Draft Regulatory Impact Analysis:

Tier 3 Motor Vehicle Emission and Fuel Standards

United States
Environmental Protection
Agency

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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
bbl	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_2	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
EPAct	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_X 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_2	nitrogen dioxide
NO_X	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
SBARP 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_2	sulfur dioxide
SO_X	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	work loss days
WTP	willingness to pay

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Executive Summary

EPA is proposing a comprehensive program to address air pollution from passenger cars and trucks. The proposed program, known as "Tier 3," would establish more stringent vehicle emissions standards and reduce the sulfur content of gasoline, considering the vehicle and its fuel as an integrated system The proposed Tier 3 standards would reduce levels of multiple air pollutants (ambient levels of ozone, particulate matter (PM), nitrogen dioxide (NO_2), 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 proposed new standards. Chapter 1 contains our technical feasibility justification for the proposed vehicle emission standards, and Chapter 2 contains the estimated costs of the proposed vehicle standards. In addition to the vehicle emission and gasoline standards, we are proposing to update the specifications of the emission test fuel with which vehicles demonstrate compliance with emissions standards; our analysis of the proposed emission test fuel parameter changes is found in Chapter 3. Chapters 4 and 5 contain our technical feasibility and cost analyses for the proposed gasoline sulfur standards, respectively. Chapter 6 describes the health and welfare effects associated with the air pollutants that would 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 proposed Tier 3 program are presented in Chapter 8. Chapter 9 contains our analysis of the proposed rule's economic impacts, and Chapter 10 provides the results of our small business flexibility analysis.

Proposed Tier 3 Standards

Vehicle Emission Standards

The proposed 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 proposed standards in this category would 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. We are proposing new standards for the sum of NMOG and NO_X emissions, presented as NMOG+NO_X, and for PM. For these pollutants, we are proposing standards as 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 proposed FTP and SFTP NMOG+NO_X standards would be fleet-average standards, meaning that a manufacturer would 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 proposed fleet average standards for NMOG+NO_X evaluated over the FTP would begin in MY 2017 and then decline through MY 2025, as summarized in Table ES-1. Similarly, the proposed NMOG+NO_X standards measured over the SFTP would also be fleet-average standards, declining from MY 2017 until MY 2025, as shown in Table ES-2.

Table ES-1 Proposed LDV, LDT, and MDPV Fleet Average NMOG+NO_X FTP Standards (mg/mi)

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

[a] For vehicles above 6000 lbs GVWR, the fleet average standards would apply beginning in MY 2018

[b] These proposed standards would apply for a 150,000 mile useful life. Manufacturers could 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 would apply, calculated by multiplying the respective 150,000 mile standard by 0.85 and rounding to the nearest mg.

Table ES-2 Proposed LDV, LDT, and MDPV Fleet-Average NMOG+NO_X SFTP Fleet Average Standards (mg/mi)

	Model Year								
	2017[a]	2018	2019	2020	2021	2022	2023	2024	2025 and later
NMOG + NO_X	103	97	90	83	77	70	63	57	50

[a] For vehicles above 6000 lbs GVWR, the fleet average standards would apply beginning in MY 2018.

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

	2017[a]	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

[a] For vehicles above 6000 lbs GVWR, the proposed FTP PM standards would apply beginning in MY 2018.

The proposed Tier 3 program also includes certification PM standards evaluated over the SFTP (specifically the US06 component of the SFTP procedure) at a level of 10 mg/mi for lighter vehicles and 20 mg/mi for heavier vehicles. As with the FTP PM standard, we propose separate in-use US06 PM standards during the percent phase-in only of 15 and 25 mg/mi for cars and trucks, respectively. The US06 PM standards would also phase in on the same schedule as the FTP PM standards.

Heavy-Duty Tailpipe Emission Standards

We are proposing 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 proposed standards include a combined NMOG+NO_X 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 would address real-world driving modes not well-represented by the FTP cycle alone. Table ES-4 presents the proposed HDV fleet average NMOG+NO_X standard, which becomes more stringent in successive model years from 2018 to 2022, with voluntary standards available in 2016 and 2017.

The proposed 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 Proposed HDV Fleet Average NMOG+NO_X Standards (mg/mi)

	Voluntary		Required Program				
Model Year	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 proposed new SFTP requirements for HDVs include NMOG+NO_X, carbon monoxide (CO) and PM standards. Compliance would 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, EPA is proposing more stringent standards that would 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 emission standard. The Tier 3 proposal also includes refueling emission standards for a portion of heavy-duty gasoline vehicles (HDGVs) over 10,000 lbs GVWR. EPA is proposing phase-in flexibilities as well as credit and allowance programs. The proposed standards, harmonized with California's zero evaporative emissions standards, are designed to essentially eliminate fuel vapor-related evaporative emissions.

Table ES-5 presents the proposed 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. The proposal also includes separate high altitude emission standards for these vehicle categories.

Table ES-5 Proposed 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

EPA is proposing a new testing requirement referred to as the bleed emission test procedure. Under the proposal, manufacturers would 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 would apply only for low altitude testing conditions, but EPA expects proportional control at higher altitudes.

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

We are also proposing to add a new emission standard and test procedure related to controlling vapor leaks from vehicle fuel and vapor control systems. The standard, which would apply to all LDVs, LDTs, MDPVs, and Class 2b/3 HDGVs, would prohibit leaks larger than 0.02 inches of cumulative equivalent diameter in the fuel/evaporative system. The proposed Tier 3 evaporative emission standards program requirements would 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.

EPA is proposing new refueling emission control requirements for HDGVs equal to or less than 14,000 lbs GVWR (i.e., Class 2b/3 HDGVs), starting in the 2018 model year. Under this proposal, EPA would extend current refueling emission control requirements for Class 2b HDGVs to Class 3 HDGVs.

We are also proposing to adopt and incorporate 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 would retain the provision that certifying with CARB's program would permit manufacturers to seek a separate EPA certificate on that basis.

Emissions Test Fuel Requirements

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

- Moving away from "indolene" (E0) to a test fuel containing 15 percent ethanol by volume (E15);
- 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 E15 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.

Gasoline Sulfur Standards

Under the Tier 3 fuel program, we are proposing that federal gasoline contain no more than 10 parts per million (ppm) sulfur on an annual average basis by January 1, 2017. We are proposing 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. We are also proposing a three-year delay for small refiners and "small volume refineries" processing less than or equal to 75,000 barrels of crude oil per day. In addition, we also proposing to either maintain the current 80-ppm refinery gate and 95-ppm downstream per-gallon caps or lower them to 50 and 65 ppm, respectively. A summary of the proposed Tier 3 sulfur standards is provided in Table ES-6.

Table ES-6 Proposed Tier 3 Gasoline Sulfur Standards

Proposed Tier 3 Gasoline Sulfur Standards	Cap Option 1		Cap Option 2	
	Limit	Effective	Limit	Effective
Refinery annual average standard	10 ppm	January 1, 2017[a]	10 ppm	January 1, 2017[a]
Refinery gate per-gallon cap	80 ppm	Already	50 ppm	January 1, 2020
Downstream per-gallon cap	95 ppm	Already	65 ppm	March 1, 2020

[a] Effective January 1, 2020 for eligible small refiners and small volume refineries.

Projected Impacts

Emission and Air Quality Impacts

The proposed Tier 3 vehicle and fuel-related standards would together reduce emissions of NO_X, VOC, $PM_{2.5}$, and air toxics. The gasoline sulfur standards, which would take effect in 2017, would provide large immediate reductions in emissions from existing gasoline vehicles and engines. The emission reductions would increase over time as newer vehicles become a larger percentage of the fleet, e.g., in 2030, when 80 percent of the light-duty fleet (and 90 percent of the vehicle miles travelled) consists of Tier 3 vehicles. Projected emission reductions from the Tier 3 standards for 2017 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 Proposed Tier 3 Standards (Annual U.S. short tons)[a]

	2017		2030	
	Tons	Percent of Onroad Inventory	Tons	Percent of Onroad Inventory
NO_X	284,381	8%	524,790	28%
VOC	44,782	3%	226,028	23%
CO	746,683	4%	5,765,362	30%
Direct $PM_{2.5}$	121	0.1%	7,458	10%
Benzene	1,625	4%	8,582	36%
SO_2	16,261	51%	17,267	51%
1,3-Butadiene	322	5%	1,087	37%
Formaldehyde	727	3%	2,707	12%
Acetaldehyde	762	3%	4,414	26%
Acrolein	23	1%	184	15%
Ethanol	2,684	2%	27,821	23%

[a] This analysis assumed emissions reductions from the Tier 3 vehicle standards would occur in all states. For the final rule we will account for LEV III vehicle standards in states that have subsequently adopted it.

Reductions in emissions of NO_X, VOC, $PM_{2.5}$ and air toxics are projected to lead to nationwide decreases in ambient concentrations of ozone, $PM_{2.5}$, NO_2, CO, and air toxics. Specifically, the proposed Tier 3 standards would significantly decrease ozone concentrations across the country, with a population-weighted average decrease of 0.47 ppb in 2017 and 1.55 ppb in 2030. The magnitude of reductions is significant enough to bring ozone levels in some areas from above the standard to below the standard, even without any additional controls. Few other strategies exist that would deliver the reductions needed for states to meet the current ozone standards. The proposed Tier 3 standards would decrease ambient annual $PM_{2.5}$ concentrations across the county as well, with a population-weighted average decrease of 0.06 $\mu g/m^3$ by 2030. Decreases in ambient concentrations of air toxics are also projected with the proposed standards, including notable nationwide reductions in benzene concentrations.

Costs and Benefits

The costs that would be incurred from our proposed 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 2010 dollars.

Vehicle Costs

The vehicle costs include the technology costs projected to meet the proposed exhaust and evaporative standards, as show in Table ES-8. The fleet mix of light-duty vehicles, light duty trucks, and medium-duty trucks represents the 2016 MY fleet used in the 2012-2016 MY light-duty GHG final rulemaking.

Table ES-8 Annual Vehicle Technology Costs, 2010$

Year	Vehicle Exhaust Emission Control Costs ($Million)	Vehicle Evaporative Emission Control Costs ($Million)	Facility Costs ($Million)	Total Vehicle Costs ($Million)[a]
2017	$634	$71	$4	$709
2030	$1,790	$253	$4	$2,050

[a] These estimates include costs associated with the proposed Tier 3 vehicle standards in all states except California.

Fuel Costs

The fuel costs consist of the additional operating costs and capital costs to the refiners to meet the proposed sulfur average of 10 ppm. The sulfur control costs assume a cost of 0.89 cents per gallon which includes the refinery operating and capital costs. The annual fuel costs of the proposed program are listed in Table ES-9.

Table ES-9 Annual Fuel Costs, 2010$

Year	Fuel Sulfur Control Costs ($Million)[a]
2017	$1,289
2030	$1,320

[a] These estimates include costs associated with the proposed 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 proposed program, as shown in Table ES-10. The proposed fuel standards are projected to lead to an average cost of 0.89 cents per gallon of gasoline, and the proposed vehicle standards would have an average cost of $134 per vehicle

Table ES-10: Total Annual Vehicle and Fuel Control Costs, 2010$

Year	Total Vehicle and Fuel Control Costs ($Million)[a]
2017	$1,999
2030	$3,367

[a] These estimates include costs associated with the proposed Tier 3 vehicle and fuel standards in all states except California.

Cost Per Ton of Emissions Reduced

We have calculated the aggregate cost per ton of the emissions reduced due to the proposed program using the projected costs and emission reductions. Note that, even though we are setting new standards for PM, we believe that those standards will be met in complying with the NMOG+NO_X standards with additional care being given to proper engineering/calibration, so there is no cost associated with the new PM standard and therefore no separate cost per ton of emissions reduced analysis for PM.

The total program costs, NO_X+VOC reductions, and results of our cost per ton of emissions reduced analysis are provided in Table ES-11. The costs of the proposed program would be higher immediately after it is implemented than they would be after several years, since both vehicle manufacturers and refiners can take advantage of decreasing capital and operating costs over time. In addition, the reductions in NO_X and VOC emissions would become greater as a larger percentage of the fleet contains the technologies required to meet the proposed standards.

Table ES-11 Cost Per Ton of Emissions Reduced in 2017 and 2030

Year	Total Proposed Program Cost ($million, 2010$)	Total NO_X + VOC Reductions (tons)	Cost Per Ton of Emissions Reduced ($/ton)
2017	$1,999	329,162	$6,072
2030	$3,367	750,818	$4,484

Benefits

Exposure to ambient concentrations of ozone, $PM_{2.5}$, 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 proposed Tier 3 standards would 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 proposed rule would lead to a net decrease in $PM_{2.5}$- and ozone-related health and environmental impacts. The range of total monetized ozone- and PM-related health impacts is presented in Table ES-12.

Table ES-12: Estimated 2030 Monetized PM-and Ozone-Related Health Benefits[a]

Description	**2030**
Total Estimated Health Benefits[b,c,d,e,f]	
3 percent discount rate	$8.0 - $23
7 percent discount rate	$7.4 - $21

Notes:

[a] Totals are rounded to two significant digits and may not sum due to rounding.

[b] The benefits presented in this table have been adjusted to remove emission reductions attributed to the Tier 3 program in California. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

[c] Total includes ozone and PM2.5 benefits. Range was developed by adding the estimate from the Bell et al., 2004 ozone premature mortality function to $PM_{2.5}$-related premature mortality derived from the American Cancer Society cohort study (Pope et al., 2002) for the low estimate and ozone premature mortality derived from the Levy et al., 2005 study to $PM_{2.5}$-related premature mortality derived from the Six-Cities (Laden et al., 2006) study for the high estimate.

[d] 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.

[e] 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).

[f] 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 would annually prevent between 670 and 1,700 PM-related premature deaths, between 160 and 710 ozone-related premature deaths, 81,000 work days lost, and approximately 1.4 million minor restricted-activity days. The estimated annual monetized health benefits of the proposed Tier 3 standards in 2030 (2010$) would be between $8.0 and $23 billion, assuming a 3-percent discount rate (or between $7.4 billion and $21 billion assuming a 7-percent discount rate).

Note that the air quality modeling conducted for the Tier 3 program included emission reductions both in California (which was recently granted a waiver for the adoption of its LEV III program) and in several other states that have adopted the LEV III program under Section 177 of the Clean Air Act. As a result, the benefits cited here have been adjusted to remove emission reductions attributed to the Tier 3 program in California. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule. Refer to Chapter 8 for more information about the benefits estimated for the proposal.

Comparison of Costs and Benefits

The estimated annual monetized health benefits of the proposed Tier 3 standards in 2030 (2010$) would be between $8.0 and $23 billion, assuming a 3 percent discount rate (or between $7.4 billion and $21 billion assuming a 7 percent discount rate). The annual benefits of the Tier 3 standards outweigh the annual cost of the overall program in 2030, which would be approximately $3.4 billion.

Economic Impact Analysis

The proposed rule will affect two sectors directly: vehicle manufacturing and petroleum refining. The estimated increase in vehicle production cost because of the proposed rule is expected to be small relative to the costs of the vehicle. Some or all of this production cost increase would 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 would 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 would expect the decrease in fuel sales to negatively affect employment in this sector, while the costs of compliance with the rule would be expected to increase employment. It is not evident whether the proposed rule would 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 would not have major employment consequences for this sector.

Chapter 1 Vehicle Program Technological Feasibility

1.1 Introduction

For the vehicles and emissions addressed in this proposed 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 proposed in the Preamble, and the technologies that we expect be available to manufacturers to meet those challenges in the time frame of this NPRM. Our feasibility assessment recognizes that the proposed Tier 3 program is composed of several new requirements for all types of new vehicles, including everything from small cars to large pick-up trucks and MDPVs with diverse applications and specific engine designs. This assessment also recognizes the critical role of gasoline sulfur content in making it possible for us to propose emission standards at these very stringent levels. 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 proposed 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 proposed FTP NMOG+NO_X 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 proposed 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).

1.2 FTP NMOG+NO_X Feasibility

The proposed new emission requirements include stringent NMOG+ NO_X 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 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. 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 a 30 mg/mi NMOG+NO_X 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 certified to an average of Tier 2 Bin 5, equivalent to 160 mg/mi NMOG+NO_X.[A] For 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 is currently no motivation for vehicle manufacturers to produce a federal fleet that over-complies with respect to the current Tier 2 standards. By comparison, in the MY 2009 California fleet, where compliance with the "PZEV" program encourages manufacturers to certify to cleaner levels, only 30 percent of the passenger cars and LDT1's are certified to Tier 2 Bin 5 and 60 percent are certified to Tier 2 Bin 3. The situation regarding the truck fleet in California is 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 in hardware and calibration are being certified to a lower standard in California and a higher standard federally. Although we recognize that there are relatively minor differences between the Tier 2 and LEV II programs that might affect manufacturers' selection of which bins to choose for federal and California certification in some cases (i.e., certification fuel differences), EPA believes that the patterns described above indicate that much of the existing Tier 2 fleet could be certified to a lower federal fleet average immediately, with no major feasibility concerns.[B]

To support this conclusion, we analyzed the measured emissions data for NMOG and NO_X from MY 2009 certifications. The results of our analysis are shown in Table 1-1 and Table 1-2 below, listing vehicles that perform at 30 mg/mi NMOG+NO_X and cleaner, and 50 mg/mi NMOG+NO_X and cleaner, respectively. The vehicles shown in Table 1-1 are mainly PZEV vehicles that are sold in California and Section 177 states. Although the vehicles presented in Table 1-1 represent only a small fraction of the federal fleet, they demonstrate that the Tier 3 standards we are proposing are feasible today for a range of vehicle sizes and types. In addition, one can note that although their NO_X performance is equal to the NO_X performance of several of the vehicles shown in Table 1-2, their respective NMOG performance is substantially lower. This supports our earlier statements that manufacturers would most likely be required to focus on

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[A] The current Tier 2 program does not combine NMOG and NO_X emissions into one fleet-average standard. The fleet-average standard in that program is for NO_X emissions alone.

[B] 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 1.2.3.1.

NMOG to meet the proposed Tier 3 FTP standards. The vehicles shown in Table 1-2 demonstrate a significant range of vehicle types and sizes that are currently performing at 50 mg/mi NMOG+NO_X or cleaner. This is approximately 30 percent of the current Tier 2 fleet standard. However, the majority of these vehicles are currently being certified to Tier 2 Bin 5.

Table 1-1: 2009 MY Engine Families with One or More Vehicle Configurations with Full Useful Life NMOG+NO_X Certification Levels at or below 30 mg/mi

Manufacturer	Models	NMOG Level (mg/mi)	NO_X Level (mg/mi)	NMOG+NO_X (mg/mi)	Federal Certification
AUDI	A3	5.2	11	16.2	Bin 2
BUICK	LUCERNE	8	10	18	Bin 5
CHEVROLET	COBALT	6	0	6	Bin 5
CHEVROLET	MALIBU	8	10	18	Bin 5
FORD	FOCUS FWD	6	0	6	Bin 3
HONDA	CIVIC HYBRID	4	10	14	Bin 2
HONDA	ACCORD 4DR SEDAN	6	10	16	Bin 2
MERCEDES-BENZ	E350 4MATIC (WAGON)	2.2	24	26.2	Bin 5
MERCURY	MARINER HYBRID 4WD	10	20	30	Bin 3
SUBARU	LEGACY WAGON AWD	8.4	12	20.4	Bin 5
VOLKSWAGEN	JETTA SPORTWAGEN	4.3	0	4.3	Bin 2

Table 1-2: 2009 MY Engine Families with One or More Vehicle Configurations with Full Useful Life NMOG+NO_X Certification Levels at or below 50 mg/mi

Manufacturer	Models	NMOG Level (mg/mi)	NO_X Level (mg/mi)	NMOG+NO_X (mg/mi)	Federal Certification
ACURA	RDX 4WD	19	30	49	Bin 5
ACURA	TSX	24	20	44	Bin 5
ACURA	TL 4WD	18	20	38	Bin 5
AUDI	S4 CABRIOLET	27	20	47	Bin 5
BENTLEY	CONTINENTAL GTC	20	21	41	Bin 5
BUICK	ENCLAVE AWD	32	10	42	Bin 5
CHEVROLET	MALIBU	30	20	50	Bin 5
CHEVROLET	IMPALA	26	10	36	Bin 4
CHEVROLET	AVEO 5	36	10	46	Bin 4
CHRYSLER	PTCRUISER CONV/CABRIO	35	10	45	Bin 5
FORD	ESCAPE 4WD	25	20	45	Bin 4
FORD	FUSION FWD	19	30	49	Bin 5

Manufacturer	**Models**	**NMOG Level (mg/mi)**	**NO_X Level (mg/mi)**	**NMOG+NO_X (mg/mi)**	**Federal Certification**
FORD	MUSTANG	30	20	50	Bin 5
HONDA	CR-V 4WD	20	30	50	Bin 5
HONDA	RIDGELINE 4WD	22	20	42	Bin 5
HONDA	FIT	21	10	31	Bin 5
HONDA	ACCORD 4DR SEDAN	19	20	39	Bin 5
HYUNDAI MOTOR COMPANY	SANTA FE 2WD	30	14	44	Bin 5
HYUNDAI MOTOR COMPANY	SANTA FE 4WD	23.6	11	34.6	Bin 5
HYUNDAI MOTOR COMPANY	TUCSON 2WD	23.7	20	43.7	Bin 5
HYUNDAI MOTOR COMPANY	ACCENT	30.7	13	43.7	Bin 5
HYUNDAI MOTOR COMPANY	ELANTRA	16.1	27	43.1	Bin 5
HYUNDAI MOTOR COMPANY	SONATA	28.9	20	48.9	Bin 5
HYUNDAI MOTOR COMPANY	GENESIS	29.9	14	43.9	Bin 5
ISUZU	ASCENDER 5-PASSENGER 4WD	36	10	46	Bin 4
JEEP	WRANGLER 4WD	27	10	37	Bin 5
KIA MOTORS CORPORATION	SPORTAGE 2WD	23.7	23	46.7	Bin 5
KIA MOTORS CORPORATION	SPORTAGE 4WD	18.9	23	41.9	Bin 5
KIA MOTORS CORPORATION	SORENTO 2WD	28	10	38	Bin 5
KIA MOTORS CORPORATION	RIO	23.3	17	40.3	Bin 5
KIA MOTORS CORPORATION	SPECTRA	19.4	22	41.4	Bin 5
KIA MOTORS CORPORATION	OPTIMA	26.6	21	47.6	Bin 5
KIA MOTORS CORPORATION	RONDO	33.5	16	49.5	Bin 5

Manufacturer	**Models**	**NMOG Level (mg/mi)**	**NO_X Level (mg/mi)**	**$NMOG+NO_X$ (mg/mi)**	**Federal Certification**
LAND ROVER LTD	LR3	12	30	42	Bin 5
LINCOLN	NAVIGATOR 4WD FFV	28	20	48	Bin 8
LINCOLN-MERCURY	TOWN CAR	29	10	39	Bin 4
MAZDA	MAZDA 5	28.2	21	49.2	Bin 5
MAZDA	MAZDA 6	21	20	41	Bin 5
MERCEDES-BENZ	ML63 AMG	9.9	35	44.9	Bin 5
MERCEDES-BENZ	G55 AMG	12.8	36	48.8	Bin 5
MITSUBISHI	ECLIPSE SPYDER	29	16	45	Bin 5
NISSAN	MAXIMA	20	20	40	Bin 5
NISSAN	ALTIMA	30	20	50	Bin 5
PORSCHE	CAYENNE TRANSSYBERIA	28	20	48	Bin 5
SAAB	9-7X AWD	36	10	46	Bin 4
SATURN	ASTRA 4DR HATCHBACK	25	20	45	Bin 5
Shelby Automobiles Incorporated	SHELBY MUSTANG GT500KR	41	9	50	Bin 5

To support the FTP emission levels proposed for heavy duty vehicles, we analyzed the certification emission results from the 2010 and 2011 MY vehicles. The proposed fleet average $NMOG+NO_X$ standard in 2022 for Class 2b vehicles is 178 mg/mi while the proposed 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 proposing 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.

