III case (the overall nationwide situation without Tier 3), it is assumed that 33 percent (the one third discussed as Tier 3 permeation benefit, similar to Tier 2 benefit) of 70

percent (≈23 percent) are prevented with the reduction in SHED test standard (white portion of middle). It is assumed that 80 percent of the remaining leaks will have a light on (red portion in middle bar). The blue portion of the middle bar is the leaks remaining undetected in the LEV III case.

Based on Tier 3 control, we assume 66 percent or two thirds (one third for Tier 3 permeation benefit in previous paragraph plus one third discussed earlier as leak standard benefit, equals two thirds emissions benefit for Tier 3) of the 70 percent durability related leaks (≈46 percent) are prevented (white portion in third bar). The modeling then assumes that 80 percent of the remaining leaks will have an evaporative system leak OBD light on as in the LEV III case (the red portion of the third bar). The remaining without lights is 11 out of 100, in the blue portion of the third bar in the figure above.

#### 7.1.3.3.7.3 Reduced frequency of liquid leaks

Similar to vapor leaks, we expect a reduction in the occurrence of liquid leaks due to improved system design and integrity. We believe that remaining liquid leaks occurring in advanced evaporative systems will be primarily caused by tampering and mal-maintenance. Therefore we have reduced the frequency rate for leaks for vehicles less than 15 years of age, and expect vehicles older than 15 to have the same rate of leak occurrence as current technologies.

**Table 7-22 Reductions of Liquid Leaks in Tier 3**

Age	Operating	Hot Soak	Cold Soak
0-9	45%	45%	45%
10-14	30%	30%	30%
15-19	0%	0%	0%
20+	0%	0%	0%

#### 7.1.3.4 Updates to MOVES Sulfur Effects

In order to evaluate the emission impacts of the sulfur standards, the version of MOVES used for this analysis made significant updates to the effect of fuel sulfur levels below 30 ppm on exhaust emissions. In MOVES2010b, these effects were based on extrapolation of data on sulfur levels above 30 ppm.<sup>22</sup> The updates made for this analysis were based on significant new data generated from EPA research conducted in 2010-11, summarized below. A final report on this research is available in the docket.<sup>23</sup>

##### 7.1.3.4.1 EPA Testing of Gasoline Sulfur Effects on Tier 2 Vehicles and the In-Use Fleet

Fuel sulfur content has long been understood to affect the performance of emission aftertreatment catalysts in light duty vehicles, where the sulfur and/or its oxides adsorb to the active precious metal sites, reducing the catalyst's efficiency in destroying harmful pollutants.

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This can severely impair the effectiveness of the catalyst to convert the products of combustion, leading to increases in these emissions relative to a “clean” catalyst. The quantity of sulfur present on the catalyst at any given time is a function of its temperature and the fuel sulfur level, with elevated catalyst temperatures and lower fuel sulfur concentration both reducing sulfur loading. Numerous studies have shown the direct impact of fuel sulfur levels above 30 ppm on emissions; these formed the basis of the Tier 2 rulemaking, which considered the impact of sulfur in terms of immediate impact, and irreversible impact due to permanent catalyst damage.<sup>24</sup>

With the advent of the Tier 2 sulfur standards, new research has focused on the emission reduction potential of lowering sulfur levels below 30 ppm, particularly on Tier 2 technology vehicles, under the hypothesis that increased reliance on the catalytic convertor would result in a higher sensitivity to sulfur accumulation. A study conducted by EPA and the auto industry on nine Tier 2 vehicles in support of the Mobile Source Air Toxics (MSAT) rule, found significant reductions in NO<sub>x</sub>, CO and total HC when the vehicles were tested on low sulfur fuel, relative to 32 ppm fuel.<sup>25</sup> In particular, the study found a nearly 50 percent increase in NO<sub>x</sub> when sulfur was increased from 6 ppm to 32 ppm. Given the preparatory procedures related to catalyst clean-out and loading used by these studies, these results may represent a “best case” scenario relative to what will be expected under more typical driving conditions. Nonetheless, these data suggested the effect of in-use sulfur loading was largely reversible for Tier 2 vehicles, and that there were likely to be significant emission reductions possible with further reductions in gasoline sulfur level. Another recent study by Umicore showed reductions of 41 percent for NO<sub>x</sub> and 17 percent for HC on a PZEV operating on fuel with 33 ppm and 3 ppm sulfur.<sup>26</sup> Both of these studies conducted testing on high and low sulfur after running the test vehicles through test cycles meant to clean the catalyst from the effects of prior sulfur exposure.

Both of these studies showed the emission reduction potential of lower sulfur fuel on Tier 2 and later technology vehicles over the FTP cycle. However, assessing the potential for reduction on the in-use fleet requires understanding how sulfur exposure over time impacts emissions, and what the state of catalyst sulfur loading is for the typical vehicle in the field. In response to these data needs, EPA conducted a new study to assess the emission reductions expected from the in-use Tier 2 fleet with a reduction in fuel sulfur level from current levels. It was designed to take into consideration what was known from prior studies on sulfur build-up in catalysts over time and the effect of periodic regeneration events that may result from higher speed and load operation over the course of day-to-day driving.

The study sample described in this analysis consisted of 93 cars and light trucks recruited from owners in southeast Michigan, covering model years 2007-9 with approximately 20,000-40,000 odometer miles.<sup>H</sup> The makes and models targeted for recruitment were chosen to be representative of high sales vehicles covering a range of types and sizes. Test fuels were two non-ethanol gasolines with properties typical of certification test fuel, one at a sulfur level of 5

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<sup>H</sup> The NPRM modeling was based on analysis of 81 passenger cars and trucks. Since the NPRM, twelve additional Tier 2 vehicles were tested and included in the statistical analysis described in the docketed final report, examining the effect of sulfur on emissions from Tier 2 vehicles. The analysis based on the complete set of 93 Tier 2 vehicles is reflected in the results presented in this section and the emissions modeling for FRM.

ppm and the other at 28 ppm. All emissions data was collected using the FTP cycle at a nominal temperature of 75°F.

Using the 28 ppm test fuel, emissions data were collected from vehicles in their as-received state as well as following a high-speed/load “clean-out” procedure consisting of two back-to-back US06 cycles intended to reduce sulfur loading in the catalyst. A statistical analysis of this data showed highly significant reductions in several pollutants including NO<sub>x</sub> and hydrocarbons, demonstrating that sulfur loadings have a large effect on exhaust catalyst performance, and that Tier 2 vehicles can achieve significant reductions based on removing, at least in part, the negative impact of the sulfur loading on catalyst efficiency (Table 7-23). For example, Bag 2 NO<sub>x</sub> emissions dropped 31 percent between the pre- and post-cleanout tests on 28 ppm fuel.

**Table 7-23 Percent Reduction in In-Use Emissions after the Clean-out Using 28 ppm Test Fuel**

	<b>NO<sub>x</sub></b> <b>(p-value)</b>	<b>THC</b> <b>(p-value)</b>	<b>CO</b> <b>(p-value)</b>	<b>NMHC</b> <b>(p-value)</b>	<b>CH<sub>4</sub></b> <b>(p-value)</b>	<b>PM</b> <b>(p-value)</b>
<b>Bag 1</b>	–	–	6.0% (0.0151)	–	–	15.4% ( $< 0.0001$ )
<b>Bag 2</b>	31.4% (0.0003)	14.9% (0.0118)	–	18.7% (0.0131)	14.4% (0.0019)	–
<b>Bag 3</b>	35.4% ( $< 0.0001$ )	20.4% ( $< 0.0001$ )	21.5% (0.0001)	27.7% ( $< 0.0001$ )	10.3% ( $< 0.0001$ )	24.5% ( $< 0.0001$ )
<b>FTP Composite</b>	11.4% (0.0002)	3.8% (0.0249)	6.8% (0.0107)	3.5% (0.0498)	6.0% (0.0011)	13.7% ( $< 0.0001$ )
<b>Bag 1 – Bag 3</b>	–	–	7.2% (0.0656)	–	–	–

The clean-out effect is not significant at  $\alpha = 0.10$ , when no reduction estimate is provided.

To assess the impact of lower sulfur fuel on in-use emissions, further testing was conducted on a representative subset of vehicles on 28 ppm and 5 ppm fuel with accumulated mileage. A first step in this portion of the study was to assess the differences in the effectiveness of the clean-out procedure under different fuel sulfur levels. Table 7-24 presents a comparison of emissions immediately following (<50 miles) the clean-out procedures at the low vs. high sulfur level. These results show significant emission reductions for the 5 ppm fuel relative to the 28 ppm fuel immediately after this clean-out; for example, Bag 2 NO<sub>x</sub> emissions were 34 percent lower on the 5 ppm fuel vs. the 28 ppm fuel. This indicates that the catalyst is not fully desulfurized, even after a clean out procedure, as long as there is sulfur in the fuel. This further indicates that current sulfur levels in gasoline continue to have a long-term, adverse effect on exhaust emissions control that is not fully removed by intermittent clean-out procedures that can occur in day-to-day operation of a vehicle and demonstrates that lowering sulfur levels to 10 ppm on average will significantly reduce the effects of sulfur impairment on emissions control technology.

**Table 7-24 Percent Reduction in Exhaust Emissions When Going from 28 ppm to 5 ppm Sulfur Gasoline for the First Three Repeat FTP Tests Immediately Following Clean-out**

	<b>NO<sub>x</sub></b> <b>(p-value)</b>	<b>THC</b> <b>(p-value)</b>	<b>CO</b> <b>(p-value)</b>	<b>NMHC</b> <b>(p-value)</b>	<b>CH<sub>4</sub></b> <b>(p-value)</b>	<b>PM<sup>‡</sup></b>
<b>Bag 1</b>	5.3% (0.0513)	6.8% (0.0053)	6.2% (0.0083)	5.7% (0.0276)	14.0% (<0.0001)	–
<b>Bag 2</b>	34.4% (0.0036)	33.9% (<0.0001)	– <sup>‡</sup>	26.4% (0.0420)	49.4% (<0.0001)	–
<b>Bag 3</b>	42.5% (<0.0001)	36.9% (<0.0001)	14.7% (0.0041)	51.7% (<0.0001)	28.5% (<0.0001)	–
<b>FTP Composite</b>	15.0% (0.0002)	13.3% (<0.0001)	8.5% (0.0050)	10.9% (0.0012)	23.6% (<0.0001)	–
<b>Bag 1 – Bag 3</b>	– <sup>‡</sup>	– <sup>‡</sup>	– <sup>‡</sup>	– <sup>‡</sup>	– <sup>‡</sup>	–

<sup>‡</sup>The effectiveness of clean-out cycle is not significant at  $\alpha = 0.10$ .

To assess the overall in-use reduction between high and low sulfur fuel, a mixed model analysis of all data as a function of fuel sulfur level and miles driven after cleanout was performed. This analysis found highly significant reductions for several pollutants, as shown in Table 7-25. Reductions for Bag 2 NO<sub>x</sub> were particularly high, estimated at 52 percent between 28 ppm and 5 ppm overall. For all pollutants, the model fitting did not find a significant miles-by-sulfur interaction, suggesting the relative differences were not dependent on miles driven after clean-out.

**Table 7-25 Percent Reduction in Emissions from 28 ppm to 5 ppm Fuel Sulfur  
on In-use Tier 2 Vehicles**

	<b>NO<sub>x</sub></b> <b>(p-value)</b>	<b>THC</b> <b>(p-value)</b>	<b>CO</b> <b>(p-value)</b>	<b>NMHC</b> <b>(p-value)</b>	<b>CH<sub>4</sub></b> <b>(p-value)</b>	<b>NMOG+NO<sub>x</sub></b> <b>(p-value)</b>	<b>PM</b> <b>†</b>
<b>Bag 1</b>	7.1% (0.0216)	9.2% (0.0002)	6.7% (0.0131)	8.1% (0.0017)	16.6% ( $< 0.0001$ )	N/A	–
<b>Bag 2</b>	51.9% ( $< 0.0001$ )	43.3% ( $< 0.0001$ )	– †	42.7% (0.0003)	51.8% ( $< 0.0001$ )	N/A	–
<b>Bag 3</b>	47.8% ( $< 0.0001$ )	40.2% ( $< 0.0001$ )	15.9% (0.0003)	54.7% ( $< 0.0001$ )	29.2% ( $< 0.0001$ )	N/A	–
<b>FTP Composite</b>	14.1% (0.0008)	15.3% ( $< 0.0001$ )	9.5% ( $< 0.0001$ )	12.4% ( $< 0.0001$ )	29.3% ( $< 0.0001$ )	14.4% ( $< 0.0001$ )	–
<b>Bag 1 – Bag 3</b>	– †	5.9% (0.0074)	– †	– ‡	– ‡	N/A	–

† Sulfur level not significant at  $\alpha = 0.10$ .

‡ Inconclusive because the mixed model did not converge.

Major findings from this study include:

- Largely reversible sulfur loading is occurring in the in-use fleet of Tier 2 vehicles and has a measureable effect on emissions of NO<sub>x</sub>, hydrocarbons, and other pollutants of interest.
- The effectiveness of high speed/load procedures in restoring catalyst efficiency is limited when operating on higher sulfur fuel.
- Reducing fuel sulfur levels from current levels to levels in the range of the gasoline sulfur standards will be expected to achieve significant reductions in emissions of NO<sub>x</sub>, hydrocarbons, and other pollutants of interest in the current in-use fleet.
- Assuming that the emissions impacts vs. gasoline sulfur content are approximately linear, changing gasoline sulfur content from 30 ppm to 10 ppm would result in NMOG+NO<sub>x</sub> emissions decreasing from 52 mg/mi to 45 mg/mi, respectively (a 13% decrease), and NO<sub>x</sub> emissions decreasing from 19 mg/mi to 16 mg/mi, respectively (a 16% decrease), for the vehicles in the study.

To evaluate the robustness of the statistical analyses assessing the overall in-use emissions reduction between operation on high and low sulfur fuel (Table 7-25), a series of sensitivity analyses were performed to assess the impacts on study results of measurements from low-emitting vehicles and influential vehicles, as documented in detail in the report.<sup>27</sup> The sensitivity analyses showed that the magnitude and the statistical significance of the results were not impacted and thus demonstrated that the results are statistically robust. We also subjected the design of the experiment and data analysis to a contractor-led independent peer-review process in accordance with EPA's peer review guidance. The results of the peer review<sup>28,29</sup> largely supported the study design, statistical analyses, and the conclusions from the program and raised

only minor concerns that have not changed the overall conclusions and have subsequently been addressed in the final version of the report.<sup>30</sup>

Overall, the reductions found in this study are in agreement with other low sulfur studies conducted on Tier 2 vehicles, namely MSAT and Umicore studies mentioned above, in terms of the magnitude of NO<sub>x</sub> and HC reductions when switching from 28 ppm to 5 ppm fuel.<sup>31,32</sup> For additional details on the impact of gasoline sulfur control on exhaust emissions, see Section IV.A.6 of the preamble.

#### 7.1.3.4.2 Implementation in MOVES

The fuel sulfur effect applies multiplicatively in conjunction with other gasoline fuel effects in MOVES. The results shown in Table 7-25 were applied in MOVES for model year 2001 and later gasoline vehicles to estimate the sulfur effects at or below 30 ppm. For sulfur levels above 30 ppm, and for all pre-2001 model year vehicles, the sulfur effect originally implemented in MOVES2010b remains in place.

Equation 7-3 shows the generic form of the low sulfur model applied to model year 2001 and later gasoline vehicles.

$$\text{sulfur adjustment } (A_s) = 1.0 - \beta_s (S_{base} - x_s)$$

**Equation 7-3 Low Sulfur Model**

The sulfur coefficients ( $\beta_s$ ) were developed by linearly interpolating between emission levels at 28 to 5 ppm, corresponding to the reductions in emissions shown in Table 7-25, and standardizing to sulfur level of 30 ppm. The sulfur coefficient simply represents the slope of the interpolated line. The emission reductions from FTP bag 2 and FTP bag1-bag3 were used to calculate the sulfur coefficients for running exhaust and start exhaust, respectively. Table 7-26 shows the resulting sulfur coefficients applied in MOVES by pollutant, process, and vehicle type.

**Table 7-26 Low Sulfur Coefficients by Vehicle Type, Process and Pollutant**

Vehicle Type	THC		CO		NO <sub>x</sub>		PM	
	Starts	Running	Starts	Running	Starts	Running	Starts	Running
Motorcycle	0	0	0	0	0	0	0	0
Passenger Car, Passenger Truck & Light Commercial Truck	0.00257	0.01813	0	0	0	0.02158	0	0
All other Vehicle Types	0	0.015488	0	0.009436	0	0.027266	0	0

The sulfur base ( $S_{base}$ ) in the low sulfur model varies as a function of the scenario being modeled and the model year group (see Table 7-27). For most states, the sulfur base is 30 ppm except for 2017 and later model years for the control scenario. For California, the sulfur base is 10 ppm for all model years and scenarios. For the Section 177 states that have adopted the LEV

III program, the sulfur base of 30 ppm and 10 ppm is used for the model years 2001 to 2016 and model years 2017 and later, respectively.

**Table 7-27 Sulfur Base in Low Sulfur Model**

	Reference		Control	
	MYG 2001-2016	MYG 2017+	MYG 2001-2016	MYG 2017+
Most States	30 ppm	30 ppm	30 ppm	10 ppm
California	10 ppm	10 ppm	10 ppm	10 ppm
Section-177 States	30 ppm	10 ppm	30 ppm	10 ppm

These equations were then used to populate the database table that stores fuel effect equations in the MOVES database (“GeneralFuelRatioExpression”). This table allows the MOVES model to compute fuel effects based on the properties of any fuel contained in the “FuelSupply” and “FuelFormulation” database tables. Additional details are documented in the docket memo addressing MOVES updates.

#### 7.1.4 Nonroad Emissions

The nonroad sector includes a wide range of mobile emission sources ranging from locomotives and construction equipment to hand-held lawn tools. In the nonroad sector, the only emissions that are directly affected by the Tier 3 regulation are the emissions from gasoline-powered equipment such as lawn-mowers, recreational boats and all-terrain vehicles. Their SO<sub>2</sub> emissions are reduced with the decrease in gasoline sulfur levels. As with onroad, reference and control case emissions were generated using the fuel supply inputs reflecting the projected fuel volumes from AEO2013.

Gasoline and land-based diesel nonroad emissions were estimated using EPA’s NONROAD2008 model, as run by the EPA’s consolidated modeling system known as the National Mobile Inventory Model (NMIM).<sup>33</sup> The fuels in the NMIM database, NCD2010201a, were developed from the reference and control fuels used for onroad vehicles, as described in Section 7.1.3.2. Onroad and nonroad gasoline formulations are assumed to be identical for all years. In 2018 and 2030, nonroad equipment is assumed to use E10 only. For all years, the reference case included the higher sulfur reference gasoline and the control case met the sulfur limits.

Since aircraft, locomotive and commercial marine emission sources do not burn gasoline, their emission factors are unaffected by the sulfur changes in gasoline fuels that were developed for this rule. Hence, their emissions are the same for both the reference and control cases. The emissions from these sources used for this rule are the same as the ones estimated for the Heavy-Duty Greenhouse Gas Rule (2011).<sup>34</sup> Estimation of emissions from locomotives and C1/C2 commercial marine used the same procedures developed for the Locomotive Marine Rule (2008), detailed in the RIA for that rule.<sup>35</sup> The procedures used for calculating C3 commercial marine emissions are those developed in the recent C3 Rule (2010).<sup>36</sup>

### 7.1.5 Criteria and Toxic Emission Impact Results

The Tier 3 rule will reduce NO<sub>x</sub> (including NO<sub>2</sub>), VOC, and SO<sub>2</sub> from all gasoline-powered on road vehicles immediately upon implementation of lower sulfur fuel, and will further reduce these emissions as well as PM<sub>2.5</sub> and CO from cars, light trucks and light heavy-duty trucks (gas and diesel) as tighter emission standards from these vehicles phase in. There also will be reductions in SO<sub>2</sub> emissions from the nonroad gasoline fleet as a result of sulfur standards. The reductions are summarized in this section for each pollutant.

NO<sub>x</sub> reductions are shown in Table 7-28 for calendar years 2018 and 2030. We project significant reductions immediately upon implementation of the program, growing to a nearly 25 percent reduction in onroad emissions by 2030. We project a nearly 33 percent reduction in onroad emissions in 2050, when the fleet will have fully turned over to vehicles meeting the fully phased in Tier 3 standards.

**Table 7-28 Tier 3 NO<sub>x</sub> Reductions by Calendar Year (Annual U.S. Short Tons)**

Year	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2018	2,753,732	2,489,364	264,369	9.6%
2030	1,331,788	1,003,279	328,509	24.7%

Table 7-29 shows the reduction in NO<sub>x</sub> emissions, in annual short tons, projected in calendar years 2018 and 2030. The reductions are split into those attributable to the introduction of low sulfur fuel in the pre-Tier 3 fleet (defined for this analysis as model years prior to 2017); and reductions attributable to vehicle standards enabled by low sulfur fuel (model year 2017 and later). As shown, in 2018 over 90 percent of the program reductions are coming from lower sulfur gasoline on the fleet already on the road. By 2030, over 80 percent of the reduction is coming from 2017 and later model year vehicles, with remaining reduction coming from lower sulfur fuel on pre-Tier 3 vehicles.<sup>1</sup>

**Table 7-29 Projected NO<sub>x</sub> Reductions from Tier 3 Program (Annual U.S. Short Tons)**

	2018	2030
<b>Total reduction</b>	<b>264,369</b>	<b>328,509</b>
Reduction from pre-Tier 3 fleet due to sulfur standard	242,434	56,324
Reduction from Tier 3 fleet due to vehicle and sulfur standards	21,934	272,185

<sup>1</sup> This is an approximate breakdown, as there will be some NO<sub>x</sub> emission reduction from heavy-duty gasoline vehicles greater than 14,000 pounds beyond the 2017 model year that are counted in the “Tier 3 fleet” here

VOC reductions are shown in Table 7-30 for calendar years 2018 and 2030. We project reductions of over 40,000 tons (3 percent of the onroad fleet emissions) immediately upon implementation of the program, growing to a 16 percent reduction in onroad emissions by 2030. We project a 28 percent reduction in onroad emissions in 2050, when the fleet will have fully turned over to vehicles meeting the fully phased in Tier 3 standards.

**Table 7-30 Tier 3 VOC Reductions by Calendar Year (Annual U.S. Short Tons)**

CY	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2018	1,703,902	1,656,399	47,504	2.8%
2030	1,078,892	911,301	167,591	15.5%

Table 7-31 shows the VOC reductions in 2018 and 2030 split into those attributable to the pre-Tier 3 fleet, and the Tier 3 fleet. The Tier 3 fleet reductions are further subdivided into the contribution of the exhaust and evaporative standards. In 2018, over 80 percent of the program reductions are coming from lower sulfur gasoline on the fleet already on the road. By 2030, over 90 percent of the reduction is coming from 2017 and later model year vehicles, with remaining reduction coming from lower sulfur fuel on pre-Tier 3 vehicles. The evaporative standards account for close to 40 percent reduction in VOC in 2030.

**Table 7-31 Projected VOC Reductions from Tier 3 Program (Annual U.S. Short Tons)**

	2018	2030
<b>Total reduction</b>	<b>47,504</b>	<b>167,591</b>
Reduction from pre-Tier 3 fleet due to sulfur standard	38,786	11,249
Reduction from Tier 3 fleet due to vehicle and sulfur standards	8,718	156,343
<i>Exhaust</i>	<i>43,009</i>	<i>105,253</i>
<i>Evaporative</i>	<i>4,495</i>	<i>62,339</i>

CO reductions are shown in Table 7-32 for calendar years 2018 and 2030. We project significant reductions immediately upon implementation of the program, growing to a 24 percent reduction in onroad emissions by 2030. We project a 38 percent reduction in onroad emissions in 2050, when the fleet will have fully turned over to vehicles meeting the fully phased-in Tier 3 standards.

**Table 7-32 Tier 3 CO Reductions by Calendar Year (Annual U.S. Short Tons)**

CY	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2018	17,517,356	17,238,477	278,879	1.6%
2030	14,663,722	11,205,680	3,458,041	23.6%

Table 7-33 shows the reductions for CO, broken down by pre- and post-Tier 3 in the manner described for NO<sub>x</sub> and VOC above. The immediate reductions in the onroad fleet from sulfur control comprise only about 40 percent of total reductions in 2018. By 2030, the Tier 3 fleet is accounting for 99 percent of program reductions. Of the Tier 3 vehicle standard reductions in 2030, we estimate that about 5 percent are contributed by the heavy-duty tailpipe standards.

**Table 7-33 CO Reductions from Tier 3 Program (Annual U.S. Short Tons)**

	<b>2018</b>	<b>2030</b>
<b>Total reduction</b>	<b>278,879</b>	<b>3,458,041</b>
Reduction from pre-Tier 3 fleet due to sulfur standard	122,171	17,734
Reduction from Tier 3 fleet due to vehicle and sulfur standards	156,708	3,440,307

Direct PM<sub>2.5</sub> impacts are shown in Table 7-34 for calendar years 2018 and 2030. For direct PM, the impact shown is solely from the tailpipe standards. Thus, unlike other pollutants, reductions do not become significant until the fleet has turned over to cleaner vehicles. By 2030, we project a reduction of about 7,900 tons annually, which represents approximately 10 percent of the onroad direct PM<sub>2.5</sub> inventory. The relative reduction in onroad emissions is projected to grow to 28 percent in 2050, when the fleet will have fully turned over to vehicles meeting the fully phased-in Tier 3 standards.

**Table 7-34 Tier 3 PM<sub>2.5</sub> Reductions by Calendar Year (Annual U.S. Short Tons)**

CY	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2018	115,560	115,430	130	0.1%
2030	78,320	70,428	7,892	10.1%

Emissions of air toxics also will be reduced by the sulfur, exhaust and evaporative standards. Air toxics are generally a subset of compounds making up VOC, so the reduction trends tend to track the VOC reductions presented above. Table 7-35 presents reductions for certain gaseous air toxics and polycyclic aromatic hydrocarbons (PAHs)<sup>J</sup>, reflecting reductions of a few percent in 2018, and 10 to 30 percent of onroad emissions, depending on the individual pollutant, in 2030.

<sup>J</sup> PAHs represents the sum of the following 15 PAH compounds: acenaphthene, acenaphthalene, anthracene, benz(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(g,h,i)perylene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorine, indeno(1,2,3,cd)pyrene, phenanthrene, and pyrene. These PAHs are included in EPA's national emissions inventory (NEI).

**Table 7-35 Reductions for Certain Individual Compounds (Annual U.S. Short Tons)**

	2018 Reduction	Percent reduction in onroad	2030 Reduction	Percent reduction in onroad
Acetaldehyde	600	3.4%	2,067	20.6%
Formaldehyde	513	2.3%	1,277	9.9%
Acrolein	40	2.6%	127	15.0%
1,3-Butadiene	257	5.2%	677	29.3%
Benzene	1,916	5.8%	4,762	26.4%
Naphthalene	99	3.0%	269	15.2%
Ethanol	2,704	1.7%	19,950	15.8%
2,2,4-Trimethylpentane	806	1.9%	3,827	11.9%
Ethyl Benzene	761	2.8%	2,451	14.3%
Hexane	1,112	3.2%	4,132	19.0%
Propionaldehyde	27	2.7%	63	16.9%
Styrene	71	5.1%	242	29.5%
Toluene	3,772	2.2%	15,261	12.9%
Xylene	2,894	2.9%	9,396	15.1%
PAHs	10	1.2%	58	18.1%

The totals shown in Table 7-36 represent the sum of all toxic species listed in Table 7A-1 of the Appendix, including the species in Table 7-35. As shown, in 2030, the overall onroad inventory of total toxics will be reduced by about 15 percent, with nearly one half of the reductions coming from the evaporative standards.

**Table 7-36 Reductions in Total Mobile Source Air Toxics (Annual U.S. Short Tons)**

	2018	2030
<b>Total reduction</b>	<b>15,583</b>	<b>64,558</b>
Reduction from pre-Tier 3 fleet due to sulfur standard	11,981	3,517
Reduction from Tier 3 fleet due to vehicle and sulfur standards	3,602	61,041
<i>Exhaust</i>	<i>13,340</i>	<i>34,595</i>
<i>Evaporative</i>	<i>2,243</i>	<i>29,963</i>

SO<sub>2</sub> emissions from mobile sources are a direct function of sulfur in the fuel, and reducing sulfur in gasoline would result in immediate reductions in SO<sub>2</sub> from the on and off-road fleet. The reductions, shown in Table 7-37, represent over 50 percent reduction in onroad SO<sub>2</sub> emissions. The breakdown of the relative contribution of onroad vehicles and off-road equipment is shown; the contribution of off-road sources is a function of off-road gasoline consumption accounting for approximately 5 percent of overall gasoline use.<sup>37</sup>

**Table 7-37 Projected SO<sub>2</sub> Reductions from Tier 3 Program (Annual U.S. Short Tons)**

	<b>2018</b>	<b>2030</b>
<b>Total reduction</b>	<b>15,565</b>	<b>13,261</b>
Reduction from onroad vehicles due to sulfur standard	14,813	12,399
Reduction from off-road equipment due to sulfur standard	752	862
<b>Percent reduction in onroad SO<sub>2</sub> emissions</b>	<b>56%</b>	<b>56%</b>

## **7.2 Criteria and Toxic Pollutant Air Quality Impacts**

### **7.2.1 Emission Inventories for Air Quality Modeling**

To estimate the benefits of the Tier 3 rule, we performed air quality modeling for the years 2018 and 2030. As noted in Section 7.1, emission inventories for air quality modeling were required for the entire U.S. by 12 km grid cell and hour of the day for each day of the year, requiring a methodology with much greater detail than the national emission inventories presented above. While most of the modeling tools and inputs used for estimating national emission inventories were also used in developing inputs for air quality modeling, the application of these tools (particularly MOVES) to produce the gridded / hourly emissions was quite different, and in essence a separate analysis. As explained in Section 7.2.1.1, the different analyses generated different onroad inventory totals, but the relative reduction from reference to control scenarios was consistent. The summary of the methodology for each sector is contained in the following sections; for brevity, details of the process for developing air-quality ready emission inventories are available in a separate technical support document.<sup>38</sup>

#### **7.2.1.1 Onroad Emissions**

For the onroad vehicle emissions inputs to our air quality modeling, we used an emission inventory approach that provided more temporal and geographical resolution than the approach used for the national inventories described above. This additional detail is needed when generating inputs to air quality models because it allows us much more precision in accounting for local ambient temperatures and local fuel properties in our air quality modeling. For this purpose, we used county-specific inputs and tools that integrated the MOVES model of onroad emissions with the Sparse Matrix Operator Kernel Emissions tool (SMOKE) emission inventory model to take advantage of the gridded hourly temperature information used in air quality modeling.

In particular, we used an automated process to run MOVES to produce emission factors by temperature and speed for the fleet mix, fuels, and I/M program for more than 100 “representing counties,” to which every other county could be mapped. The emission factors then were multiplied by activity at the grid-cell-hour level to produce gridded hourly emissions

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for the entire continental U.S. These emissions were input into the Community Multiscale Air Quality Modeling System (CMAQ). We summarize this approach in the sections below.

Because of the differences in methodology between the national inventories and air quality inventories, particularly the treatment of local variables such as vehicle speed distributions and the handling of non-linear temperature effects in MOVES, the more detailed approach used for the air quality inventory produced different emission estimates than those described in the national inventory section above. This is pronounced, especially, in pollutants with strong temperature sensitivities in MOVES, such as PM<sub>2.5</sub>, where the finer temperature resolution in the air quality approach produced significantly higher emissions than the aggregate national inventory approach.

In addition to the methodological differences, because this modeling methodology with added precision is time consuming and resource intensive, the inventories for the air quality modeling had to begin months before the national inventory modeling and used a slightly older version of the MOVES model. The model and the input differences between the national inventory and the inventories developed for air quality modeling are described below.

#### *Phase-in Assumptions for LDT3 and LDT4*

As described in Section 7.1.3.3.1, for the national inventory, the onset of the Tier 3 phase-in for gaseous pollutants (HC, CO, NO<sub>x</sub>) starts in 2018 for truck classes with gross vehicle weight ratings greater than 6,000 lbs. (LDT3 and LDT4), in contrast to LDV, LDT1, and LDT2, which begin phasing-in in 2017. However, for the air quality modeling, the phase-in was modeled uniformly in 2017 for all light-duty fleet, resulting in slight overestimation of the Tier 3 emission reductions in calendar year 2018.

#### *E200/E300 to T50/T90 Conversion*

While the primary impact of gasoline sulfur control is the changes in sulfur content of the fuel, we do expect slight changes in other fuel properties, including fuel distillation, as discussed in Section 7.1.3.2. Fuel distillation is one of a number of fuel properties that have been found to impact vehicle emissions. Specific fuel properties in question are the T50 and T90 of the gasoline (the temperature at which 50 percent and 90 percent of the fuel is evaporated, respectively), which are often discussed instead in terms of E200 and E300 (the percent of the fuel evaporated at 200°F and 300°F, respectively). Both T50 and T90 are among the fuel properties modeled in MOVES that have impacts on emissions. Thus, estimating the overall impact of Tier 3 sulfur control on emissions requires the characterization of the changes in fuel distillation resulting from changes in gasoline sulfur.

Both T50/T90 and E200/E300 data is available from the fuel compliance database. For the reference case, the values for T50 and T90 were derived directly from the fuel compliance database. However, the changes for the control case were modeled using a refinery model which only provides changes in the form of E200 and E300. Therefore, we applied changes in E200/E300 from the refinery modeling to E200 and E300 values derived from the fuel compliance database, and then converted into T50 and T90 values using characteristic transformation equations.

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Typically, E200/E300 and T50/T90 values are well correlated using the transformation equations. However, if the distillation properties vary in a non-typical way, these transformations can provide inaccurate results compared to tested values of E200/E300 and T50/T90. For the 2012 fuel compliance data, fuels in all regions except the West and Pacific Northwest behave in a typical way regarding distillation properties and characteristic transformations between those properties. However, in the West and Pacific Northwest, when the transformation equation was used, E200/E300 did not correlate with T50/T90 as was expected.

The choice to start with T50/T90 data from the fuels compliance database for the reference case and E200/E300 data from the same database for the control case resulted in unexpected differences in fuel properties between the two scenarios, and in turn, affected the emissions inventory in the West and Pacific Northwest. These effects on the emissions inventory are not real effects; they are simply an artifact of our methodology. In summary, for air quality modeling inputs in the West and Pacific Northwest, there is up to a 5 percent increase in T50 and T90 values in the control case compared to the reference case that is caused by improper translation from E200/E300 and not caused by a real change in these data. This error was corrected for the inputs used in the national inventory modeling.

#### *Evaporative Emissions*

Overall, the updates made to the evaporative emissions for the national inventory resulted in reduced evaporative emissions inventory by 10 to 20 percent. Most of the differences between the national inventory and the inventories for air quality modeling results from a change in the vapor venting leak prevalence rates. The distribution of leak sizes shifted towards smaller leaks causing a reduction in emissions from leaks. An error was also corrected in the temperature adjustment coefficients for running loss emissions, resulting in lower running loss emissions. There was another update to correct an error in the database for the LEV III/Section 177 States' I/M versus non-I/M rates, which was very minor. Additional details are provided in the docket memo documenting the MOVES updates.

#### *Modeling of I/M Programs*

For states that have I/M programs and submitted county databases<sup>K</sup>, the inventories for air quality modeling did not properly account for the I/M program, resulting in overestimation of the inventory for both the reference and the control cases. However, the emission reductions from Tier 3 are not affected.

#### *Modeling of Section 177 States*

The sulfur base (see Table 7-27) for the three Non-Section 177 states (VA, NH, and DC) were inadvertently modeled as Section 177 states in the inventories for air quality modeling. For these states, the emission reductions from Tier 3 were underestimated.

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<sup>K</sup> A total of 411 counties were affected. For additional detail, please refer to the docket memo describing MOVES updates.

The updates and the fixes to the above described issues were included only in the national inventories. However, the fundamental MOVES updates incorporating new research, the custom inputs developed for the reference and control scenarios, and the modeling of LEV III programs, described in detail in Section 7.1.3, were also included in the inventories for the air quality modeling.

The two sets of results are compared in Table 7-38 below.

**Table 7-38 Comparison of Calendar Year 2030 Onroad Emission National Inventories and Inventories Used for Air Quality Modeling [U.S. Short tons]**

Pollutant	Reference			Control		
	National Inventory	Air Quality Inventory	Difference AQ vs. NI	National Inventory	Air Quality Inventory	Difference AQ vs. NI
NO <sub>x</sub>	1,317,412	1,367,429	4%	993,724	1,018,962	3%
VOC	1,065,457	1,260,883	18%	900,680	1,079,042	20%
CO	14,480,459	14,434,283	0%	11,085,515	10,780,871	3%
PM <sub>2.5</sub>	77,838	82,138	6%	70,048	73,620	5%
Benzene	17,772	18,742	6%	13,092	13,603	4%
Ethanol	124,933	150,592	21%	105,324	129,002	23%
Acrolein	839	852	2%	714	717	1%
1,3-Butadiene	2,285	2,288	0%	1,619	1,572	3%
Formaldehyde	12,846	13,454	5%	11,588	12,092	4%
Acetaldehyde	9,946	10,143	2%	7,909	7,957	1%
SO <sub>2</sub>	21,973	22,310	2%	9,734	10,040	3%

Because the reference and control case emissions rate inputs were the same for the national inventory and air quality inventory runs, the percent reductions due to the Tier 3 rule are very similar, considering the differences described earlier, as shown in Table 7-39.

**Table 7-39 Comparison of Emission Reductions from Reference to Control Case in “National” and “Air Quality” Onroad Inventories**

Pollutant	2018		2030	
	National Inventory Reduction	Air Quality Inventory Reduction	National Inventory Reduction	Air Quality Inventory Reduction
NO <sub>x</sub>	-9.6%	-9.9%	-24.6%	-25.5%
VOC	-2.8%	-2.4%	-15.5%	-14.4%
CO	-1.6%	-1.6%	-23.4%	-25.3%
PM <sub>2.5</sub>	-0.1%	-0.4%	-10.0%	-10.4%
Benzene	-5.8%	-6.4%	-26.3%	-27.4%
Ethanol	-1.7%	-1.3%	-15.7%	-14.3%
Acrolein	-2.6%	-2.8%	-14.9%	-15.8%
1,3-Butadiene	-5.2%	-5.7%	-29.2%	-31.3%
Formaldehyde	-2.3%	-2.3%	-9.8%	-10.1%
Acetaldehyde	-3.3%	-3.5%	-20.5%	-21.5%
SO <sub>2</sub>	-56.3%	-55.9%	-55.7%	-55.0%

The following sections summarize the analysis done to generate the air quality inventories.

#### *7.2.1.1.1 Representing Counties*

Air quality modeling requires emission inventories for nearly all of the more than 3,000 counties in the United States. Although EPA compiles county-specific databases for all counties in the nation, actual county-specific data is not available for all counties. Instead, much of our “county” data is based on state-wide estimates or national defaults. For this proposal, rather than explicitly model every county in the nation, we have grouped counties together with counties with similar characteristics to generate emission rates that can be used in all of the counties in the grouping.

We explicitly model only one county in the group (the "representing" county) to determine emission rates. These rates are then used in combination with county specific activity and meteorology data, to generate inventories for all of the counties in the group. This approach dramatically reduces the number of modeling runs required to generate inventories and still takes into account differences between counties.

The representing counties are chosen so that they can be used to compute rates, such as g/mi factors, that will be representative across the group of counties. To assure this, the counties are grouped based on vehicle age, fuel parameters, emission standards, I/M programs and altitude. However, representative counties are not meant to represent VMT. VMT is estimated for every Continental U.S. county. As explained in Section 7.2.1.1.3, the SMOKE model calculates emissions by multiplying the county-specific VMT by the county-group specific g/mi emission rates produced in the MOVES run. The characteristics used to group the counties are summarized in Table 7-40 below.

**Table 7-40 Characteristics for Representing County Groupings**

County Grouping Characteristic	Description
State	Counties in each group must be in the same state as the representing county.
Fuel Parameters	Average gasoline fuel properties for January and July 2005, including RVP, sulfur level, ethanol fraction and percent benzene
Emission Standards	Some states have adopted California highway vehicle emission standards or plan to adopt them. Since implementation of the standards varies, each state with California standards is treated separately.
Inspection/Maintenance Programs	Counties were grouped within a state according to whether or not they had an I/M program. All I/M programs within a state were considered as a single program, even though each county may be administered separately and have a different program design.
Altitude	Counties were categorized as high or low altitude based on the criteria set forth by EPA certification procedures (4,000 feet above sea level).
Vehicle Age	The average age of passenger vehicles is calculated for each county. The counties in each group must be in the same average age category as the representing county.

The result is a set of 146 county groups with similar ages, fuel, emission standards, altitude and I/M programs in each state. For each group, the county with the highest VMT was chosen as the representing county. Only these 146 counties were needed to model the 48 states included in the air quality analysis inventory.

For each county group, SMOKE-MOVES generated a set of rates that varied by vehicle type, speed and temperature, thus we did not need to consider the fleet mix, speed or temperature range in our grouping characteristics. This greatly increases the number of counties that can be in each grouping, and reduces the number of MOVES runs required.

More detail on the process for selecting representative counties and a list of all of the 3,322 counties in the nation and the counties selected to represent is provided in the emission inventory technical support document.<sup>39</sup>

#### *7.2.1.1.2 SMOKE-MOVES*

The official EPA highway vehicle emissions model (MOVES) was updated as described in Section 7.1.3 for national emission inventory development, but in order to take advantage of the gridded hourly temperature information used in air quality modeling, MOVES and SMOKE have been integrated into an inventory generation system called SMOKE-MOVES.<sup>40</sup> MOVES can be run in “inventory mode” to calculate the mass of pollutant emissions, as was done for the national inventories, or in “emission rate” mode, in which it calculates emissions in grams per

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mile (for running emissions) or grams per vehicle (for start and evaporative emissions). For our air quality runs, we used the rates approach. This creates a set of “lookup tables” with emission rates by temperature, speed, pollutant, and vehicle class (Source Classification Code (SCC)). SMOKE then transforms these rates into emission inventories for the air quality modeling by multiplying these emission factors by activity specific to each grid cell hour.<sup>41</sup>

The SMOKE-MOVES process generates MOVES run specification files to produce the emission rate lookup tables (in MOVES, there are three per run to cover all emission processes: Rate Per Distance, Rate Per Vehicle, and Rate Per Profile) covering the range of temperatures needed, across each combination of fuel and I/M program in the nation. A series of post-processing scripts was developed to take the MOVES emission rate tables and translate them into the emission rates tables needed by SMOKE to produce mass emissions by 12 km grid and hour of the day for an entire year. For expediency, MOVES lookup tables were generated for July and January to get the full range of temperatures needed for an entire year’s worth of meteorology data. This efficiency step introduces uncertainty because it does not account for fuel “shoulder” seasons in the fall and spring, where the actual fuel pool is a blend of winter and summer fuel. This is mainly an issue for fuel RVP, which is not changing between the reference and control scenarios.

#### *7.2.1.1.3 Inputs to MOVES*

The county-level fuel-property inputs for the air quality runs were the same as for the national inventories described in Section 7.1.3. However, for the air quality runs, we were able to use grid-level temperatures. We also needed county-specific information on vehicle populations, VMT, age distributions, and inspection-maintenance programs for each of the representing counties. The source data for each of these inputs is described below.

##### *7.2.1.1.3.1 Temperature and Humidity*

Ambient temperature can have a large impact on emissions. Low temperatures are associated with high start emissions for many pollutants. High temperatures are associated with greater running emissions due to the higher engine load of air conditioning. High temperatures also are associated with higher evaporative emissions.

The 12-km gridded meteorological input data for the entire year of 2007 covering the continental United States were derived from simulations of version 3.1 of the Weather Research and Forecasting Model<sup>42</sup>, Advanced Research WRF<sup>43</sup> core. The WRF Model is a mesoscale numerical weather prediction system developed for both operational forecasting and atmospheric research applications. The Meteorology-Chemistry Interface Processor (MCIP)<sup>44</sup> version 3.6 was used as the software for maintaining dynamic consistency between the meteorological model, the emissions model, and air quality chemistry model.

EPA applied the SMOKE-MOVES tool, Met4moves, to the gridded, hourly meteorological data (output from MCIP) to generate a list of the maximum temperature ranges, average relative humidity, and temperature profiles that are needed for MOVES to create the emission-factor lookup tables. “Temperature profiles” are arrays of 24 temperatures that describe how temperatures change over a day, and they are used by MOVES to estimate vapor

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venting emissions. The hourly gridded meteorological data (output from MCIP) was also used directly by SMOKE.

The temperature lists were organized based on the representative counties and fuel months as described in Sections 4.6.4.1 and 4.6.4.2, respectively in the documentation for the 2008 National Emission Inventory.<sup>45</sup> Temperatures were analyzed for all of the counties that are mapped to the representative counties, i.e., for the county groups, and for all the months that were mapped to the fuel months. EPA used Met4moves to determine the minimum and maximum temperatures in a county group for the January fuel month and for the July fuel month, and the minimum and maximum temperatures for each hour of the day. Met4moves also generated idealized temperature profiles using the minimum and maximum temperatures and 10 degree intervals. In addition to the meteorological data, the representative counties and the fuel months, Met4moves uses spatial surrogates to determine which grid cells from the meteorological data to collect temperature and relative humidity statistics. For example, if a county had a mountainous area with no roads, this would be excluded from the meteorological statistics. The output for the daily mode is one temperature range per county per day and is a more detailed approach for modeling the vapor venting emissions. EPA ran Met4moves in daily mode for 2007 base year.

The treatment of humidity was simpler. The humidity values that correspond to each temperature value in each temperature bin are averaged and used as the humidity for calculations for that temperature bin. Each set of temperature bins for a grouping of counties will have its own set of corresponding humidity values. Humidity affects the formation of oxides of nitrogen (NO<sub>x</sub>) during combustion and the calculation of air conditioning load effects.

2007 calendar year temperatures and humidity values described above were used for the 2018 and 2030 projection years as well.

#### *7.2.1.1.3.2 Required Vehicle Population and VMT Inputs*

Vehicle population and vehicle miles traveled (VMT) data are required input for MOVES when modeling on a county basis. Using the technical guidance provided to states by EPA, a contractor generated appropriate national estimates for vehicle populations and VMT for use in the MOVES databases using the county specific VMT and national average ratios of vehicle populations versus vehicle VMT from the MOVES application. This method is described in Section 3.3 of the document, "Technical Guidance on the Use of MOVES2010 for Emission Inventory Preparation in State Implementation Plans and Transportation Conformity."<sup>46</sup>

#### *7.2.1.1.3.3 Other Local Inputs*

In addition to temperature, vehicle population and fuels, we also needed inputs such as age distribution and Inspection/Maintenance program descriptions for each of the representing counties. These inputs are required for the model to run at the county level and provided an opportunity to assure that the model was properly accounting for the most recent available local data. These county inputs were derived from the inputs used for the National Emissions Inventory (NEI). This inventory covers the 50 United States (U.S.), Washington DC, Puerto Rico and U.S. Virgin Islands. The NEI was created by the U.S. Environmental Protection

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Agency's (EPA's) Emission Inventory Group (EIG) in Research Triangle Park, North Carolina, in cooperation with the Office of Transportation and Air Quality in Ann Arbor, Michigan. The inputs for the NEI are stored in the National Mobile Inventory Model (NMIM) county database (NCD). Details of how the NCD was developed are documented for the 2008 NEI. These inputs were then converted to a format consistent with MOVES.

#### *7.2.1.1.4 VMT, Population, and Speed*

In addition to the lookup tables, SMOKE requires county VMT, population, and average speed by road type to calculate the necessary emissions for air quality modeling.

The annual vehicle miles traveled (VMT) values calculated for calendar year 2007 are estimated using VMT estimates from the Federal Highways Administration (FHWA) for 2007 and 2008, combined with the state supplied VMT estimates submitted for the 2008 calendar year. The FHWA estimates, found in the Vehicle-miles of travel by functional system table (VM-2) can be obtained from the web at:

<http://www.fhwa.dot.gov/policyinformation/statistics/2007/>

<http://www.fhwa.dot.gov/policyinformation/statistics/2008/>

The VMT data from the VM2 tables are broken out by state and HPMS road type. The VMT values from both 2007 and 2008 are placed into a single table (matched on state and road type) and an adjustment factor (2007 VMT / 2008 VMT) is calculated for each state and road type.

The VMT used for the 2008 NEI is obtained from the FF10 format file (by county and SCC) used with SMOKE for Version 3 of the 2008 NEI (VMT\_NEI\_2008\_updated2\_18jan2012\_v3.csv). The development of the 2008 VMT estimates using state supplied data and FHWA estimates is described in the technical support document for 2008 NEI.<sup>47</sup>

The 2007 VMT values were calculated by applying the adjustment factors calculated from the FHWA tables to the appropriate rows in the 2008 VMT data, matching on state and HPMS road type. The same adjustment was used for all counties in a state and that all Source Classification Code (SCC) vehicle types used the same adjustment for each road type.

The 2018 and 2030 VMT was created by multiplying the base year 2007 platform VMT by growth adjustment factors. The adjustment factors are at the state level by the 12 SCC vehicle types. The resulting total VMT values by SCC in 2018 are normalized to match the total VMT by SCC from MOVES runs using VMT projections from the “early release” of the 2013 AEO. Adjustment factors by state were derived using the National Mobile Inventory Model (NMIM) County Database (NCD) growth from 2007 to 2018 and 2018 to 2030 to account for the relative growth among states. The NCD20080522 database contains the most recent county specific VMT projections available. So, while the AEO projections are used to calculate national totals, the relative growth among states is derived from the NCD.

Once the annual VMT by county has been estimated, the population can be determined by assigning a fixed average VMT to each vehicle. The VMT for each SCC is calculated from the MOVES runs used to generate VMT from the AEO estimates. These MOVES runs also generated population estimates using MOVES default growth and scrappage algorithms. A ratio of the VMT per vehicle by SCC vehicle type is calculated using the VMT values and the corresponding population estimates. Using this VMT/population ratio, the vehicle population for each county by SCC can be calculated from the VMT estimates by SCC.

The average speeds provided to SMOKE for each county were derived from the default national average speed distributions found in the default MOVES2010b database AvgSpeedDistribution table. These average speeds are the average speeds originally developed for the previous EPA highway vehicle emission factor model, MOBILE6.<sup>48</sup> In MOVES, there is a distribution of average speeds for each hour of the day for each road type. The average speeds in these distributions were used to calculate an overall average speed for each hour of the day. These hourly average speeds were weighted together using the default national average hourly vehicle miles traveled (VMT) distribution found in the MOVES default database HourlyVMTFraction table, to calculate an average speed for each road type. This average speed by road type was provided to SMOKE for each county.

#### 7.2.1.2 Nonroad Emissions

The “primary” nonroad emissions used in air quality modeling are identical to those used for national inventories as presented in Section 7.1.4 above. The NMIM model was run to generate county-month inventories by SCC, which were processed to gridded-hourly emissions by SMOKE. For more details on SMOKE processing of nonroad emissions, see the emissions modeling technical support document.<sup>49</sup> Table 7-41 shows that the only effect of the rule captured by the NONROAD model is a decrease in SO<sub>2</sub> due to a drop in fuel sulfur. Not modeled are a probable decrease in sulfate PM and possible decreases in other pollutants due to improved catalyst performance in new equipment that may be equipped with catalysts. Both of these un-modeled effects would be due to that decreases in gasoline fuel sulfur that are part of this rule.

**Table 7-41 National Nonroad Emissions for Calendar Year 2018 and 2030**

Pollutant	2018			2030		
	Reference	Control	Difference	Reference	Control	Difference
NO <sub>x</sub>	1,076,370	1,076,370	0%	729,721	729,721	0%
VOC	1,436,324	1,436,324	0%	1,225,104	1,225,104	0%
CO	13,566,942	13,566,942	0%	14,935,644	14,935,644	0%
PM <sub>2.5</sub>	105,409	105,409	0%	68,308	68,308	0%
Benzene	26,124	26,124	0%	24,146	24,146	0%
Acrolein	613	613	0%	541	541	0%
1,3-Butadiene	3,298	3,298	0%	3,215	3,215	0%
Formaldehyde	16,225	16,225	0%	13,940	13,940	0%
Acetaldehyde	8,094	8,094	0%	6,902	6,902	0%
SO <sub>2</sub>	2,729	1,977	-28%	3,113	2,251	-28%

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### 7.2.1.3 Heavy-Duty Extended Idle

#### 7.2.1.3.1 Methodology

A non-negligible amount of heavy duty vehicles emissions occur during long idling of heavy duty diesel trucks engaged in long distance hauling during federally required “down” time. These “extended idle” emissions are accounted for in our MOVES model. However, the amount of extended idle that occurs in counties varies significantly, depending on the presence of interstate highways, freight routes and the presence of truck stops.

We have developed a method to generate an extended idle adjustment using the county specific extended idle activity and county specific combination truck vehicle populations. These adjustments are applied in SMOKE to adjust the representing county extended idle emission rates produced by MOVES (in units of grams per vehicle) to reflect the different amount of extended idle activity in the represented counties.

$$RPV_c = RPV * (POP_n * EIAAllocFactor) / POP_c$$

Where:

- $RPV_c$  : Rate per vehicle for the county.
- $RPV$ : Rate per vehicle of the representing county.
- $POP_n$ : National vehicle population.
- $POP_c$ : Vehicle population of the county.
- $EIAAllocFactor$ : Emission rate (grams per vehicle).

### 7.2.1.4 Portable Fuel Container and Upstream Emissions

The Tier 3 rule has no impact on portable fuel container (PFC) emissions. The standards are also not expected to impact upstream emissions associated with fuel transport/distribution. For fuel production, the results of our refinery permitting analysis described in Section V.B. of the preamble and Chapter 4 of the RIA project minor emissions increases at some refineries due to the reductions in fuel sulfur content that would be required by the Tier 3 standards. We did not include these emission impacts in our modeling because the projected increases are small and may be even less than projected if refineries apply emissions controls to reduce emissions increases.

Although there is no modeled impact of the Tier 3 standards on upstream or PFC emissions a significant number of modifications were made to the 2007 v.5 platform inventory reflecting the renewable fuel volumes projected by AEO2013 in the reference case air quality inventory. These modifications are described in detail in a memorandum to the docket.<sup>50</sup> Modifications to point and nonpoint inventories include adjustments to agricultural emissions,

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increases in emissions associated with production of corn ethanol, cellulosic ethanol, cellulosic diesel, and biodiesel, decreases in petroleum refinery emissions to account for gasoline displacement, and changes in vapor loss emissions from transport of ethanol and gasoline/ethanol fuel blends. Modifications to mobile source inventories include increases in combustion emissions from water, rail and truck transport of biofuels. PFC emissions were adjusted to account for impacts of RVP changes associated with use of gasoline/ethanol blends.

#### 7.2.1.5 Hydrocarbon Speciation Profiles and SMOKE

We used the Community Multi-scale Air Quality (CMAQ) model, described in detail in the following section, to conduct air quality modeling for this analysis. The SMOKE tool is used to process emission inventories for air quality modeling.<sup>L</sup> Specifically, SMOKE converts our air quality emissions inventories into CMAQ-ready inputs by transforming the emission inventories based on the temporal allocation, chemical speciation, and spatial allocation requirements of CMAQ. In processing our Tier 3 emissions inventories for CMAQ, SMOKE uses hydrocarbon speciation profiles to break total hydrocarbons down into individual constituent compounds and create the needed chemical speciation inputs required for CMAQ. Given the complexity of the atmospheric chemistry, the hydrocarbon speciation can have an important influence on the air quality modeling results. The EPA maintains a database of VOC and particulate matter (PM) speciation profiles for various emission sources including mobile sources. This database, called SPECIATE, maintains the record of each profile including its referenced source, testing methods, a subjective rating of the quality of the data, and other detailed data that allow researchers to decide which profile is most suitable for model input.<sup>M</sup> Mobile source hydrocarbon speciation profiles used in this analysis are from EPA's SPECIATE database (version 4.4), and additional information on the use of these profiles in air quality modeling, such as applicable source categories, can be found in the Emissions Inventory TSD.

### 7.2.2 Air Quality Modeling Methodology

Air quality models use mathematical and numerical techniques to simulate the physical and chemical processes that affect air pollutants as they disperse and react in the atmosphere. Based on inputs of meteorological data and source information, these models are designed to characterize primary pollutants that are emitted directly into the atmosphere and secondary pollutants that are formed as a result of complex chemical reactions within the atmosphere. Photochemical air quality models have become widely recognized and routinely utilized tools for regulatory analysis by assessing the effectiveness of control strategies. These models are applied at multiple spatial scales - local, regional, national, and global. This section provides detailed information on the photochemical model used for our air quality analysis (the Community Multi-scale Air Quality (CMAQ) model), atmospheric reactions and the role of chemical mechanisms in modeling, and model uncertainties and limitations. Further discussion of the modeling methodology is included in the Air Quality Modeling Technical Support Document (AQM TSD)

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<sup>L</sup> For more information, please see the website for SMOKE: <http://www.smoke-model.org/index.cfm>.

<sup>M</sup> For more information, please see the website for SPECIATE: <http://www.epa.gov/ttn/chief/software/speciate/index.html>.

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found in the docket for this rule. Results of the air quality modeling are presented in Section 7.2.4.

#### 7.2.2.1 Modeling Methodology

A national-scale air quality modeling analysis was performed to estimate future year 8-hour ozone concentrations, annual PM<sub>2.5</sub> concentrations, 24-hour PM<sub>2.5</sub> concentrations, annual NO<sub>2</sub> concentrations, air toxics concentrations, visibility levels and nitrogen and sulfur deposition levels for 2018 and 2030. The 2007-based CMAQ modeling platform was used as the basis for the air quality modeling for this rule. This platform represents a structured system of connected modeling-related tools and data that provide a consistent and transparent basis for assessing the air quality response to projected changes in emissions. The base year of data used to construct this platform includes emissions and meteorology for 2007. The platform was developed by the U.S. EPA's Office of Air Quality Planning and Standards in collaboration with the Office of Research and Development and is intended to support a variety of regulatory and research model applications and analyses.

The CMAQ modeling system is a non-proprietary, publicly available, peer-reviewed, state-of-the-science, three-dimensional, grid-based Eulerian air quality model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations, acid deposition, and air toxics, over regional and urban spatial scales for given input sets of meteorological conditions and emissions.<sup>51,52,53</sup> The CMAQ model version 5.0 was most recently peer-reviewed in September of 2011 for the U.S. EPA.<sup>54</sup> The CMAQ model is a well-known and well-respected tool and has been used in numerous national and international applications.<sup>55,56,57</sup> This 2007 multi-pollutant modeling platform used the most recent multi-pollutant CMAQ code available at the time of air quality modeling (CMAQ version 5.0.1<sup>N</sup>).

CMAQ includes many science modules that simulate the emission, production, decay, deposition and transport of organic and inorganic gas-phase and particle-phase pollutants in the atmosphere. We used CMAQ v5.0.1 which reflects updates to version 4.7 to improve the underlying science. Section 7.2.3 of this RIA discusses the chemical mechanism and SOA formation.

#### 7.2.2.2 Model Domain and Configuration

The CMAQ modeling domain encompasses all of the lower 48 States and portions of Canada and Mexico. The modeling domain is made up of a large continental U.S. 36 kilometer (km) grid and a 12 km grid as shown in Figure 7-11. The modeling domain contains 25 vertical layers with the top of the modeling domain at about 17,600 meters, or 50 millibars (mb) of atmospheric pressure.

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<sup>N</sup> CMAQ version 5.0.1 was released on October 19, 2011. It is available from the Community Modeling and Analysis System (CMAS) as well as previous peer-review reports at: <http://www.cmascenter.org>.



**Figure 7-11 Map of the CMAQ Modeling Domain**

### 7.2.2.3 Model Inputs

The key inputs to the CMAQ model include emissions from anthropogenic and biogenic sources, meteorological data, and initial and boundary conditions. The CMAQ meteorological input files were derived from simulations of the Weather Research and Forecasting Model (WRF) version 3.3, Advanced Research WRF (ARW) core<sup>58</sup> for the entire year of 2007 over model domains that are slightly larger than those shown in Figure 7-11. Previous CMAQ annual simulations have typically utilized meteorology provided by the 5th Generation Mesoscale Model (MM5).<sup>59</sup> The WRF Model is a next-generation mesoscale numerical weather prediction system developed for both operational forecasting and atmospheric research applications (<http://wrf-model.org>). The meteorology for the national 36 km grid and 12 km grid were developed by EPA and are described in more detail within the AQM TSD. The meteorological outputs from WRF were processed to create model-ready inputs for CMAQ using the Meteorology-Chemistry Interface Processor (MCIP) version 4.1.2. Outputs include: horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer.<sup>60</sup>

The lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry model, the GEOS-CHEM model (standard version 8-03-02 with version 8-02-03 chemistry).<sup>61</sup> The global GEOS-CHEM model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS). This model was run for 2007 with a grid resolution of 2 degree x 2.5 degree (latitude-longitude) and 46 vertical layers up to 0.01 hPa. The predictions were used to provide one-way dynamic boundary conditions at three-hour intervals and an initial concentration field for the 36 km CMAQ simulations. The future base

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conditions from the 36 km coarse grid modeling were used as the initial/boundary state for all subsequent 12 km finer grid modeling.

The emissions inputs used for the 2007 base year and each of the future year base cases and control scenarios analyzed for this rule are summarized in Section 7.1.2 of this RIA.

#### 7.2.2.4 CMAQ Evaluation

An operational model performance evaluation for ozone, PM<sub>2.5</sub> and its related speciated components (e.g., sulfate, nitrate, elemental carbon, organic carbon, etc.), nitrate and sulfate deposition, and specific air toxics (formaldehyde, acetaldehyde, benzene, 1,3-butadiene, and acrolein) was conducted using 2007 state/local monitoring data in order to estimate the ability of the CMAQ modeling system to replicate base year concentrations. Model performance statistics were calculated for observed/predicted pairs of daily/monthly/seasonal/annual concentrations. Statistics were generated for five large subregions:<sup>O</sup> Midwest, Northeast, Southeast, Central, and West U.S. The “acceptability” of model performance was judged by comparing our results to those found in recent regional PM<sub>2.5</sub> model applications for other, non-EPA studies.<sup>P</sup> Overall, the performance for the 2007 modeling platform is within the range or close to that of these other applications. The model was able to reproduce historical concentrations of ozone and PM<sub>2.5</sub> over land with low bias and error results. Model predictions of annual formaldehyde, acetaldehyde and benzene showed relatively small bias and error results when compared to observations. The model yielded larger bias and error results for 1,3 butadiene and acrolein based on limited monitoring sites. A more detailed summary of the 2007 CMAQ model performance evaluation is available within the AQM TSD found in the docket of this rule.

#### 7.2.2.5 Model Simulation Scenarios

As part of our analysis for this rulemaking, the CMAQ modeling system was used to calculate 8-hour ozone concentrations, daily and annual PM<sub>2.5</sub> concentrations, annual NO<sub>2</sub> concentrations, annual and seasonal (summer and winter) air toxics concentrations, visibility levels and annual nitrogen and sulfur deposition total levels for each of the following emissions scenarios:

- 2007 base year
- 2018 Tier 3 reference case
- 2018 Tier 3 control case
- 2030 Tier 3 reference case

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<sup>O</sup> The subregions are defined by States where: Midwest is IL, IN, MI, OH, and WI; Northeast is CT, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT; Southeast is AL, FL, GA, KY, MS, NC, SC, TN, VA, and WV; Central is AR, IA, KS, LA, MN, MO, NE, OK, and TX; West is AK, CA, OR, WA, AZ, NM, CO, UT, WY, SD, ND, MT, ID, and NV.

<sup>P</sup> These other modeling studies represent a wide range of modeling analyses which cover various models, model configurations, domains, years and/or episodes, chemical mechanisms, and aerosol modules.

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- 2030 Tier 3 control case

The emission inventories used in the air quality and benefits modeling are different from the rule inventories due to the considerable length of time required to conduct the modeling. As noted above, emission inventories for air quality modeling were required for the entire U.S. by 12 km grid cell and hour of the day for each day of the year, requiring a methodology of much greater detail than the national emission inventories presented in Section 7.1. While most of the modeling tools and inputs used for estimating national emission inventories were also used in developing inputs for air quality modeling as well, the application of these tools (particularly MOVES) to produce the gridded / hourly emissions was quite different, and in essence a separate analysis. As explained in Section 7.2.1.1, the different analyses generated different onroad inventory totals, but the reduction from reference to control scenarios was consistent. The emission inventories used for air quality modeling are discussed in Section 7.2.1 of this RIA. The emissions modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2011-0135), contains a detailed discussion of the emissions inputs used in our air quality modeling.

We use the predictions from the model in a relative sense by combining the 2007 base-year predictions with predictions from each future-year scenario and applying these modeled ratios to ambient air quality observations to estimate 8-hour ozone concentrations, daily and annual PM<sub>2.5</sub> concentrations, annual NO<sub>2</sub> concentrations and visibility impairment for each of the 2018 and 2030 scenarios. The ambient air quality observations are average conditions, on a site-by-site basis, for a period centered around the model base year (i.e., 2005-2009).

The projected daily and annual PM<sub>2.5</sub> design values were calculated using the Speciated Modeled Attainment Test (SMAT) approach. The SMAT uses a Federal Reference Method (FRM) mass construction methodology that results in reduced nitrates (relative to the amount measured by routine speciation networks), higher mass associated with sulfates (reflecting water included in FRM measurements), and a measure of organic carbonaceous mass that is derived from the difference between measured PM<sub>2.5</sub> and its non-carbon components. This characterization of PM<sub>2.5</sub> mass also reflects crustal material and other minor constituents. The resulting characterization provides a complete mass balance. It does not have any unknown mass that is sometimes presented as the difference between measured PM<sub>2.5</sub> mass and the characterized chemical components derived from routine speciation measurements. However, the assumption that all mass difference is organic carbon has not been validated in many areas of the U.S. The SMAT methodology uses the following PM<sub>2.5</sub> species components: sulfates, nitrates, ammonium, organic carbon mass, elemental carbon, crustal, water, and blank mass (a fixed value of 0.5 µg/m<sup>3</sup>). More complete details of the SMAT procedures can be found in the report "Procedures for Estimating Future PM<sub>2.5</sub> Values for the CAIR Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT)".<sup>62</sup> For this latest analysis, several datasets and techniques were updated. These changes are fully described within the technical support document for the Final Transport Rule AQM TSD.<sup>63</sup> The projected 8-hour ozone design values were calculated using the approach identified in EPA's guidance on air quality modeling attainment demonstrations.<sup>64</sup>

Additionally, we conducted an analysis to compare the absolute and percent differences between the future year reference and control cases for annual and seasonal ethanol, formaldehyde, acetaldehyde, benzene, 1,3-butadiene, naphthalene, and acrolein, as well as

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annual nitrate and sulfate deposition. These data were not compared in a relative sense due to the limited observational data available.

### 7.2.3 Chemical Mechanisms in Modeling

This rule presents inventories for NO<sub>x</sub>, VOC, CO, PM<sub>2.5</sub>, SO<sub>2</sub>, NH<sub>3</sub>, and seven air toxics: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, ethanol, naphthalene and acrolein. The air toxics were added as explicit model species to the carbon bond 5 (CB05) mechanisms used in CMAQv5.0.1.<sup>65</sup> Emissions of all the pollutants included in the rule inventories, except ethanol, were generated using the Motor Vehicle Emissions Simulator (MOVES) VOC emissions and toxic-to-VOC ratios calculated using EPAAct data.<sup>66</sup> Ethanol emissions for air quality modeling were based on speciation of VOC using different ethanol profiles (E0, E10 and E85) (see Section 7.2.1.5 for more information). In addition to direct emissions, photochemical processes mechanisms are responsible for formation of some of these compounds in the atmosphere from precursor emissions. For some pollutants such as PM, formaldehyde, and acetaldehyde, many photochemical processes are involved. CMAQ therefore also requires inventories for a large number of other air toxics and precursor pollutants. Methods used to develop the air quality inventories can be found in Section 7.2.1.

In the CB05 mechanism, the chemistry of thousands of different VOCs in the atmosphere are represented by a much smaller number of model species which characterize the general behavior of a subset of chemical bond types; this condensation is necessary to allow the use of complex photochemistry in a fully 3-D air quality model.<sup>67</sup>

Complete combustion of ethanol in fuel produces carbon dioxide (CO<sub>2</sub>) and water (H<sub>2</sub>O). Incomplete combustion results in the production of other air pollutants, such as acetaldehyde and other aldehydes, and the release of unburned ethanol. Ethanol is also present in evaporative emissions. In the atmosphere, ethanol from unburned fuel and evaporative emissions can undergo photodegradation to form aldehydes (acetaldehyde and formaldehyde) and peroxyacetyl nitrate (PAN), and also plays a role in ground-level ozone formation. Mechanisms for these reactions are included in CMAQ. Additionally, alkenes and other hydrocarbons are considered because any increase in acetyl peroxy radicals due to ethanol increases might be counterbalanced by a decrease in radicals resulting from decreases in other hydrocarbons.