Table 1-3: 2010/11 MY Heavy Duty Vehicle FTP 120k Certification Results

	Manufacturer	**Models**	**Fuel Type**	**NMOG Level [a] (mg/mi)**	**NO_X Level (mg/mi)**	**NMOG $+NO_X$ (mg/mi)**	**CO (g/mi)**	**PM (mg/ mi)**
Class 2b [b]	Altech	F250	CNG	10	100	110	5.9	-
	Chrysler	Ram 2500	Gasoline	101	60	161	2.4	-
	Chrysler	Ram 2500	Diesel	82	200	282	.1	3
	Ford	F250	Diesel	53	180	233	.6	10
	General Motors	Silverado 2500	Diesel	94	166	260	1	0
Class 3	Baytech	Silverado 3500	CNG	11	100	111	1.3	-
	Chrysler	Ram 3500	Gasoline	119	120	239	3.6	-
	Chrysler	Ram 3500	Diesel	52	400	452	.2	3
	Ford	E350 [c]	Gasoline	51	82	133	2	-
	Ford	E350 [c]	E85	70	65	135	1.1	-
	Ford	F350	Diesel	51	320	371	.6	10
	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	76	184	260	.8	0

Notes:
[a] Diesel reported as NMHC
[b] Gasoline Class 2b models from General Motors and Ford certified using worst case Class 3 data
[c] Tested at LVW with MDPVs

1.2.2 NMOG and NO_X Emissions on the FTP

To understand how the several currently-used technologies described below could be used by manufacturers to reach the stringent proposed Tier 3 NMOG+NO_X standards, it is helpful to consider emissions formation in common modes of operation for gasoline engines, or modal analysis.[C] As previously stated during the discussion of the NMOG+NO_X standard, many gasoline engines produce very little NO_X over the FTP. Thus, the challenge faced by manufacturers for producing Tier 3 compliant gasoline powertrains would be 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_X emissions occur in these early seconds. Figure 1-1 below shows the second-by-second emissions for NMOG and NO_X following a cold start.

[C] A modal analysis provides a second-by-second view of the total amount of emissions over the entire cycle being considered.

Thus, effective control of these cold-start emissions, especially NMOG emissions, would be the primary technological goal of manufacturers complying with the proposed 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.

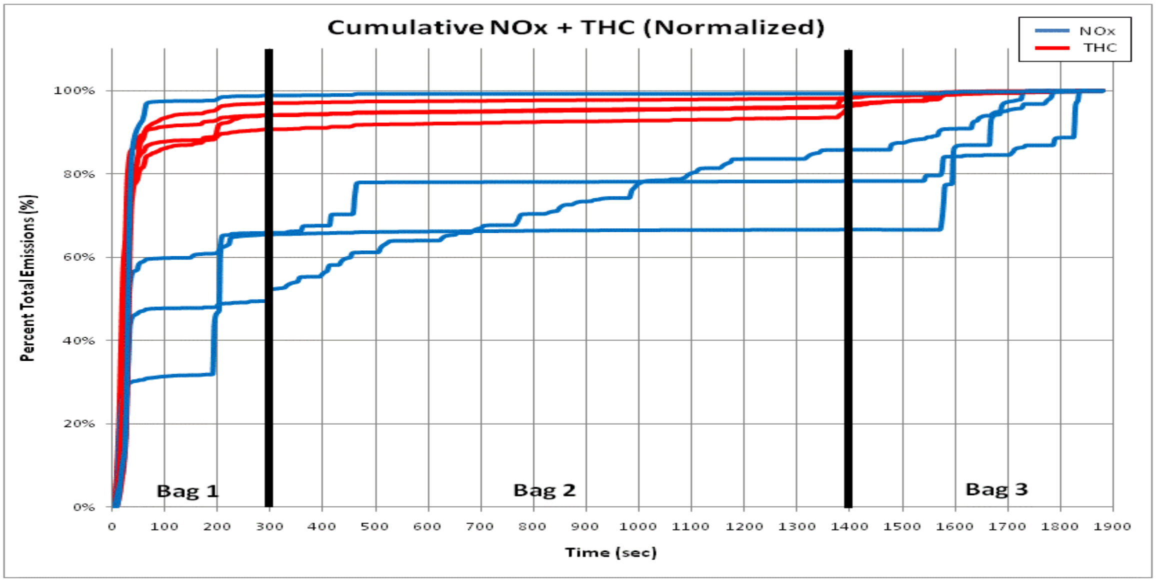

Figure 1-1 Modal Analysis of NMOG and NO_X Emissions (LA92)

1.2.3 Compliance Margin

Vehicle manufacturers generally design 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 catalyst poisons (e.g., 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. Thus, the emission design targets for Tier 3 standards at full useful life would be approximately 15 mg/mi MOG+NO_X for a Bin 30 certified vehicle. 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 2009, the compliance margin for a Tier 2 Bin 5 vehicle averaged approximately 60 percent. In other words, actual vehicle emissions performance was on average about 40 percent of a 160 mg/mi NMOG+NO_X standard, or about 64 mg/mi. By comparison, for MY 2009 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 compliance margins that manufacturers would design for in order to comply with the proposed Tier 3 FTP standards. Thus, a typical Tier 2 Bin 5 vehicle, performing at 40 percent of the current standard (i.e., at about 64 mg/mi) would need improvements sufficient to reach about 15 mg/mi (50 percent of a 30 mg/mi standards).

1.2.3.1 Impact of Gasoline Sulfur Control on the Feasibility of the Proposed Vehicle Emission Standards

1.2.3.1.1 Fuel Sulfur Impacts on Exhaust Catalysts

Modern three-way catalytic exhaust systems utilize platinum group metals, metal oxides and other active materials to selectively oxidize organic compounds and carbon monoxide in the exhaust gases. These systems simultaneously reduce nitrogen oxides 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 platinum group metals (PGM) three-way exhaust catalyst systems.[1,2,3,4,5,6,7,8,9,10] The nature of sulfur interactions with active catalytic materials, catalyst washcoating materials, and catalyst substrate materials is complex and varies with catalyst composition and 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_2 and, to a much lesser extent, SO_3^{-2}. Sulfur oxides selectively chemically bind (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 alumina washcoatings (see Figure 1-2) .[11] The amount of sulfur retained by the catalyst is primarily a function of its operating temperature, the active materials and coatings used within the catalyst, the concentration of sulfur oxides in the incoming exhaust gases, and air-to-fuel ratio feedback and control by the engine management system.

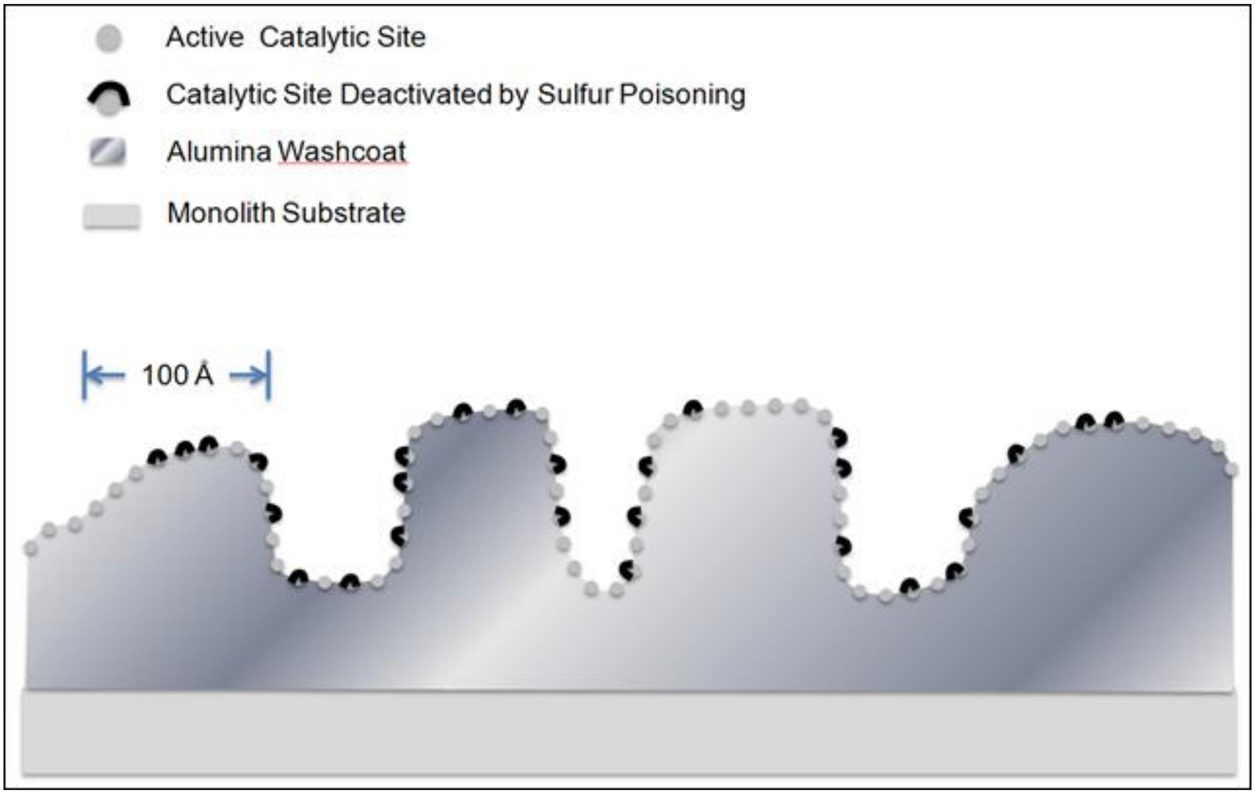

Figure 1-2 Functional schematic showing selective poisoning of active catalytic sites by sulfur compounds. Adapted from Heck and Farrauto 2002.[11]

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_2O_2S, present in both surface and bulk form (i.e., below the surface layer).[4,5,12,13] Ceria, zirconia and other oxygen storage components (OSC) play an important role that is crucial to NO_X reduction over Rh as the engine air-to-fuel ratio oscillates about the stoichiometric closed-loop control point.[14] Water-gas-shift reactions are important for NO_X reduction over catalysts combining Pd and ceria. This reaction can be blocked by sulfur poisoning and may be responsible for observations of reduced NO_X activity over Pd/ceria catalysts even with exposure to fairly low levels of sulfur (equivalent to 15 ppm in gasoline).[2,12] Pd is also of increased importance for meeting Tier 3 standards due to its unique application in the closed-coupled-catalysts location required for vehicles certifying to very stringent emission standards. Pd is required in closed-coupled catalysts due to its resistance to high temperature thermal sintering. Sulfur removal from Pd requires rich operation at higher temperatures than required for sulfur removal from other PGM catalysts.[2]

In addition to its interaction with catalyst materials, sulfur can also react with the washcoating itself to form alumina sulfate, which in turn can block coating pores and reduce gaseous diffusion to active materials below the coating surface.[11] 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 when high-load, high-temperature conditions are encountered.[15]

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 the catalyst components. Thus, regular operation at sufficiently high temperatures at 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. Furthermore, regular operation at these temperatures and at rich air-to-fuel ratios is not desirable, for several reasons. 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. Additionally, it is not always possible to maintain these catalyst temperatures (because of cold weather, idle conditions, light load operation) and the rich air-to-fuel ratios necessary can result in increased PM, NMOG and CO emissions. Thus, reducing fuel sulfur levels has been the primary regulatory mechanism to minimize sulfur contamination of the catalyst and ensure optimum emissions performance over the useful life of a vehicle.

The impact of gasoline sulfur has become even more important as vehicle emission standards have become more stringent. Some studies have suggested an 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 negligible. The Tier 2 program recognized the importance of sulfur and reduced the sulfur levels in the fuel from 300 ppm to 30 ppm in conjunction with the new emission standards.[16] 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.

In 2005 EPA and several automakers jointly conducted a program that examined the effects of sulfur and other gasoline properties, benzene, and volatility on emissions from a fleet of nine Tier 2 compliant vehicles, the "MSAT (Mobile Source Air Toxics) Study.[17] Reductions for FTP-weighted emissions for the sulfur changes in this program were 33 percent for NO_X, 11 percent for THC, 17 percent for CO, and 32 percent for methane. Given the prep procedures related to catalyst clean-out and loading, these results may represent a "best case" scenario that magnifies what would be expected under more typical driving conditions. Nonetheless, these data suggested the effect of sulfur loading was reversible for Tier 2 vehicles, and that there were likely to be significant emission reductions possible with further reductions in gasoline sulfur level. For more discussion of the impact of gasoline fuel sulfur on the current light-duty vehicle fleet, see Chapter 7 of this draft RIA.

1.2.3.2 EPA Tier 2 In-Use Gasoline Sulfur Effects Study

Goals of this study included assessment of reversible sulfur loading in catalysts of Tier 2 compliant light duty gasoline vehicles in the in-use fleet, as well as characterization of the effects of fuel sulfur level on emissions as a function of accumulated mileage. The study sample consisted of 81 cars and light trucks recruited from owners in southeast Michigan, covering model years 2007-9 with approximately 20,000-40,000 odometer miles. 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 fuel, one at a sulfur level of 5 ppm and the other at 28 ppm. A nominal concentration of approximately 30 ppm was targeted for the high level to be representative of retail fuel available to the public in the vehicle recruiting area. All emissions data were collected using the FTP cycle at a nominal temperature of 75°F.

After vehicles were received at the test facility, the high-sulfur test fuel was installed and a set of emission tests were performed to establish a baseline representative of the vehicle's as-received state. A high-speed/load "clean-out" procedure consisting of two back-to-back US06 cycles was then performed with the intent to produce a reduction in catalyst sulfur loading. This was followed by another set of emission tests to assess the change in emissions performance from baseline. A statistical analysis of this data showed highly significant reductions in several pollutants including NO_X and hydrocarbons (Table 1-4), suggesting that reversible sulfur loading exists in the in-use fleet and has a measurable effect on aftertreatment performance.

Table 1-4: Average clean-out effect on in-use emissions using 28 ppm test fuel

	NO_X (p-value)	**THC (p-value)**	**CO (p-value)**	**NMHC (p-value)**	**CH_4 (p-value)**	**PM (p-value)**
Bag 1	–	–	4.7% (0.0737)	–	–	15.4% (< 0.0001)
Bag 2	31.9% (0.0009)	16.5% (0.0024)	–	17.8% (0.0181)	15.3% (0.0015)	–
Bag 3	38.3% (<0.0001)	21.4% (<0.0001)	19.5% (0.0011)	27.8% (<0.0001)	12.0% (<0.0001)	24.5% (<0.0001)
FTP Composite	11.4% (<0.0001)	4.1% (0.0187)	7.6% (0.0008)	3.0% (0.0751)	6.9% (0.0003)	13.7% (<0.0001)
Bag 1 – Bag 3	–	–	4.2% (0.0714)	–	–	–

Note:
The clean-out effect is not significant at $\alpha = 0.10$ when no reduction estimate is provided.

Next, a subset of approximately one in five vehicles (one of each make/model) was kept for an extended test schedule consisting of additional emission test replicates alternated with mileage accumulation. This dataset was used to assess the behavior of emissions as sulfur reloaded toward and beyond the baseline level observed in the vehicles as-received. The fuel was then changed to the low-sulfur test fuel and the procedure repeated, starting with a clean-out procedure followed by alternating emission tests and mileage accumulation. This dataset was used to assess differences in the rate at which sulfur reloading occurred as a function of fuel sulfur level.

Comparing results of emission tests immediately following (<50 miles) the clean-out procedures at each fuel sulfur level shows a statistically significant difference of 35 percent for Bag 2 NO_X. This suggests that the effectiveness of a high-temperature regeneration cycle in reducing emissions is limited by fuel sulfur level. Moreover, it also suggests that the clean-out effects shown in Table 1-4 would likely be larger if the low-sulfur test fuel had been used for the cleanout procedure and tests immediately following the as-received baseline emissions.

Mixed model analysis of all emissions data as a function of fuel sulfur level and miles driven after cleanout found highly significant model fits for several pollutants. These results show cold-start and hot-running NO_X emissions were reduced by 11 percent and 59 percent, respectively, comparing low vs. high-sulfur test fuels. In these particular results, the model fitting did not find a miles-by-sulfur interaction to be significant, suggesting the relative differences were not dependent on miles driven after cleanout, confirming the substantial magnitude of what was found for tests immediately following the clean-out procedures, as described above. Other results, such as FTP-composite NO_X, as well as cold-start and FTP-composite hydrocarbons, did show a significant miles-by-sulfur interaction. In this case, determining a sulfur level effect for the in-use fleet requires estimation of a miles-equivalent level of sulfur loading, which can be gleaned from the cleanout results obtained from the baseline testing on the vehicles as-received. Figure 1-3 shows this graphically for FTP-composite NO_X. Other mixed model results are summarized in Table 1-5.

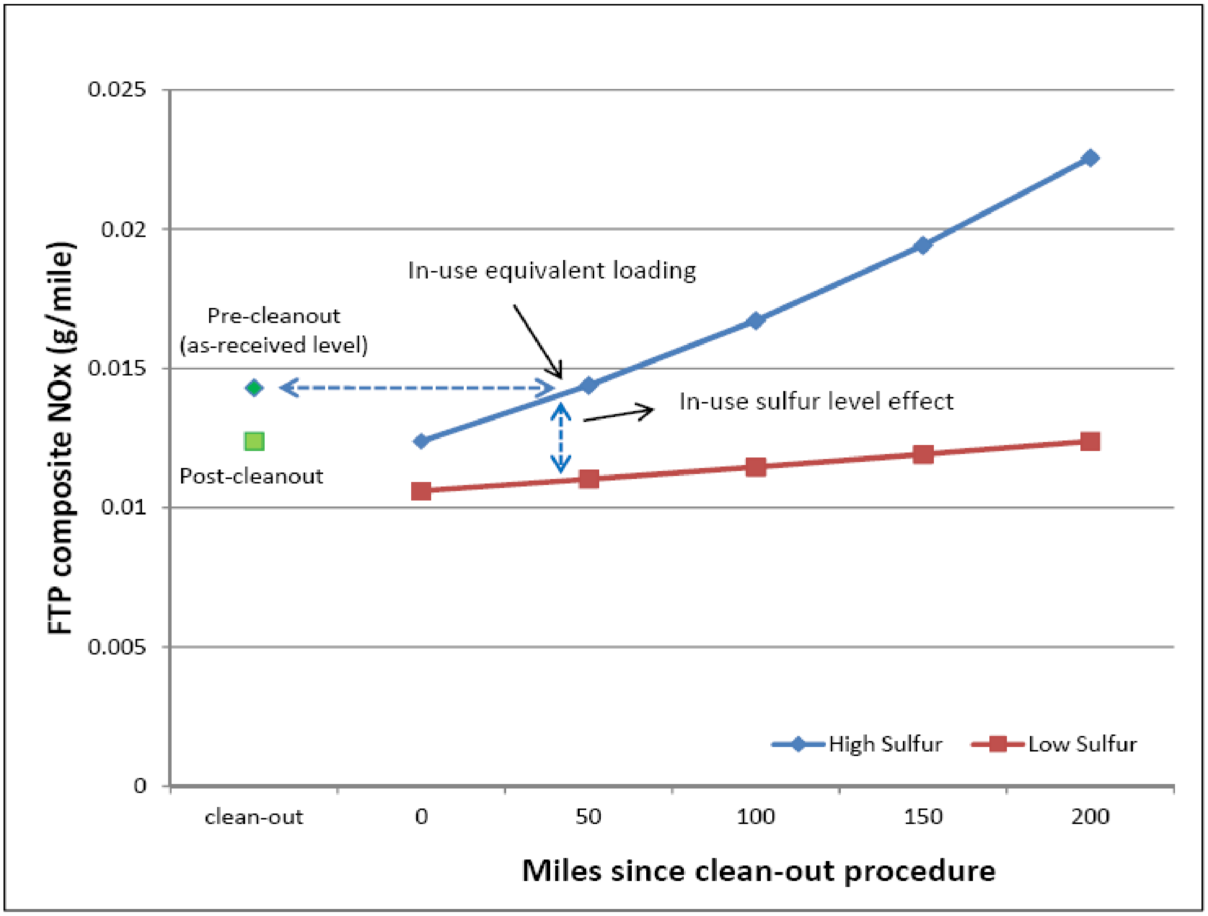

Figure 1-3: Estimation of sulfur level effect on FTP-composite NO_X in in-use fleet

Table 1-5: Summary of mixed model results for emission reductions from 28 to 5 ppm sulfur, adjusted for in-use sulfur loading where appropriate

	NO_X (p-value)	**THC (p-value)**	**CO (p-value)**	**NMHC (p-value)**	**CH_4 (p-value)**	**NO_X+NMOG (p-value)**	**PM‡**
Bag 1	10.7% (0.0033)	8.5%† (0.0382)	7.5%† (0.0552)	7.5% (< 0.0001)	13.9%† (< 0.0001)	N/A	–
Bag 2	59.2% (< 0.0001)	48.8% (< 0.0001)	– ‡	44.8%† (0.0260)	49.9% (< 0.0001)	N/A	–
Bag 3	62.1% (< 0.0001)	40.2% (< 0.0001)	20.1% (< 0.0001)	49.9% (< 0.0001)	29.2% (< 0.0001)	N/A	–
FTP Composite	23.0%† (0.0180)	13.0%† (0.0027)	11.9%† (0.0378)	10.6%† (0.0032)	25.8%† (< 0.0001)	17.3% (0.0140)	–
Bag 1 – Bag 3	– ‡	5.2% (0.0063)	4.3% (0.0689)	5.1% (0.0107)	4.6% (0.0514)	N/A	–

Notes:

† Model with significant sulfur and mileage interaction term.

‡ Sulfur level not significant at $\alpha = 0.10$. For THC Bag 1 and CH_4 Bag 1, because the effect of clean-out was not statistically significant, the reduction estimates are based on the estimates of least squares means.

Major findings from this study include:

- Reversible sulfur loading is occurring in the in-use fleet of Tier 2 vehicles and has a measureable effect on emissions of NO_X, hydrocarbons, and other pollutants of interest
- The effectiveness of high speed/load procedures in restoring catalyst efficiency is a function of fuel sulfur level
- Reducing fuel sulfur levels from 28 to 5 ppm is likely to achieve significant reductions in emissions of NO_X, hydrocarbons, and other pollutants of interest in the in-use fleet

Findings of this study are in general agreement with data presented in the Alliance of Automobile Manufacturers National Clean Gasoline Study published in 2009.[18] Section 3 of that document presents analysis of the Tech 5 vehicle class portion of the California Air Resources Board Predictive Model, as well as the MSAT test program conducted jointly by EPA and several automakers in 2005-6. Figure 6 of the Alliance study shows changes in FTP-composite NO_X emissions as a function of sulfur as predicted by these two data sources. The results of this study are bracketed by the Tech 5 results lower in magnitude, and the MSAT data as higher in magnitude. This seems reasonable given the fact that Tech 5 vehicles are compliant with a lower NO_X standard than the Tier 2 vehicles used in this study, and thus sulfur loading would be expected to have lower leverage on emission performance, and the fact that the MSAT test program made a comparison between emissions data for the low sulfur fuel collected immediately after a more aggressive cleanout procedure than used in this study (CRC E-60) and data from the high sulfur fuel collected after a sulfur loading procedure consisting of >100 miles of low-speed cruising.

Figure 5 in Section 3 of the Alliance study shows hydrocarbon emissions (as THC) from the same data sources. The results of this study show a slightly larger emission effect than predicted by the MSAT program results; a possible explanation for this is that the larger database in this study allowed the model to discern a clearer effect for this pollutant (whose sulfur effect appears to be smaller and more variable across vehicle types than for NO_X). In any case, both studies showed statistically significant results in the same direction and of similar magnitude.

1.2.3.3 Fuel Sulfur Impacts on Vehicles at the Proposed Tier 3 Levels

The Tier 3 Program would reduce fleet average NMOG+NO_X emissions by over 80 percent. The feasibility of the proposed 30 mg/mi NMOG+NO_X fleet average standard depends on a degree of emissions control from exhaust catalyst systems that will require gasoline at 10 ppm sulfur or lower. The most likely control strategies will involve using exhaust catalyst technologies and powertrain calibration to reduce NO_X emissions to near-zero levels. This would allow sufficient NMOG compliance margin to meet the combined NMOG+NO_X emissions standards for the full useful life.

Achieving the proposed Tier 3 emission standards would require very careful control of the exhaust chemistry and exhaust temperatures to ensure high catalyst efficiency. The impact of sulfur on OSC in the catalyst makes this a challenge even at relatively low (10 ppm) gasoline sulfur levels.

Light-duty vehicles certified to CARB SULEV and Federal Tier 2 Bin 2 exhaust emission standards accounted for approximately 3.5% and 1%, respectively of vehicle sales for MY2009. Nonhybrid vehicles certified in California as SULEV are typically not certified to Federal Tier 2 Bin 2 emissions standards even though the numeric limits for NO_X 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 gasoline up to the Tier 2 80-ppm gasoline sulfur cap. While vehicles certified to the SULEV and Tier 2 Bin 2 standards both demonstrate compliance using 15-40 ppm certification gasoline, in-use compliance of SULEV vehicles in California occurs after operation on gasoline with an average of 10 ppm sulfur and a 30-ppm sulfur cap while federally certified vehicles 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 certification of California SULEV vehicles to emissions standards under the Federal Tier 2 program that are typically 1-2 certification bins higher (e.g., SULEV certified 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.

Emissions of vehicles certified to the SULEV standard of the California LEV II program, or the equivalent Tier 2 Bin 2 standards, can provide some insight into the impact of fuel sulfur on vehicles at the very low proposed Tier 3 emissions levels. Vehicle testing by Toyota of LEV I, LEV II ULEV and prototype SULEV vehicles showed larger percentage increases in NO_X and HC emissions for SULEV vehicles as gasoline sulfur increased from 8 ppm to 30 ppm, as compared to other LEV vehicles they tested. Testing of a SULEV-certified PZEV vehicle by Umicore showed a pronounced, progressive trend of increasing NO_X emissions (referred to as "NO_X creep") when switching from a 3 ppm sulfur gasoline to repeated, back-to-back FTP tests using 33 ppm sulfur gasoline.[10] The PZEV Chevrolet Malibu, after being aged to an equivalent of 150,000 miles, demonstrated emissions at a level equivalent to the compliance margin for the Tier 3 Bin 30 NMOG+NO_X standard 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_X emissions alone were more than double the proposed Tier 3 30 mg/mi NMOG+NO_X standard.[19] This represents a NO_X percentage increase that is approximately 2-3 times of what has been reported for similar changes in fuel sulfur level for Tier 2 and older vehicles over a similar difference in fuel sulfur.[20,21]

Although there are no vehicles larger than LDT2 and no non-HEV vehicles above the LDV D-segment size, we expect that additional catalyst technologies, for example increasing catalyst surface area (volume or substrate cell density) and/or increased PGM loading, would need to be applied to larger vehicles in order to achieve the catalyst efficiencies necessary to comply with the proposed Tier 3 standards. Any sulfur impact on catalyst efficiency would have a larger impact on vehicles and trucks that rely more on very high catalyst efficiencies in order to achieve very low emissions.

The negative impact of gasoline sulfur on NO_X, NMOG and air toxic emissions occurs across all vehicle categories. However, the impact of gasoline sulfur on NO_X emissions control of catalysts in the fully-warmed-up condition is particularly of concern for larger vehicles (E- and F-segment LDVs, LDT3, LDT4 trucks, 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_X levels, any significant degradation in NO_X emissions control over the useful life of the vehicle would likely prevent some if not most larger vehicles from reaching a combined NMOG+NO_X low enough to comply with the 30 mg/mi fleet-average standard . These vehicles represent a sufficiently large segment of light-duty vehicle sales now and in the foreseeable future that their emissions could not be offset (and thus the fleet-average standard achieved) by certifying vehicles to bins below the fleet average. Any degradation in catalyst performance due to gasoline sulfur would reduce or eliminate the margin necessary to ensure in-use compliance with the proposed Tier 3 emissions standards. Certifying to a useful life of 150,000 miles vs. the current 120,000 miles would further add to manufacturers' compliance challenge for Tier 3 large light trucks (see Figure 1-6). (See Section IV.7.b in the preamble for more on the proposed useful life requirements.)

1.2.3.4 Gasoline Sulfur Control Required to Meet Tier 3 Emissions Standards

The impact of gasoline sulfur poisoning on exhaust catalyst performance and the relative stringency of the Tier 3 standards, particularly for larger vehicles and trucks, when considered together make a compelling argument for the virtual elimination of sulfur from gasoline. The 10-ppm standard for sulfur in gasoline represents the lowest practical limit from a standpoint of fuel handling and transport. A gasoline sulfur standard of 10 ppm also represents the highest level of gasoline fuel sulfur that will allow compliance with a national fleet average of 30 mg/mi NMOG+NO_X.

1.3 SFTP NMOG+NO_X Feasibility

The proposed new emission requirements include stringent NMOG+ NO_X composite standards over the SFTP that would 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 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 a 50 mg/mi NMOG+NO_X 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 certification results for model years 2010 and 2011. These data included FTP composites, as well as results for the US06, and SC03 cycles. We focused on results for hydrocarbons (HC) and NO_X. For the FTP results HC represents non-methane organic gases (NMOG). The US06 and SC03 results represent NMHC+NO_X.

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

$$\mathrm{SFTP} = 0.35 \cdot (\mathrm{FTP}_{NOx} + \mathrm{FTP}_{NMOG}) + 0.28 \cdot \mathrm{US06} + 0.37 \cdot \mathrm{SC03}$$

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 1-6 shows the numbers of test groups in each combination of standard level and vehicle class.

Table 1-6: 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 1-4 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 1-5 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.

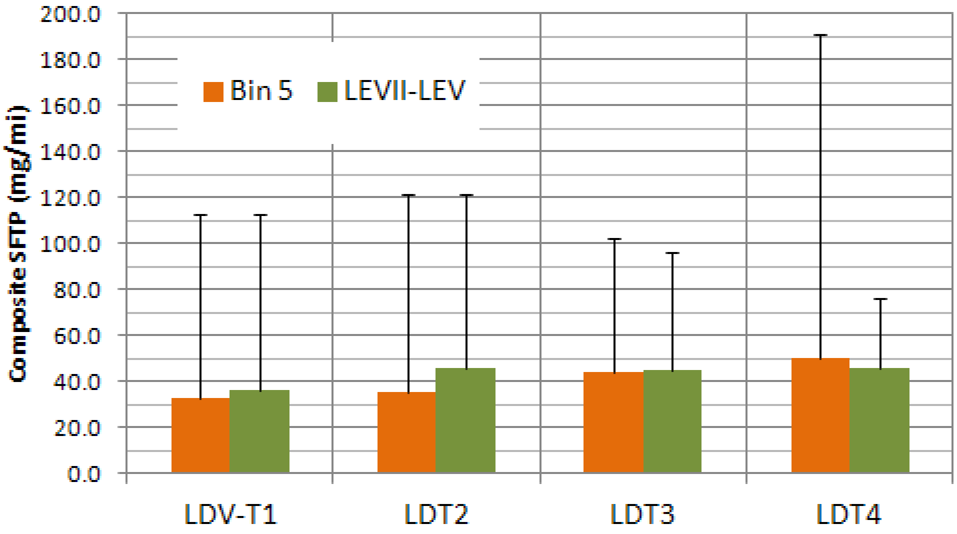

Figure 1-4: Mean and Maximum Composite SFTP Results for HC+NO$_X$ for Test Groups certified to Bin-5 and LEV-II/LEV Standards (bars and error-bars represent means and maxima for sets of test groups, respectively)

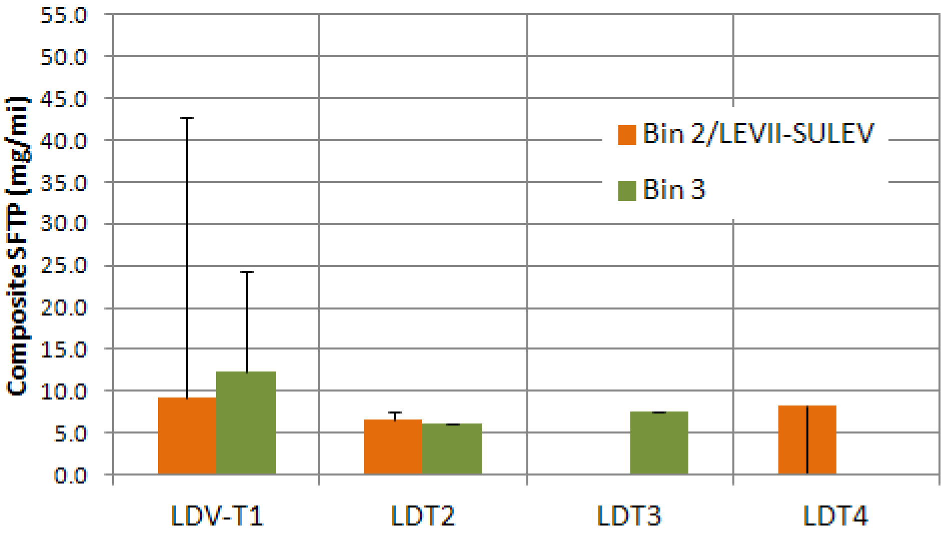

Figure 1-5: Mean and Maximum Composite SFTP Results for HC+NO_X for Test Groups certified to Bin-2 and Bin-3 Standards (bars and error-bars represent means and maxima for sets of test groups, respectively)

1.4 Technology Description for NMOG+NO_X Control

A range of technology options exist to reduce NMOG and NO_X 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 unique benefits and limitations. This section describes the technical challenge 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 proposed rule. Unique diesel technologies are addressed in Section 1.4.2.

1.4.1 Summary of the Technical Challenge for NMOG+NO_X control

The proposed Tier 3 rule would require vehicle manufacturers to reduce the level of both NMOG and NO_X 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_X emissions from gasoline fueled vehicles measured during the FTP test occur during the cold start phase. Figure 1-1, above, graphically demonstrates when NMOG and NO_X 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_X emissions occur during this same 50 second period. Unlike NMOG which is mostly controlled after the first 50 seconds, NO_X emissions tend to be released throughout the remainder of the FTP test. Achieving the proposed Tier 3 NMOG+NO_X FTP emissions standard may require manufacturers to reduce both cold start NMOG and NO_X emissions and further reduce NO_X emissions when the vehicle is warmed up.

The proposed Tier 3 rule would also require manufacturers to maintain their current high vehicle load NMOG+NO_X 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_X 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_X emissions.

It is anticipated that manufacturers will change the design of their exhaust and catalyst systems to reduce catalyst light-off times to achieve the proposed Tier 3 30 mg/mi FTP NMOG+NO_X 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_X 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_X emissions during the FTP will also reduce NO_X emissions during warmed up operation on the US06.

For the catalyst to effectively reduce NMOG+NO_X 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_X emissions requires improving the efficiency of the catalyst system.

To achieve the proposed NMOG+NO_X FTP emissions standards it is anticipated that vehicle manufacturers will focus on three areas to reduce emissions:

- reducing 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_X efficiency of the catalyst during warmed-up operation.

It is anticipated that improvements in all three areas will be required for heavier passenger cars, light-duty trucks in classes LDT3 and LDT4, and MDPVs. The NO_X efficiency during warmed-up operation of vehicles certified to the Tier 2 Bin 4 emission level are such that it is anticipated that reductions in cold start emissions are all that will be required to achieve the proposed Tier 3 NMOG+NO_X standard.

Heavy-duty trucks (8,501 up to 14,000 lbs) will have a similar challenge to meet their proposed 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 proposed 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 would be expected to be significantly greater than the reductions achievable during the cold start and idle phase. Fuel enrichment events cause criteria pollutant and CO_2 emission rates to increase and also reduces the vehicle's fuel economy. To achieve the proposed NMOG+NO_X 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_X 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 achieve the proposed NMOG+NO_X 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;
- reducing the time required for the catalysts and SCR system to reach the proper operating temperature;
- improving the NO_X 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_X than NMOG. As the engine warms up and as the load increases the concentration of NO_X 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. [22]

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.[23] 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.

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.[24]

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_X 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^oC. 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 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_X 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_X 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.[25,26] 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 also improves 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 therefore 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 increases. As the torque variations increase, the combustion process is deteriorating and the engine performance degrades 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. [27]

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 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_X 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 proposed 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 proposed Tier 3 NMOG and NO_X 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 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_X 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 reactions. Therefore, as the loading levels and composition of the PGM changes the light-off performance for both NMOG and NO_X 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 proposed Tier 3 NMOG and NO_X emission standards it is anticipated that manufacturers will make changes to catalyst substrates and PGM loadings. [28] To achieve the emission levels required to meet the proposed Tier 3 NMOG+NO_X 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_X emission levels of the proposed 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.[29,30]

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 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_2 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.

It is anticipated that if manufacturers have difficulty achieving the proposed Tier 3 NMOG+NO_X emission standards that manufacturers will evaluate including a hydrocarbon trap 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.[31]

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 proposed standard.

1.4.1.3 Improving catalyst NO_X efficiency during warmed-up operation

Significant quantities of NO_X emissions are produced by vehicles during warmed-up vehicle operation on the FTP for Tier 2 Bin 5 certified vehicles. The stabilized NO_X emission levels will need to be reduced to achieve the proposed Tier 3 NMOG+NO_X emission standard. Improving the NO_X 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 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_X 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_X emission performance of the vehicles is maintained at or below the 30 mg/mi NMOG+NO_X 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_X emissions beyond the proposed Tier 3 standard.

It is anticipated that manufacturers will use these catalyst and calibration technologies to improve the warmed up NO_X 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 between EPA, CARB, vehicle manufacturers and major component suppliers indicated that large light-duty trucks (e.g., pickups and full-size SUVs in the LDT3 and LDT4 categories) will be the most challenging light-duty vehicles to bring into compliance with the proposed Tier 3 NMOG+NO_X 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 1-6 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_X and NMOG when going from Tier 2 to Tier 3 also includes a reduction in gasoline sulfur levels from 30 ppm to 10 ppm.

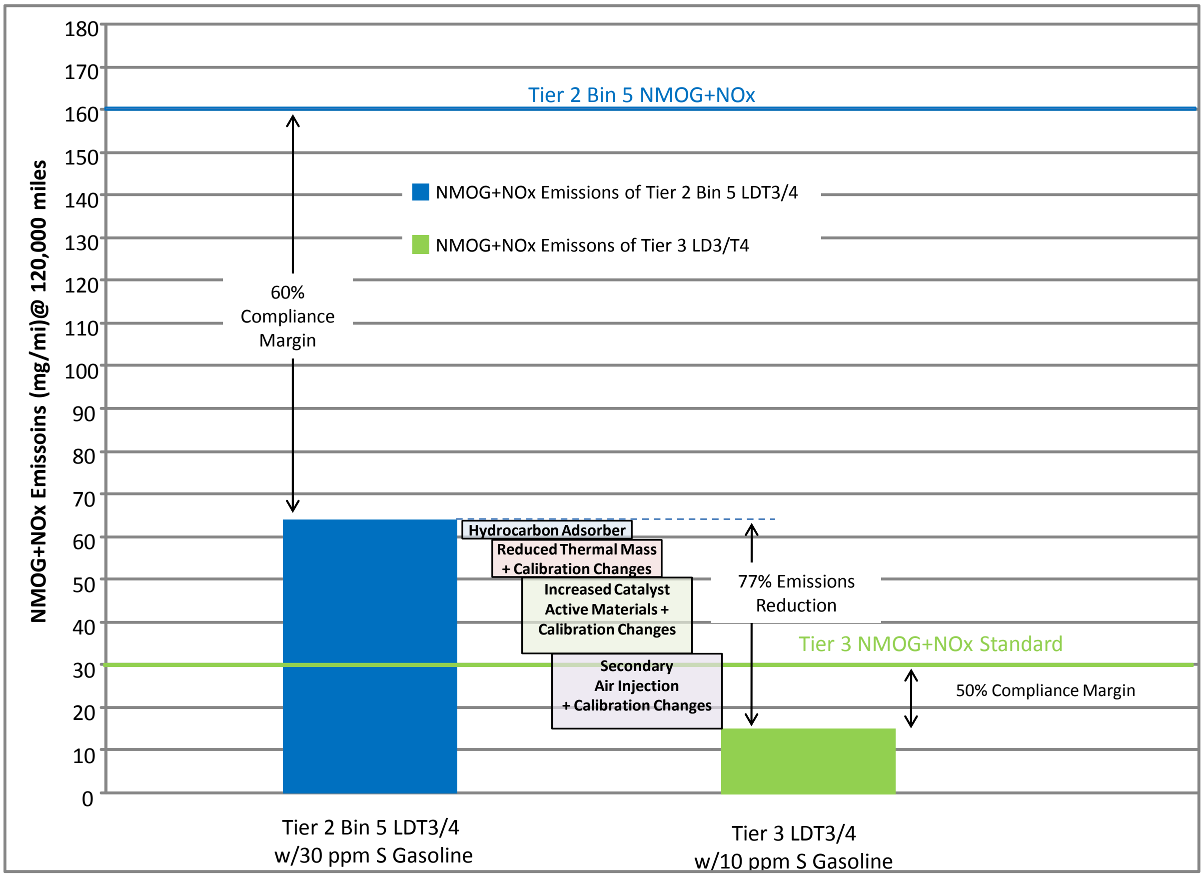

Figure 1-6: Contribution of the expected Tier 3 technologies to large light-duty truck compliance with the Tier 3 standards with a comparison to Tier 2 Bin 5. The technologies and levels of control are based on a combination of confidential business information submitted by auto manufacturers and suppliers, public data and EPA staff engineering judgment.

1.4.2 Diesel Technologies for Achieving Tier 3 NMOG and NO_X 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_X emissions. The technical challenge for diesel engines to achieve the proposed Tier 3 NMOG+NO_X emission levels will be to obtain significant NO_X emission reductions. It is anticipated that improvements in NO_X emissions performance of diesel exhaust catalysts during the cold start phase will be a major technical challenge. Depending on the performance of the exhaust catalyst system, additional reductions in warmed-up NO_X emissions may also be required to achieve the proposed Tier 3 emission levels.

It is not anticipated that diesel engines will have difficulty achieving the proposed 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_X 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_X 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_X.