CMAQ includes 63 inorganic reactions to account for the cycling of all relevant oxidized nitrogen species and cycling of radicals, including the termination of NO<sub>2</sub> and formation of nitric acid (HNO<sub>3</sub>) without PAN formation.<sup>Q</sup>



The CB05 mechanism also includes more than 90 organic reactions that include alternate pathways for the formation of acetyl peroxy radical, such as by reaction of ethene and other alkenes, alkanes, and aromatics. Alternate reactions of acetyl peroxy radical, such as oxidation of NO to form NO<sub>2</sub>, which again leads to ozone formation, are also included.

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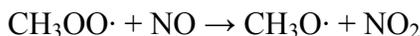
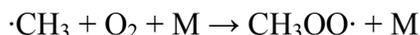
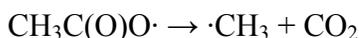
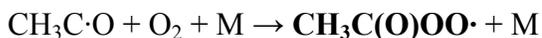
<sup>Q</sup> All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

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Atmospheric reactions and chemical mechanisms involving several key formation pathways are discussed in more detail in the following sections.

### 7.2.3.1 Acetaldehyde

Acetaldehyde is the main photodegradation product of ethanol, as well as other precursor hydrocarbons. Acetaldehyde is also a product of fuel combustion. In the atmosphere, acetaldehyde can react with the OH radical and O<sub>2</sub> to form the acetyl peroxy radical [CH<sub>3</sub>C(O)OO·].<sup>R</sup> When NO<sub>x</sub> is present in the atmosphere this radical species can then further react with nitric oxide (NO), to produce formaldehyde (HCHO), or with nitrogen dioxide (NO<sub>2</sub>), to produce PAN [CH<sub>3</sub>C(O)OONO<sub>2</sub>].<sup>S</sup> An overview of these reactions and the corresponding reaction rates are provided below.



Acetaldehyde can react with the NO<sub>3</sub> radical, ground state oxygen atom (O<sub>3</sub>P) and chlorine, although these reactions are much slower. Acetaldehyde can also photolyze (hν), which predominantly produces ·CH<sub>3</sub> (which reacts as shown above to form CH<sub>3</sub>OO·) and HCO (which rapidly forms HO<sub>2</sub> and CO):



As mentioned above, CH<sub>3</sub>OO· can react in the atmosphere to produce formaldehyde (HCHO). Formaldehyde is also a product of hydrocarbon combustion. In the atmosphere, the most important reactions of formaldehyde are photolysis and reaction with the OH, with atmospheric lifetimes of approximately 3 hours and 13 hours, respectively.<sup>73</sup> Formaldehyde can also react with NO<sub>3</sub> radical, ground state oxygen atom (O<sup>3</sup>P) and chlorine, although these reactions are much slower. Formaldehyde is removed mainly by photolysis whereas the higher

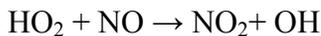
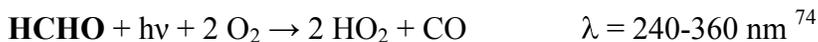
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<sup>R</sup> Acetaldehyde is not the only source of acetyl peroxy radicals in the atmosphere. For example, dicarbonyl compounds (methylglyoxal, biacetyl, and others) also form acetyl radicals, which can further react to form peroxyacetyl nitrate (PAN).

<sup>S</sup> All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

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aldehydes, those with two or more carbons such as acetaldehyde, react predominantly with OH radicals. The photolysis of formaldehyde is an important source of new hydroperoxy radicals (HO<sub>2</sub>), which can lead to ozone formation and regenerate OH radicals.



Photolysis of HCHO can also proceed by a competing pathway which makes only stable products: H<sub>2</sub> and CO.

CB05 mechanisms for acetaldehyde formation warrant a detailed discussion given the increase in vehicle and engine exhaust emissions for this pollutant and ethanol, which can form acetaldehyde in the air. Acetaldehyde is represented explicitly in the CB05 chemical mechanism<sup>75,76</sup> by the ALD2 model species, which can be both formed from other VOCs and can decay via reactions with oxidants and radicals. The reaction rates for acetaldehyde, as well as for the inorganic reactions that produce and cycle radicals, and the representative reactions of other VOCs have all been updated to be consistent with recommendations in the literature.<sup>77</sup>

The decay reactions of acetaldehyde are fewer in number and can be characterized well because they are explicit representations. In CB05, acetaldehyde can photolyze in the presence of sunlight or react with molecular oxygen (O(<sup>3</sup>P)), hydroxyl radical (OH), or nitrate radicals. The reaction rates are based on expert recommendations,<sup>78</sup> and the photolysis rate is from IUPAC recommendations.

In CMAQ v5.0, the acetaldehyde that is formed from photochemical reactions is tracked separately from that which is due to direct emission and transport of direct emissions. In CB05, there are 25 different reactions that form acetaldehyde in molar yields ranging from 0.02 (ozone reacting with lumped products from isoprene oxidation) to 2.0 (cross reaction of acylperoxy radicals, CXO<sub>3</sub>). The specific parent VOCs that contribute the most to acetaldehyde concentrations vary spatially and temporally depending on characteristics of the ambient air, but alkenes in particular are found to play a large role.<sup>79</sup> The IOLE model species, which represents internal carbon-carbon double bonds, has high emissions and relatively high yields of acetaldehyde. The OLE model species, representing terminal carbon double bonds, also plays a role because it has high emissions although lower acetaldehyde yields. Production from peroxypropional nitrate and other peroxyacylnitrates (PANX) and aldehydes with 3 or more carbon atoms can in some instances increase acetaldehyde, but because they also are a sink of radicals, their effect is smaller. Thus, the amount of acetaldehyde (and formaldehyde as well) formed in the ambient air, as well as emitted in the exhaust (the latter being accounted for in emission inventories), is affected by changes in these precursor compounds due to the addition of ethanol to fuels (e.g., decreases in alkenes would cause some decrease of acetaldehyde, and to a larger extent, formaldehyde).

The reaction of ethanol (CH<sub>3</sub>CH<sub>2</sub>OH) with OH is slower than some other important reactions but can be an important source of acetaldehyde if the emissions are large. Based on kinetic data for molecular reactions, the only important chemical loss process for ethanol (and other alcohols) is reaction with the hydroxyl radical (·OH).<sup>80</sup> This reaction produces

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acetaldehyde (CH<sub>3</sub>CHO) with a 90 percent yield.<sup>81</sup> The lifetime of ethanol in the atmosphere can be calculated from the rate coefficient, *k*, and due to reaction with the OH radical, occurs on the order of a day in polluted urban areas or several days in unpolluted areas.<sup>T</sup> For example, an atmospheric lifetime for acetaldehyde under nominal oxidant conditions, OH of 1.0 x 10<sup>-6</sup> cm<sup>3</sup>molecule<sup>-1</sup>s<sup>-1</sup>, would be 3.5 days.

In CB05, reaction of one molecule of ethanol yields 0.90 molecules of acetaldehyde. It assumes the majority of the reaction occurs through H-atom abstraction of the more weakly-bonded methylene group, which reacts with oxygen to form acetaldehyde and hydroperoxy radical (HO<sub>2</sub>), and the remainder of the reaction occurs at the -CH<sub>3</sub> and -OH groups, creating formaldehyde (HCHO), oxidizing NO to NO<sub>2</sub> (represented by model species XO<sub>2</sub>) and creating glycoaldehyde, which is represented as ALDX:



#### 7.2.3.2 Secondary Organic Aerosols (SOA)

Secondary organic aerosol (SOA) chemistry research described below has led to implementation of new pathways for secondary organic aerosol (SOA) in CMAQ v5.0, based on recommendations of Edney et al. (2007) and Carlton et al. (2008).<sup>82, 83</sup> In previous versions of CMAQ, all SOA was semivolatile and resulted from the oxidation of compounds emitted entirely in the gas-phase. In CMAQ v5.0, parameters in existing pathways were revised and new formation mechanisms were added. Some of the new pathways, such as low-NO<sub>x</sub> oxidation of aromatics and particle-phase oligomerization, result in nonvolatile SOA.

Organic aerosol (OA) can be classified as either primary or secondary depending on whether it is emitted into the atmosphere as a particle (primary organic aerosol, POA) or formed in the atmosphere (SOA). SOA precursors include volatile organic compounds (VOCs) as well as low-volatility compounds that can react to form even lower volatility compounds. Current research suggests SOA contributes significantly to ambient OA concentrations, and in Southeast and Midwest States may make up more than 50 percent (although the contribution varies from area to area) of the organic fraction of PM<sub>2.5</sub> during the summer (but less in the winter).<sup>84,85</sup> A wide range of laboratory studies conducted over the past twenty years show that anthropogenic aromatic hydrocarbons and long-chain alkanes, along with biogenic isoprene, monoterpenes, and sesquiterpenes, contribute to SOA formation.<sup>86,87,88,89,90</sup> Modeling studies, as well as carbon isotope measurements, indicate that a significant fraction of SOA results from the oxidation of biogenic hydrocarbons.<sup>91,92</sup> Based on parameters derived from laboratory chamber experiments, SOA chemical mechanisms have been developed and integrated into air quality models such as the CMAQ model and have been used to predict OA concentrations.<sup>93</sup>

Over the past 10 years, ambient OA concentrations have been routinely measured in the U.S. and some of these data have been used to determine, by employing source/receptor methods, the contributions of the major OA sources, including biomass burning and vehicular gasoline and diesel exhaust. Since mobile sources are a significant source of VOC emissions,

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<sup>T</sup> All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

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currently accounting for almost 40 percent of anthropogenic VOC,<sup>94</sup> mobile sources are also an important source of SOA, particularly in populated areas.

Toluene is an important contributor to anthropogenic SOA.<sup>95,96</sup> Mobile sources are the most significant contributor to ambient toluene concentrations as shown by analyses done for the 2005 National Air Toxics Assessment (NATA)<sup>97</sup> and the Mobile Source Air Toxics (MSAT) Rule.<sup>98</sup> The 2005 NATA indicates that onroad and nonroad mobile sources accounted for almost 60 percent ( $1.46 \mu\text{g}/\text{m}^3$ ) of the total average nationwide ambient concentration of toluene ( $2.48 \mu\text{g}/\text{m}^3$ ), when the contribution of the estimated “background” is apportioned among source sectors.

The amount of toluene in gasoline influences the amount of toluene emitted in vehicle exhaust and evaporative emissions, although, like benzene, some toluene is formed in the combustion process. In turn, levels of toluene and other aromatics in gasoline are potentially influenced by the amount of ethanol blended into the fuel. Due to the high octane quality of ethanol, it greatly reduces the need for and levels of other high-octane components such as aromatics including toluene (which is the major aromatic compound in gasoline). Since toluene contributes to SOA and the toluene level of gasoline is decreasing, it is important to assess the effect of these reductions on ambient PM.

In addition to toluene, other mobile-source hydrocarbons such as benzene, xylene, and alkanes form SOA. Similar to toluene, the SOA produced by benzene and xylene from low- $\text{NO}_x$  pathways is expected to be less volatile and be produced in higher yields than SOA from high- $\text{NO}_x$  conditions.<sup>99</sup> Oxidation of alkanes with longer chains as well as cyclic alkanes form SOA with relatively higher yields than small straight-chain alkanes.<sup>100</sup>

It is unlikely that ethanol would form SOA directly or affect SOA formation indirectly through changes in the radical populations due to increasing ethanol exhaust. Nevertheless, scientists at the U.S. EPA’s Office of Research and Development recently directed experiments to investigate ethanol’s SOA forming potential.<sup>101</sup> The experiments were conducted under conditions where peroxy radical reactions would dominate over reaction with NO (i.e., irradiations performed in the absence of  $\text{NO}_x$  and OH produced from the photolysis of hydrogen peroxide). This was the most likely scenario under which SOA formation could occur, since a highly oxygenated C4 organic could form. As expected, no SOA was produced. From these experiments, the upper limit for the aerosol yield is less than 0.01 percent based on scanning mobility particle sizer (SMPS) data. Given the lack of aerosol formation found in these initial smog chamber experiments, these data were not published.

In general, measurements of OA represent the sum of POA and SOA and the fraction of aerosol that is secondary in nature can only be estimated. One of the most widely applied method of estimating total ambient SOA concentrations is the EC tracer method using ambient data which estimates the OC/EC ratio in primary source emissions.<sup>102,103</sup> SOA concentrations have also been estimated using OM (organic mass) to OC (organic carbon) ratios, which can indicate that SOA formation has occurred, or by subtracting the source/receptor-based total POA from the measured OC concentration.<sup>104</sup> Aerosol mass spectrometer (AMS) measurements along with positive matrix factorization (PMF) can also be used to identify surrogates for POA and SOA in ambient as well as chamber experiments. Such methods, however, may not be quantitatively

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accurate and provide no information on the contribution of individual biogenic and anthropogenic SOA sources, which is critical information needed to assess the impact of specific sources and the associated health risk. These methods assume that OM containing additional mass from oxidation of OC comes about largely (or solely) from SOA formation. In particular, the contributions of anthropogenic SOA sources, including those of aromatic precursors, are required to determine exposures and risks associated with replacing fossil fuels with biofuels.

Upon release into the atmosphere, numerous VOC compounds can react with free radicals in the atmosphere to form SOA. While this has been investigated in the laboratory, there is relatively little information available on the specific chemical composition of SOA compounds themselves from specific VOC precursors. This absence of complete compositional data from the precursors has made the identification of aromatically-derived SOA in ambient samples challenging, which in turn has prevented observation-based measurements of individual SOA source contributions to ambient PM levels.

As a first step in estimating ambient SOA concentrations, EPA has developed a tracer-based method.<sup>105,106</sup> The method is based on using mass fractions of SOA tracer compounds, measured in smog chamber-generated SOA samples, to convert ambient concentrations of SOA tracer compounds to ambient SOA concentrations. This method consists of irradiating the SOA precursor of interest in a smog chamber in the presence of NO<sub>x</sub>, collecting the SOA produced on filters, and then analyzing the samples for highly polar compounds using advanced analytical chemistry methods. Employing this method, candidate tracers have been identified for several VOC compounds which are emitted in significant quantities and known to produce SOA in the atmosphere. Some of these SOA-forming compounds include toluene, a variety of monoterpenes, isoprene, and β-caryophyllene, the latter three of which are emitted by vegetation and are more significant sources of SOA than toluene. Smog chamber work can also be used to investigate SOA chemical formation mechanisms.<sup>107,108,109,110</sup>

Although these concentrations are only estimates, due to the assumption that the mass fractions of the smog chamber SOA samples using these tracers are equal to those in the ambient atmosphere, there are presently no other means available for estimating the SOA concentrations originating from individual SOA precursors. Among the tracer compounds observed in ambient PM<sub>2.5</sub> samples are two tracer compounds that have been identified in smog chamber aromatic SOA samples.<sup>111</sup> To date, these aromatic tracer compounds have been identified in the laboratory for toluene and *m*-xylene SOA. Additional work is underway by the EPA to determine whether these tracers are also formed by benzene and other alkylbenzenes (including *o*-xylene, *p*-xylene, 1,2,4-trimethylbenzene, and ethylbenzene).

One caveat regarding this work is that a large number of VOCs emitted into the atmosphere, which have the potential to form SOA, have not yet been studied in environmental smog chambers. These unstudied compounds could produce SOA species that are being used as tracers for other VOCs thus overestimating the amount of SOA formed in the atmosphere by the VOCs studied to date. This approach may also estimate entire hydrocarbon classes (e.g., all methylsubstituted-monoaromatics or all monoterpenes) and not individual precursor hydrocarbons. Thus the tracers could be broadly representative and not indicative of individual precursors. This is still unknown. Also, anthropogenic precursors play a role in formation of atmospheric radicals and aerosol acidity, and these factors influence SOA formation from

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biogenic hydrocarbons.<sup>112,113</sup> This anthropogenic and biogenic interaction, important to EPA and others, needs further study. The issue of SOA formation from aromatic precursors is an important one to which EPA and others are paying significant attention.

The aromatic tracer compounds and their mass fractions have been used to estimate monthly ambient aromatic SOA concentrations from March 2004 to February 2005 in five U.S. Midwestern cities.<sup>114</sup> The annual tracer-based SOA concentration estimates were 0.15, 0.18, 0.13, 0.15, and 0.19  $\mu\text{g carbon/m}^3$  for Bondville, IL, East St. Louis, IL, Northbrook, IL, Cincinnati, OH and Detroit, MI, respectively, with the highest concentrations occurring in the summer. On average, the aromatic SOA concentrations made up 17 percent of the total SOA concentration. Thus, this work suggests that we are finding ambient PM levels on an annual basis of about 0.15  $\mu\text{g/m}^3$  associated with present toluene levels in the ambient air in these Midwest cities. Based on preliminary analysis of recent laboratory experiments, it appears the toluene tracer could also be formed during photooxidation of some of the xylenes.<sup>115</sup>

Over the past decade a variety of modeling studies have been conducted to predict ambient SOA levels. While early studies focused on the contribution of biogenic monoterpenes, additional precursors, such as sesquiterpenes, isoprene, benzene, toluene, and xylene, have been implemented in atmospheric models such as GEOS-Chem, PMCAMx, and CMAQ.<sup>116, 117, 118, 119, 120,121,122</sup> Studies have indicated that ambient OC levels may be underestimated by current model parameterizations.<sup>123</sup> While the treatment of new precursors has likely reduced the model/measurement bias, underestimates can persist.<sup>124</sup> In general, modeling studies focus on comparing the sum of the POA and SOA concentrations with ambient OC or estimated OA concentrations. Without a method to attribute measured OC to different sources or precursors, identifying causes of the underestimates in modeled OC via model/measurement comparisons can be challenging. Oxidation of low-volatility organic compounds as well as particle-phase reactions resulting from acidity have been explored as potential missing sources of OC in models.<sup>125,126</sup>

### 7.2.3.3 Ozone

As mentioned above, the addition of ethanol to fuels has been shown to contribute to PAN formation and this is one way for it to contribute therefore to ground-level ozone formation downwind of  $\text{NO}_x$  sources. PAN is a reservoir and carrier of  $\text{NO}_x$  and is the product of acetyl radicals reacting with  $\text{NO}_2$  in the atmosphere. One source of PAN is the photooxidation of acetaldehyde (Section 7.2.3.1), but many VOCs have the potential for forming acetyl radicals and therefore PAN or a PAN-type compound.<sup>U</sup> PAN can undergo thermal decomposition with a lifetime of approximately 1 hour at 298K or 148 days at 250K.<sup>V</sup>



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<sup>U</sup> Many aromatic hydrocarbons, particularly those present in high percentages in gasoline (toluene, m-, o-, p-xylene, and 1,3,5-, 1,2,4-trimethylbenzene), form methylglyoxal and biacetyl, which are also strong generators of acetyl radicals (Smith, D.F., T.E. Kleindienst, C.D. McIver (1999) Primary product distribution from the reaction of OH with m-, p-xylene and 1,2,4- and 1,3,5-Trimethylbenzene. J. Atmos. Chem., 34: 339- 364.).

<sup>V</sup> All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

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The reaction above shows how NO<sub>2</sub> is released in the thermal decomposition of PAN, along with a peroxy radical which can oxidize NO to NO<sub>2</sub> as previously shown in Section 7.2.3.1. NO<sub>2</sub> can also be formed in photochemical reactions where NO is converted to NO<sub>2</sub> (see OH radical reaction of acetaldehyde in Section 7.2.3.1). In both cases, NO<sub>2</sub> further photolyzes to produce ozone (O<sub>3</sub>).



The temperature sensitivity of PAN allows it to be stable enough at low temperatures to be transported long distances before decomposing to release NO<sub>2</sub>. NO<sub>2</sub> can then participate in ozone formation in regions remote from the original NO<sub>x</sub> source.<sup>129</sup> A discussion of CB05 mechanisms for ozone formation can be found in Yarwood et al. (2005).<sup>130</sup>

Another important way that ethanol fuels contribute to ozone formation is by increasing the formation of new radicals through increases in formaldehyde and acetaldehyde. As shown in Section 7.2.3.1, the photolysis of both aldehydes results in up to two molecules of either hydroperoxy radical or methylperoxy radical, both of which oxidize NO to NO<sub>2</sub> leading to ozone formation.

#### 7.2.3.4 Uncertainties Associated with Chemical Mechanisms

A key source of uncertainty with respect to the air quality modeling results is the photochemical mechanisms in CMAQ v5.0. Pollutants such as ozone, PM, acetaldehyde, formaldehyde, and acrolein can be formed secondarily through atmospheric chemical processes. Since secondarily formed pollutants can result from many different reaction pathways, there are uncertainties associated with each pathway. Simplifications of chemistry must be made in order to handle reactions of thousands of chemicals in the atmosphere. Mechanisms for formation of ozone, PM, acetaldehyde and peroxyacetyl nitrate (PAN) are discussed in Section 7.2.3.

For PM, there are a number of uncertainties associated with SOA formation that should be addressed explicitly. As mentioned in Section 7.2.3, a large number of VOCs emitted into the atmosphere, which have the potential to form SOA, have not yet been studied in detail. Not only have known VOCs not been studied in detail, but unknown (or unmeasured) VOCs can also produce SOA. This makes reconciling SOA from combustion sources extremely difficult. In addition, the amount of ambient SOA that comes from benzene is uncertain. Simplifications to the SOA treatment in CMAQ have also been made in order to preserve computational efficiency. These simplifications are described in release notes for CMAQ 4.7 on the Community Modeling and Analysis System (CMAS) website.<sup>131</sup>

#### 7.2.4 Impacts of the Rule on Air Quality

Air quality modeling performed for this rule estimates the changes in ambient concentrations of PM<sub>2.5</sub>, ozone and NO<sub>2</sub>, as well as changes in ambient concentrations of ethanol and the following air toxics: acetaldehyde, acrolein, benzene, 1,3-butadiene, naphthalene, and

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formaldehyde. The air quality modeling results also include changes in deposition of nitrogen and sulfur and changes in visibility levels due to this rule.

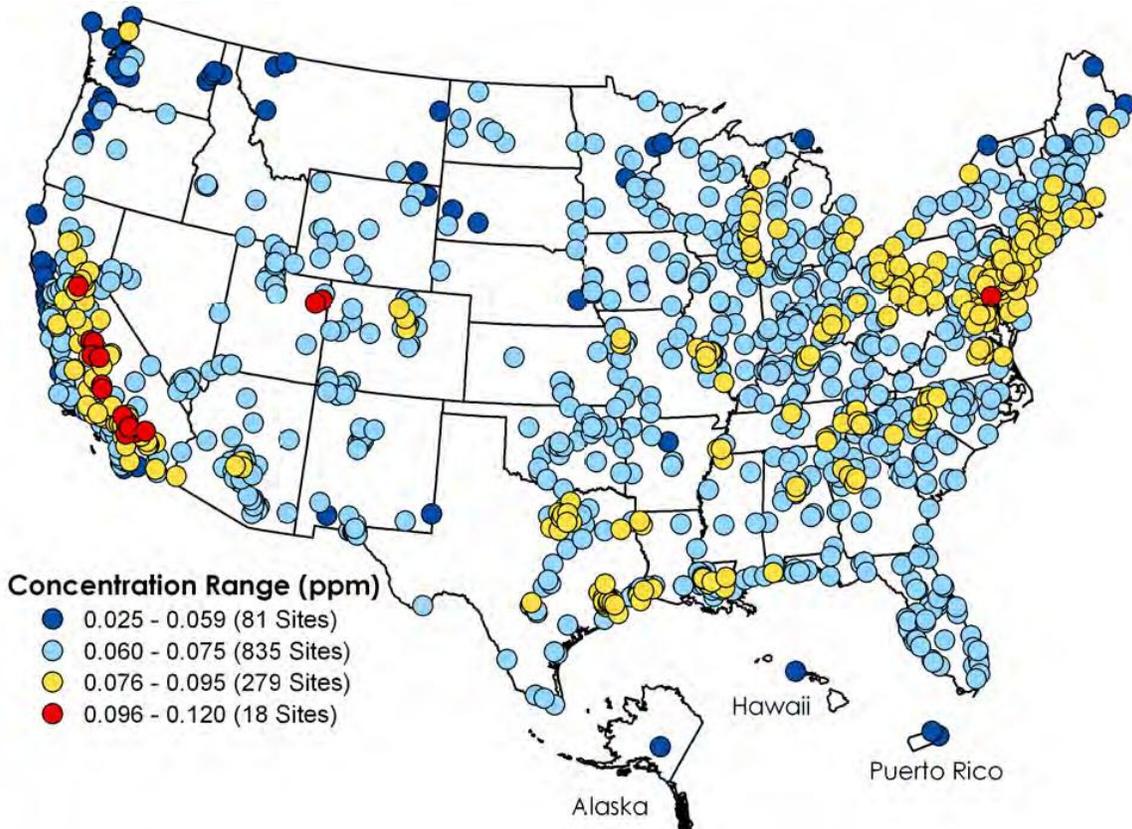
This section describes current ambient levels of the modeled pollutants and presents the projected future ambient levels resulting from the rule.

#### 7.2.4.1 Ozone

As described in Section 6.1.2 of this RIA, ozone causes adverse health effects, and the EPA has set national ambient air quality standards (NAAQS) to protect against those health effects. In this section, we present information on current and model-projected future ozone levels.

##### *7.2.4.1.1 Current Concentrations of Ozone*

Figure 7-12 shows a snapshot of measured ozone concentrations in 2010. The highest ozone concentrations were located in California.



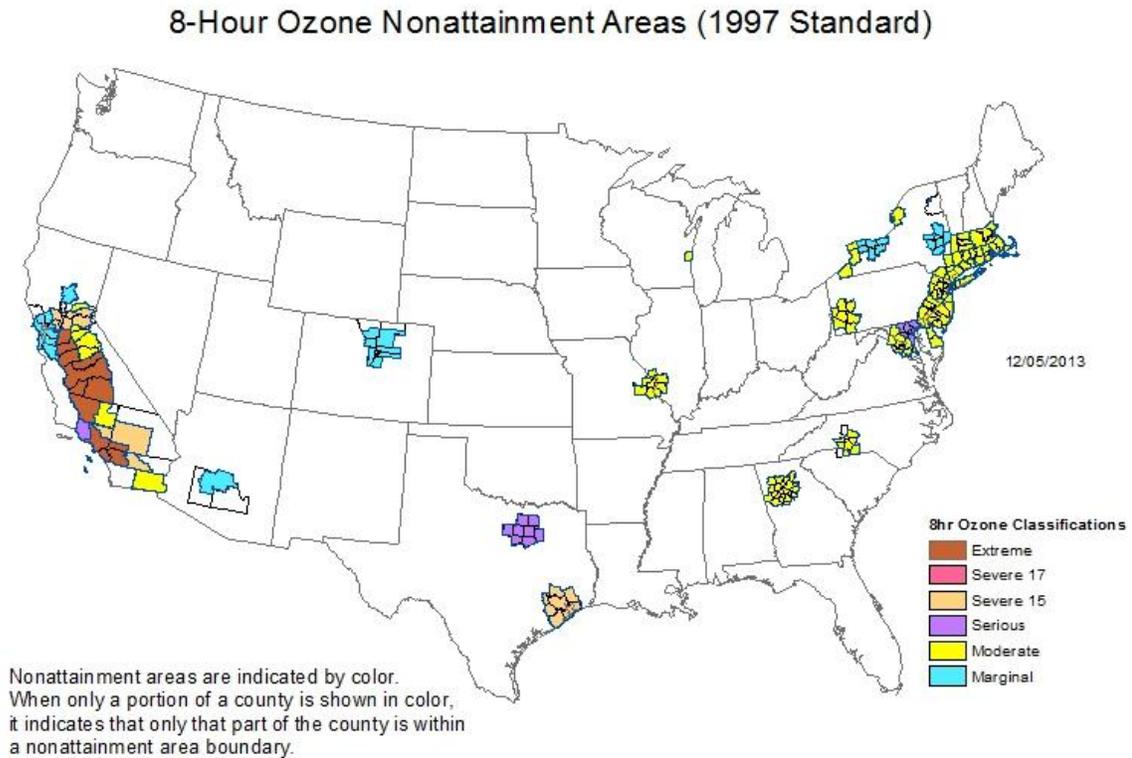
**Figure 7-12 Ozone Concentrations (fourth highest daily maximum 8-hour concentration) in ppm for 2010<sup>w</sup>**

The primary and secondary NAAQS for ozone are 8-hour standards with a level of 0.075 ppm. The most recent revision to the ozone standards was in 2008; the previous 8-hour ozone standards, set in 1997, had a level of 0.08 ppm. In 2004, the U.S. EPA designated nonattainment areas for the 1997 8-hour ozone NAAQS (69 FR 23858, April 30, 2004).<sup>x</sup> As of December 5, 2013, there were 39 8-hour ozone nonattainment areas for the 1997 ozone NAAQS, composed of 216 full or partial counties, with a total population of over 112 million. Nonattainment areas for the 1997 8-hour ozone NAAQS are pictured in Figure 7-13. Nonattainment designations for the 2008 ozone standards were finalized on April 30, 2012 and May 31, 2012.<sup>132</sup> As of December 5, 2013, there were 46 ozone nonattainment areas for the 2008 ozone NAAQS, composed of 227 full or partial counties, with a population of over 123 million. Nonattainment areas for the 2008

<sup>w</sup> From U.S. EPA, 2011. Our Nation's Air: Status and Trends through 2010. EPA-454/R-12-001. February 2012. Available at: <http://www.epa.gov/airtrends/2011/>.

<sup>x</sup> A nonattainment area is defined in the Clean Air Act (CAA) as an area that is violating an ambient standard or is contributing to a nearby area that is violating the standard.

ozone NAAQS are pictured in Figure 7-14. As of December 5, 2013, over 135 million people are living in ozone nonattainment areas.<sup>Y</sup>



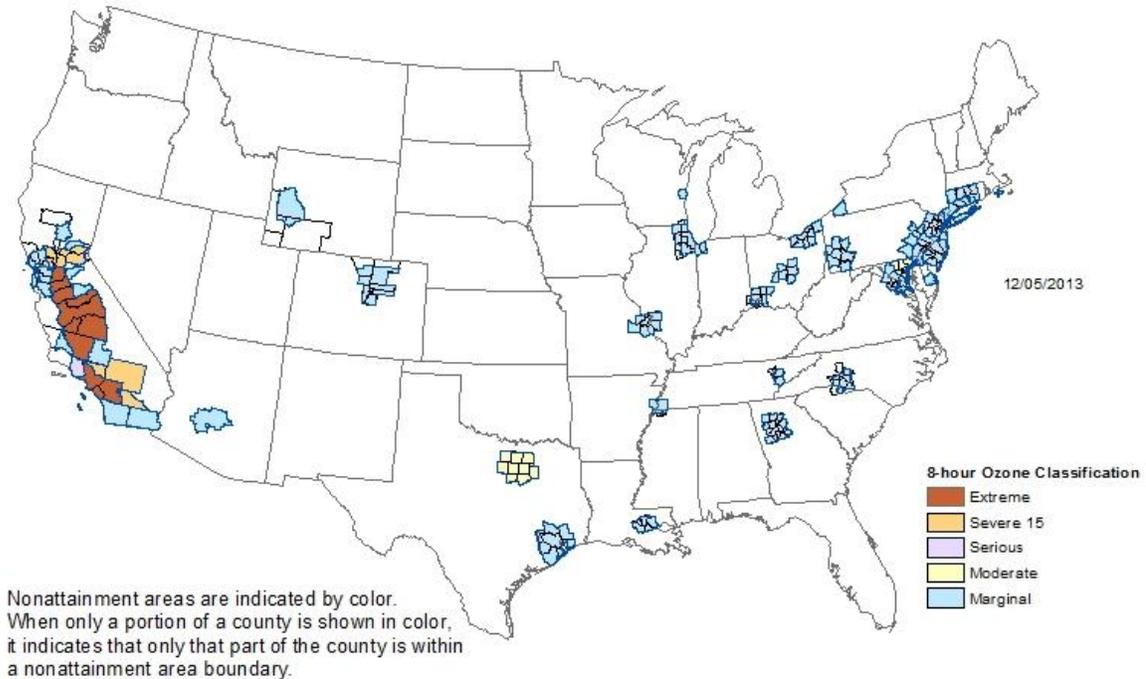
The St. Louis, MO-IL 8-hr Ozone (1997 Standard) multi-state nonattainment area has a state that has been redesignated but it is not considered a maintenance area until all states in the area are redesignated. The counties for this area are displayed as nonattainment areas:

The South Carolina portion of the Charlotte-Gastonia-Rock Hill, NC-SC 8-hr Ozone (1997 Standard) nonattainment area has been redesignated and the North Carolina portion will be redesignated effective January 2, 2014. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

**Figure 7-13 1997 8-hour Ozone Nonattainment Areas**

<sup>Y</sup> The 135 million total is calculated by summing, without double counting, the 1997 and 2008 ozone nonattainment populations contained in the Summary Nonattainment Area Population Exposure report (<http://www.epa.gov/oar/oaqps/greenbk/popexp.html>). If there is a population associated with both the 1997 and 2008 nonattainment areas, and they are not the same, then the larger of the two populations is included in the sum.

## 8-Hour Ozone Nonattainment Areas (2008 Standard)



**Figure 7-14 2008 8-hour Ozone Nonattainment Areas**

States with ozone nonattainment areas are required to take action to bring those areas into attainment. The attainment date assigned to an ozone nonattainment area is based on the area's classification. Most ozone nonattainment areas were required to attain the 1997 8-hour ozone NAAQS in the 2007 to 2013 time frame and then to maintain it thereafter.<sup>Z</sup> The attainment dates for areas designated nonattainment for the 2008 8-hour ozone NAAQS are in the 2015 to 2032 timeframe, depending on the severity of the problem in each area. In addition, EPA is currently working on a review of the ozone NAAQS. If EPA revises the ozone standards pursuant to that review, the attainment dates associated with areas designated nonattainment for that NAAQS would be 5 or more years after the final rule is promulgated, depending on the severity of the problem in each area.

### 7.2.4.1.2 Projected Concentrations of Ozone Without the Rule

EPA has already adopted many mobile source emission control programs that are expected to reduce ambient ozone levels. These control programs include the Heavy-Duty

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<sup>Z</sup> The Los Angeles South Coast Air Basin 8-hour ozone nonattainment area and the San Joaquin Valley Air Basin 8-hour ozone nonattainment area are designated as Extreme and will have to attain before June 15, 2024. The Sacramento, Coachella Valley, Western Mojave and Houston 8-hour ozone nonattainment areas are designated as Severe and will have to attain by June 15, 2019.

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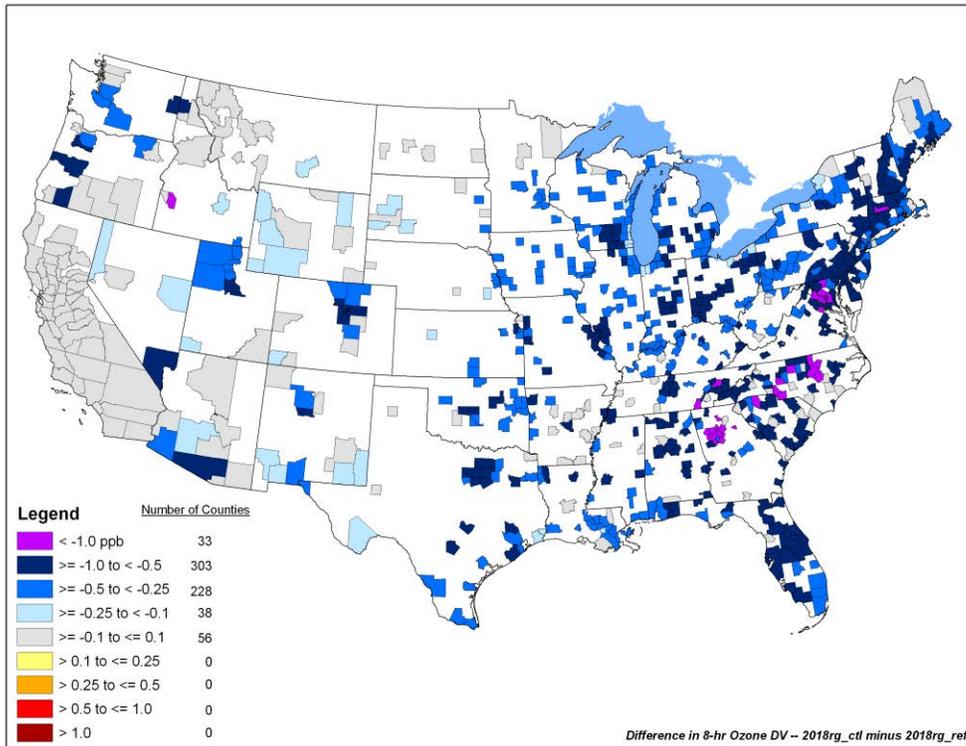
Greenhouse Gas Rule (76 FR 57106, September 15, 2011), New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895, April 30, 2010), the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034, October 8, 2008), the Locomotive and Marine Rule (73 FR 25098, May 6, 2008), the Clean Air Nonroad Diesel Rule (69 FR 38957, June 29, 2004), the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, January 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, February 10, 2000). As a result of these and other federal, state and local programs, 8-hour ozone levels are expected to improve in the future. However, even with the implementation of all current state and federal regulations, there are projected to be counties violating the ozone NAAQS well into the future. Thus additional federal control programs, such as Tier 3, can assist areas with attainment dates in 2017 and beyond in attaining the NAAQS as expeditiously as practicable and may relieve areas with already stringent local regulations from some of the burden associated with adopting additional local controls.

The air quality modeling projects that in 2018, with all current controls in effect but excluding the emissions changes expected to occur as a result of this action or any other additional controls, at least 19 counties, with a projected population of over 37 million people, will have projected design values above the level of the 2008 8-hour ozone standard of 75 ppb. Even in 2030 the modeling projects there will be 6 counties with a population of over 19 million people that will have projected design values above the level of the 2008 8-hour ozone standard of 75 ppb without additional controls. Since the emission changes from this rule go into effect during the period when some areas are still working to attain the ozone NAAQS, the projected emission changes will help state and local agencies in their effort to attain and maintain the ozone standard. In the following section we discuss the projected ozone reductions associated with the standards.

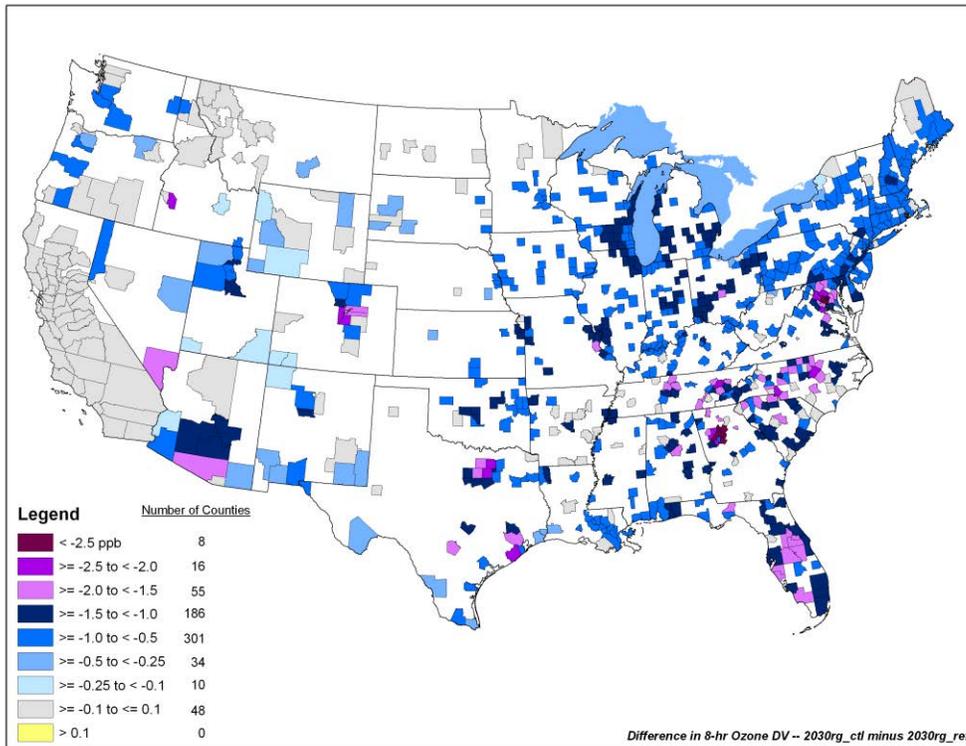
#### *7.2.4.1.1 Projected Concentrations of Ozone With the Rule*

This section summarizes the results of our modeling of ozone air quality impacts in the future with the standards. Specifically, for the years 2018 and 2030 we compare a reference scenario (a scenario without the standards) to a control scenario that includes the standards. Our modeling indicates that ozone design value concentrations will decrease dramatically in many areas of the country as a result of this rule rule. Additional information on the emissions reductions that are projected with this final action is available in Section 7.2.1 of this RIA.

Figure 7-15 and Figure 7-16 present the changes in 8-hour ozone design value concentrations in 2018 and 2030 respectively.



**Figure 7-15 Projected Change in 2018 8-hour Ozone Design Values Between the Reference Case and Control Case**



**Figure 7-16 Projected Change in 2030 8-hour Ozone Design Values Between the Reference Case and Control Case**

As can be seen in Figure 7-15, the majority of the design value decreases in 2018 are between 0.5 and 1.0 ppb. There are also 33 counties with projected 8-hour ozone design value decreases of more than 1 ppb; these counties are generally in urban areas in states that have not adopted California LEV III standards. The maximum projected decrease in an 8-hour ozone design value in 2018 is 1.56 ppb in Henry County, Georgia near Atlanta. Figure 7-16 presents the ozone design value changes for 2030. In 2030 the ozone design value decreases are larger than in 2018; most decreases are projected to be between 0.5 and 1.0 ppb, but over 250 more counties have design values with projected decreases greater than 1.5 ppb. The maximum projected decrease in an 8-hour ozone design value in 2030 is 2.8 ppb in Gwinnett County, Georgia, the northeastern part of the Atlanta metropolitan area.

Table 7-42 and Table 7-43 show the average change, due to this rule, in 2018 and 2030 8-hour ozone design values for: (1) all counties with 2007 baseline design values, (2) counties with 2007 baseline design values that exceeded the 2008 ozone standard, (3) counties with 2007 baseline design values that did not exceed the 2008 standard, but were within 10 percent of it, (4) counties with 2018/2030 design values that exceeded the 2008 ozone standard, and (5) counties with 2018/2030 design values that did not exceed the standard, but were within 10 percent of it. Counties within 10 percent of the standard are intended to reflect counties that although not violating the standards, will also be impacted by changes in ozone as they work to ensure long-term maintenance of the ozone NAAQS. All of these metrics show a decrease in 2018 and 2030, indicating in five different ways the overall improvement in air quality.

On a population-weighted basis, the average modeled future-year 8-hour ozone design values are projected to decrease by 0.49 ppb in 2018 and 0.98 ppb in 2030.

**Table 7-42 Average Change in Projected 8-hour Ozone Design Value in 2018**

Average <sup>a</sup>	Number of U.S. Counties	2020 Population	Change in 2018 design value (ppb)
All	658	234,598,095	-0.53
All, population-weighted			-0.49
Counties whose 2007 base year is violating the 2008 8-hour ozone standard	319	159,636,546	-0.60
Counties whose 2007 base year is violating the 2008 8-hour ozone standard, population-weighted			-0.51
Counties whose 2007 base year is within 10 percent of the 2008 8-hour ozone standard	241	52,115,093	-0.51
Counties whose 2007 base year is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.50
Counties whose 2018 control case is violating the 2008 8-hour ozone standard	16	35,732,987	-0.24
Counties whose 2018 control case is violating the 2008 8-hour ozone standard, population-weighted			-0.20
Counties whose 2018 control case is within 10 percent of the 2008 8-hour ozone standard	97	55,924,864	-0.50
Counties whose 2018 control case is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.55

<sup>a</sup> Averages are over counties with 2007 modeled design values.

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS)..

**Table 7-43 Average Change in Projected 8-hour Ozone Design Value in 2030**

Average <sup>a</sup>	Number of U.S. Counties	2030 Population	Change in 2030 design value (ppb)
All	658	257,693,543	-0.94
All, population-weighted			-0.98
Counties whose 2007 base year is violating the 2008 8-hour ozone standard	319	175,088,003	-1.06
Counties whose 2007 base year is violating the 2008 8-hour ozone standard, population-weighted			-1.01
Counties whose 2007 base year is within 10 percent of the 2008 8-hour ozone standard	241	57,122,153	-0.90

Counties whose 2007 base year is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.97
Counties whose 2030 control case is violating the 2008 8-hour ozone standard	6	19,415,241	-0.16
Counties whose 2030 control case is violating the 2008 8-hour ozone standard, population-weighted			-0.12
Counties whose 2030 control case is within 10 percent of the 2008 8-hour ozone standard	32	33,059,752	-0.86
Counties whose 2030 control case is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.95

<sup>a</sup> Averages are over counties with 2007 modeled design values

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

There are still six counties, five of them in California, that are projected to have 8-hour ozone design values above the 2008 NAAQS in 2030 without the standards or any other additional controls in place. Table 7-44 below presents the changes in design values for these counties.

**Table 7-44 Change in Ozone Design Values (ppb) for Counties Projected to be Above the 2008 Ozone NAAQS in 2030**

County Name	Change in 8-hour Ozone Design Value (ppb)	Population in 2030 <sup>a</sup>
San Bernardino, California	-0.10	2,784,490
Los Angeles, California	-0.10	10,742,722
Riverside, California	-0.10	2,614,198
Kern, California	-0.02	981,806
Westchester, New York	-0.64	1,196,950
Fresno, California	-0.01	1,095,075

<sup>a</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

In terms of modeling accuracy, the count of modeled nonattainment counties is much less certain than the average changes in air quality. Bearing this in mind, our modeling predicts that the Tier 3 standards will reduce ozone design values in some counties from above the level of the standard to below it. In 2018, ozone design values in three counties (Harford County in Maryland, Denton County in Texas and Fairfield County in Connecticut) are projected to move from being above the standard to below. The projected population in these three counties in 2018 is almost 2 million people.

As described in Section 6.1.2.1 of this RIA, the science of ozone formation, transport, and accumulation is complex. The air quality modeling projects ozone decreases as a result of emissions changes from the fuel and vehicle standards. This change in ozone results from interactions between photochemistry, background concentrations of ozone, VOC and NO<sub>x</sub>, local

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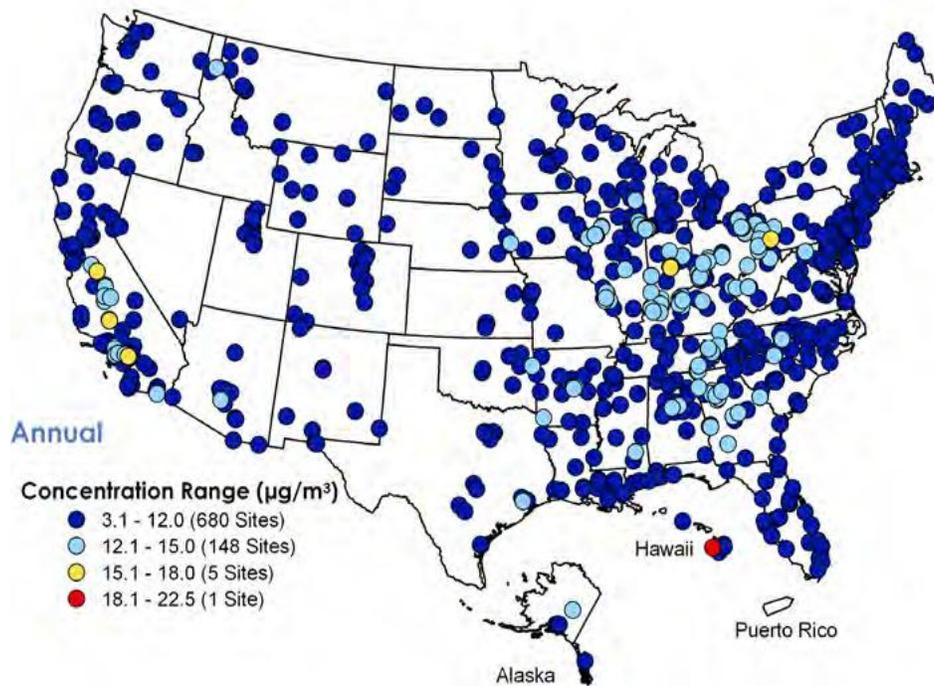
emissions and meteorology. There is one county in 2018 that is projected to have an increase in modeled ozone design value concentration (Cuyahoga County, OH, where Cleveland is located). When NO<sub>x</sub> levels are relatively high and VOC levels relatively low, NO<sub>x</sub> forms inorganic nitrates (*i.e.*, particles) but relatively little ozone. In addition, NO<sub>x</sub> can react directly with ozone resulting in suppressed ozone concentrations near NO<sub>x</sub> emissions sources. Such conditions are called “NO<sub>x</sub>-saturated.” Under these conditions, VOC reductions are effective in reducing ozone, but NO<sub>x</sub> reductions can actually increase local ozone under certain circumstances. We believe that this is the case in Cuyahoga County in 2018. In 2030, when the fleet would be composed of vehicles meeting the new standards and the NO<sub>x</sub> and VOC emissions reductions are larger, this ozone disbenefit is eliminated, and the design values for all the modeled counties are decreasing.

#### 7.2.4.2 Particulate Matter

As described in Section 6.1.1 of this RIA, PM causes adverse health effects, and the EPA has set national ambient air quality standards (NAAQS) to protect against those health effects. In this section we present information on current and model-projected future PM levels.

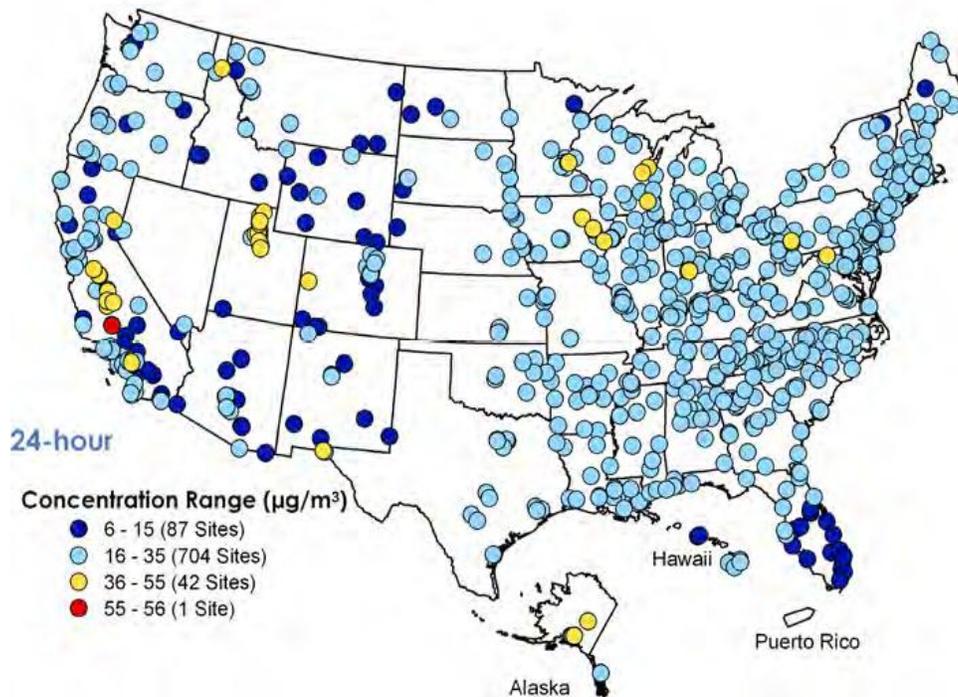
##### *7.2.4.2.1 Current Concentrations of PM*

Figure 7-17 and Figure 7-18 respectively show a snapshot of annual and 24-hour PM<sub>2.5</sub> concentrations in 2010. In 2010, the highest annual average PM<sub>2.5</sub> concentrations were in California, Indiana, Pennsylvania and Hawaii and the highest 24-hour PM<sub>2.5</sub> concentrations were in California and Alaska.



**Figure 7-17 Annual Average PM<sub>2.5</sub> Concentrations in  $\mu\text{g}/\text{m}^3$  for 2010<sup>AA</sup>**

<sup>AA</sup> From U.S. EPA, 2011. Our Nation's Air: Status and Trends through 2010. EPA-454/R-12-001. February 2012. Available at: <http://www.epa.gov/airtrends/2011/>.



**Figure 7-18 24-hour (98<sup>th</sup> percentile 24-hour concentrations) PM<sub>2.5</sub> Concentrations in  $\mu\text{g}/\text{m}^3$  for 2010<sup>BB</sup>**

There are two primary NAAQS for PM<sub>2.5</sub>: an annual standard ( $12.0 \mu\text{g}/\text{m}^3$ ) and a 24-hour standard ( $35 \mu\text{g}/\text{m}^3$ ), and two secondary NAAQS for PM<sub>2.5</sub>: an annual standard ( $15.0 \mu\text{g}/\text{m}^3$ ) and a 24-hour standard ( $35 \mu\text{g}/\text{m}^3$ ). The initial PM<sub>2.5</sub> standards were set in 1997 and revisions to the standards were finalized in 2006 and in December 2012. The December 2012 rule revised the level of the primary annual PM<sub>2.5</sub> standard from  $15.0 \mu\text{g}/\text{m}^3$  to  $12.0 \mu\text{g}/\text{m}^3$ .<sup>133</sup>

In 2005 the EPA designated 39 nonattainment areas for the 1997 PM<sub>2.5</sub> NAAQS (70 FR 19844, April 14, 2005). As of December 5, 2013, over 68 million people lived in the 24 areas that are still designated as nonattainment for the 1997 annual PM<sub>2.5</sub> NAAQS. These PM<sub>2.5</sub> nonattainment areas are comprised of 135 full or partial counties. Nonattainment areas for the 1997 annual PM<sub>2.5</sub> NAAQS are pictured in Figure 7-19. EPA anticipates making initial area designation decisions for the 2012 primary annual PM<sub>2.5</sub> NAAQS in December 2014, with those designations likely becoming effective in early 2015.<sup>134</sup> On November 13, 2009 and February 3, 2011, the EPA designated 32 nonattainment areas for the 2006 24-hour PM<sub>2.5</sub> NAAQS (74 FR 58688, November 13, 2009 and 76 FR 6056, February 3, 2011). As of December 5, 2013, 28 of these areas remain designated as nonattainment, and they are composed of 104 full or partial counties, with a population of over 65 million. Nonattainment areas for the 2006 PM<sub>2.5</sub> NAAQS

<sup>BB</sup> From U.S. EPA, 2011. Our Nation's Air: Status and Trends through 2010. EPA-454/R-12-001. February 2012. Available at: <http://www.epa.gov/airtrends/2011/>.

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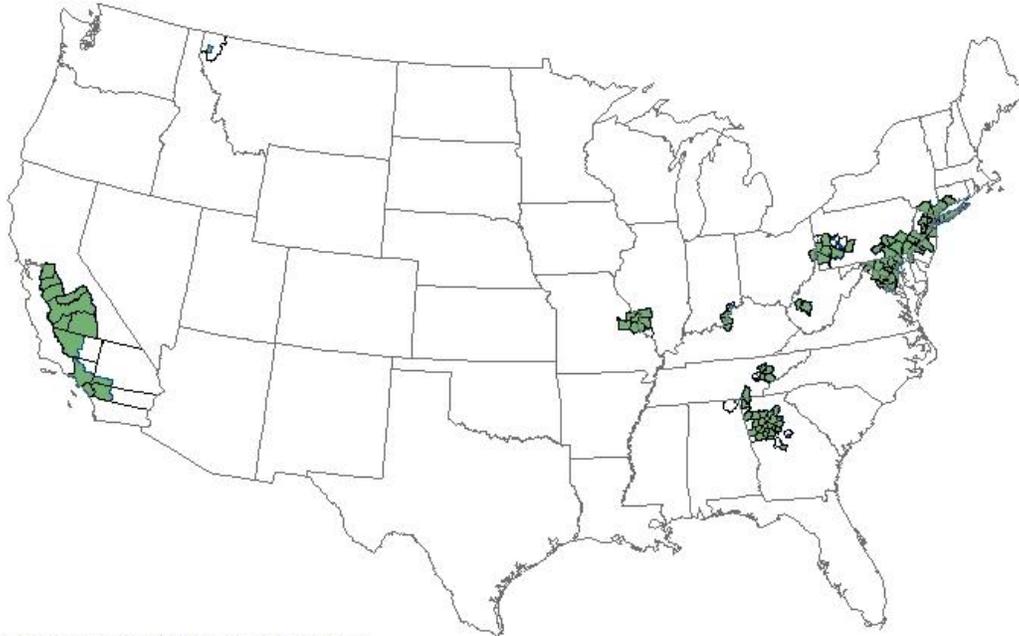
are pictured in Figure 7 20. In total, there are currently 39 PM<sub>2.5</sub> nonattainment areas with a population of over 84 million people.<sup>CC</sup>

States with PM<sub>2.5</sub> nonattainment areas will be required to take action to bring those areas into attainment in the future. Designated nonattainment areas not currently attaining the 1997 annual PM<sub>2.5</sub> NAAQS are required to attain the NAAQS by 2015 and will be required to maintain the 1997 annual PM<sub>2.5</sub> NAAQS thereafter. The 2006 24-hour PM<sub>2.5</sub> nonattainment areas are required to attain the 2006 24-hour PM<sub>2.5</sub> NAAQS in the 2015 to 2019 time frame and will be required to maintain the 2006 24-hour PM<sub>2.5</sub> NAAQS thereafter. Areas to be designated nonattainment for the 2012 primary annual PM<sub>2.5</sub> NAAQS will likely be required to attain the 2012 NAAQS in the 2021 to 2025 time frame.

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<sup>CC</sup> Data come from Summary Nonattainment Area Population Exposure Report, current as of December 5, 2013 at: <http://www.epa.gov/oar/oaqps/greenbk/popexp.html> and contained in Docket EPA-HQ-OAR-2011-0135. The 84 million total is calculated by summing, without double counting, the 1997 and 2006 PM<sub>2.5</sub> nonattainment populations contained in the Summary Nonattainment Area Population Exposure report (<http://www.epa.gov/oar/oaqps/greenbk/popexp.html>). If there is a population associated with both the 1997 and 2006 nonattainment areas, and they are not the same, then the larger of the two populations is included in the sum.

## PM-2.5 Nonattainment Areas (1997 Standard)



Nonattainment areas are indicated by color.  
When only a portion of a county is shown in color,  
it indicates that only that part of the county is within  
a nonattainment area boundary.

12/05/2013

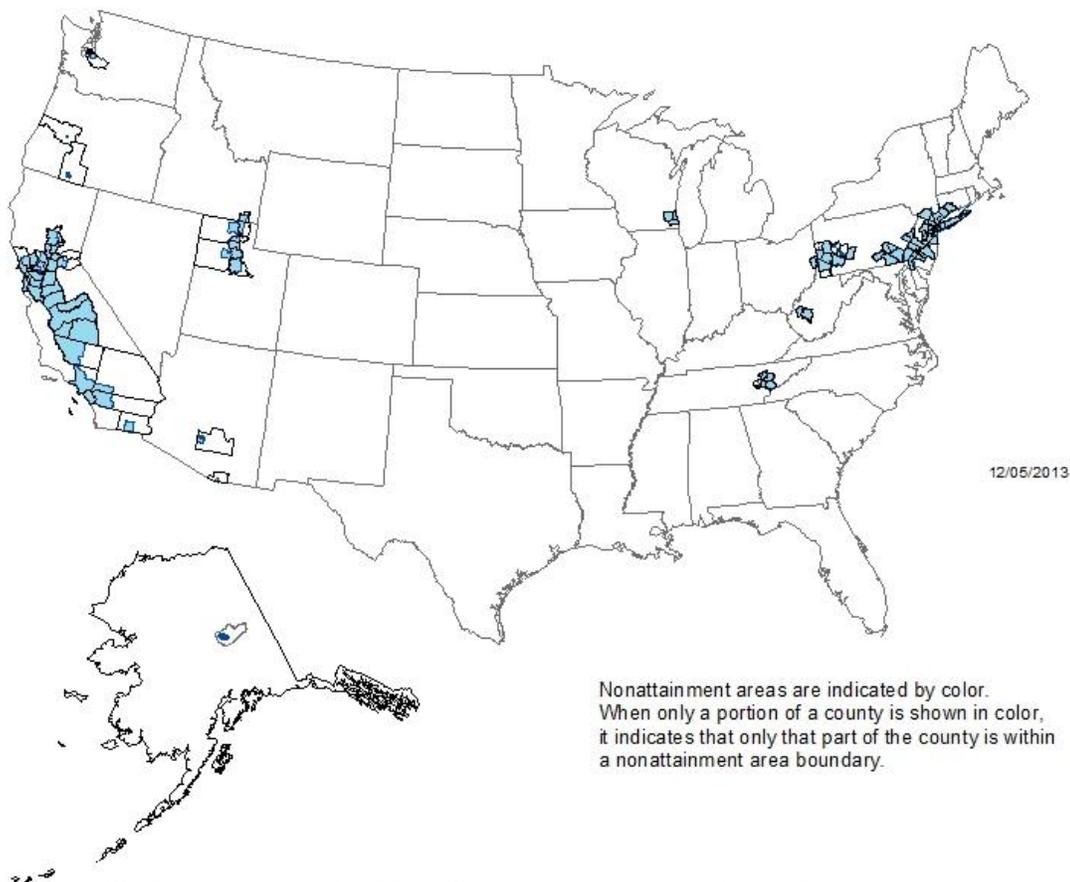
The New Jersey portion of the Philadelphia-Wilmington, PA-NJ-DE PM-2.5 nonattainment area (1997 Standard) has been redesignated, while the Pennsylvania and Delaware portions have not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

The New Jersey and Connecticut portions of the New York-N. New Jersey-Long Island, NY-NJ-CT PM-2.5 nonattainment area (1997 Standard) have been redesignated, while the New York portion has not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

The Ohio portion of the Steubenville-Weirton, OH-WV PM-2.5 (1997 Standard) nonattainment area has been redesignated, while the West Virginia portion has not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

**Figure 7-19 1997 PM<sub>2.5</sub> Nonattainment Areas**

## PM-2.5 Nonattainment Areas (2006 Standard)



Nonattainment areas are indicated by color. When only a portion of a county is shown in color, it indicates that only that part of the county is within a nonattainment area boundary.

The New Jersey portion of the Philadelphia-Wilmington, PA-NJ-DE PM-2.5 (2006 Standard) nonattainment area has been redesignated, while the Pennsylvania and Delaware portions have not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

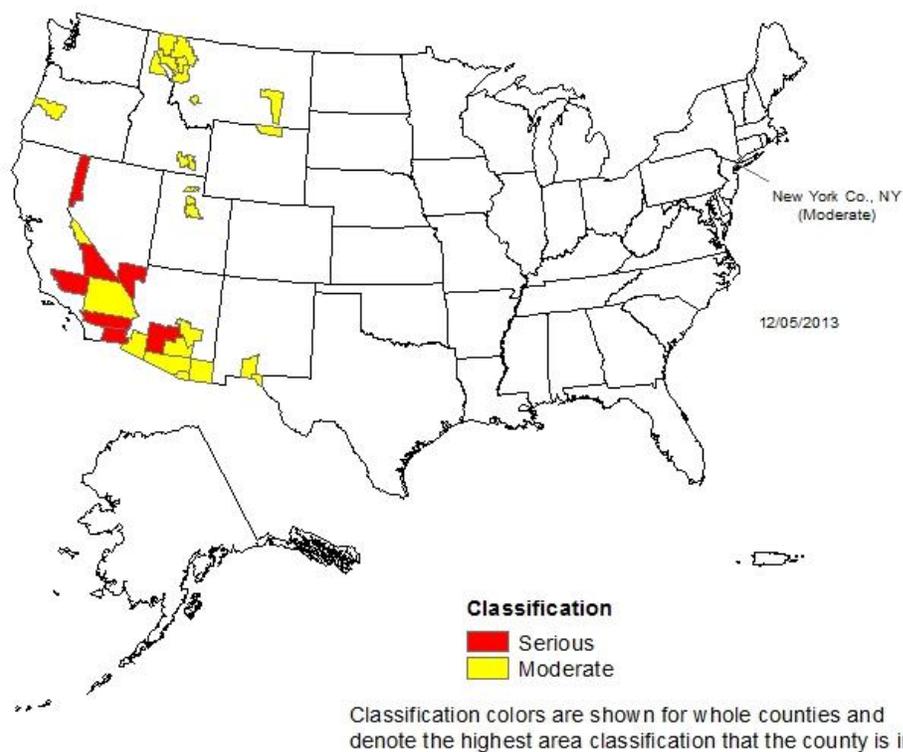
The New Jersey and Connecticut portions of the New York-N. New Jersey-Long Island, NY-NJ-CT PM-2.5 (2006 Standard) nonattainment area have been redesignated, while the New York portion has not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

The Ohio portion of the Steubenville-Weirton, OH-WV PM-2.5 (2006 Standard) nonattainment area has been redesignated, while the West Virginia portion has not. The entire area is not considered in maintenance until all states in a multi-state area are redesignated.

**Figure 7-20 2006 PM<sub>2.5</sub> Nonattainment Areas**

As of December 5, 2013, over 11 million people live in the 40 areas that are designated as nonattainment for the PM<sub>10</sub> NAAQS. There are 33 full or partial counties that make up the PM<sub>10</sub> nonattainment areas. Nonattainment areas for the PM<sub>10</sub> NAAQS are pictured in Figure 7-21.

## Counties Designated Nonattainment for PM-10



**Figure 7-21 PM<sub>10</sub> Nonattainment Areas**

### 7.2.4.2.2 Projected Concentrations of PM<sub>2.5</sub> Without the Rule

EPA has already adopted many mobile source emission control programs that are expected to reduce ambient PM levels. These control programs include the Heavy-Duty Greenhouse Gas Rule (76 FR 57106, September 15, 2011), the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895, April 30, 2010), the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034, October 8, 2008), the Locomotive and Marine Compression-Ignition Engine Rule (73 FR 25098, May 6, 2008), the Clean Air Nonroad Diesel (69 FR 38957, June 29, 2004), the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, January 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, February 10, 2000). As a result of these and other federal, state and local programs, the number of areas that fail to meet the PM<sub>2.5</sub> NAAQS in the future is expected to decrease. However, even with the implementation of all current state and federal regulations, there are projected to be counties violating the PM<sub>2.5</sub> NAAQS well into the future. Thus additional federal control programs, such as Tier 3, can assist areas with attainment dates in 2017 and beyond in attaining the NAAQS as expeditiously as practicable and may relieve areas with

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already stringent local regulations from some of the burden associated with adopting additional local controls.

The air quality modeling conducted for this rule projects that in 2030, with all current controls in effect but excluding the emissions changes expected to occur as a result of this rule or any other additional controls, at least 13 counties, with a projected population of over 21 million people, will have projected design values above the level of the annual standard of  $12.0 \mu\text{g}/\text{m}^3$  and at least 18 counties, with a projected population of over 12 million people, will have projected design values above the level of the 2006 24-hour standard of  $35 \mu\text{g}/\text{m}^3$ . Since the emission changes from this action would go into effect during the period when some areas are still working to attain the  $\text{PM}_{2.5}$  NAAQS, the projected emission changes will help state and local agencies in their effort to attain and maintain the  $\text{PM}_{2.5}$  standard. In the following section we discuss projected  $\text{PM}_{2.5}$  reductions from these standards.

#### *7.2.4.2.3 Projected Annual Average Concentrations of $\text{PM}_{2.5}$ With the Rule*

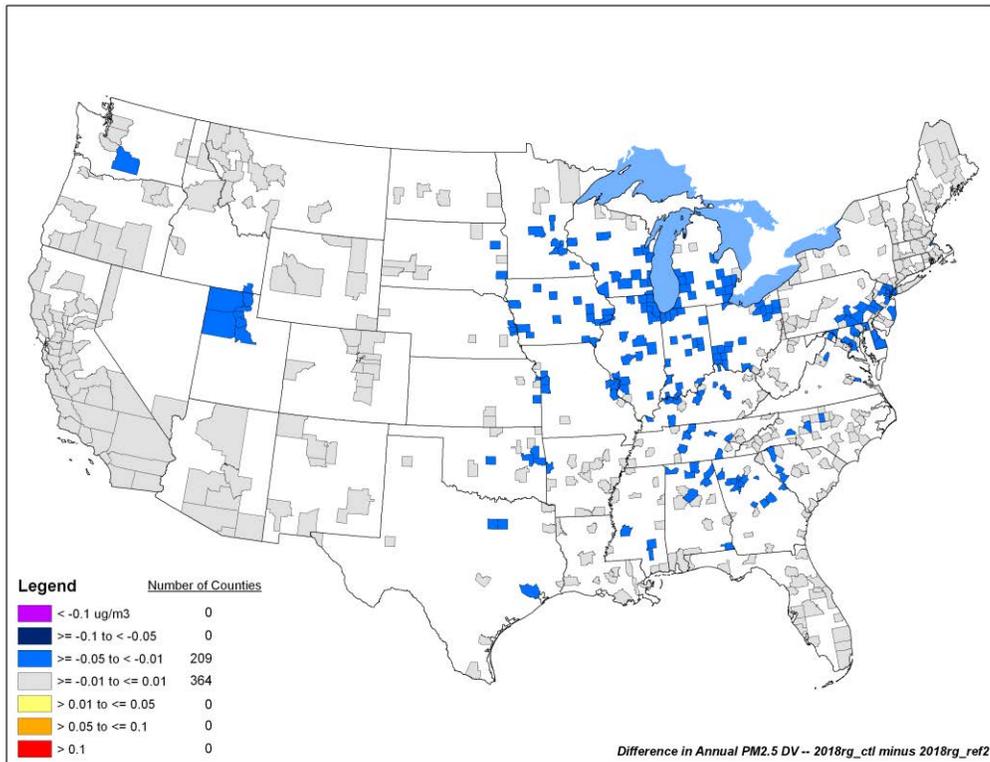
This section summarizes the results of our modeling of annual average  $\text{PM}_{2.5}$  air quality impacts in the future due to the standards in this action. Specifically, for the years 2018 and 2030 we compare a reference scenario (a scenario without the standards) to a control scenario that includes the standards. Our modeling indicates that annual  $\text{PM}_{2.5}$  design values will decrease due to the Tier 3 standards. The decreases in annual  $\text{PM}_{2.5}$  design values are likely due to the projected reductions in primary  $\text{PM}_{2.5}$ ,  $\text{NO}_x$ ,  $\text{SO}_x$  and VOC emissions. As described in Section 7.2.1.1, the air quality modeling used inventories that included an increase in direct  $\text{PM}_{2.5}$  emissions in the West and Pacific Northwest that is an artifact of a difference in fuel properties that isn't real.<sup>DD</sup> Although in most areas this direct  $\text{PM}_{2.5}$  increase is outweighed by reductions in secondary  $\text{PM}_{2.5}$ , the air quality modeling does predict ambient  $\text{PM}_{2.5}$  increases in a few places in the West and Pacific Northwest. These modeled increases are a result of the inventory issue, and we do not expect them to actually occur. Ambient  $\text{PM}_{2.5}$  projections are discussed in more detail below. Additional information on the emissions reductions that are projected with this action is available in Section 7.2.1 of this RIA.