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_X emissions from diesel engines. Once light-off has been achieved, NO_X emissions reduction for modern, base-metal zeolite SCR systems approaches that of modern three-way catalyst systems used for stoichiometric gasoline spark-ignition applications.[32]

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 pyrolize 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) 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_2, NO and NO_2). 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_2 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_2 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 proposed PM emission standards for the Tier 3 rule, 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.

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 1-7. 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.[D]

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.[33] 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[34].

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 in time for the proposed 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 UDDS 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 UDDS 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 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

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[D] 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.

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_X, NMHC, NMOG, alcohols, carbonyls, CO, CH_4, CO_2 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,[35] 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[E] which describes the original analysis and corrective actions in greater detail.

Table 1-7: 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[a]	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

[E] Sobotowski, R. (February, 2013). Test Program to Establish LDV Full Useful Life PM Performance. Memorandum to the docket.

Manufacturer's Development Vehicle[b]	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:
[a] PFI is Naturally aspirated, port fuel injected; GDI is Naturally aspirated, gasoline direct injection; TGDI is Turbocharged, gasoline direct injection
[b] 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 1-8 and Table 1-9 for the FTP and US06 test cycles, respectively. FTP NMOG +NO$_X$ and PM results are also plotted in Figure 1-7 and Figure 1-8, respectively. The US06 NMOG+NO$_X$ 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$_2$ 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 1-8: FTP Composite Emissions Results

Vehicle	CO$_2$ g/mile	CO g/mile	NO$_X$ g/mile	NMOG g/mile	NO$_X$+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 1-9: US06 Emissions Results

Vehicle	CO_2 g/mile	CO g/mile	NO_X g/mile	NMOG g/mile	NO_X+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 1-7, with the exception of one PFI passenger car (vehicle D), the FTP NMOG+NO_X emissions of all tested vehicles remained below their respective proposed fleet average 2017 standards, but none performed below the proposed 2025 standard.

FTP PM emissions increased with CO_2 emissions for the PFI vehicles and remained well below the proposed 3 mg/mile standard, confirming that most current light duty vehicles are already capable of meeting the proposed Tier 3 PM standard (Figure 1-8). Two GDI vehicles demonstrated FTP PM emissions above the proposed standard, indicating that additional combustion system development would be necessary in some vehicles to achieve compliance.

As shown in Figure 1-9, with the exception of two LDTs (vehicles I and J), all vehicles met their respective proposed fleet average 2017 (for vehicles below 6,000pounds GVWR) or 2018 (for vehicles above 6,000 pounds GVWR) US06 NMOG+NO_X standards. Five vehicles, four passenger cars (vehicles A, B, F and L) and one LDT (vehicle L), produced US06 NMOG+NO_X emissions lower than the proposed 2025 standard.

As in the case of FTP results, US06 PM emissions increased with the increase in CO_2 emissions in PFI vehicles (Figure 1-10). All PFI passenger cars remained well below the proposed 10 mg/mile standard. 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 performed below the proposed 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.

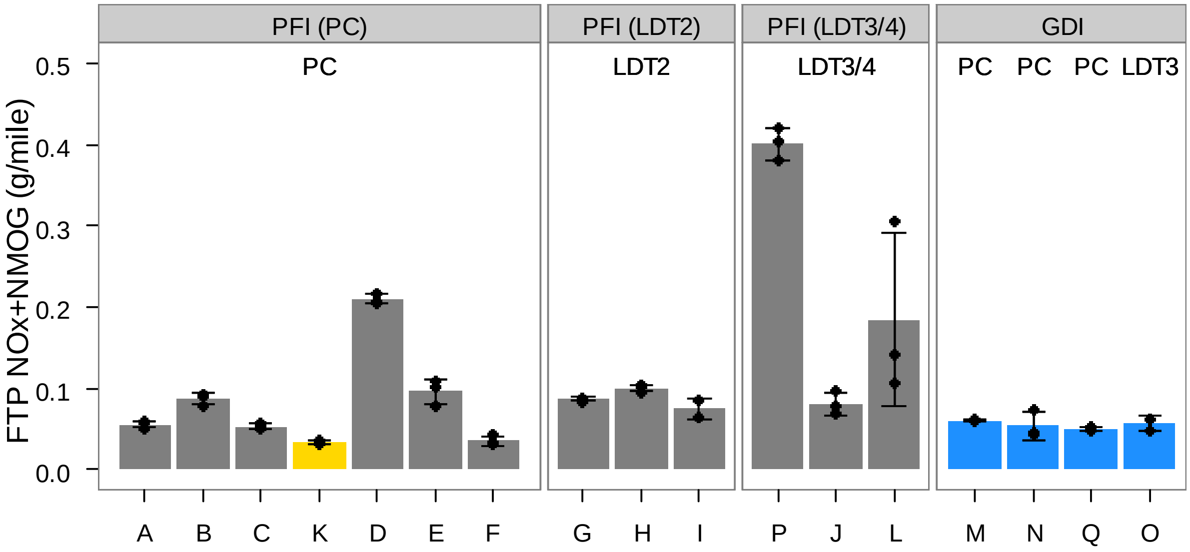

Figure 1-7: Composite FTP NMOG+NO_X Emissions Results

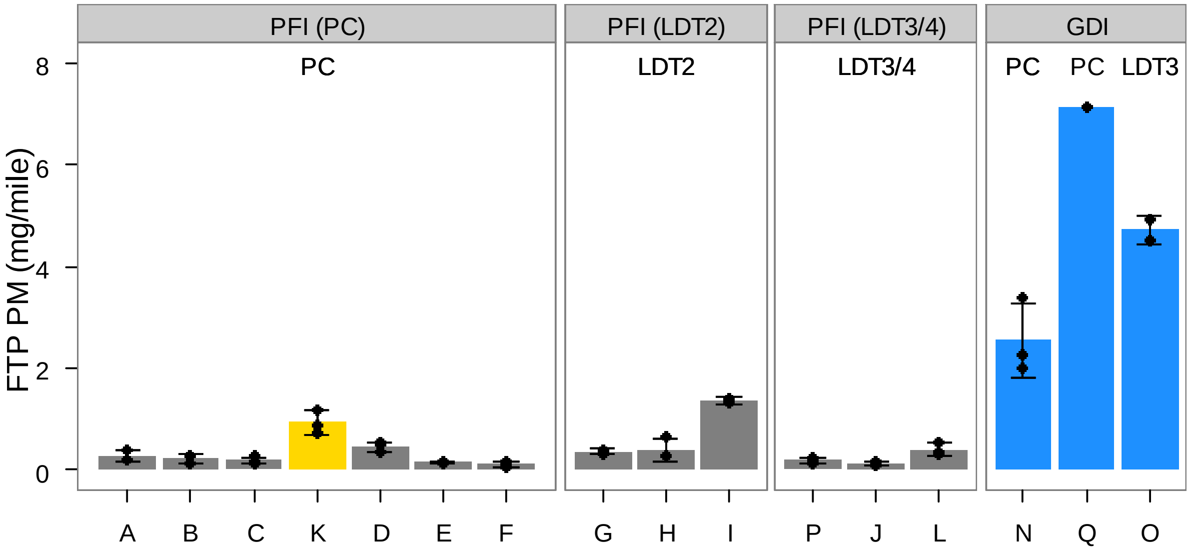

Figure 1-8: Composite FTP PM Emission Results

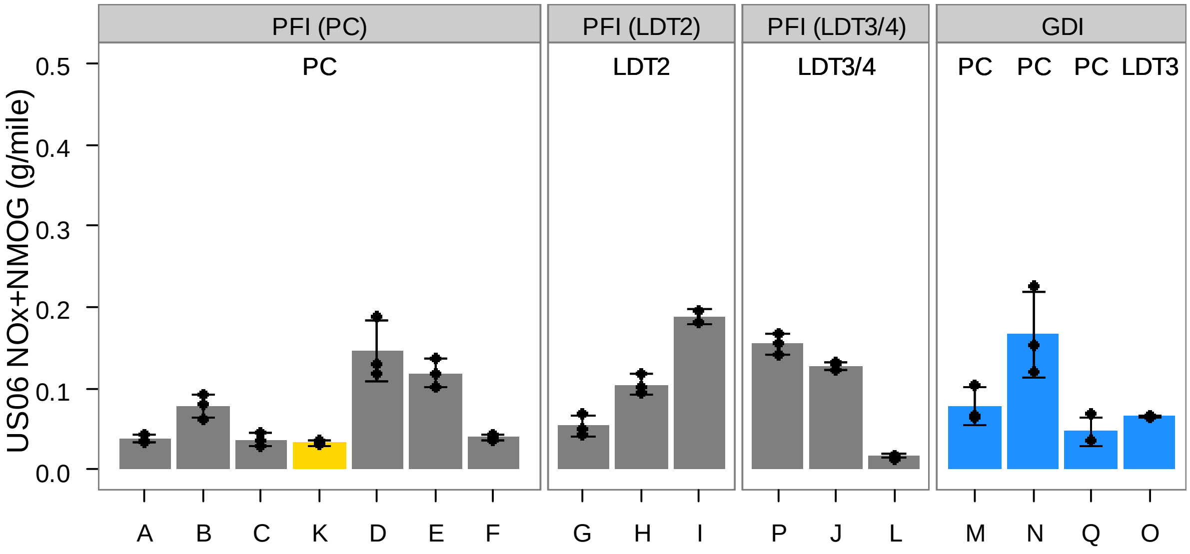

Figure 1-9 US06 NMOG+NO$_X$ Emissions Results

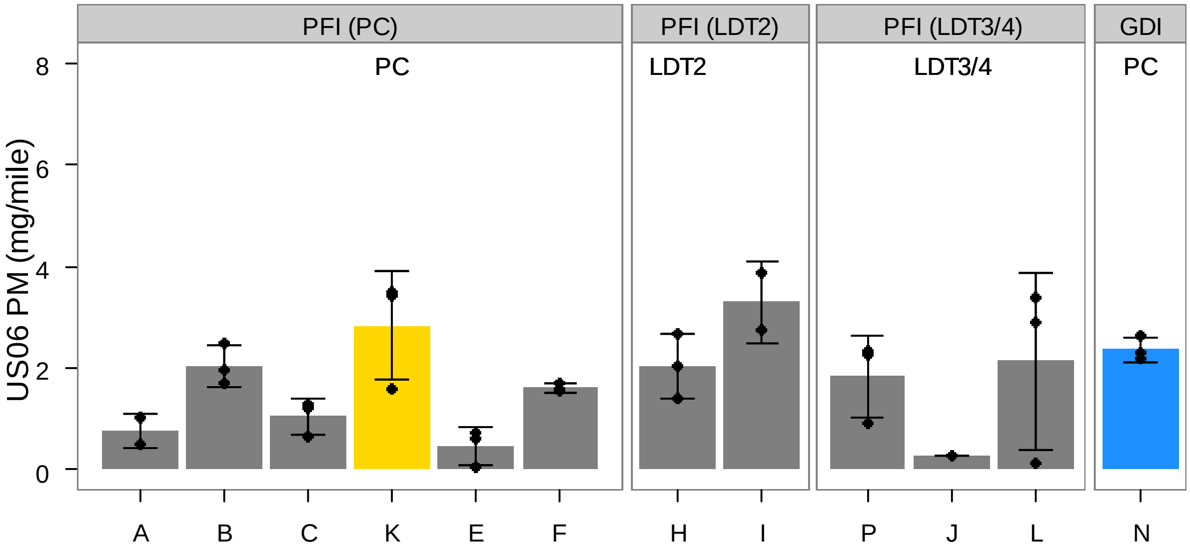

Figure 1-10: US06 PM Emissions Results

1.5.2 FTP PM Feasibility

With regard to the feasibility of the light-duty fleet to meet the proposed PM standards for testing on 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 proposed Tier 3 FTP standards. A small number of vehicles are at or just over the proposed 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 proposed 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, 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 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 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 proposed evaporative emission requirements include more stringent hot-soak plus diurnal standards that are expected to require new vehicle hardware and improved fuel system designs. The type of new hardware that would 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 proposed 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 proposed evaporative emission standards, EPA conducted two analyses. The first analysis performed was based on the certification results for the current EPA-certified evaporative families. This provided a baseline for the current federal fleet emissions performance. The second analysis looked at the list of PZEV-certified vehicles in the California LEV II fleet. The proposed Tier 3 evaporative emission standards are similar to the current evaporative requirements for PZEVs in California. Both of these analyses are described in greater detail below.

1.6.1 Assessment of the Current EPA Certification Emissions

EPA’s current evaporative emission standards vary by vehicle category. Table 1-10 shows the currently applicable hot-soak plus diurnal emission standards.

Table 1-10 Current EPA Evaporative Emission Standards

Vehicle Category	Hot-soak plus Diurnal (2-day)	Hot-soak plus Diurnal (3-day)
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
Complete HDV <14,000 pounds GVWR	1.75 g/test	1.4 g/test

Based on MY2010 certification data, EPA analyzed the certification hot-soak plus diurnal emission levels for all certified vehicle categories that will be subject to the proposed 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 1-11 also shows the proposed Tier 3 evaporative emission standards.

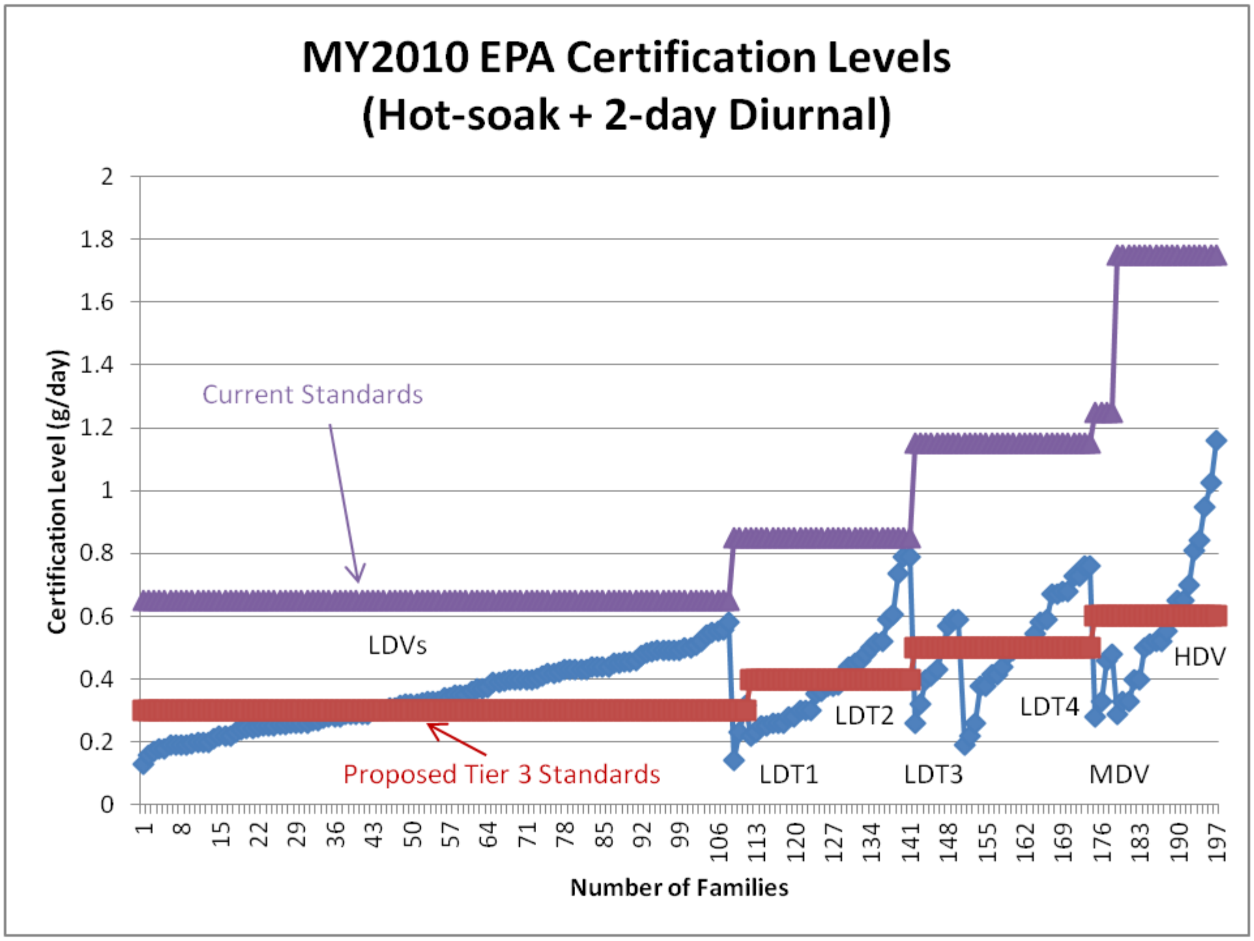

Figure 1-11: MY2010 Hot-soak Plus Diurnal (2-Day) Emission Certification Levels

It should be noted that the current evaporative emission data is based on a different certification test fuel than what is being proposed for the Tier 3 program. While both the current and proposed certification fuels have a Reid vapor pressure of nominally 9.0 psi, EPA's current certification test fuel contains no ethanol, whereas the proposed certification fuel contains 15 percent ethanol. While the discussion below is based on the current certification fuel without ethanol, EPA believes it is still useful in gauging the level of effort needed by manufacturers to comply with the proposed 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 proposed certification fuel.

As can be seen from the figure, there are many families certified below the proposed Tier 3 hot-soak plus diurnal standards. Of the nearly 200 evaporative families included in the analysis, 40 percent had certification levels below the proposed Tier 3 standards. Some of these families are certified to the more stringent PZEV standards, upon which the proposed Tier 3 evaporative emission standards are based, but many of the families are not. However, the proposed 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 without further modification.) Therefore, even though many families are certified below the proposed 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 proposed standards.

1.6.2 Assessment of California-certified PZEVs

Based on the California Air Resources Board's MY2011 certification list, EPA identified the vehicles certified by manufacturers to the PZEV requirements. As noted earlier, the proposed Tier 3 evaporative emission standards are very similar to the PZEV evaporative emission requirements and, as allowed with one of the proposed 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 proposed Tier 3 evaporative emission standards. As described in more detail below, EPA expects manufacturers will employ a number of technologies to meet the proposed Tier 3 standards. The anticipated control technologies to comply with the proposed emission standards have already been included on many of the PZEVs and include improved carbon canister designs to even better capture vapor emissions from the canister, air intake designs to prevent the escape of unburned fuel from the engine's crankcase, various upgrades to further limit potential micro-sized leaks, and further steps to reduce permeation rates. Table 1-11 shows the manufacturers and models certified to the PZEV standards in MY2011.

Table 1-11 List of MY2011 Models Certified to CARB's PZEV Requirements

Manufacturer	Models
AUDI/VOLKSWAGEN	Audi A3, Volkswagen GTI, Volkswagen Jetta, Volkswagen Golf, Volkswagen Jetta Sportwagen, Volkswagen EOS, Volkswagen CC
BMW	BMW 128i, BMW 328i, BMW 328Ci
CHRYSLER	Chrysler 200, Dodge Avenger
FORD	Ford Escape Hybrid, Mercury Mariner Hybrid, Mazda Tribute Hybrid, Ford Focus, Ford Fusion Hybrid, Mercury Milan Hybrid, Lincoln MKZ Hybrid
GENERAL MOTORS	Chevy Malibu, Buick LaCrosse, Buick Regal
HONDA	Honda Civic GX (CNG-fueled), Honda Civic Hybrid, Honda CR-Z Hybrid, Honda Insight Hybrid, Honda Accord
HYUNDAI	Hyundai Tucson, Hyundai Sonata
KIA	Kia Sportage, Kia Forte, Kia Forte ECO, Kia Forte KOUP, Kia Optima, Kia Optima Hybrid
MAZDA	Mazda 3, Mazda 6
MERCEDES	Mercedes S400 Hybrid, Mercedes C300, Mercedes C350/E350/GLK350
MITSUBISHI	Mitsubishi Outlander Sport, Mitsubishi RVR, Mitsubishi Lancer, Mitsubishi Lancer Sportback, Mitsubishi Galant
NISSAN	Nissan Sentra, Nissan Altima, Nissan Altima Hybrid
SUBARU	Subaru Legacy AWD, Subaru Outback Wagon AWD, Subaru Forester AWD
TOYOTA	Toyota Camry, Toyota Camry Hybrid, Toyota Prius Hybrid
VOLVO	Volvo S80, Volvo XC60, Volvo XC70

1.6.3 Hot Soak Plus Diurnal

The current baseline technology for LDVs, LDTs, and MDPVs is a properly designed and assembled fuel/evaporative system for controlling emissions over the 2-and 3-day test sequences to meet the current standard of 0.650 grams/test. This involves activated carbon canisters which capture gasoline vapors, with engine calibrations designed to maximize canister purge over the test sequence. Fuel systems generally include widespread use of various grades of permeation-resistant materials.

The anticipated control technologies to comply with the proposed hot soak plus diurnal evaporative emission standards include an improved carbon canister designs to even better capture vapor emissions from the canister, air intake designs to prevent the escape of unburned fuel from the engine's crankcase, various upgrades to further limit potential micro-sized leaks, and further steps to reduce permeation rates. Applying these new or improved technologies will allow manufacturers to meet the proposed 300 mg standard for LDVs/LDT1s. The proposed evaporative emission standards are slightly higher for larger vehicles to account for potentially higher background emissions and in some cases larger surface area components, but the baseline and anticipated control technologies follow a very similar path. These baseline and control technologies are described further in the rest of this section.

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. Testing indicates that the total canister adsorption capacity in grams of gasoline vapor is generally dictated by the requirements of the refueling emission test and standard rather than the evaporative emission test (either the 2 or 3-day sequence).

Manufacturers have identified the engine's intake system as another source of evaporative emissions. These result from crankcase vapors and from unburned fuel injectors, or sometimes from an injection event that occurred shortly before engine shutdown. We estimate a typical emission rate of about 40 mg associated with each engine shutdown event; however, since the actual emission rates depend on timing of individual injection events and cylinder position at shutdown, baseline emission rates can vary significantly. These vapors must follow a contorted path before reaching the ambient air, which would generally cause these emissions to show up during the first day of the diurnal test rather than the hot soak test. One way to prevent these emissions is to add 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 at engine shutdown. This carbon insert would almost completely eliminate any vapor emissions from the air intake system.