Figure 7-22 and Figure 7-23 present the changes in annual  $\text{PM}_{2.5}$  design values in 2018 and 2030 respectively.<sup>EE</sup>

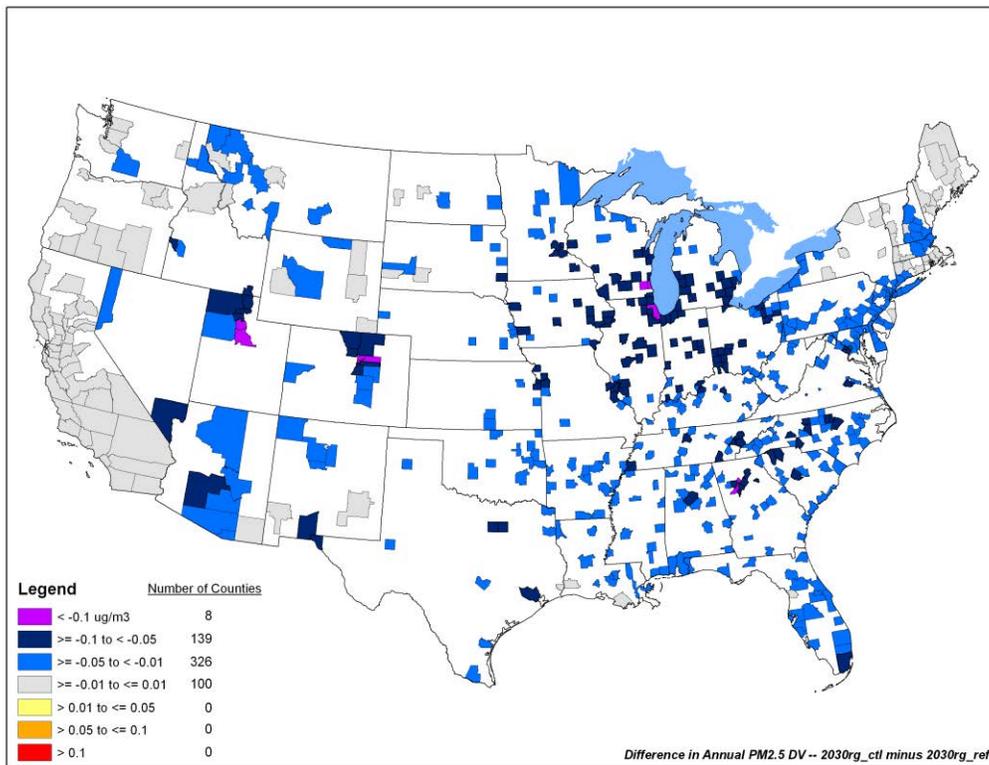
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<sup>DD</sup> The issue is with the way that some of the fuel property data, specifically E200/E300 and T50/T90, matched up in the fuel compliance database in the West and Pacific Northwest, see Section 7.2.1.1 for additional information.

<sup>EE</sup> An annual  $\text{PM}_{2.5}$  design value is the concentration that determines whether a monitoring site meets the annual NAAQS for  $\text{PM}_{2.5}$ . The full details involved in calculating an annual  $\text{PM}_{2.5}$  design value are given in appendix N of 40 CFR part 50.



**Figure 7-22 Projected Change in 2018 Annual PM<sub>2.5</sub> Design Values Between the Reference Case and Control Case**



**Figure 7-23 Projected Change in 2030 Annual PM<sub>2.5</sub> Design Values Between the Reference Case and Control Case**

As shown in Figure 7-22, we project that in 2018 over 200 counties will have design value decreases of between 0.01  $\mu\text{g}/\text{m}^3$  and 0.05  $\mu\text{g}/\text{m}^3$ . These counties tend to be in urban areas in states that have not adopted California LEV III standards. The maximum projected decrease in a 2018 annual PM<sub>2.5</sub> design value is 0.04  $\mu\text{g}/\text{m}^3$  in Waukesha County, Wisconsin and Cook County, Illinois. There are two counties with very small projected increases in their annual PM<sub>2.5</sub> design values in 2018: Lewis & Clark County, Montana, and Gallatin County, Montana. These projected increases are a result of the issue with the air quality modeling inventories discussed in Section 7.2.1.1, and we do not expect these increases will occur.

Figure 7-23 presents the annual PM<sub>2.5</sub> design value changes in 2030. The annual PM<sub>2.5</sub> design value decreases in 2030 are larger than the decreases in 2018; most design values are projected to decrease between 0.01 and 0.05  $\mu\text{g}/\text{m}^3$  and over 140 additional counties have projected design value decreases greater than 0.05  $\mu\text{g}/\text{m}^3$ . The maximum projected decrease in an annual PM<sub>2.5</sub> design value in 2030 is 0.15  $\mu\text{g}/\text{m}^3$  in Milwaukee County, Wisconsin.

Table 7-45 and Table 7-46 show the average change in 2018 and 2030 annual PM<sub>2.5</sub> design values for: (1) all counties with 2007 baseline design values, (2) counties with 2007 baseline design values that exceeded the 2012 annual PM<sub>2.5</sub> standard, (3) counties with 2007 baseline design values that did not exceed the 2012 standard, but were within 10 percent of it, (4) counties with 2018/2030 design values that exceeded the 2012 annual PM<sub>2.5</sub> standard, and (5)

counties with 2018/2030 design values that did not exceed the standard, but were within 10 percent of it. Counties within 10 percent of the standard are intended to reflect counties that although not violating the standards, will also be impacted by changes in PM<sub>2.5</sub> as they work to ensure long-term maintenance of the annual PM<sub>2.5</sub> NAAQS. All of these metrics show either no change or a small decrease in 2018 and 2030. On a population-weighted basis, there is a 0.01 µg/m<sup>3</sup> reduction in the average modeled future-year annual PM<sub>2.5</sub> design values in 2018 and a 0.04 µg/m<sup>3</sup> decrease in 2030.

**Table 7-45 Average Change in 2018 Annual PM<sub>2.5</sub> Design Value as a Result of the Rule**

AVERAGE	Number of U.S. Counties	2020 Population	Change in 2018 design value (µg/m <sup>3</sup> )
All	573	230,583,259	-0.01
All, population-weighted			-0.01
Counties whose 2007 base year is violating the annual PM <sub>2.5</sub> standard	231	111,371,097	-0.02
Counties whose 2007 base year is violating the annual PM <sub>2.5</sub> standard, population-weighted			-0.02
Counties whose 2007 base year is within 10 percent of the annual PM <sub>2.5</sub> standard	123	45,480,691	-0.01
Counties whose 2007 base year is within 10 percent of the annual PM <sub>2.5</sub> standard, population-weighted			-0.01
Counties whose 2018 control case is violating the annual PM <sub>2.5</sub> standard	13	19,690,375	-0.01
Counties whose 2018 control case is violating the annual PM <sub>2.5</sub> standard, population-weighted			0.00
Counties whose 2018 control case is within 10 percent of the annual PM <sub>2.5</sub> standard	28	29,073,863	-0.02
Counties whose 2018 control case is within 10 percent of the annual PM <sub>2.5</sub> standard, population-weighted			-0.02

<sup>a</sup> Averages are over counties with 2007 modeled design values

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

**Table 7-46 Average Change in 2030 Annual PM<sub>2.5</sub> Design Value as a Result of the Rule**

AVERAGE	Number of U.S. Counties	2030 Population	Change in 2030 design value (µg/m <sup>3</sup> )
All	573	252,063,937	-0.04
All, population-weighted			-0.04
Counties whose 2007 base year is violating the annual PM <sub>2.5</sub> standard	231	119,932,361	-0.05
Counties whose 2007 base year is violating the annual PM <sub>2.5</sub> standard, population-weighted			-0.05
Counties whose 2007 base year is within 10 percent of the annual PM <sub>2.5</sub> standard	123	50,009,709	-0.04
Counties whose 2007 base year is within 10 percent of the annual PM <sub>2.5</sub> standard, population-weighted			-0.05
Counties whose 2030 control case is violating the annual PM <sub>2.5</sub> standard	13	21,376,437	-0.01
Counties whose 2030 control case is violating the annual PM <sub>2.5</sub> standard, population-weighted			-0.01
Counties whose 2030 control case is within 10 percent of the annual PM <sub>2.5</sub> standard	20	22,244,541	-0.07
Counties whose 2030 control case is within 10 percent of the annual PM <sub>2.5</sub> standard, population-weighted			-0.09

<sup>a</sup> Averages are over counties with 2007 modeled design values

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

There are 13 counties, mostly in California, that are projected to have annual PM<sub>2.5</sub> design values above the NAAQS in 2030 without the standards or any other additional standards in place. Table 7-47 below presents the changes in design values for these counties.

**Table 7-47 Change in Annual PM<sub>2.5</sub> Design Values (µg/m<sup>3</sup>) for Counties Projected to be Above the Annual PM<sub>2.5</sub> NAAQS in 2030**

County Name	Change in Annual PM <sub>2.5</sub> Design Value (µg/m <sup>3</sup> )	Population in 2030 <sup>a</sup>
Kern County, California	-0.01	981,806
Imperial County, California	-0.01	174,175
Tulare County, California	-0.01	528,662
Riverside County, California	-0.01	2,614,198
Fresno County, California	0	1,196,949
San Bernardino County, California	-0.01	2,784,489
Santa Cruz County, Arizona	-0.03	55,393
Kings County, California	0	195,067
Lincoln County, Montana	-0.02	20,454
El Paso County, Texas	-0.06	1,080,944
Merced County, California	0	313,333
Stanislaus County, California	0	688,245
Los Angeles County, California	0	10,742,722

<sup>a</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

In terms of modeling accuracy, the count of modeled nonattainment counties is much less certain than the average changes in air quality. Bearing this in mind, in 2018 our modeling predicts that the Tier 3 standards will reduce annual PM<sub>2.5</sub> design values in Allegheny County, PA from above the level of the standard to below it. The projected population in Allegheny County in 2018 is over one million people.

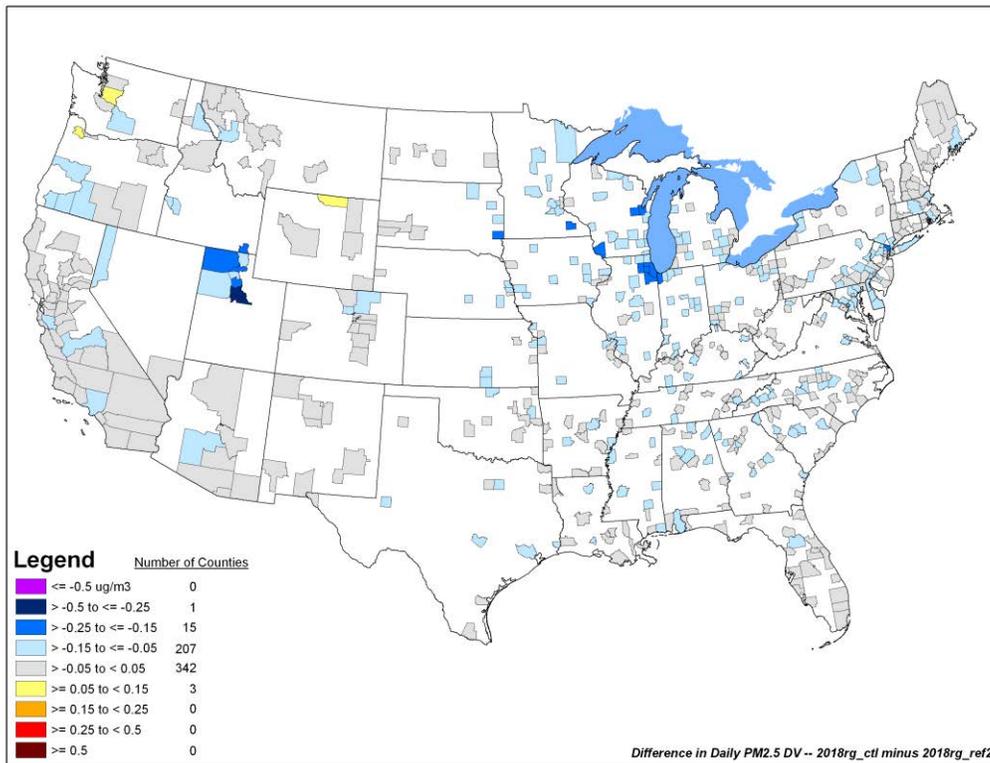
#### 7.2.4.2.4 Projected 24-hour Average Concentrations of PM<sub>2.5</sub> With the Rule

This section summarizes the results of our modeling of 24-hour PM<sub>2.5</sub> air quality impacts in the future due to the rule. Specifically, for the years 2018 and 2030 we compare a reference scenario (a scenario without the standards) to a control scenario that includes the standards. Our modeling indicates that 24-hour PM<sub>2.5</sub> design values will decrease due to the Tier 3 standards. The decreases in 24-hour PM<sub>2.5</sub> design values are likely due to the projected reductions in primary PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>x</sub> and VOCs. As described in Section 7.2.1.1, the air quality modeling used inventories that include an increase in direct PM<sub>2.5</sub> emissions in the West and Pacific Northwest that is an artifact of a difference in fuel properties that isn't real.<sup>FF</sup> Although in most areas this direct PM<sub>2.5</sub> increase is outweighed by reductions in secondary PM<sub>2.5</sub>, the air quality

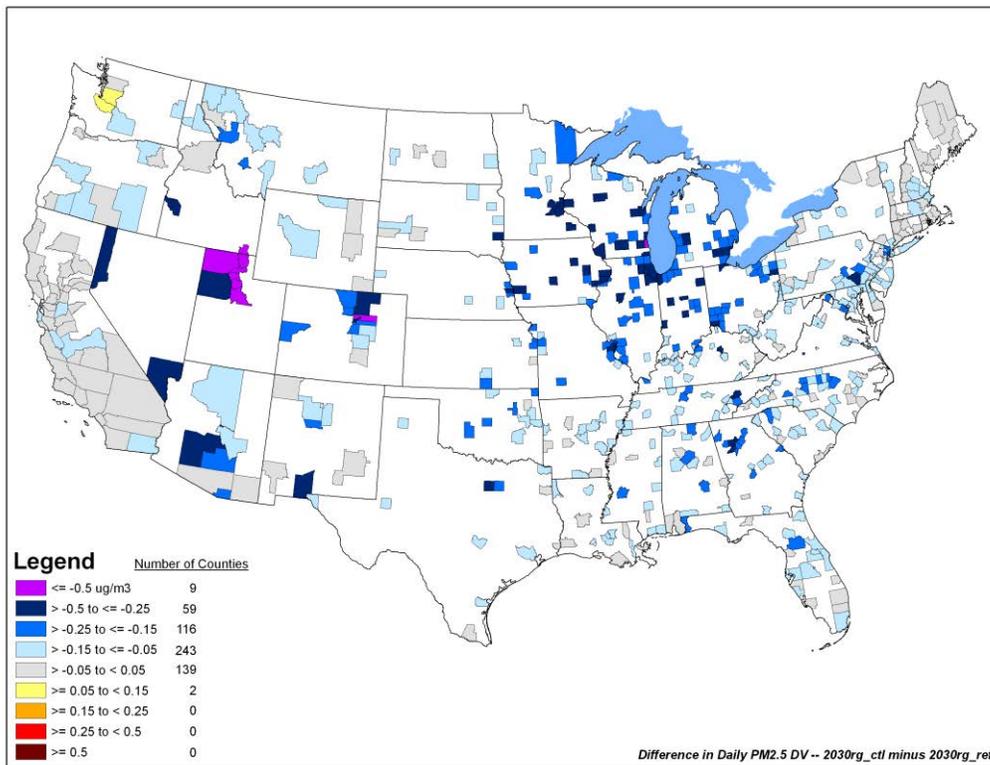
<sup>FF</sup> The issue is with the way that some of the fuel property data, specifically E200/E300 and T50/T90, matched up in the fuel compliance database in the West and Pacific Northwest, see Section 7.2.1.1 for additional information.

modeling does predict ambient PM<sub>2.5</sub> increases in a few places in the West and Pacific Northwest. These modeled increases are a result of the inventory issue, and we do not expect them to actually occur. Ambient PM<sub>2.5</sub> projections are discussed in more detail below. Additional information on the emissions reductions that are projected with this action is available in Section 7.2.1 of this RIA.

Figure 7-24 and Figure 7-25 present the changes in 24-hour PM<sub>2.5</sub> design values in 2018 and 2030 respectively



**Figure 7-24 Projected Change in 2018 24-hour PM<sub>2.5</sub> Design Values Between the Reference Case and the Control Case**



**Figure 7-25 Projected Change in 2030 24-hour PM<sub>2.5</sub> Design Values Between the Reference Case and the Control Case**

As shown in Figure 7-24, in 2018 there are 16 counties with projected 24-hour PM<sub>2.5</sub> design value decreases greater than 0.15  $\mu\text{g}/\text{m}^3$ . These counties are in urban areas in states that have not adopted California LEV III standards. The maximum projected decrease in a 2018 24-hour PM<sub>2.5</sub> design value is 0.30  $\mu\text{g}/\text{m}^3$  in Utah County, Utah. There are three counties with projected increases in their 24-hour PM<sub>2.5</sub> design values in 2018: Washington County, Oregon; King County, Washington; and Sheridan County, Wyoming. These projected increases are a result of the issue with the air quality modeling emissions inventories discussed in Section 7.2.1.1, and we do not expect these increases will occur.

Figure 7-25 presents the 24-hour PM<sub>2.5</sub> design value changes in 2030. In 2030 the 24-hour PM<sub>2.5</sub> design value decreases are larger; most design values are projected to decrease between 0.05 and 0.15  $\mu\text{g}/\text{m}^3$  and over 50 counties have projected design value decreases greater than 0.25  $\mu\text{g}/\text{m}^3$ . The maximum projected decrease in a 24-hour PM<sub>2.5</sub> design value in 2030 is 0.8  $\mu\text{g}/\text{m}^3$  in Salt Lake County, Utah. As shown in Figure 7-25, design values in 9 counties are projected to decrease by more than 0.5  $\mu\text{g}/\text{m}^3$ . These counties are in Utah, Idaho, Colorado and Wisconsin. There are two counties with projected increases in their 24-hour PM<sub>2.5</sub> design values in 2030: King County, Washington, and Pierce County, Washington. These projected increases are a result of the issue with the air quality modeling emissions inventories discussed in Section

7.2.1.1 and we do not expect these increases will occur. Additional information on the emissions reductions that are projected with this action is available in Section 7.2.1.

Table 7-48 and Table 7-49 show the average change in 2018/2030 24-hour PM<sub>2.5</sub> design values for: (1) all counties with 2007 baseline design values, (2) counties with 2007 baseline design values that exceeded the 24-hour PM<sub>2.5</sub> standard, (3) counties with 2007 baseline design values that did not exceed the standard, but were within 10 percent of it, (4) counties with 2018/2030 design values that exceeded the 24-hour PM<sub>2.5</sub> standard, and (5) counties with 2018/2030 design values that did not exceed the standard, but were within 10 percent of it. Counties within 10 percent of the standard are intended to reflect counties that although not violating the standards, will also be impacted by changes in PM<sub>2.5</sub> as they work to ensure long-term maintenance of the 24-hour PM<sub>2.5</sub> NAAQS. On a population-weighted basis, the average modeled future-year 24-hour PM<sub>2.5</sub> design values are projected to decrease by 0.13 µg/m<sup>3</sup> in 2030 due to the Tier 3 standards.

**Table 7-48 Average Change in Projected 24-hour PM<sub>2.5</sub> Design Values in 2018**

Average <sup>a</sup>	Number of U.S. Counties	2030 Population <sup>b</sup>	Change in 2030 design value (µg/m <sup>3</sup> )
All	568	229,741,229	-0.04
All, population-weighted			-0.05
Counties whose 2007 base year is violating the 2006 24-hour PM <sub>2.5</sub> standard	55	56,171,551	-0.05
Counties whose 2007 base year is violating the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.06
Counties whose 2007 base year is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard	84	39,543,851	-0.06
Counties whose 2007 base year is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.06
Counties whose 2030 control case is violating the 2006 24-hour PM <sub>2.5</sub> standard	24	18,382,427	-0.04
Counties whose 2030 control case is violating the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.03
Counties whose 2030 control case is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard	14	16,167,178	-0.07
Counties whose 2030 control case is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.09

Note:

<sup>a</sup> Averages are over counties with 2007 modeled design values

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

**Table 7-49 Average Change in Projected 24-hour PM<sub>2.5</sub> Design Values in 2030**

Average <sup>a</sup>	Number of U.S. Counties	2030 Population <sup>b</sup>	Change in 2030 design value (µg/m <sup>3</sup> )
All	568	251,240,080	-0.13
All, population-weighted			-0.13
Counties whose 2007 base year is violating the 2006 24-hour PM <sub>2.5</sub> standard	55	60,280,914	-0.17
Counties whose 2007 base year is violating the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.13
Counties whose 2007 base year is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard	84	42,498,707	-0.18
Counties whose 2007 base year is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.16
Counties whose 2030 control case is violating the 2006 24-hour PM <sub>2.5</sub> standard	18	12,363,252	-0.11
Counties whose 2030 control case is violating the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			-0.14
Counties whose 2030 control case is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard	13	22,759,997	-0.05
Counties whose 2030 control case is within 10 percent of the 2006 24-hour PM <sub>2.5</sub> standard, population-weighted			0.00

<sup>a</sup> Averages are over counties with 2007 modeled design values

<sup>b</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

There are 18 counties that are projected to have 24-hour PM<sub>2.5</sub> design values above the NAAQS in 2030 without the Tier 3 standards or any other additional controls in place. Table 7-50 below presents the changes in design values for these counties.

**Table 7-50 Change in 24-hour PM<sub>2.5</sub> Design Values (µg/m<sup>3</sup>) for Counties Projected to be Above the 24-hour PM<sub>2.5</sub> NAAQS in 2030**

County Name	Change in 24-hour PM <sub>2.5</sub> Design Value (µg/m <sup>3</sup> )	Population in 2030 <sup>a</sup>
Sacramento County, California	0	1,856,970
Butte County, California	0	287,235
Klamath County, Oregon	-0.1	77,199
Imperial County, California	-0.1	174,175
Pierce County, Washington	0.1	1,082,578
Stanislaus County, California	0	688,245
Fresno County, California	-0.1	1,196,949
Merced County, California	0	313,333
Kings County, California	0	195,067
Kern County, California	0	981,806
Lake County, Oregon	0	9,462
Salt Lake County, Utah	-0.8	1,431,946
Pinal County, Arizona	-0.2	348,831
Lane County, Oregon	-0.1	460,992
Allegheny County, Pennsylvania	0	1,234,930
San Joaquin County, California	-0.1	833,417
Utah County, Utah	-0.6	661,455
Tulare County, California	0	528,662

<sup>a</sup> Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. (2011). 2012 Complete Economic and Demographic Data Source (CEDDS).

#### 7.2.4.3 Nitrogen Dioxide

As described in Section 6.1.3 of this RIA, NO<sub>2</sub> causes adverse health effects, and the EPA has set national ambient air quality standards (NAAQS) to protect against those health effects. In this section we present information on current and model-projected future NO<sub>2</sub> levels.

##### 7.2.4.3.1 Current Concentrations of NO<sub>2</sub>

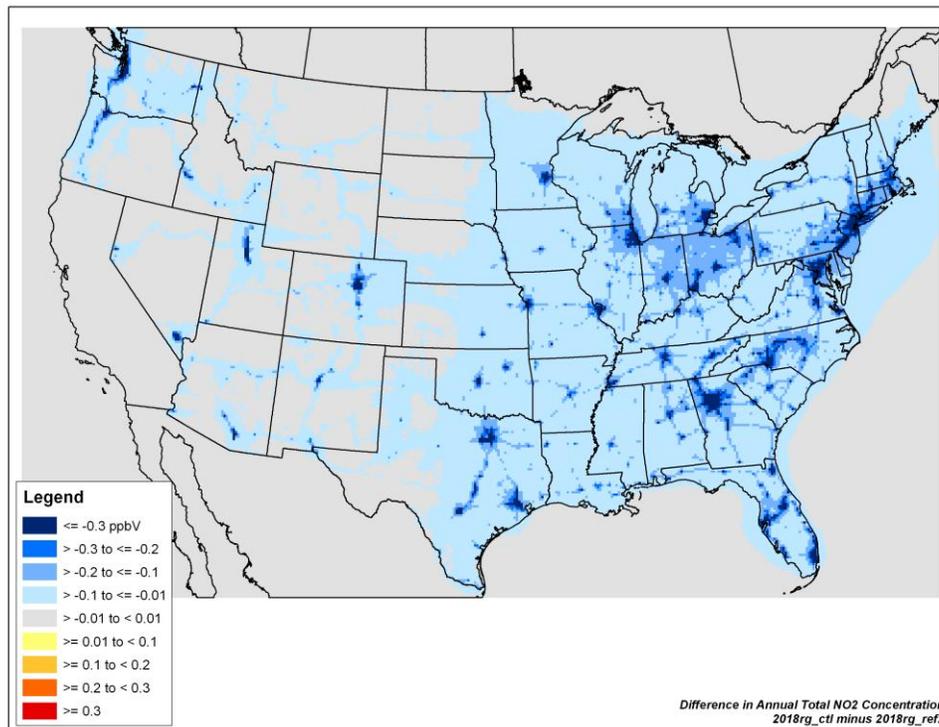
The EPA most recently completed a review of the primary NAAQS for NO<sub>2</sub> in January 2010. There are two primary NAAQS for NO<sub>2</sub>: an annual standard (53 ppb) and a 1-hour standard (100 ppb). The EPA promulgated area designations in the Federal Register on February 17, 2012. In this initial round of designations, all areas of the country were designated as “unclassifiable/attainment” for the 2010 NO<sub>2</sub> NAAQS based on data from the existing air quality monitoring network. The EPA and state agencies are working to establish an expanded network of NO<sub>2</sub> monitors, expected to be deployed in the 2014-2017 time frame. Once three years of air quality data have been collected from the expanded network, the EPA will be able to evaluate NO<sub>2</sub> air quality in additional locations.<sup>135,136</sup>

#### 7.2.4.3.2 Projected Concentrations of NO<sub>2</sub> without the Rule

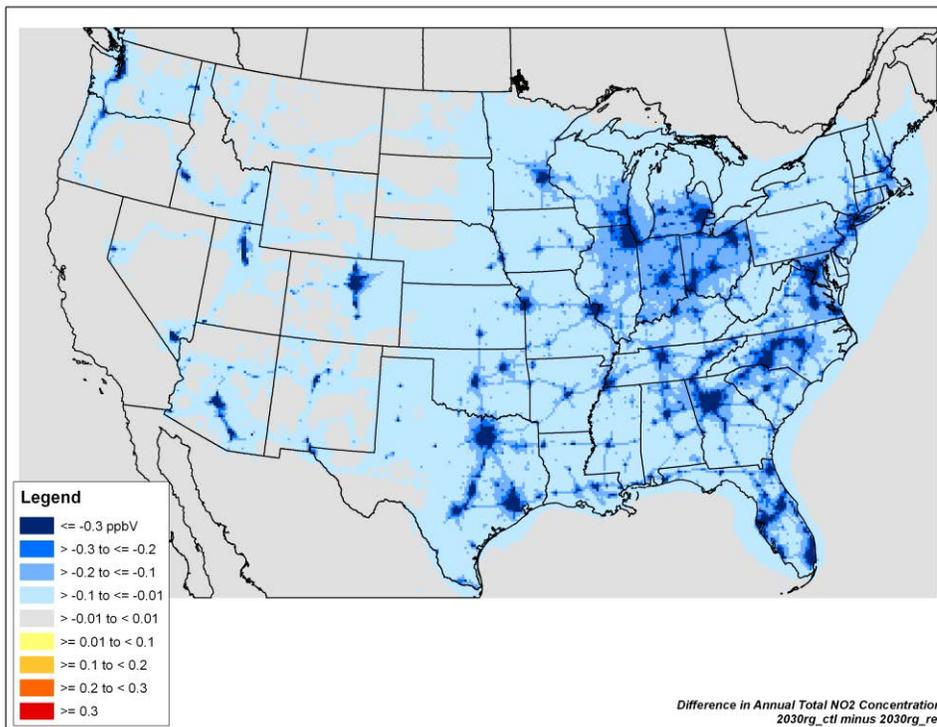
EPA has already adopted many mobile source emission control programs that are expected to reduce ambient NO<sub>2</sub> levels. These control programs include the Heavy-Duty Greenhouse Gas Rule (76 FR 57106, September 15, 2011), New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895, April 30, 2010), the Locomotive and Marine Compression-Ignition Engine Rule (73 FR 25098, May 6, 2008), the Clean Air Nonroad Diesel (69 FR 38957, June 29, 2004), the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, January 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, February 10, 2000). As a result of these and other federal, state and local programs, ambient concentrations of NO<sub>2</sub> in the future are expected to decrease.

#### 7.2.4.3.3 Projected Concentrations of NO<sub>2</sub> with the Rule

This section summarizes the results of our modeling of annual average NO<sub>2</sub> air quality impacts in the future due to the final Tier 3 standards. Specifically, for the years 2018 and 2030 we compare a reference scenario (a scenario without the standards) to a control scenario that includes the standards. Figure 7-26 and Figure 7-27 present the changes in annual NO<sub>2</sub> concentrations in 2018 and 2030 respectively.



**Figure 7-26 Projected Change in 2018 Annual NO<sub>2</sub> Concentrations Between the Reference Case and Control Case**



**Figure 7-27 Projected Change in 2030 Annual NO<sub>2</sub> Concentrations Between the Reference Case and Control Case**

As shown in Figure 7-27, our modeling indicates that by 2030 annual NO<sub>2</sub> concentrations in the majority of the country would decrease less than 0.1 ppb due to this rule. However, decreases in annual NO<sub>2</sub> concentrations are greater than 0.3 ppb in most urban areas. These emissions reductions would also likely decrease 1-hour NO<sub>2</sub> concentrations and help any potential nonattainment areas to attain and maintain the standard.

#### 7.2.4.4 Air Toxics

As described in Section 6.1.5 of this RIA, air toxics cause adverse health effects. In this section we present information on current and model-projected future levels of air toxics.

##### 7.2.4.4.1 Current Concentrations of Air Toxics

The majority of Americans continue to be exposed to ambient concentrations of air toxics at levels which have the potential to cause adverse health effects.<sup>137</sup> The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage, as discussed in detail in U.S. EPA’s most recent Mobile Source Air Toxics (MSAT) Rule.<sup>138</sup> In order to identify and prioritize air toxics, emission source types and locations which are of greatest potential concern, U.S. EPA conducts the National-Scale Air Toxics Assessment (NATA). The most recent NATA was conducted for calendar year 2005, and was released in March 2011.<sup>139</sup> NATA for 2005 includes four steps:

- 
- 1) Compiling a national emissions inventory of air toxics emissions from outdoor sources
  - 2) Estimating ambient concentrations of air toxics across the United States
  - 3) Estimating population exposures across the United States
  - 4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

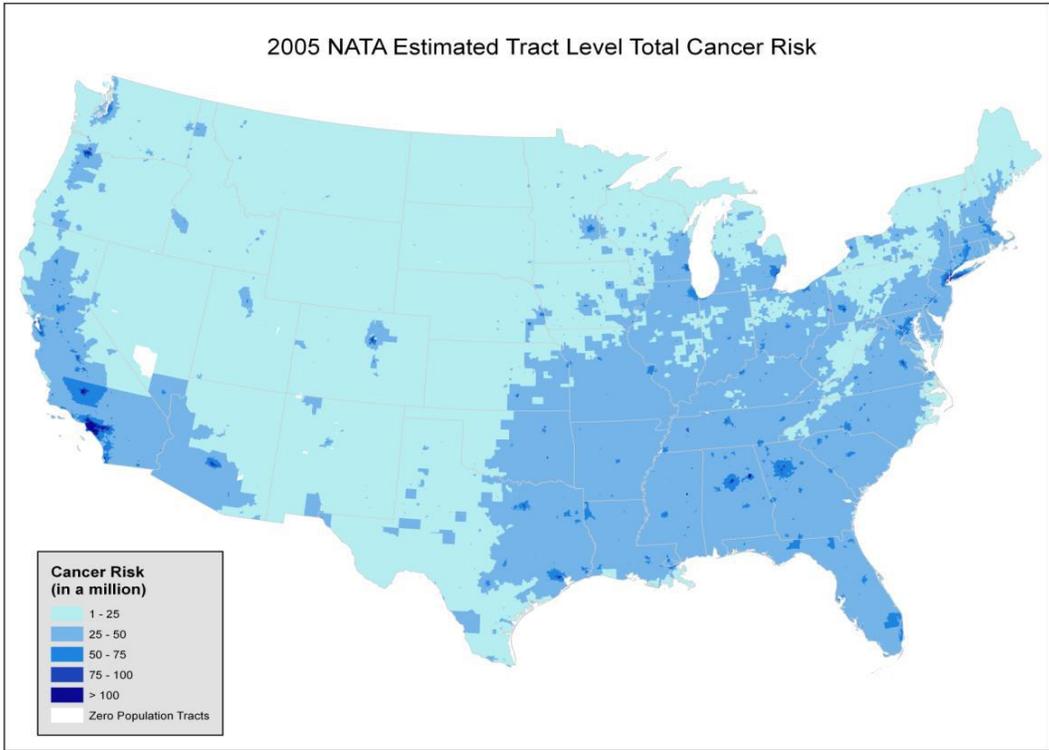
Figure 7-28 and Figure 7-29 depict estimated tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. The respiratory hazard is dominated by a single pollutant, acrolein.

According to the NATA for 2005, mobile sources were responsible for 43 percent of outdoor toxic emissions and over 50 percent of the cancer risk and noncancer hazard attributable to direct emissions from mobile and stationary sources.<sup>GG,HH,140</sup> Mobile sources are also large contributors to precursor emissions which react to form secondary concentrations of air toxics. Formaldehyde is the largest contributor to cancer risk of all 80 pollutants quantitatively assessed in the 2005 NATA, and mobile sources were responsible for over 40 percent of primary emissions of this pollutant in 2005, and are major contributors to formaldehyde precursor emissions. Benzene is also a large contributor to cancer risk, and mobile sources account for over 70 percent of ambient exposure. Over the years, EPA has implemented a number of mobile source and fuel controls which have resulted in VOC reductions, which also reduced formaldehyde, benzene and other air toxic emissions.

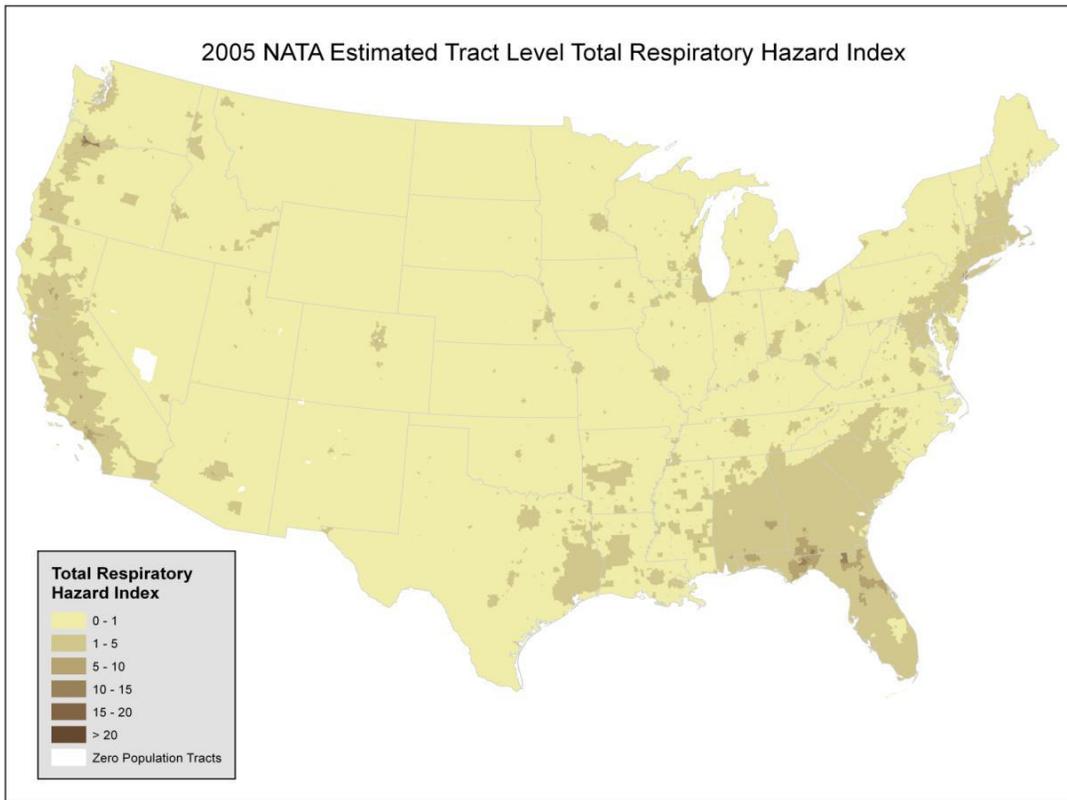
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<sup>GG</sup> NATA also includes estimates of risk attributable to background concentrations, which includes contributions from long-range transport, persistent air toxics, and natural sources; as well as secondary concentrations, where toxics are formed via secondary formation. Mobile sources substantially contribute to long-range transport and secondarily formed air toxics.

<sup>HH</sup> NATA relies on a Gaussian plume model, Assessment System for Population Exposure Nationwide (ASPEN), to estimate toxic air pollutant concentrations. Projected air toxics concentrations presented in this final action were modeled with CMAQ 4.7.1.



**Figure 7-28 Tract Level Average Carcinogenic Risk, 2005 NATA**



**Figure 7-29 County Level Average Noncancer Hazard Index, 2005 NATA**

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#### 7.2.4.4.2 Projected Concentrations of Air Toxics

Since 2005, and in future years when this rulemaking takes effect, the contribution of mobile sources to overall cancer risk is likely to change as a result of the impact of controls on both stationary and mobile sources. Overall, EPA anticipates a substantial decrease in overall cancer risk from ambient sources. In the following sections, we describe results of our modeling of air toxics concentrations in the future with the Tier 3 standards. Although there are a large number of compounds which are considered air toxics, we focused on those which were identified as national and regional-scale cancer and noncancer risk drivers in past NATA assessments and were also likely to be significantly impacted by the standards. These compounds include benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein. Impacts on ethanol concentrations were also included in our analyses. Information on the air quality modeling methodology is contained in Section 7.2.2. Additional detail can be found in the air quality modeling technical support document (AQM TSD) in the docket for this rule. Additional maps, including the seasonal concentration maps for 2030 and 2018, are included in Appendix 7.A.

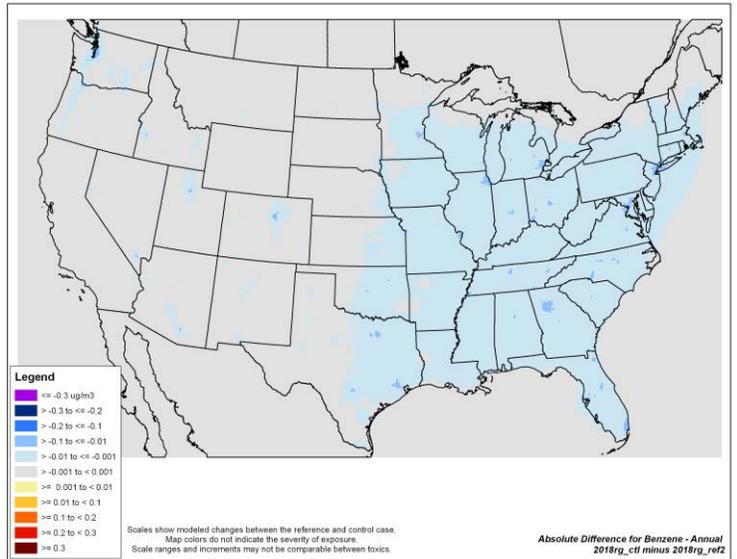
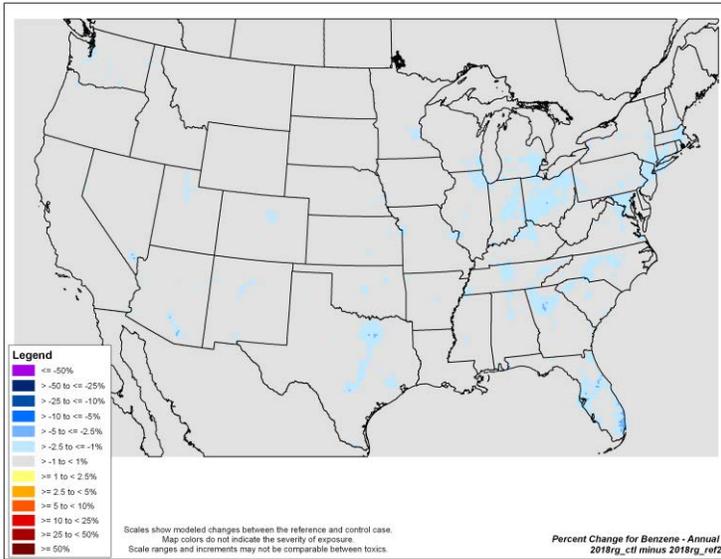
It should be noted that EPA has adopted many mobile source emission control programs that are expected to reduce ambient air toxics levels. These control programs include the Heavy-Duty Greenhouse Gas Rule (76 FR 57106, September 15, 2011), the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895, April 30, 2010), Heavy-duty Onboard Diagnostic Rule (74 FR 8310, February 24, 2009), Small SI and Marine SI Engine Rule (73 FR 59034, October 8, 2008), Locomotive and Commercial Marine Rule (73 FR 25098, May 6, 2008), Mobile Source Air Toxics Rule (72 FR 8428, February 26, 2007), Clean Air Nonroad Diesel Rule (69 FR 38957, June 29, 2004), Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, Feb. 10, 2000). As a result of these programs, the ambient concentration of air toxics in the future is expected to decrease. The reference case and control case scenarios include these controls.

Our modeling indicates that the impacts of the standards include generally small decreases in ambient concentrations of air toxics, with the greatest reductions in urban areas. Air toxics pollutants dominated by primary emissions (or a decay product of a directly emitted pollutant), such as benzene and 1,3-butadiene, have the largest impacts. Air toxics that primarily result from photochemical transformation, such as formaldehyde and acetaldehyde, are not impacted as much as those dominated by direct emissions. Our modeling shows decreases in ambient air toxics concentrations for both 2018 and 2030. Reductions are greater in 2030, when Tier 3 cars and trucks would contribute nearly 90 percent of fleet-wide vehicle miles travelled, than in 2018. However, our 2018 modeling projects there would be small immediate reductions in ambient concentrations of air toxics due to the sulfur controls that take effect in 2017. Furthermore, the full reduction of the vehicle program would be realized after 2030, when the fleet has fully turned over to Tier 3 vehicles. Because overall impacts are relatively small in both future years, we concluded that assessing exposure to ambient concentrations and conducting a quantitative risk assessment of air toxic impacts was not warranted. However, we did develop population metrics, including the population living in areas with increases or decreases in concentrations of various magnitudes.

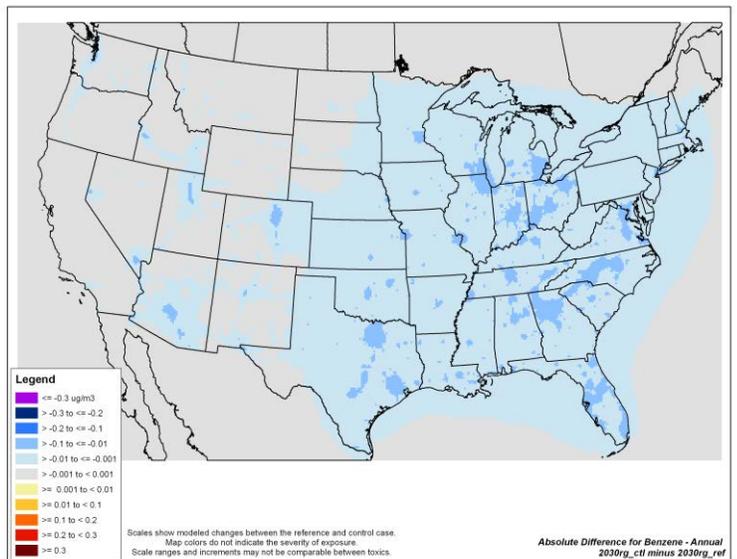
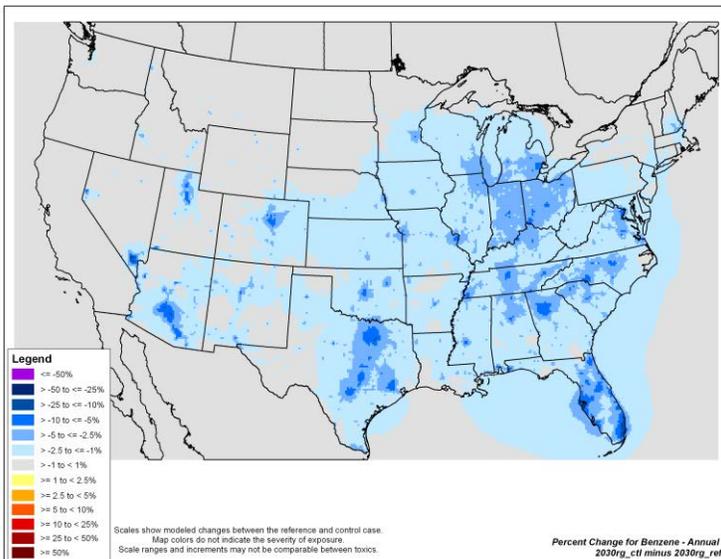
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## **Benzene**

Our modeling projects that the standards would have a notable impact on ambient benzene concentrations. In 2018, soon after the Tier 3 standards take effect, ambient benzene reductions are generally between 0.001 and 0.01  $\mu\text{g}/\text{m}^3$ , or between 1 and 2.5 percent in some areas (Figure 7-30). In 2030, our modeling projects that the rule will decrease ambient benzene concentrations across much of the country on the order of 1 to 5 percent, with reductions ranging from 10 to 25 percent in some urban areas (Figure 7-31). Absolute decreases in ambient concentrations of benzene are generally between 0.001 and 0.01  $\mu\text{g}/\text{m}^3$  in rural areas and as much as 0.1  $\mu\text{g}/\text{m}^3$  in urban areas (Figure 7-31).



**Figure 7-30 Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

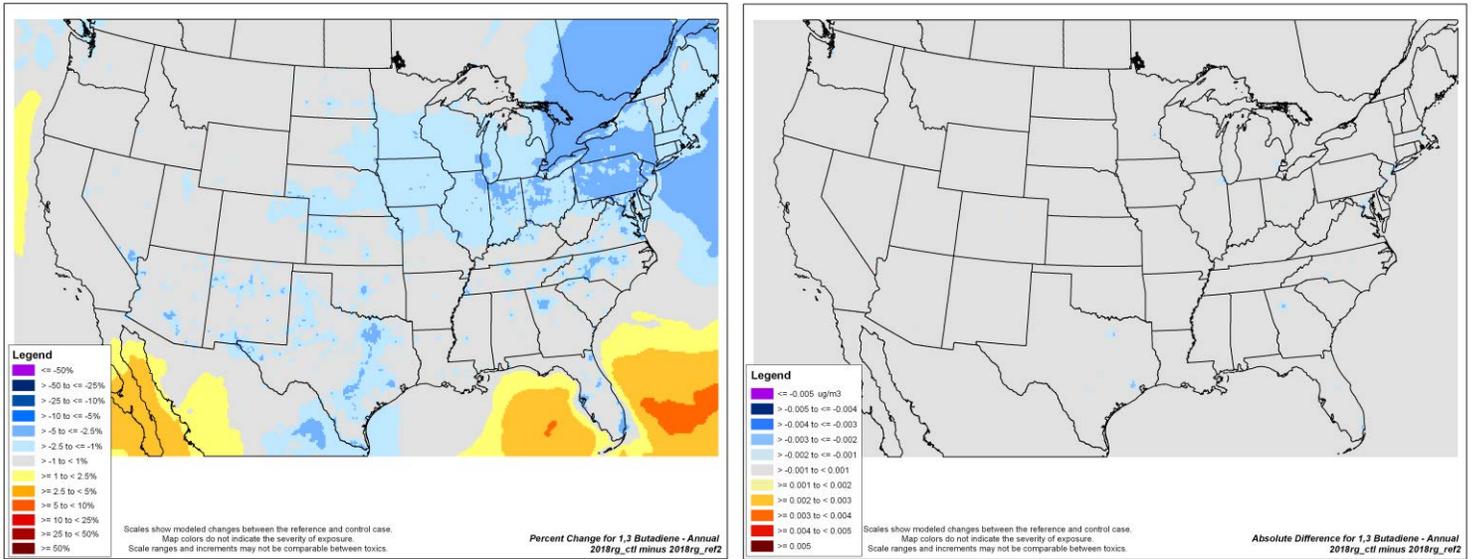


**Figure 7-31 Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

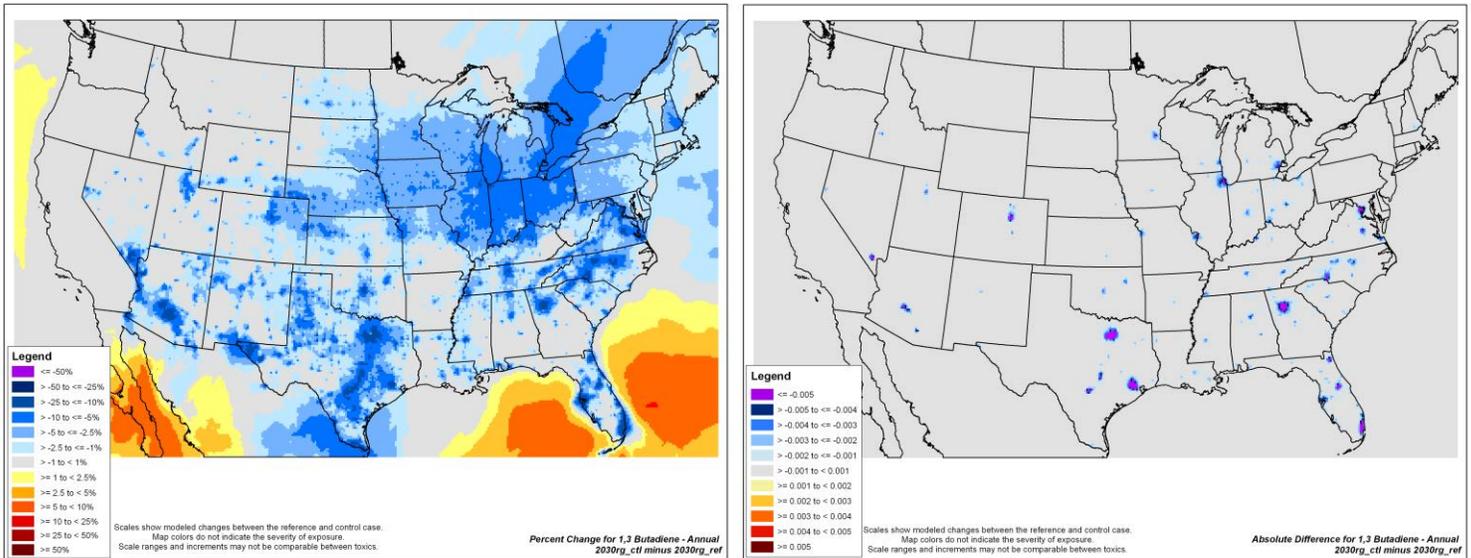
### 1,3-Butadiene

Our modeling also shows reductions of ambient 1,3-butadiene concentrations in 2018 and 2030. Figure 7-32 shows that in 2018, ambient concentrations of 1,3-butadiene generally decrease between 1 and 5 percent across parts of the country, corresponding to small decreases in absolute concentrations (less than  $0.001 \mu\text{g}/\text{m}^3$ ). In 2030, reductions of 1,3-butadiene

concentrations range between 1 and 25 percent, with decreases of at least 0.005  $\mu\text{g}/\text{m}^3$  in urban areas (Figure 7-33).



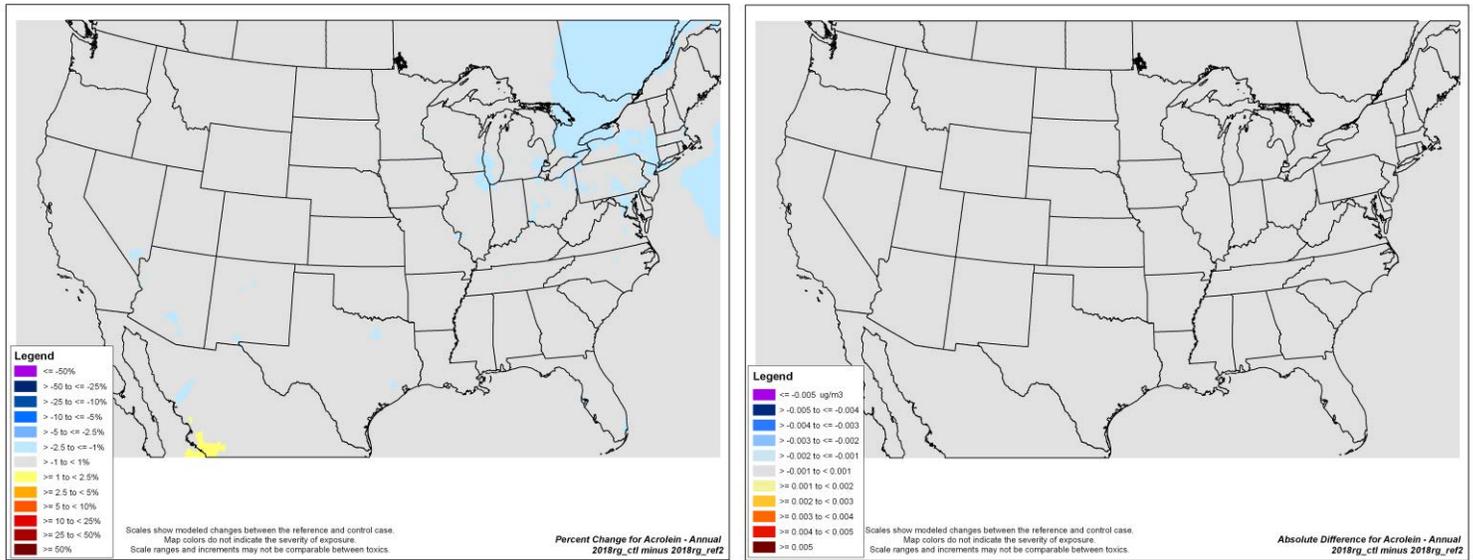
**Figure 7-32 Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



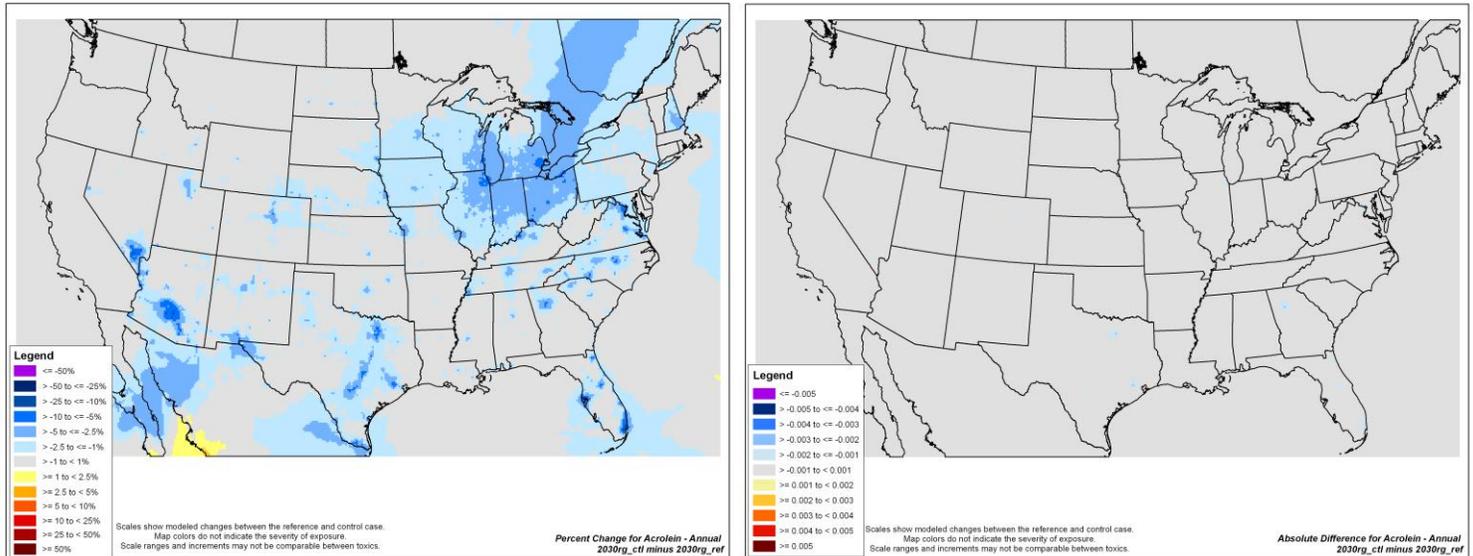
**Figure 7-33 Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Acrolein

Our modeling indicates the standards would reduce ambient concentrations of acrolein in 2018 and 2030. Figure 7-34 shows decreases in ambient concentrations of acrolein generally between 1 and 2.5 percent in parts of the country in 2018, corresponding to small decreases in absolute concentrations (less than 0.001  $\mu\text{g}/\text{m}^3$ ). Reductions of acrolein concentrations in 2030 range between 1 and 10 percent, with decreases as high as 0.003  $\mu\text{g}/\text{m}^3$  in a few urban areas.



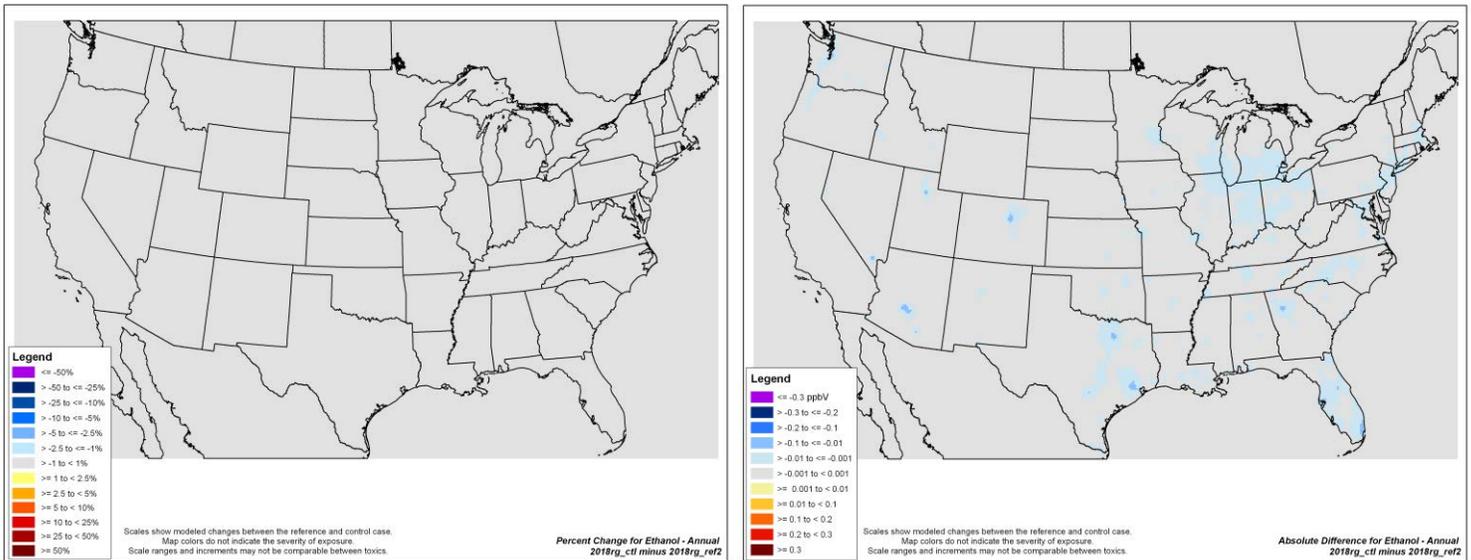
**Figure 7-34 Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



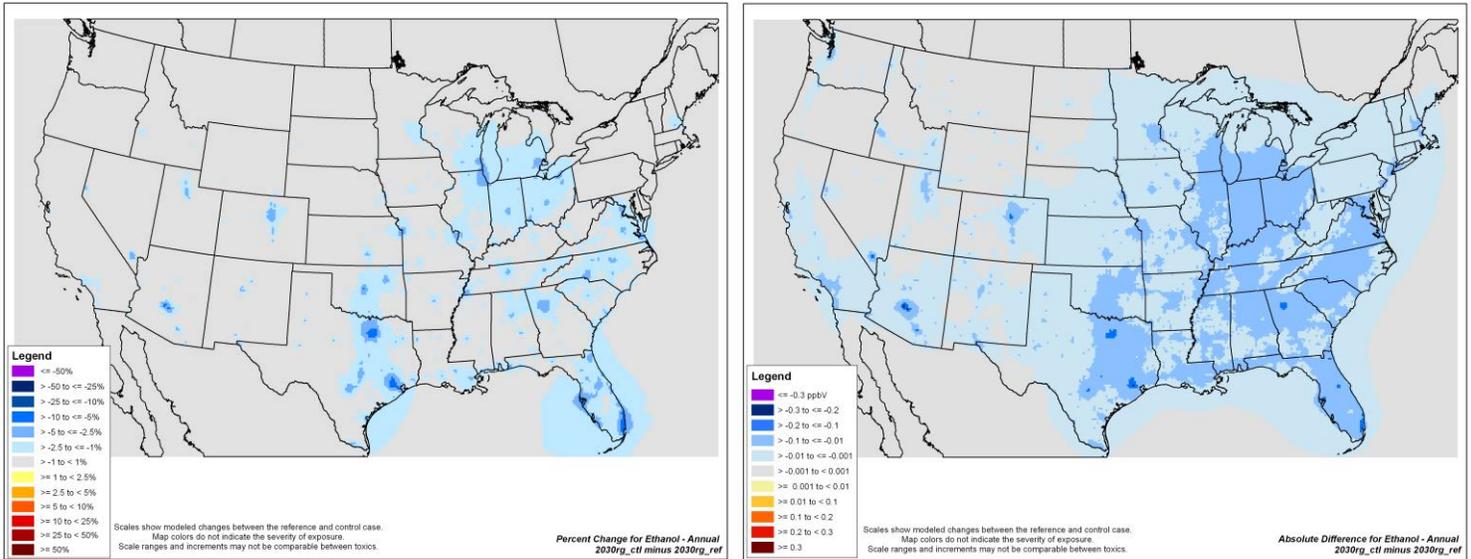
**Figure 7-35 Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Ethanol

Our modeling projects that the standards would slightly decrease ambient ethanol concentrations in 2018 and 2030. As shown in Figure 7-36, in 2018, annual percent changes in ambient concentrations of ethanol are less than 1 percent across the country, with absolute reductions of up to 0.1 ppb in some places. In 2030, some parts of the country, especially urban areas, are projected to have reductions in ethanol concentrations on the order of 1 to 10 percent as a result of the rule (Figure 7-37). Figure 7-37 also shows that absolute decreases in ambient concentrations of ethanol are generally between 0.001 and 0.1 ppb in 2030 with decreases in a few urban areas as high as 0.2 ppb.



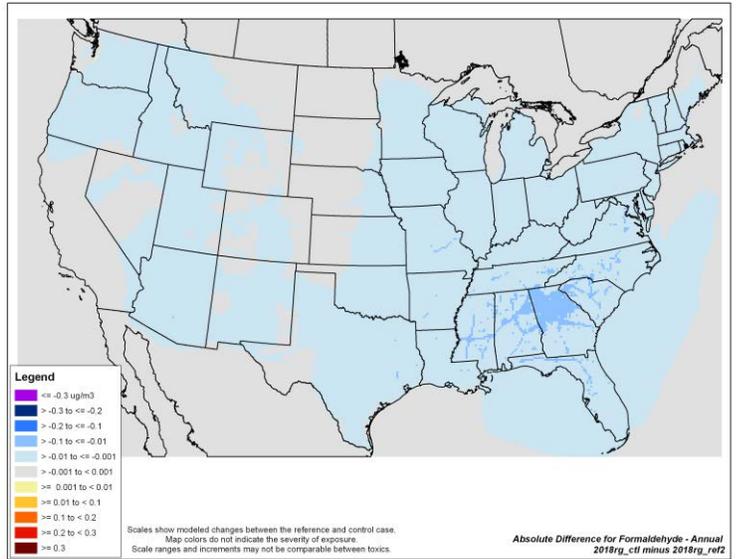
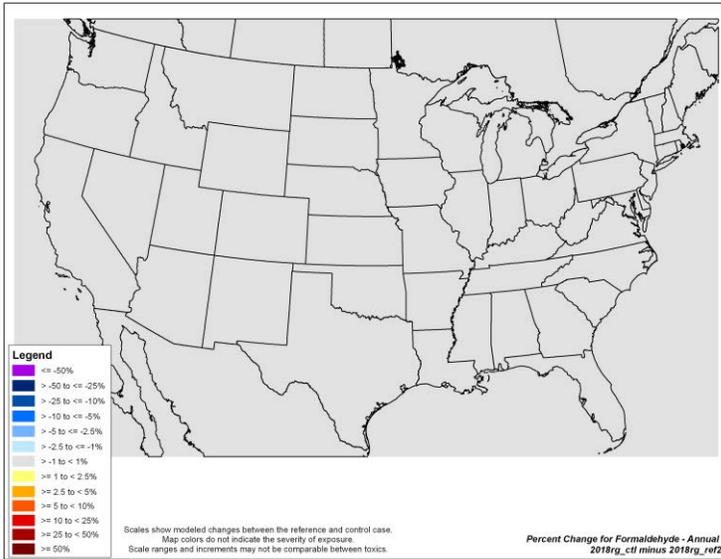
**Figure 7-36 Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



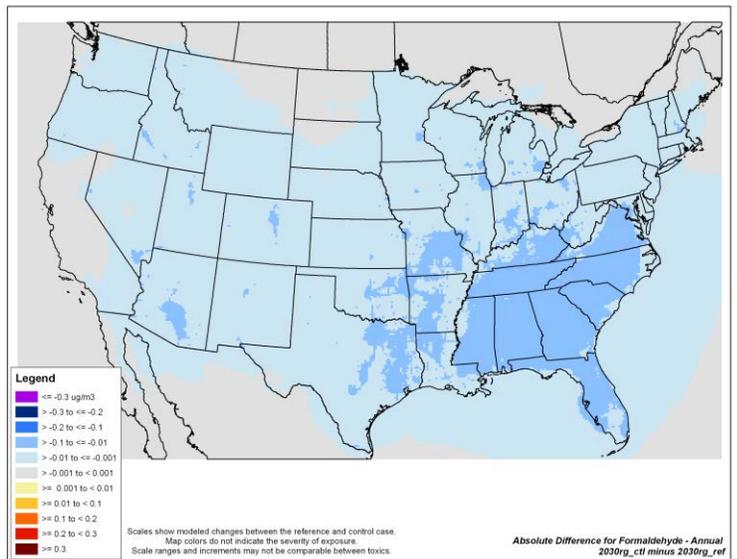
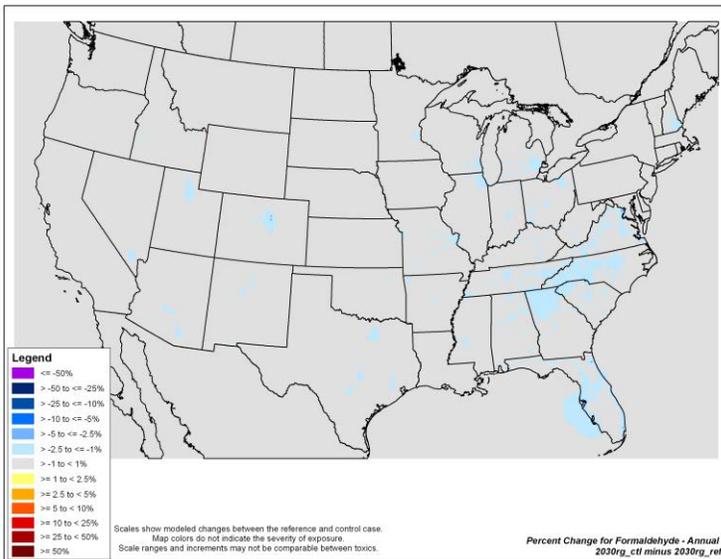
**Figure 7-37 Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Formaldehyde

Our modeling projects that formaldehyde concentrations would slightly decrease in parts of the country (mainly urban areas) as a result of the rule. As shown in Figure 7-38 and Figure 7-39, annual percent changes in ambient concentrations of formaldehyde are less than 1 percent across much of the country for 2018 but are on the order of 1 to 5 percent in 2030 in some urban areas as a result of the rule. Figure 7-38 and Figure 7-39 also show that absolute changes in ambient concentrations of formaldehyde are generally between 0.001 and 0.01  $\mu\text{g}/\text{m}^3$  in both years, with some areas as high as 0.1  $\mu\text{g}/\text{m}^3$  in 2030.



**Figure 7-38 Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

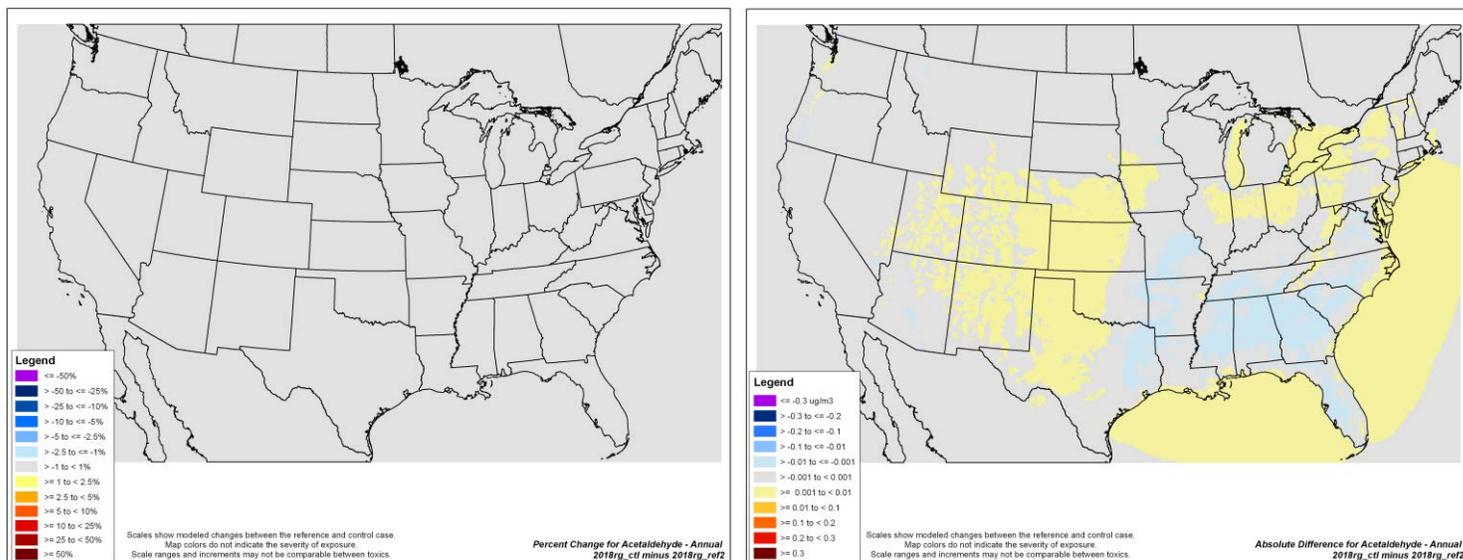


**Figure 7-39 Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

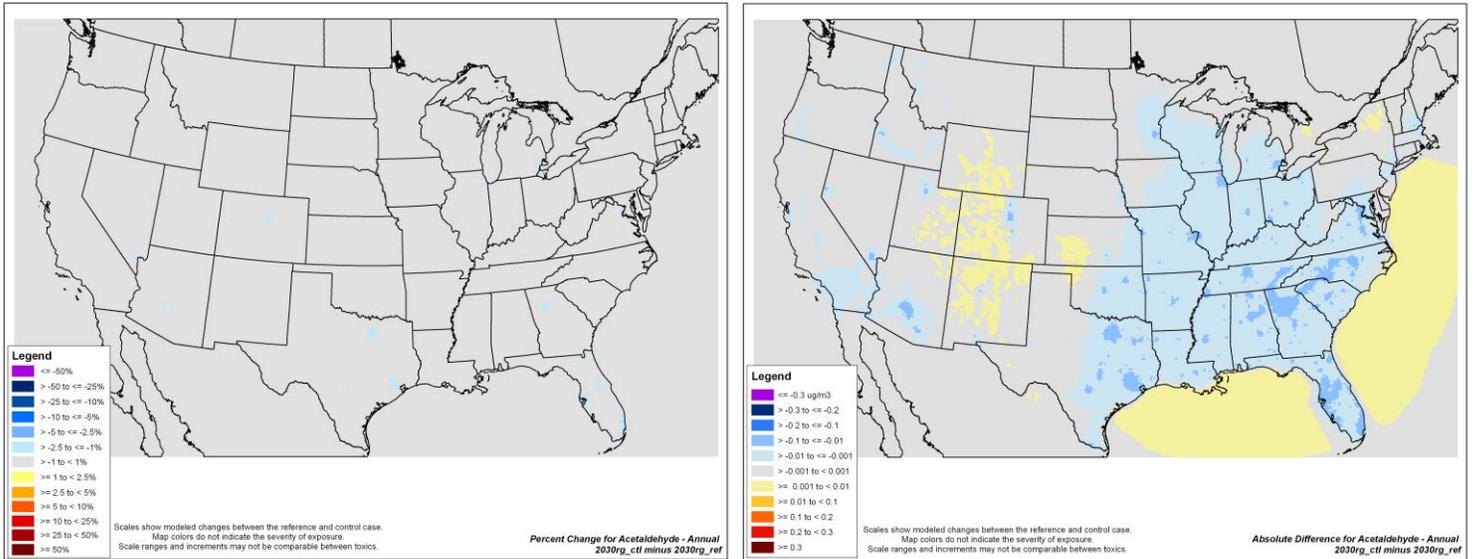
## Acetaldehyde

Our air quality modeling shows annual percent changes in ambient concentrations of acetaldehyde of generally less than 1 percent across the U.S., although the rule may decrease acetaldehyde concentrations in some urban areas by 1 to 2.5 percent in 2030 (Figure 7-40). Changes in ambient concentrations of acetaldehyde are generally in the range of  $0.01 \mu\text{g}/\text{m}^3$  to  $-0.01 \mu\text{g}/\text{m}^3$  with decreases happening in the more populated areas and increases happening in more rural areas (Figure 7-40).

The complex photochemistry associated with  $\text{NO}_x$  emissions and acetaldehyde formation appears to be the explanation for the split between increased rural concentrations and decreased urban concentrations. In the atmosphere, acetaldehyde precursors react with  $\text{NO}_x$  to form peroxyacetyl nitrate (PAN). Reducing  $\text{NO}_x$  allows acetaldehyde precursors to be available to form acetaldehyde instead. This phenomenon is more prevalent in rural areas where  $\text{NO}_x$  is low. The chemistry involved is further described by a recent study done by EPA's Office of Research and Development and Region 3 evaluating the complex effects of reducing multiple emissions on reactive air toxics and criteria pollutants.<sup>141</sup>



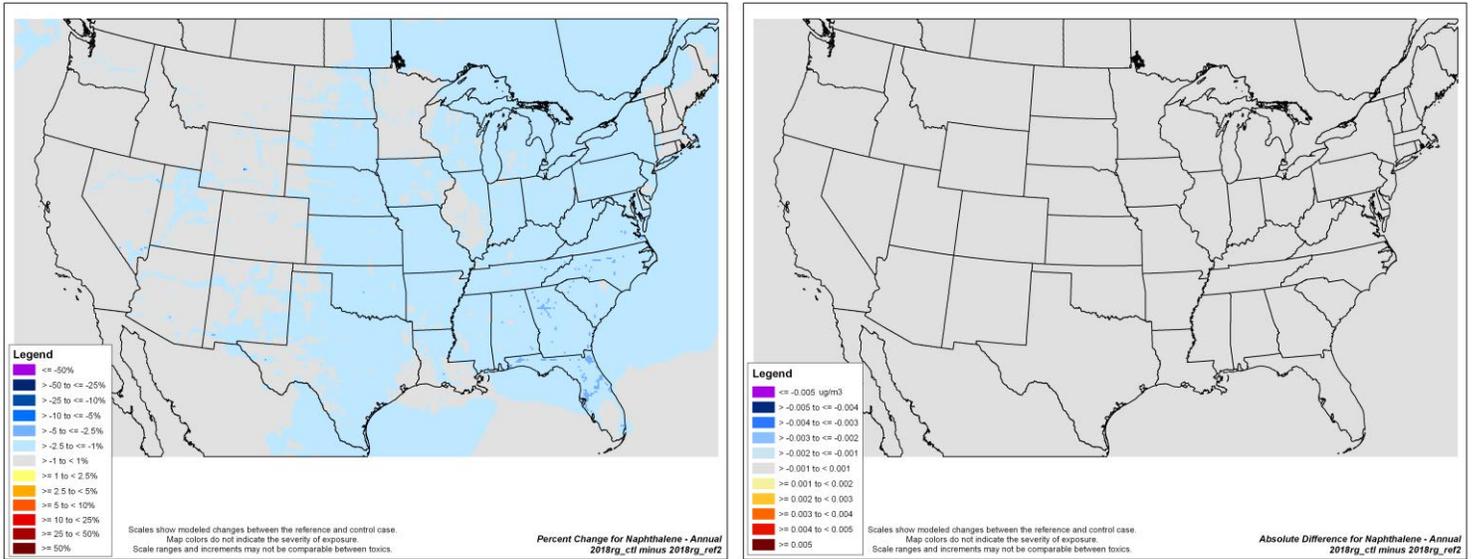
**Figure 7-40 Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



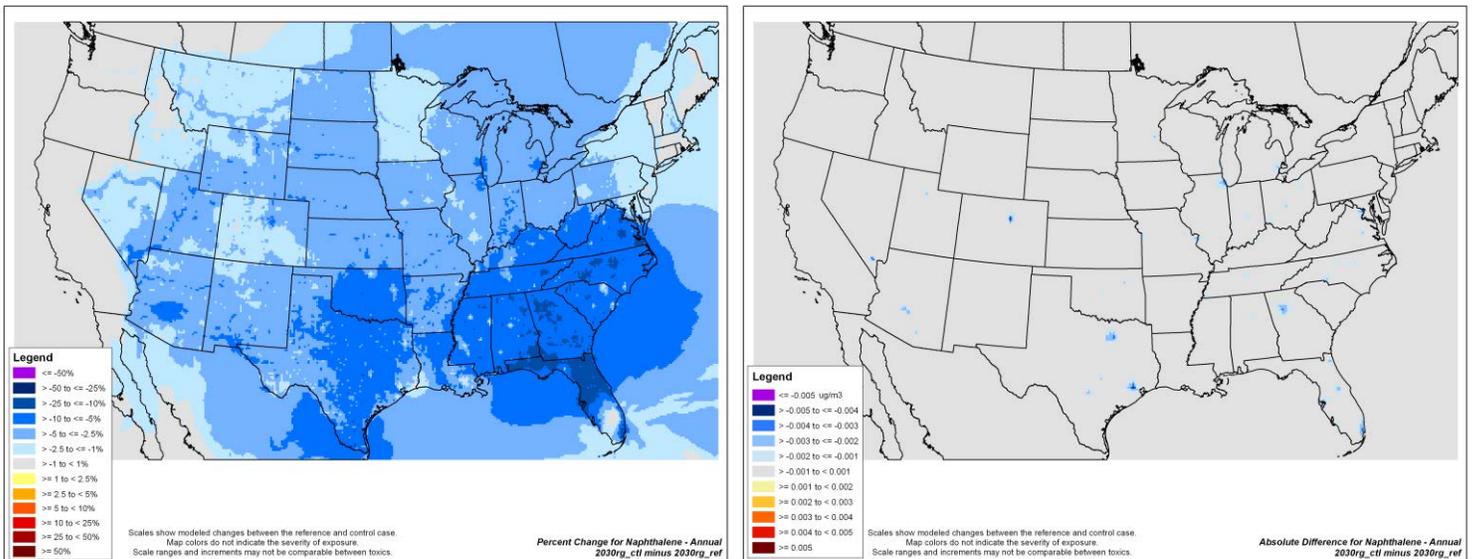
**Figure 7-41 Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Naphthalene

Our modeling projects reductions in naphthalene concentrations in 2018 and 2030. As shown in Figure 7-42, annual percent changes in ambient concentrations of naphthalene are between 1 and 2.5 percent across much of the country for 2018, with small decreases in absolute concentrations (less than  $0.001 \mu\text{g}/\text{m}^3$ ). In 2030, reductions of naphthalene concentrations generally range between 1 and 10 percent but are as high as 25 percent in some areas of the Southeast, with corresponding absolute decreases in urban areas of up to  $0.005 \mu\text{g}/\text{m}^3$  (Figure 7-43).



**Figure 7-42 Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



**Figure 7-43 Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

### Population Metrics

Although the reductions in ambient air toxics concentrations expected from the Tier 3 standards are generally small, they are projected to benefit the majority of the U.S. population. As shown in Table 7-51, over 75 percent of the total U.S. population is projected to experience a decrease in ambient benzene and 1,3-butadiene concentrations of at least 1 percent. Table 7-51 also shows that over 60 percent of the U.S. population is projected to experience at least a 1

percent decrease in ambient ethanol and acrolein concentrations, and over 35 percent would experience a similar decrease in ambient formaldehyde concentrations with the standards.

**Table 7-51 Percent of Total Population Experiencing Changes in Annual Ambient Concentrations of Toxic Pollutants in 2030 as a Result of the Standards**

Percent Change	Benzene	Acrolein	1,3-Butadiene	Formaldehyde	Ethanol	Acetaldehyde	Naphthalene
≤ -50							
> -50 to ≤ -25							
> -25 to ≤ -10	2.29%	0.75%	19.07%				10.74%
> -10 to ≤ -5	20.63%	12.72%	27.29%		5.39%		31.56%
> -5 to ≤ -2.5	27.50%	25.17%	15.37%	0.60%	24.08%		20.58%
> -2.5 to ≤ -1	28.60%	24.62%	18.33%	35.34%	34.10%	11.77%	14.98%
> -1 to < 1	20.97%	36.74%	19.93%	64.06%	36.43%	88.23%	22.14%
≥ 1 to < 2.5							
≥ 2.5 to < 5							
≥ 5 to < 10							
≥ 10 to < 25							
≥ 25 to < 50							
≥ 50							

Of note, the rule is expected to decrease population exposure to acrolein, which is currently a national risk driver for noncancer respiratory health effects as described in Section 7.2.5.4.1. Our modeling projects that acrolein concentrations would decrease to levels below the inhalation reference concentration for acrolein (0.02 µg/m<sup>3</sup>) for over 5 million people in 2030, meaning that as a result of the Tier 3 standards, 5 million fewer Americans will be exposed to ambient levels of acrolein high enough to present a potential for adverse health effects. The inhalation reference concentration for acrolein and other risk drivers is described in Section 6.1.5.6. In addition, the decrease in population exposure to the toxic compounds in Table 7-36 will decrease cancer risks that are described in Section 6.1.5.

#### 7.2.4.5 Visibility

As described in Section 6.2.1 of this RIA, PM also causes adverse visibility effects, and the EPA has set national ambient air quality standards (NAAQS) and regional haze rules to protect against visibility impairment. In this section we present information on current and model-projected future visibility levels at Mandatory Class I Federal Areas.

##### 7.2.4.5.1 Current Visibility Levels

Designated PM<sub>2.5</sub> nonattainment areas indicate that, as of December 5, 2013, over 84 million people live in nonattainment areas for the PM<sub>2.5</sub> NAAQS. Thus, at least these populations would likely be experiencing visibility impairment, as well as many thousands of

individuals who travel to these areas. In addition, while visibility trends have improved in Mandatory Class I Federal areas, these areas continue to suffer from visibility impairment.<sup>142</sup> Calculated from light extinction efficiencies from Trijonis et al. (1987, 1988), annual average visual range under natural conditions in the East is estimated to be 150 km ± 45 km (i.e., 65 to 120 miles) and 230 km ± 35 km (i.e., 120 to 165 miles) in the West.<sup>143,144,145</sup> In summary, visibility impairment is experienced throughout the U.S., in multi-state regions, urban areas, and remote Mandatory Class I Federal areas.

#### 7.2.4.5.2 Projected Visibility Levels

Air quality modeling conducted for the final action was used to project visibility conditions in 137 Mandatory Class I Federal areas across the U.S. The results show that in 2030 all the modeled areas would continue to have annual average deciview levels above background and the rule would improve visibility in all these areas.<sup>ii</sup> The average visibility on the 20 percent worst days at all modeled Mandatory Class I Federal areas is projected to improve by 0.02 deciviews, or 0.16 percent, in 2030. The greatest improvement in visibilities will be seen in Craters of the Moon National Monument, where visibility is projected to improve by 0.7 percent (0.09 DV) in 2030 due to the standards. Table 7-52 contains the full visibility results from 2030 for the 137 analyzed areas.

**Table 7-52 Visibility Levels (in Deciviews) for Mandatory Class I Federal Areas on the 20 Percent Worst Days with and without this Rule**

Class 1 Area (20% worst days)	State	2007 Baseline Visibility (dv) <sup>a</sup>	2018 Reference	2018 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Sipsey Wilderness	AL	28.32	20.59	20.55	20.43	20.37	10.99
Upper Buffalo Wilderness	AR	25.86	20.01	19.98	19.93	19.88	11.57
Chiricahua NM	AZ	12.22	11.82	11.82	12.38	12.37	7.20
Chiricahua Wilderness	AZ	12.22	11.83	11.82	12.38	12.37	7.20
Galiuro Wilderness	AZ	12.22	11.99	11.98	12.41	12.40	7.20
Grand Canyon NP	AZ	11.97	11.21	11.20	11.31	11.30	7.04
Mazatzal Wilderness	AZ	13.40	12.65	12.65	12.88	12.85	6.68
Mount Baldy Wilderness	AZ	11.79	10.98	10.98	11.24	11.22	6.24
Petrified Forest NP	AZ	13.02	12.24	12.23	12.37	12.35	6.49
Pine Mountain Wilderness	AZ	13.40	12.69	12.69	12.93	12.91	6.68
Saguaro NM	AZ	13.63	13.02	13.00	13.04	12.99	6.46
Superstition Wilderness	AZ	13.81	13.18	13.18	13.38	13.34	6.54

<sup>ii</sup> The level of visibility impairment in an area is based on the light-extinction coefficient and a unitless visibility index, called a “deciview”, which is used in the valuation of visibility. The deciview metric provides a 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.

<b>Class 1 Area (20% worst days)</b>	<b>State</b>	<b>2007 Baseline Visibility (dv)<sup>a</sup></b>	<b>2018 Reference</b>	<b>2018 Tier 3 Control</b>	<b>2030 Reference</b>	<b>2030 Tier 3 Control</b>	<b>Natural Background</b>
Sycamore Canyon Wilderness	AZ	15.18	14.94	14.94	15.03	15.02	6.65
Agua Tibia Wilderness	CA	20.92	17.67	17.66	16.85	16.85	7.64
Ansel Adams Wilderness (Minarets)	CA	15.72	14.57	14.57	14.38	14.38	7.12
Caribou Wilderness	CA	15.99	15.54	15.54	15.48	15.48	7.31
Cucamonga Wilderness	CA	18.03	15.37	15.36	14.91	14.90	6.99
Desolation Wilderness	CA	13.62	12.89	12.89	12.76	12.75	6.05
Dome Land Wilderness	CA	19.23	17.89	17.89	17.60	17.60	7.46
Emigrant Wilderness	CA	16.87	15.84	15.84	15.67	15.66	7.64
Hoover Wilderness	CA	12.19	11.49	11.48	11.41	11.41	7.71
John Muir Wilderness	CA	15.72	14.76	14.76	14.60	14.60	7.12
Joshua Tree NM	CA	17.83	15.75	15.75	15.33	15.32	7.19
Kaiser Wilderness	CA	15.72	14.80	14.80	14.59	14.59	7.12
Kings Canyon NP	CA	23.39	21.56	21.55	21.06	21.05	7.70
Lassen Volcanic NP	CA	15.99	15.52	15.52	15.45	15.45	7.31
Lava Beds NM	CA	14.17	13.78	13.78	13.68	13.67	7.85
Marble Mountain Wilderness	CA	17.34	17.02	17.01	16.91	16.91	7.90
Mokelumne Wilderness	CA	13.62	12.88	12.88	12.75	12.75	6.05
Pinnacles NM	CA	18.37	16.44	16.43	16.05	16.05	7.99
Point Reyes NS	CA	22.03	21.04	21.03	20.71	20.71	15.77
Redwood NP	CA	19.14	18.72	18.70	18.43	18.42	13.91
San Gabriel Wilderness	CA	18.03	15.71	15.71	15.31	15.30	6.99
San Geronio Wilderness	CA	20.48	17.68	17.68	16.94	16.93	7.30
San Jacinto Wilderness	CA	20.48	17.76	17.76	16.95	16.95	7.30
San Rafael Wilderness	CA	19.20	17.46	17.46	17.10	17.10	7.57
Sequoia NP	CA	23.39	21.28	21.28	20.74	20.73	7.70
South Warner Wilderness	CA	14.17	13.60	13.60	13.49	13.49	7.85
Thousand Lakes Wilderness	CA	15.99	15.53	15.53	15.46	15.45	7.31
Ventana Wilderness	CA	18.37	16.79	16.79	16.50	16.49	7.99
Yolla Bolly Middle Eel Wilderness	CA	17.34	17.06	17.06	16.99	16.99	7.90
Yosemite NP	CA	16.87	15.98	15.98	15.85	15.84	7.64
Black Canyon of the Gunnison NM	CO	10.04	9.21	9.20	9.26	9.24	6.21
Eagles Nest Wilderness	CO	8.94	7.98	7.97	7.97	7.93	6.06
Flat Tops Wilderness	CO	8.94	8.26	8.26	8.28	8.27	6.06
Great Sand Dunes NM	CO	11.44	10.57	10.56	10.59	10.57	6.66

<b>Class 1 Area (20% worst days)</b>	<b>State</b>	<b>2007 Baseline Visibility (dv)<sup>a</sup></b>	<b>2018 Reference</b>	<b>2018 Tier 3 Control</b>	<b>2030 Reference</b>	<b>2030 Tier 3 Control</b>	<b>Natural Background</b>
La Garita Wilderness	CO	10.04	9.36	9.35	9.44	9.43	6.21
Maroon Bells-Snowmass Wilderness	CO	8.94	8.15	8.14	8.18	8.17	6.06
Mesa Verde NP	CO	11.28	10.48	10.47	10.57	10.55	6.81
Mount Zirkel Wilderness	CO	9.72	9.12	9.11	9.10	9.08	6.08
Rawah Wilderness	CO	9.72	8.92	8.91	8.88	8.86	6.08
Rocky Mountain NP	CO	12.62	11.66	11.64	11.55	11.50	7.15
Weminuche Wilderness	CO	10.04	9.38	9.37	9.45	9.44	6.21
West Elk Wilderness	CO	8.94	8.12	8.11	8.18	8.16	6.06
Chassahowitzka	FL	23.68	18.63	18.59	18.38	18.31	11.03
Everglades NP	FL	20.41	17.43	17.42	17.28	17.25	12.15
St. Marks	FL	25.58	20.07	20.04	19.86	19.81	11.67
Cohutta Wilderness	GA	28.01	18.77	18.73	18.59	18.52	10.78
Okefenokee	GA	26.00	21.32	21.30	21.33	21.31	11.44
Wolf Island	GA	26.00	20.53	20.51	20.45	20.41	11.44
Craters of the Moon NM	ID	13.63	12.91	12.86	12.63	12.54	7.53
Sawtooth Wilderness	ID	14.76	14.61	14.61	14.58	14.57	6.42
Mammoth Cave NP	KY	30.68	21.59	21.55	21.47	21.41	11.08
Acadia NP	ME	21.45	17.41	17.38	17.22	17.19	12.43
Moosehorn	ME	19.92	16.23	16.21	16.14	16.12	12.01
Roosevelt Campobello International Park	ME	19.92	16.45	16.43	16.34	16.32	12.01
Isle Royale NP	MI	21.76	18.49	18.45	18.21	18.13	12.37
Seney	MI	24.21	20.30	20.26	20.17	20.09	12.65
Boundary Waters Canoe Area	MN	20.05	17.05	17.01	16.77	16.70	11.61
Voyageurs NP	MN	19.78	17.60	17.57	17.35	17.29	12.06
Hercules-Glades Wilderness	MO	26.05	20.36	20.32	20.21	20.14	11.30
Mingo	MO	27.08	21.09	21.06	20.88	20.83	11.62
Bob Marshall Wilderness	MT	15.32	15.13	15.13	15.06	15.05	7.73
Cabinet Mountains Wilderness	MT	13.47	13.16	13.15	13.01	13.00	7.52
Glacier NP	MT	18.70	18.39	18.38	18.23	18.21	9.18
Medicine Lake	MT	18.02	16.67	16.66	16.47	16.45	7.89
Mission Mountains Wilderness	MT	15.32	15.08	15.07	14.98	14.97	7.73
Red Rock Lakes	MT	11.53	11.20	11.19	11.13	11.11	6.44
Scapegoat Wilderness	MT	15.32	15.17	15.17	15.12	15.11	7.73
UL Bend	MT	14.86	14.41	14.41	14.37	14.36	8.16

<b>Class 1 Area (20% worst days)</b>	<b>State</b>	<b>2007 Baseline Visibility (dv)<sup>a</sup></b>	<b>2018 Reference</b>	<b>2018 Tier 3 Control</b>	<b>2030 Reference</b>	<b>2030 Tier 3 Control</b>	<b>Natural Background</b>
Linville Gorge Wilderness	NC	27.39	18.40	18.37	18.33	18.28	11.22
Shining Rock Wilderness	NC	26.60	18.17	18.13	18.04	17.98	11.47
Lostwood	ND	19.56	18.58	18.57	18.45	18.44	8.00
Great Gulf Wilderness	NH	20.19	15.15	15.13	15.08	15.05	11.99
Presidential Range-Dry River Wilderness	NH	20.19	15.05	15.03	14.97	14.94	11.99
Brigantine	NJ	27.32	20.66	20.63	20.59	20.55	12.24
Bandelier NM	NM	11.84	10.81	10.79	10.89	10.85	6.26
Bosque del Apache	NM	13.40	12.32	12.30	12.54	12.50	6.73
Carlsbad Caverns NP	NM	15.85	15.19	15.18	15.88	15.86	6.65
Gila Wilderness	NM	12.49	11.94	11.94	12.40	12.39	6.66
Pecos Wilderness	NM	9.13	8.19	8.18	8.34	8.32	6.08
San Pedro Parks Wilderness	NM	9.89	9.06	9.05	9.28	9.27	5.72
Wheeler Peak Wilderness	NM	9.13	8.13	8.13	8.25	8.23	6.08
White Mountain Wilderness	NM	13.20	12.34	12.33	12.74	12.73	6.80
Jarbidge Wilderness	NV	12.42	12.17	12.16	12.13	12.12	7.87
Wichita Mountains	OK	22.97	19.63	19.60	19.52	19.45	7.53
Crater Lake NP	OR	13.79	13.33	13.32	13.22	13.22	7.62
Diamond Peak Wilderness	OR	13.79	13.23	13.22	13.07	13.07	7.62
Eagle Cap Wilderness	OR	16.23	15.61	15.59	15.22	15.20	8.92
Gearhart Mountain Wilderness	OR	13.79	13.35	13.35	13.27	13.27	7.62
Hells Canyon Wilderness	OR	18.15	17.54	17.50	17.20	17.16	8.32
Kalmiopsis Wilderness	OR	16.45	15.82	15.81	15.63	15.62	9.44
Mount Hood Wilderness	OR	13.72	12.71	12.68	12.25	12.23	8.43
Mount Jefferson Wilderness	OR	16.18	15.58	15.57	15.33	15.31	8.79
Mount Washington Wilderness	OR	16.18	15.57	15.55	15.32	15.31	8.79
Mountain Lakes Wilderness	OR	13.79	13.28	13.28	13.16	13.16	7.62
Strawberry Mountain Wilderness	OR	16.23	15.37	15.34	15.00	14.97	8.92
Three Sisters Wilderness	OR	16.18	15.63	15.61	15.45	15.44	8.79
Cape Romain	SC	26.45	19.75	19.72	19.61	19.56	12.12
Badlands NP	SD	16.55	15.25	15.24	15.19	15.17	8.06
Wind Cave NP	SD	15.50	14.41	14.39	14.26	14.24	7.71
Great Smoky Mountains NP	TN	28.50	19.57	19.52	19.44	19.38	11.24

<b>Class 1 Area (20% worst days)</b>	<b>State</b>	<b>2007 Baseline Visibility (dv)<sup>a</sup></b>	<b>2018 Reference</b>	<b>2018 Tier 3 Control</b>	<b>2030 Reference</b>	<b>2030 Tier 3 Control</b>	<b>Natural Background</b>
Joyce-Kilmer-Slickrock Wilderness	TN	28.50	19.65	19.61	19.52	19.46	11.24
Big Bend NP	TX	16.69	16.39	16.38	17.32	17.31	7.16
Guadalupe Mountains NP	TX	15.85	15.23	15.22	15.94	15.92	6.65
Arches NP	UT	11.02	10.33	10.32	10.30	10.27	6.43
Bryce Canyon NP	UT	11.88	11.40	11.40	11.39	11.37	6.80
Canyonlands NP	UT	11.02	10.50	10.48	10.57	10.55	6.43
Capitol Reef NP	UT	11.30	10.73	10.72	10.74	10.72	6.03
James River Face Wilderness	VA	27.29	19.05	19.02	18.89	18.83	11.13
Shenandoah NP	VA	27.26	17.67	17.63	17.60	17.54	11.35
Lye Brook Wilderness	VT	23.01	16.74	16.70	16.58	16.53	11.73
Alpine Lake Wilderness	WA	16.09	14.87	14.84	14.22	14.17	8.43
Glacier Peak Wilderness	WA	13.72	12.78	12.77	12.56	12.54	8.39
Goat Rocks Wilderness	WA	12.66	11.92	11.90	11.66	11.64	8.35
Mount Adams Wilderness	WA	12.66	12.04	12.02	11.77	11.75	8.35
Mount Rainier NP	WA	16.38	15.53	15.52	15.25	15.24	8.54
North Cascades NP	WA	13.72	12.87	12.86	12.71	12.70	8.01
Olympic NP	WA	15.20	14.30	14.28	13.94	13.92	8.44
Pasayten Wilderness	WA	14.09	13.51	13.50	13.26	13.25	8.25
Dolly Sods Wilderness	WV	27.55	17.97	17.94	17.99	17.95	10.39
Otter Creek Wilderness	WV	27.55	18.11	18.07	18.08	18.04	10.39
Bridger Wilderness	WY	10.68	10.23	10.22	10.20	10.19	6.45
Fitzpatrick Wilderness	WY	10.68	10.21	10.21	10.18	10.17	6.45
Grand Teton NP	WY	11.53	11.14	11.13	11.09	11.07	6.44
Teton Wilderness	WY	11.53	11.18	11.18	11.15	11.14	6.44
Yellowstone NP	WY	11.53	11.26	11.26	11.23	11.22	6.44

<sup>a</sup> The level of visibility impairment in an area is based on the light-extinction coefficient and a unitless visibility index, called a “deciview”, which is used in the valuation of visibility. The deciview metric provides a 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.

#### 7.2.4.6 Deposition of Nitrogen and Sulfur

As described in Section 6.2.2 of this RIA, deposition of nitrogen and sulfur can cause adverse environmental effects. In this section we present information on current and model-projected future nitrogen and sulfur deposition levels.

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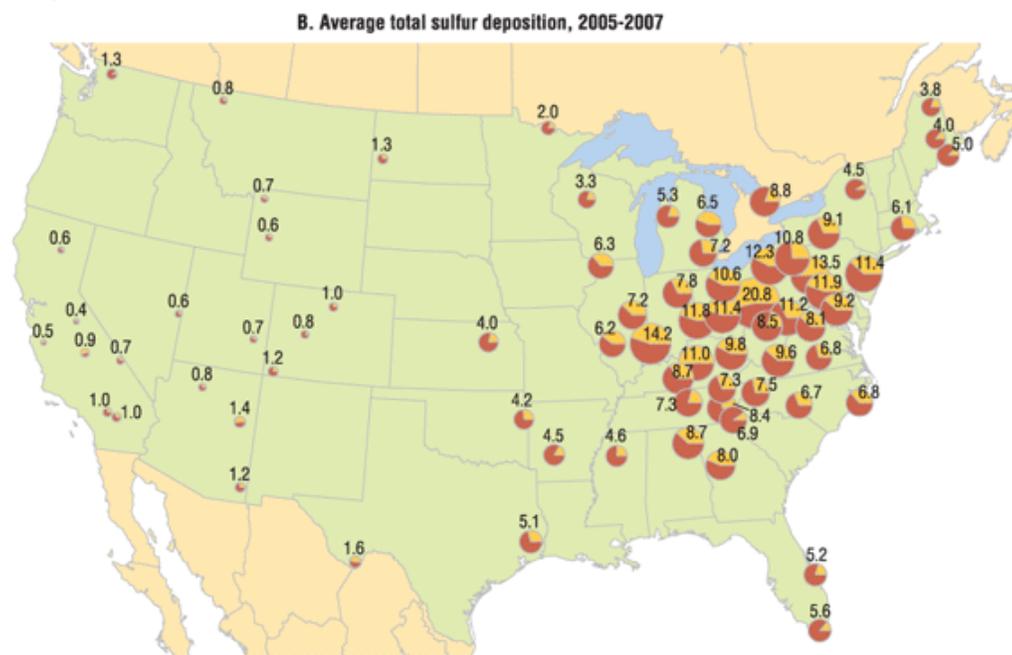
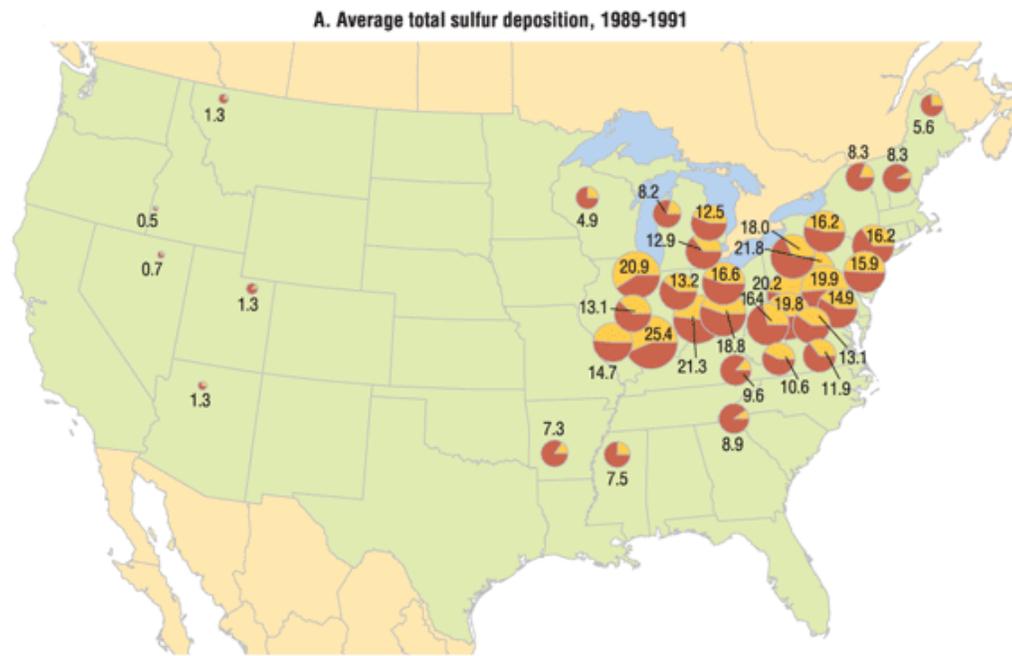
#### 7.2.4.6.1 Current Levels of Nitrogen and Sulfur Deposition

Over the past two decades, the EPA has undertaken numerous efforts to reduce nitrogen and sulfur deposition across the U.S. Analyses of long-term monitoring data for the U.S. show that deposition of both nitrogen and sulfur compounds has decreased over the last 17 years. The data show that reductions were more substantial for sulfur compounds than for nitrogen compounds. In the eastern U.S., where data are most abundant, total sulfur deposition decreased by about 44 percent between 1990 and 2007, while total nitrogen deposition decreased by 25 percent over the same time frame.<sup>JJ</sup> These numbers are generated by the U.S. national monitoring network and they likely underestimate nitrogen deposition because neither ammonia nor organic nitrogen is measured. Although total nitrogen and sulfur deposition has decreased over time, many areas continue to be negatively impacted by deposition. Deposition of inorganic nitrogen and sulfur species routinely measured in the U.S. between 2005 and 2007 were as high as 9.6 kilograms of nitrogen per hectare (kg N/ha) averaged over three years and 20.8 kilograms of sulfur per hectare (kg S/ha) averaged over three years.<sup>KK</sup>

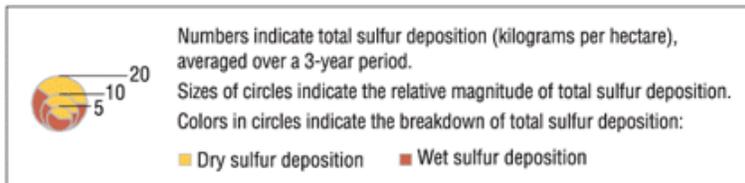
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<sup>JJ</sup> U.S. EPA. (2012). U.S. EPA's Report on the Environment. Data accessed online February 15, 2012 at: <http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewPDF&ch=46&lShowInd=0&subtop=341&lv=list.listByChapter&r=216610> and contained in Docket EPA-HQ-OAR-2011-0135.

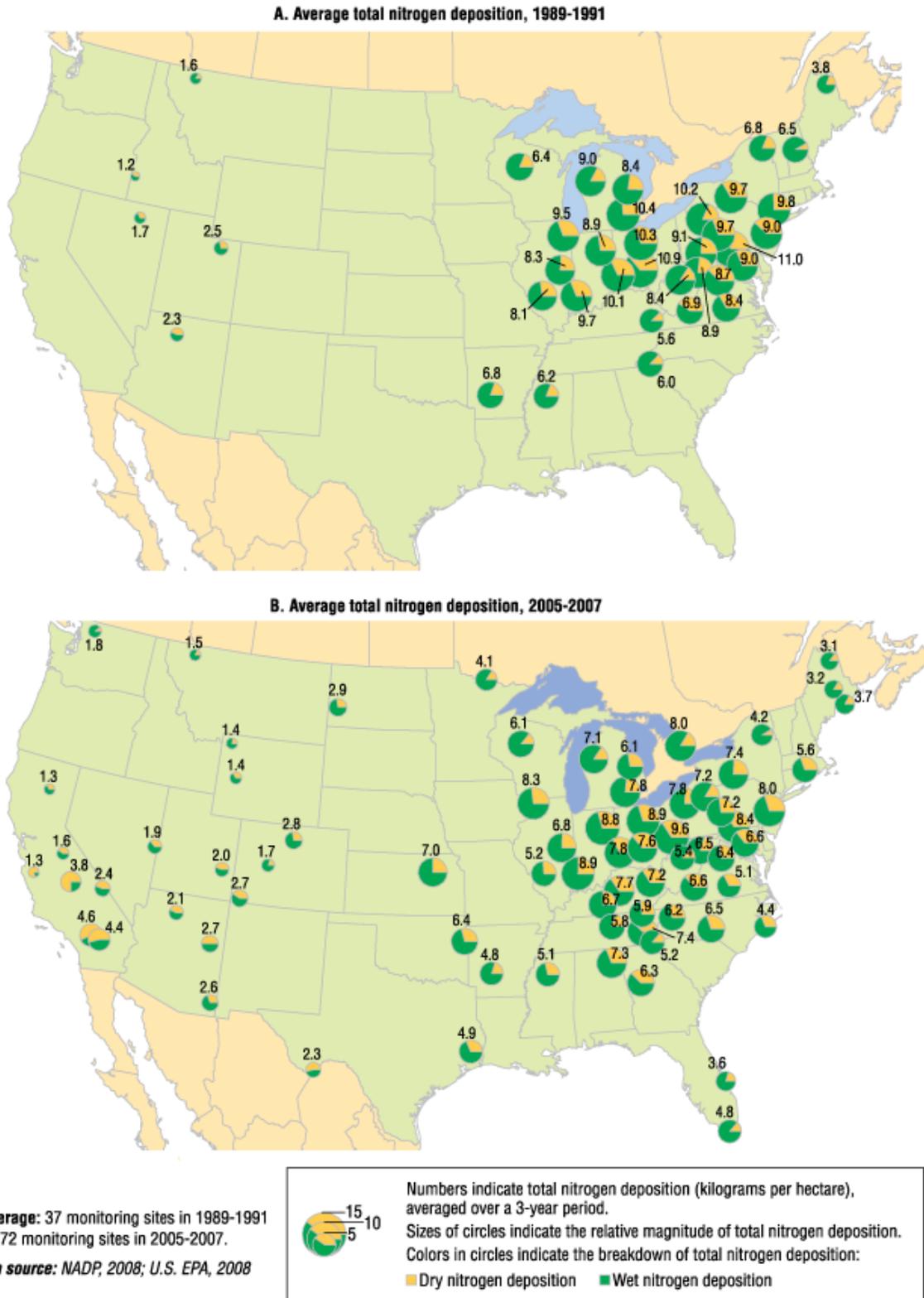
<sup>KK</sup> U.S. EPA. (2012). U.S. EPA's Report on the Environment. Data accessed online February 15, 2012 at: <http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewPDF&ch=46&lShowInd=0&subtop=341&lv=list.listByChapter&r=216610> and contained in Docket EPA-HQ-OAR-2011-0135.



<sup>a</sup>Coverage: 37 monitoring sites in 1989-1991 and 72 monitoring sites in 2005-2007.  
 Data source: NADP, 2008; U.S. EPA, 2008



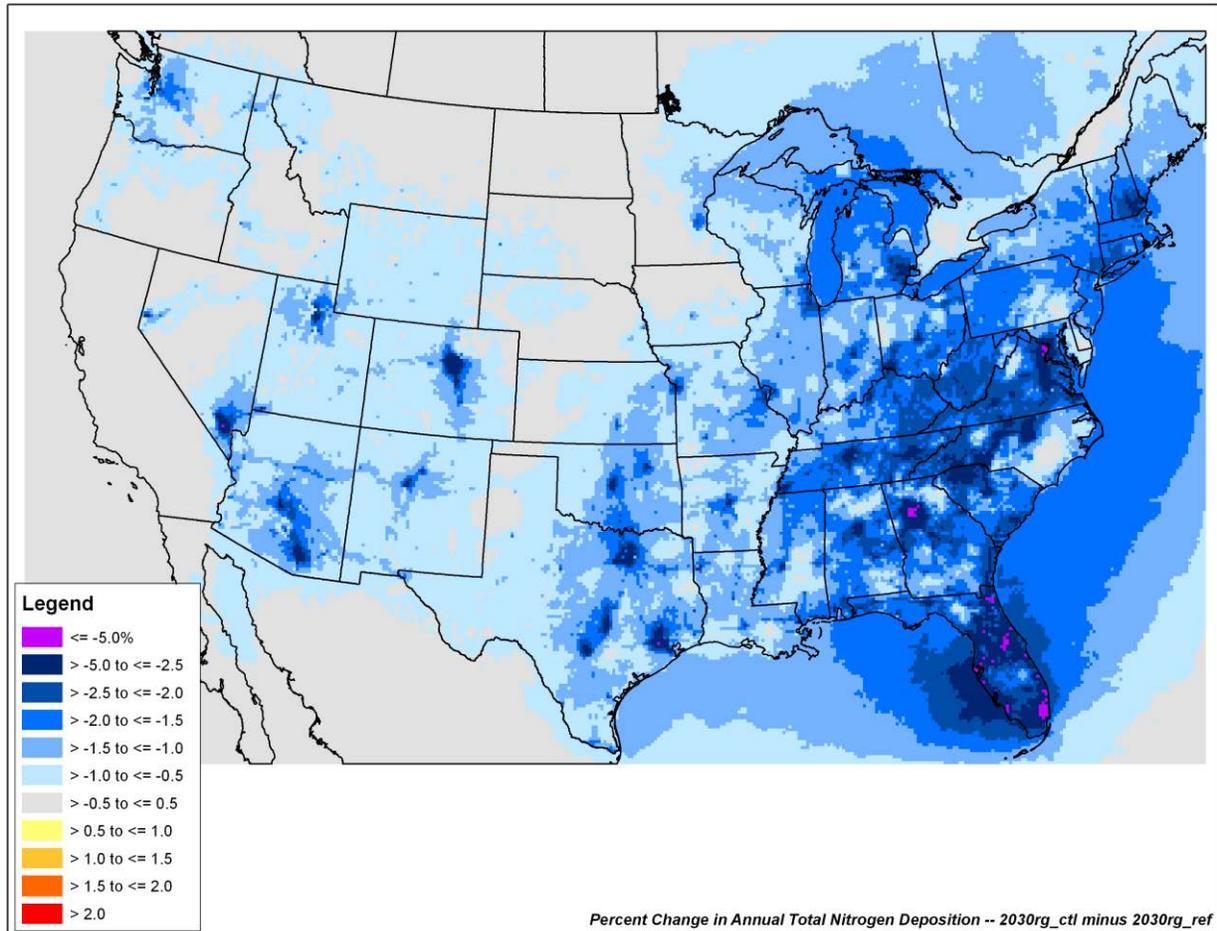
**Figure 7-44 Total Sulfur Deposition in the Contiguous U.S., 1989-1991 and 2005 -2007**



**Figure 7-45 Total Nitrogen Deposition in the Contiguous U.S., 1989-1991 and 2005-2007**

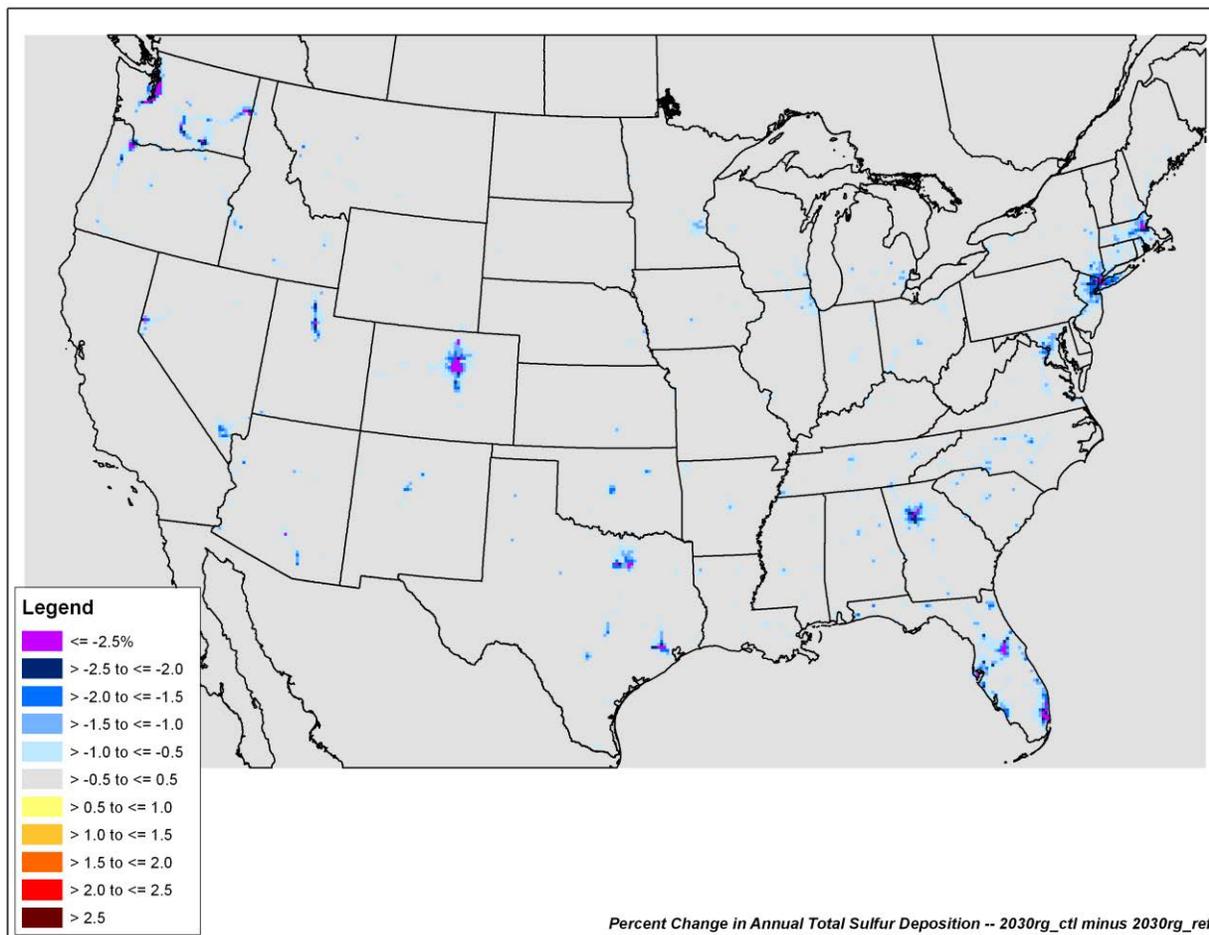
#### 7.2.4.6.2 Projected Levels of Nitrogen and Sulfur Deposition

Our air quality modeling projects decreases in both nitrogen and sulfur deposition due to this rule. Figure 7-46 shows that for nitrogen deposition by 2030 the standards would result in annual percent decreases of more than 2.5 percent in most urban areas with decreases of more than 5 percent in urban areas in Nevada, Florida, Georgia and Virginia. In addition, smaller decreases, in the 1 to 1.5 percent range, would occur over much of the rest of the country.



**Figure 7-46 Percent Change in Annual Total Nitrogen Deposition over the U.S. Modeling Domain as a Result of the Tier 3 Standards**

Figure 7-47 shows that for sulfur deposition the standards will result in annual percent decreases of more than 2 percent in some urban areas in 2030. The decreases in sulfur deposition are likely due to projected reductions in the sulfur level in fuel. Minimal changes in sulfur deposition, ranging from decreases of less than 0.5 percent to no change, are projected for the rest of the country.



**Figure 7-47 Percent Change in Annual Total Sulfur Deposition over the U.S. Modeling Domain as a Result of the Tier 3 Standards**

### 7.3 Greenhouse Gas Emission Impacts

Reductions in nitrous oxide (N<sub>2</sub>O) emissions and methane (CH<sub>4</sub>) emissions, both potent greenhouse gas emissions (with global warming potentials 298 and 25 times greater than CO<sub>2</sub>, respectively),<sup>LL</sup> are projected for gasoline cars and trucks due to the sulfur and tailpipe standards. These projections are based on studies that provide a basis for reductions in N<sub>2</sub>O and CH<sub>4</sub> emissions due to the Tier 3 sulfur and vehicle standards. With respect to sulfur, a study published in 2004 by the University of California at Riverside found a 29 percent reduction in N<sub>2</sub>O emissions over the FTP and a 50 percent reduction over the US06 when sulfur was reduced from 30 to 5 ppm.<sup>146</sup> EPA's sulfur study, detailed in Section 7.1.3.4.1, found close to a 30 percent reduction in CH<sub>4</sub> emissions over the FTP when sulfur was reduced from 28 to 5 ppm (the EPA study did not measure N<sub>2</sub>O emissions).

<sup>LL</sup> The global warming potentials (GWP) used in this rule are consistent with the 100-year time frame values in the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4). N<sub>2</sub>O has a 100-year GWP of 298 and CH<sub>4</sub> has a 100-year GWP of 25 according to the 2007 IPCC AR4.

Several studies have also established that reductions in tailpipe standards for NO<sub>x</sub> and HC result in reductions in N<sub>2</sub>O and CH<sub>4</sub>, respectively. N<sub>2</sub>O is unique in that it is not formed during combustion, but in the catalyst, during catalyst warm-up, before the catalyst reaches the temperatures required for full effectiveness (known as “light-off”). Improvements to catalyst technology required to meet lower emission standards reduce the time required for the catalyst to reach light-off, which reduces the window of N<sub>2</sub>O formation. Studies conducted by EPA and Environment Canada found that N<sub>2</sub>O emissions are lower on vehicles certified to more stringent NO<sub>x</sub> emission standards.<sup>147,148</sup> A study by Meffert, et al. established a strong correlation between improvements in NO<sub>x</sub> catalytic conversion efficiency and reductions in N<sub>2</sub>O emissions.<sup>149</sup> A study published by Behrentz, et al. in 2004 examined the relationship between N<sub>2</sub>O and NO<sub>x</sub> from data collected by the California Air Resources Board (CARB) on 37 passenger cars and light-duty trucks ranging from the mid-1980s through early 2000’s Low Emission Vehicle (LEV) technology.<sup>150</sup> Another study by Winer, et al (2005) tested 134 light-duty vehicles, including passenger cars and light-duty trucks, as part of the CARB’s vehicle surveillance program, varying from Tier 0 to ULEV in emissions standards.<sup>151</sup> These two studies reported N<sub>2</sub>O:NO<sub>x</sub> ratios of 0.06 and 0.095, respectively, and supported the application of N<sub>2</sub>O:NO<sub>x</sub> ratios to NO<sub>x</sub> emissions as a reasonable method for estimating N<sub>2</sub>O emission inventories. Meszler, et al. subsequently analyzed the dataset by Behrentz and found that for vehicles equipped with more modern controls, N<sub>2</sub>O emissions increased with vehicle mileage, suggesting deterioration in N<sub>2</sub>O emissions as vehicles age.<sup>152</sup>

The Meszler and Environment Canada studies cited above also established that vehicles certified to more stringent HC standards emit less CH<sub>4</sub>, even though HC standards from Tier 1 and later do not include methane in the regulated standards. This trend is also reflected in the MOVES model, based on analysis of correlation between CH<sub>4</sub> and HC emissions. MOVES estimates methane as a function of total HC emissions, so the CH<sub>4</sub> emission inventories account for effects such as deterioration, temperature, aggressive driving, and reductions in tailpipe emission standards. Because of this, CH<sub>4</sub> reductions from the Tier 3 program can be estimated directly by MOVES, as a function of reductions in HC from the sulfur and vehicle standards (although this will provide a conservative estimate of reductions, as the percent reduction in CH<sub>4</sub> from using low sulfur fuel is about double that for total HC (Table 7-25)). The estimated methane reductions from Tier 3, using the 100-year global warming potential of 25 according to the 2007 IPCC AR4, are shown in Table 7-53.

**Table 7-53 Estimated Reduction in CH<sub>4</sub> from Tier 3 Program (MMTCO<sub>2</sub>eq)**

	<b>2018</b>	<b>2030</b>
Reference case onroad mobile emissions	1.5	1.2
Control case onroad mobile emissions	1.4	0.9
<b>Reduction</b>	<b>0.1</b>	<b>0.3</b>

In contrast, MOVES N<sub>2</sub>O emissions are based directly on a limited sample of N<sub>2</sub>O emission data, rather than linking N<sub>2</sub>O emissions to NO<sub>x</sub> emissions as suggested by Winer and Behrentz; as a result, the model does not estimate potential N<sub>2</sub>O reduction concurrent with the Tier 3 program. Because of this, the MOVES-based inventories are significantly lower than

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inventories that take into account the N<sub>2</sub>O:NO<sub>x</sub> link, because they do not account for the factors affecting light-duty NO<sub>x</sub> emissions, such as deterioration, aggressive driving, and lower NO<sub>x</sub> standards.

In an effort to estimate the N<sub>2</sub>O inventory accounting for the factors that affect N<sub>2</sub>O emissions, we analyzed the data collected by CARB from 2000 to 2007, as a part of CARB's vehicle surveillance program. The data described in Winer and Behrentz were also collected as a part of the same program. However, the data we analyzed, available in the docket,<sup>153</sup> is the most comprehensive since it included additional tests that CARB collected since the studies by Winer and Behrentz. A regression analysis was performed to examine the relationship between N<sub>2</sub>O and NO<sub>x</sub>, and the resulting regression model correlating N<sub>2</sub>O emissions to NO<sub>x</sub> emissions is shown in Equation 7-4. The details of the regression analysis are documented in a separate memorandum to the Tier 3 docket.<sup>154</sup>

$$N_2O = e^{(-3.12854 + 0.62825 (\ln(NO_x)))}$$

**Equation 7-4 Regression Model Correlating N<sub>2</sub>O Emissions to NO<sub>x</sub> Emissions**

The N<sub>2</sub>O reductions due to Tier 3 vehicle and sulfur standards are estimated by employing two different methodologies, resulting in a range of reductions. The first method applies the relationship between N<sub>2</sub>O and NO<sub>x</sub> from the regression model in Equation 7-4 to NO<sub>x</sub> inventories from both Tier 3 and pre-Tier 3 vehicles. The second method applies the regression of N<sub>2</sub>O and NO<sub>x</sub> only to Tier 3 fleet (2017 and later model year vehicles) and applies the percent reduction in N<sub>2</sub>O from the UC Riverside study to MOVES inventory estimates to pre-Tier 3 vehicles. These two methods are outlined in Table 7-54, along with the range of reductions that result.

**Table 7-54 Estimated Reduction in N<sub>2</sub>O from the Tier 3 Program**

	<b>2018</b>	<b>2030</b>
<b>Reduction from Tier 3 fleet</b>		
NO <sub>x</sub> reduction from Tier 3 fleet due to vehicle and sulfur standards (U.S. Short Tons)	21,934	272,185
N <sub>2</sub> O reduction based on the regression (MMTCO <sub>2</sub> eq <sup>a</sup> )	0.3	3.5
<b>Reduction from pre-Tier 3 fleet</b>		
<i><b>Method 1</b></i>		
Reference case onroad gasoline NO <sub>x</sub> emissions (U.S. Short Tons)	2,599,284	377,811
Reference case onroad gasoline N <sub>2</sub> O emissions based on the regression (MMTCO <sub>2</sub> eq <sup>a</sup> )	31.6	5.0
Reduction from pre-Tier 3 fleet due to sulfur standard (U.S. Short Tons)	242,434	56,324
N <sub>2</sub> O reduction based on the regression (MMTCO <sub>2</sub> eq <sup>a</sup> )	1.9	0.5
<i><b>Method 2</b></i>		
U.S. onroad gasoline N <sub>2</sub> O emissions from pre-Tier 3 fleet using MOVES (MMTCO <sub>2</sub> eq)	8.9	1.5
Percent reduction in N <sub>2</sub> O going from 30 to 10 ppm	23% <sup>b</sup>	23%
N <sub>2</sub> O reduction (MMTCO <sub>2</sub> eq)	1.9	0.3
<b>Total Range of N<sub>2</sub>O Reduction (MMTCO<sub>2</sub>eq)</b>	<b>2.2</b>	<b>3.8-4.0</b>

<sup>a</sup> Using GWP of 298

<sup>b</sup> 29 percent from 25ppm sulfur reduction in UC Riverside study scaled to 20 ppm reduction

The estimated N<sub>2</sub>O reduction is 2.2 million metric tons of carbon dioxide equivalent (MMTCO<sub>2</sub>eq) in 2018, growing to a range between 3.8 and 4.0 MMTCO<sub>2</sub>eq in 2030. For 2018, there was an agreement between the two methodologies described above, resulting in a single estimate. Summing the results from Table 7-53 and Table 7-54, the total GHG reductions from the Tier 3 rule is 2.3 million metric tons of carbon dioxide equivalent (MMTCO<sub>2</sub>eq) in 2018, growing to a range between 4.1 and 4.3 MMTCO<sub>2</sub>eq in 2030.

These reductions will be offset to some degree by CO<sub>2</sub> emissions associated with higher energy use required in the process of removing sulfur within the refinery. As an extension of our refinery-by-refinery cost modeling, we calculated the CO<sub>2</sub> emission impacts of Tier 3 gasoline sulfur control. We estimated refinery-specific changes in process energy and then applied emission factors that correspond to those changes, on a refinery-by-refinery basis. As described in Chapter 4.5 of the RIA, the results showed an increase of up to 1.9 MMTCO<sub>2</sub>e in 2018 and 1.6 MMTCO<sub>2</sub>e in 2030 for all U.S. refineries complying with the lower sulfur standards assuming that the sulfur standards are fully phased-in. In 2018, the combined impact of CH<sub>4</sub> and N<sub>2</sub>O emission reductions from the vehicles and CO<sub>2</sub> emission increases from the refineries shows a

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slight net decrease on a CO<sub>2</sub> equivalent basis. While still small, this net decrease grows to a range between 2.5 to 2.7 MMTCO<sub>2</sub>e by 2030.

We do not expect the Tier 3 vehicle standards to result in any discernible changes in vehicle CO<sub>2</sub> emissions or fuel economy. Emissions of the pollutants that are controlled by the Tier 3 program – NMOG, NO<sub>x</sub>, and PM – are not a function of the amount of fuel consumed, since manufacturers need to design their catalytic emission control systems to reduce these emissions regardless of their engine-out levels.

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## 7.A. Appendix to Chapter 7: Additional Air Toxics Emissions and Air Quality Modeling Results

### 7A.1. Air Toxics Emissions

**Table 7A-1 Mobile Source Air Toxics Included in Inventory Reductions**

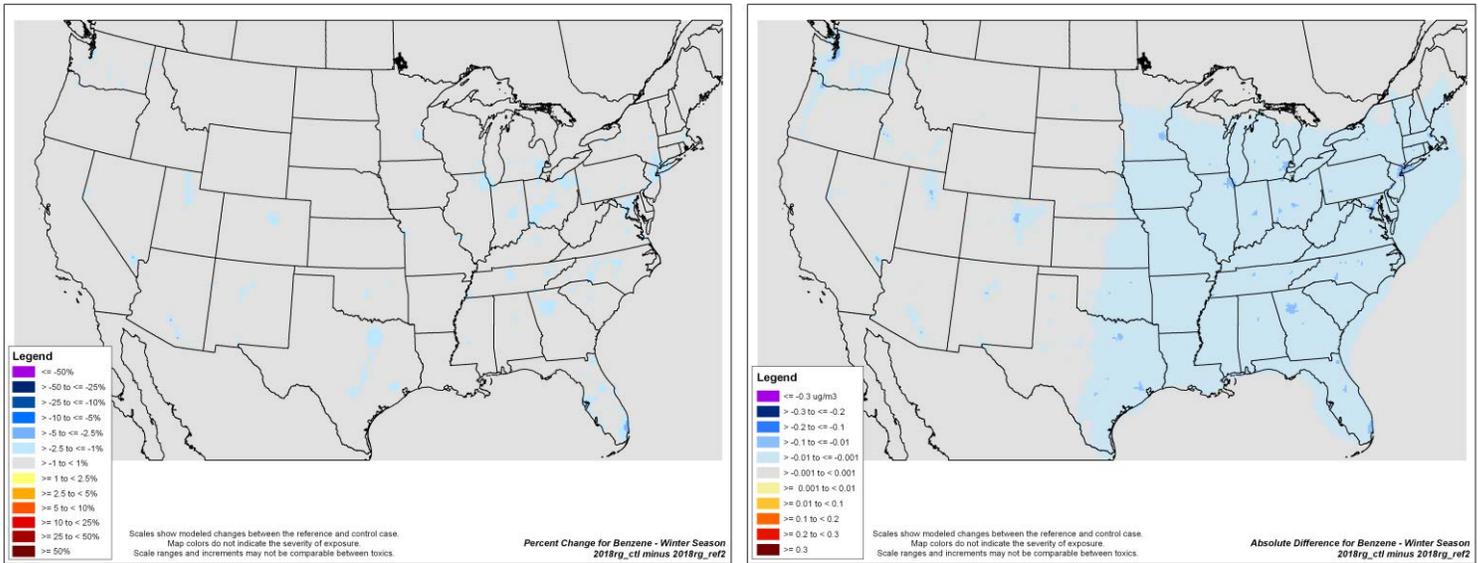
Pollutant ID number	Pollutant Name
144	1,2,3,4,6,7,8-Heptachlorodibenzofuran
132	1,2,3,4,6,7,8-Heptachlorodibenzo-p-Dioxin
137	1,2,3,4,7,8,9-Heptachlorodibenzofuran
145	1,2,3,4,7,8-Hexachlorodibenzofuran
134	1,2,3,4,7,8-Hexachlorodibenzo-p-Dioxin
140	1,2,3,6,7,8-Hexachlorodibenzofuran
141	1,2,3,6,7,8-Hexachlorodibenzo-p-Dioxin
146	1,2,3,7,8,9-Hexachlorodibenzofuran
130	1,2,3,7,8,9-Hexachlorodibenzo-p-Dioxin
139	1,2,3,7,8-Pentachlorodibenzofuran
135	1,2,3,7,8-Pentachlorodibenzo-p-Dioxin
24	1,3-Butadiene
40	2,2,4-Trimethylpentane
143	2,3,4,6,7,8-Hexachlorodibenzofuran
138	2,3,4,7,8-Pentachlorodibenzofuran
136	2,3,7,8-Tetrachlorodibenzofuran
142	2,3,7,8-Tetrachlorodibenzo-p-Dioxin
170	Acenaphthene gas
70	Acenaphthene particle
171	Acenaphthylene gas
71	Acenaphthylene particle
26	Acetaldehyde
27	Acrolein
172	Anthracene gas
72	Anthracene particle
63	Arsenic Compounds
173	Benz(a)anthracene gas
73	Benz(a)anthracene particle
20	Benzene
174	Benzo(a)pyrene gas
74	Benzo(a)pyrene particle
175	Benzo(b)fluoranthene gas
75	Benzo(b)fluoranthene particle

Pollutant ID number	Pollutant Name
176	Benzo(g,h,i)perylene gas
76	Benzo(g,h,i)perylene particle
177	Benzo(k)fluoranthene gas
77	Benzo(k)fluoranthene particle
64	Chromium 3+
65	Chromium 6+
178	Chrysene gas
78	Chrysene particle
168	Dibenzo(a,h)anthracene gas
68	Dibenzo(a,h)anthracene particle
21	Ethanol
41	Ethyl Benzene
169	Fluoranthene gas
69	Fluoranthene particle
181	Fluorene gas
81	Fluorene particle
25	Formaldehyde
42	Hexane
182	Indeno(1,2,3,c,d)pyrene gas
82	Indeno(1,2,3,c,d)pyrene particle
66	Manganese Compounds
61	Mercury Divalent Gaseous
60	Mercury Elemental Gaseous
62	Mercury Particulate
22	MTBE
185	Naphthalene gas
23	Naphthalene particle
67	Nickel Compounds
133	Octachlorodibenzofuran
131	Octachlorodibenzo-p-dioxin
183	Phenanthrene gas
83	Phenanthrene particle
43	Propionaldehyde
184	Pyrene gas
84	Pyrene particle
44	Styrene
45	Toluene
46	Xylene

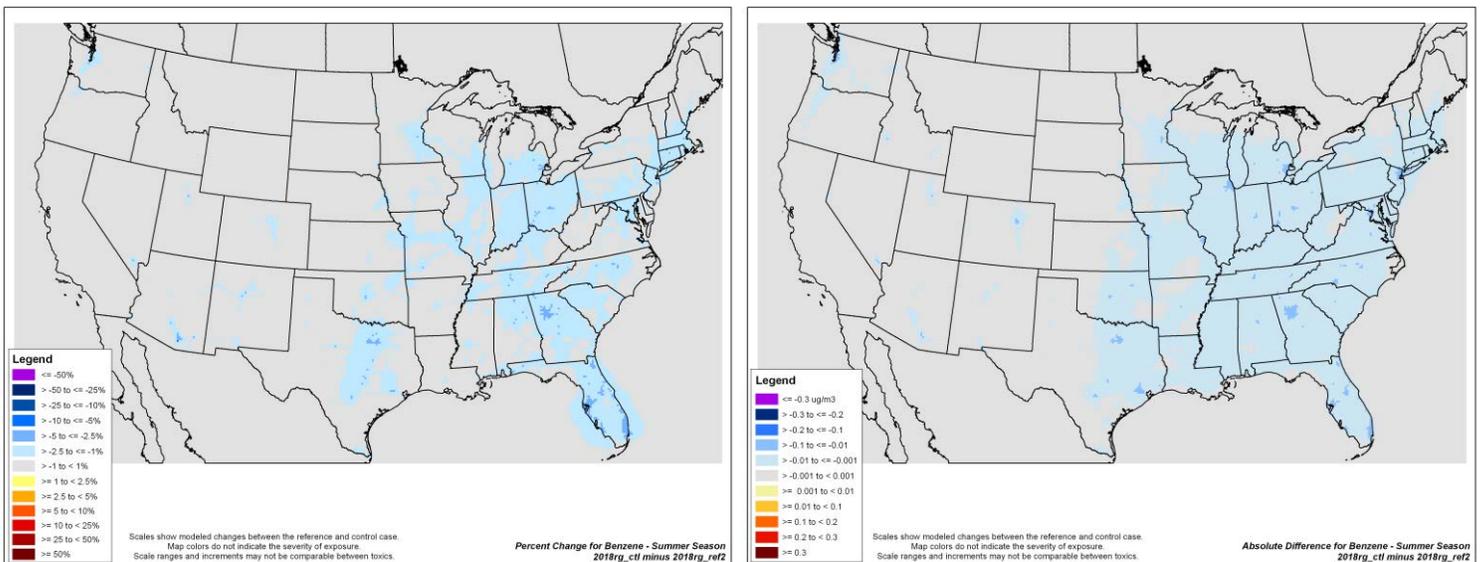
## 7A.2. Seasonal Air Toxics Air Quality Modeling Results for 2018

The following section presents maps of seasonal changes in ambient concentrations of modeled air toxics in 2018.