Manufacturers wanting to avoid adding any specialized emission control component to control evaporative emissions from the air intake could pursue alternative approaches. First, it is possible to allow the engine to continue rotating for 2-3 revolutions after engine shutdown to sweep any hydrocarbon vapors from the intake system into or through the cylinder. These vapors could be burned in the cylinder, oxidized at the catalyst, or stored until the engine starts again. This may still allow for a small amount of residual vapor release, but this should be a very small quantity. Vehicle owners would be unlikely to notice this amount of engine operation after shutdown. Second, to the extent that manufacturers use direct injection, there should be no 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.

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. 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. We are expecting manufacturers to 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. 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.

Fuel lines are also already 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.

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 to achieve the desired performance at the lowest possible price.

The bigger area of expected development with respect to fuel lines is to re-engineer fuel systems to further reduce the number of connections between fuel-system components and other fuel-line segments. Today these systems may 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.

A remaining area of potential evaporative emissions is the connection between the fill neck and the fuel tank. Manufacturers can reduce emissions by perhaps 10 mg per day by making this connection permeation-resistant. The challenge is to design a low-cost solution that is easily assembled and works for the demanding performance needs related to stiffness/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.

Purge rates are currently designed to flow relatively large volumes of outside air through the canister when the purge solenoid is activated. This involves using available manifold vacuum to create purge flow, with limits in place to avoid drawing too much unmetered fuel vapor from the canister. Tightening the evaporative emission standard would lead manufacturers to address remaining emission sources from micro-size leak points, permeation, and diffusion, as noted above. Since the amount of additional vapor being captured by the carbon canister is small and the test procedure is not changing, we do not expect the change in standards to drive changes in purge strategy, rates, or canister capacity. Nonetheless, vehicle system and engine changes to improve fuel economy could impact future purge strategies. Thus, as part of this approach, manufacturers may incorporate designs to reduce vapor volume/mass directed to the canister and thus potentially reduce the purge air volume requirements. In addition, canister designs can be optimized to increase the effectiveness of a given volume of purge air. This could involve selecting different combinations of carbon characteristics and canister architecture types and by adding features to add heat (or preserve heat) in the canister during a purge event.

The technology discussed above is in use to varying degrees on many of the CARB PZEV zero evap vehicles mentioned above. Taken together, we believe these technologies provide manufacturers with effective tools for reducing emissions sufficiently to meet the proposed evaporative emission standards.

1.6.4 Canister Bleed Emission Standard

More stringent evaporative emission standards have led to more careful measurements, which led manufacturers to discover that 80 mg or more of fuel vapor would diffuse from the canister vent as a result of the normal redistribution of vapors within the activated carbon while the vehicle is at rest. The emission rate depends on the tank volume, its fill quantity, and the size and architecture of the canister and the characteristics of the carbon itself. While the biggest effect of this vapor distribution is a uniform concentration within the canister, it can also cause vapors to escape through the canister vent even without continued canister loading that would result from fuel tank heating. These are referred to as canister bleed emissions. These emissions occur to some degree during the 2- and 3-day evaporative emissions test, but a separate standard is needed if the goal of near zero fuel vapor emissions is to be achieved.

The design to address this concern is a supplemental "scrubber" canister (or canister compartment) with a very low working capacity carbon. Adding 100 or 200 ml of this type of carbon near the canister vent provides a margin of "reserve capacity" to capture diffusion losses from the canister. Since this extra carbon has low working capacity and it purges readily, it is typically cleared of hydrocarbon vapors and ready to perform its function after any amount of engine operation or even with natural back purge which occurs when the fuel in the tank cools. This scrubber element is expected to eliminate all but 5-10 mg of emissions from the evaporative canister over the measurement procedure.

1.6.5 Leak Emission Standard

Vapor leaks in the vehicle fuel/evaporative system can arise from micro-cracks or other flaws in various fuel/evaporative system component structures or welds, problems with component installations, and more generally from connections between components and fuel lines and vapor lines. Because these emissions from these areas would occur in the 2-3 day evaporative emissions test if the problems were present, manufacturers have taken steps to address these potential problem areas as part of their overall evaporative emissions control strategy. Since the 2-3-day hot soak plus diurnal standards are proposed to become even more stringent and leak emissions occur during the evaporative emissions test, we expect manufacturers to take the measures described above in Section 1.6.1. These include reducing connections, improving the quality of fuel and vapor line connections, use of improved component materials and revised installation practices. Manufacturers could also review their OBD leak warranty data and related information from OBD queries to help inform their strategies. One of the key reasons for focusing on a leak emission standard is to increase focus on designs which will yield improved in-use emissions performance. EPA believes this focus on in-use durability is important because a vehicle with even a small leak, say the 0.020-0.040 inch orifice diameter monitored by OBD systems would likely emit above the proposed hot soak plus diurnal evaporative emission standard in use. See Appendix 1A: Technical Report on Leak Test Procedure.

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1.A. Appendix to Chapter 1: Technical Report on Leak Test Procedure

Technical Report

Draft Recommended Test Procedure

and Supporting Testing Data for the Proposed

Evaporative Emissions Leak Test

By

Peter Smith

July 2012

NOTICE

Technical Reports do not necessarily represent final EPA decisions or positions. They are intended to present technical analysis of issues using data or testing results which are currently available. The purpose in the release of such reports is to facilitate the exchange of technical information and to inform the public of technical developments which may form the basis for a final EPA decision, position or regulatory action.

Assessment and Standards Division

Office of Air and Radiation

U.S. Environmental Protection Agency

I. Introduction

Evaporative emission control systems have been present on new light-duty vehicles since the 1971 model year. These systems have gone through several generations of upgrades over the years and have become more sophisticated and complex as fuel properties have varied, test procedures have changed, emission standards have increased in stringency, and new requirements have been added to meet greater demands for improved air quality. These onboard systems are currently responsible for capturing evaporative emissions produced from gasoline during diurnal, hot soak and running conditions as well as in vehicle refueling situations. Toluene and benzene, which currently account for about five percent of the tank headspace vapor composition, have been linked to possible adverse health effects.[1,2] In addition these compounds and others commonly found in gasoline vapor such as butane and pentane are also responsible for the creation of photochemical smog. Due to these concerns, EPA has sought to increase the capability of these systems to strictly limit the release of these compounds to the atmosphere.

Over the past several months, the Agency has developed an evaporative emissions leak test procedure which could be used in both laboratory and field conditions to quickly test the integrity of a test vehicle's evaporative system. Such a test is independent of On-Board Diagnostics (OBD) leak detection requirements and as such would not be bound by the limitations and restrictions commonly present in such a monitoring system. The leak test as presently envisioned would be a stand-alone test designed to find any vapor leaks in the fuel/evaporative system. This test is not designed to indentify leaks outside of the fuel and vapor containment portion of the vehicle fuel system.

Past and current work at the Agency has found that not all evaporative emissions leaks are being identified by current OBD systems. This is especially important since these emissions are a potentially significant portion of the evaporative emissions inventory. This test procedure and accompanying leak standard could serve as a means to reduce vapor from system leaks in use. Concurrent with Tier 3 emissions levels it is being proposed that the leak test emission standard be proposed at a value of 0.02 inches cumulative diameter orifice.

This report details the evaporative emissions leak test procedure as presently proposed as well as the vehicle preconditioning necessary prior to undergoing the leak test. It also presents the various testing that has been performed at NVFEL both in the creation of the test procedure as well as supporting data to ensure that the leak test provides accurate results on as many different vehicle configurations as possible. Examples of calculations of relative leak orifice sizes are also presented.

II. History of Evaporative Emissions Controls and Standards

Even though present day fuel evaporative emission controls are relatively mature, the development of the present emission standards and related requirements and the control technology applied by the manufacturers has evolved over about 40 years. The activated carbon canister and the basics of evaporative system as it is known today for controlling hot soak and diurnal emissions were required by the for 1971 model year light -duty vehicles even before the creation of EPA. The purpose of this system is to capture fuel vapors created by the presence or operation of the motor vehicle and store these hydrocarbon vapors in an onboard activated charcoal media known as the charcoal canister. Until recently, most manufacturers placed this canister under the hood where it was responsible for capturing the fuel vapors generated when the fuel tank was heated via atmospheric conditions (diurnal cycle) as well as the vapors generated from the carburetor float bowls (hot soak) and fuel tank when the vehicle was parked. In uncontrolled vehicles fuel tank and carburetor evaporative emissions were vented to the atmosphere. The fuel vapors generated during vehicle operation, known as "running loss" were basically not controlled in early designs.

These early systems did not focus on full vehicle evaporative emissions thus early carbon trap test procedures were deficient in gaining control. Early evaporative systems did not have any type of microprocessor interface for controlling vapor loads and purge and were controlled via a series of vacuum check valves, mechanical linkages, and/or solenoids. The canister had a finite storage volume, much like present day systems, and was purged of stored vapors during vehicle operation. Unfortunately, many of these early systems were disconnected or otherwise modified by unknowing motorists thinking these systems had a detrimental effect on the performance or running operation of their vehicle.

Over the past 40 years there have been about five major changes in evaporative emission control requirements. These have involved test procedure changes, more stringent numerical standards, control of evaporative emissions from other sources on the vehicle, or control of emissions from various other operating modes. Following the initial requirements for the 1971 model year, noteworthy changes in the regulatory requirements as indicated in the Code of Federal Regulations included: (1) the change from the carbon trap to SHED test method in 1978, (2) the numerically more stringent 1981 model year hot soak plus diurnal evaporative emission standards, (3) enhanced evaporative requirements which phased-in for the 1996—1999 model years and incorporated multi-day hot soak plus test requirements and emission standards, fuel spit back standards, and running loss controls,(4) new onboard refueling vapor recovery requirements which phased in from model years 1998-2006, and (5) the Tier 2/MSAT requirements for 2004-2010 model years which further tightened the hot soak plus standards, addressed resting losses, and brought in to play consideration of ethanol-blend fuels. New provisions for “zero evaporative” vehicles are now in place in California as part of the PZEV allowance in the ZEV program and have recently been included in the evaporative emission control standards for California’s LEV III program. EPA expects to propose “zero evaporative” emission standards as parts of its Tier 3 rule to include a more stringent multi-day hot soak plus diurnal emission standard and a canister bleed emission standard and test procedure.

Computerized emission control system monitoring became necessary when the California Air Resources Board (ARB) mandated that all vehicles sold in that state in 1988 have an onboard diagnostic system to detect problems in the performance of emission control systems. These early systems were known as On Board Diagnostics (OBD) monitored the oxygen sensor, the fuel delivery system, engine control module, and the exhaust gas recirculation (EGR) system. If a problem is detected with a vehicle or engine system that is monitored by OBD, the OBD monitor illuminates a Check Engine or Malfunction Indicator Light (MIL) and stores a diagnostic trouble code in memory which can be later retrieved. While some of these codes and problems may be noticed through vehicle drivability changes or other discernible problems with the vehicle performance, some are not. Thus, the MIL provides the driver notice of a need to check for a problem in the operation or performance of a given vehicle/engine system based on the diagnostic trouble code (DTC) set in the OBD system. Vehicle-based computers also created the opportunity for more sophisticated and precise control of canister purge and management of the effects of canister purge on exhaust emission rates.

These controls were further refined with the advent of OBDII which was required beginning in 1996 with full compliance by 1999. OBDII requirements enhanced the requirements of the original OBD systems and added specific requirements related to detecting problems in the fuel /evaporative control system. Current OBD systems are required to monitor for vapor leaks of various diameters within the fuel /evaporative control system and to check for proper operation of the purge system, and other general malfunctions related to items such as pressure sensors. It is clear that OBD and the use of the onboard computer control system has greatly increased the ability of vehicle evaporative and refueling control systems to function more precisely and effectively and to monitor for problems in performance.

III. Reasons for Creation of an Evaporative Emissions Leak Test

At certification current evaporative and refueling emission standards provide reductions in excess of 95 percent over uncontrolled levels when evaluated over the specified test procedures. While programs such as OBD, extended useful life requirements, and in-use verification programs (IUVP) testing have improved the overall in-use performance of these systems, full life durability and performance in off cycle situations remain important objectives.

Even with the upgrades in technology and test procedures over the past years, it was possible for a vehicle with a small leak in the fuel/evaporative control system to meet the hot soak plus diurnal emission standards. This is because leaks are not expected in certification vehicles and more generally because the test procedures and standards were not as rigorous and did not require control under all of the various in-use conditions which affect evaporative emissions . Some leak emissions could be accommodated and the vehicle would still pass the standard. The leak detection requirements of the OBDII regulations have helped to focus more attention on preventing leaks over the vehicle life. However, from an in-use performance perspective OBD alone is not sufficient for at several reasons. First, OBD systems do not operate under all conditions and do not require that the owner/operator seek a repair if a MIL is indicated. While repairs are far more likely areas with inspection /maintenance (I/M) programs, repairs are not always made and if so they may well wait until the I/M check is due. Second, is the issue of OBD system readiness. There are operating circumstances when an OBD system is not required to monitor the evaporative system. These are commonly termed global disables and deficiencies. For example, global disables include specifications on outside air temperature, elevation (i.e., barometric pressure), and tank fuel volume. Deficiencies include manufacturer specific exceptions provided on a case-by-case basis when the system cannot meet the OBD monitoring requirements either due to an element of fuel/evaporative system design or if there is some operating condition in which the OBD leak detection methodology does not operates reliably in the sense of not giving false fails or false passes. If the vehicle is operating in one of these “disable” or “deficiency” conditions the OBD system will not run and not detect a leak. Third, OBD systems are not required to detect leaks of less than 0.020”. While the prevalence of these very small leaks is not known, it is reasonable to project that they are at least as prevalent as larger leaks. Limited data indicates that the leak emission rate for vehicles with leaks less than a 0.020” diameter orifice is not significantly less than at 0.020”. Thus, they are potentially significant.

Tier 3 evaporative emission standards are intended to allow for essentially zero fuel vapor emissions over the vehicle useful life. Full life Tier 3 evaporative emission standards coupled with upgraded OBD will help to encourage focus on designs and technology which will improve in-use durability. However, a vehicle with a vapor leak in the fuel evaporative emission system will emit VOCs at a greater rate than anticipated from the “zero evaporative” technology on which the proposed Tier 3 evaporative emission standard is based. To help insure that the reductions envisioned by proposed Tier 3 evaporative emission standards are achieved in-use, EPA is considering an evaporative emissions leak test procedure and standard. The leak emission standard would help to ensure added focus on efforts to improve in-use durability by reducing the diameter and prevalence of leaks.

The remainder of this memorandum covers the following areas. Section IV, which follows next, discusses current leak measurement methods and work done by EPA. Following this is a presentation on the basics of the recommended test procedure, (section V), a validation of the recommended test procedure by testing on some more unusual fuel/evaporative system configurations (section VI), and finally an assessment of the leak test procedure results to several key pre-conditioning variables (section VII).

IV. Measurement Methods

At present, at least two different methods exist for determining evaporative system leaks. The first and more commonly used method is via positive pressure and flow measurement of the system. In this instance, the evaporative system is pressurized with a gas (normally inert nitrogen) to a set and measured pressure. In-line with the test apparatus is a flow meter designed to measure the flow of the test gas being introduced to the evaporative system. Once the system is pressurized to a certain level, the resulting gas flow is measured and compared to that at known conditions and leak sizes. In this manner, any resultant leaks on the vehicle's evaporative system are determined.

The second manner in which leaks are measured and quantified is through a process of measured vacuum decay. In this method, a certain amount of pressure or vacuum is placed on the evaporative system and then monitored as to how long the evaporative system takes to release any such pressure or vacuum. By comparing this rate to that of known decay rates for an identical system, any such leak present in the test system can be quantified.

a. Pressure and Flow Measurement Systems

The most common devices for finding evaporative leaks are based on the pressure and flow measurement basis. There are many versions on the market today with some being used in individual states' I/M programs. Most of these devices will use an external source of inert test gas so as to mitigate the combustion hazard of mixing oxygen with flammable hydrocarbon vapors.

i. Current Production Versions

Two examples of current production leak testers are shown in Figures 6 and 7. They are the EELD (Evaporative Emissions Leak Detector) 500 tester produced by Snap On and the Delphi 2010 produced by Delphi. Both devices operate on the same principle of flow and pressure measurement into the test vehicle.

Figure 1 – Snap On EELD 500 Tester

Figure 2 – Delphi 2010 Evaporative Tester

The Snap On unit has the capability to also introduce smoke into the test vehicle's evaporative system in order to determine not only the resultant leak size but also its location. The Delphi unit also has an optional smoke generation feature. Both machines are similar in that they also provide for individual calibration of the units. The EELD performs a calibration check each time the unit is switched on, while the Delphi unit comes with a test tank and calibrated orifices to perform a field calibration of the unit.

Both devices are portable with onboard rechargeable batteries or 110V power and both devices pressurize the evaporative system with up to 18" of water pressure.

The EELD unit was extensively tested by NVFEL staff over the course of several months as well as compared to the EPA Test Console created using laboratory grade equipment also designed to measure leaks. While we used this tool in our evaluation program and in developing the test procedure, manufacturers can use any tool or other method which meets the requirements of the regulations.

Several tests were conducted so as to ascertain the EELD's performance. These test units were purchased by NVFEL for testing through normal distribution channels. All measurements were obtained using a series of stainless or brass orifices obtained from O'Keefe Controls. The orifices tested ranged in sizes under 0.010 to over 0.050. Figure 8 shows the relative performance between two different EELD units, serial #'s SA 3890 and SA 3888, respectively. In addition # SA 3890 was also tested in the same manner on a different day to determine any day to day variability with the units. Upon analysis of the results, it was noticed that both SA 3890 and SA 3888 units underestimated the size of the resultant evaporative leak on the order of 0.003-0.004" as compared to the orifices obtained from O'Keefe Controls. Discussion with the parent company Star Envirotech, which produces the unit for Snap On, resulted in the procurement on a new prototype test device which did not include the smoke feature. The performance of this new version is indicated by the "New Board" data on the graph in Figure 3. Its performance was greatly improved versus the production versions. Upon further testing it was realized that the flowing of smoke through the test orifice displaced a certain volume of measured test gas which caused the units to indicate a leak size less than actual.

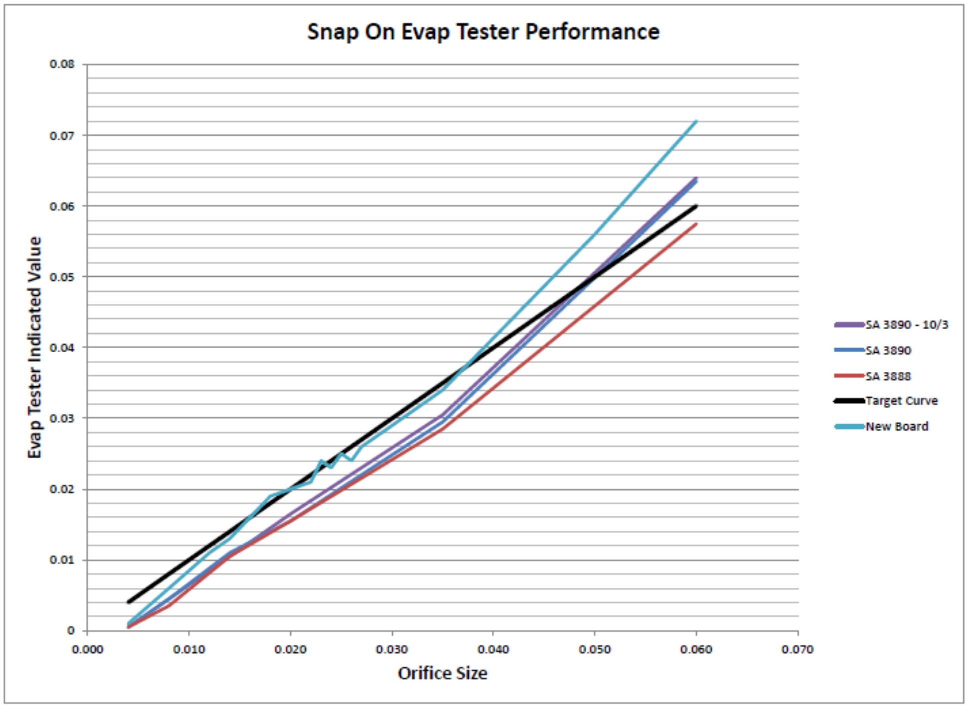


Figure 3 – Production EELD Samples with Smoke vs Non Smoke Version

As seen in Figure 4, the EELD without the smoke feature was also compared directly to the results obtained via the NVFEL Test Console.