### Benzene

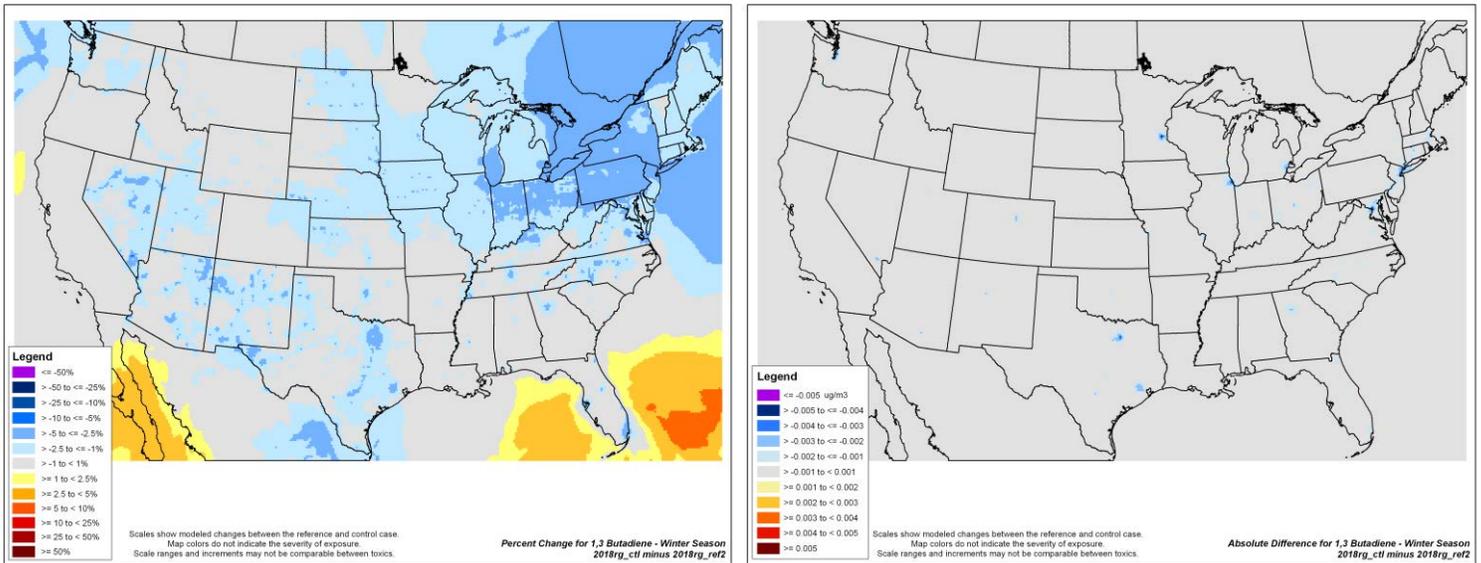


**Figure 7A-1 Winter Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

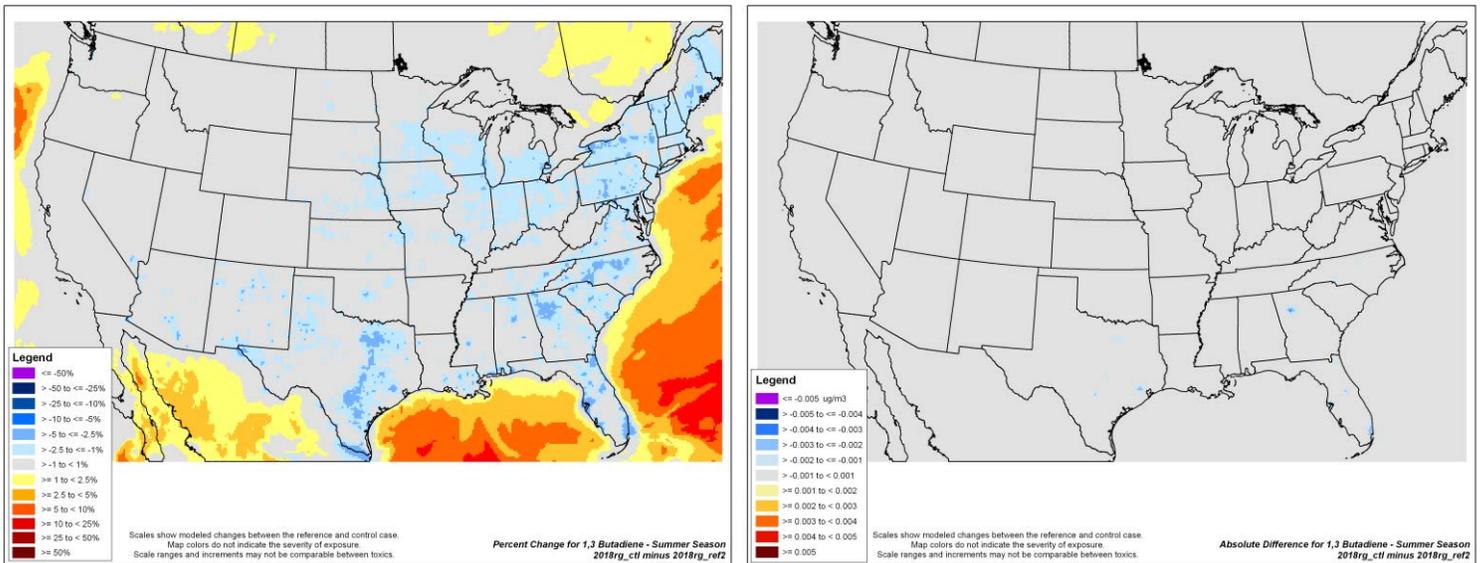


**Figure 7A-2 Summer Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## 1,3-Butadiene

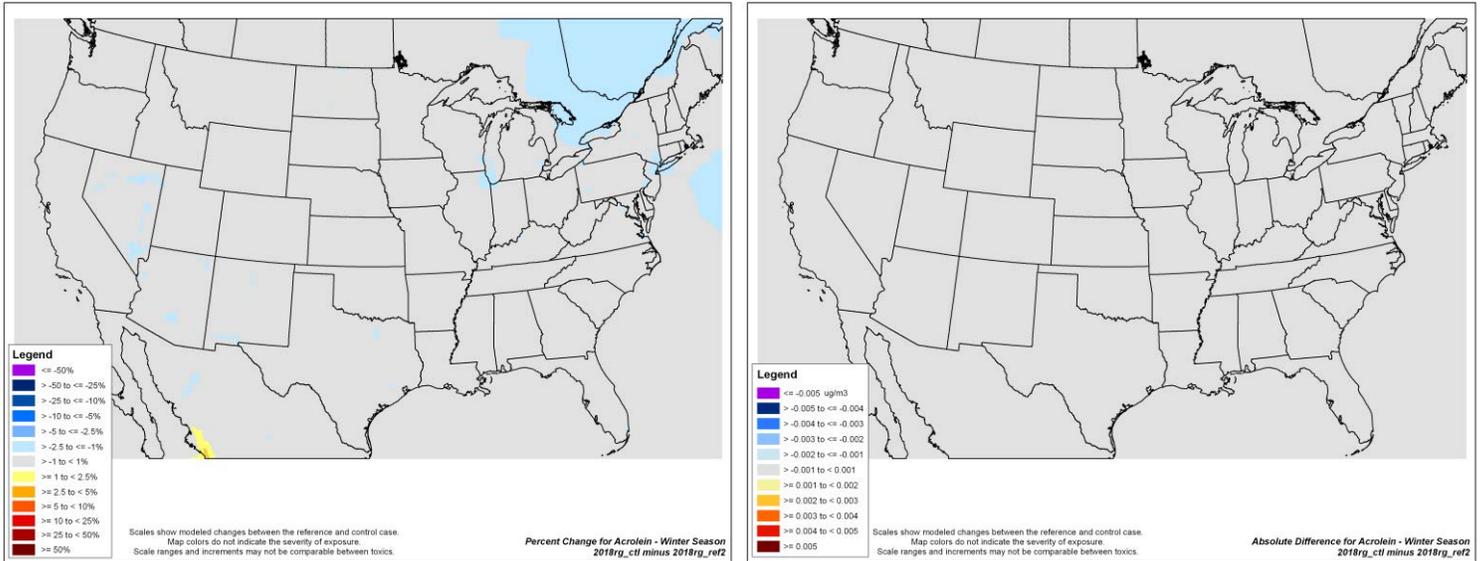


**Figure 7A-3 Winter Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

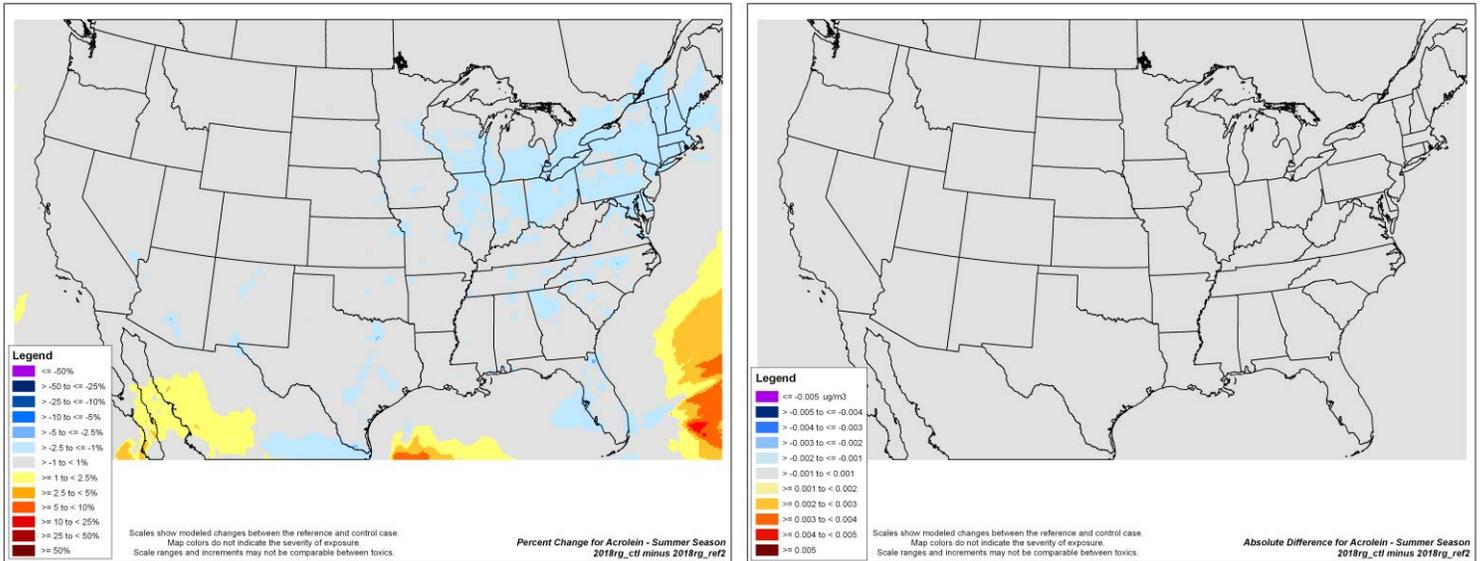


**Figure 7A-4 Summer Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Acrolein

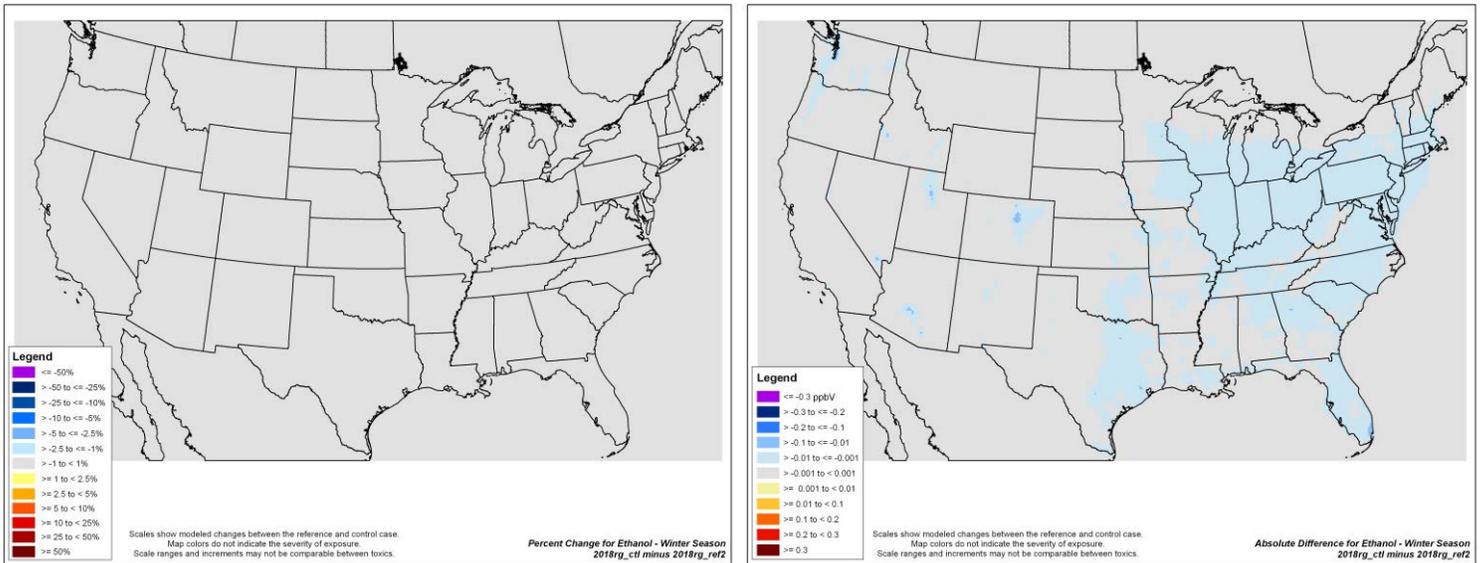


**Figure 7A-5 Winter Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

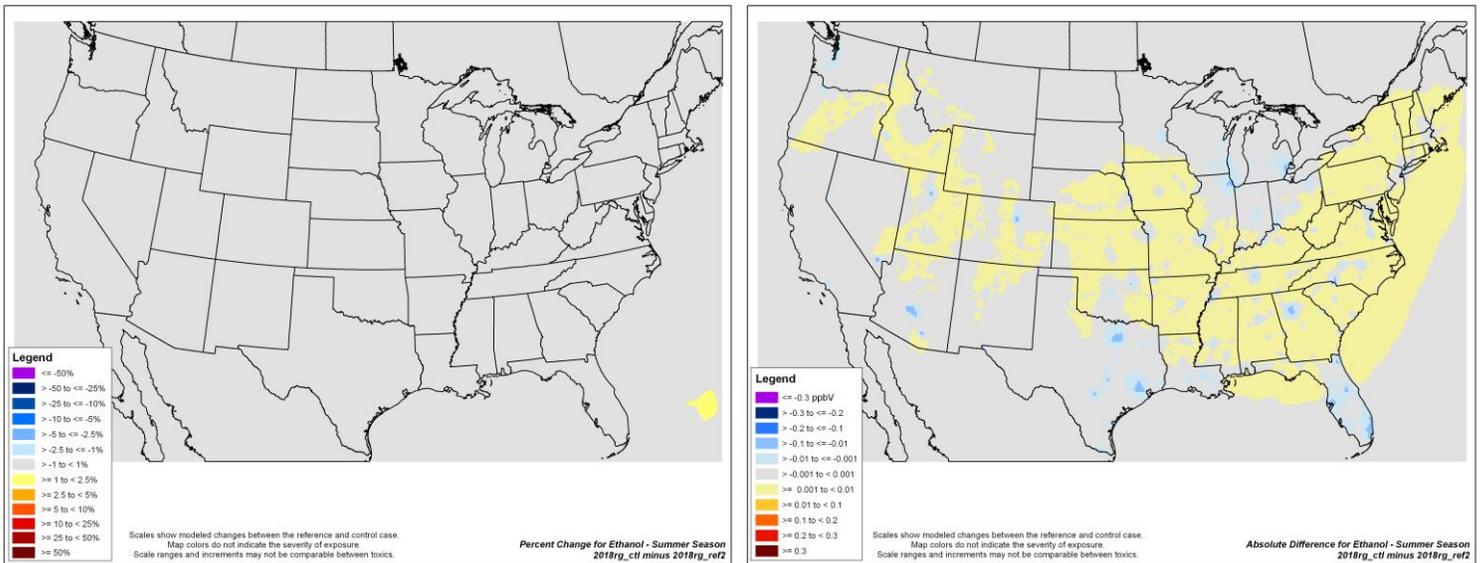


**Figure 7A-6 Summer Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Ethanol

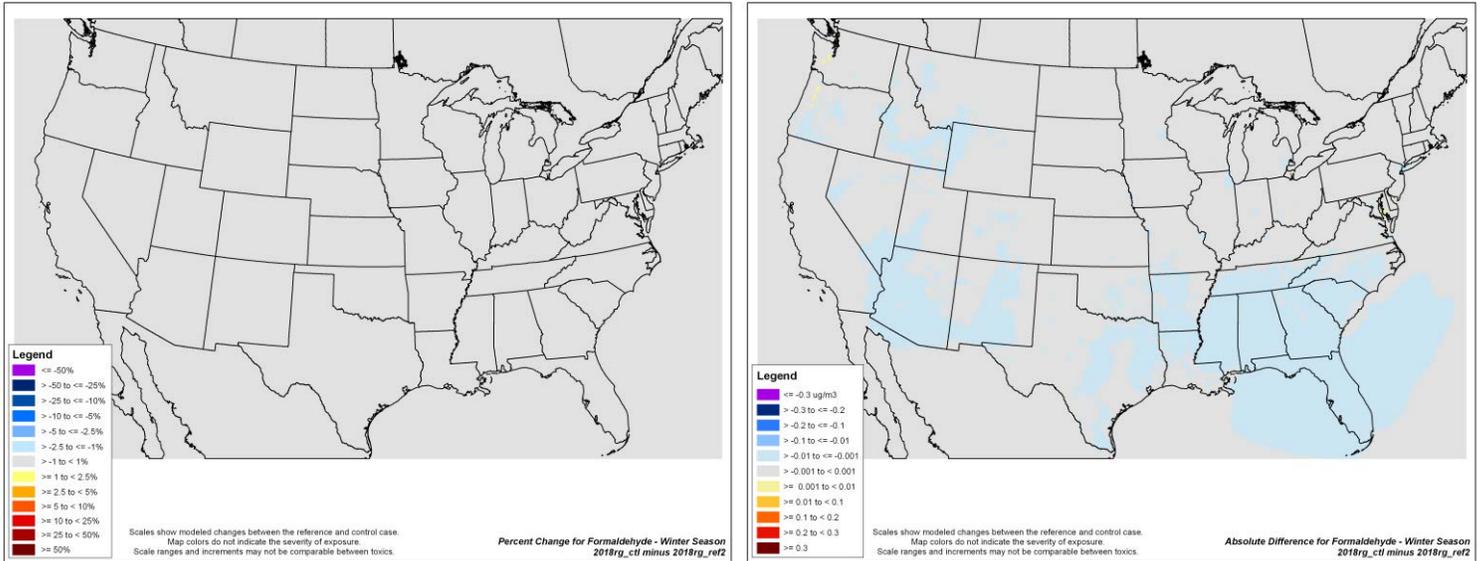


**Figure 7A-7 Winter Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

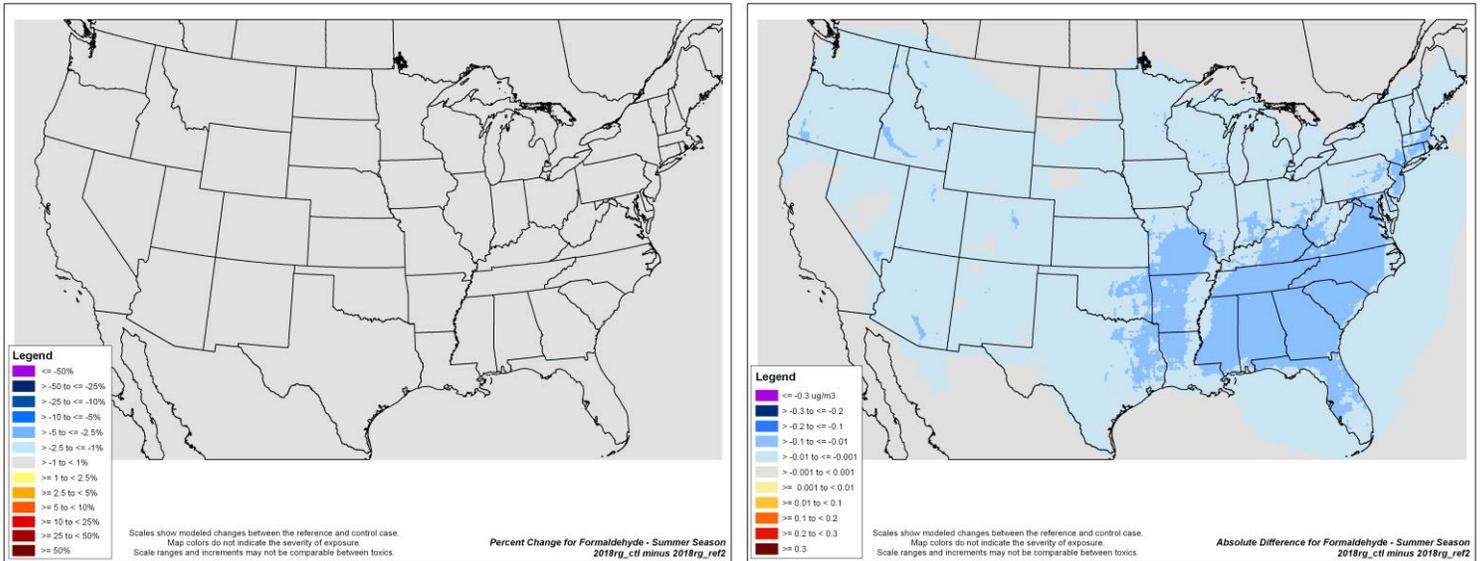


**Figure 7A-8 Summer Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Formaldehyde

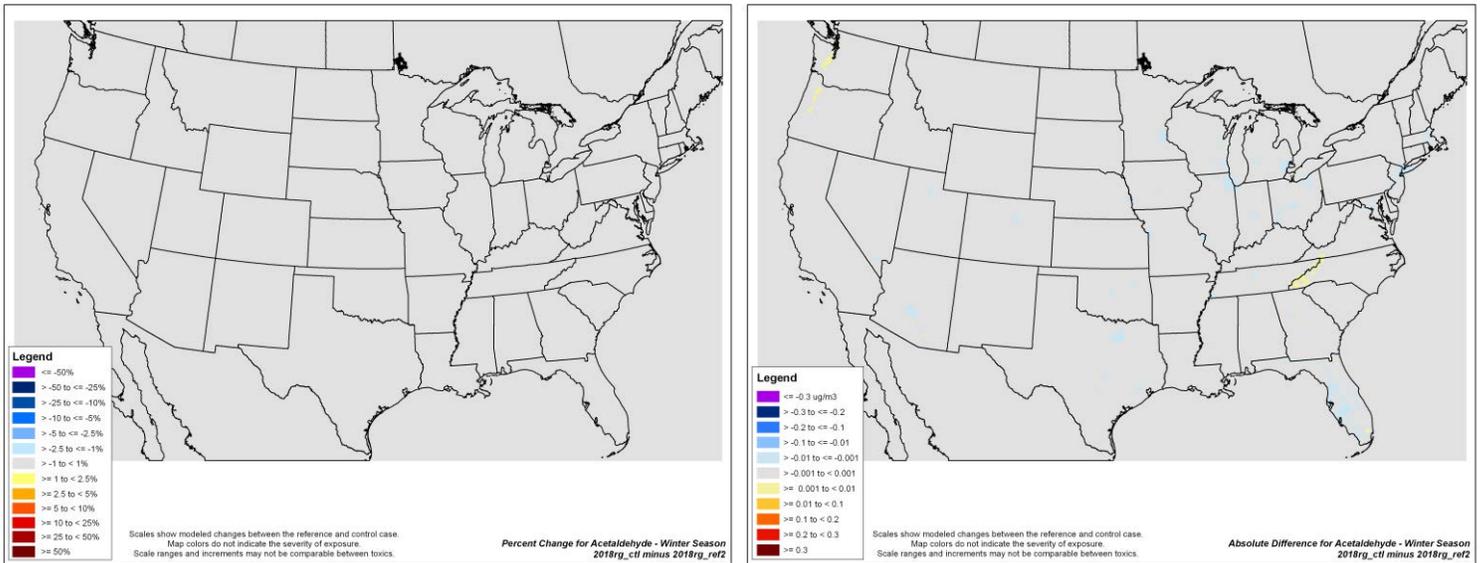


**Figure 7A-9 Winter Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

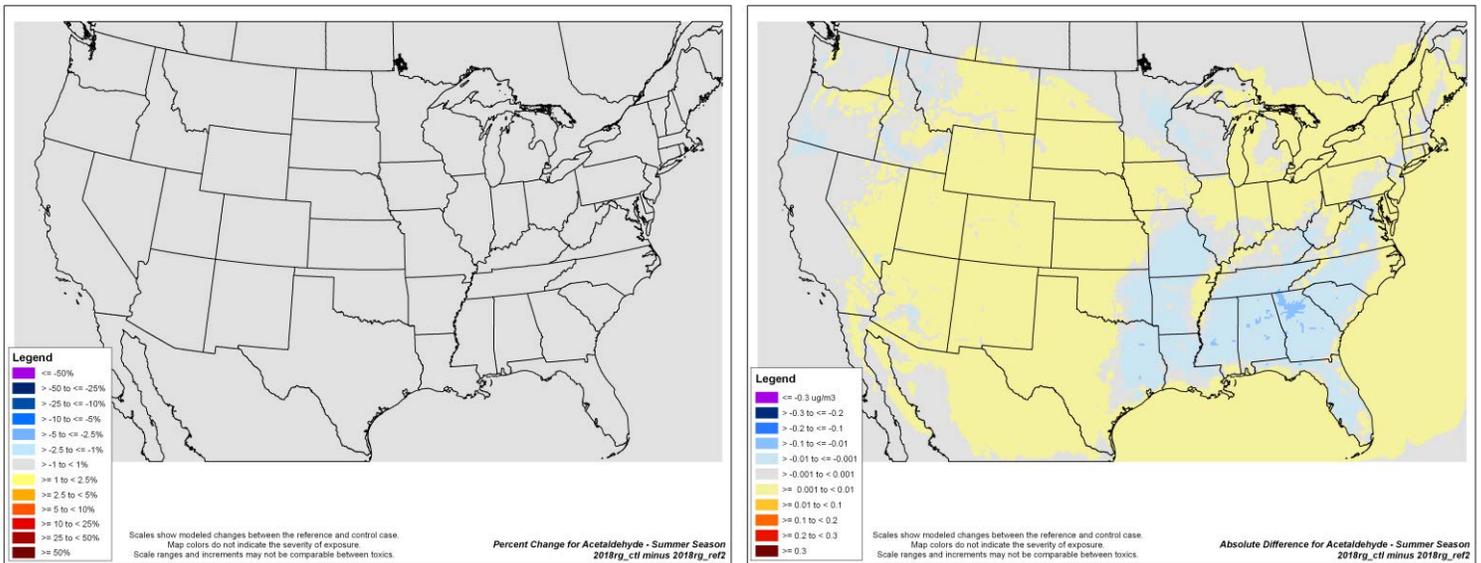


**Figure 7A-10 Summer Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Acetaldehyde

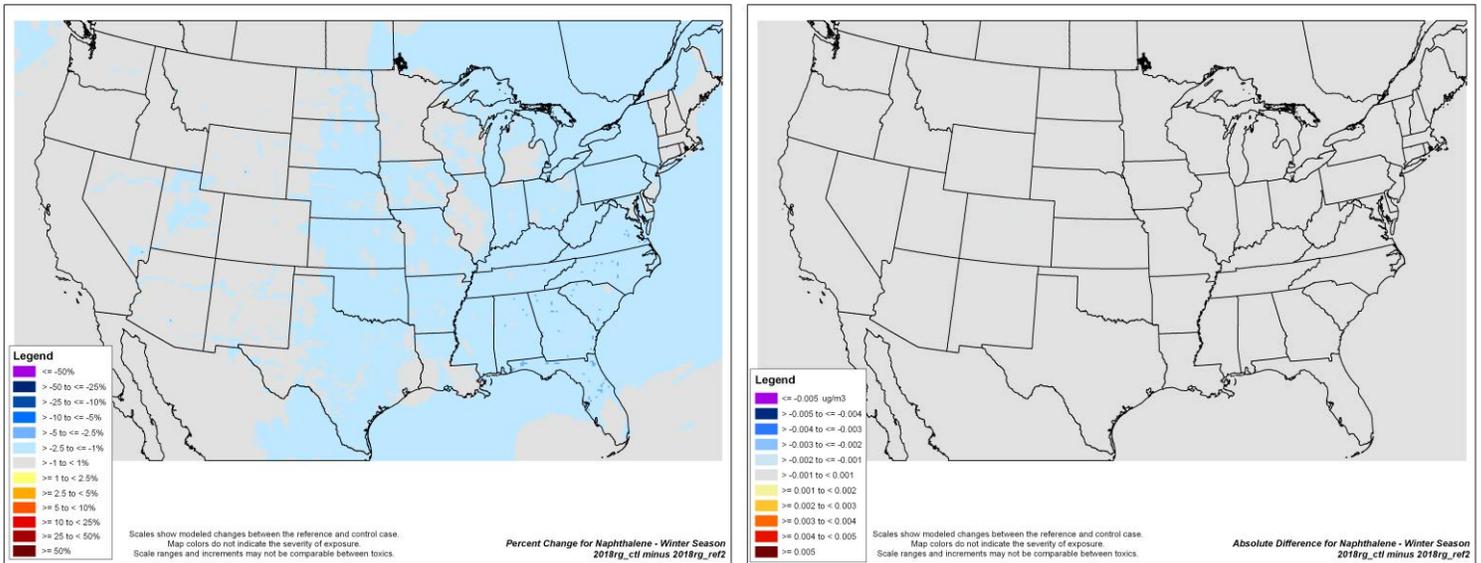


**Figure 7A-11 Winter Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

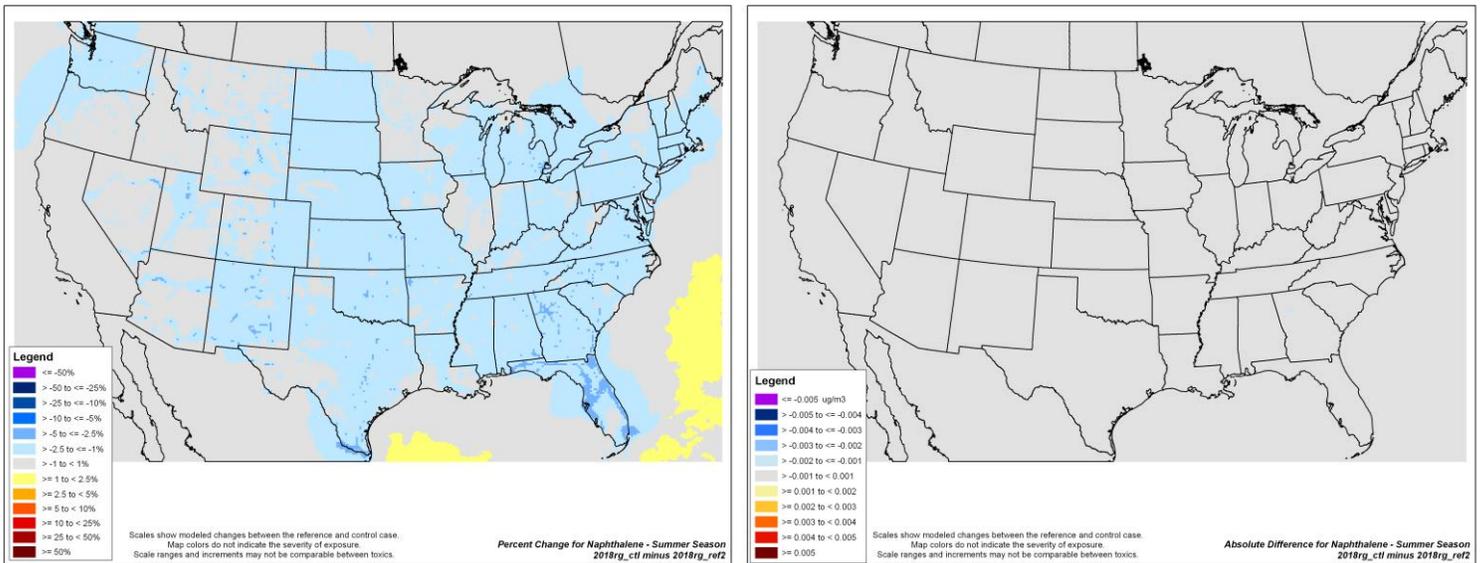


**Figure 7A-12 Summer Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Naphthalene



**Figure 7A-13 Winter Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

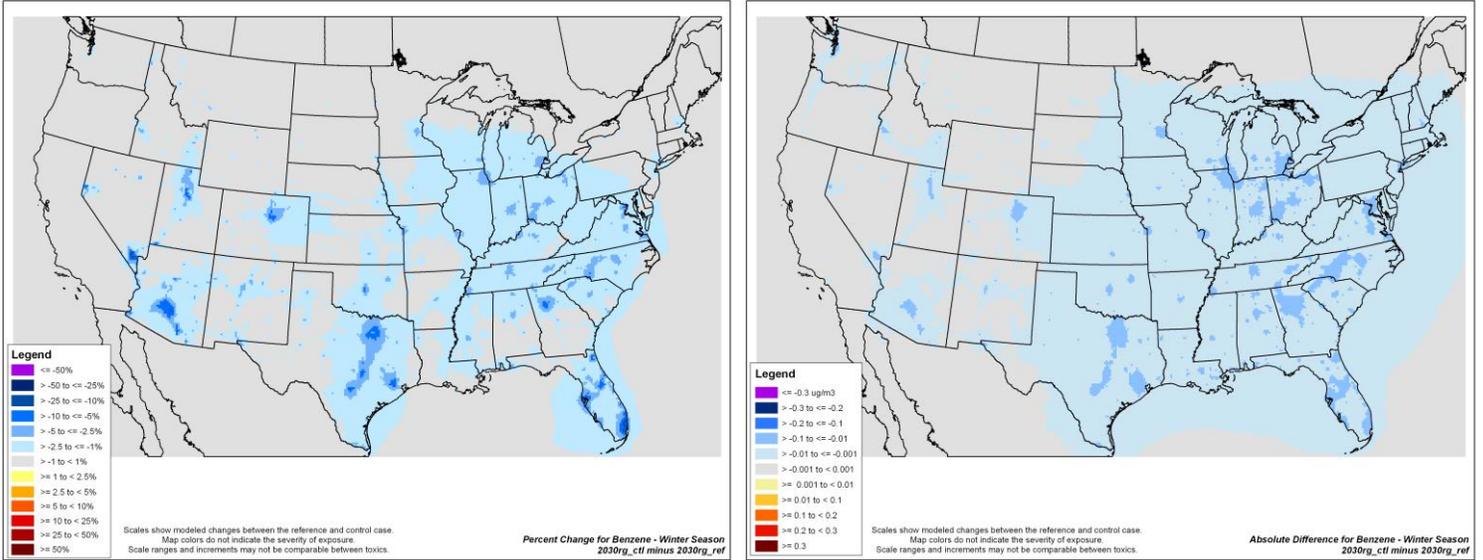


**Figure 7A-14 Summer Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2018: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

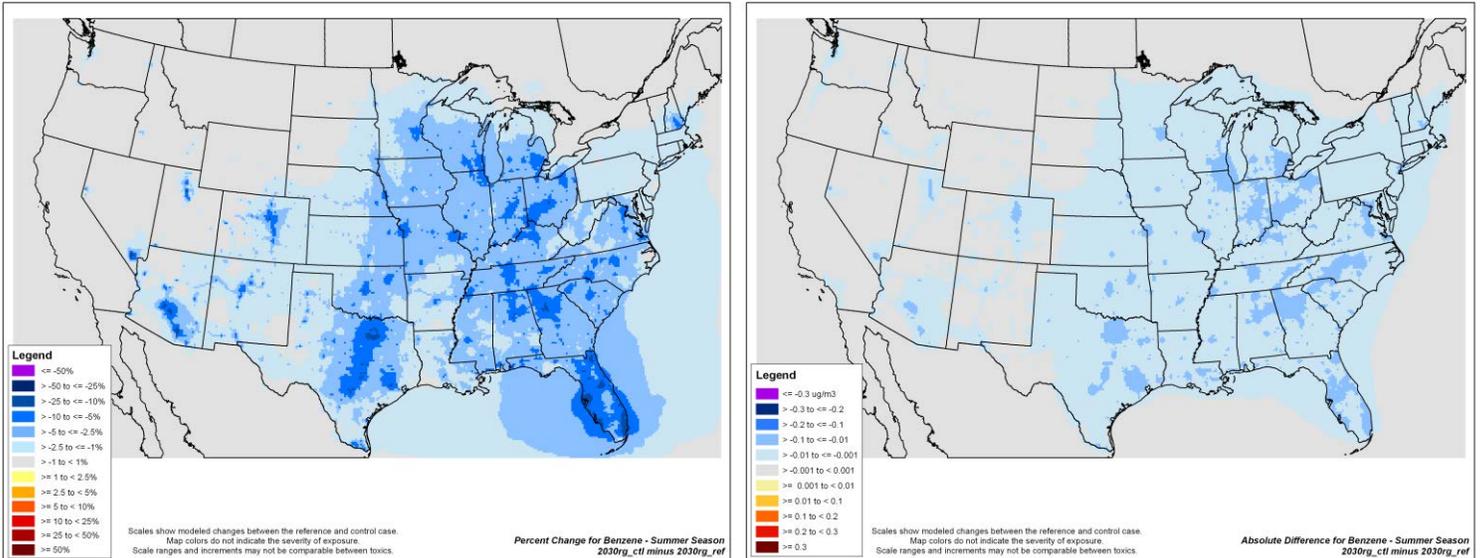
### 7A.3. Seasonal Air Toxics Air Quality Modeling Results for 2030

The following section presents maps of seasonal changes in ambient concentrations of modeled air toxics in 2030.

#### Benzene

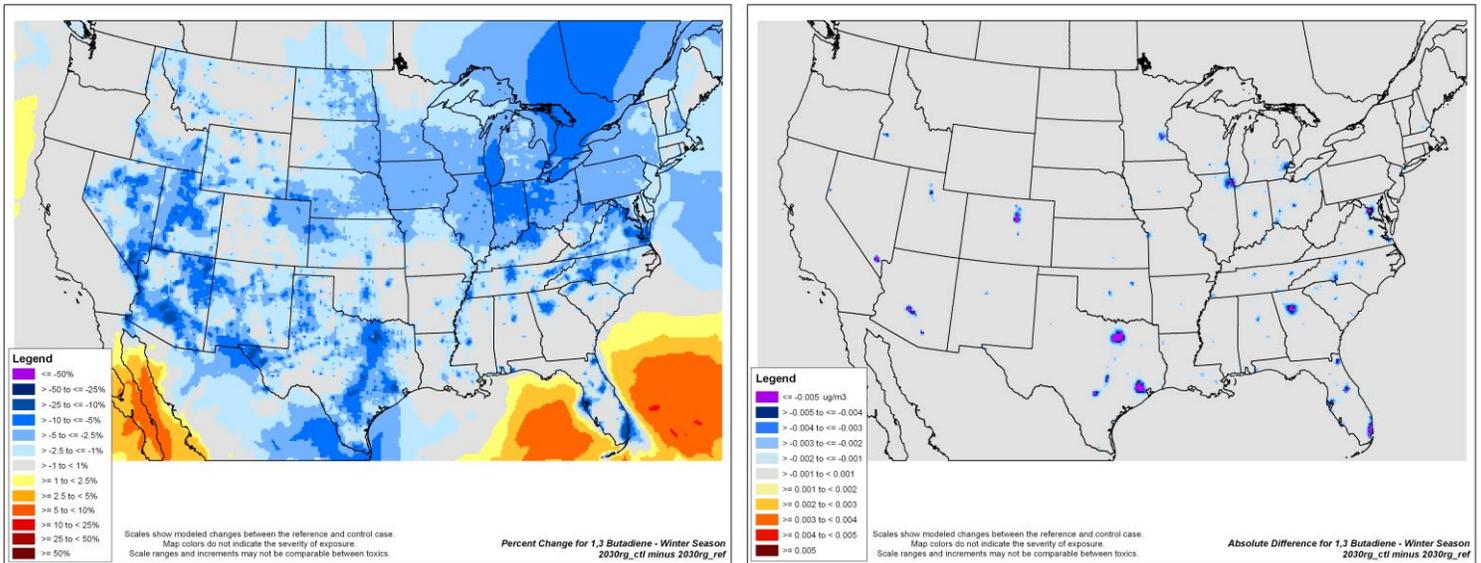


**Figure 7A-15 Winter Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

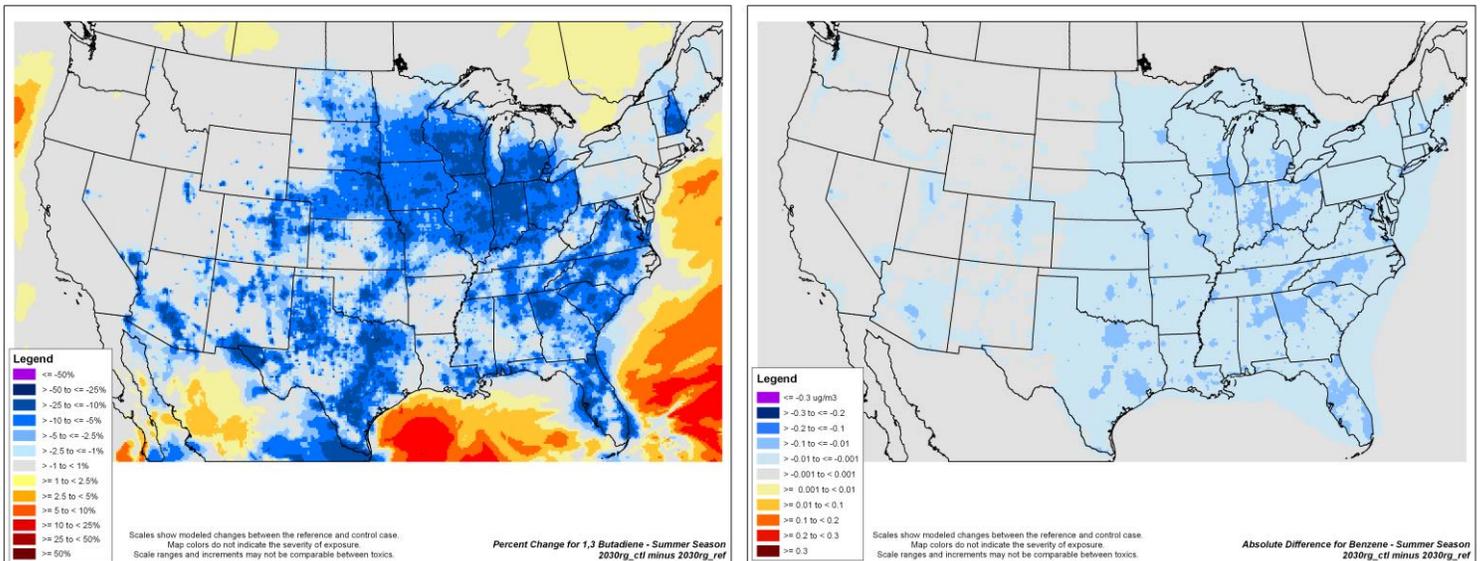


**Figure 7A-16 Summer Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## 1,3-Butadiene

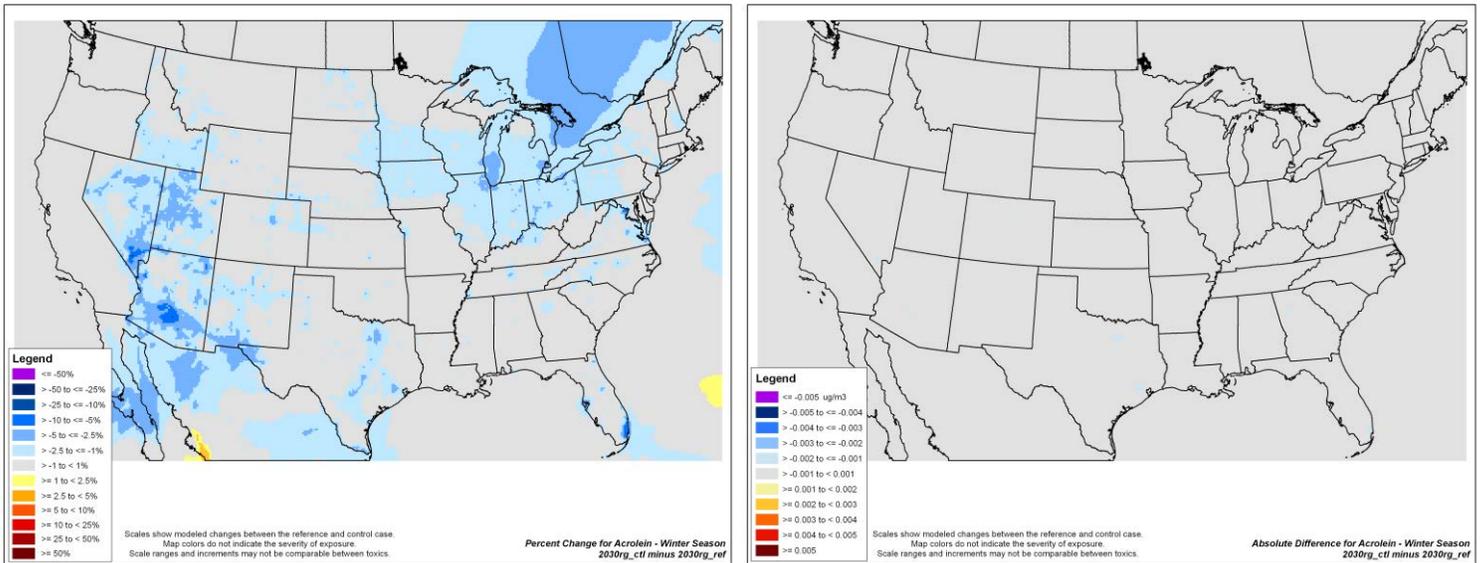


**Figure 7A-17 Winter Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

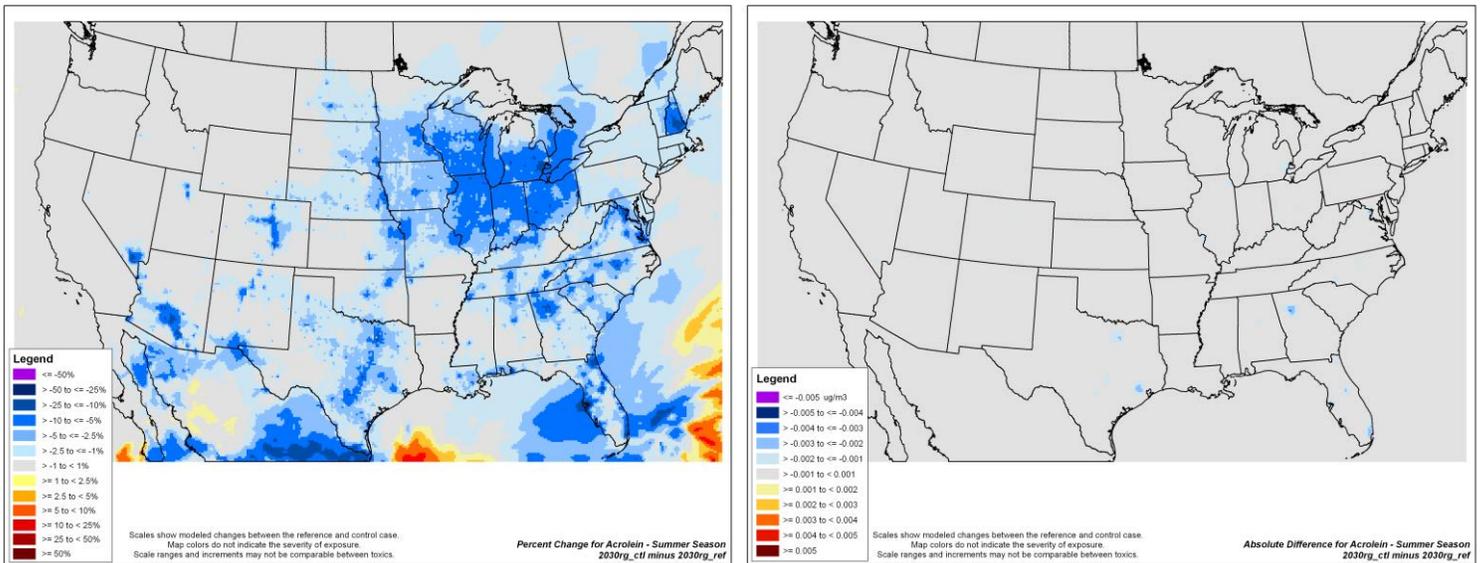


**Figure 7A-18 Summer Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Acrolein

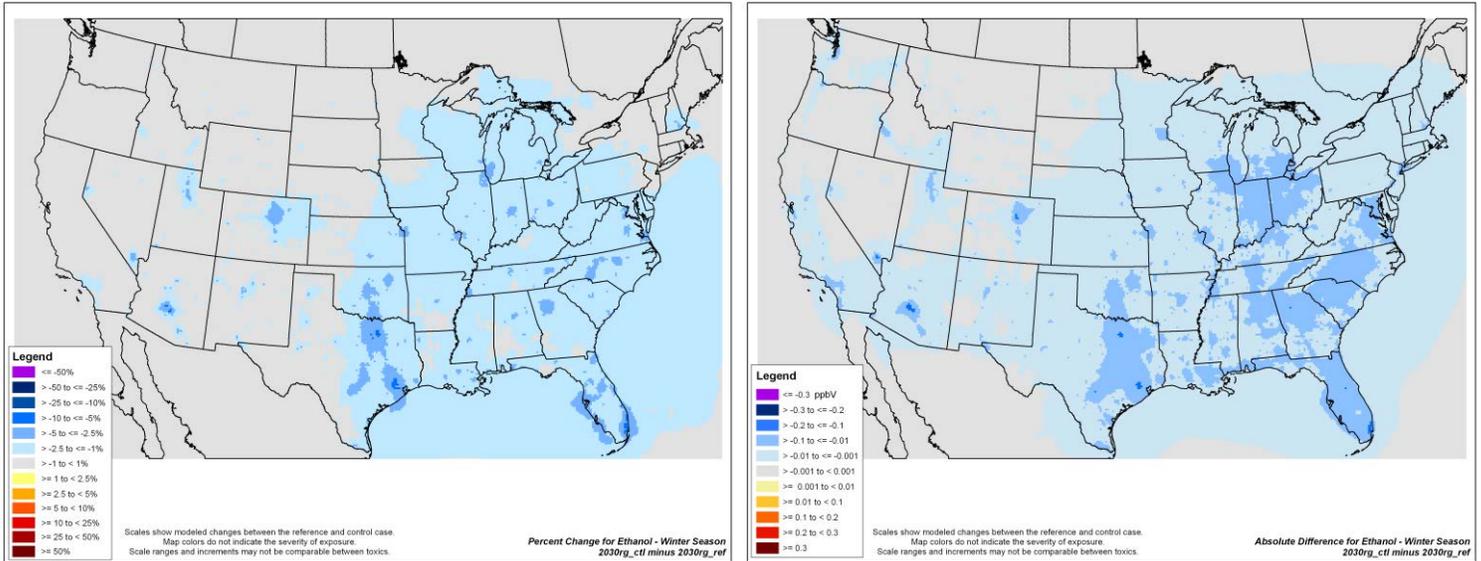


**Figure 7A-19 Winter Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

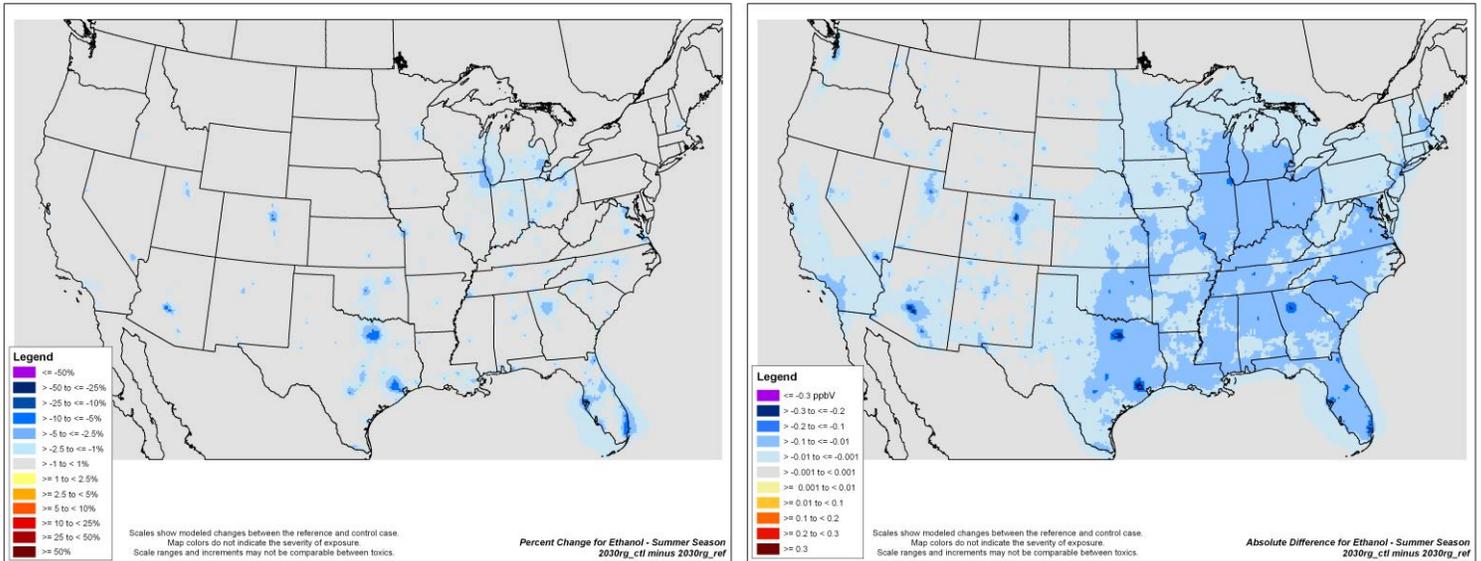


**Figure 7A-20 Summer Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Ethanol

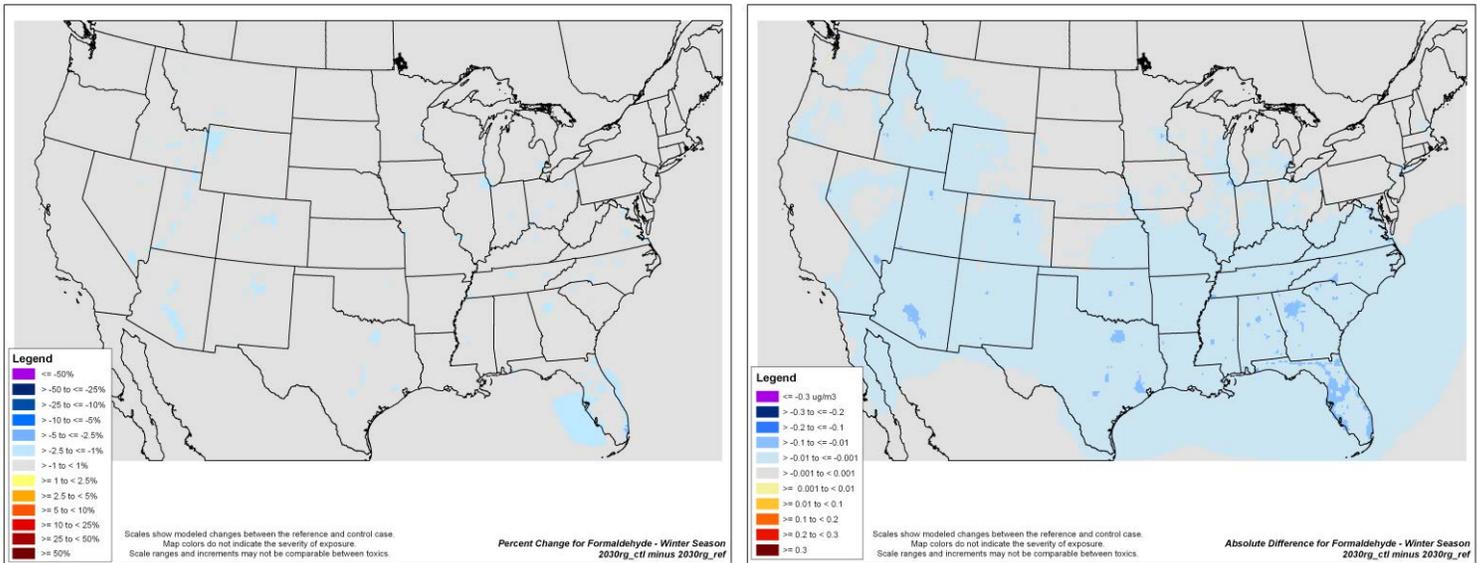


**Figure 7A-21 Winter Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

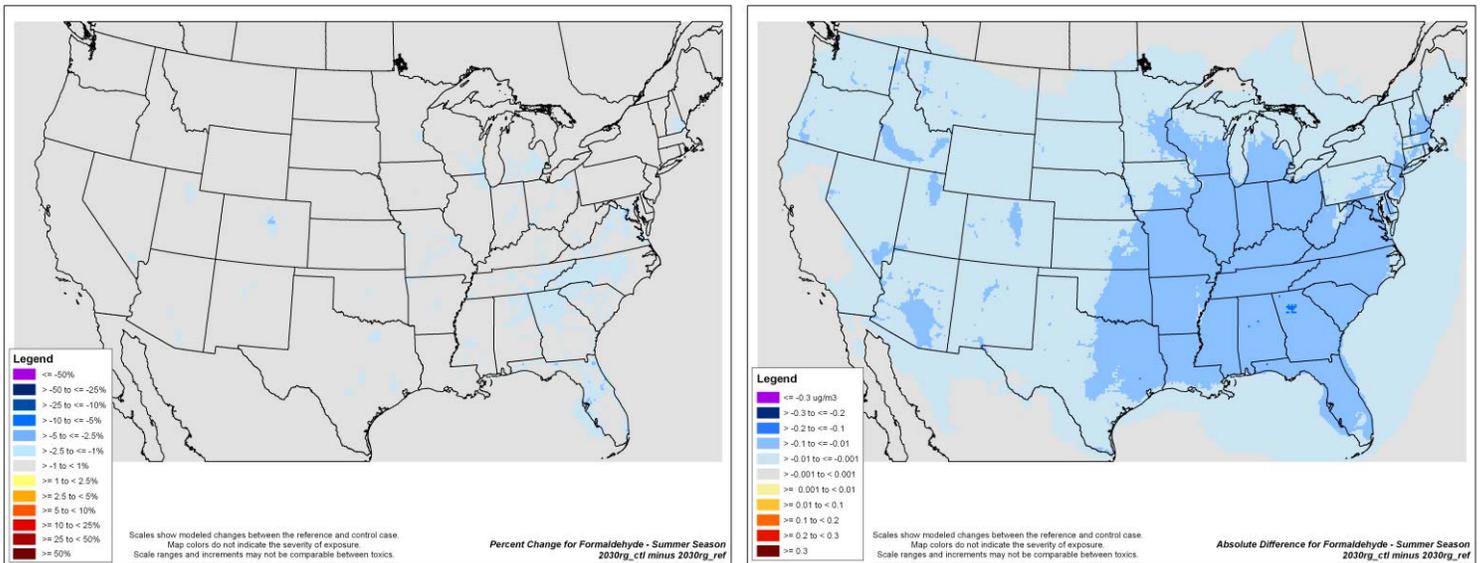


**Figure 7A-22 Summer Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Formaldehyde

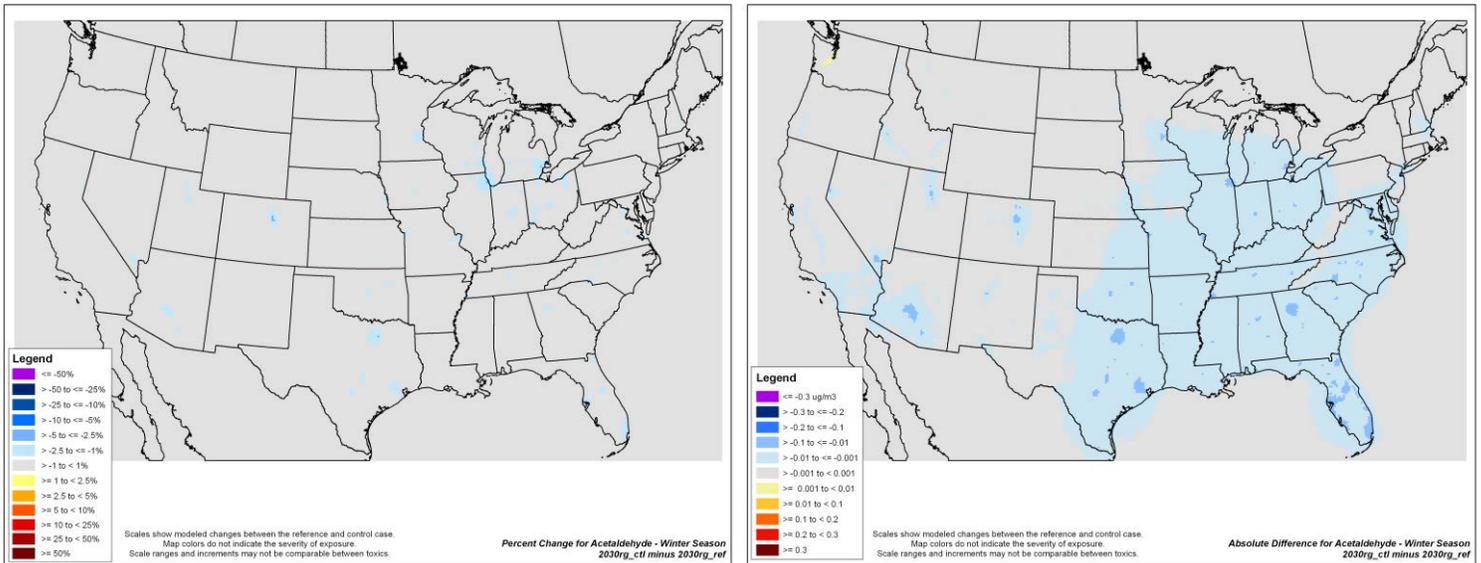


**Figure 7A-23 Winter Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

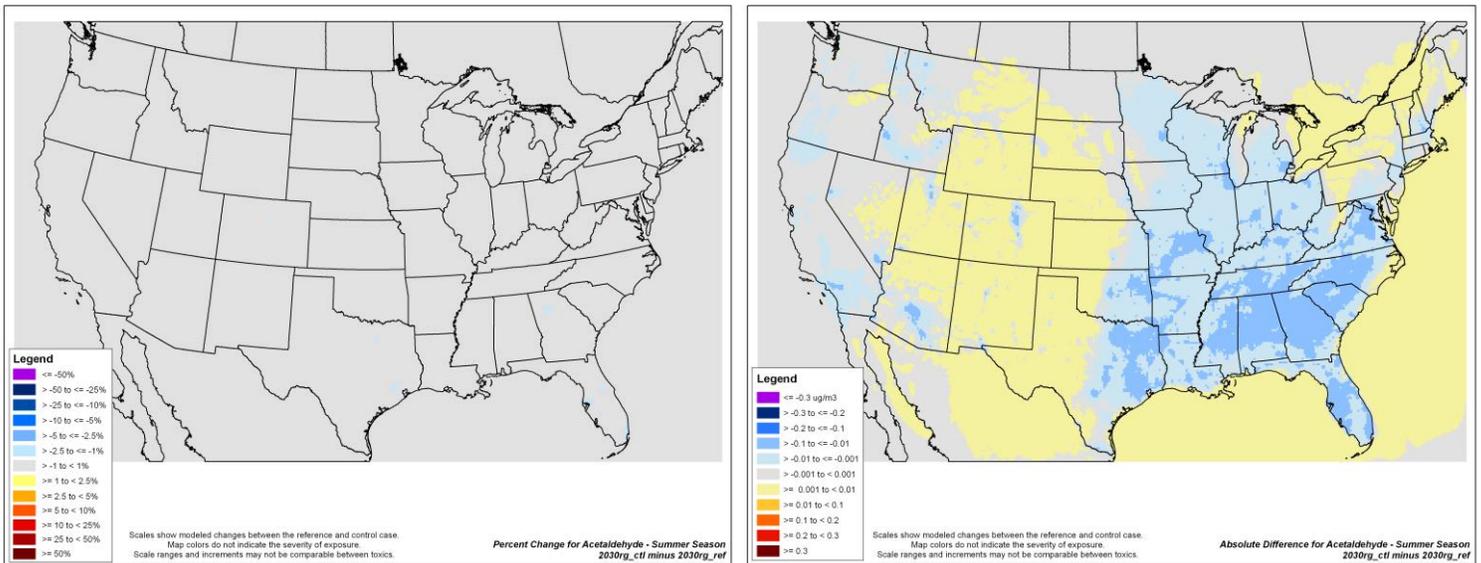


**Figure 7A-24 Summer Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Acetaldehyde

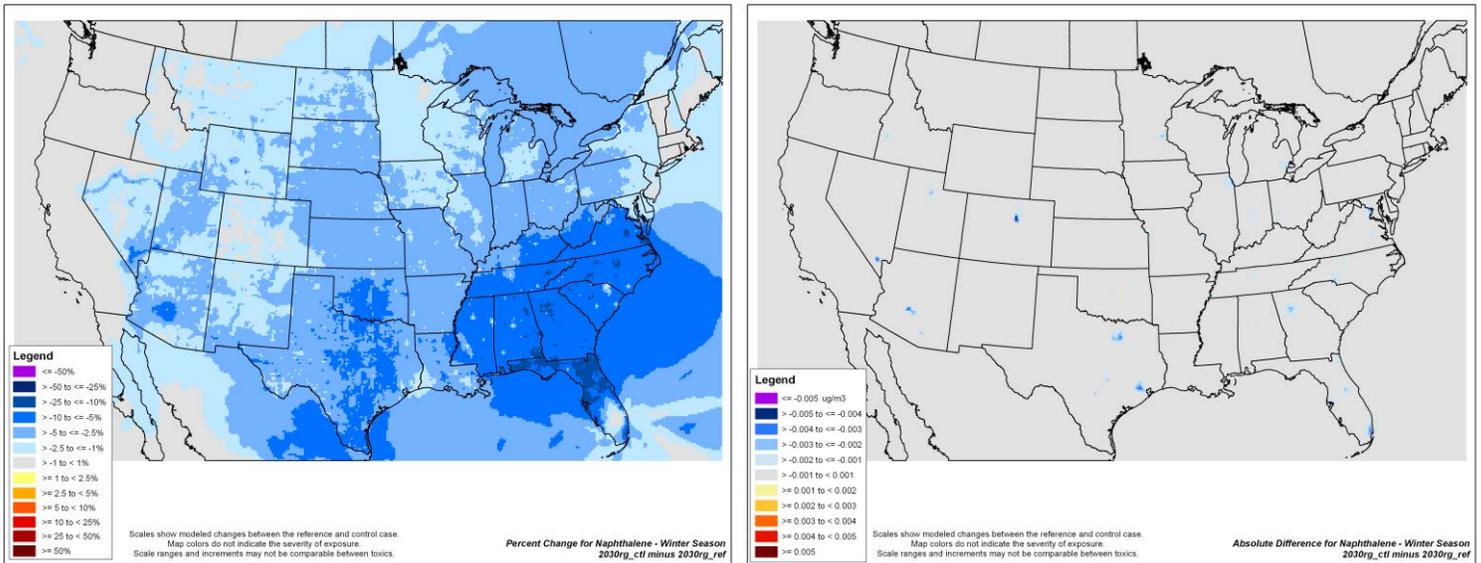


**Figure 7A-25 Winter Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

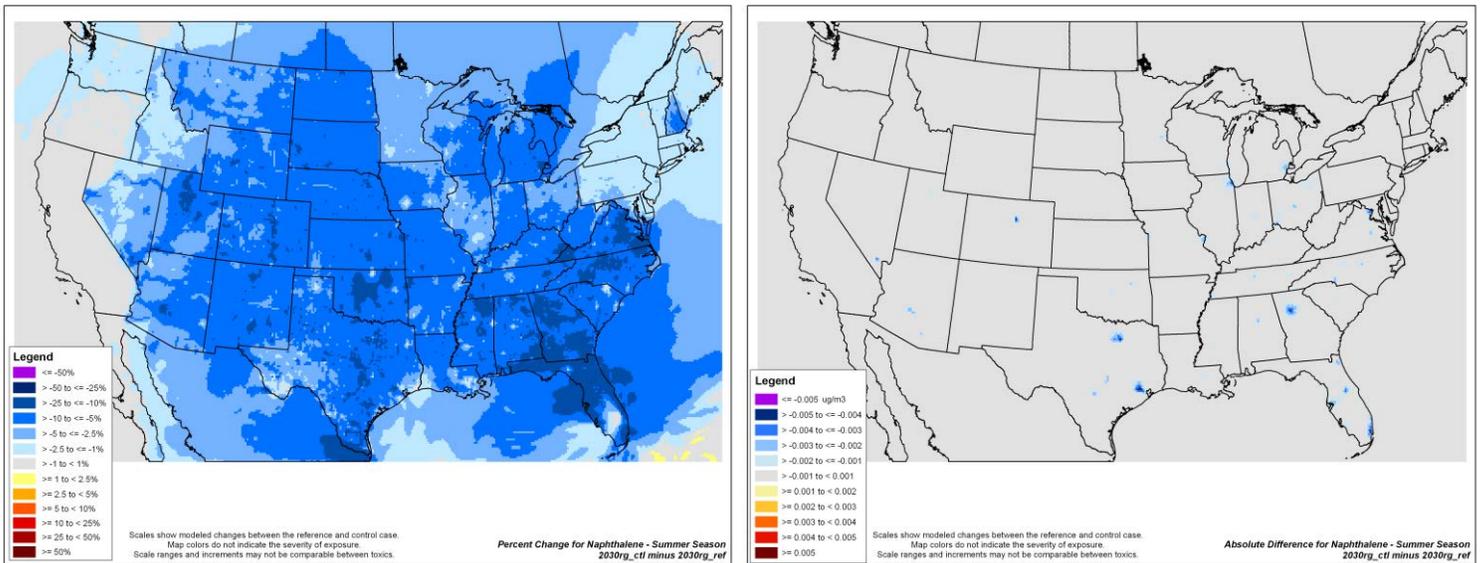


**Figure 7A-26 Summer Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

# Naphthalene



**Figure 7A-27 Winter Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**



**Figure 7A-28 Summer Changes in Naphthalene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in  $\mu\text{g}/\text{m}^3$  (right)**

## Chapter 8 Comparison of Program Costs to Program Air Quality Benefits

EPA traditionally evaluates the effectiveness of a final rule in terms of net benefits. Section 8.1 below presents the cost-benefit analysis of the final rule.

### 8.1 Cost-Benefit Analysis

The net benefits of the final Tier 3 program are determined by the effects of the program on the costs to comply with the vehicle and fuel aspects of the program along with the benefits of improved air quality on health and the environment.

#### 8.1.1 Program-Wide Costs

The costs that are incurred from our final program fall into three categories - for the Tier 3 exhaust standards, Tier 3 evaporative standards, and reductions in sulfur content of gasoline. While we present these three categories of costs separately in this section, for purposes of the calculation of cost per ton of emissions reduced analysis we have summed them to represent the estimated costs of the final program.

All costs represent the fleet-weighted average of light-duty vehicles and trucks. All costs are represented in 2011dollars.

##### 8.1.1.1 Vehicle Program Costs

The vehicle costs include the technology costs projected to meet the final exhaust and evaporative standards including the facility and operating cost impacts, as detailed in RIA Chapter 2 and shown in Table 8-1. The fleet mix of light-duty vehicles, light duty trucks, and medium-duty trucks represents the MYs 2017-2025 fleet mix projected to result from the most recent GHG and fuel economy rules. The final vehicle costs are lower than the values projected in the proposal due to the items outlined in RIA Section 2.1 in addition to the exclusion of the vehicle sales in California and the states that have adopted the LEV III program.

**Table 8-1: Annual Vehicle Program Costs, 2011\$**

Year	Vehicle Exhaust Emission Control Costs (\$Million)	Vehicle Evaporative Emission Control Costs (\$Million)	Operating Costs (\$Million)	Facility Costs (\$Million)	Total Vehicle Program Costs (\$Million) <sup>a</sup>
2016	\$0	\$0	\$0	\$21	\$21
2017	\$268	\$26	\$0	\$4	\$297
2018	\$539	\$73	-\$1	\$4	\$615
2019	\$579	\$72	-\$2	\$4	\$653
2020	\$599	\$98	-\$3	\$4	\$697
2021	\$630	\$97	-\$5	\$4	\$725
2022	\$640	\$121	-\$6	\$4	\$758
2023	\$639	\$116	-\$8	\$4	\$751

Year	Vehicle Exhaust Emission Control Costs (\$Million)	Vehicle Evaporative Emission Control Costs (\$Million)	Operating Costs (\$Million)	Facility Costs (\$Million)	Total Vehicle Program Costs (\$Million) <sup>a</sup>
2024	\$653	\$114	-\$9	\$4	\$761
2025	\$668	\$113	-\$11	\$4	\$773
2030	\$664	\$113	-\$19	\$4	\$761

<sup>a</sup> These estimates include costs associated with the Tier 3 vehicle standards in all states except California and states that have adopted the LEV III program.

#### 8.1.1.2 Fuel Program Costs

The annual fuel costs of the Tier 3 program consist of the costs to the refiners to control sulfur on a per gallon basis and the total number of gallons consumed annually in the U.S. except in the state of California.

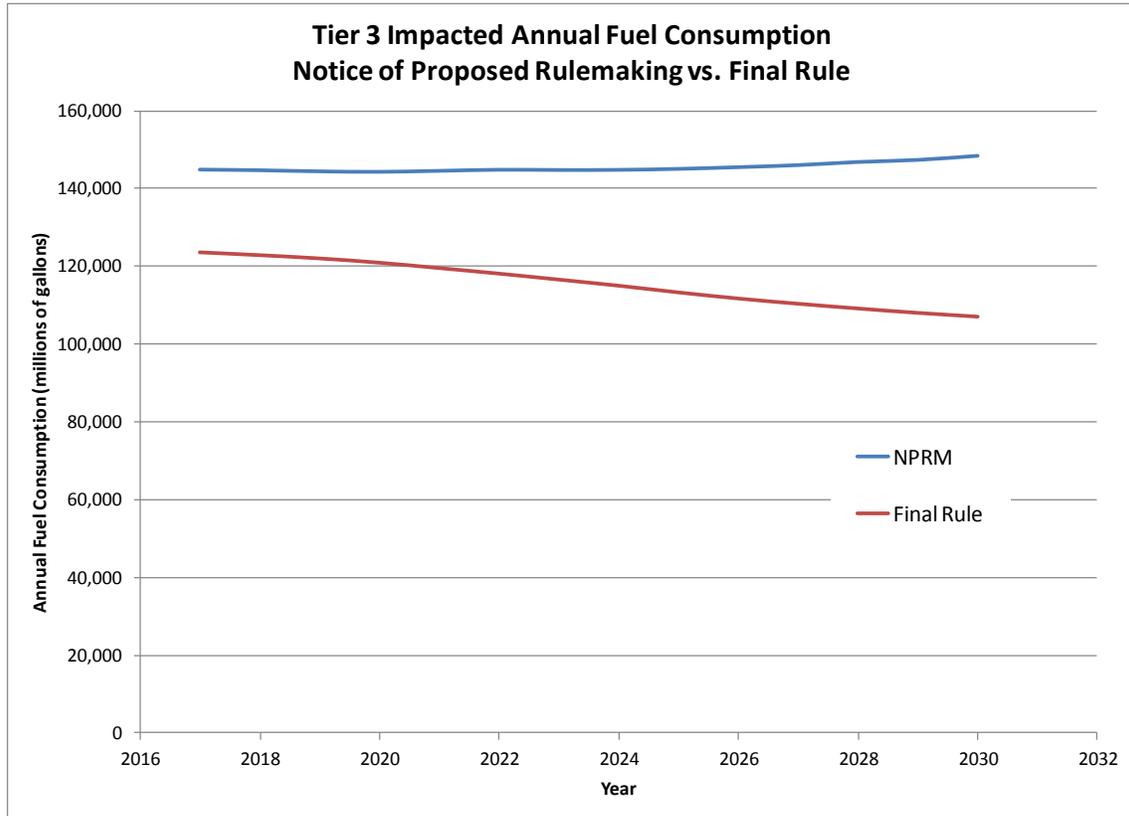
The fuel costs associated with the additional operating and capital costs to refiners to meet the final sulfur average of 10 ppm, as described in detail in RIA Chapter 5, is 0.65 cents per gallon. The annual fuel costs of the final Tier 3 program are lower than the proposed fuel costs, 0.89 cents, due to the reduction in cost per gallon to control sulfur.

The fuel consumption values used in the annual fuel cost projections are based on the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2013. The latest AEO projection used in the final rule cost projections contain lower annual fuel consumption than the values used in the Tier 3 proposal because AEO 2013 now reflects the light-duty GHG and fuel economy standards for the 2017-2025 model years. The light-duty standards are projected to decrease the national gasoline fuel consumption due to more efficient vehicles.

The annual fuel consumption in AEO 2013 represents the national fuel usage in terms of BTU. For the fuel program cost analysis, it was necessary to convert the national BTU fuel consumption to millions of gallons of fuel consumed in the U.S. in all states except California. This conversion process is explained here using a sample year of 2017. Based on AEO 2013, the annual fuel consumption of motor gasoline and E85 in the transportation sector is projected to be 15,342 trillion BTU in 2017.<sup>1</sup> AEO's million BTU/barrel conversion factors for E85 and Motor Gasoline Average along with a conversion factor of 42 U.S. gallons of fuel per barrel were used to calculate the annual fuel consumption in terms of million gallons.<sup>2</sup> Based on these conversions, the national fuel consumption in 2017 is projected to be 128,318 million gallons. Finally, the national fuel consumption values from AEO 2013 were reduced for this analysis to remove the fraction of gasoline sold in California. The AEO 2013 Prime Supplier Sales Volumes of Motor Gasoline provides the sales of motor gasoline by state.<sup>3</sup> Based on the average between 1983 and 2012, the fraction of national gasoline sales in California was 3.6 percent. After removing the fraction of fuel consumed in California, the annual fuel costs in 2017 are calculated based on a fuel consumption level of 123,689 million gallons.

The Tier 3 fuel program provides flexibilities, including the ability for refiners to phase-in the sulfur standards and earn early credits. The fuel program costs presented here assume a start date of 2017 and do not reflect the sulfur control program phase in.

A comparison of the annual fuel consumption values used in the proposal and this final rule is shown in Figure 8-1.



**Figure 8-1: Annual Fuel Consumption Comparison between NPRM and Final Rule**

The projected annual fuel consumption and annual fuel costs of the final program are listed in Table 8-2.

**Table 8-2: Annual Fuel Costs, 2011\$**

Year	Annual Fuel Consumption Impacted by Tier 3 Program (million gallons)	Fuel Sulfur Control Costs (\$Million) <sup>a</sup>
2016	0	\$0
2017	123,698	\$804
2018	122,962	\$799
2019	122,121	\$794
2020	121,015	\$787
2021	119,625	\$778
2022	118,190	\$768
2023	116,645	\$758
2024	115,066	\$748
2025	113,335	\$737
2030	107,065	\$696

<sup>a</sup> These estimates include costs associated with the Tier 3 fuel standards in all states except California.

#### 8.1.1.3 Total Costs

The sum of the vehicle technology costs to control exhaust and evaporative emissions, in addition to the costs to control the sulfur level in the fuel, represent the total costs of the program, as shown in Table 8-3.

**Table 8-3: Total Annual Vehicle and Fuel Control Costs, 2011\$**

Year	Total Vehicle Program Costs (\$Million)	Fuel Sulfur Control Costs (\$Million)	Total Program Costs (\$Million) <sup>a</sup>
2016	\$21.4	\$0	\$21
2017	\$297	\$804	\$1,101
2018	\$615	\$799	\$1,414
2019	\$653	\$794	\$1,447
2020	\$697	\$787	\$1,484
2021	\$725	\$778	\$1,503
2022	\$758	\$768	\$1,526
2023	\$751	\$758	\$1,509
2024	\$761	\$748	\$1,509
2025	\$773	\$737	\$1,510
2030	\$761	\$696	\$1,457

<sup>a</sup> These estimates include: (a) costs associated with the Tier 3 vehicle standards in all states except California and states that have adopted the LEV III program and (b) the Tier 3 fuel standards in all states except California.

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### 8.1.2 Quantified and Monetized Health and Environmental Impacts

This section presents EPA's analysis of the criteria pollutant-related health and environmental impacts that would occur as a result of the final Tier 3 standards. The vehicles and fuels subject to the final standards are significant sources of mobile source air pollution such as direct PM, NO<sub>x</sub>, SO<sub>x</sub>, VOCs and air toxics. The standards will affect exhaust and evaporative emissions of these pollutants from vehicles. Emissions of NO<sub>x</sub> (a precursor to ozone formation and secondarily-formed PM<sub>2.5</sub>), SO<sub>x</sub> (a precursor to secondarily-formed PM<sub>2.5</sub>), VOCs (a precursor to ozone formation and, to a lesser degree, secondarily-formed PM<sub>2.5</sub>) and directly-emitted PM<sub>2.5</sub> contribute to ambient concentrations of PM<sub>2.5</sub> and ozone. Exposure to ozone and PM<sub>2.5</sub> is linked to adverse human health impacts such as premature deaths as well as other important public health and environmental effects.

The analysis in this section aims to characterize the benefits of the final standards by answering two key questions:

1. What are the health and welfare effects of changes in ambient particulate matter (PM<sub>2.5</sub>) and ozone air quality resulting from reductions in precursors including NO<sub>x</sub> and SO<sub>2</sub>?
2. What is the economic value of these effects?

For the final rulemaking, we have quantified and monetized the health and environmental impacts in 2030, representing projected impacts associated with a year when the program is fully implemented and most of the fleet is turned over. Overall, we estimate that the final standards will lead to a net decrease in PM<sub>2.5</sub>- and ozone-related health impacts in 2030. The estimated decrease in population-weighted national average PM<sub>2.5</sub> exposure results in a net decrease in adverse PM-related human health impacts (the decrease in national population-weighted annual average PM<sub>2.5</sub> is 0.04 µg/m<sup>3</sup> in 2030).<sup>A</sup> The estimated decrease in population-weighted national average ozone exposure results in a net decrease in ozone-related health impacts (population-weighted maximum 8-hour average ozone decreases by 0.32 ppb in 2030).

Using the lower end of EPA's range of preferred premature mortality estimates (Krewski et al., 2009 for PM<sub>2.5</sub> and Bell et al., 2004 for ozone),<sup>4,5</sup> we estimate that by 2030, implementation of the standards will reduce approximately 770 premature mortalities annually and will yield between \$6.7 and \$7.4 billion in total annual benefits, depending on the discount rate used.<sup>B</sup> The upper end of the range of avoided premature mortality estimates associated with the final standards (based on Lepeule et al., 2012 for PM<sub>2.5</sub> and Levy et al., 2005 for ozone)<sup>6,7</sup>

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<sup>A</sup> Note that the national, population-weighted PM<sub>2.5</sub> and ozone air quality metrics presented in this Chapter represent an average for the entire, gridded U.S. CMAQ domain. These are different than the population-weighted PM<sub>2.5</sub> and ozone design value metrics presented in Chapter 7, which represent the average for areas with a current air quality monitor.

<sup>B</sup> The monetized value of PM<sub>2.5</sub>-related mortality accounts for a twenty-year segmented cessation lag. To discount the value of premature mortality that occurs at different points in the future, we apply both a 3 and 7 percent discount rate. We also use both a 3 and 7 percent discount rate to value PM-related nonfatal heart attacks (myocardial infarctions). Nonfatal myocardial infarctions (MI) are valued using age-specific cost-of-illness values that reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI.

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results in approximately 2,000 premature mortalities avoided in 2030 and will yield between \$18 and \$19 billion in total benefits. Thus, even using the lower end of the range of premature mortality estimates, the health impacts of the final standards presented in this rule are projected to be substantial.

We note that of necessity, decisions on the emissions and other elements used in the air quality modeling were made early in the analytical process for the final rulemaking. For this reason, the modeled changes in emissions used to support the air quality and benefits analyses are slightly different than those used to represent the final emissions impacts of the Tier 3 standards. The magnitude of the differences is small, however, and for that reason we do not expect these differences to materially impact our cost-benefit conclusions. See Chapter 7.2.1.1 for more details.

#### 8.1.2.1 Overview

This analysis reflects the impacts of the final Tier 3 rule in 2030 compared to a future-year reference scenario without the program in place. Overall, we estimate that the final rule will lead to a net decrease in PM<sub>2.5</sub>-related health and environmental impacts (see Section 7.2.4 for more information about the air quality modeling results). The estimated decrease in population-weighted national average PM<sub>2.5</sub> exposure results in a net decrease in adverse PM-related human health and environmental impacts (the decrease in national population weighted annual average PM<sub>2.5</sub> is 0.04 µg/m<sup>3</sup> in 2030).

The air quality modeling also projects decreases in ozone concentrations (see Section 7.2.4). The overall estimated decrease in population-weighted national average ozone exposure results in decreases in ozone-related health and environmental impacts (population weighted maximum 8-hour average ozone decreases by 0.32 ppb in 2030).

We base our analysis of the program's impact on human health and the environment on peer-reviewed studies of air quality and human health effects.<sup>8,9,10</sup> Our benefits methods are consistent with the RIA that accompanied the final revisions to the National Ambient Air Quality Standards (NAAQS) for Particulate Matter, the 2008 final ozone NAAQS, and the 2010 ozone NAAQS reconsideration. To model the ozone and PM air quality impacts of the final standards, we used the Community Multiscale Air Quality (CMAQ) model (see Chapter 7.2.2). The modeled ambient air quality data serves as an input to the Environmental Benefits Mapping and Analysis Program version 4.065 (BenMAP).<sup>C</sup> BenMAP is a computer program developed by the U.S. EPA that integrates a number of the modeling elements used in previous analyses (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.

The range of total monetized ozone- and PM-related health impacts projected in 2030 is presented in Table 8-4. We present total benefits based on the PM- and ozone-related premature

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<sup>C</sup> Information on BenMAP, including downloads of the software, can be found at <http://www.epa.gov/ttn/ecas/benmodels.html>.

mortality function used. The benefits ranges therefore reflect the addition of each estimate of ozone-related premature mortality (each with its own row in Table 8-4) to estimates of PM-related premature mortality.

**Table 8-4: Estimated 2030 Monetized PM-and Ozone-Related Health Benefits**

2030 Total Ozone and PM Benefits – PM Mortality Derived from American Cancer Society Analysis and Six-Cities Analysis <sup>a</sup>			
Premature Ozone Mortality Function	Reference	Total Benefits (Billions, 2011\$, 3% Discount Rate) <sup>b,c</sup>	Total Benefits (Billions, 2011\$, 7% Discount Rate) <sup>b,c</sup>
Multi-city analyses	Bell et al., 2004	Total: \$7.4 - \$15 PM: \$6.0 - \$14 Ozone: \$1.1	Total: \$6.7 - \$14 PM: \$5.4 - \$12 Ozone: \$1.1
	Huang et al., 2005	Total: \$7.9 - \$16 PM: \$6.0 - \$14 Ozone: \$1.7	Total: \$7.3 - \$14 PM: \$5.4 - \$12 Ozone: \$1.7
	Schwartz, 2005	Total: \$8.0 - \$16 PM: \$6.0 - \$14 Ozone: \$1.7	Total: \$7.3 - \$14 PM: \$5.4 - \$12 Ozone: \$1.7
Meta-analyses	Bell et al., 2005	Total: \$9.8 - \$18 PM: \$6.0 - \$14 Ozone: \$3.6	Total: \$9.2 - \$16 PM: \$5.4 - \$12 Ozone: \$3.6
	Ito et al., 2005	Total: \$11 - \$19 PM: \$6.0 - \$14 Ozone: \$4.9	Total: \$11 - \$18 PM: \$5.4 - \$12 Ozone: \$4.9
	Levy et al., 2005	Total: \$11 - \$19 PM: \$6.0 - \$14 Ozone: \$5.0	Total: \$11 - \$18 PM: \$5.4 - \$12 Ozone: \$5.0

<sup>a</sup>Total includes premature mortality-related and morbidity-related ozone and PM<sub>2.5</sub> estimated benefits. Range was developed by adding the estimate from the ozone premature mortality function to the estimate of PM<sub>2.5</sub>-related premature mortality derived from either the ACS study (Krewski et al., 2009) or the Six-Cities study (Lepeule et al., 2012). Range also reflects alternative estimates of non-fatal heart attacks avoided based on either Peters et al. (2001) or a pooled estimate of four studies.

<sup>b</sup>Note that total benefits presented here do not include a number of unquantified benefits categories. A detailed listing of unquantified health effects is provided in Table 8-5.

<sup>c</sup>Results reflect the use of both a 3 and 7 percent discount rate, as recommended by EPA’s Guidelines for Preparing Economic Analyses and OMB Circular A-4. Results are rounded to two significant digits for ease of presentation and computation. Totals may not sum due to rounding.

The benefits analysis presented in this chapter incorporates an array of policy and technical changes that the Agency has adopted since the Tier 3 proposal’s draft RIA. These changes reflect EPA’s work to update PM-related benefits reflected in the most recent PM NAAQS.<sup>11</sup> Below we note the aspects of this analysis that differ from the Tier 3 proposal’s draft RIA.<sup>12</sup>

- *Incorporation of the newest American Cancer Society (ACS) mortality study and newest Harvard Six Cities mortality study.* In 2012, Lepeule et al. published an extended analysis of the Six Cities cohort.<sup>13</sup> Compared to the study it replaces (Laden et al., 2006),<sup>14</sup> this new analysis follows the cohort for a longer time and includes more years of PM<sub>2.5</sub> monitoring data. The all-cause PM<sub>2.5</sub> mortality risk coefficient drawn from Lepeule et al. is roughly similar to the Laden et al. risk

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coefficient applied in the EPA's recent analyses of long-term PM<sub>2.5</sub> mortality and has narrower confidence intervals.

In 2009, the Health Effects Institute published an extended analysis of the ACS cohort (Krewski et al., 2009).<sup>15</sup> Compared to the study it replaces (Pope et al., 2002),<sup>16</sup> this new analysis incorporates a number of methodological improvements.<sup>D</sup> The all-cause PM<sub>2.5</sub> mortality risk estimate drawn from Krewski et al. (2009) is identical to the Pope et al. (2002) risk estimate applied in recent EPA analyses of long-term PM<sub>2.5</sub> mortality but has narrower confidence intervals.

- *Updated health endpoints.* We have removed the quantification of chronic bronchitis from our main analysis. This change is consistent with the findings of the PM Integrated Science Assessment (ISA) that the evidence for an association between long-term exposure to PM<sub>2.5</sub> and respiratory effects is more tenuous.<sup>17</sup>
- *Updated demographic data.* We updated the population demographic data in BenMAP to reflect the 2010 Census and future projections based on economic forecasting models developed by Woods and Poole, Inc.<sup>18</sup> These data replace the earlier demographic projection data from Woods and Poole (2011).<sup>19</sup>
- *Incorporation of new morbidity studies.* Since the publication of the 2004 Criteria Document for Particulate Matter,<sup>20</sup> the publication of the more recent PM ISA,<sup>21</sup> and the Provisional Assessment of Recent Studies on Health Effects of Particulate Matter Exposure ("Provisional Assessment"),<sup>22</sup> the epidemiological literature has produced several new studies examining the association between short-term PM<sub>2.5</sub> exposure and acute myocardial infarctions, respiratory and cardiovascular hospitalizations, respiratory and cardiovascular emergency department visits, acute respiratory symptoms and exacerbation of asthma, respiratory and cardiovascular hospitalizations. Upon careful evaluation of this new literature, we added several new studies to our health impact assessment; in many cases we have replaced older single-city time-series studies with newer multi-city time-series analyses.
- *Updated the survival rates for non-fatal acute myocardial infarctions.* Based on recent data from Agency for Healthcare Research and Quality's Healthcare Utilization Project National Inpatient Sample database,<sup>23</sup> we identified death rates for adults hospitalized with acute myocardial infarction stratified by age. These rates replace the survival rates from Rosamond et al. (1999).<sup>24</sup>
- *Updated hospital cost-of-illness (COI), including median wage data.* In previous benefits analyses, estimates of hospital charges and lengths of hospital stays were based on discharge statistics provided by the Agency for Healthcare Research and Quality's Healthcare Utilization Project National Inpatient Sample (NIS) database

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<sup>D</sup> Refer to the 2012 PM NAAQS RIA for more detail regarding the studies themselves.

for 2000.<sup>25</sup> The version of BenMAP (version 4.0.65) used in this analysis updated this information to use the 2007 database. The data source for the updated median annual income is the 2007 American Community Survey.

The benefits in Table 8-4 include all of the estimated human health impacts we are able to quantify and monetize at this time. However, the full complement of human health effects associated with PM and ozone remain unquantified because of current limitations in methods or available data. We have not quantified a number of known or suspected health effects linked with ozone and PM for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (*e.g.*, changes in heart rate variability). These are listed in Table 8-5. As a result, the health benefits quantified in this analysis are likely underestimates of the total benefits attributable to the final program.

**Table 8-5: Estimated Quantified and Unquantified Health Effects**

<i>BENEFITS CATEGORY</i>	<i>SPECIFIC EFFECT</i>	<i>EFFECT HAS BEEN QUANTIFIED</i>	<i>EFFECT HAS BEEN MONETIZED</i>	<i>MORE INFORMATION</i>
<b><i>Improved Human Health</i></b>				
Reduced incidence of premature mortality and morbidity from exposure to PM <sub>2.5</sub>	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM NAAQS RIA, Section 5.6
	Infant mortality (age <1)	✓	✓	PM NAAQS RIA, Section 5.6
	Non-fatal heart attacks (age > 18)	✓	✓	PM NAAQS RIA, Section 5.6
	Hospital admissions—respiratory (all ages)	✓	✓	PM NAAQS RIA, Section 5.6
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM NAAQS RIA, Section 5.6
	Emergency department visits for asthma (all ages)	✓	✓	PM NAAQS RIA, Section 5.6
	Acute bronchitis (age 8–12)	✓	✓	PM NAAQS RIA, Section 5.6
	Lower respiratory symptoms (age 7–14)	✓	✓	PM NAAQS RIA, Section 5.6
	Upper respiratory symptoms (asthmatics age 9–11)	✓	✓	PM NAAQS RIA, Section 5.6
	Asthma exacerbation (asthmatics age 6–18)	✓	✓	PM NAAQS RIA, Section 5.6
	Lost work days (age 18–65)	✓	✓	PM NAAQS RIA,

<i>BENEFITS CATEGORY</i>	<i>SPECIFIC EFFECT</i>	<i>EFFECT HAS BEEN QUANTIFIED</i>	<i>EFFECT HAS BEEN MONETIZED</i>	<i>MORE INFORMATION</i>
				Section 5.6
	Minor restricted-activity days (age 18–65)	✓	✓	PM NAAQS RIA, Section 5.6
	Chronic Bronchitis (age >26)	—	—	PM NAAQS RIA, Section 5.6 <sup>c</sup>
	Emergency department visits for cardiovascular effects (all ages)	—	—	PM NAAQS RIA, Section 5.6 <sup>c</sup>
	Strokes and cerebrovascular disease (age 50–79)	—	—	PM NAAQS RIA, Section 5.6 <sup>c</sup>
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA <sup>a</sup>
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA <sup>a</sup>
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA <sup>a,b</sup>
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA <sup>a,b</sup>
Reduced incidence of premature mortality and morbidity from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA <sup>c</sup>
	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Hospital admissions—respiratory causes (age <2)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	✓	✓	Ozone ISA
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA <sup>a</sup>

<i>BENEFITS CATEGORY</i>	<i>SPECIFIC EFFECT</i>	<i>EFFECT HAS BEEN QUANTIFIED</i>	<i>EFFECT HAS BEEN MONETIZED</i>	<i>MORE INFORMATION</i>
	Cardiovascular and nervous system effects	—	—	Ozone ISA <sup>b</sup>
	Reproductive and developmental effects	—	—	Ozone ISA <sup>b</sup>
Reduced incidence of morbidity from exposure to air toxics	Cancer (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 mucus membranes (formaldehyde) Respiratory irritation (formaldehyde) 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 and congestion (acrolein)	—	—	IRIS <sup>a,b</sup>

<sup>a</sup> We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

<sup>b</sup> We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

<sup>c</sup> We assess these benefits qualitatively due to time and resource limitations for this analysis.

While there will be impacts associated with reductions in air toxic pollutant emissions that result from the final program, we do not attempt to monetize those impacts. This is primarily because currently available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.<sup>26</sup> While EPA has since improved these tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics.

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As part of the second prospective analysis of the benefits and costs of the Clean Air Act,<sup>27</sup> EPA conducted a case study analysis of the estimated health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act. While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods."<sup>28</sup> EPA continues to work to address these limitations; however, we did not have the methods and tools available for national-scale application in time for the analysis of the final program.<sup>E</sup>

The reduction in air pollution emissions that will result from the final program is projected to have "welfare" co-benefits in addition to human health benefits, including changes in visibility, materials damage, ecological effects from PM deposition, ecological effects from nitrogen and sulfur emissions, vegetation effects from ozone exposure, and climate effects.<sup>F</sup> Despite our goal to quantify and monetize as many of the benefits as possible for the final rulemaking, the welfare co-benefits of the Tier 3 standards remain unquantified and nonmonetized in this RIA due to data, methodology, and resource limitations. As a result, the benefits quantified in this analysis are likely underestimates of the total benefits attributable to the final program. We refer the reader to Chapter 6 of the PM NAAQS RIA for a complete discussion of these welfare co-benefits.<sup>29</sup>

#### 8.1.2.2 Human Health Impacts

Table 8-6 and Table 8-7 present the core estimates of annual PM<sub>2.5</sub> and ozone health impacts in the 48 contiguous U.S. states associated with the final Tier 3 program. For each endpoint presented in Table 8-6 and Table 8-7, we provide both the point estimate and the 90 percent confidence interval.

Using EPA's preferred estimates, based on the American Cancer Society (ACS) and Six-Cities studies and no threshold assumption in the model of mortality, we estimate that the final program would result in between 660 and 1,500 cases of avoided PM<sub>2.5</sub>-related premature deaths annually in 2030. A sensitivity analysis was conducted to understand the impact of alternative concentration response functions suggested by experts in the field. As shown in Table 8-8, when

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<sup>E</sup> In April, 2009, EPA hosted a workshop on estimating the benefits of reducing hazardous air pollutants. This workshop built upon the work accomplished in the June 2000 Science Advisory Board/EPA Workshop on the Benefits of Reductions in Exposure to Hazardous Air Pollutants, which generated thoughtful discussion on approaches to estimating human health benefits from reductions in air toxics exposure, but no consensus was reached on methods that could be implemented in the near term for a broad selection of air toxics. Please visit <http://epa.gov/air/toxicair/2009workshop.html> for more information about the workshop and its associated materials.

<sup>F</sup> We project that the Tier 3 vehicle and fuel standards will reduce nitrous oxide (N<sub>2</sub>O) and methane (CH<sub>4</sub>) emissions from vehicles. The reductions in these potent greenhouse gases will be offset to some degree by the increase in CO<sub>2</sub> emissions from refineries. The combined impact is a net decrease on a CO<sub>2</sub>-equivalent basis and would yield a net benefit if these reductions were monetized.

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the range of expert opinion is used, we estimate between 130 and 2,200 fewer premature mortalities in 2030.

The range of ozone impacts is based on changes in risk estimated using several sources of ozone-related mortality effect estimates. This analysis presents six alternative estimates for the association based upon different functions reported in the scientific literature, derived from both the National Morbidity, Mortality, and Air Pollution Study (NMMAPS)<sup>30,31,32</sup> and from a series of meta-analyses.<sup>33,34,35</sup> This approach is not inconsistent with recommendations provided by the NRC in their report (NRC, 2008) on the estimation of ozone-related mortality risk reductions, “The committee recommends that the greatest emphasis be placed on estimates from new systematic multicity analyses that use national databases of air pollution and mortality, such as in the NMMAPS, without excluding consideration of meta-analyses of previously published studies.”<sup>36</sup> For ozone-related premature mortality in 2030, we estimate a range of between 110 to 500 fewer premature mortalities.

Following these tables, we also provide a more comprehensive presentation of the distributions of incidence generated using the available information from empirical studies and expert elicitation.

Table 8-8 presents the distributions of the reduction in PM<sub>2.5</sub>-related premature mortality based on the C-R distributions provided by each expert, as well as that from the data-derived health impact functions, based on the statistical error associated with the ACS study and the Six-Cities study. The 90 percent confidence interval for each separate estimate of PM-related mortality is also provided.

In 2030, the effect estimates of nine of the twelve experts included in the elicitation panel fall within the empirically-derived range provided by the ACS and Six-Cities studies. Only one expert falls below this range, while two of the experts are above this range. Although the overall range across experts is summarized in these tables, the full uncertainty in the estimates is reflected by the results for the full set of 12 experts. The twelve experts’ judgments as to the likely mean effect estimate are not evenly distributed across the range illustrated by arraying the highest and lowest expert means.

**Table 8-6: Estimated PM<sub>2.5</sub>-Related Health Impacts**

Health Effect	2030 Annual Reduction in Incidence (5 <sup>th</sup> % - 95 <sup>th</sup> %ile)
Premature Mortality – Derived from epidemiology literature <sup>b</sup> Adult, age 30+, ACS Cohort Study (Krewski et al., 2009)	660 (480 – 840)
Adult, age 25+, Six-Cities Study (Lepeule et al., 2012)	1,500 (860 – 2,100)
Infant, age <1 year (Woodruff et al., 1997)	
Non-fatal myocardial infarction (adult, age 18 and over) Peters et al. (2001)	790 (290 – 1,300)
Pooled estimate of 4 studies	85 (42 – 190)
Hospital admissions - respiratory (all ages) <sup>c,e</sup>	210 (-38 – 380)
Hospital admissions - cardiovascular (adults, age >18) <sup>d</sup>	250 (130 – 440)
Emergency room visits for asthma (age 18 years and younger) <sup>e</sup>	340 (-58 – 660)
Acute bronchitis, (children, age 8-12) <sup>e</sup>	980 (-35 – 2,000)
Lower respiratory symptoms (children, age 7-14)	13,000 (6,000 – 19,000)
Upper respiratory symptoms (asthmatic children, age 9-18)	18,000 (5,600 – 30,000)
Asthma exacerbation (asthmatic children, age 6-18)	19,000 (2,300 – 37,000)
Work loss days	81,000 (70,000 – 91,000)
Minor restricted activity days (adults age 18-65)	480,000 (400,000 – 550,000)

<sup>a</sup> Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.

<sup>b</sup> PM-related adult mortality based upon the most recent American Cancer Society (ACS) Cohort Study (Krewski et al., 2009) and the most recent Six-Cities Study (Lepeule et al., 2012). Note that these are two alternative estimates of adult mortality and should not be summed. PM-related infant mortality based upon a study by Woodruff, Grillo, and Schoendorf, (1997).<sup>37</sup>

<sup>c</sup> Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

<sup>d</sup> Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

<sup>e</sup> The negative estimates at the 5th percentile confidence estimates for these morbidity endpoints reflect the statistical power of the study used to calculate these health impacts. These results do not suggest that reducing air pollution results in additional health impacts.

**Table 8-7: Estimated Ozone-Related Health Impacts**

Health Effect	2030 Annual Reduction in Incidence (5th% - 95th%ile)
Premature Mortality, All ages <sup>b</sup>	
Multi-City Analyses	
Bell et al. (2004) – Non-accidental	110 (46 – 170)
Huang et al. (2005) – Cardiopulmonary	160 (74 – 250)
Schwartz (2005) – Non-accidental	170 (68 – 270)
Meta-analyses:	
Bell et al. (2005) – All cause	350 (190 – 510)
Ito et al. (2005) – Non-accidental	490 (320 – 660)
Levy et al. (2005) – All cause	500 (360 – 630)
Hospital admissions- respiratory causes (adult, 65 and older) <sup>c</sup>	740 (87 – 1,400)
Hospital admissions -respiratory causes (children, under 2)	310 (160 – 450)
Emergency room visit for asthma (all ages) <sup>d</sup>	330 (-8 – 990)
Minor restricted activity days (adults, age 18-65)	600,000 (290,000 – 910,000)
School absence days	210,000 (92,000 – 300,000)

<sup>a</sup> Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous U.S.

<sup>b</sup> Estimates of ozone-related premature mortality are based upon incidence estimates derived from several alternative studies: Bell et al. (2004); Huang et al. (2005); Schwartz (2005) ; Bell et al. (2005); Ito et al. (2005); Levy et al. (2005). The estimates of ozone-related premature mortality should therefore not be summed.

<sup>c</sup> Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

<sup>d</sup> The negative estimate at the 5th percentile confidence estimate for this morbidity endpoint reflects the statistical power of the study used to calculate this health impact. This result does not suggest that reducing air pollution results in additional health impacts.

**Table 8-8: Results of Application of Expert Elicitation: Annual Reductions in Premature Mortality in 2030 Associated with the Final Program**

Source of Mortality Estimate	2030 Tier 3 Control		
	5th Percentile	Mean	95th Percentile
Krewski et al. (2009)	480	660	840
Lepeule et al. (2012)	860	1,500	2,100
Expert A	340	1,700	3,300
Expert B	88	1,400	2,900
Expert C	480	1,300	2,200
Expert D	58	950	1,500
Expert E	1,100	2,200	3,300

Source of Mortality Estimate	2030 Tier 3 Control		
	5th Percentile	Mean	95th Percentile
Expert F	790	1,200	1,700
Expert G	-1	790	1,400
Expert H	-2	980	2,300
Expert I	110	1,300	2,300
Expert J	160	1,100	2,300
Expert K	0	130	590
Expert L	1	860	1,800

### 8.1.2.3 Monetized Estimates of Human Health and Environmental Impacts

Table 8-9 presents the estimated monetary value of changes in the incidence of ozone and PM<sub>2.5</sub>-related health and environmental effects. Total aggregate monetized benefits are presented in Table 8-10. All monetized estimates are presented in 2011\$. Where appropriate, estimates account for growth in real gross domestic product (GDP) per capita between 2000 and 2030.<sup>G</sup> The monetized value of PM<sub>2.5</sub>-related mortality also accounts for a twenty-year segmented cessation lag.<sup>H</sup> To discount the value of premature mortality that occurs at different points in the future, we apply both a 3 and 7 percent discount rate. We also use both a 3 and 7 percent discount rate to value PM-related nonfatal heart attacks (myocardial infarctions).<sup>I</sup>

In addition to omitted benefits categories such as air toxics and various welfare effects, not all known PM<sub>2.5</sub>- and ozone-related health and welfare effects could be quantified or monetized. The estimate of total monetized health benefits of the final program is thus equal to the subset of monetized PM<sub>2.5</sub>- and ozone-related health impacts we are able to quantify plus the sum of the nonmonetized health and welfare benefits. Our estimate of total monetized benefits in 2030 for the final program, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, is between \$7.4 and \$19 billion billion, assuming a 3 percent

<sup>G</sup> 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. Benefits are therefore adjusted by multiplying the unadjusted benefits by the appropriate adjustment factor to account for income growth over time. For growth between 2000 and 2030, this factor is 1.23 for long-term mortality, 1.27 for chronic health impacts, and 1.08 for minor health impacts. For a complete discussion of how these adjustment factors were derived, we refer the reader to the PM NAAQS regulatory impact analysis. Note that similar adjustments do not exist for cost-of-illness-based unit values. For these, we apply the same unit value regardless of the future year of analysis.

<sup>H</sup> Based in part on prior SAB advice, EPA has typically assumed that there is a time lag between changes in pollution exposures and the total realization of changes in health effects. Within the context of benefits analyses, this term is often referred to as “cessation lag”. 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. In this analysis, we apply a twenty-year distributed lag to PM mortality reductions. This method is consistent with the most recent recommendation by the EPA’s Science Advisory Board. Refer to: EPA – Science Advisory Board, 2004. Advisory Council on Clean Air Compliance Analysis Response to Agency Request on Cessation Lag. Letter from the Health Effects Subcommittee to the U.S. Environmental Protection Agency Administrator, December.

<sup>I</sup> Nonfatal myocardial infarctions (MI) are valued using age-specific cost-of-illness values that reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI.

discount rate, or between \$6.7 and \$18 billion, assuming a 7 percent discount rate. As the results indicate, total benefits are driven primarily by the reduction in PM<sub>2.5</sub>- and ozone-related premature fatalities each year and represent the benefits of the Tier 3 program anticipated to occur annually when the program is fully implemented and most of the fleet turned over.

The next largest benefit is for reductions in nonfatal heart attacks, although this value is more than an order of magnitude lower than for premature mortality. Hospital admissions for respiratory and cardiovascular causes, minor restricted activity days, and work loss days account for the majority of the remaining benefits. The remaining categories each account for a small percentage of total benefit; 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 many more work loss days than PM-related 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 of willingness-to-pay (e.g., cost-of-illness). As such, the true value of these effects may be higher than that reported here.

**Table 8-9: Estimated Monetary Value of Changes in Incidence of Health and Welfare Effects (millions of 2010\$)**

HEALTH ENDPOINTS		2030 (5 <sup>TH</sup> AND 95 <sup>TH</sup> PERCENTILE)
<b>PM<sub>2.5</sub>-Related Health Effects</b>		
Premature Mortality – Derived from Epidemiology Studies <sup>b,c</sup>	Adult, age 30+ - ACS study (Krewski et al., 2009) 3% discount rate	\$6,100 (\$910 - \$14,000)
	7% discount rate	\$5,500 (\$820 - \$13,000)
	Adult, age 25+ - Six-Cities study (Lepeule et al., 2012) 3% discount rate	\$14,000 (\$2,000 - \$33,000)
	7% discount rate	\$12,000 (\$1,800 - \$30,000)
	Infant Mortality, <1 year – (Woodruff et al. 1997)	\$13 (\$1.8 - \$32)
	Non-fatal acute myocardial infarctions Peters et al., 2001 3% discount rate	\$96 (\$21 - \$230)
7% discount rate	\$93 (\$19 - \$220)	
Pooled estimate of 4 studies 3% discount rate	\$10 (\$2.6 - \$27)	
7% discount rate	\$10 (\$2.4 - \$27)	

Hospital admissions for respiratory causes <sup>d</sup>		\$5.9 (-\$1.6 - \$11)
Hospital admissions for cardiovascular causes		\$9.9 (\$5.0 - \$17)
Emergency room visits for asthma <sup>d</sup>		\$0.15 (-\$0.02 - \$0.29)
Acute bronchitis (children, age 8–12) <sup>d</sup>		\$0.49 (-\$0.02 - \$1.2)
Lower respiratory symptoms (children, 7–14)		\$0.27 (\$0.11 - \$0.51)
Upper respiratory symptoms (asthma, 9–11)		\$0.62 (\$0.18 - \$1.4)
Asthma exacerbations		\$1.1 (\$0.14 - \$2.7)
Work loss days		\$12 (\$11 - \$14)
Minor restricted-activity days (MRADs)		\$34 (\$20 - \$49)
<b>Ozone-Related Health Effects</b>		
Premature Mortality, All ages – Derived from Multi-city analyses	Bell et al., 2004	\$1,100 (\$150 - \$2,800)
	Huang et al., 2005	\$1,600 (\$220 - \$4,100)
	Schwartz, 2005	\$1,700 (\$220 - \$4,400)
Premature Mortality, All ages – Derived from Meta-analyses	Bell et al., 2005	\$3,600 (\$510 - \$8,800)
	Ito et al., 2005	\$5,000 (\$740 - \$12,000)
	Levy et al., 2005	\$5,100 (\$760 - \$12,000)
Hospital admissions- respiratory causes (adult, 65 and older)		\$21 (\$2.5 - \$39)
Hospital admissions- respiratory causes (children, under 2)		\$3.7 (\$1.9 - \$5.4)
Emergency room visit for asthma (all ages)		\$0.14 (-\$0.003 - \$0.41)
Minor restricted activity days (adults, age 18-65)		\$43 (\$19 - \$73)
School absence days		\$21 (\$9.3 - \$31)

<sup>a</sup> Monetary benefits are rounded to two significant digits for ease of presentation and computation. PM and ozone benefits are nationwide.

<sup>b</sup> Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2030).

<sup>c</sup> Valuation assumes discounting over the SAB recommended 20 year segmented lag structure. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses.

<sup>d</sup> The negative estimate at the 5th percentile confidence estimate for this morbidity endpoint reflects the statistical power of the study used to calculate this health impact. This result does not suggest that reducing air pollution results in additional health impacts.

**Table 8-10: Total Monetized Ozone and PM-related Benefits Associated with the Final Program in 2030**

<b>Total Ozone and PM Benefits (billions, 2011\$) – PM Mortality Derived from the ACS and Six-Cities Studies</b>					
<b>3% Discount Rate</b>			<b>7% Discount Rate</b>		
Ozone Mortality Function	Reference	Mean Total Benefits	Ozone Mortality Function	Reference	Mean Total Benefits
Multi-city	Bell et al., 2004	\$7.4 - \$15	Multi-city	Bell et al., 2004	\$6.7 - \$14
	Huang et al., 2005	\$7.9 - \$16		Huang et al., 2005	\$7.3 - \$14
	Schwartz, 2005	\$8.0 - \$16		Schwartz, 2005	\$7.3 - \$14
Meta-analysis	Bell et al., 2005	\$9.8 - \$18	Meta-analysis	Bell et al., 2005	\$9.2 - \$16
	Ito et al., 2005	\$11 - \$19		Ito et al., 2005	\$11 - \$18
	Levy et al., 2005	\$11 - \$19		Levy et al., 2005	\$11 - \$18
<b>Total Ozone and PM Benefits (billions, 2011\$) – PM Mortality Derived from Expert Elicitation (Lowest and Highest Estimate)</b>					
<b>3% Discount Rate</b>			<b>7% Discount Rate</b>		
Ozone Mortality Function	Reference	Mean Total Benefits	Ozone Mortality Function	Reference	Mean Total Benefits
Multi-city	Bell et al., 2004	\$2.4 - \$22	Multi-city	Bell et al., 2004	\$2.4 - \$20
	Huang et al., 2005	\$2.9 - \$22		Huang et al., 2005	\$2.9 - \$20
	Schwartz, 2005	\$3.0 - \$22		Schwartz, 2005	\$3.0 - \$20
Meta-analysis	Bell et al., 2005	\$4.9 - \$24	Meta-analysis	Bell et al., 2005	\$4.9 - \$22
	Ito et al., 2005	\$6.3 - \$26		Ito et al., 2005	\$6.3 - \$24
	Levy et al., 2005	\$6.3 - \$26		Levy et al., 2005	\$6.3 - \$26

#### 8.1.2.4 Methodology

We follow a “damage-function” approach in calculating total benefits of the modeled changes in environmental quality. This approach estimates changes in individual health endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the values for those individual endpoints. Total benefits are calculated simply as the sum of the values for all non-overlapping health endpoints. The “damage-function” approach is the standard method for assessing costs and benefits of environmental quality programs and has been used in several recent published analyses.<sup>38,39,40</sup>

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. In other cases, such as for

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changes in ozone and PM, an 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 (HIA) includes those health effects that are directly linked to ambient levels of air pollution and specifically to those linked to ozone and PM<sub>2.5</sub>.

We note at the outset that the EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to Kunzli et al. (2000)<sup>41</sup> and other, more 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. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

#### 8.1.2.4.1 Human Health Impact Assessment

The health impact assessment (HIA) quantifies the changes in the incidence of adverse health impacts resulting from changes in human exposure to PM<sub>2.5</sub> and ozone air quality. HIAs are a well-established approach for estimating the retrospective or prospective change in adverse health impacts expected to result from population-level changes in exposure to pollutants.<sup>42</sup> PC-based tools such as the environmental *Benefits Mapping and Analysis Program* (BenMAP) can systematize health impact analyses by applying a database of key input parameters, including health impact functions and population projections—provided that key input data are available, including air quality estimates and risk coefficients.<sup>43</sup> Analysts have applied the HIA approach to estimate human health impacts resulting from hypothetical changes in pollutant levels.<sup>44, 45 46</sup> The EPA and others have relied upon this method to predict future changes in health impacts expected to result from the implementation of regulations affecting air quality.<sup>47</sup> For this assessment, the HIA is limited to those health effects that are directly linked to ambient ozone and PM<sub>2.5</sub> concentrations.

The HIA approach used in this analysis involves three basic steps: (1) utilizing projections of PM<sub>2.5</sub> air quality<sup>J</sup> and estimating the change in the spatial distribution of the ambient air quality; (2) determining the subsequent change in population-level exposure; (3) calculating health impacts by applying concentration-response relationships drawn from the epidemiological literature to this change in population exposure.

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 (the product of the baseline incidence rate times the potentially affected population),  $\beta$  is the effect estimate, and  $\Delta x$  is the estimated change in the summary

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<sup>J</sup> Projections of ambient PM<sub>2.5</sub> concentrations for this analysis were generated using the Community Multiscale Air Quality model (CMAQ). See Chapter 7 of this RIA for more information on the air quality modeling.

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pollutant measure. There are other functional forms, but the basic elements remain the same. The following subsections describe the sources for each of the first three elements: size of the potentially affected populations; PM<sub>2.5</sub> and ozone effect estimates; and baseline incidence rates. We also describe the treatment of potential thresholds in PM-related health impact functions in Section 8.1.2.5.3. Section 8.1.2.4.6 describes the ozone and PM air quality inputs to the health impact functions.

#### 8.1.2.4.2 *Potentially Affected Populations*

Quantified and monetized human health impacts depend on the demographic characteristics of the population, including age, location, and income. We use population projections based on economic forecasting models developed by Woods and Poole, Inc.<sup>48</sup> The Woods and Poole (WP) database contains county-level projections of population by age, sex, and race out to 2040, relative to a baseline using the 2010 Census data. Projections in each county are determined simultaneously with every other county in the United States 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.<sup>49</sup> 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, and populations are forecasted.
- Second, employment projections are made for 179 economic areas defined by the Bureau of Economic Analysis,<sup>50</sup> 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-based 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 2040 based on historical rates of mortality, fertility, and migration.

#### 8.1.2.4.3 *Effect Estimate Sources*

The first step in selecting effect coefficients is to identify the health endpoints to be quantified. We base our selection of health endpoints on consistency with the EPA’s Integrated Science Assessments (which replace previous Criteria Documents), with input and advice from the SAB-HES, a scientific review panel specifically established to provide advice on the use of the scientific literature in developing benefits analyses for the EPA’s Report to Congress on *The Benefits and Costs of the Clean Air Act 1990 to 2020*.<sup>51</sup> In addition, we have included more

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recent epidemiology studies from the PM ISA and the Provisional Assessment.<sup>52,53</sup> In general, we follow a weight of evidence approach, based on the biological plausibility of effects, availability of concentration-response functions from well conducted peer-reviewed epidemiological studies, cohesiveness of results across studies, and a focus on endpoints reflecting public health impacts (like hospital admissions) rather than physiological responses (such as changes in clinical measures like Forced Expiratory Volume [FEV1]).

There are several types of data that can support the determination of types and magnitude of health effects associated with air pollution exposures. These sources of data include toxicological studies (including animal and cellular studies), human clinical trials, and observational epidemiology studies. All of these data sources provide important contributions to the weight of evidence surrounding a particular health impact. However, only epidemiology studies provide direct concentration-response relationships that can be used to evaluate population-level impacts of reductions in ambient pollution levels in a health impact assessment.

For the data-derived estimates, we relied on the published scientific literature to ascertain the relationship between PM<sub>2.5</sub>, ozone, and adverse human health effects. We evaluated epidemiological studies using the selection criteria summarized in Table 8-11. 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. In general, the use of concentration-response functions from more than a single study can provide a more representative distribution of the effect estimate. 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 BenMAP Manual Technical Appendices provides details of the procedures used to combine multiple impact functions.<sup>54</sup> In general, we used fixed or random effects models to pool estimates from different single city 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 used the fixed effects model as our null hypothesis and then determined whether the data suggest that we should reject this null hypothesis, in which case we would use the random effects model.<sup>K</sup> Pooled impact functions are used to estimate hospital admissions

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<sup>K</sup> EPA recently changed the algorithm BenMAP uses to calculate study variance, which is used in the pooling process. Prior versions of the model calculated population variance, while the version used here calculated sample

and asthma exacerbations. When combining evidence across multi-city studies (e.g., cardiovascular hospital admission studies), we use equal weights pooling. The effect estimates drawn from each multi-city study are themselves pooled across a large number of urban areas. For this reason, we elected to give each study an equal weight rather than weighting by the inverse of the variance reported in each study. For more details on methods used to pool incidence estimates, see the BenMAP Manual Appendices.

Effect estimates selected for a given health endpoint were 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., because of differences in population susceptibilities or differences in the composition of PM), location-specific effect estimates are generally not available.

**Table 8-11: Criteria Used When Selecting C-R Functions**

<i>Consideration</i>	<i>Comments</i>
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 ecological studies because they control for important individual-level confounding variables that cannot be controlled for in ecological 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. Studies that are more recent are also preferred because of possible changes in pollution mixes, medical care, and lifestyle 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. When available, multi-city studies are preferred to single city studies because they provide a more generalizable representation of the concentration-response function.
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, including through a large population or through repeated observations on a smaller population (e.g., 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 lifestyle. National estimates are most appropriate when benefits are nationally distributed; the impact of regional differences may be important when benefits only accrue to a single area.
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. Using single-pollutant models in cases where both pollutants are expected to affect a health

variance. This change did not affect the selection of random or fixed effects for the pooled incidence estimates between the proposal and final RIA.

	outcome can lead to double-counting when pollutants are correlated.
Measure of PM	For this analysis, impact functions based on PM <sub>2.5</sub> are preferred to PM <sub>10</sub> because of the focus on reducing emissions of PM <sub>2.5</sub> precursors, and because air quality modeling was conducted for this size fraction of PM. Where PM <sub>2.5</sub> functions are not available, PM <sub>10</sub> functions are used as surrogates, recognizing that there will be potential downward (upward) biases if the fine fraction of PM <sub>10</sub> is more (less) toxic than the coarse fraction.
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 note that we are unable to separately quantify all of the possible PM and ozone health effects that have been reported in the literature for three reasons: (1) the possibility of double counting (such as hospital admissions for specific respiratory diseases versus hospital admissions for all or a sub-set of respiratory diseases); (2) uncertainties in applying effect relationships that are based on clinical studies to the potentially affected population; or (3) the lack of an established concentration-response (CR) relationship. Table 8-12 lists the health endpoints included in this analysis.

**Table 8-12: Health Impact Functions Used in BenMAP to Estimate Impacts of PM<sub>2.5</sub> and Ozone Reductions**

<i>ENDPOINT</i>	<i>POLLUTANT</i>	<i>STUDY</i>	<i>STUDY POPULATION</i>
<b>Premature Mortality</b>			
Premature mortality – daily time series	O <sub>3</sub>	<u>Multi-city</u> Bell et al (2004) (NMMAPS study) <sup>55</sup> – Non-accidental Huang et al (2005) <sup>56</sup> - Cardiopulmonary Schwartz (2005) <sup>57</sup> – Non-accidental <u>Meta-analyses:</u> Bell et al (2005) <sup>58</sup> – All cause Ito et al (2005) <sup>59</sup> – Non-accidental Levy et al (2005) <sup>60</sup> – All cause	All ages
Premature mortality —cohort study, all-cause	PM <sub>2.5</sub>	Krewski et al. (2009) <sup>61</sup> Lepeule et al. (2012) <sup>62</sup>	>29 years >25 years
Premature mortality, total exposures	PM <sub>2.5</sub>	Expert Elicitation (IEc, 2006) <sup>63</sup>	>24 years
Premature mortality — all-cause	PM <sub>2.5</sub>	Woodruff et al. (1997) <sup>64</sup>	Infant (<1 year)
<b>Chronic Illness</b>			

<i>ENDPOINT</i>	<i>POLLUTANT</i>	<i>STUDY</i>	<i>STUDY POPULATION</i>
Nonfatal heart attacks	PM <sub>2.5</sub>	Peters et al. (2001) <sup>65</sup> Pooled estimate: Pope et al. (2006) <sup>66</sup> Sullivan et al. (2005) <sup>67</sup> Zanobetti et al. (2009) <sup>68</sup> Zanobetti and Schwartz (2006) <sup>69</sup>	Adults (>18 years)
<b>Hospital Admissions</b>			
Respiratory	O <sub>3</sub>	Pooled estimate: Schwartz (1995) - ICD 460-519 (all resp) <sup>70</sup> Schwartz (1994a; 1994b) - ICD 480-486 (pneumonia) <sup>71,72</sup> Moolgavkar et al. (1997) - ICD 480-487 (pneumonia) <sup>73</sup> Schwartz (1994b) - ICD 491-492, 494-496 (COPD) Moolgavkar et al. (1997) - ICD 490-496 (COPD)	>64 years
		Burnett et al. (2001) <sup>74</sup>	<2 years
	PM <sub>2.5</sub>	Pooled estimate: Zanobetti et al. (2009)—ICD 460-519 (All respiratory) Kloog et al. (2012)—ICD 460-519 (All Respiratory) <sup>75</sup>	>64 years
	PM <sub>2.5</sub>	Moolgavkar (2000)—ICD 490–496 (Chronic lung disease) <sup>76</sup>	18–64 years
	PM <sub>2.5</sub>	Pooled estimate: Babin et al. (2007)—ICD 493 (asthma) <sup>77</sup> Sheppard (2003)—ICD 493 (asthma) <sup>78</sup>	<18 years
Cardiovascular	PM <sub>2.5</sub>	Pooled estimate: Zanobetti et al. (2009)—ICD 390-459 (all cardiovascular) Peng et al. (2009)—ICD 426-427; 428; 430-438; 410-414; 429; 440-449 (Cardio-, cerebro- and peripheral vascular disease) <sup>79</sup> Peng et al. (2008)—ICD 426-427; 428; 430-438; 410-414; 429; 440-449 (Cardio-, cerebro- and peripheral vascular disease) <sup>80</sup> Bell et al. (2008)—ICD 426-427; 428; 430-438; 410-414; 429; 440-449 (Cardio-, cerebro- and peripheral vascular disease) <sup>81</sup>	>64 years
	PM <sub>2.5</sub>	Moolgavkar (2000)—ICD 390-429 (all cardiovascular)	20–64 years
Asthma-related ER visits	O <sub>3</sub>	Pooled estimate: Peel et al (2005) <sup>82</sup> Wilson et al (2005) <sup>83</sup>	All ages All ages
Asthma-related ER visits (cont'd)	PM <sub>2.5</sub>	Pooled estimate: Mar et al. (2010) <sup>84</sup> Slaughter et al. (2005) <sup>85</sup> Glad et al. (2012) <sup>86</sup>	All ages

<i>ENDPOINT</i>	<i>POLLUTANT</i>	<i>STUDY</i>	<i>STUDY POPULATION</i>
<b>Other Health Endpoints</b>			
Acute bronchitis	PM <sub>2.5</sub>	Dockery et al. (1996) <sup>87</sup>	8–12 years
Upper respiratory symptoms	PM <sub>2.5</sub>	Pope et al. (1991) <sup>88</sup>	Asthmatics, 9–11 years
Lower respiratory symptoms	PM <sub>2.5</sub>	Schwartz and Neas (2000) <sup>89</sup>	7–14 years
Asthma exacerbations	PM <sub>2.5</sub>	<u>Pooled estimate:</u> Ostro et al. (2001) <sup>90</sup> (cough, wheeze and shortness of breath) Mar et al. (2004) (cough, shortness of breath)	6–18 years <sup>a</sup>
Work loss days	PM <sub>2.5</sub>	Ostro (1987) <sup>91</sup>	18–65 years
School absence days	O <sub>3</sub>	<u>Pooled estimate:</u> Gilliland et al. (2001) <sup>92</sup> Chen et al. (2000) <sup>93</sup>	5–17 years <sup>b</sup>
Minor Restricted Activity Days (MRADs)	O <sub>3</sub>	Ostro and Rothschild (1989) <sup>94</sup>	18–65 years
	PM <sub>2.5</sub>	Ostro and Rothschild (1989)	18–65 years

Notes:

<sup>a</sup> The original study populations were 8 to 13 for the Ostro et al. (2001) study and 7 to 12 for the Mar et al. (2004) study. Based on advice from the SAB-HES, we extended the applied population to 6-18, reflecting the common biological basis for the effect in children in the broader age group. See: U.S. EPA-SAB (2004) and NRC (2002).

<sup>b</sup> Gilliland et al. (2001) studied children aged 9 and 10. Chen et al. (2000) studied children 6 to 11. Based on advice from the National Research Council and the EPA SAB-HES, we have calculated reductions in school absences for all school-aged children based on the biological similarity between children aged 5 to 17.

For detailed descriptions of each of the individual studies referenced in Table 8-12, please refer to the RIAs that accompanied the final revisions to the National Ambient Air Quality Standards (NAAQS) for Particulate Matter, the 2008 final ozone NAAQS, and the 2010 ozone NAAQS reconsideration.<sup>95,96,97</sup>

#### 8.1.2.4.4 Baseline Incidence Rates

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 estimating the absolute number of avoided cases. For example, a typical result might be that a 10 µg/m<sup>3</sup> decrease in daily PM<sub>2.5</sub> levels might be associated with a decrease in hospital admissions of 3%. The baseline incidence of the health effect is necessary to convert this relative change into a number of cases. A baseline incidence rate is the estimate of the number of cases of the health effect per year in the assessment location, as it corresponds 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. For example, if the baseline incidence rate is the number of cases per year per million people, that number must be multiplied by the millions of people in the total population.

Table 8-13 summarizes the sources of baseline incidence rates and provides average incidence rates for the endpoints included in the analysis. For both baseline incidence and prevalence data, we used age-specific rates where available. We applied concentration-response functions to individual age groups and then summed over the relevant age range to provide an

estimate of total population benefits. In most cases, we used a single national incidence rate, due to a lack of more spatially disaggregated data. Whenever possible, the national rates used are national averages, because these data are most applicable to a national assessment of benefits. For some studies, however, 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. County, state and regional incidence rates are available for hospital admissions, and county-level data are available for premature mortality.

We projected mortality rates such that future mortality rates are consistent with our projections of population growth.<sup>98</sup> To perform this calculation, we began first with an average of 2004–2006 cause-specific mortality rates. Using Census Bureau projected national-level annual mortality rates stratified by age range, we projected these mortality rates to 2050 in 5-year increments.<sup>99,100</sup>

The baseline incidence rates for hospital admissions and emergency department visits reflect the revised rates first applied in the CSAPR RIA.<sup>101</sup> In addition, we have revised the baseline incidence rates for acute myocardial infarction. These revised rates are more recent, which provides a better representation of the rates at which populations of different ages, and in different locations, visit the hospital and emergency department for air pollution-related illnesses. Also, the new baseline incidence rates are more spatially refined. For many locations within the U.S., these data are resolved at the county- or state-level, providing a better characterization of the geographic distribution of hospital and emergency department visits than the previous national rates. Lastly, these rates reflect unscheduled hospital admissions only, which represent a conservative assumption that most air pollution-related visits are likely to be unscheduled. If air pollution-related hospital admissions are scheduled, this assumption would underestimate these benefits.

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 8-14 lists the prevalence rates used to determine the applicable population for asthma symptoms. Note that these reflect current asthma prevalence and assume no change in prevalence rates in future years. We updated these rates in the CSAPR RIA.

**Table 8-13: Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population**

<i>Endpoint</i>	<i>Parameter</i>	<i>Rates</i>	
		<i>Value</i>	<i>Source</i>
Mortality	Daily or annual mortality rate projected to 2020	Age-, cause-, and county-specific rate	CDC Wonder (2006–2008) <sup>102</sup> U.S. Census bureau
Hospitalizations	Daily hospitalization rate	Age-, region-, state-, county- and cause-specific rate	2007 HCUP data files <sup>a,103</sup>
Asthma ER Visits	Daily asthma ER visit rate	Age-, region-, state-, county- and cause-specific rate	2007 HCUP data files <sup>a</sup>
Nonfatal Myocardial	Daily nonfatal myocardial	Age-, region-, state-,	2007 HCUP data files; <sup>a</sup> adjusted by

<i>Endpoint</i>	<i>Parameter</i>	<i>Rates</i>	
		<i>Value</i>	<i>Source</i>
Infarction (heart attacks)	infarction incidence rate per person, 18+	and county- specific rate	0.93 for probability of surviving after 28 days (Rosamond et al., 1999) <sup>104</sup>
Asthma Exacerbations	Incidence among asthmatic African-American children daily wheeze daily cough daily shortness of breath	0.173 0.145 0.074	Ostro et al. (2001)
Acute Bronchitis	Annual bronchitis incidence rate, children	0.043	American Lung Association (2002, Table 11) <sup>105</sup>
Lower Respiratory Symptoms	Daily lower respiratory symptom incidence among children <sup>b</sup>	0.0012	Schwartz et al. (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) Aged 18–24 Aged 25–44 Aged 45–64	0.00540 0.00678 0.00492	1996 HIS (Adams, Hendershot, and Marano, 1999, Table 41); <sup>106</sup> U.S. Bureau of the Census (2000) <sup>107</sup>
School Loss Days	Rate per person per year, assuming 180 school days per year	9.9	National Center for Education Statistics (1996) <sup>108</sup> and 1996 HIS (Adams et al., 1999, Table 47);
Minor Restricted-Activity Days	Daily MRAD incidence rate per person	0.02137	Ostro and Rothschild (1989, p. 243)

Notes:

<sup>a</sup> Healthcare Cost and Utilization Program (HCUP) database contains individual level, state and regional-level hospital and emergency department discharges for a variety of ICD codes.

<sup>b</sup> Lower respiratory symptoms are defined as two or more of the following: cough, chest pain, phlegm, and wheeze.