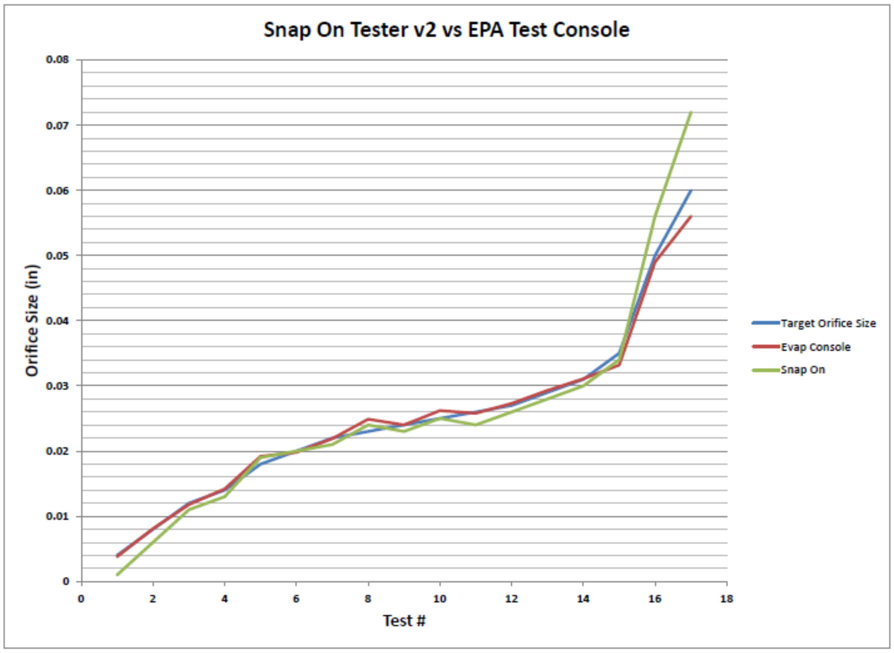
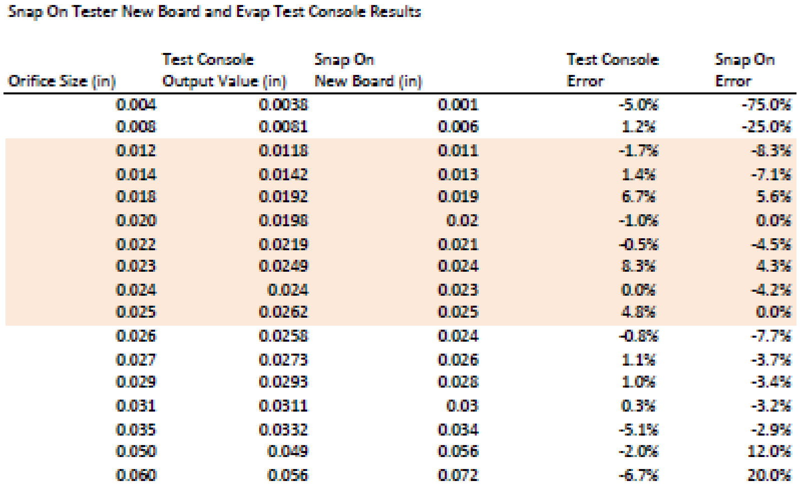


Figure 4 – Comparison of EELD Non Smoke Board vs Test Console

In all instances, the EELD version without the smoke compared favorably to the Test Console. Some variation was seen at the extreme ends of the orifice sizes, primarily under 0.010” and over 0.045”. Since leaks at these ranges were not of concern for the ongoing test program, the EELD was used for validation of the test procedure due to its ease of use and fast reporting of test results. The raw data from the testing is presented below in Figure 5. It is important to note that in the range of interest 0.010 - 0.030, that both the Test Console and the EELD displayed similar errors in the calculation of the test orifice size. This could possibly be due to slightly inconsistent sizing in the test orifices themselves leading to even better unit performance once these sizing errors are taken into account.


Snap On Tester New Board and Evap Test Console Results

Orifice Size (in)	Test Console Output Value (in)	Snap On New Board (in)	Test Console Error	Snap On Error
0.004	0.0038	0.001	-5.0%	-75.0%
0.008	0.0081	0.006	1.2%	-25.0%
0.012	0.0118	0.011	-1.7%	-8.3%
0.014	0.0142	0.013	1.4%	-7.1%
0.018	0.0192	0.019	6.7%	5.6%
0.020	0.0198	0.02	-1.0%	0.0%
0.022	0.0219	0.021	-0.5%	-4.5%
0.023	0.0249	0.024	8.3%	4.3%
0.024	0.024	0.023	0.0%	-4.2%
0.025	0.0262	0.025	4.8%	0.0%
0.026	0.0258	0.024	-0.8%	-7.7%
0.027	0.0273	0.026	1.1%	-3.7%
0.029	0.0293	0.028	1.0%	-3.4%
0.031	0.0311	0.03	0.3%	-3.2%
0.035	0.0332	0.034	-5.1%	-2.9%
0.050	0.049	0.056	-2.0%	12.0%
0.060	0.056	0.072	-6.7%	20.0%

Figure 5 – Data Obtained from Comparison of Test Console and EELD

ii. NVFEL Constructed Device

The EPA constructed test device is also based on the principle of flow and pressure measurement. The test device (Test Console) was built using a Honeywell FP200 pressure transducer calibrated in the range of 0-2.5 psi as well as Teledyne Hastings HFM-300 flow meter s calibrated in ranges of 0-2 slpm and 0-10 slpm. Figure 6 depicts the flow layout and construction of the test console.

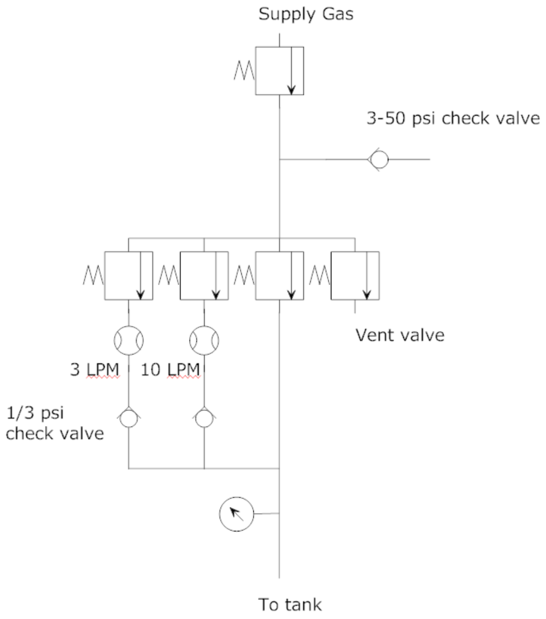


Figure 6 – NVFEL Test Console Flow Diagram

The equation presented in the test procedure (see below) was developed through NVFEL testing. It allows the calculation of an effective orifice leak diameter in inches based on the type of test gas being used, the temperature of the test gas, as well as the measured pressure and flow of the test gas through the Test Console. Figure 5 shows the correlation between the test console equation constants and empirical data obtained from a wide range of O’Keefe orifices. In all measurements, error was less than 3 percent from actual to measured values.

The overall equation as presented in the test procedure was then implemented in the control software for the Test Console. Flow and pressure values were recorded by flowing N_2 gas through the test console and test orifice. A variety of orifice sizes were tested ranging from 0.008” to 0.031”. The pressure was varied from 0.25 to 1 psi and the corresponding flow recorded at each pressure point. The orifice diameter was calculated via software using the supplied equation and plotted in Figure 7.

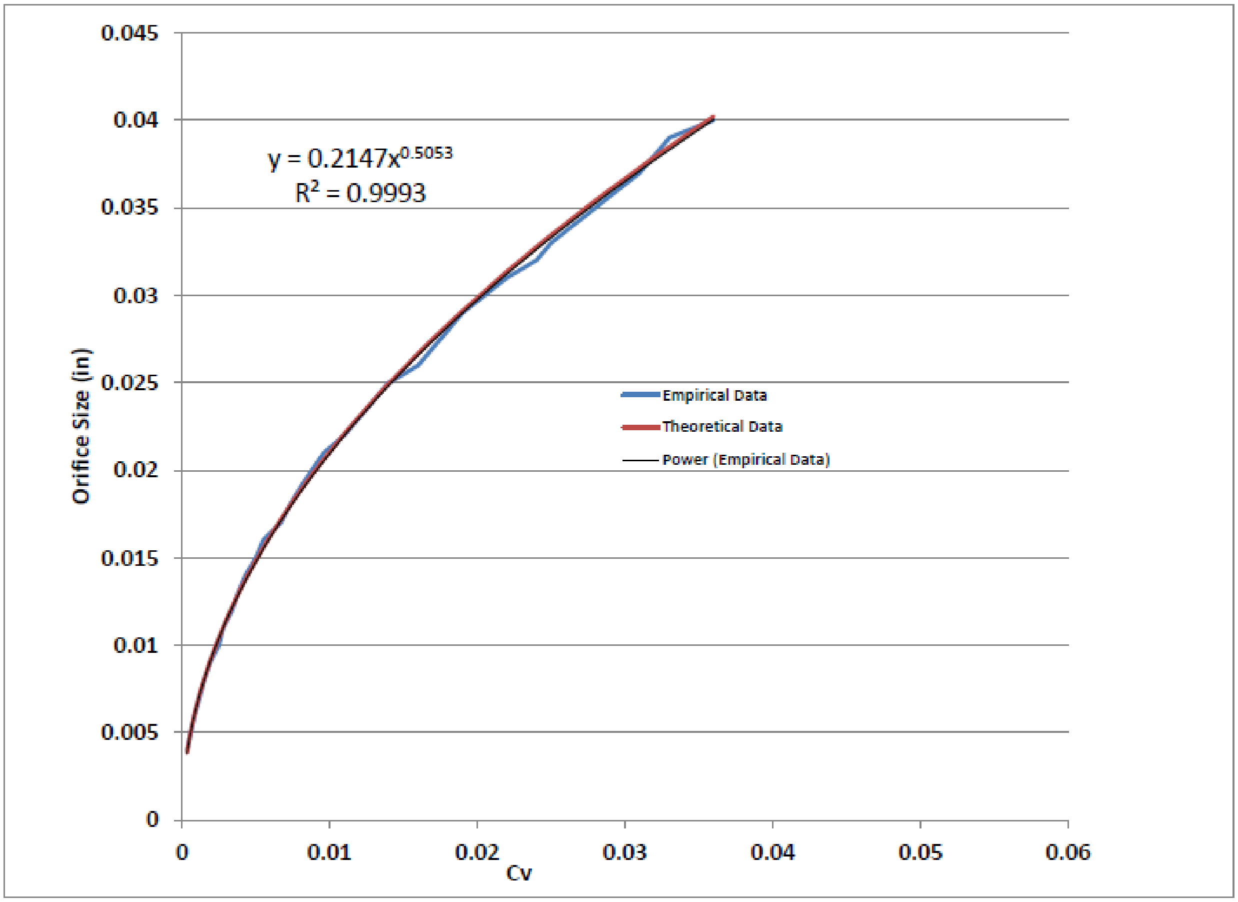


Figure 7 – Validation of Test Console Equation Constants

The actual orifice size is modeled as a straight line and is indicated as the orifice size - TGT on the plot legend from Figure 8. For all orifice sizes tested, the equation deviated from the actual value by less than 0.001" in actual reading. Good correlation was seen throughout the pressure ranges tested.

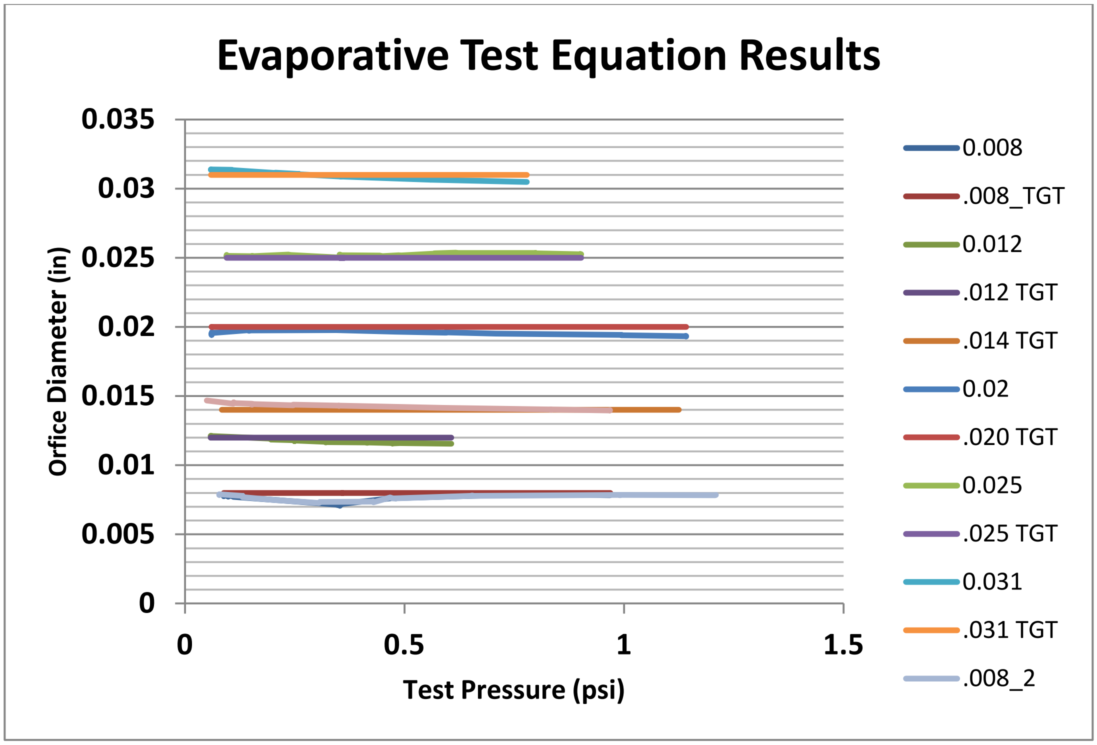


Figure 8 – Validation of Supplied Test Procedure Equation

b. Vacuum or Pressure Decay Measurement Systems

Most commonly available evaporative test devices operate on the principle of pressure and flow measurement to find evaporative system leaks. At the time of the report, initial conversations were underway with Mahle Test Systems regarding their new tester for evaporative systems that operated on the principle of drawing a fixed vacuum on the evaporative system and measuring the decay over a short period of time. Currently such a system is being used in several OEM assembly plants to find leaks prior to the vehicles being fueled. According to Mahle, proprietary algorithms allow leak detection down to 0.010" and smaller can be found on less than 0.5 psig of vacuum. Typical test times are on the order of 10-30 seconds. No vacuum or pressure decay systems were available for evaluation.

V. Recommended Test Procedure

Based on our developmental work with the EPA NVFEL Console and the Snap-On EELD 500 (no smoke) meter, EPA developed a draft recommended test procedure. The proposed test procedure for fuel/evaporative system leak testing provided in Code of Federal Regulation format is as follows. It does not require the use of any specific instrument.

§86.167-18 Leak test procedure.

(a) Scope. Verify that there are no significant leaks in your fuel storage system using the leak test described in this section. Perform this check as required in the standard-setting part.

(b) Measurement principles. A leak may be detected by measuring pressure, temperature, and flow to calculate an equivalent orifice diameter for the system. Use good engineering judgment to develop and implement leak test equipment. Your leak test equipment must meet the following requirements:

(1) Pressure, temperature, and flow sensors must be calibrated with NIST-traceable standards.

(2) Correct flow measurements to standard temperature and pressure of 20 °C and 101.3 kPa.

(3) Leak test equipment must have the ability to pressurize fuel storage systems to at least 4.1 kPa and have an internal leak rate of less than 0.20 slpm.

(4) You must be able to attach the test equipment to the vehicle without permanent alteration of the fuel storage or evaporative emission control systems.

(5) The point of attachment to the fuel storage system must allow pressurization to test system integrity of the fuel tank and fuel and vapor lines reaching up to and including the gas cap and the evaporative canister. An example of an effective attachment point is the evaporative emission system test port available on some vehicles.

(c) Leak test procedure. Test a vehicle's fuel storage system for leaks as follows:

(1) Fill the vehicle's fuel tank to 40% capacity.

(2) Soak the vehicle for 6 to 24 hours at a temperature of 20 to 30 °C and maintain this temperature throughout the leak test.

(3) Before performing the test, purge the fuel storage system of any residual pressure, bringing the system into equilibration with the ambient.

(4) Seal the evaporative canister's vent to atmosphere and ensure that the system purge valve is closed.

(5) Attach the leak test equipment to the vehicle.

(6) Pressurize the fuel storage system with nitrogen or another inert gas to at least 2.4 kPa. Use good engineering judgment to avoid over pressurizing the system.

(7) Maintain gas flow through the system for at least three minutes, ensuring that the flow reading is stable for an effective leak diameter of ± 0.002 inches.

(8) Use the following equation, or a different equation you develop based on good engineering judgment, to calculate the effective leak diameter, D_{eff}.

$$D_{\text{eff}} = 0.2153 \cdot \left(\frac{V_{\text{gas}}}{960 \cdot \sqrt{\frac{P_1 - P_2 \ \cdot \ P_1 + P_2}{G \cdot \ T + 459.67}}} \right)^{0.5057}$$

Where:

D_{eff} = Effective leak diameter, rounded to the nearest 0.01 inch.

V_{gas} = Volumetric flow of gas (scfh).

P_1 = Inlet pressure to orifice (psia).

P_2 = Atmospheric pressure (psia).

G = Specific gravity of gas at 14.7 psia and 60°F.

T = Temperature of flowing medium (°F).

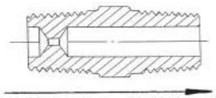
(9) You may perform any number of replicate tests; however, you must perform the same number of tests at the same attachment points for every vehicle from a given model year. The average value of replicate tests is the official result for a given vehicle.

(10) You may use special or alternative test procedures as described in 40 CFR 1065.10(c). For example, a manufacturer may use a vacuum-based instrument or approach if it can demonstrate correlation and meet the requirements of the applicable regulations.

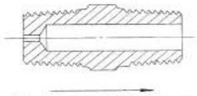
(d) Equipment calibration. Use good engineering judgment to calibrate the leak check device.

For example, you may compare measured and calculated values to a calibration orifice such as that defined as an O’Keefe Controls Co, Type B precision-machined brass or stainless steel orifice having a gas flow path depicted in the following figure:

Figure 1 of §86.167



Orifice diameter .021" or larger



Orifice diameter .020" or smaller

Validation of Test Procedure

There are many minor design and architecture variations, but essentially all vehicle evaporative control systems involve the use of a carbon canister to capture vapors from the gasoline tank and a vent and purge solenoid system for refreshing the storage capacity. Leak detection approaches as part of this system are based on either natural vacuum or an integrated pump and orifice approach. The leak detection instruments described above are commercially available and in use in the auto industry today; there is a high degree of confidence in their capability to detect leaks when applied properly for the intended purpose. This was confirmed during the testing we conducted on a number of different production vehicles in developing this recommended practice. For further validation purposes, we looked at several unique design and test conditions to confirm the utility of the test equipment and test procedure in these applications. These included testing on a Ford F150 with the “No Cap” style fuel fill, a Chrysler 300 equipped with both an ESIM valve and a “No Cap” style fuel fill, a Ford E350 cargo van with a fuel tank larger than 20 gallons and a Honda Accord. For all the vehicles tested, the following EELD tester procedure was used.

Evaporative Emissions EELD Tester Attachment Procedure

1. Connect EELD Tester to Test Vehicle
    a. Locate purge solenoid (typically located under hood nearby intake manifold or throttle body)
    b. Remove vapor line on fuel tank side of purge solenoid (various clips can be used)
    c. Insert hose adapter and modify as necessary to ensure a proper seal to the vapor line
2. Attach Scan Tool to OBD port
    a. Verify engine size and details from under hood emissions label
    b. Follow options and screens necessary to allow tool to control evaporative vent solenoid
    c. Arrive at vent solenoid command screen (typically under special tests or emissions test sub-menus)
3. Power up EELD Tester
    a. Attach N2 gas to tester (set to 85-100 psi inlet)
    b. Select menu for proper gas while tester is booting (must do this at the right time or tester will default to AIR for test medium) Menu selection is done by pressing display select on the side of the tester until N2 is displayed. Tester can accommodate N_2, CO_2 and air for test gas.
4. Conduct Test
    a. Command tester to flow nitrogen to test vehicle.
    b. Close vent solenoid on test vehicle using the scan tool

c. Monitor flow and pressure in tank and read resultant orifice leak size on tester screen. (Test value will start off high and stabilize to a final reading as fuel tank is pressurized. Test runs for 5 minutes and then tester will turn off. To continue flowing nitrogen simply command the EELD to test again)

a. Ford "No Cap" System

The Ford vehicle tested was a 2011 Ford F150 pickup VIN# 1FTFX1CT5BFA93342. The vehicle had 252 miles on it at the time of testing. The fuel tank was drained and filled to 40 percent with certification fuel. The vent solenoid was commanded by a Genisys OTC scan tool. The system was pressurized by disconnecting the evaporative line from the purge solenoid and pressurizing the system via this interface point. All testing was done with the updated version of the EELD500 which did not include the provision for smoke. The inlet pressure for nitrogen test gas for the EELD was set to 90 psi. Readings were taken approximately four minutes after the start of each test. Seven test repeats were run with the tester disconnected and the system allowed to vent for several minutes between tests.

This vehicle was chosen in order to asses any differences in testing necessary to accommodate Ford Motor Company's "No Cap" style of fuel tank system. In all cases, a well sealed system was indicated. The indicated leak value on the EELD was at .000 at four minutes duration for each of the seven tests. It took approximately 3.5 minutes for the tester to pressurize the tank and indicate a .000 reading. The final pressure indicated by the EELD was relatively consistent as well, with readings ranging from 17.3 – 17.6 inches water. No changes to the test procedure were necessary for this application.

b. Chrysler " No Cap" ESIM System

The next configuration tested was a 2012 Chrysler 300 VIN# 2C3CCACG2CH266160 equipped with Chrysler's version of the "No Cap" fuel filler system as well as the ESIM style of vent valve. The vehicle had 1942 miles on it at time of testing. The updated EELD unit (no smoke) was used to test this vehicle. The fuel tank was drained and filled identically as the F150 previously tested. Because of the year of the vehicle, available scan tool equipment was unable to communicate with the vehicle's ECM. In all testing, the vent line was disconnected from the ESIM valve. The evaporative system was pressurized via the line going to the under hood purge solenoid. The ESIM valve and charcoal canister were located behind the right hand rear wheel well liner.

This vehicle was chosen in order to asses any differences in testing necessary to accommodate Chrysler's "No Cap" style of fuel tank system as well as any special procedures needed in testing a system which did not have a traditional solenoid controlled vent valve. In all cases, a well sealed system was indicated. The indicated leak value on the EELD was at .000 at four minutes duration for each of the seven tests. It took approximately 2.0 minutes for the tester to pressurize the tank and indicate a .000 reading. The final pressure indicated by the EELD was relatively consistent as well with readings ranging from 17.4 to 17.5 inches water. No changes to the test procedure were necessary for the application with the exception of the understanding that sealing the vent line from the ESIM valve acted in a similar fashion as commanding the vent valve closed on a traditional system. Figure 9 below shows the "No Cap" style of filler system. The Ford system is similar with the exception that it does not have the sealing cover for the filler inlet pipe.