**Table 8-14: Asthma Prevalence Rates Used for this Analysis**

<i>Population Group</i>	<i>Asthma Prevalence Rates</i>	
	<i>Value</i>	<i>Source</i>
All Ages	0.0780	American Lung Association (2010, Table 7) <sup>109</sup>
< 18	0.0941	
5–17	0.1070	
18–44	0.0719	
45–64	0.0745	
65+	0.0716	
African American, 5 to 17	0.1776	American Lung Association (2010, Table 9)
African American, <18	0.1553	American Lung Association <sup>a</sup>

Notes:

<sup>ab</sup> Calculated by ALA for U.S. EPA, based on NHIS data (CDC, 2008).<sup>110</sup>

#### 8.1.2.4.5 Economic Values for Health Outcomes

After quantifying the change in adverse health impacts, we estimate the economic value of these avoided impacts. The appropriate economic value for a change in a health effect depends

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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 effects by a small amount for a large population. The appropriate economic measure is therefore ex ante willingness to pay (WTP) for changes in risk.<sup>111</sup> Epidemiological studies generally provide estimates of the relative risks of a particular health effect for a given increment of air pollution (often per 10  $\mu\text{g}/\text{m}^3$  for  $\text{PM}_{2.5}$ ). These relative risks can be used to develop risk coefficients that relate a unit reduction in  $\text{PM}_{2.5}$  to changes in the incidence of a health effect. In order to value these changes in incidence, WTP for changes in risk need to be converted into WTP per statistical incidence. 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. 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 cost-of-illness (COI) estimates generally (although not necessarily in every case) 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.<sup>112,113</sup>

We provide unit values for health endpoints (along with information on the distribution of the unit value) in Table 8-15. All values are in constant year 2011 dollars, adjusted for growth in real income out to 2030 using projections provided by Standard and Poor's. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real income increases. Many of the valuation studies used in this analysis were conducted in the late 1980s and early 1990s. Because real income has grown since the studies were conducted, people's willingness to pay for reductions in the risk of premature death and disease likely has grown as well. We did not adjust cost of illness-based values because they are based on current costs. Similarly, we did not adjust the value of school absences, because that value is based on current wage rates. For details on valuation estimates for PM-related endpoints, see the the RIA that accompanied the final revisions to the National Ambient Air Quality Standards (NAAQS) for Particulate Matter.<sup>114</sup> For details on valuation estimates for ozone-related endpoints, see the RIAs for the 2008 Ozone NAAQS RIA and the 2010 ozone NAAQS reconsideration.<sup>115,116</sup>

**Table 8-15: Unit Values for Economic Valuation of Health Endpoints (2011\$)**

Health Endpoint	Central Estimate of Value Per Statistical Incidence		Derivation of Distributions of Estimates
	1990 Income Level	2030 Income Level <sup>a</sup>	
Premature Mortality (Value of a Statistical Life)	\$8,300,000	\$10,200,000	EPA currently recommends a central VSL of \$6.3m (2000\$, 1990 income) based on a Weibull distribution fitted to 26 published VSL estimates (5 contingent valuation and 21 labor market studies). The underlying studies, the distribution parameters, and other useful information are available in Appendix B of EPA's current Guidelines for Preparing Economic Analyses (U.S. EPA, 2010). <sup>117</sup>
Nonfatal Myocardial Infarction (heart attack) 3% discount rate			No distributional information available. Age-specific cost-of-illness values reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI. Lost earnings estimates are based on Cropper and Krupnick (1990). <sup>118</sup> Direct medical costs are based on simple average of estimates from Russell et al. (1998) <sup>119</sup> and Wittels et al. (1990). <sup>120</sup> Lost earnings: Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings: age of onset: at 3% at 7% 25-44 \$9,000 \$8,000 45-54 \$13,000 \$12,000 55-65 \$77,000 \$69,000 Direct medical expenses: An average of: 1. Wittels et al. (1990) (\$100,000—no discounting) 2. Russell et al. (1998), 5-year period (\$22,000 at 3% discount rate; \$21,000 at 7% discount rate)
Age 0-24	\$100,000	\$100,000	
Age 25-44	\$110,000	\$110,000	
Age 45-54	\$120,000	\$120,000	
Age 55-65	\$210,000	\$210,000	
Age 66 and over	\$100,000	\$100,000	
7% discount rate			
Age 0-24	\$100,000	\$100,000	
Age 25-44	\$110,000	\$110,000	
Age 45-54	\$110,000	\$110,000	
Age 55-65	\$200,000	\$200,000	
Age 66 and over	\$100,000	\$100,000	
<b>Hospital Admissions</b>			
Chronic Obstructive Pulmonary Disease (COPD)	\$22,000	\$22,000	
Asthma Admissions	\$17,000	\$17,000	No distributional information available. 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 (2007) (www.ahrq.gov).
All Cardiovascular			No distributional information available. 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 (2007) (www.ahrq.gov).
Age 18-64	\$43,000	\$43,000	
Age 65-99	\$42,000	\$42,000	
All respiratory (ages 65+)	\$37,000	\$37,000	No distributions 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, 2007 (www.ahrq.gov).
All respiratory (ages 0–2)	\$13,000	\$13,000	No distributions 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, 2007 (www.ahrq.gov).
Emergency Room Visits for Asthma	\$440	\$440	No distributional information available. Simple average of two unit COI values: (1) \$311.55, from Smith et al. (1997) <sup>122</sup> and (2) \$260.67, from Stanford et al. (1999). <sup>123</sup>
<b>Respiratory Ailments Not Requiring Hospitalization</b>			
Upper Respiratory Symptoms (URS)	\$32	\$34	Combinations of the three symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in seven 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 (Neumann et al., 1994) <sup>124</sup> 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 assumed a uniform distribution between \$9.2 and \$43 (2000\$).
Lower Respiratory Symptoms (LRS)	\$21	\$22	Combinations of the four 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 (Neumann et al., 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 11 types of LRS occurs within the LRS symptom complex, we assumed a uniform distribution between \$6.9 and \$25 (2000\$).
Asthma Exacerbations	\$57	\$59	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). <sup>125</sup> 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 \$16 and \$71 (2000\$).
Acute Bronchitis	\$470	\$510	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 daily estimate of \$10 is the sum of the mid-range values recommended by IEc 1994 for two symptoms believed to be associated with acute bronchitis: coughing and chest tightness. The high daily estimate was taken to be twice the value of a minor respiratory restricted-activity day, or \$110 (2000\$).
Work Loss Days (WLDs)	Variable (U.S. median = \$150)	Variable (U.S. median = \$150)	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. (Geolytics, 2002) <sup>126</sup>

Minor Restricted Activity Days (MRADs)	\$66	\$71	Median WTP estimate to avoid one MRAD from Tolley et al. (1986). <sup>127</sup> Distribution is assumed to be triangular with a minimum of \$22 and a maximum of \$83, with a most likely value of \$52 (2000\$). 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.
School Absence Days	\$98	\$98	No distribution available

Note:

<sup>a</sup> Willingness-to-pay-based benefits are adjusted by multiplying the unadjusted benefits by the appropriate adjustment factor to account for income growth over time using projections provided by Standard and Poor’s. Due to a lack of reliable projections of income growth past 2024, we assume constant WTP from 2024 through 2030. This results in an underestimate of benefits occurring between 2024 and 2030. For growth between 2000 and 2024, this factor is 1.23 for long-term mortality, 1.27 for chronic health impacts, and 1.08 for minor health impacts. Note that similar adjustments do not exist for cost-of-illness-based unit values. For these, we apply the same unit value regardless of the future year of analysis.

#### 8.1.2.4.6 *Manipulating Air Quality Modeling Data for Health Impacts Analysis*

In Chapter 7, we summarized the methods for and results of estimating air quality for the program. These air quality results are in turn associated with human populations to estimate changes in health effects. For the purposes of this analysis, we focus on the health effects that have been linked to ambient changes in ozone and PM<sub>2.5</sub> related to emission reductions estimated to occur due to the implementation of the program. We estimate ambient PM<sub>2.5</sub> and ozone concentrations using the Community Multiscale Air Quality model (CMAQ). This section describes how we converted the CMAQ modeling output into full-season profiles suitable for the health impacts analysis.

#### General Methodology

First, we extracted hourly, surface-layer PM and ozone concentrations for each grid cell from the standard CMAQ output files. For ozone, 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.<sup>L,M</sup> 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 impact functions of the benefits analysis (*i.e.*, BenMAP).

To estimate ozone-related health effects for the contiguous United States, full-season ozone data are required for every BenMAP grid-cell. Given available ozone monitoring data, we generated full-season ozone profiles for each location in two steps: (1) we combined monitored

<sup>L</sup> The ozone season for this analysis is defined as the 5-month period from May to September.

<sup>M</sup> Based on AIRS, there were 961 ozone monitors with sufficient data (*i.e.*, 50 percent or more days reporting at least nine hourly observations per day [8 am to 8 pm] during the ozone season).

observations and modeled ozone predictions to interpolate hourly ozone concentrations to a grid of 12-km by 12-km population grid cells for the contiguous 48 states, and (2) we converted these full-season hourly ozone profiles to an ozone measure of interest, such as the daily 8-hour maximum.<sup>N,O</sup>

For PM<sub>2.5</sub>, we also use the model predictions in conjunction with observed monitor data. CMAQ generates predictions of hourly PM species concentrations for every grid. The species 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<sub>2.5</sub> is calculated as the sum of the primary fine fraction and all of the secondarily formed particles. Future-year estimates of PM<sub>2.5</sub> were calculated using relative reduction factors (RRFs) applied to 2005 ambient PM<sub>2.5</sub> and PM<sub>2.5</sub> species concentrations. A gridded field of PM<sub>2.5</sub> concentrations was created by interpolating Federal Reference Monitor ambient data and IMPROVE ambient data. Gridded fields of PM<sub>2.5</sub> species concentrations were created by interpolating EPA speciation network (ESPN) ambient data and IMPROVE data. The ambient data were interpolated to the CMAQ 12 km grid.

The procedures for determining the RRFs are similar to those in EPA’s draft guidance for modeling the PM<sub>2.5</sub> standard (EPA, 2001).<sup>128</sup> The guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major PM<sub>2.5</sub> species. The procedure for calculating future-year PM<sub>2.5</sub> design values is called the “Speciated Modeled Attainment Test (SMAT).” EPA used this procedure to estimate the ambient impacts of the final program.

Table 8-16 provides those ozone and PM<sub>2.5</sub> metrics for grid cells in the modeled domain that enter the health impact functions for health benefits endpoints. The population-weighted average reflects the baseline levels and predicted changes for more populated areas of the nation. This measure better reflects the potential benefits through exposure changes to these populations.

**Table 8-16: Summary of CMAQ-Derived Population-Weighted Ozone and PM<sub>2.5</sub> Air Quality Metrics for Health Benefits Endpoints Associated with the Final Tier 3 Program**

Statistic <sup>a</sup>	2030	
	Baseline	Change <sup>b</sup>
Ozone Metric: National Population-Weighted Average (ppb) <sup>c</sup>		
Daily Maximum 8-Hour Average Concentration	43.65	0.32
PM <sub>2.5</sub> Metric: National Population-Weighted Average (µg/m <sup>3</sup> )		
Annual Average Concentration	7.94	0.04

Notes:

<sup>N</sup> The 12-km grid squares contain the population data used in the health benefits analysis model, BenMAP.

<sup>O</sup> This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (EVNA) spatial interpolation. See the BenMAP manual for technical details, available for download at <http://www.epa.gov/air/benmap>.

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<sup>a</sup> Ozone and PM<sub>2.5</sub> metrics are calculated at the CMAQ grid-cell level for use in health effects estimates. Ozone metrics are calculated over relevant time periods during the daylight hours of the “ozone season” (*i.e.*, May through September). Note that the national, population-weighted PM<sub>2.5</sub> and ozone air quality metrics presented in this chapter represent an average for the entire, gridded U.S. CMAQ domain. These are different than the population-weighted PM<sub>2.5</sub> and ozone design value metrics presented in Chapter 7, which represent the average for areas with a current air quality monitor.

<sup>b</sup> The change is defined as the base-case value minus the control-case value.

<sup>c</sup> Calculated by summing the product of the projected CMAQ grid-cell population and the estimated CMAQ grid cell seasonal ozone concentration and then dividing by the total population.

Emissions and air quality modeling decisions are made early in the analytical process. For this reason, the emission control scenarios used in the air quality and benefits modeling are slightly different than the final emission inventories estimated for the Tier 3 standards. Please refer to Section 7.2.1.1 for more information about the inventories used in the air quality modeling that supports the health impacts analysis.

#### 8.1.2.5 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. This analysis is no exception. As outlined both in this and preceding chapters, this analysis includes many data sources as inputs, including emission inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the world (*i.e.*, regulations, technology, and human behavior). Each of these inputs may be uncertain and would affect the benefits estimate. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits.

After reviewing the EPA’s approach, the National Research Council (NRC) (2002, 2008),<sup>129,130</sup> which is part of the National Academies of Science, concluded that the EPA’s general methodology for calculating the benefits of reducing air pollution is reasonable and informative in spite of inherent uncertainties. The NRC also highlighted the need to conduct rigorous quantitative analyses of uncertainty and to present benefits estimates to decision makers in ways that foster an appropriate appreciation of their inherent uncertainty. Since the publication of these reports, the EPA has continued work to improve the characterization of uncertainty in both health incidence and benefits estimates. In response to these recommendations, we have expanded our previous analyses to incorporate additional quantitative and qualitative characterizations of uncertainty. Although we have not yet been able to make as much progress towards a full, probabilistic uncertainty assessment as envisioned by the NAS as we had hoped, we have added a number of additional quantitative and qualitative analyses to highlight the impact that uncertain assumptions may have on the benefits estimates. In addition, for some inputs into the benefits analysis, such as the air quality data, it is difficult to address uncertainty probabilistically due to the complexity of the underlying air quality models and emission inputs. Therefore, we decline to make up alternative assumptions simply for the purpose of probabilistic uncertainty characterization when there is no scientific literature to support alternate assumptions.

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To characterize uncertainty and variability, the 2012 PM NAAQS RIA utilized an approach that combined elements from two recent analyses by the EPA,<sup>131,132</sup> and used a tiered approach developed by the World Health Organization (WHO) for characterizing uncertainty.<sup>133</sup> We refer the reader to this tiered assessment as an assessment of the potential impact and magnitude of each aspect of uncertainty that is also present in the final Tier 3 RIA (see Appendix 5c of the 2012 PM NAAQS RIA).

Data limitations prevent us from treating each source of uncertainty quantitatively and from reaching a full-probabilistic simulation of our results, but we were able to consider the influence of uncertainty in the risk coefficients and economic valuation functions by incorporating four quantitative analyses described in more detail below:

1. A Monte Carlo assessment that accounts for random sampling error and between study variability in the epidemiological and economic valuation studies;
2. The quantification of PM-related mortality using alternative PM<sub>2.5</sub> mortality effect estimates drawn from two long-term cohort studies and an expert elicitation;
3. A concentration benchmark assessment that characterizes the distribution of avoided PM<sub>2.5</sub>-related deaths relative to specific concentrations in the long-term epidemiological studies used to estimate PM<sub>2.5</sub>-related mortality;
4. The quantification of ozone-related mortality using alternative ozone mortality effect estimates drawn from six short-term studies: three multi-city studies and three meta-analyses of the existing literature;
5. An analysis of the influence of various parameters on total monetized benefits.

#### *8.1.2.5.1 Monte Carlo Assessment*

Similar to other recent RIAs, we used Monte Carlo methods for characterizing random sampling error associated with the concentration response functions from epidemiological studies and random effects modeling to characterize both sampling error and variability across the economic valuation functions. The Monte Carlo simulation in the BenMAP software randomly samples from a distribution of incidence and valuation estimates to characterize the effects of uncertainty on output variables. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and monetized benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates for endpoints estimated using a single study. For endpoints estimated using a pooled estimate of multiple studies, the confidence intervals reflect both the standard errors and the variance across studies. The confidence intervals around the monetized benefits incorporate the epidemiology standard errors as well as the distribution of the valuation function. These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

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#### 8.1.2.5.2 *Alternative Concentration-Response Functions for PM<sub>2.5</sub>-Related Mortality*

We assign the greatest economic value to the reduction in PM<sub>2.5</sub> related mortality risk. Therefore, it is particularly important to attempt to characterize the uncertainties associated with reductions in premature mortality. To better understand the concentration-response relationship between PM<sub>2.5</sub> exposure and premature mortality, the EPA conducted an expert elicitation in 2006.<sup>134,135</sup> In general, the results of the expert elicitation support the conclusion that the benefits of PM<sub>2.5</sub> control are very likely to be substantial.

Alternative concentration-response functions are useful for assessing uncertainty beyond random statistical error, including uncertainty in the functional form of the model or alternative study design. Thus, we include the expert elicitation results as well as standard errors approaches to provide insights into the likelihood of different outcomes and about the state of knowledge regarding the benefits estimates. In this analysis, we present the results derived from the expert elicitation as indicative of the uncertainty associated with a major component of the health impact functions, and we provide the independent estimates derived from each of the twelve experts to better characterize the degree of variability in the expert responses.

In previous RIAs, the EPA presented benefits estimates using concentration response functions derived from the PM<sub>2.5</sub> Expert Elicitation as a range from the lowest expert value (Expert K) to the highest expert value (Expert E). However, this approach did not indicate the agency's judgment on what the best estimate of PM<sub>2.5</sub> benefits may be, and the EPA's independent Science Advisory Board (SAB) recommended refinements to the way EPA presented the results of the elicitation.<sup>136</sup> As a result of this recommendation, we have presented the ACS and Six-Cities cohort-based studies as our core premature mortality estimates, such as in the RIA for the final PM NAAQS. Using alternate relationships between PM<sub>2.5</sub> and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates of the mean PM<sub>2.5</sub> effect on mortality fall between the two epidemiology-based estimates. Please note that the benefits estimates results presented are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the effect coefficients provided in those studies or by experts. In addition, the experts provided distributions around their mean PM<sub>2.5</sub> effect estimates, which provide more information regarding the overall range of uncertainty, and this overall range is larger than the range of the mean effect estimates from each of the experts.

Even these multiple characterizations with confidence intervals omit the contribution to overall uncertainty from uncertainty in air quality changes, baseline incidence rates, and populations exposed. Furthermore, the approach presented here does not yet include methods for addressing correlation between input parameters and the identification of reasonable upper and lower bounds for input distributions characterizing uncertainty in additional model elements. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the estimates. This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis.

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### 8.1.2.5.3 Concentration Benchmark Analysis for PM<sub>2.5</sub>

In this analysis, we estimate the number of avoided PM<sub>2.5</sub>-related deaths occurring due to PM<sub>2.5</sub> reductions down to various PM<sub>2.5</sub> concentration benchmarks, including the Lowest Measured Level (LML) of each long-term PM<sub>2.5</sub> mortality study. This analysis is one of several sensitivities that the EPA has historically performed that characterize the uncertainty associated with the PM-mortality relationship and the economic value of reducing the risk of premature death.<sup>137,138,139</sup>

Our review of the current body of scientific literature indicates that a log-linear no-threshold model provides the best estimate of PM-related long-term mortality. The PM ISA,<sup>140</sup> which was twice reviewed by the EPA's Clean Air Scientific Advisory Committee,<sup>141,142</sup> concluded that the evidence supports the use of a no-threshold log-linear model while also recognizing potential uncertainty about the exact shape of the concentration-response function.<sup>P</sup> Consistent with this finding, we estimate benefits associated with the full range of PM<sub>2.5</sub> exposure in conjunction with sensitivity analyses to recognize the potential uncertainty at lower concentrations. Specifically, we incorporated a LML assessment, a method the EPA has employed in several recent RIAs.<sup>143,144,145</sup> In addition, we have incorporated an assessment using specific concentration benchmarks identified in the EPA's *Policy Assessment for Particulate Matter*.<sup>146</sup>

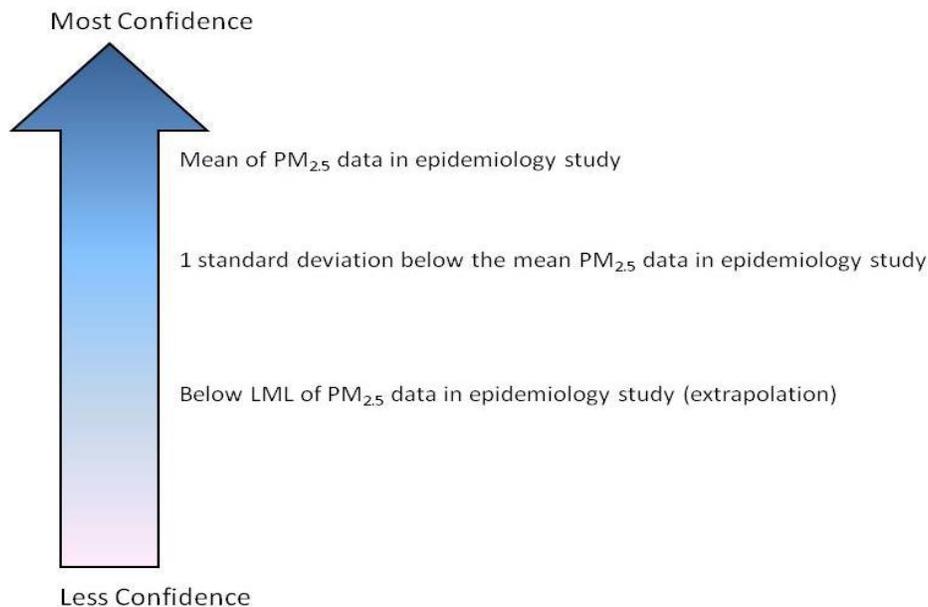
These two approaches summarize the distribution of avoided PM<sub>2.5</sub>-related mortality impacts relative to baseline (i.e., pre-rule) annual mean PM<sub>2.5</sub> levels. The LML approach compares the percentage of avoided premature deaths estimated to occur above and below the minimum observed air quality level of each long-term cohort study we use to quantify PM. In the air quality benchmark approach, we summarize the impacts occurring at different points in the distribution of the air quality data used in these same epidemiology studies.

Our confidence in the estimated number of premature deaths avoided (but not in the existence of a causal relationship between PM and premature mortality) diminishes as we estimate these impacts in locations where PM<sub>2.5</sub> levels are below the LML. This interpretation is consistent with the *Policy Assessment* and advice from SAB-CASAC during their peer review.<sup>147</sup> The *Policy Assessment* concludes that the range from the 25<sup>th</sup> to the 10<sup>th</sup> percentile is a reasonable range of the air quality distribution below which we start to have appreciably less confidence in the magnitude of the associations observed in the epidemiological studies. In general, we are more confident in the magnitude of the risks we estimate from simulated PM<sub>2.5</sub> concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies at are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated PM<sub>2.5</sub> concentrations that fall below the bulk of the observed data in these studies. However, there are uncertainties inherent in identifying any particular point at which our confidence in reported associations becomes appreciably less, and the scientific evidence provides no clear dividing line.

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<sup>P</sup> For a summary of the scientific review statements regarding the lack of a threshold in the PM<sub>2.5</sub>-mortality relationship, see the Technical Support Document (TSD) entitled *Summary of Expert Opinions on the Existence of a Threshold in the Concentration-Response Function for PM<sub>2.5</sub>-related Mortality* (U.S. EPA, 2010f).

For these reasons, we consider the LML as well as one standard deviation below the mean<sup>Q</sup> air quality levels when characterizing the distribution of mortality impacts. It is important to emphasize that “less confidence” does not mean “no confidence.” In addition, while we may have less confidence in the magnitude of the risk, we still have high confidence that PM<sub>2.5</sub> is causally associated with risk at those lower air quality concentrations. To clarify this concept, Figure 8-2 graphically displays the spectrum of confidence using illustrative concentration benchmarks from the major epidemiology studies cited in this chapter.



**Figure 8-2: Relationship between the Size of the PM Mortality Estimates and the PM<sub>2.5</sub> Concentration Observed in the Epidemiology Study**

Although these types of concentration benchmark analyses (e.g., LML, one standard deviation below the mean, etc.) provide some insight into the level of uncertainty in the estimated PM<sub>2.5</sub> mortality benefits, the EPA does not view these concentration benchmarks as a concentration threshold below which we would not quantify health benefits of air quality improvements. Rather, the core benefits estimates reported in this RIA (i.e., those based on Krewski et al. (2009) and Lepeule et al. (2012)) are the best measures because they reflect the full range of modeled air quality concentrations associated with the emission reduction strategies. In reviewing the *Policy Assessment*, SAB-CASAC confirmed that “[a]lthough there is increasing uncertainty at lower levels, there is no evidence of a threshold (i.e., a level below which there is no risk for adverse health effects)”.<sup>148</sup> In addition, in reviewing the *Costs and Benefits of the Clean Air Act*,<sup>149</sup> the SAB-HES noted that “[t]his [no-threshold] decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels. Analyses of cohorts using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality”.<sup>150</sup> Therefore,

<sup>Q</sup> A range of one standard deviation around the mean represents approximately 68 percent of normally distributed data, and, below the mean falls between the 25<sup>th</sup> and 10<sup>th</sup> percentiles.

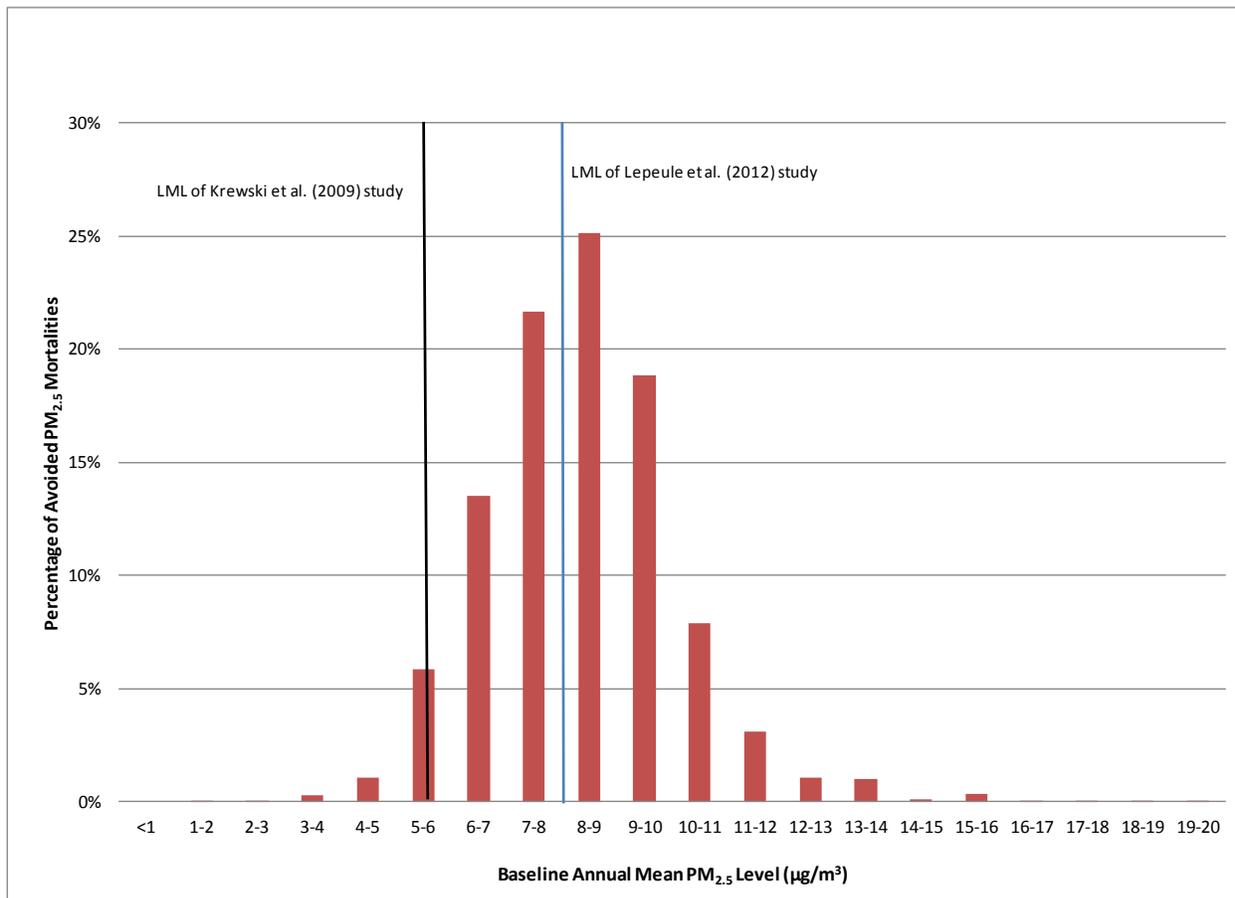
the best estimate of benefits includes estimates below and above these concentration benchmarks but uncertainty is higher in the magnitude of health benefits estimated at lower concentrations, with the lowest confidence below the LML. Estimated health impacts reflecting air quality improvements below and above these concentration benchmarks are appropriately included in the total benefits estimate. In other words, our higher confidence in the estimated benefits above these concentration benchmarks should not imply an absence of confidence in the benefits estimated below these concentration benchmarks.

We estimate that most of the avoided PM-related impacts quantified in this analysis occur among populations exposed at or above the LML of the Lepeule et al. (2012) study, while a majority of the impacts occur at or above the LML of the Krewski et al. (2009) study. We show the estimated reduction in incidence of premature mortality above and below the LML or air quality benchmarks of these studies in Table 8-17, and we graphically display the distribution of PM<sub>2.5</sub>-related mortality impacts for the final standard in Figure 8-3 and Figure 8-4.

**Table 8-17: Estimated Reduction in Incidence of Adult Premature Mortality Occurring Above and Below Various Concentration Benchmarks in the Underlying Epidemiology Studies<sup>a</sup>**

Epidemiology Study	Total Reduced Mortality Incidence	Allocation of Reduced Mortality Incidence			
		Below 1 Std. Dev. Below AQ Mean	At or Above 1 Std. Dev. Below AQ Mean	Below LML	At or Above LML
Krewski et al. (2009)	660	620 (94%)	38 (6%)	37 (6%)	620 (94%)
Lepeule et al. (2012)	1,500	N/A	N/A	630 (42%)	860 (58%)

<sup>a</sup> Mortality incidence estimates are rounded to whole numbers and two significant digits, so estimates may not sum across columns. One standard deviation below the mean is equivalent to the middle of the range between the 10<sup>th</sup> and 25<sup>th</sup> percentile. For Krewski, the LML is 5.8 µg/m<sup>3</sup> and one standard deviation below the mean is 11.0 µg/m<sup>3</sup>. For Lepeule et al., the LML is 8 µg/m<sup>3</sup> and we do not have the data for one standard deviation below the mean. It is important to emphasize that although we have lower levels of confidence in levels below the LML for each study, the scientific evidence does not support the existence of a level below which health effects from exposure to PM<sub>2.5</sub> do not occur.

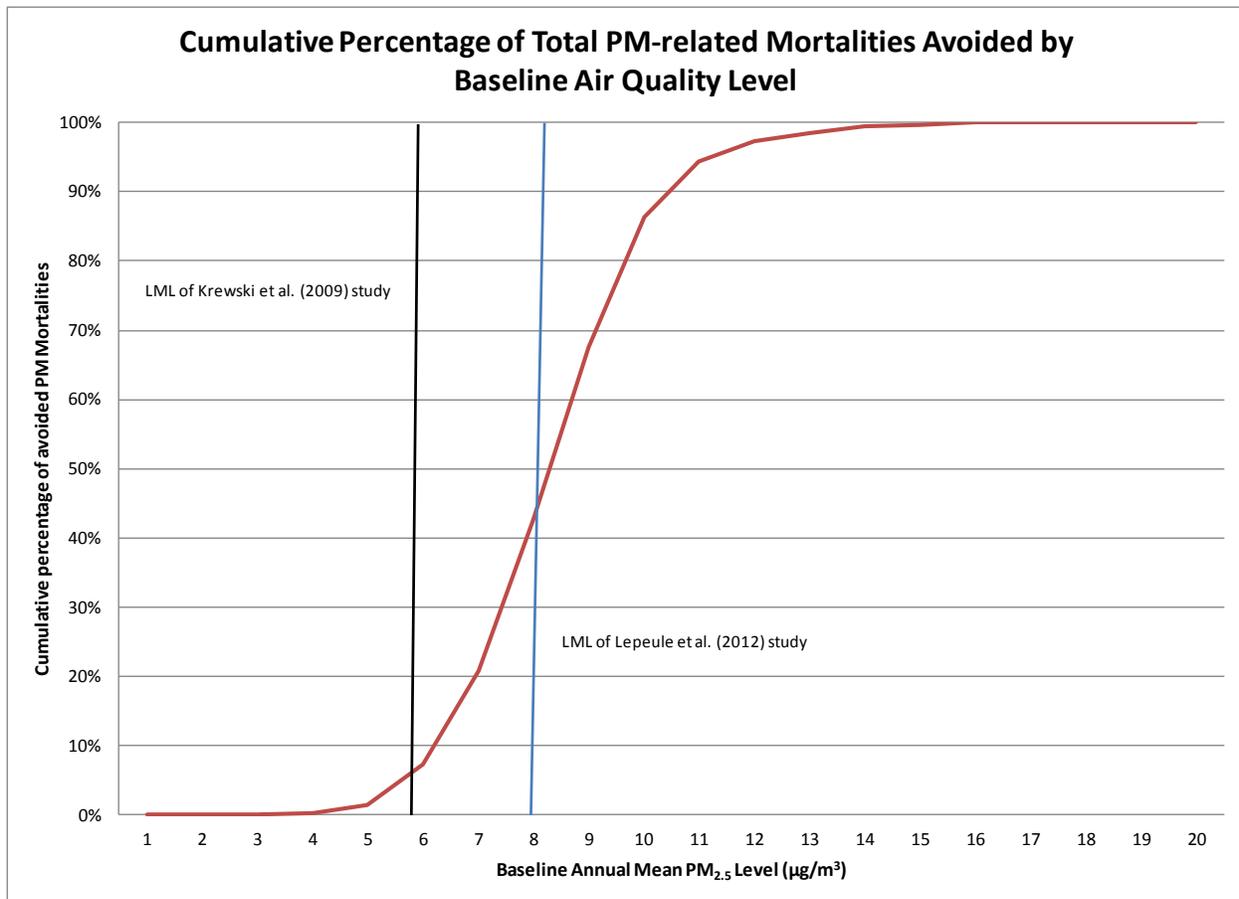


**Of total PM<sub>2.5</sub>-Related deaths avoided for 12 µg/m<sup>3</sup> :**

**94%** occur among populations exposed to PM<sub>2.5</sub> levels at or above the LML of the Krewski et al. (2009) study.

**58%** occur among populations exposed to PM<sub>2.5</sub> levels at or above the LML of the Lepeule et al. (2012) study.

**Figure 8-3. Number of Premature PM<sub>2.5</sub>-related Deaths Avoided for the Final Tier 3 Standards in 2030 According to the Baseline Level of PM<sub>2.5</sub> and the Lowest Measured Air Quality Levels of Each Mortality Study**



**Of total PM<sub>2.5</sub>-Related deaths avoided for 12 µg/m<sup>3</sup>:**  
**94%** occur among populations exposed to PM<sub>2.5</sub> levels at or above the LML of the Krewski et al. (2009) study.  
**58%** occur among populations exposed to PM<sub>2.5</sub> levels at or above the LML of the Lepeule et al. (2012) study.

**Figure 8-4. Number of Premature PM<sub>2.5</sub>-related Deaths Avoided for the Final Tier 3 Standards in 2030 According to the Baseline Level of PM<sub>2.5</sub> and the Lowest Measured Air Quality Levels of Each Mortality Study**

While the LML of each study is important to consider when characterizing and interpreting the overall level of PM<sub>2.5</sub>-related benefits, as discussed earlier in this chapter, the EPA believes that both of the cohort-based mortality estimates are suitable for use in air pollution health impact analyses. When estimating PM-related premature deaths avoided using risk coefficients drawn from the Lepeule et al. (2012) analysis of the Harvard Six Cities and the Krewski et al. (2009) analysis of the ACS cohorts there are innumerable other attributes that may affect the size of the reported effect estimates—including differences in population demographics, the size of the cohort, activity patterns and particle composition among others. The LML assessment presented here provides a limited representation of one key difference between the two studies.

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#### 8.1.2.5.4 *Alternative Concentration-Response Functions for Ozone-Related Mortality*

In 2006 the EPA requested an NAS study to evaluate the extent to which the epidemiological literature to that point improved the understanding of ozone-related mortality. The NAS found that short-term ozone exposure was likely to contribute to ozone-related mortality<sup>151</sup> and issued a series of recommendations to EPA, including that the Agency should present multiple short-term ozone mortality estimates, including those based on multi-city analyses such as the National Morbidity, Mortality and Air Pollution Study (NMMAPS) as well as meta-analytic studies. The NAS also recommended that EPA remove reference to a no-causal relationship between ozone exposure and premature mortality. The quantification and presentation of ozone-related premature mortality in this analysis is responsive to these recommendations.

#### 8.1.2.5.5 *Influence Analysis – Quantitative Assessment of Uncertainty*

In the past few years, the EPA has initiated several projects to improve the characterization of uncertainty for benefits analysis. In particular, the EPA recently completed the first phase of a quantitative uncertainty analysis of benefits, hereafter referred to as the “Influence Analysis”.<sup>152</sup> The Influence Analysis diagrammed the uncertain components of each step within the benefits analysis process, identified plausible ranges for a sensitivity analysis, and assessed the sensitivity to total benefits to changes in each component. Although this analysis does not quite fulfill the goal of a full probabilistic assessment, it accomplished the necessary first steps and identified the challenges to accomplishing that goal. Below are some of the preliminary observations from the first phase of the project.

- The components that contribute the most to uncertainty of the monetized benefits and mortality incidence (in order of importance) are the value-of-a-statistical-life (VSL), the concentration-response (C-R) function for mortality, and change in PM<sub>2.5</sub> concentration.
- The components that contribute the least to uncertainty of the monetized benefits and mortality incidence are population, morbidity valuation, and income elasticity.
- The choice of a C-R function for mortality affects the mortality incidence and monetized benefits more than other sources of uncertainty within each C-R function.
- Alternative cessation lag structures for mortality have a moderate effect on the monetized benefits.
- Because the health impact function is essentially linear, the key components show the same sensitivity across all mortality C-R functions even if the midpoints differ significantly from one expert to another.

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8.1.2.5.6 *Qualitative Assessment of Uncertainty and Other Analysis Limitations*

Although we strive to incorporate as many quantitative assessments of uncertainty as possible, there are several aspects we are only able to address qualitatively. These aspects are important factors to consider when evaluating the benefits of the final Tier 3 standards.

The total monetized benefit estimates presented in this chapter are based on our interpretation of the best available scientific literature and methods and supported by the EPA's independent SAB (Health Effects Subcommittee) (SAB-HES) and the National Academies of Science (NAS).<sup>153,154</sup> The benefit estimates are subject to a number of assumptions and uncertainties. For example, the key assumptions underlying the estimates for premature mortality, which account for over 98% of the total monetized benefits in this analysis, include the following:

1. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM<sub>2.5</sub> varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The 2009 PM ISA, which was twice reviewed by Clean Air Scientific Advisory Committee (SAB-CASAC), concluded that “many constituents of PM<sub>2.5</sub> can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes”.<sup>155</sup>
2. We assume that the health impact function for fine particles is log-linear without a threshold in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM<sub>2.5</sub>, including both areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.
3. We assume that there is a “cessation” lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to PM<sub>2.5</sub> exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES,<sup>156</sup> which affects the valuation of mortality benefits at different discount rates.
4. To characterize the uncertainty in the relationship between PM<sub>2.5</sub> and premature mortality, we include a set of twelve estimates based on results of the expert elicitation study in addition to our core estimates. Even these multiple characterizations omit the uncertainty in air quality estimates, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the PM<sub>2.5</sub> estimates.

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This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis.

5. There is uncertainty in the magnitude of the association between ozone and premature mortality. The range of ozone benefits associated with the final standards is estimated based on the risk of several sources of ozone-related mortality effect estimates. In a report on the estimation of ozone-related premature mortality published by the National Research Council, a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health benefits of reducing ozone exposure.<sup>R</sup>

As previously described, we strive to monetize as many of the benefits anticipated from the revised and alternative standards as possible given data and resource limitations, but the monetized benefits estimated in this RIA inevitably only reflect a portion of the benefits. Specifically, only certain benefits attributable to the health impacts associated with exposure to ambient fine particles have been monetized in this analysis. Data and methodological limitations prevented the EPA from quantifying or monetizing the benefits from several important health benefit categories (see Table 8-5 for more information). If we could fully monetize all of the benefit categories, the total monetized benefits would exceed the costs by an even greater margin than we currently estimate.

To more fully address these uncertainties, including those we cannot quantify, the 2012 PM NAAQS RIA utilized a four-tiered approach using the WHO uncertainty framework,<sup>157</sup> which provides a means for systematically linking the characterization of uncertainty to the sophistication of the underlying risk assessment. The EPA has applied similar approaches in other analyses.<sup>158,159</sup> Using this framework, the PM NAAQS summarized the key uncertainties in the health benefits analysis, including our assessment of the direction of potential bias, magnitude of impact on the monetized benefits, degree of confidence in our analytical approach, and our ability to assess the source of uncertainty. We refer the reader to this tiered assessment as an assessment of the potential impact and magnitude of each aspect of uncertainty that is also present in the final Tier 3 RIA (see Appendix 5b of the 2012 PM NAAQS RIA).<sup>160</sup>

### 8.1.3 Comparison of Costs and Benefits

This section presents the cost-benefit comparison related to the expected impacts of the final Tier 3 program. In estimating the net benefits of the program, the appropriate cost measure is ‘social costs.’ Social costs represent the welfare costs of a rule to society and do not consider transfer payments (such as taxes) that are simply redistributions of wealth. For this analysis, we estimate that the social costs of the program are equivalent to the estimated vehicle and fuel compliance costs of the program. While vehicle manufacturers and fuel producers would see their costs increase by the amount of those compliance costs, they are expected to pass them on

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<sup>R</sup> National Research Council (NRC), (2008). Estimating Mortality Risk Reduction and Economic Benefits from Controlling Ozone Air Pollution. The National Academies Press: Washington, D.C.

in their entirety to vehicle and fuel consumers in the form of increased prices. Ultimately, these costs will be borne by the final consumers of these goods. The social benefits of the program are represented by the monetized value of health and welfare improvements experienced by the U.S. population. Table 8-18 contains the estimated social costs and the estimated monetized benefits of the program.

The results in Table 8-18 suggest that the 2030 monetized benefits of the final standards are greater than the expected costs. Specifically, the annual benefits of the total program will range between \$7.4 to \$19 billion annually in 2030 using a three percent discount rate, or between \$6.7 to \$18 billion assuming a 7 percent discount rate, compared to estimated social costs of approximately \$1.5 billion in that same year. Though there are a number of health and environmental effects associated with the final standards that we are unable to quantify or monetize (see Table 8-5), the benefits of the final standards outweigh the projected costs.

Using a conservative benefits estimate, the 2030 benefits outweigh the costs by a factor of 4.5. Using the upper end of the benefits range, the benefits could outweigh the costs by a factor of 13. Thus, even taking the most conservative benefits assumptions, benefits of the final standards clearly outweigh the costs.

**Table 8-18: Summary of Annual Benefits and Costs Associated with the Final Tier 3 Program (Billions, 2011\$)<sup>a</sup>**

<b>Description</b>	<b>2030</b>
Vehicle Program Costs	\$0.76
Fuels Program Costs	\$0.70
Total Estimated Costs <sup>b</sup>	\$1.5
Total Estimated Health Benefits <sup>c,d,e,f</sup>	
3 percent discount rate	\$7.4 - \$19
7 percent discount rate	\$6.7 - \$18
Annual Net Benefits (Total Benefits – Total Costs)	
3 percent discount rate	\$5.9 - \$18
7 percent discount rate	\$5.2 - \$17

Notes:

<sup>a</sup> All estimates represent annual benefits and costs anticipated for the year 2030. Totals are rounded to two significant digits and may not sum due to rounding.

<sup>b</sup> The calculation of annual costs does not require amortization of costs over time. Therefore, the estimates of annual cost do not include a discount rate or rate of return assumption (see Chapter 2 of the RIA for more information on vehicle costs, Chapter 5 for fuel costs, and Section 8.1.1 for a summary of total program costs).

<sup>c</sup> Total includes ozone and PM<sub>2.5</sub> benefits. Range was developed by adding the estimate from the Bell et al., 2004 ozone premature mortality function to PM<sub>2.5</sub>-related premature mortality derived from the American Cancer Society cohort study (Krewski et al., 2009) for the low estimate and ozone premature mortality derived from the Levy et al., 2005 study to PM<sub>2.5</sub>-related premature mortality derived from the Six-Cities (Lepeule et al., 2012) study for the high estimate.

<sup>d</sup> Annual benefits analysis results reflect the use of a 3 percent and 7 percent discount rate in the valuation of premature mortality and nonfatal myocardial infarctions, consistent with EPA and OMB guidelines for preparing economic analyses.

<sup>e</sup> Valuation of premature mortality based on long-term PM exposure assumes discounting over the SAB recommended 20-year segmented lag structure described in the Regulatory Impact Analysis for the 2012 PM National Ambient Air Quality Standards (December, 2012).

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<sup>f</sup>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 8-5.

#### 8.1.4 Illustrative Analysis of Estimated Quantified and Monetized Impacts Associated with the Rule in 2018

For illustrative purposes, this section presents the quantified and monetized impacts associated with the final standards in 2018. As presented in Section 7.1.5, the emissions impacts of the final standards in 2018 are primarily due to the effects of sulfur on the existing (pre-Tier 3) fleet.

This analysis reflects the impacts of the final Tier 3 rule in 2018 compared to a future-year reference scenario without the program in place. Overall, we estimate that the final rule will lead to a net decrease in PM<sub>2.5</sub>-related health and environmental impacts in 2018 (see Section 7.2.4 for more information about the air quality modeling results). The decrease in population-weighted national average PM<sub>2.5</sub> exposure results in a net decrease in adverse PM<sub>2.5</sub>-related human health and environmental impacts (the decrease in national population-weighted annual average PM<sub>2.5</sub> is 0.012 µg/m<sup>3</sup> in 2018). The air quality modeling also projects decreases in ozone concentrations. The overall decrease in population-weighted national average ozone exposure results in decreases in ozone-related health and environmental impacts (population-weighted maximum 8-hour average ozone decreases by 0.15 ppb in 2018).

Table 8-19 and Table 8-20 present the annual PM<sub>2.5</sub> and ozone health impacts in the 48 contiguous U.S. states associated with the final Tier 3 program. For each endpoint presented in Table 8-19 and Table 8-20, we provide both the point estimate and the 90 percent confidence interval. Using EPA's preferred estimates, based on the American Cancer Society (ACS) and Six-Cities studies and no threshold assumption in the model of mortality, we estimate that the final standards would result in between 180 and 400 cases of avoided PM<sub>2.5</sub>-related premature mortalities annually in 2018. For ozone-related premature mortality in 2018, we estimate a range of between 45 to 210 fewer premature mortalities.

Table 8-21 presents the estimated monetary value of changes in the incidence of ozone and PM<sub>2.5</sub>-related health and environmental effects. Total aggregate monetized benefits are presented in Table 8-22. All monetized estimates are presented in 2011\$. Where appropriate, estimates account for growth in real gross domestic product (GDP) per capita between 2000 and 2018. The monetized value of PM<sub>2.5</sub>-related mortality also accounts for a twenty-year segmented cessation lag.<sup>s</sup> To discount the value of premature mortality that occurs at different points in the

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<sup>s</sup> Based in part on prior SAB advice, EPA has typically assumed that there is a time lag between changes in pollution exposures and the total realization of changes in health effects. Within the context of benefits analyses, this term is often referred to as "cessation lag". 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. In this analysis, we apply a twenty-year distributed lag to PM mortality reductions. This method is consistent with the most recent recommendation by the EPA's Science Advisory Board. Refer to: EPA – Science Advisory Board, 2004. Advisory Council on Clean Air Compliance Analysis Response to Agency Request on

future, we apply both a 3 and 7 percent discount rate. We also use both a 3 and 7 percent discount rate to value PM<sub>2.5</sub>-related nonfatal heart attacks (myocardial infarctions).<sup>T</sup>

In addition to omitted benefits categories such as air toxics and various welfare effects, not all known PM<sub>2.5</sub>- and ozone-related health and welfare effects could be quantified or monetized. The estimate of total monetized health benefits of the final standards is thus equal to the subset of monetized PM<sub>2.5</sub>- and ozone-related health impacts we are able to quantify plus the sum of the nonmonetized health and welfare benefits. Our estimate of total monetized benefits associated with the final standards in 2018, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, is between \$2.1 and \$5.6 billion, assuming a 3 percent discount rate, or between \$1.9 and \$5.3 billion, assuming a 7 percent discount rate.

The results in Table 8-21 demonstrate that the gasoline sulfur standards provide large immediate benefits in the program’s first year, related to emission reductions from existing gasoline vehicles. The benefits increase substantially after 2018, as the vehicle standards phase in after 2018 and as the fleet turns over.

**Table 8-19: Estimated PM<sub>2.5</sub>-Related Health Impacts<sup>a</sup>**

Health Effect	2018 Annual Reduction in Incidence (5 <sup>th</sup> % - 95 <sup>th</sup> %ile)
Premature Mortality – Derived from epidemiology literature <sup>b</sup> Adult, age 30+, ACS Cohort Study (Krewski et al., 2009)	180 (130 – 220)
Adult, age 25+, Six-Cities Study (Lepeule et al., 2012)	400 (230 – 570)
Infant, age <1 year (Woodruff et al., 1997)	0 (0 – 1)
Non-fatal myocardial infarction (adult, age 18 and over) Peters et al. (2001)	200 (74 – 330)
Pooled estimate of 4 studies	22 (11 – 48)
Hospital admissions - respiratory (all ages) <sup>c,e</sup>	51 (-6 – 93)
Hospital admissions - cardiovascular (adults, age >18) <sup>d</sup>	64 (33 – 110)
Emergency room visits for asthma (age 18 years and younger) <sup>e</sup>	100 (-18 – 200)
Acute bronchitis, (children, age 8-12) <sup>e</sup>	280 (-10 – 560)
Lower respiratory symptoms (children, age 7-14)	3,500 (1,700 – 5,300)

Cessation Lag. Letter from the Health Effects Subcommittee to the U.S. Environmental Protection Agency Administrator, December.

<sup>T</sup> Nonfatal myocardial infarctions (MI) are valued using age-specific cost-of-illness values that reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI.

Upper respiratory symptoms (asthmatic children, age 9-18)	5,000 (1,600 – 8,500)
Asthma exacerbation (asthmatic children, age 6-18)	5,200 (650 – 10,000)
Work loss days	23,000 (20,000 – 27,000)
Minor restricted activity days (adults age 18-65)	140,000 (120,000 – 160,000)

<sup>a</sup> Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.

<sup>b</sup> PM-related adult mortality based upon the most recent American Cancer Society (ACS) Cohort Study (Krewski et al., 2009) and the most recent Six-Cities Study (Lepeule et al., 2012). Note that these are two alternative estimates of adult mortality and should not be summed. PM-related infant mortality based upon a study by Woodruff, Grillo, and Schoendorf, (1997).<sup>U</sup>

<sup>c</sup> Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

<sup>d</sup> Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

<sup>e</sup> The negative estimates at the 5th percentile confidence estimates for these morbidity endpoints reflect the statistical power of the study used to calculate these health impacts. These results do not suggest that reducing air pollution results in additional health impacts.

**Table 8-20: Estimated Ozone-Related Health Impacts<sup>a</sup>**

Health Effect	2018 Annual Reduction in Incidence (5 <sup>th</sup> - 95 <sup>th</sup> percentile)
Premature Mortality, All ages <sup>b</sup> Multi-City Analyses	
Bell et al. (2004) – Non-accidental	45 (17 – 73)
Huang et al. (2005) – Cardiopulmonary	65 (27 – 100)
Schwartz (2005) – Non-accidental	69 (25 – 110)
Meta-analyses:	
Bell et al. (2005) – All cause	150 (75 – 220)
Ito et al. (2005) – Non-accidental	200 (130 – 280)
Levy et al. (2005) – All cause	210 (150 – 270)
Hospital admissions- respiratory causes (adult, 65 and older) <sup>c</sup>	260 (130 – 280)
Hospital admissions -respiratory causes (children, under 2)	130 (60 – 210)
Emergency room visit for asthma (all ages)	140

<sup>U</sup> Woodruff, T.J., J. Grillo, and K.C. Schoendorf. (1997). The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Air Pollution in the United States. *Environmental Health Perspectives* 105(6):608-612.

Health Effect	2018 Annual Reduction in Incidence (5 <sup>th</sup> - 95 <sup>th</sup> percentile)
	(-19 – 430)
Minor restricted activity days (adults, age 18-65)	270,000 (120,000 – 420,000)
School absence days	92,000 (36,000 – 140,000)

Notes:

<sup>a</sup> Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous U.S.

<sup>b</sup> Estimates of ozone-related premature mortality are based upon incidence estimates derived from several alternative studies: Bell et al. (2004); Huang et al. (2005); Schwartz (2005); Bell et al. (2005); Ito et al. (2005); Levy et al. (2005). The estimates of ozone-related premature mortality should therefore not be summed.

<sup>c</sup> Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

**Table 8-21: Estimated Monetary Value of Changes in Incidence of Health and Welfare Effects (millions of 2011\$) <sup>a,b</sup>**

HEALTH ENDPOINTS		2018 (5 <sup>TH</sup> AND 95 <sup>TH</sup> PERCENTILE)
<b>PM<sub>2.5</sub>-Related Health Effects</b>		
Premature Mortality – Derived from Epidemiology Studies <sup>b,c</sup>	Adult, age 30+ - ACS study (Krewski et al., 2009)	
	3% discount rate	\$1,600 (\$230 - \$3,700)
	7% discount rate	\$1,400 (\$210 - \$3,300)
	Adult, age 25+ - Six-Cities study (Lepeule et al., 2012)	
	3% discount rate	\$3,500 (\$510 - \$8,600)
	7% discount rate	\$3,200 (\$460 - \$7,700)
	Infant Mortality, <1 year – (Woodruff et al. 1997)	\$4.0 (\$0.55 - \$10)
Non-fatal acute myocardial infarctions		
Peters et al., 2001		
3% discount rate		\$26 (\$5.9 - \$60)
7% discount rate		\$25 (\$5.5 - \$59)
Pooled estimate of 4 studies		
3% discount rate		\$2.8 (\$0.74 - \$7.3)
7% discount rate		\$2.7 (\$0.68 - \$7.2)
Hospital admissions for respiratory causes <sup>d</sup>		\$1.4 (-\$0.32 - \$2.7)
Hospital admissions for cardiovascular causes		\$2.6 (\$1.3 - \$4.4)
Emergency room visits for asthma <sup>d</sup>		\$0.045 (-\$0.007 - \$0.087)

Acute bronchitis (children, age 8–12) <sup>d</sup>		\$0.14 (-\$0.005 - \$0.34)
Lower respiratory symptoms (children, 7–14)		\$0.076 (\$0.030 - \$0.14)
Upper respiratory symptoms (asthma, 9–11)		\$0.17 (\$0.049 - \$0.38)
Asthma exacerbations		\$0.31 (\$0.039 - \$0.74)
Work loss days		\$3.5 (\$3.1 - \$4.0)
Minor restricted-activity days (MRADs)		\$9.8 (\$5.7 - \$14)
<b>Ozone-Related Health Effects</b>		
Premature Mortality, All ages – Derived from Multi-city analyses	Bell et al., 2004	\$440 (\$56 - \$1,100)
	Huang et al., 2005	\$670 (\$95 - \$1,700)
	Schwartz, 2005	\$710 (\$96 - \$1,800)
Premature Mortality, All ages – Derived from Meta-analyses	Bell et al., 2005	\$1,400 (\$200 - \$3,600)
	Ito et al., 2005	\$2,000 (\$290 - \$4,800)
	Levy et al., 2005	\$2,000 (\$300 - \$4,800)
Hospital admissions- respiratory causes (adult, 65 and older)		\$7.5 (\$0.62 - \$14)
Hospital admissions- respiratory causes (children, under 2)		\$1.6 (\$0.74 - \$2.5)
Emergency room visit for asthma (all ages)		\$0.061 (-\$0.008 - \$0.18)
Minor restricted activity days (adults, age 18-65)		\$19 (\$7.7 - \$33)
School absence days		\$9.4 (\$3.6 - \$14)

<sup>a</sup> Monetary benefits are rounded to two significant digits for ease of presentation and computation. PM and ozone benefits are nationwide.

<sup>b</sup> Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2018).

<sup>c</sup> Valuation assumes discounting over the SAB recommended 20 year segmented lag structure. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses.

<sup>d</sup> The negative estimate at the 5th percentile confidence estimate for this morbidity endpoint reflects the statistical power of the study used to calculate this health impact. This result does not suggest that reducing air pollution results in additional health impacts.

**Table 8-22: Total Estimated Monetized Ozone and PM-related Benefits Associated with the Final Program in 2018**

<b>Total Ozone and PM Benefits (billions, 2011\$) – PM Mortality Derived from the ACS and Six-Cities Studies</b>					
<b>3% Discount Rate</b>			<b>7% Discount Rate</b>		
<b>Ozone Mortality Function</b>	<b>Reference</b>	<b>Mean Total Benefits</b>	<b>Ozone Mortality Function</b>	<b>Reference</b>	<b>Mean Total Benefits</b>
Multi-city	Bell et al., 2004	\$2.1 - \$4.1	Multi-city	Bell et al., 2004	\$1.9 - \$3.7
	Huang et al., 2005	\$2.3 - \$4.2		Huang et al., 2005	\$2.1 - \$3.9
	Schwartz, 2005	\$2.3 - \$4.3		Schwartz, 2005	\$2.1 - \$3.9
Meta-analysis	Bell et al., 2005	\$3.1 - \$5.0	Meta-analysis	Bell et al., 2005	\$2.9 - \$4.7
	Ito et al., 2005	\$3.6 - \$5.6		Ito et al., 2005	\$3.4 - \$5.2
	Levy et al., 2005	\$3.6 - \$5.6		Levy et al., 2005	\$3.5 - \$5.3

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## Chapter 9 Economic Impact Analysis

### 9.1 Introduction

The standards will affect two sectors directly: vehicle manufacturing and petroleum refining. For these two regulated sectors, the economic impact analysis discusses the market impacts from the standards: the changes in price and quantity sold. In addition, although analysis of employment impacts is not part of a benefit-cost analysis (except to the extent that labor costs contribute to costs), employment impacts of federal rules are of particular concern in the current economic climate of sizeable unemployment. Executive Order 13563, “Improving Regulation and Regulatory Review” (January 18, 2011), states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation” (emphasis added). For this reason, we are examining the effects of these standards on employment in the regulated sectors.

The employment effects of environmental regulation are difficult to disentangle from other economic changes and business decisions that affect employment, over time and across regions and industries. In light of these difficulties, economic theory provides a constructive framework for approaching these assessments and for better understanding the inherent complexities in such assessments. Neoclassical microeconomic theory describes how profit-maximizing firms adjust their use of productive inputs in response to changes in their economic conditions.<sup>A</sup> In this framework, labor demand impacts for regulated sectors can be decomposed into output and substitution effects. For the output effect, by affecting the marginal cost of production, regulation affects the profit-maximizing quantity of output. The substitution effect describes how, holding output constant, regulation affects the labor-intensity of production. Because the output and substitution effects may be both positive, both negative or some combination, standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand at regulated firms.

In the labor economics literature there is an extensive body of peer-reviewed empirical work analyzing various aspects of labor demand, relying on the above theoretical framework.<sup>B</sup> This work focuses primarily on the effects of employment policies, e.g. labor taxes, minimum wage, etc.<sup>C</sup> In contrast, the peer-reviewed empirical literature specifically estimating employment effects of environmental regulations is very limited. Several empirical studies, including Berman and Bui (2001)<sup>1</sup> and Morgenstern et al (2002),<sup>2</sup> suggest that net employment impacts may be zero or slightly positive but small even in the regulated sector. Other research suggests that more highly regulated counties may generate fewer jobs than less regulated ones.<sup>3</sup> However, since these latter studies compare more regulated to less regulated counties, they

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<sup>A</sup> See Layard, P.R.G., and A. A. Walters (1978), *Microeconomic Theory* (McGraw-Hill, Inc.), Chapter 9 (Docket EPA-HQ-OAR-2011-0135), a standard microeconomic theory textbook treatment, for a discussion.

<sup>B</sup> See Hamermesh (1993), *Labor Demand* (Princeton, NJ: Princeton University Press), Chapter 2 (Docket EPA-HQ-OAR-2011-0135) for a detailed treatment.

<sup>C</sup> See Ehrenberg, Ronald G., and Robert S. Smith (2000), *Modern Labor Economics: Theory and Public Policy* (Addison Wesley Longman, Inc.), Chapter 4 (Docket EPA-HQ-OAR-2011-0135), for a concise overview.

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overstate the net national impact of regulation to the extent that regulation causes plants to locate in one area of the country rather than another. List et al. (2003)<sup>4</sup> find some evidence that this type of geographic relocation may be occurring. Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

Analytic challenges make it very difficult to accurately produce net employment estimates for the whole economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Quantitative estimates are further complicated by the fact that macroeconomic models often have very little sectoral detail and usually assume that the economy is at full employment. The EPA is currently in the process of seeking input from an independent expert panel on modeling economy-wide impacts, including employment effects. For more information, see: <https://federalregister.gov/a/2014-02471>.

## **9.2 Impacts on Vehicle Manufacturing Sector**

### **9.2.1 Vehicle Sales Impacts**

This rule takes effect from MY 2017-2025. In the intervening years, it is possible that the assumptions underlying a quantitative analysis, as well as market conditions, might change. For this reason, we present a qualitative discussion of the effects on vehicle sales of the standards at the aggregate market level. Light-duty vehicle manufacturers are expected to comply with the standards primarily through technological changes to vehicles. These changes to vehicle design and manufacturing are expected to increase manufacturers' costs of vehicle production. The calculation is performed for an average car, an average truck and an average Class 2b/3 vehicle rather than for individual vehicles. The analysis conducted for this rule does not have the precision to examine effects on individual manufacturers or different vehicle classes.

Section VII.A estimates the increase in vehicle costs due to the standards. These costs differ across years and range from \$46 to \$65 for cars, \$73 to \$88 for trucks and \$33 to \$75 for Class 2b/3 vehicles (see Section VII.A). These costs are small relative to the cost of a vehicle. In a fully competitive industry, these costs would be entirely passed through to consumers. However in an oligopolistic industry such as the automotive sector, these increases in cost may not fully pass through to the purchase price, and the consumers may face an increase in price that is less than the increased manufacturers' costs of vehicle production.<sup>D</sup> We do not quantify the expected level of cost pass-through or the ultimate vehicle price increase consumers are expected to face, apart from noting that prices are expected to increase by an amount up to the increased manufacturers' costs.

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<sup>D</sup> See, for instance, Gron, Ann, and Deborah Swenson, 2000. "Cost Pass-Through in the U.S. Automobile Market," Review of Economics and Statistics 82: 316-324 (Docket EPA-HQ-OAR-2011-0135-0056), who found significantly less than full-cost pass-through using data from 1984-1994. Using full-cost pass-through overstates costs and thus contributes to lower vehicle sales than using a lower estimate. To the extent that the auto industry has become more competitive over time, full-cost pass-through may be more appropriate than a result based on this older study.

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This increase in price is expected to lower the quantity of vehicles sold. Given that we expect that vehicle prices will not change by more than the cost increase, we expect that the decrease in vehicle sales will be negligible.

The effect of these standards on the use and scrappage of older vehicles will be related to its effects on new vehicle prices and the total sales of new vehicles. The increase in price is likely to cause the turnover of the vehicle fleet (i.e., the retirement of used vehicles and their replacement by new models) to slow slightly, thus reducing the anticipated effect of the standards on fleet-wide emissions. Because we do not estimate the effect of the standards on new vehicle price changes nor do we have a good estimate of the effect of new vehicle price changes on vehicle turnover, we have not attempted to estimate explicitly the effects of the standards on scrappage of older vehicles and the turnover of the vehicle fleet.

### 9.2.2 Employment Impacts in the Auto Sector

This chapter describes changes in employment in the auto sector due to this rule. As with the refinery sector, discussed below, we focus on the auto manufacturing sector because it is directly regulated, and because it is likely to bear a substantial share of changes in employment due to this rule. We include discussion of effects on the parts manufacturing sector, because the auto manufacturing sector can either produce parts internally or buy them from an external supplier, and we do not have estimates of the likely breakdown of effort between the two sectors.

When the economy is at full employment, an environmental regulation is unlikely to have much impact on net overall U.S. employment; instead, labor would primarily be shifted from one sector to another. These shifts in employment impose an opportunity cost on society, approximated by the wages of the employees, as regulation diverts workers from other activities in the economy. In this situation, any effects on net employment are likely to be transitory as workers change jobs (e.g., some workers may need to be retrained or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers).

On the other hand, if a regulation comes into effect during a period of high unemployment, a change in labor demand due to regulation may affect net overall U.S. employment because the labor market is not in equilibrium. Schmalansee and Stavins point out that net positive employment effects are possible in the near term when the economy is at less than full employment due to the potential hiring of idle labor resources by the regulated sector to meet new requirements (e.g., to install new equipment) and new economic activity in sectors related to the regulated sector.<sup>5</sup> In the longer run, the net effect on employment is more difficult to predict and will depend on the way in which the related industries respond to the regulatory requirements. As Schmalansee and Stavins note, it is possible that the magnitude of the effect on employment could vary over time, region, and sector, and positive effects on employment in some regions or sectors could be offset by negative effects in other regions or sectors. For this reason, they urge caution in reporting partial employment effects since it can “paint an inaccurate picture of net employment impacts if not placed in the broader economic context.”

We follow the theoretical structure in a study by Berman and Bui<sup>6</sup> of the impacts of regulation in employment in the regulated sectors. In Berman and Bui’s (2001, p. 274-75)

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theoretical model, the change in a firm's labor demand arising from a change in regulation is decomposed into two main components: output and substitution effects.<sup>E</sup>

- The output effect describes how, if labor-intensity of production is held constant, a decrease in output generally leads to a decrease in labor demand. However, as noted by Berman and Bui, although it is often assumed that regulation increases marginal cost, and thereby reduces output, it need not be the case. A regulation could induce a firm to upgrade to less polluting and more efficient equipment that lowers marginal production costs, for example. In such a case, output could theoretically increase.
- The substitution effect describes how, holding output constant, regulation affects the labor-intensity of production. Although increased environmental regulation generally results in higher utilization of production factors such as pollution control equipment and energy to operate that equipment, the resulting impact on labor demand is ambiguous. For example, equipment inspection requirements, specialized waste handling, or pollution technologies that are added to the production process may affect the number of workers necessary to produce a unit of output. Berman and Bui (2001) model the substitution effect as the effect of regulation on pollution control equipment and expenditures that are required by the regulation and the corresponding change in labor-intensity of production.

In summary, as the output and substitution effects may be both positive, both negative or some combination, standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand at regulated firms.

Following the Berman and Bui framework for the impacts of regulation on employment in the regulated sector, we consider two effects for the auto sector: the output effect and the substitution effect.

#### 9.2.2.1 The Output Effect

The output effect depends on the effects of this rule on vehicle sales. If vehicle sales decrease, employment associated with these activities will decrease. As discussed in Chapter 9.2.1, we do not make a quantitative estimate on the effect of the rule on vehicle sales, but we note that the decrease in vehicle sales is expected to be negligible. Thus we expect any decrease in employment in the auto sector through the output effect to be small as well.

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<sup>E</sup> The authors also discuss a third component, the impact of regulation on factor prices, but conclude that this effect is unlikely to be important for large competitive factor markets, such as labor and capital. Morgenstern, Pizer and Shih (2002) use a very similar model, but they break the employment effect into three parts: 1) the demand effect; 2) the cost effect; and 3) the factor-shift effect. See Morgenstern, Richard D., William A. Pizer, and Jih-Shyang Shih. "Jobs Versus the Environment: An Industry-Level Perspective." *Journal of Environmental Economics and Management* 43 (2002): 412-436 (Docket EPA-HQ-OAR-2011-0135-0057).

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### 9.2.2.2 The Substitution Effect

The output effect, above, measures the effect due to new vehicle sales only. The substitution effect includes the impacts due to the changes in technologies needed for vehicles to meet the standards, separate from the effect on output (that is, as though holding output constant). This effect includes both changes in employment due to incorporation of abatement technologies and overall changes in the labor intensity of manufacturing.

One way to estimate this effect, given the cost estimates for complying with the rule, is to use the ratio of workers to each \$1 million of expenditures in that sector. The use of these ratios has both advantages and limitations. It is often possible to estimate these ratios for quite specific sectors of the economy: for instance, it is possible to estimate the average number of workers in the light-duty vehicle manufacturing sector per \$1 million spent in the sector, rather than use the ratio from another, more aggregated sector, such as motor vehicle manufacturing. As a result, it is not necessary to extrapolate employment ratios from possibly unrelated sectors. On the other hand, these estimates are averages for the sectors, covering all the activities in those sectors; they may not be representative of the labor required when expenditures are required on specific activities, or when manufacturing processes change sufficiently that labor intensity changes. For instance, the ratio for the motor vehicle manufacturing sector represents the ratio for all vehicle manufacturing, not just for emissions reductions associated with compliance activities. In addition, these estimates do not include changes in sectors that supply these sectors, such as steel or electronics producers. They thus may best be viewed as the effects on employment in the auto sector due to the changes in expenditures in that sector, rather than as an assessment of all employment changes due to these changes in expenditures. In addition, this approach estimates the effects of increased expenditures while holding constant the labor intensity of manufacturing; it does not take into account changes in labor intensity due to changes in the nature of production. This latter effect could either increase or decrease the employment impacts estimated here.<sup>F</sup>

Some of the costs of this rule will be spent directly in the auto manufacturing sector, but it is also likely that some of the costs will be spent in the auto parts manufacturing sector. We separately present the ratios for both the auto manufacturing sector and the auto parts manufacturing sector.

There are several public sources for estimates of employment per \$1 million expenditures. The U.S. Bureau of Labor Statistics (BLS) provides its Employment Requirements Matrix (ERM),<sup>7</sup> which provides direct estimates of the employment per \$1 million in sales of goods in 202 sectors. The values considered here are for Motor Vehicle Manufacturing (NAICS 3361) and Motor Vehicle Parts Manufacturing (NAICS 3363) for 2010.

The Census Bureau provides both the Annual Survey of Manufacturers<sup>8</sup> (ASM) and the Economic Census. The ASM is a subset of the Economic Census, based on a sample of

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<sup>F</sup> As noted above, Morgenstern et al. (2002) separate the effect of holding output constant into two effects: the cost effect, which holds labor intensity constant, and the factor shift effect, which estimates those changes in labor intensity.

establishments; though the Census itself is more complete, it is conducted only every 5 years, while the ASM is annual. Both include more sectoral detail than the BLS ERM: for instance, while the ERM includes the Motor Vehicle Manufacturing sector, the ASM and Economic Census have detail at the 6-digit NAICS code level (e.g., light truck and utility vehicle manufacturing). While the ERM provides direct estimates of employees/\$1 million in expenditures, the ASM and Economic Census separately provide number of employees and value of shipments; the direct employment estimates here are the ratio of those values. The values reported are for Motor Vehicle Manufacturing (NAICS 3361), Automobile and Light Duty Motor Vehicle Manufacturing (NAICS 33611), and Motor Vehicle Parts Manufacturing (NAICS 3363), for 2011 for the ASM, and 2007 for the Economic Census.

The values used here are adjusted to remove the employment effects of imports through use of a ratio of domestic production to domestic sales of 0.667.<sup>G</sup>

Table 9-1 provides the values, either given (BLS) or calculated (ASM, Economic Census) for employment per \$1 million of expenditures, all based on 2011 dollars, though the underlying data come from different years (which may account for some of the differences). These values have changed from the Draft RIA to use the most recent values for the ASM, and to put them all in 2011\$. The different data sources provide similar magnitudes for the estimates for the sectors. Parts manufacturing appears to be more labor-intensive than vehicle manufacturing; light-duty vehicle manufacturing appears to be slightly less labor-intensive than motor vehicle manufacturing as a whole.