Figure 9 – Chrysler 300 "No Cap" Fuel Filler Inlet

d. Fuel Tank Systems Greater Than 20 Gallons

The vehicle tested was a 2012 Ford E350 Passenger Van VIN# 1FBSS3BL3CDA75451. The vehicle had 3452 miles on it at the time of testing. The fuel tank was drained and filled to 40 percent certification test fuel. The capacity of the fuel tank was 40 gallons as indicated in the owner's manual and via measurement of the external tank dimensions. The vent solenoid was commanded by a Genisys OTC scan tool. The system was pressurized by disconnecting the evaporative line from the purge solenoid and pressurizing the system via this interface point. Figure 10 shows the EELD attachment point. All testing was done with the updated version of the EELD500 which did not include the provision for smoke. The inlet pressure for nitrogen test gas for the EELD was set to 90 psi. Readings were taken approximately four and a half minutes after the start of each test. Seven test repeats were run with the tester disconnected and the system allowed to vent for several minutes between tests.

Figure 10 – Ford E350 EELD Attachment Point

This vehicle was chosen in order to asses any differences in testing necessary to accommodate tank sizes larger than 20 gallons. The indicated leak value on the EELD ranged from 0.001 to 0.005 for each of the seven test repeats for this vehicle. There was indication that the default five minute test time on the EELD was not sufficient for this vehicle to fully pressurize such a large tank volume leading to the variation in "found" leak values. In addition, it was seen that the variation in indicated leak values was affected by the depressurize time between tests. In prior testing, two minutes was allocated between tests to allow the evaporative system and fuel tank to equalize to atmospheric pressure with an open vent valve and fuel cap. With the larger tank system of 40 gallons two minutes was seen as not enough depressurization time. If the subsequent test was started within two minutes, the ramp time down to the indicated leak value was faster than that measured between tests with more than a two minute wait time. Figure 11 shows this effect. Based on this testing , it is recommended, when testing large tank sizes, to wait at least 5 minutes between test intervals if repeated testing is necessary as well as to test longer than 5 minutes (in the case of the EELD) in order to give larger systems the appropriate pressurization time needed to achieve representative results. It should be noted that even though the larger system took longer to fill and achieve a final reading, indicated leak values were within .004" of each other after three minutes of testing.

Test Time (min)	Indicated Leak Value w/ 2 Min Wait	Indicated Leak Value w/ 5 Min Wait
1	0.014	0.021
2	0.006	0.01
3	0.002	0.006
4	0.001	0.004
5	0	0.002

Figure 11 – EELD Indicated Values on 40 Gallon Test Tank

e. Honda Produced Fuel Systems

The Honda vehicle tested was a 2007 Accord sedan VIN# 1HGCM56727A141399. The vehicle had 123821 miles on it at the time of testing. The fuel tank was drained and filled to 40 percent with certification test fuel. The vent solenoid was commanded by a Vectronix Mastertech scan tool. The system was pressurized by disconnecting the evaporative line from the purge solenoid and pressurizing the system via this interface point. All testing was done with the updated version of the EELD500 which did not include the provision for smoke. The inlet pressure for nitrogen test gas for the EELD was set to 95 psi. Readings were taken approximately four minutes after the start of each test. Seven test repeats were run with the tester disconnected and the system allowed to vent for several minutes between tests.

This vehicle was chosen based on concerns initially expressed by Honda regarding the interface of the leak detection test methodology with their OBD leak detection scheme. We assessed a Honda vehicle equipped with a Honda evaporative control system using a solenoid controlled vent and purge valve. In all cases, a well sealed system was indicated. The indicated leak value on the EELD was at .000 at four minutes duration for each of the seven tests. It took approximately 3 minutes for the tester to pressurize the tank and indicate a .000 reading. The final pressure indicated by the EELD was relatively consistent as well with readings ranging from 17.5 – 17.7 inches water. No changes to the test procedure were necessary for this application.

VI. Tested Vehicle Variables for Preconditioning

Current preconditioning required prior to conducting the evaporative test is as follows:

1. 6-24 our soak at 20-30 °C prior and during testing
2. 40 percent fuel fill capacity using Tier III certification fuel (9 RVP E15)
3. Purge of any residual fuel tank pressure prior to testing

The cold soak and fuel tank fill level is consistent with the preconditioning needed for the FTP test so as to minimize any additional testing burden associated with running the leak test. Prior to setting these preconditioning requirements, several factors that were thought to possibly influence the leak test results were investigated. These factors were the fuel fill level, the fuel tank temperature, test vehicle inclination and the leak location relative to the insertion point of the leak tester. These factors were investigated by using a first generation Snap On EELD500 tester. The EELD had the provision to introduce smoke into the evaporative system but was not filled with the smoke solution for this testing. The vehicle used for all of the preconditioning investigation was a 2006 Chevrolet Silverado, VIN# 1GCEK19B6GZ154114. This vehicle had approximately 110,056 miles on it and the vent valve was controlled via a GM Tech 2 service tool. An evaporative test port was located under the hood and was used as an attachment point for the EELD tester.

a. Fuel Fill Level

To investigate the influence of fuel fill level on the leak test, the test vehicle was drained and filled to various levels of certification test fuel. The levels investigated were 10, 40, 80, and 100 percent tank capacity. Each test was performed at a temperature of 25°C. At each fuel level, seven repeat tests were performed with the EELD tester. After each reading the tester was removed and the system was allowed to depressurize for several minutes. A simulated leak was created by tying in a 0.020 stainless O'Keefe orifice at the purge valve. The results are presented below in Figure 12. The error bars represent the inherent repeatability of the unit. It was felt that the EELD was accurate to a +/- .001" reading while operating under the testing conditions. While the 10 percent fill levels had the highest indicated leak reading, on average these were .001" or less than what was indicated at the 40 percent fill levels. This difference was also within the accuracy of the EELD unit. So based on the collected data, it was determined that the fuel fill level had a minimal, if any, effect on the test reading.

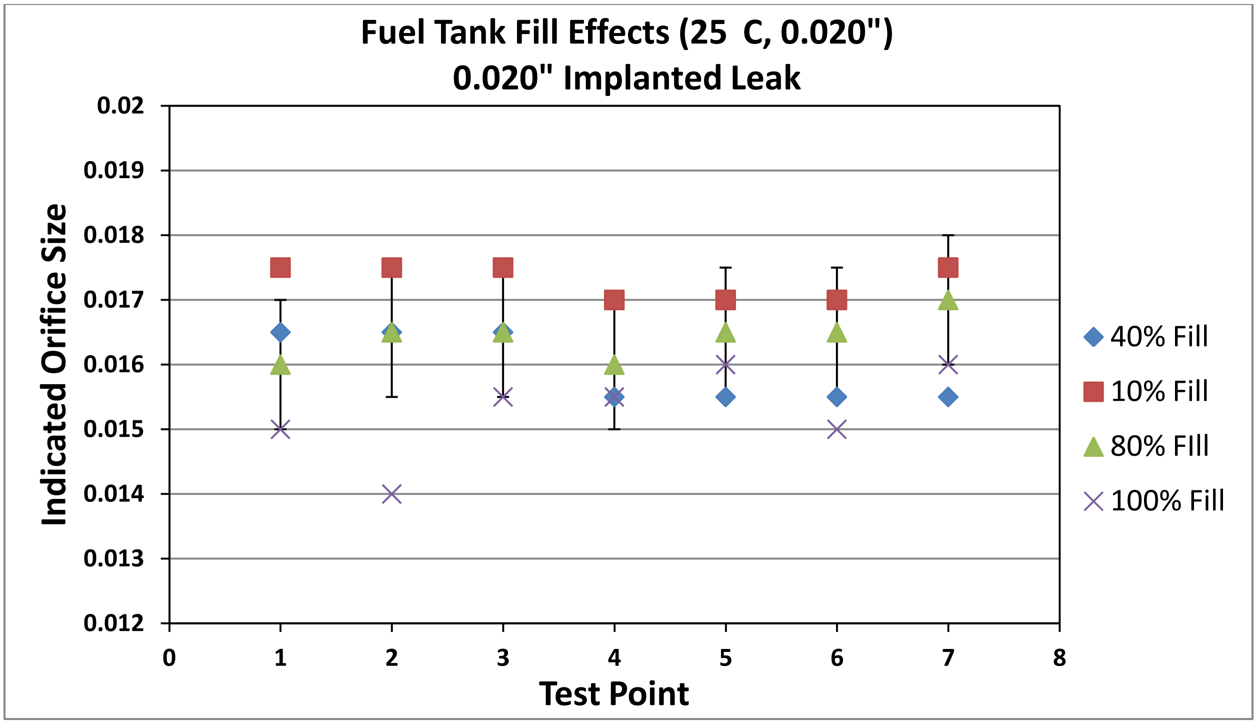


Figure 12 – EELD Readings for Several Fuel Fill Levels

b. Fuel Temperature

To investigate any fuel temperature effects on the leak test, the same test vehicle was used and filled to a 40 percent fill level with certification test fuel. The temperature of the vehicle was varied by subjecting it and the fuel to an overnight soak at the prescribed temperature in a VT SHED. The three temperatures tested were 25, 30, and 35 °C. Data obtained from the testing is presented in Figure 13. As can be seen, most values are within the accuracy of the EELD, however those obtained at 35 °C show a slight trend for higher readings. Since the existing FTP preconditioning was from 20-30 °C, it was determined to stay within that range. In this range, fuel tank temperature did not affect the EELD readings.

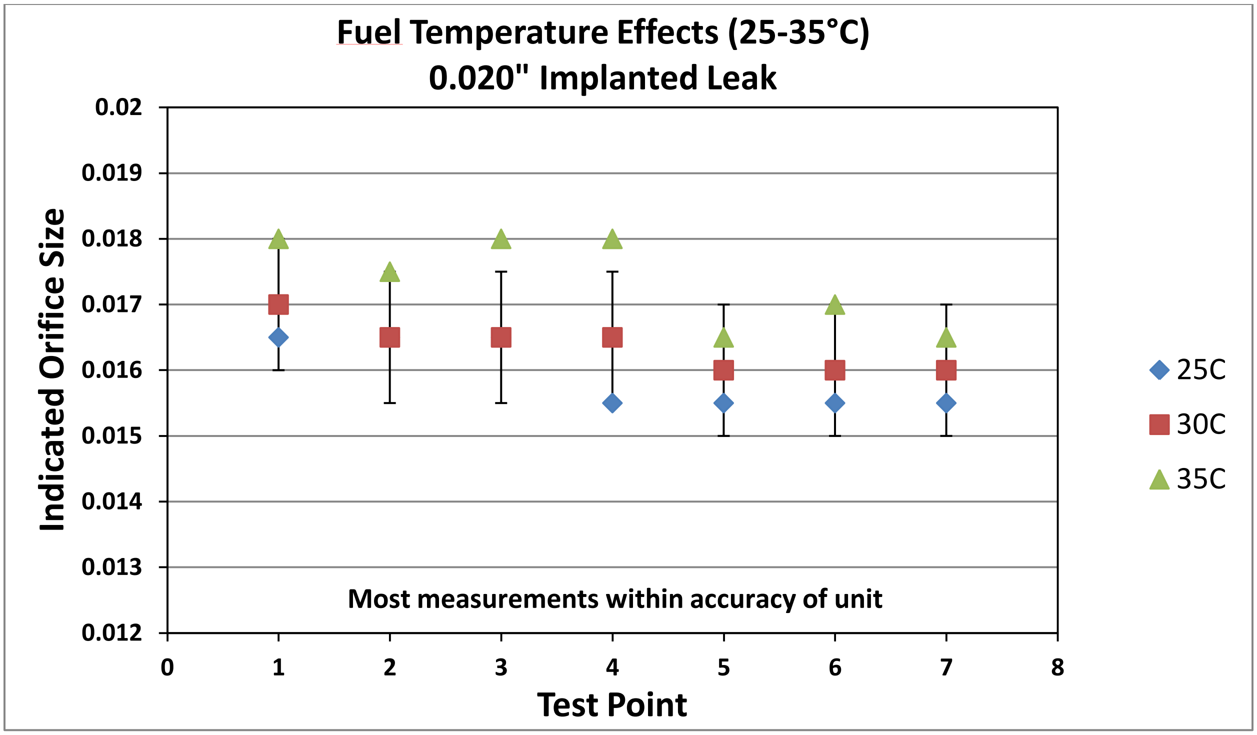


Figure 13 – EELD readings for Various Fuel Temperatures

c. Vehicle and Tank Inclination

Another factor investigated was the inclination of the test vehicle. Again, the same vehicle was used and filled to a 40 percent level with certification test fuel. The test vehicle was then placed on a two post hoist and the appropriate lift arms positioned to cant the vehicle in various directions. The inclinations tested were 5° left and right (roll), as well as 5° front and back (pitch). All readings for the EELD were within the accuracy of the unit for the various vehicle inclinations tested. These results can be seen in Figure 14.

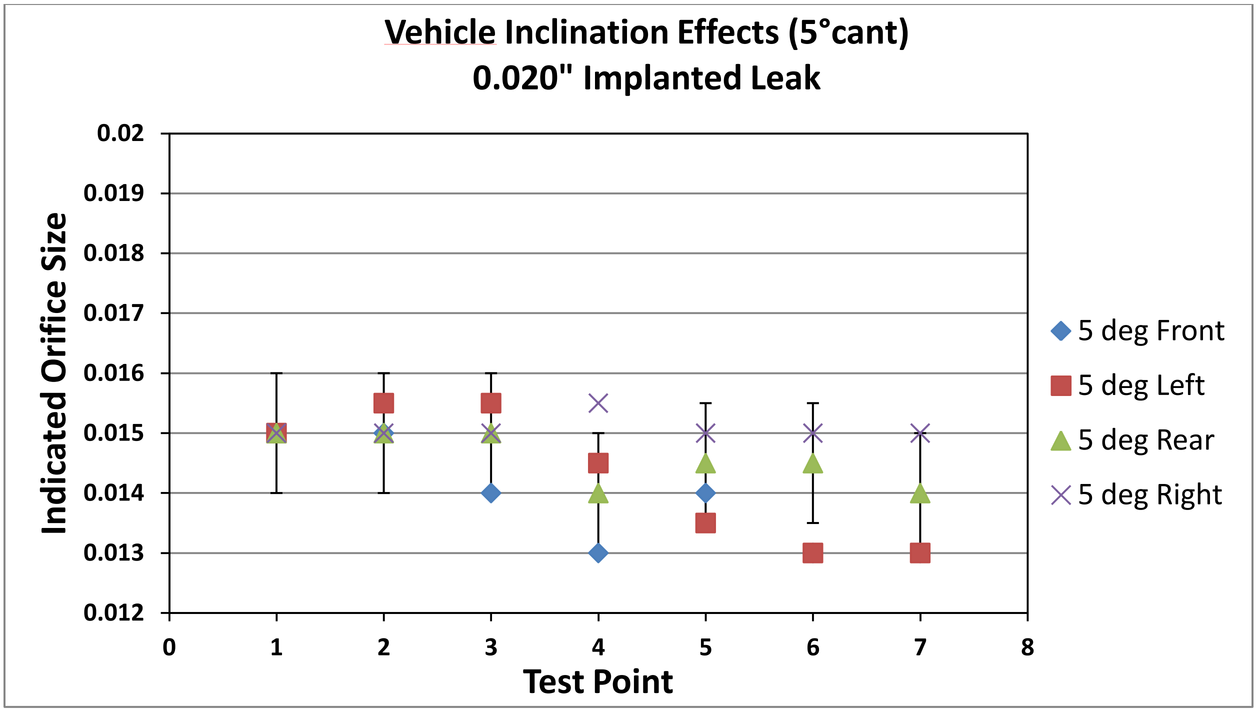


Figure 14 – EELD Readings for Various Vehicle Inclinations

d. Leak Location

The last possible influencing factor tested was the location of the leak relative to the insertion or test point of the EELD. In these tests, the identical test vehicle was used and filled to a 40 percent fuel level with certification test fuel. In all cases, the EELD attachment point remained consistent at the under hood evaporative test port. The location of the leak was varied between the purge valve (near to the test attachment point) and the top of the fuel cap (far from the attachment point). The results are presented in Figure 15. Within these results a definitive trend could be observed. The EELD indicated higher leak values when the orifice was placed near the test attachment point versus those where the leak was placed far away from the attachment point. On average the near leak values were higher than the far leak values by 0.002-0.003”. This was outside of the margin of error of the EELD was considered a definitive test influence.

A plausible explanation for this difference was due to the way the EELD and similar devices compute the leak values. For the EELD and similar test instruments, the effective leak values are calculated via onboard pressure and flow sensors. Normally they are calibrated to provide an accurate reading at the instrument or attachment hose. When the instrument is placed on a test vehicle some pressure drop is always present as long as there is flow through the evaporative system and attaching lines. It is conceivable that the pressure drop present in the evaporative system is greater when the leak location is farther away from the test insertion point. In the data obtained in NVFEL testing, leak locations farther away from the test point were reported as 0.002-0.003” smaller than those that were implanted closer to the test point. Based on this testing it may be advisable to consider multiple test points as part of the requirement to show compliance with the requirements

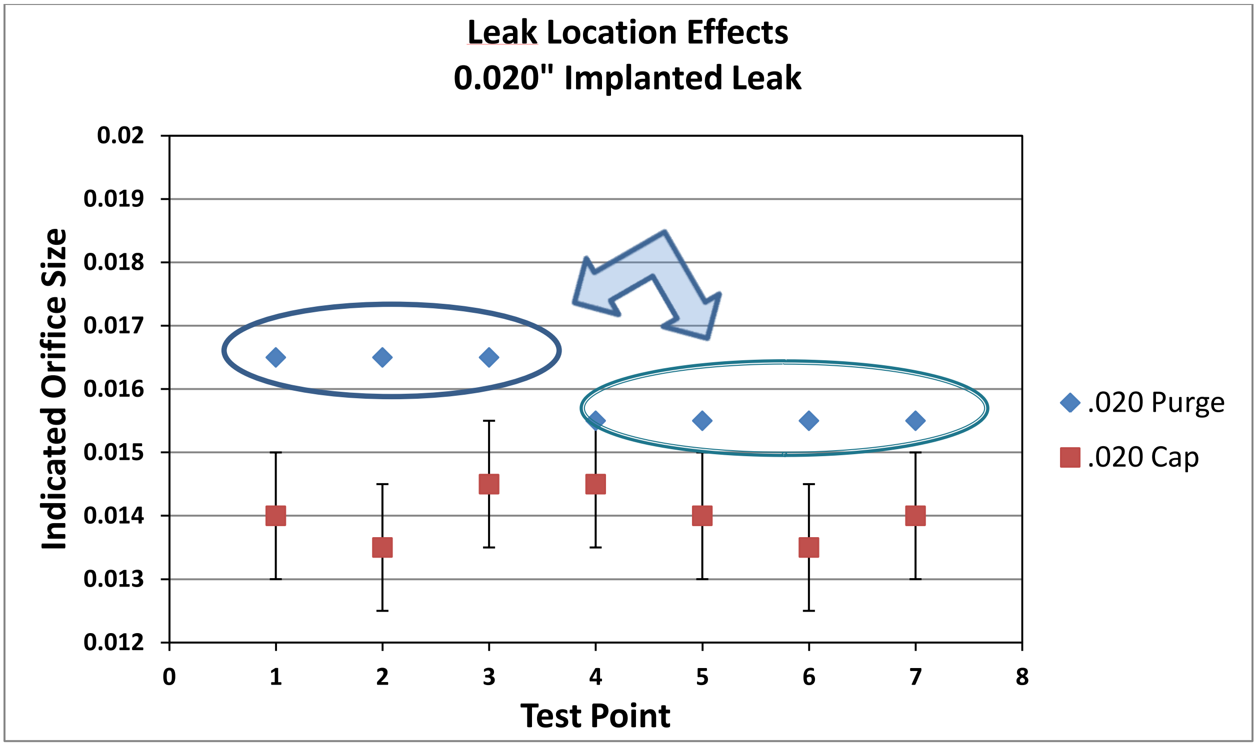


Figure 15 – EELD readings for Various Leak Locations

VII. Conclusions

This report is the summary of several months of work of NVFEL testing and test procedure development. Pressure leak test equipment was both constructed in-house as well as purchased from outside vendors for testing. Both types of equipment produced good results and correlation when tested against known orifice sizes. In addition the in-house construction of evaporative test equipment gave particularly well placed insight on the governing physical properties and equations necessary to accurately predict leak sizes from flow and pressure measurements of an evaporative emissions system.

Several influencing factors affecting the outcome of the leak test were investigated. Within tested limits, the test temperature, vehicle inclination, and fill level all displayed minor influences on the overall test readings obtained. The only influence that was seen among the factors investigated was the leak location, which cannot be controlled in a typical testing fashion. In this case, existing instruments can under predict the actual leak by a few thousandths of an inch.

The test procedure was validated against known vehicle types which represented a difference from the “norm” in evaporative emission system control or construction. In all instances, the test procedure was effective either as is or with minor well understood modifications.

Based on the work so far, the test procedure is seen as robust and applicable to many different types of vehicles and evaporative emission systems. However, alternative test procedures are allowed as per 40 CFR 1065.10(c) for those systems which cannot be tested under the given procedure or if new fuel evaporative control system or OBD leak detection methods are developed which are not compatible with this methodology.

VIII. References

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Chapter 2 Vehicle Program Costs

2.1 Vehicle Technology Costs

Although the proposed increase in standard stringency is substantial for the vehicles affected by this proposed 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. 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 proposed 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 active hydrocarbon adsorbers. 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 proposed standards. These technologies were then combined into technology packages which reflected vehicle design attributes that directly contribute to a vehicle's emissions performance. The attributes considered included 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.

2.1.1 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.[1] We have also considered the results of our own in-house testing.[2] 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 which we are proposing 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. 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 including:

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 NOx to meet the proposed Tier 3 standards. Increasing the catalyst PGM loading results in greater catalyst efficiency. Vehicle manufacturers and suppliers have supplied 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. As our feasibility study in Chapter 1 points out many vehicles are performing much cleaner than the Tier 2 Bin 5 fleet average they are required to meet. As a result we concluded that the incremental costs for PGM loading would be less than the estimates we received. We estimate the costs to be $60, $80, and $100 for an I4, V6 and V8 respectively. All DMC are in 2009 dollars.

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. 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. As a result we have estimated the cost for an I4 gasoline engine to be $20, a V6 at $40, and a V8 at $60. All DMC are in 2009 dollars.

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. Based on CBI submitted by exhaust system suppliers and vehicle manufacturers we estimate that the cost of implementing dual wall exhaust designs are approximately $30 for all engine applications. All DMC are in 2009 dollars.