**Table 9-1 Employment per \$1 Million Expenditures (2011\$) in the Motor Vehicle Manufacturing Sector<sup>a</sup>**

Source	Sector	Ratio of workers per \$1 million expenditures	Ratio of workers per \$1 million expenditures, adjusted for domestic vs. foreign production
BLS ERM	Motor Vehicle Mfg	0.754	0.503
ASM	Motor Vehicle Mfg	0.633	0.422
ASM	Light Duty Vehicle Mfg	0.583	0.389
Economic Census	Motor Vehicle Mfg	0.651	0.434
Economic Census	Light Duty Vehicle Mfg	0.590	0.393
BLS ERM	Motor Vehicle Parts Mfg	2.558	1.706
ASM	Motor Vehicle Parts Mfg	2.190	1.461
Economic Census	Motor Vehicle Parts Mfg	2.656	1.771

Note:

<sup>G</sup> To estimate the proportion of domestic production affected by the change in sales, we use data from Ward's Automotive Group for total car and truck production in the U.S. compared to total car and truck sales in the U.S. For the period 2001-2010, the proportion is 66.7 percent (Docket EPA-HQ-OAR-2011-0135).

<sup>a</sup> BLS ERM refers to the U.S. Bureau of Labor Statistics' Employment Requirement Matrix. ASM refers to the U.S. Census Bureau's Annual Survey of Manufactures. Economic Census refers to the U.S. Census Bureau's Economic Census.

Over time, the amount of labor needed in the auto industry has changed: automation and improved methods have led to significant productivity increases. The BLS ERM, for instance, provided estimates that, in 1993, 1.64 workers in the Motor Vehicle Manufacturing sector were needed per \$1 million of 2005\$, but only 0.86 workers by 2010 (in 2005\$).<sup>9</sup> Because the ERM is available annually for 1993-2010, we used these data to estimate productivity improvements over time. We regressed logged ERM values on year for both the Motor Vehicle Manufacturing and Motor Vehicle Parts Manufacturing sectors. We used this approach because the coefficient describing the relationship between time and productivity is a direct measure of the percent change in productivity per year. The results suggest a 3.9 percent per year productivity improvement in the Motor Vehicle Manufacturing Sector, and a 3.8 percent per year improvement in the Motor Vehicle Parts Manufacturing Sector. We then used the equation resulting from the regression to project the ERM through 2025. In the results presented below, these projected values (adjusted to 2011\$) were used directly for the BLS ERM estimates. For the ASM, we used the ratio of the projected value in each future year to the projected value in 2011 (the base year for the ASM) to determine how many workers will be needed per \$1 million of 2011\$; for the Economic Census estimates, we used the ratio of the projected value in the future years to the projected value in 2007 (the base year for that estimate).

Section 2.7 of the RIA discusses the vehicle cost estimates developed for this rule. The maximum value for employment impacts per \$1 million (before adjustments for changes in productivity, after accounting for the share of domestic production) is 1.771 in 2011\$ if all the additional costs are in the parts sector; the minimum value is 0.389 in 2011\$, if all the additional costs are in the light-duty vehicle manufacturing sector. Increased costs of vehicles and parts would, by itself, and holding labor intensity constant, be expected to increase employment between 2017 and 2025 by some hundreds of jobs each year.

While we estimate employment impacts, measured in job-years, beginning with program implementation, some of these employment gains may occur earlier as auto manufacturers and parts suppliers hire staff in anticipation of compliance with the standard. A job-year is a way to calculate the amount of work needed to complete a specific task. For example, a job-year is one year of work for one person. The decline in maximum employment between 2024 and 2025 is due to a combination of expected higher productivity and rounding, which makes an employment decrease from 760 to 743 job-years appear larger than it is.

**Table 9-2 Employment Effects due to Increased Costs of Vehicles and Parts, in job-years**

Year	Costs (Millions of 2011\$)	Maximum Employment Due to Substitution Effect (if all expenditures are in the Parts Sector)	Minimum Employment Due to Substitution Effect (if all expenditures are in the Light Duty Vehicle Mfg Sector)
2016	\$ 21	0	0
2017	\$ 297	400	100
2018	\$ 615	800	200
2019	\$ 653	800	200

2020	\$ 697	800	200
2021	\$ 725	800	200
2022	\$ 758	800	200
2023	\$ 751	800	200
2024	\$ 761	800	200
2025	\$ 773	700	200

### 9.2.2.3 Summary of Employment Effects in the Auto Sector

The overall effect of the rule on auto sector employment depends on the relative magnitude of the output effect and the substitution effect. Because we do not have quantitative estimates of the output effect, and only a partial estimate of the substitution effect, we cannot reach a quantitative estimate of the overall employment effects of the rule on auto sector employment or even whether the total effect will be positive or negative. However, given that the expected increase in production costs to the auto manufacturers is relatively small, we expect that the magnitudes of all effects combined will be small as well.

The standards are not expected to provide incentives for manufacturers to shift employment between domestic and foreign production. This is because the standards will apply to vehicles sold in the U.S. regardless of where they are produced. If foreign manufacturers already have increased expertise in satisfying the requirements of the standards, there may be some initial incentive for foreign production, but the opportunity for domestic manufacturers to sell in other markets might increase. To the extent that the requirements of this rule might lead to installation and use of technologies that other countries may seek now or in the future, developing this capacity for domestic production now may provide some additional ability to serve those markets. This potential benefit will not apply if other countries are not likely to have similar standards.

## 9.3 Impacts on Petroleum Refinery Sector

### 9.3.1 Refinery Sales Impacts

The key change for refiners from the standards will be more stringent sulfur requirements. This change to fuels is expected to increase manufacturers' costs of gasoline production by about 0.7 cents per gallon (see Section VII.B of the Preamble).

In a perfectly competitive industry, this cost would be passed along completely to consumers. In an imperfectly competitive industry, as noted above, full cost pass-through is not necessary: firms may choose to reduce impacts on sales by not passing along full costs. In 2004, the Federal Trade Commission reported that "concentration for most levels of the petroleum industry has remained low to moderate."<sup>10</sup> Thus the assumption of competitive markets has some foundation in this industry. We estimate that the price increase that consumers are likely to face should be positive and up to the increase in manufacturers' costs of gasoline production.

The effect of higher gasoline prices on gasoline sales is expected to be different over the short and long term. In the long run, in response to the increase in fuel costs, consumers can more easily change their driving habits, including where they live or what vehicles they use.

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Because of this, we expect that gasoline sales will decrease more in the long run compared to the short run as a result of the price increase due to the rule. However, because manufacturers' costs are expected to increase less than one cent per gallon, we expect that the decrease in gasoline sales will be negligible over all time horizons.

### 9.3.2 Refinery Employment Impacts

The Berman and Bui framework of output and substitution effects can also be applied to the impact of the rule on employment in the refinery sector.<sup>11</sup> Here we use a fully qualitative approach. A qualitative discussion allows for a wider incorporation of additional considerations, such as timing of impacts and the effects of the rule on imports and exports. Because the discussion is qualitative, we do not sum the net effects on employment.

The output effect on refining sector employment is expected to be negative. The discussion in Chapter 9.3.1 above suggests that the standards will cause a small decrease in the quantity of gasoline demanded due to higher production costs being passed through to consumers. This slightly reduced level of sales will likely have a negative impact on employment in the refining sector. This effect will persist as long as the increase in price is in place. The higher long-run elasticity suggests that sales will be lower in the long run than in the short run, leading to a greater reduction in employment due to the output effect over time. While we do not quantify the level of job losses that are expected here, recall that the quantity of gasoline sold as a result of the standards here is expected to decrease by only a very small amount over any time horizon.

The substitution effect of the rule on employment in the refining sector can be either positive or negative in the Berman and Bui framework; here, we expect a small, possibly positive impact. In order to satisfy the requirements of the rule, firms in the refining industry are expected to need to perform additional work that will require hiring more employees. This effect may be larger in the short run, when initial investments for compliance need to be made; over time, the increase in employment due to these investments may be reduced. Chapter 4.5.1 discusses the expected employment needed to reduce the sulfur content of fuels; as noted there, to meet the Tier 3 sulfur standards, refiners are expected to invest \$2 billion between 2012 and 2019 and utilize approximately 250 front-end design and engineering jobs and 15000 construction jobs. As the petroleum sector employed approximately 71,000 workers in 2011, this increase in employment is small when compared to 2011 levels.

These standards are not expected to provide incentives to shift employment between domestic and foreign production. First, the standards apply to gasoline sold in the U.S. regardless of where it has been produced. U.S. gasoline demand is projected to continue to decline for the foreseeable future in response to higher gasoline prices, more stringent vehicle and engine greenhouse gas and fuel economy standards as well as increased use of renewable fuels. As a result, this analysis of incentives to shift employment between domestic and foreign production focuses on investments for existing capacity instead of expanding capacity.<sup>H</sup> In this

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<sup>H</sup> While refinery capacity has been increasing around the world in recent years, it has been designed primarily to supply foreign markets other than the U.S. (e.g., increasing demand in China and India).

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case, what is relevant is whether the necessary modifications to comply with Tier 3 would be significantly cheaper overseas than in the U.S.

The main impacts on capital and operating costs to comply with Tier 3 associated with adding hydrotreating capacity are likely to be similar overseas as in the U.S. This is particularly true when analyzing likely sources of U.S. imports. The majority of gasoline imported to the U.S. today comes into the East Coast and is sourced out of either Europe or refineries in Canada or the Caribbean that exist almost solely to supply the U.S. market.

These Canadian and Caribbean refineries, by virtue of their focus on the U.S. market, are very similar to U.S.-based refineries and are expected to have to incur similar capital and operating costs as their U.S.-based competitors meeting the 10-ppm standard. Furthermore, the European refineries are already producing gasoline to a 10-ppm sulfur cap for Europe. To the extent they have refinery streams that are more difficult to hydrotreat, the U.S. market currently serves as an outlet for their higher sulfur gasoline streams. As a result, they may incur capital and operating costs on a per gallon basis at least as high as for their U.S.-based competitors for these remaining higher sulfur gasoline streams. Alternatively, they may instead choose to find markets outside the U.S., opening the way for increased U.S.-based refinery demand.

Finally, despite refining industry projections that previously imposed diesel rules would lead to greater U.S. reliance on imports through major negative impacts on domestic refining, the reverse has actually occurred. Over the last 8 years, imports of gasoline and diesel fuel have continued to be the marginal supply, and have even dropped precipitously so that the U.S. is now a net exporter of diesel fuel and is importing half the gasoline that it did at its peak in 2006. With the projected decline in future gasoline demand in the U.S. as vehicle fuel efficiency improves, gasoline imports are expected to continue to decline.

Thus it is expected that for the refining sector, the output effect will lower employment, and the substitution effect may raise employment. As a whole then, it is not evident whether the rule will increase or decrease employment in the refining sector. However, given the small anticipated reduction in quantity sold, it appears that the standards will not have major employment consequences for this sector.

The petroleum refining industry is one of the manufacturing industries studied by Berman and Bui (2001)<sup>7</sup> when they looked at the effect of environmental expenditures on employment. They found that “Employment effects are very small, generally positive, but not statistically different from zero” (p. 281) [Berman and Bui, Table 3]. Berman and Bui also state that the estimates rule out large negative effects (p. 282). Because most of the abatement cost of the regulations they analyze is incurred by refineries, in their sample, they report separate employment effects for refineries and non-refineries “which are also all small.” (p. 282). Berman and Bui suggest some explanations for the zero or small estimates, particularly for oil refineries: they are capital-intensive industries with relatively little employment when compared to other manufacturing; they face relatively inelastic demand because they sell output in local markets and/or because there are no unregulated refineries to compete with; and, finally, regulations may have been associated with productivity gains in petroleum refineries. We note that the regulations that these estimate are derived from are not directly comparable to the current rule; it

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is based on the costs of reductions in refinery air pollution emissions instead of changing fuel properties, and therefore may not be applicable for the standards here.

Section VII.B.5 of the Preamble contains some historical discussion regarding the impact on refineries and refining capacity of earlier rules which resulted in higher costs for refiners. Over the period 2003-2011, when a number of rules were being implemented, EIA data show a net of two refinery closures on its website. Meanwhile, over this same period the average size of U.S. refineries increased from 113,000 barrels per day to 123,000 barrels per day, and total U.S. refining capacity increased by six percent. Thus, historically during a time when rules with much larger expected impacts were being implemented (the 2003 ultra-low sulfur nonroad diesel proposal alone was expected to have a cost impact on refineries more than five times greater than the current rule), U.S. refining capacity increased even as the number of U.S. refineries slightly fell. While closing refineries has a negative effect on industry employment, it is likely that the increased refining capacity at many of the remaining plants had a positive effect on industry employment.

The standards are also likely to have a positive impact on employment among producers of equipment that refiners will use to comply with the standards. Chapter 5 notes that some refiners are expected to revamp their current treatment units, and others will need to add additional treatment units. Producers of this equipment are expected to hire additional labor to meet this increased demand. We also note that the employment effects may be different in the immediate implementation phase than in the ongoing compliance phase. It is expected that the employment increases through the substitution effect from revamping old equipment and installing additional equipment should occur in the near term, when current unemployment levels are high, and the opportunity cost of workers is relatively low. Meanwhile, the employment decreases in the refining sector from the output effect will not start until 2017, when compliance is required, and when unemployment is expected to be reduced; in a time of full employment, any changes in employment levels in the regulated sector are mostly expected to be offset by changes in employment in other sectors.

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## References

<sup>1</sup>Berman, E. and L. T. M. Bui (2001). "Environmental Regulation and Labor Demand: Evidence from the South Coast Air Basin." *Journal of Public Economics* 79(2): 265-295 (Docket EPA-HQ-OAR-2011-0135).

<sup>2</sup>Morgenstern, Richard D., William A. Pizer, and Jhih-Shyang Shih. "Jobs Versus the Environment: An Industry-Level Perspective." *Journal of Environmental Economics and Management* 43 (2002): 412-436 (Docket EPA-HQ-OAR-2011-0135-0057).

<sup>3</sup>Greenstone, M. (2002). "The Impacts of Environmental Regulations on Industrial Activity: Evidence from the 1970 and 1977 Clean Air Act Amendments and the Census of Manufactures," *Journal of Political Economy* 110(6): 1175-1219 (Docket EPA-HQ-OAR-2011-0135); Walker, Reed. (2011). "Environmental Regulation and Labor Reallocation." *American Economic Review: Papers and Proceedings* 101(3): 442-447 (Docket EPA-HQ-OAR-2011-0135).

<sup>4</sup>List, J. A., D. L. Millimet, P. G. Fredriksson, and W. W. McHone (2003). "Effects of Environmental Regulations on Manufacturing Plant Births: Evidence from a Propensity Score Matching Estimator." *The Review of Economics and Statistics* 85(4): 944-952 (Docket EPA-HQ-OAR-2011-0135).

<sup>5</sup>Schmalensee, Richard, and Robert N. Stavins. "A Guide to Economic and Policy Analysis of EPA's Transport Rule." White paper commissioned by Excelon Corporation, March 2011 (Docket EPA-HQ-OAR-2011-0135-0054).

<sup>6</sup>Berman, E. and L. T. M. Bui (2001). "Environmental Regulation and Labor Demand: Evidence from the South Coast Air Basin." *Journal of Public Economics* 79(2): 265-295 (Docket EPA-HQ-OAR-2011-0135).

<sup>7</sup>[http://www.bls.gov/emp/ep\\_data\\_emp\\_requirements.htm](http://www.bls.gov/emp/ep_data_emp_requirements.htm).

<sup>8</sup><http://www.census.gov/manufacturing/asm/index.html>.

<sup>9</sup>[http://www.bls.gov/emp/ep\\_data\\_emp\\_requirements.htm](http://www.bls.gov/emp/ep_data_emp_requirements.htm); this analysis used data for sectors 88 (Motor Vehicle Manufacturing) and 90 (Motor Vehicle Parts Manufacturing) from "Chain-weighted (2000 dollars) real domestic employment requirements table. . . adjusted to remove imports."

<sup>10</sup> Federal Trade Commission, Bureau of Economics. "The Petroleum Industry: Mergers, Structural Change, and Antitrust Enforcement." <http://www.ftc.gov/os/2004/08/040813mergersinpetrolberpt.pdf>, accessed 8/16/11 (Docket EPA-HQ-OAR-2011-0135-0055).

<sup>11</sup> Berman, E. and L. T. M. Bui (2001). "Environmental Regulation and Labor Demand: Evidence from the South Coast Air Basin." *Journal of Public Economics* 79(2): 265-295 (Docket EPA-HQ-OAR-2011-0135).

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## Chapter 10 Final Regulatory Flexibility Analysis

### 10.1 Introduction

This chapter discusses our Final Regulatory Flexibility Analysis (FRFA) which evaluates the potential impacts of the proposed standards on small entities. The Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 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 ID Number EPA-HQ-OAR-2011-0135-0423). Pursuant to this requirement, we have prepared an IRFA for the proposed rule. Throughout the process of developing the IRFA, we conducted outreach and held meetings with representatives from the various small entities that could be affected by the rulemaking to gain feedback, including recommendations, on how to reduce the impact of the rule on these entities. The small business recommendations stated here reflect the comments of the small entity representatives (SERs) and members of the Small Business Advocacy Review Panel (SBAR Panel, or ‘the Panel’).

### 10.2 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 FRFA. A summary of the Panel’s recommendations is presented in the preamble to the proposed rule. Further, a detailed discussion of the Panel’s advice and recommendations (as well as comments from the Small Entity Representatives) can be found in the Final Panel Report contained in the docket for this proposed rulemaking.<sup>1</sup> The regulatory alternatives that are being adopted in the 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 of and, where feasible, an estimate of the number of small entities to which the rule will apply;
- Projected reporting, recordkeeping, and other compliance requirements of the rule, including an estimate of the classes of small entities which will be subject to the requirements and the type of professional skills necessary for preparation of the report or record;

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- An identification to the extent practicable, of all other relevant Federal rules which may duplicate, overlap, or conflict with the rule;
  - Any significant alternatives to the rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the 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.

### **10.3 Need for the Rulemaking and Rulemaking Objectives**

A detailed discussion on the need for, and objectives of, this rule are located in the preamble to the final rule. As presented in Chapter 9 of this RIA, controlling exhaust and evaporative emissions from light-duty vehicles and trucks and complete heavy-duty vehicles and reducing sulfur levels in gasoline have important public health and welfare benefits. Further, as discussed in Section II of the preamble to the final rule, section 202 of the Clean Air Act (specifically, sections 202(a) and (k)) authorizes EPA to establish emissions standards for motor vehicles to address air pollution that may reasonably be anticipated to endanger public health or welfare. EPA also has authority to establish fuel controls to address such air pollution under section 211(c) of the Clean Air Act. Emissions from motor vehicles and their fuels contribute to pollutants for which EPA has established health-based NAAQS, and motor vehicles also emit air toxics and contribute to near-road air pollution.

EPA's current Tier 2 Vehicle and Gasoline Sulfur Program, which was finalized in February 2000, took a systems-based approach to motor vehicle pollution by setting standards for both passenger vehicles and their fuel (gasoline). The Tier 2 program set stricter tailpipe and evaporative emissions standards for criteria pollutants from vehicles beginning with model year (MY) 2004 and phasing in through 2009. The program also lowered the sulfur content of gasoline, to a 30 parts per million (ppm) annual refinery average, 80 ppm per-gallon cap, and 95 ppm downstream cap; beginning in 2004 and phasing in through 2011.

The Tier 3 rule is a comprehensive, systems-based approach to address the impact of motor vehicles on air quality and health, similar to the Tier 2 rule. The Tier 3 program establishes new standards for light-duty vehicles and trucks and complete heavy-duty vehicles and new fuel standards for gasoline. Such standards were assumed in the 2008 NAAQS as part of the strategy for reaching attainment with the NAAQS. Subsequently, a May 21, 2010 Presidential Memorandum directed EPA to "review for adequacy" the current non-greenhouse gas (GHG) emissions regulations for new motor vehicles and fuels, including tailpipe emissions standards for NO<sub>x</sub> and air toxics, and sulfur standards for gasoline. The memo further directed EPA to "promulgate such regulations as part of a comprehensive approach toward regulating motor vehicles" if EPA determines new regulations are required. Based on our review, we have

concluded that improved vehicle technology, combined with lower sulfur gasoline, make it feasible and cost-effective to reduce emissions well below the current Tier 2 levels. These emission reductions are necessary to reduce air pollution that is (and projected to continue to be) at levels that endanger public health and welfare.

In the absence of additional controls such as Tier 3 standards, areas would have to adopt other measures to reduce emissions from other sources under their state or local authority. Few other measures exist for providing multi-pollutant reductions of the same magnitude and cost-effectiveness as those expected from the Tier 3 standards.

#### 10.4 Definition and Description of Small Entities

The Regulatory Flexibility Act defines small entities as including small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of a 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<sup>A</sup>; (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 which is independently owned and operated and is not dominant in its field. This rulemaking is expected to affect a variety of small businesses, but will not affect any small governmental jurisdictions or small organizations as described above. Table 10-1 below provides an overview of the primary SBA small business categories potentially affected by this regulation.

**Table 10-1 Industry Sectors Potentially Affected by the Rule**

Industry Sector	NAICS Code	SBA Size Standard for Small Business (less than or equal to):
Gasoline fuel refiners and importers	324110	1,500 employees
Ethanol producers	325193	1,000 employees
Gasoline additive manufacturers	325199	1,000 employees
	325998	500 employees
	424690	100 employees
Transmix processors	Varied	1,500 employees
Petroleum bulk stations & terminals	424710	100 employees
Other warehousing and storage-bulk petroleum storage	493190	\$25.5 million (annual receipts)
Light-duty vehicle and light-duty truck manufacturers	336111, 336112	1,000 employees
On-highway heavy-duty engine & vehicle (>8,500 pounds)	333618, 336120, 336211 336312	1,000 employees 750 employees

<sup>A</sup> The SBA definitions of small business by size standards using the North American Industry Classification System (NAICS) can be found at 13 CFR 121.201.

GVWR) manufacturers		
Independent commercial importers	811111, 811112, 811198	\$7 million (annual receipts)
Alternative fuel converters	335312 336312, 336322, 336399 811198	1,000 employees 750 employees \$7 million (annual receipts)

EPA used a variety of sources to identify which entities are appropriately considered “small” using the criteria for small entities developed by the Small Business Administration as a guide. Information about these entities came from sources including the Energy Information Administration (EIA) within the U.S. Department of Energy, oil industry literature, EPA’s motor vehicle certification data, and previous vehicle and fuel rulemakings that have affected these industries. EPA then found employment information or annual revenue information for these companies using the business information database Hoover’s Online (a subsidiary of Dun and Bradstreet).

## 10.5 Summary of Small Entities to Which the Rulemaking Will Apply

### 10.5.1 Fuels-related Industries

Small entities that may be subject to the Tier 3 gasoline sulfur standards include: domestic gasoline refiners, importers of gasoline into the U.S., ethanol producers, gasoline additive manufacturers, transmix processors, and terminal operators. Based on current data, EPA believes that there are about 50 gasoline refiners, of these, we believe that there are currently 13 refiners producing gasoline that meet SBA’s small business definition. Of the seven transmix processors that we have identified, we believe that five would be considered small entities. Transmix processors do not have a specific NAICS code, and thus do not have a corresponding SBA definition, so these parties were estimated to be small entities by using the respective size standard for the industry these entities had listed as their “primary” business (refining- 1,500 employees or less). For fuel terminals, we believe that there are 1,100 companies; of the 980 companies that we were able to find employee count and/or revenue information for, we believe that 900 of these companies would be considered small entities. There are approximately 204 ethanol producers; for those companies for which we were able to find employment data, we believe that the majority of this sector (all but 16 ethanol producers) would be considered small businesses.

It should be noted that because of the dynamics in the fuels industry (i.e., mergers and acquisitions), the actual number of refiners that ultimately qualify as a small business under this program could be different from this initial estimate.

### 10.5.2 Vehicle-related Industries

The motor vehicle manufacturing industry is made up primarily of large manufacturers including General Motors, Ford, Toyota, and Honda. Based on EPA certification records, we have identified a total of 27 car and truck manufacturers which have certified vehicles for sale in the U.S. Of these companies, EPA has identified 4 motor vehicle manufacturers that qualify as a small business under SBA definitions. Two of these small entities produce either gasoline-

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fueled, natural-gas fueled, or hybrid gasoline-electric vehicles. Two additional small manufacturers exclusively produce all-electric vehicles.

Companies that convert motor vehicles to run on alternative fuels will be subject to the proposed regulations. Based on EPA certification records, we have identified 13 companies which convert vehicles to run on alternative fuels. Of these companies, EPA has identified 9 alternative fuel converters that qualify as a small business under the SBA definitions.

Another industry sector that will be subject to the proposed regulations consists of companies that import specialized cars and trucks into the United States (U.S.), referred to as Independent Commercial Importers (ICIs). ICIs work with customers to bring in cars from overseas either because the owners are moving to the U.S., or because the vehicle is not otherwise available in the U.S. (e.g., high-performance sports cars and right-hand drive postal vehicles). We have identified 8 ICIs that are currently importing cars and trucks into the U.S. All of these companies qualify as a small business under the SBA definitions.

## **10.6 Related Federal Rules**

The primary federal rules that are related to this final rule are: the Tier 2 Vehicle/Gasoline Sulfur rulemaking (65 FR 6698, February 10, 2000), the 2017 Light-duty Greenhouse Gas (LD GHG) rule (77 FR 62623), and the Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (HD GHG) rule (76 FR 57106).

The LD GHG and HD GHG rules are coordinated efforts by EPA and the National Highway Traffic Safety Administration (NHTSA) taking steps to reduce GHG emissions and improve fuel efficiency from on-road vehicles and engines.

## **10.7 Reporting, Recordkeeping, and Other Compliance Requirements**

For any fuel control program, EPA must have assurance that fuel produced, distributed, sold and used meets the applicable standard. The recordkeeping, reporting, and compliance provisions of the Tier 3 fuels program will be consistent with those currently in place for the Tier 2 gasoline program. Further, to the program will use existing registration and reporting systems that parties in the fuel production and distribution industry are already familiar with. A complete discussion of the fuel-related compliance provisions can be found in Section V.F of the preamble to the final rule.

For any motor vehicle emissions control program, EPA must have assurances that the regulated products will meet the standards. The final program for manufacturers subject to this rule will include testing, reporting, and record keeping requirements for manufacturers of vehicles covered by the Tier 3 regulations. Testing requirements for these manufacturers will include certification emissions (including deterioration factor) testing and in-use testing. Reporting requirements will include emissions test data and technical data on the vehicles. Manufacturers must keep records of this information.

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## 10.8 Regulatory Alternatives

As a part of the SBREFA process, we conducted outreach to small entities and convened a SBREFA Panel to gain feedback and advice from these entities. Prior to convening the Panel, we held outreach meetings with the SERs to learn the needs of small entities and potential challenges that these entities may face. The feedback that we received from SERs as a result of these meetings was used during the Panel process to develop a wide range of regulatory alternatives to mitigate the impacts of the rulemaking on small businesses. It was agreed that EPA should consider the issues raised by the SERs (and issues raised in the course of the Panel) and that EPA should consider the comments on flexibility alternatives that would help to mitigate any negative impacts on small businesses.

The Panel consisted of members from EPA, the Office of Management and Budget (OMB), and SBA's Office of Advocacy. Following the Panel convening, a Final Panel Report detailing all of the alternatives that were recommended by the Panel was issued. A full discussion of the regulatory alternatives discussed and recommended by the Panel, all written comments received from SERs during the SBREFA process, and summaries of the outreach meetings held with the SERs can be found in the SBREFA Final Panel Report.<sup>2</sup> In the proposal, 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. All of the flexibilities that are being finalized for small businesses, as well as those for all entities that may be affected by the rulemaking, are described in Sections IV and V of the preamble to the final rule.

### 10.8.1 Fuel-related Alternatives

#### 10.8.1.1 Delayed Standards for Small Refiners

##### Panel Recommendations

The Panel recommended that EPA propose a delay option, similar to previous fuels rulemakings, in the Tier 3 proposed rule. The Panel recommended that EPA allow small refiners to postpone their compliance with the Tier 3 program for up to three years. Small refiners choosing this flexibility option would have from January 1, 2017 through December 31, 2019 to continue production of gasoline with an average sulfur level of 30 ppm (per the Tier 2 gasoline sulfur program), and compliance with the 10 ppm sulfur standard would begin on January 1, 2020. Any small refiner choosing this proposed option would be allowed to continue use of their Tier 2 gasoline sulfur credits through December 31, 2019 to meet the refiner average 30 ppm sulfur standard.

The Panel also recommended that EPA request comment on case-by-case hardship provisions that would provide additional relief for any refiner experiencing extreme difficulty in compliance with the Tier 3 requirements, as discussed below in Section 10.8.1.1.4.

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## What We Proposed and Public Comments Received on the NPRM

We proposed to allow small refiners to postpone their compliance with the Tier 3 program for up to three years—small refiners choosing this flexibility option would have from January 1, 2017 through December 31, 2019 to continue production of gasoline with an average sulfur level of 30 ppm (per the Tier 2 gasoline sulfur program). Compliance with the 10 ppm sulfur standard would begin on January 1, 2020. We also proposed that small refiners would be allowed to continue use of their Tier 2 gasoline sulfur credits through December 31, 2019 to meet their refinery average 30 ppm sulfur standard, but these credits could not be used for compliance with the proposed Tier 3 10 ppm average sulfur standard. With regard to early credit generation, we proposed that all refiners and importers (including small refiners) could generate early credits relative to the 30 ppm sulfur standard from January 1, 2014 through December 31, 2016, and relative to the 10 ppm sulfur standard from January 1, 2017 through December 31, 2019. We also proposed to extend the small refiner provisions to small volume refineries (refineries with a crude oil throughput of less than or equal to 75,000 barrels per calendar day (bpcd)).

Comments received on the proposed rule were generally in support of allowing an additional three years for small refiners (and small volume refineries) to comply with the Tier 3 program. However, some commenters did not agree with our proposed provisions for early credits. Some small refiners commented that they believe small refiners should also have their own three-year early credit generation period, from January 1, 2017 through December 31, 2019, relative to the 30 ppm sulfur standard.

## What We're Finalizing

As described in Section V.E. of the preamble to the final rule, we are finalizing a three-year delay for approved small refiners, until January 1, 2020. With regard to the ABT program, as discussed in preamble Section V.D.5, we are finalizing that small refiners may generate early credits relative to the 30 ppm average sulfur standard from January 1, 2014 through December 31, 2019, and these credits could be used for either Tier 2 or Tier 3 compliance. (However, credits generated by a small refiner from January 1, 2017 through December 31, 2019 could only be traded and used by other small refiners.) Further, from January 1, 2017 through December 31, 2019, if a small refiner's annual average sulfur level is below 10 ppm, they may elect to split the generation of credits between both the 10 ppm and 30 ppm standards (without double-counting). For example, during this time, a small refiner with an annual gasoline sulfur average of 8 ppm could generate 20 Tier 2 credits (30 ppm-10 ppm) and 2 Tier 3 credits (10 ppm-8 ppm).

All of the small refiner provisions are also applicable to approved small volume refineries.

### 10.8.1.2 Provisions for Additive Manufacturers

#### Panel Recommendations

During the SBREFA Panel process, different requirements than those proposed (and being finalized today) were discussed for additive manufacturers. Thus, the provisions

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recommended by the Panel were not applicable to the provisions proposed and now finalized for these parties. More information on the Panel's recommendations for gasoline additive manufacturers can be found in the Final Panel Report, located in the rulemaking docket.

### What We Proposed and Public Comments Received on the NPRM

We proposed that parties introducing additives to gasoline greater than 1.0 volume percent would be required to satisfy all of the obligations of a fuel manufacturer, including demonstration that the finished blend meets the applicable sulfur specification. We also proposed a maximum sulfur contribution of 3 ppm from the use of a gasoline additive added downstream of the refinery at less than 1.0 volume percent (when added at the maximum recommended treatment rate). Lastly, we proposed that additive manufacturers would need to maintain records of their additive production quality control activities for five years.

### What We're Finalizing

As discussed further in Section V.C., manufacturers of gasoline additives that are used downstream of the refinery at less than 1.0 volume percent will be required to limit the sulfur contribution to the finished gasoline from the use of the additive to less than 3 ppm when the additive is used at the maximum recommended treatment rate. For each batch of additive produced, the manufacturer must retain sulfur test records for 5 years, and must make these records available to EPA upon request. Parties that introduce additives to gasoline at over 1.0 volume percent will be required to satisfy all of the obligations of a fuel manufacturer, including demonstration that the finished blend meets the applicable sulfur specification.

#### 10.8.1.3 Refinery Gate and Downstream Caps

### Panel Recommendations

The Panel recommended that EPA assess and request comment on retaining the current Tier 2 refinery gate and downstream caps of 80 and 95 ppm, respectively, to help provide maximum flexibility and avoid system upsets for the entire refining and distribution system. Further, the SBA and OMB Panel members recommended that EPA propose retaining the 80 ppm and 95 ppm caps.

With regard to a 20 ppm refinery gate cap, the Panel had concerns that such a standard could cause operational problems for small refiners during a refinery turnaround or an upset, because a cap of this level could result in a refiner not being able to produce gasoline (as noted in their comments in Section 8 of the Panel Report). The Panel likewise had concerns that a downstream cap of 25 ppm could cause problems for small downstream entities, such as transmix processors, because they may not be able to reprocess finished gasoline down to this level (also noted in their comments in Section 8 of the Panel Report). Thus, the Panel recommended that EPA request comment on additional refinery gate and downstream caps above 20/25 ppm, but below 80/95 ppm. Additionally, the Panel recommended that EPA allow the current Tier 2 80 ppm sulfur refinery gate cap and 95 ppm sulfur downstream cap in Alaska to remain at these levels indefinitely.

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## What We Proposed and Public Comments Received on the NPRM

We proposed two options for the per-gallon sulfur caps—maintaining the Tier 2 80 ppm refinery gate sulfur and 95 ppm downstream sulfur caps and, beginning January 1, 2020, lowering to 50 ppm refinery gate and 65 ppm downstream caps. In addition, we requested comment on lowering to a 20 ppm refinery gate cap and a 25 ppm downstream cap. Due to technical and economic concerns for refiners and distributors in the state of Alaska, we also proposed that if we were to finalize 50/65 ppm caps, Alaska would be allowed to retain the 80/95 ppm caps.

We received comments on both of the proposed per-gallon cap options of 80/95 ppm and 50/65 ppm, as well as comments on finalizing lower caps of 20/25 ppm and a 20 ppm overall cap. Comments in support of lower refinery gate and downstream caps noted potential environmental benefits, greater certainty that vehicles would see lower and more uniform gasoline sulfur levels, and the ability to enable new vehicle technologies that require very low sulfur levels. Comments in support of maintaining the 80/95 ppm caps cited concerns over cost, flexibility during turnarounds/unplanned shut downs (due to refinery fire, natural disaster, etc.), and potential impacts on gasoline supply and pricing.

### What We're Finalizing

As discussed in greater detail in Section V.C of the preamble, we are retaining the Tier 2 per-gallon sulfur caps of 80 ppm at the refinery gate and 95 ppm downstream. We are also committing to monitor and further evaluate in-use sulfur levels and their impact on vehicle emissions, which will include: analyses of in-use fuel surveys, refinery batch data, and the sulfur credit market; evaluation of any implementation issues; and an ongoing evaluation of vehicle manufacturers' data on Tier 3 vehicles' in-use performance. If it is warranted, we will reassess the sulfur cap level and the need for potential future regulatory action.

#### 10.8.1.4 Hardship Provisions

### Panel Recommendations

During the Panel process, EPA stated its intent to propose hardship provisions (for all gasoline refiners and importers) similar to those in prior EPA fuels programs: a) the extreme unforeseen circumstances hardship provision, and b) the extreme hardship provision. A hardship based on extreme unforeseen circumstances is intended to provide short term relief due to unanticipated circumstances beyond the control of the refiner, such as a natural disaster or a refinery fire. An extreme hardship is intended to provide short-term relief based on extreme circumstances (e.g., extreme financial problems, extreme operational or technical problems, etc.) that impose extreme hardship and thus significantly affect a refiner's ability to comply with the program requirements by the applicable dates. In the context of the proposal, the Panel agrees that such relief could consider long-term relief on the sulfur cap (similar to that for Alaska) if the circumstances both warrant it and can be structured in a way to allow for it. The Panel agrees with the proposal of such provisions and recommended that EPA include them in the Tier 3 proposed rulemaking.

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## What We Proposed and Public Comments Received on the NPRM

Similar to previous EPA fuels programs, we proposed the extreme hardship and extreme unforeseen circumstances hardship provisions both to accommodate a refiner's inability to comply with at the start of the Tier 3 program and to deal with unforeseen circumstances that may occur at any point during the program. We proposed that any refiner could apply for a hardship waiver, but relief would be granted on a case-by-case basis following a showing of certain requirements; primarily that compliance through the use of credits is not feasible. Further, we proposed that any hardship waiver granted would likely consist of short-term relief, and would be based on the nature and degree of the hardship and EPA's assessment of the credit market at that time.

In general, comments received agreed with the inclusion of hardship provisions in the Tier 3 program. While not directly related to the hardship provisions, we received comments on the one-year deficit carryforward provision (an individual refinery that does not meet the average sulfur standard in a given year may carry a credit deficit forward for 1 year). We received comments expressing concern that it will be more challenging for refineries to make up their credit deficit in one year with a 10 ppm sulfur standard, thus the commenters requested that the deficit carryforward allowance be extended to two or three years. One commenter suggested that an extension of the deficit carryforward provision could also be used as a form of hardship relief.

## What We're Finalizing

We are finalizing both the extreme hardship and extreme unforeseen circumstances hardship provisions. We continue to believe that providing short-term relief to those refiners that need additional time due to hardship circumstances will help to facilitate the adoption of the overall Tier 3 program for the majority of the industry. The provisions themselves, and the conditions under which a refiner would receive hardship relief, are similar to those in previous fuels regulations, and are necessary and appropriate to ensure that any waivers granted would be limited in scope. Further, we expect to impose appropriate conditions to ensure that the refiner is making best efforts to achieve compliance offsetting any loss of emission control from the program. A complete discussion of the hardship provisions is located in Section V.E.2 of the preamble to the final rule.

As discussed more fully in preamble Section V.D.7, while we acknowledge the increased hurdle to make up a deficit in the Tier 3 program, we have concerns with the enforceability allowing for deficit carryforward greater than one year. Further, refiners also have the opportunity to purchase credits from others. However, if for some reason credits are unavailable or are prohibitively expensive such that the refiner could not make up the deficit in one year, we would consider this in an evaluation of a hardship application. As such, we are finalizing that hardship waivers could grant relief in the form of additional deficit carryforward of up to three years, depending on the level of hardship and the status of the credit market.

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## 10.8.2 Vehicle-Related Alternatives

### 10.8.2.1 Lead Time for Exhaust and Evaporative Emission Standards

#### Panel Recommendations

In the types of businesses subject to the potential Tier 3 standards, small businesses have limited resources available for developing new designs to comply with new emission standards. In addition, it is often necessary for these businesses to rely on vendor companies for technology. Moreover, percentage phase-in requirements pose a dilemma for a small manufacturer that has a limited product line (e.g., the manufacturer certifies vehicles in only one or two test groups). Thus, similar to the flexibility provisions implemented in previous vehicle rules, the Panel recommended that EPA allow small businesses the following flexibility options for meeting the potential Tier 3 exhaust emissions standards.

The Panel recommended that small businesses be given additional leadtime to comply with the potential Tier 3 exhaust standards and allow small businesses to comply with the standards with 100 percent of their vehicles starting in model year 2022. (This is similar to the Tier 2 rule where EPA allowed small manufacturers to wait until the end of the phase-in to comply with the Tier 2 standards.) During the Panel process, the proposed Tier 3 rule was expected to have several different phase-in schedules; with the final dates varying from model year 2021 for the new exhaust PM standards and use of the new E15 certification fuel, to model year 2022 for the new evaporative emission standards, to model year 2025 for the new exhaust gaseous pollutant standards. The Panel noted that requiring all small businesses to comply with the full slate of Tier 3 requirements in model year 2022 should provide sufficient lead time for manufacturers to plan for and implement the technology changes needed to comply with the Tier 3 standards.

One of the SERs recommended that EPA adopt relaxed exhaust standards for small manufacturers. The SER noted that the exhaust emission averaging program being proposed by EPA would allow large manufacturers that have many engine families to certify their small, niche products at levels numerically higher than the standards. Small manufacturers that typically do not have more than one or two emission families generally cannot use averaging to the same extent because of their limited product offerings. The SER's concern was that the high-performance vehicles produced by large manufacturers which they compete against would be able to certify at numerically higher levels at less cost than the SER would incur. While EPA was planning to propose the same standards for all manufacturers, the Panel recommended that EPA request comment on allowing small manufacturers to meet relaxed exhaust emission standards. This could also be included as part of the hardship provision discussed below. The Panel recommended that EPA request comment on the relaxed standards recommended by the SER. The SER-recommended relaxed NMOG+NO<sub>x</sub> standards over the Federal Test Procedure (FTP) are 0.125 grams/mile in model year 2020 and 0.070 grams/mile in model year 2025. In addition, the Supplemental FTP standards would be the standards for the corresponding bins which the manufacturer selected for complying with the FTP standards. For example, if the manufacturer certified to the proposed Tier 3 Bin 125 standards over the FTP, the manufacturer would have to comply with the corresponding Tier 3 Bin 125 standards for the Supplemental FTP.

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The Panel recommended that small businesses comply with the Tier 3 evaporative emission standards, including the leak standard, with 100 percent of their vehicles starting in model year 2022. For evaporative emissions, where the Tier 3 standards could begin as early as 2017 and phase-in through 2022, this provision would allow small businesses and SVMs to wait until the last year of the Tier 3 phase-in period for evaporative emission standards for all of their vehicles. This start date is consistent with the start date described above for the Tier 3 exhaust emission requirements being recommended by the Panel for small businesses.

### What We Proposed

We proposed that small businesses be given additional lead time to comply with the potential Tier 3 exhaust and evaporative emission standards and that small businesses be allowed to comply with the standards with 100 percent of their vehicles starting in model year 2022. (This is similar to the Tier 2 rule where EPA allowed small manufacturers to wait until the end of the phase-in to comply with the Tier 2 standards.) The proposed Tier 3 rule has several different phase-in schedules; with the final dates varying from model year 2021 for the new light-duty exhaust PM standards to model year 2025 for the new light-duty exhaust gaseous pollutant standards. Our assessment was that requiring all small businesses to comply with the full slate of Tier 3 requirements in model year 2022 would provide sufficient lead time for manufacturers to plan for and implement the technology changes needed to comply with the Tier 3 standards.

Although we proposed the same standards for all manufacturers starting with model year 2022, we also requested comment on allowing small manufacturers to meet relaxed exhaust emission standards. The relaxed standards could be written directly into the regulations, or potentially we could allow manufacturers to request relaxed exhaust standards as part of the hardship provision discussed below, or we could allow manufacturers to request alternative standards based on a comparison of vehicles with similar attributes that are certified by larger manufacturers. With regard to the relaxed standard, we are requested comment on the standards recommended by the SER. The SER-recommended relaxed NMOG+NO<sub>x</sub> standards over the Federal Test Procedure (FTP) are 0.125 grams/mile in model year 2020 and 0.070 grams/mile in model year 2025. In addition, the Supplemental FTP standards would be the standards for the corresponding bins which the manufacturer selected for complying with the FTP standards. For example, if the manufacturer certified to the proposed Tier 3 Bin 125 standards over the FTP, the manufacturer would have to comply with the corresponding Tier 3 Bin 125 standards for the Supplemental FTP.

### Public Comments Received on the NPRM and What We Are Finalizing

We did not receive comments from non-SVM small businesses subject to the Tier 3 vehicle standards about our proposed small entity phase-in provisions. However, we received comments from SVMs, as well as from the Alliance of Automobile Manufacturers and the Association of Global Automakers, arguing that the proposed phase-in did not provide adequate lead time relief for SVMs, and that the long-term Tier 3 standards for light-duty vehicles are not technologically feasible for SVMs. They especially highlighted the ability of large manufacturers to offset high emissions from high-performance, luxury models by averaging with their low-emitting models, while competing SVM products must be designed to actually achieve low emissions while still meeting customers' performance expectations. Their limited

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production can also result in emission control technology suppliers placing a lower priority on SVM orders than on those of larger, high-volume manufacturers.

Because of these factors, SVMs suggested that their companies meet a slightly more stringent NMOG+NO<sub>x</sub> standard than what we proposed for SVMs in the early years of the program (125 mg/mi) and a permanently relaxed standard of 51 mg/mi beginning in MY 2022. Ferrari (which also raised the issue of “operational independence” as described below) suggested a compliance schedule for SVMs similar to the California LEV III program, with either a permanently relaxed standard (matching the California LEV III 70 mg/mi long-term standard) or a delay until MY 2030 to meet the primary 30 mg/mi Tier 3 standard (when they suggest that SVMs could potentially comply). CARB comments supported Tier 3 adoption of its LEV III provisions for SVMs, including the long-term 70 mg/mi standard beginning in MY 2025.

After considering the comments, we agree with SVMs that their unique logistical and technological challenges, especially in the later years of the primary phase-in schedule, warrant a significant period of relaxed standards for these manufacturers. However, we see no fundamental reasons why, given sufficient lead time, all companies, regardless of company size and vehicle characteristics, will not be able to meet the Tier 3 standards. Thus, we are finalizing a program for SVMs, available to non-SVM small businesses as well, under which they can choose an alternative NMOG+NO<sub>x</sub> fleet average phase-in schedule: Meeting a standard of 125 mg/mi for model years 2017 through 2021, meeting a standard of 51 mg/mi for model years 2022 through 2027, and then meeting the final Tier 3 standard of 30 mg/mi thereafter.

Because companies choosing this 3-stage compliance option are certifying to Tier 3 bin standards in MY 2017, we expect that other exhaust emissions standards, including SFTP and PM standards, would apply for their vehicles as well, to the same degree and on the same schedule as for other manufacturers. Application of evaporative emissions and onboard diagnostics (OBD) standards, on the other hand, is not affected by choice of the 3-stage compliance option, and small companies may separately choose to delay compliance with evaporative emissions and OBD standards (except as noted in Section IV.G.3) until MY 2022, as proposed. In addition, small companies choosing the 3-stage compliance option may also delay the longer useful life and new test fuel requirements for exhaust emissions standards until MY 2022 to align these changes with the 3-stage schedule. This option would not preclude use of other applicable small entity flexibility provisions discussed in this subsection.

Although we are adopting this revised implementation schedule for SVMs and small businesses, we believe the proposed approach of allowing postponement of Tier 3 compliance until MY 2022 may be useful for small companies needing more lead time to begin certifying Tier 3 vehicles. Therefore we are finalizing the proposed approach as an additional but separate option for such companies, including SVMs, ICIs, and alternative fuel vehicle converters. Furthermore, because the optional 3-stage SVM implementation schedule, and the record of comments that prompted it, are specific to the light-duty sector, we are not extending it to heavy-duty vehicles and instead are finalizing only the proposed approach of allowing postponement of Tier 3 compliance until MY 2022 for any SVMs and small businesses in the heavy-duty sector.

Companies that take advantage of one of the SVM and small business implementation schedule provisions in either the light-duty or heavy-duty sector are not allowed to generate or

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use exhaust emissions Tier 3 credits in that sector while doing so. That is, they cannot earn or use exhaust emissions Tier 3 credits before MY 2027 while using the light-duty SVM revised implementation schedule, and they also cannot do so before MY 2022 while using the postponed compliance schedule that we proposed.

#### 10.8.2.2 Assigned Deterioration Factors

##### Panel Recommendations

Under EPA's regulations, manufacturers must demonstrate that their vehicles comply with the emission standards throughout the "useful life" period. This is generally done by testing vehicles at low-mileage and then applying a deterioration factor to these emission levels. The deterioration factors are determined by aging new emission control systems and then testing the aged systems again to determine how much deterioration in emissions has occurred. In order to reduce the testing burden on small manufacturers, EPA suggested that small manufacturers could use deterioration factor values assigned by EPA instead of performing the extended testing. A manufacturer would apply the assigned deterioration factors to its low-mileage emission level to demonstrate whether it complied with the Tier 3 emission standards. EPA currently allows this flexibility for small manufacturers. The Panel recommended that EPA propose that small businesses be allowed the option to use EPA-developed assigned deterioration factors in demonstrating compliance with the Tier 3 exhaust and evaporative emission standards. In the past, EPA has relied on deterioration factor data from large manufacturers to develop the assigned DFs for small manufacturers. EPA would expect to follow a similar procedure to determine the assigned DFs for the Tier 3 standards once large manufacturers start certifying their Tier 3 designs. Given that larger manufacturers would begin phasing in to the Tier 3 standards in model year 2017, EPA should have a significant set of emissions deterioration data upon which to base the assigned DFs for small businesses within the first few years of the Tier 3 program. EPA recognizes that assigned DFs need to be determined well in advance of model year 2022 in order to provide sufficient time for small businesses to decide whether or not to use the assigned DFs for certification purposes.

##### What We Proposed

We proposed that small businesses be allowed the option to use EPA-developed assigned deterioration factors in demonstrating compliance with the Tier 3 exhaust and evaporative emission standards. In the past, EPA has relied on deterioration factor data from large manufacturers to develop the assigned deterioration factors for small manufacturers. EPA would expect to follow a similar procedure to determine the assigned deterioration factors for the Tier 3 standards once large manufacturers start certifying their Tier 3 designs. Given that larger manufacturers would begin phasing in to the Tier 3 standards in model year 2017, we expected that we would have a significant set of emissions deterioration data upon which to base the assigned deterioration factors for small businesses within the first few years of the Tier 3 program. We recognized in the proposal that assigned deterioration factors need to be determined well in advance of model year 2022 in order to provide sufficient time for small businesses to decide whether or not to use the assigned deterioration factors for certification purposes.

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## Public Comments Received on the NPRM and What We Are Finalizing

We are adopting the assigned deterioration factor provisions for small businesses and SVMs (as well as for small volume test groups), as proposed. Commenters expressed support, but asked that the Agency commit itself to keeping these factors up to date as durability data accumulates. We are committed to periodically updating and publishing these assigned deterioration factors. Given that SVMs will now be allowed to use the revised implementation schedule, starting in MY 2017, it becomes necessary to consider assigned deterioration factors in stages. Because there may not be a sufficient base of accumulated durability data on Tier 3 vehicles by MY 2017, we expect that the current set of assigned factors based on Tier 2 vehicles may continue in place for some time, noting that the MY 2017-2021 SVM fleet average of 125 mg/mi is not too much different from the average of today's Tier 2 vehicle emissions. By MY 2022, when the SVM NMOG+NO<sub>x</sub> fleet average standard drops to 51 mg/mile, we expect to have new assigned factors available. We note that small businesses and SVMs may also, with advance EPA approval, use deterioration factors developed by another manufacturer (40CFR 86.1826-01(b)).

### 10.8.2.3 Reduced Testing Burden and OBD Requirements

#### Panel Recommendations

Under EPA's regulations, manufacturers must perform in-use testing on their vehicles and demonstrate their in-use vehicles comply with the emission standards. The current in-use testing regulations provide for reduced levels of testing for small manufacturers, including no testing in some cases. EPA suggested that these provisions should continue for small manufacturers with the Tier 3 program. The Panel recommended that EPA propose that small businesses be allowed to have reduced burden under the in-use testing program for Tier 3 vehicles.

One SER requested that EPA eliminate some of the evaporative emission testing requirements for small businesses based on its belief that some of the tests may be duplicative. While EPA noted (during the Panel process) that it understood the reasons behind the manufacturer's suggestion, EPA believed it may be premature to consider such an option in the Tier 3 rule given the impact of the CO<sub>2</sub> emission standards on engine and fuel system development. Currently, it is generally understood that the 2-day diurnal test drives the purge characteristics of evaporative control systems, while the refueling test, and to a lesser degree the 3-day test, drive the capacity requirement of evaporative canisters. Prospectively, due to expected changes in engine and fuel system designs in response to upcoming CO<sub>2</sub> emission standard requirements, this may not be the case. Therefore, at the time of the Panel process, EPA noted its belief that it is appropriate to retain all of the evaporative test procedures. It can be noted that under current regulations, EPA does allow manufacturers to waive 2-day diurnal testing for certification purposes (see 40 CFR 86.1829-01(b)(2)(iii)) and perform only the 2-day diurnal test as part of the in-use testing program (see 40 CFR 86.1845-04(c)(5)(ii)). These provisions would continue in the Tier 3 program. In general, EPA noted that it is open to changes that reduce test burden while maintaining the environmental effectiveness of its programs and could consider changes like those suggested by the SER in the future as the impacts of the future regulations on engine and vehicle design become clearer. EPA also stated

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that it intends to request comment in the Tier 3 proposal on streamlining the current test procedures for small businesses in ways that would still maintain the overall stringency of the tests.

### What We Proposed

Under EPA's regulations, manufacturers must perform in-use testing on their vehicles and demonstrate their in-use vehicles comply with the emission standards. The current in-use testing regulations provide for reduced levels of testing for small manufacturers, including no testing in some cases. We proposed that small businesses be allowed to have reduced burden under the in-use testing program for Tier 3 vehicles. Small manufacturers that sell less than 5,000 units per year would not be required to do any in-use testing. Small manufacturers that sell between 5,001 and 15,000 units per year would be required to test 2 vehicles per test group, but only under the high-mileage conditions specified in the program.

Under current regulations, manufacturers may waive testing for PM emissions for light-duty vehicles and trucks, except for diesel-fueled vehicles. Manufacturers are still subject to the standards and must make a statement of compliance with the PM standards. With the Tier 3 proposal, we proposed new PM standards and further proposed to require manufacturers to test for PM emissions for all fuels. Because PM testing requires additional test equipment and facilities, the costs incurred for PM testing can be substantial, especially for a company selling small numbers of vehicles. Therefore, we proposed to continue the waiver for PM testing in the Tier 3 timeframe for small businesses. Small businesses would not be required to measure PM emissions when they certify to the Tier 3 emission standards. In lieu of testing, small businesses would be required to make a statement of compliance with the Tier 3 PM standards. We would retain the ability to determine the PM emissions results in confirmatory or in-use testing.

We proposed new OBD requirements for vehicles certifying to the Tier 3 standards. The proposed OBD requirements were the same as CARB's existing OBD requirements. The proposed OBD provisions require additional amounts of testing and information that can add significant cost to manufacturers if they are not already meeting the CARB OBD requirements. Small business vehicle manufacturers tend to comply with the CARB OBD requirements because they want to sell in the California market. On the other hand, alternative-fuel converters do not generally certify with CARB because of the significant cost burden of complying with the CARB OBD requirements. We therefore proposed that small business alternative-fuel converters may continue to comply with EPA's existing OBD requirements (see 40 CFR 86.1806-05) when the Tier 3 standards become effective.

Alternative-fueled vehicles, MDPVs, and FFVs do not have SFTP emissions requirements under the existing regulations. We proposed to apply the Tier 3 SFTP standards to all vehicles, including alternative-fueled vehicles, MPDVs, and FFVs. Because SFTP testing includes emission measurement over the SC03 test cycle, which requires additional test facilities beyond those needed to run the FTP, the costs incurred for SC03 testing can be substantial, especially for companies like alternative fuel converters that sell very low numbers of converted vehicles. We proposed that the categories of vehicles newly subject to the SFTP standards, including alternative-fuel conversions, have the option to substitute the FTP emissions levels for the SC03 emissions results for purposes of compliance when calculating the SFTP emissions.

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However, we would retain the ability to determine the composite emissions using SC03 test results in confirmatory or in-use testing. Because the vehicles being converted to an alternative fuel will likely have been tested for SFTP compliance, we expressed the view that the SFTP emissions would be similarly low, and therefore the added SC03 testing burden is unnecessary.

#### Public Comments Received on the NPRM and What We Are Finalizing

We received no adverse comments on our proposal to continue providing for reduced levels of in-use testing and for waiving of PM testing for SVMs and small businesses, and are retaining these existing provisions in Tier 3. In lieu of PM testing, these companies will be required to make a statement of compliance with the Tier 3 PM standards. We may however measure PM emissions in EPA confirmatory or in-use testing.

VNG, a natural gas fuel network provider, objected that the proposed OBD exception disadvantages larger manufacturers and should be made equally available to all vehicle manufacturers' small volume test groups. We expect that larger manufacturers (as well as SVMs) wishing to produce alternative fuel vehicles will be well familiar with CARB's OBD requirements and will be well-positioned to implement these requirements in Tier 3. We note that larger OEMs themselves did not make an argument for extending this provision beyond converters. We are finalizing the exception to the Tier 3 OBD requirements as proposed. We further note that the optional delay in Tier 3 implementation until MY 2022 that is available to small businesses, discussed above, includes a delay in the Tier 3 OBD requirement to MY 2022, as proposed, except that vehicles already meeting this requirement in MY 2017 must continue to do so in subsequent years. We are also adopting this Tier 3 OBD delay to MY 2022 for small companies taking advantage of the revised light-duty 3-stage implementation schedule discussed above, even though it involves other Tier 3 requirements starting in MY 2017, in order to avoid overburdening these manufacturers with multiple sets of new OBD design constraints.

#### 10.8.2.4 Hardship Relief Provisions

##### Panel Recommendations

The Panel recommended that hardship provisions be provided to small businesses for the Tier 3 exhaust and evaporative emission standards. Under the hardship provisions, small businesses would be allowed to apply for additional time to meet the 100 percent phase-in requirements for exhaust and evaporative emissions. All hardship requests would be subject to EPA review and approval. Appeals for such hardship relief would be required to be made in writing and submitted well before the earliest date of noncompliance. The request should identify how much time is being requested. It must also include evidence that the noncompliance would occur despite the manufacturer's best efforts to comply, and must contain evidence that severe economic hardship would be faced by the company if the relief is not granted. The above provision should effectively provide the opportunity for small businesses to obtain more time to comply with the new Tier 3 standards. (The existing hardship provisions limit the extra time that can be requested to 1 year, but such a limit may or may not be included in the proposed Tier 3 hardship provisions.)

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## What We Proposed

We proposed hardship relief provisions for small businesses subject to the Tier 3 exhaust and evaporative emission standards. Under the proposed hardship provisions, small businesses would be allowed to apply for additional time to meet the 100 percent phase-in requirements for exhaust and evaporative emissions. All hardship relief requests would be subject to EPA review and approval. Appeals for such hardship relief would need to be made in writing and must be submitted well before the earliest date of potential noncompliance. The request would need to identify how much time is being requested. It must also include evidence that the noncompliance would occur despite the manufacturer's best efforts to comply, and must contain evidence that severe economic hardship would be faced by the company if the relief is not granted. The proposed hardship relief provision would effectively provide the opportunity for small businesses to obtain more time to comply with the new Tier 3 standards. The existing hardship relief provisions limit the extra time that can be requested to 1 year, but we proposed that such a limit is not needed as part of the Tier 3 hardship relief provisions.

## Public Comments Received on the NPRM and What We Are Finalizing

Commenters supported these proposed provisions, within the context of a revised approach to SVM lead time, discussed above. We are finalizing the provisions as proposed.

### 10.8.2.5 Applicability of Flexibilities

#### Panel Recommendations

Under EPA's current Tier 2 regulations, EPA provides a number of flexibilities for small volume manufacturers. The criteria for determining if a company is a small volume manufacturer is based on the annual production level of vehicles and is based on whether the company produces less than 15,000 vehicles per year. Unlike EPA's small volume manufacturer criteria noted above, SBA defines which manufacturers are small businesses (and therefore should be considered under the SBAR Panel process) based on the number of employees for vehicle manufacturers and annual revenues for ICIs and alternative fuel converters. For example, SBA defines small business vehicle manufacturers as those who have less than 1,000 employees. Similarly, SBA defines small business ICIs as those who have annual revenues of less than \$7 million per year.

The Panel recommended that EPA propose to allow all small businesses that meet the SBA criteria be eligible for the flexibilities described above. In addition, in the Panel Report, EPA stated that it is expecting to propose that manufacturers that meet a specified sales-based criterion to be eligible for the flexibilities described above. It is relatively easy for a manufacturer to project and ultimately determine sales. Determining the annual revenues or number of employees is less straightforward. In the recent rule setting the first light-duty vehicle and truck CO<sub>2</sub> emission standards, EPA adopted provisions for small manufacturers based on a sales cutoff of 5,000 vehicles per year as opposed to the 15,000 level noted earlier that is used in the Tier 2 program. In the Panel Report, EPA noted that it expects to propose a small volume manufacturer definition based on the 5,000 vehicle per year level for the Tier 3 program. EPA believes the 5,000 unit cut-off for small volume manufacturers would include all of the small

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business vehicle manufacturers, ICIs, and alternative fuel converters that meet the applicable SBA definition as well as some additional companies that have similar concerns to small businesses. Lastly, EPA noted in the Panel Report that it expects to propose the flexibilities described above to be available to any manufacturer that meets either the SBA small business criteria or the sales-based criteria.

### What We Proposed

Under EPA's Tier 2 regulations, EPA provides a number of flexibilities for small volume manufacturers. The criteria for determining if a company is a "small volume manufacturer" is based on the annual production level of vehicles and is based on whether the company produces less than 15,000 vehicles per year. Unlike EPA's existing small volume manufacturer criteria, the Small Business Administration (SBA) defines which manufacturers are small businesses based on the number of employees for vehicle manufacturers and annual revenues for ICIs and alternative fuel converters. For example, SBA defines a small business vehicle manufacturer as those who have less than 1,000 employees.

We proposed that all small businesses that are subject to the Tier 3 standards and that meet the SBA criteria be eligible for the flexibilities described above. Unless otherwise noted, the proposed flexibilities would be available to all small business vehicle manufacturers, ICIs, and alternative fuel converters subject to the Tier 3 standards. In addition, we proposed that manufacturers subject to the Tier 3 standards which meet a specified sales-based criteria be eligible for the flexibilities described above. It is relatively easy for a manufacturer to project and ultimately determine sales. Determining the annual revenues or number of employees is less straightforward. In the recent rule setting the first light-duty vehicle and truck CO<sub>2</sub> emission standards, EPA adopted provisions for small manufacturers based on a sales cutoff of 5,000 vehicles per year as opposed to the 15,000 level noted earlier that is used in the Tier 2 program.<sup>B</sup> We proposed that the small volume manufacturer definition be based on the 5,000 vehicle per year level for the Tier 3 program. For purposes of the Tier 3 rule, the 5,000 limit would be based on a running three-year average of the number of light-duty vehicles, light-duty trucks, medium-duty passenger vehicles, and complete heavy-duty trucks below 14,000 pounds GVWR. We expressed the belief that the 5,000 unit cut-off for small volume manufacturers would include all of the small entity vehicle manufacturers, ICIs, and alternative fuel converters that currently meet the applicable SBA definition, as well as a few additional companies that have similar concerns to small businesses.

We requested comment on extending eligibility for the Tier 3 SVM provisions to small manufacturers that are owned by large manufacturers but are able to demonstrate that they are operationally independent. We established such a provision in the light-duty greenhouse gas (GHG) program, and CARB did so in LEV III as well.

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<sup>B</sup> See 75 FR 25324, May 7, 2010.

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## Public Comments Received on the NPRM and What We Are Finalizing

As proposed, we are using the federal Small Business Administration (SBA) criteria to define small businesses eligible for the special provisions. SBA defines small business vehicle manufacturers as those with less than 1,000 employees, and small business ICIs and alternative fuel vehicle converters are evaluated using SBA criteria based on annual revenues. See Section IV.H.3 for a discussion of additional provisions that apply specifically to ICIs. Also, as proposed, we are defining SVMs in 40 CFR 86.1838-01 for purposes of Tier 3 as companies with nationwide annual U.S. sales volumes at or below 5,000 vehicles, though the 15,000 vehicle threshold used in Tier 2 continues to apply in a few regulatory provisions that Tier 3 changes are not impacting. Eligibility will be evaluated using an average of 2012-2014 MY sales. For companies with no 2012 MY sales, projected sales may be used, but their eligibility will be re-evaluated thereafter using a three-year running average.

VNG commented that the proposed 5,000 vehicle threshold could potentially limit the ability (or willingness) of natural gas SVMs to scale up production by forcing a tradeoff between sales and regulatory burden, pointing also to the fact that 15,000 vehicles is only 0.1% of annual light-duty vehicle sales. We do not believe that the SVM relief provisions are so advantageous as to cause self-limiting of sales, except perhaps for a company very near the threshold. Even if this were to happen, we do not see how moving the threshold to 15,000 would prevent the same dynamic from happening at that sales level. Furthermore, our use of a three-year rolling average of sales for determining SVM eligibility protects the SVMs from being penalized for having an especially good year not reflective of its long-term growth trend. See the 2017 and later light-duty GHG final rule for a discussion of our basis for adopting the 5,000 vehicle threshold (77 FR 62793, October 15, 2012).

Comments from CARB and Ferrari supported the extension of SVM eligibility to operationally independent small manufacturers. No commenters opposed it; however, Advanced Biofuels USA recommended caution to avoid advantaging SVMs capable of leveraging parent company resources to drastically increase U.S. market share within 2-3 years. Given the precedent established in our GHG program, and the value of this extension for harmonization with LEV III, we are adopting this change into Tier 3 using the same eligibility criteria as in our GHG program, described in 40 CFR 86.1838-01(d). We believe these criteria are sufficiently strict and objective to address the concerns expressed by Advanced Biofuels USA.

### **10.9 Economic Effects**

The following section summarizes the economic impact on small businesses of the Tier 3 exhaust and evaporative emission standards and the fuel requirements. As noted earlier, the types of companies that will be affected by the Tier 3 exhaust and evaporative emissions include vehicle manufacturers, ICIs, and alternative fuel converters. Similarly, the types of companies that will be affected by the fuel requirements include gasoline refiners and importers, ethanol producers, gasoline additive manufacturers, transmix processors, and terminal operators.

To gauge the impact of the Tier 3 standards on small businesses, EPA employed a cost-to-sales ratio test to estimate the number of small businesses that would be impacted by less than one percent, between one and three percent, and above three percent. The costs used in this

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analysis for the in-use gasoline requirements are based on the cost estimates developed in Chapter 5 of this RIA. The costs used in this analysis for the Tier 3 exhaust and evaporative emission standards are based on the cost estimates developed in Chapter 2 of this RIA, supplemented with additional information for alternative fuel converters. A description of the inputs used for the vehicle-related sectors and the methodology used to develop the estimated impact on small businesses in each vehicle-related sector is presented in the docket for this rulemaking.<sup>3</sup>

During discussions with SERs during the SBREFA Panel process, ethanol SERs mentioned that ethanol producers are largely already meeting a 10 ppm sulfur standard and terminal operator SERs indicated that effects on their industry would largely be based on decisions made by refiners upstream. The final Tier 3 program retains the 80 ppm refinery gate cap and 95 ppm downstream cap, which means that downstream parties such as transmix processors, gasoline additive manufacturers, and terminal operators should not incur additional costs as a result of this program.

While many gasoline refiners and importers are currently meeting, or are close to, a 10 ppm sulfur standard, there are some refiners that could incur increased costs as a result of the Tier 3 program. Of the 12 refiners that EPA believes would be considered small refiners for the Tier 3 program, it is projected that the majority of these refiners will experience costs less than one percent of their sales, three refiners will experience costs between one and three percent of their sales, and two refiners would incur costs of three percent or more of sales, as noted in Table 10-2 below.

For vehicle manufacturers, EPA identified four small businesses. One of the small businesses manufactures adaptive vehicles (vehicles with adaptive equipment for persons with disabilities) in both gasoline-powered and CNG-powered versions. One of small businesses manufactures a hybrid gasoline-electric vehicle. Both of these manufacturers purchase engines from large manufacturers and then use the engines in their vehicles. Both of these manufacturers rely on third-party testing facilities to perform emissions testing. Both of these manufacturers are projected to incur compliance costs of less than one percent. Finally, two additional small businesses identified by EPA manufacture all-electric vehicles. For the two small businesses manufacturing all-electric vehicles, the estimated costs for meeting the Tier 3 vehicle standards are zero.

For alternative fuel converters, EPA identified nine small businesses. Of the small business alternative fuel converters, four are projected to incur compliance costs above three percent and three are projected to incur compliance costs between one and three percent. Two small business alternative fuel converters will be impacted by less than one percent.

For ICIs, EPA identified eight small businesses. All eight of the small business ICIs are projected to incur compliance costs between one and three percent.

Table 10-2 summarizes the impacts of the regulations on small businesses impacted by the Tier 3 fuel requirements and exhaust and evaporative emission standards.

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**Table 10-2 Summary of Impacts on Small Businesses**

Industry Sector	0-1 Percent	1-3 Percent	>3 Percent
Gasoline refiners and importers	7	3	2
Vehicle manufacturers	4	0	0
Alternative fuel converters	2	3	4
Independent commercial importers	0	8	0
Totals	13	14	6

For a complete discussion of the economic impacts of the final Tier 3 rulemaking, see Chapter 9, the Economic Impact Analysis chapter, of this Regulatory Impact Analysis.

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## References

<sup>1</sup> Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Control of Air Pollution from New Motor Vehicles: Tier 3 Emission and Fuel Standards, October 3, 2011.

<sup>2</sup> Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Control of Air Pollution from New Motor Vehicles: Tier 3 Emission and Fuel Standards, October 3, 2011.

<sup>3</sup> "Small Business Impact Memo, Proposed Tier 3 Motor Vehicle Emission Standards and Related Provisions," EPA memorandum from Phil Carlson to EPA Docket EPA-HQ-OAR-2011-0135, December 1, 2011.