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. We have estimated that the final direct manufacturing cost for secondary air is $100 for all applications. All DMC are in 2009 dollars.

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 and hydrocarbon adsorbers. 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. We have estimated that 2 additional engineers would be required per vehicle at an annual salary and benefits of $300,000. Assuming they are supporting an annual powertrain volume of 150,000 units, the per vehicle cost is $2. All DMC are in 2010 dollars.

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. 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. We anticipate manufacturers will apply only active systems due limited ability of passive systems to mitigate NMOG. Estimates for active hydrocarbon adsorber systems ranged from $150 to $450. For our cost estimates we concluded that the lower estimate is appropriate. In addition, we expect hydrocarbon adsorbers to be applied in only large displacement V8 powered vehicles. All DMC are in 2009 dollars.

This rulemaking also addresses control of evaporative emissions. We expect also for evaporative emissions that most vehicles will be able to comply with the proposed Tier 3 standards through refinements of current emission control components and systems. Many of these technologies have already seen commercial use, while others are variations on established technologies. For example, manufacturers have designed vehicles to comply with CARB's PZEV evaporative emission standards, which are very similar to the new standards proposed in this rulemaking. We anticipate that manufacturers will use some combination of the following technology upgrades:

Evaporative canisters: 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 proposal will need a canister scrubber. The scrubbers will vary in size, but a typical unit would cost about $10. 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. All DMC are in 2009 dollars.

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. Manufacturers wanting to avoid adding specialized emission control components to control evaporative emissions from the air intake could pursue other approaches. First, it is possible to allow the engine to continue rotating for 2-3 revolutions after engine shutdown to sweep any hydrocarbon vapors from the intake system into or through the combustion chamber. These vapors could be burned in the cylinder, oxidized at the catalyst, or stored until the engine starts again. This may still allow for some residual vapor release, but this should be a very small quantity. Vehicle owners would be unlikely to notice this amount of engine operation after shutdown. Second, to the extent that manufacturers use direct injection, there should be no 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. These alternative approaches would generally not involve any incremental costs. We estimate that 25 percent of vehicles will use the air intake scrubber to address this source of emissions. The intake scrubber would cost approximately $7.50 per vehicle. All DMC are in 2009 dollars.

Fuel tank permeation: 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. We are expecting manufacturers to 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, which we would anticipate for about 30 percent of the fleet. Heavier HDGVs (HHDGVs) usually have one large volume (>25 gallon) fuel tank per vehicle mounted on the frame rail or underbody although in the past there have been dual tank offerings. They are usually metal, but the use of limited offerings of plastics now or in the future cannot be eliminated. If they are metal there is no permeation cost, if they are plastic they will incur incremental permeation emission control costs as discussed above for each tank. We assume the market is 90 percent metal and 90 percent single tank. All DMC are in 2009 dollars.

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 that 40 percent of vehicles will make upgrades, each involving $1.60 of additional cost for materials with greater permeation resistance. All DMC are in 2009 dollars.

Fuel-system architecture: 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. Overall, we estimate that this initiative will involve no net change in costs.

Filler neck: A remaining 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 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. However, we estimate that a technology upgrade costing $5 will be applied to 30 percent of vehicles. An alternative scenario would involve a simpler $2 upgrade to be applied to 75 percent of vehicles. Heavy HDGVs with metal tanks mounted on the outside of the frame rail do not have filler necks and thus would not incur this cost. All DMC are in 2009 dollars.

Purge/vapor generation strategies: Recent and projected engine design changes are increasing the challenge to maintain manifold vacuum for drawing purge air over 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. Adding a heating element to the canister has been shown to decrease the desorption energy for drawing hydrocarbon vapors away from activated carbon. Purge pumps could replace or supplement manifold vacuum as the driving force for drawing air through the evaporative canister. All of these approaches have merit. Another effective solution to this new and increasing challenge may be to install a vapor blocking valve that would allow for pressurized fuel tanks. Before refueling emission controls, it was common for standard, high-density polyethylene fuel tanks to be pressurized up to about 2 psi. Vapor blocking valves could be designed to relieve pressure at any appropriate set point. Pressurized fuel tanks would contain vapors in the fuel tank instead of routing them to the evaporative canister. The hydrocarbon load and the corresponding purge demand would therefore be reduced. The design could be targeted to reduce diurnal vapor loading, which would then reduce purge demands between refueling events. Vapor blocking valves and the corresponding control systems could have widely varying complexity and cost. We believe a relatively simple design would be sufficient to achieve the objective safely and effectively. We estimate that 15 percent of vehicles would employ such canister purge or vapor valve approaches at a cost of about $6 per vehicle.

Vapor leaks: 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 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 fewer than one test group representative 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 $0.25 (2009$) 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 incremental cost of $17 per vehicle in 2009 dollars.

Onboard Refueling Vapor Recovery (ORVR): Current EPA standards require vehicle-based control of refueling emissions for all LDVs and LDTs up to 10,000 lbs GVWR. We are proposing to extend EPA's refueling emission standard to heavy-duty gasoline vehicles (HDGVs) up to 14,000 lbs GVWR starting with the 2018 model year. Today these HDGVs are produced by only two 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.

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 proposing to adopt current CARB OBD certification, verification, and monitoring requirements. As part of our proposal, we are also seeking to include 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 $0.50 (2009$) per vehicle or less. These are reflected in evaporative emission and calibration costs

2.1.2 Indirect Costs

We are using an approach to estimating indirect costs that is consistent with that used in our 2012-2016 Greenhouse Gas (GHG) final rule and our recent 2017-2025 GHG final rule.[3] 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.

2.1.2.1 Cost markups to account for indirect costs

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 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. This methodology was used in the cost estimation for the MYs 2012-2016 GHG final rule. The ICMs were developed in a peer-reviewed report from RTI International and were subsequently discussed in a peer-reviewed journal article.[4] 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 this proposed rulemaking, EPA is using the ICM approach but we have made some changes to both the ICM factors and to the method of applying those factors to arrive at a final cost estimate since publishing the 2012-2016 GHG final rule. Both of these changes make the ICMs used in this analysis consistent with those used in the 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.[5] Because that discussion is meant to present changes made in the time between the 2012-2016 GHG final rule and the 2017-2025 GHG final rule, the full text is not really relevant in the context of this Tier 3 proposal. 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 this Tier 3 proposal.

Table 2-1 shows the ICMs used in this analysis. As noted, these ICMs are consistent with those used in our recent 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 this Tier 3 proposal are 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 this Analysis

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 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 x 1.24). As a result, indirect costs would be reduced from $24 to $20. 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 (since 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 are no longer attributable to the rulemaking effort that imposed them (such as R&D).

As a result, the ICM calculation has become more complex. 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 MY 2015 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). For example, consider a technology with an estimated direct manufacturing cost of $70 in

MY 2015. For this technology, the non-warranty portion of the indirect costs would be $24.01 ($70 x 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 x 0.259). Additionally, the $70 cost in 2015 would become $67.90 in MY 2016 due to learning ($70 x (1-3%)). So, while the warranty portion of the indirect costs would be $3.15 ($70 x 0.045) in 2015, the warranty portion would decrease to $3.06 ($67.90 x 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 MY 2015 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

	Near term		Long term	
Complexity	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

2.1.3 Cost reduction through manufacturer learning

For this proposal, we have not changed our estimates of learning and how learning will impact costs going forward from what was employed in the analysis for the MYs 2012-2016 light-duty vehicle rule. However, we have updated our terminology in an effort to clarify that we consider there to be one learning effect—learning by doing—which results in cost reductions occurring with every doubling of production.[A] This updated terminology is entirely consistent with our approach in the HD GHG rule and the recent 2017-2025 GHG final rule.[6] In the past, we have referred to volume-based and time-based learning. Our 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, our 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. Our new terminology—steep portion of the curve and flat portion of curve—is simply meant to make more 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. These two portions of the volume learning curve are shown in Figure 2-1.

[A] Note that this new terminology was described in the recent heavy-duty GHG final rule (see 76 FR 57320). The learning approach used in this analysis is entirely consistent with that used and described for that analysis.

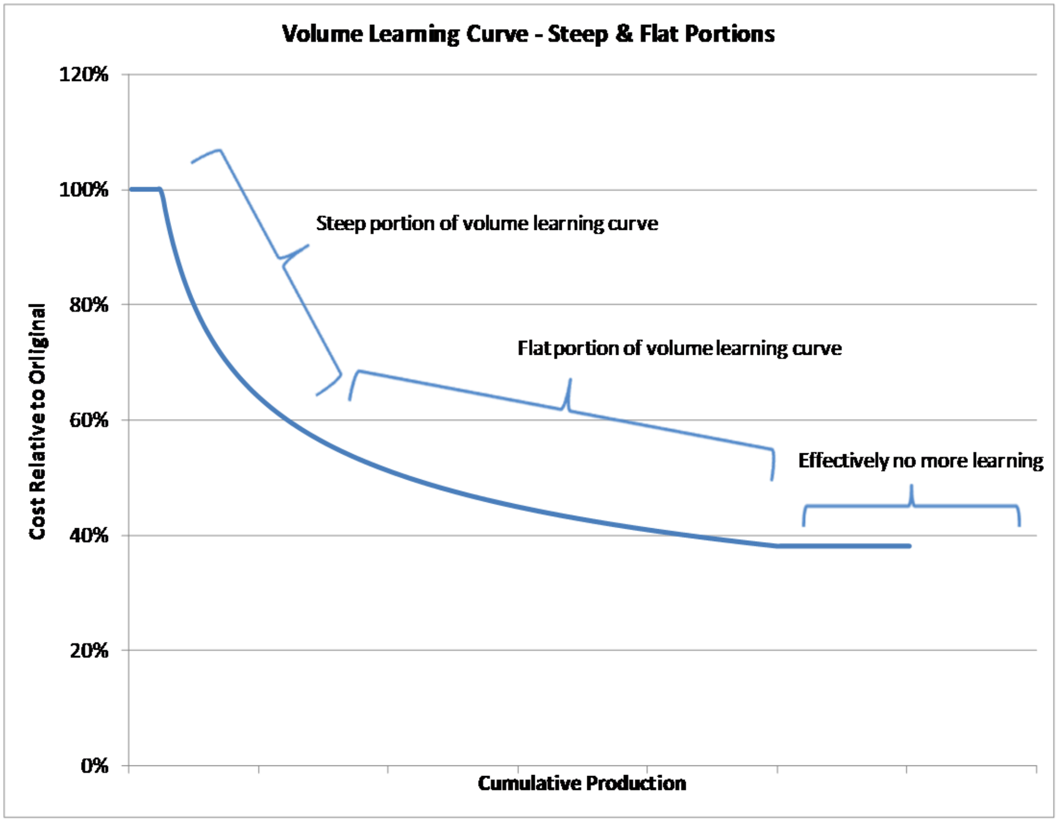

Figure 2-1 Steep and Flat Portions of the Volume Learning Curve

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 MYs 2012-2016 light-duty GHG rule and the more recent heavy-duty GHG rule.[7] Most studies of the effect of experience or learning on production costs appear to assume that cost reductions begin only after some initial volume threshold has been reached, but not all of these studies specify this threshold volume. The rate at which costs decline beyond the initial threshold is usually expressed as the percent reduction in average unit cost that results from each successive doubling of cumulative production volume, sometimes referred to as the learning rate. Many estimates of experience curves do not specify a cumulative production volume beyond which cost reductions would no longer occur, instead depending on the asymptotic behavior of the effect for learning rates below 100 percent to establish a floor on costs.

In past rulemaking analyses, as noted above, 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).[B]

In the MYs 2012-2016 light-duty GHG rule and the recent heavy-duty GHG final rule, the agencies employed an additional learning algorithm to reflect the volume-based learning cost reductions that occur further along on the learning curve. This additional learning algorithm was termed "time-based" learning in the 2012-2016 rule simply as a means of distinguishing this algorithm from the volume-based algorithm mentioned above, although both of the algorithms reflect the volume-based learning curve supported in the literature. As described above, we are now referring to this learning algorithm as the "flat portion" of the learning curve. This way, we maintain the clarity that all learning is, in fact, volume-based learning, and that the level of cost reductions depend only on where on the learning curve a technology's learning progression is. We distinguish the flat portion of the curve from the steep portion of the curve to indicate the level of learning taking place in the years following implementation of the technology (see Table 2-3). We have applied 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 MY 2016 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

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[B] 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.

algorithm applied to each technology and the applicable timeframes are summarized in Table 2-3.

Table 2-3 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/OBD		2015-2025	
Selective Catalytic Reduction Optimization		2015-2025	

2.1.4 Costs Updated to 2010 Dollars

For this analysis, we are estimating all costs in terms of 2010 dollars. We have updated any non-2010 dollar values to 2010 dollars using GDP price deflator as reported by the Bureau of Economic Analysis on June 27, 2011. The factors used to update costs from 2009 dollars are shown below in Table 2-4.

Table 2-4 Factors used to Convert 2009 dollars to 2010 dollars

	2009	2010
Price Index for Gross Domestic Product	109.6	110.7
Factor applied to convert to 2010 dollars	1.010	1.000

Source: Bureau of Economic Analysis, Table 1.1.4. Price Indexes for Gross Domestic Product, downloaded 1/27/2011, last revised 12/22/2010.

2.1.5 Technology 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 summarize our actual technology cost estimates by year for each technology. Below, we present our approach to developing package costs—a package being a group of individual technologies added to a given vehicle—and then our approach to moving from package costs to program costs.

Each of the technology costs we have estimated in this analysis are considered to be applicable to the 2015 MY and, as shown in Table 2-3, we consider each to be on the flat portion of the learning curve going forward. For all but one technology, we have applied a low complexity ICM of 1.24 through 2022 then 1.19 thereafter. For the hydrocarbon adsorber technology, we have applied a medium complexity ICM of 1.39 through 2022 then 1.29 thereafter. Table 2-5 presents the 2015 MY DMC we have estimated for each technology along with the engine type to which that DMC applies.

The evaporative emissions standards and OBD system upgrades that we are proposing for LDVs, LDTs, MDPVs, and complete HDGVs under 14,000 lbs GVWR are feasible with relatively small cost impacts. We estimate the DMC of system improvements to be about $17 per vehicle, for all car classes. This incremental cost reflects the cost of moving to low permeability materials, reduced number of connections, longer contiguous lengths of plumbing, and low-loss connectors for evaporative control and minor costs for OBD upgrades. We have applied the same learning and ICMs to evaporative emission controls as to exhaust controls discussed above.

Table 2-5 Technology Direct Manufacturing Costs for the 2015MY (2010$)

Technology	Gasoline				Diesel			
	I4	V6	V8	HD V8	I4	V6	V8	HD V8
Catalyst Loading	$61	$81	$101	$51				
Optimized Close-coupled Catalyst	$20	$40	$61	$61				
Secondary Air Injection		$101	$101	$101				
Hydrocarbon Adsorber			$152	$152				
Evaporative Emissions Controls/OBD	$17	$17	$17	$17				
Engine Calibration	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	$30	$30	$30	$30	$30	$30	$30	$30
SCR Optimization					$51	$51	$51	$51

Note: Empty cells reflect the fact that the technology is not considered as an enabler for compliance with the proposed standards.

The following tables present our estimated DMC over time. These changing DMC by year reflect the effects of learning as described above. The tables also show the indirect costs (IC) by year. These changing IC by year reflect the effects of learning on warranty costs and the effects of the long term ICM (seen in 2023 for each technology in this analysis). The tables also show the total costs for each technology. Note that these tables do not reflect penetration rates of technologies or phase-in rates of standards. These impacts are reflected in our package level costs discussed below. The tables that follow present costs for, in order: passenger car and light-truck I4 gasoline; passenger car and light-truck V6 gasoline; passenger car and light-truck V8 gasoline; heavy-duty gasoline; passenger car, light-truck and heavy-duty diesel.

Table 2-6 Technology Costs by Year for I4 Gasoline (2010$)

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	DMC	$57	$55	$54	$52	$51	$50	$49	$48	$47
Optimized Close-coupled Catalyst	DMC	$19	$18	$18	$17	$17	$17	$16	$16	$16
Secondary Air Injection	DMC									

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Hydrocarbon Adsorber	DMC									
Evaporative Emissions Controls/OBD Upgrades	DMC	$16	$16	$15	$15	$14	$14	$14	$14	$13
Engine Calibration	DMC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	DMC	$29	$28	$27	$26	$25	$25	$24	$24	$24
Catalyst Loading	IC	$15	$15	$15	$15	$15	$15	$12	$12	$12
Optimized Close-coupled Catalyst	IC	$5	$5	$5	$5	$5	$5	$4	$4	$4
Secondary Air Injection	IC									
Hydrocarbon Adsorber	IC									
Evaporative Emissions Controls/OBD Upgrades	IC	$4	$4	$4	$4	$4	$4	$3	$3	$3
Engine Calibration	IC	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optimized Thermal Management	IC	$7	$7	$7	$7	$7	$7	$6	$6	$6
Catalyst Loading	TC	$72	$70	$69	$67	$66	$65	$61	$60	$59
Optimized Close-coupled Catalyst	TC	$24	$23	$23	$22	$22	$22	$20	$20	$20
Secondary Air Injection	TC									
Hydrocarbon Adsorber	TC									
Evaporative Emissions Controls/OBD Upgrades	TC	$20	$20	$19	$19	$18	$18	$17	$17	$16
Engine Calibration	TC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	TC	$36	$35	$34	$33	$32	$32	$30	$30	$30

Note: Empty cells reflect the fact that the technology is not considered as an enabler for compliance with the proposed standards; $0 values reflect rounding for presentation but are non-zero.

Table 2-7 Technology Costs by Year for V6 Gasoline (2010$)

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	DMC	$76	$74	$72	$69	$68	$67	$65	$64	$63
Optimized Close-coupled Catalyst	DMC	$38	$37	$36	$35	$34	$33	$33	$32	$31
Secondary Air Injection	DMC	$95	$92	$89	$87	$85	$83	$82	$80	$78
Hydrocarbon Adsorber	DMC									
Evaporative Emissions Controls/OBD Upgrades	DMC	$16	$16	$15	$15	$14	$14	$14	$14	$13
Engine Calibration	DMC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	DMC	$29	$28	$27	$26	$25	$25	$24	$24	$24
Catalyst Loading	IC	$19	$19	$19	$19	$19	$19	$15	$15	$15
Optimized Close-coupled Catalyst	IC	$10	$10	$10	$10	$10	$10	$8	$8	$8
Secondary Air Injection	IC	$24	$24	$24	$24	$24	$24	$19	$19	$19
Hydrocarbon Adsorber	IC									
Evaporative Emissions Controls/OBD Upgrades	IC	$4	$4	$4	$4	$4	$4	$3	$3	$3
Engine Calibration	IC	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optimized Thermal	IC	$7	$7	$7	$7	$7	$7	$6	$6	$6

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Management										
Catalyst Loading	TC	$95	$93	$91	$88	$87	$86	$80	$79	$78
Optimized Close-coupled Catalyst	TC	$48	$47	$46	$45	$44	$43	$41	$40	$39
Secondary Air Injection	TC	$119	$116	$113	$111	$109	$107	$101	$99	$97
Hydrocarbon Adsorber	TC									
Evaporative Emissions Controls/OBD Upgrades	TC	$20	$20	$19	$19	$18	$18	$17	$17	$16
Engine Calibration	TC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	TC	$36	$35	$34	$33	$32	$32	$30	$30	$30

Note: Empty cells reflect the fact that the technology is not considered as an enabler for compliance with the proposed standards; $0 values reflect rounding for presentation but are non-zero.

Table 2-8 Technology Costs by Year for V8 Gasoline (2010$)

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	DMC	$95	$92	$89	$87	$85	$83	$82	$80	$78
Optimized Close-coupled Catalyst	DMC	$57	$55	$54	$52	$51	$50	$49	$48	$47
Secondary Air Injection	DMC	$95	$92	$89	$87	$85	$83	$82	$80	$78
Hydrocarbon Adsorber	DMC	$143	$138	$134	$130	$127	$125	$122	$120	$118
Evaporative Emissions Controls/OBD Upgrades	DMC	$16	$16	$15	$15	$14	$14	$14	$14	$13
Engine Calibration	DMC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	DMC	$29	$28	$27	$26	$25	$25	$24	$24	$24
Catalyst Loading	IC	$24	$24	$24	$24	$24	$24	$19	$19	$19
Optimized Close-coupled Catalyst	IC	$15	$15	$15	$15	$15	$15	$12	$12	$12
Secondary Air Injection	IC	$24	$24	$24	$24	$24	$24	$19	$19	$19
Hydrocarbon Adsorber	IC	$58	$58	$58	$58	$58	$58	$43	$43	$43
Evaporative Emissions Controls/OBD Upgrades	IC	$4	$4	$4	$4	$4	$4	$3	$3	$3
Engine Calibration	IC	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optimized Thermal Management	IC	$7	$7	$7	$7	$7	$7	$6	$6	$6
Catalyst Loading	TC	$119	$116	$113	$111	$109	$107	$101	$99	$97
Optimized Close-coupled Catalyst	TC	$72	$70	$69	$67	$66	$65	$61	$60	$59
Secondary Air Injection	TC	$119	$116	$113	$111	$109	$107	$101	$99	$97
Hydrocarbon Adsorber	TC	$201	$196	$192	$188	$185	$183	$165	$163	$161
Evaporative Emissions Controls/OBD Upgrades	TC	$20	$20	$19	$19	$18	$18	$17	$17	$16
Engine Calibration	TC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	TC	$36	$35	$34	$33	$32	$32	$30	$30	$30

Note: $0 values reflect rounding for presentation but are non-zero. There is at present one V-10 gasoline engine product offering for HHDGVs

Table 2-9 Technology Costs by Year for HD Gasoline (2010$)

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	DMC	$48	$46	$45	$43	$42	$42	$41	$40	$39
Optimized Close-coupled Catalyst	DMC	$57	$55	$54	$52	$51	$50	$49	$48	$47
Secondary Air Injection	DMC	$95	$92	$89	$87	$85	$83	$82	$80	$78
Hydrocarbon Adsorber	DMC	$143	$138	$134	$130	$127	$125	$122	$120	$118
Evaporative Emissions Controls/OBD Upgrades	DMC	$16	$16	$15	$15	$14	$14	$14	$14	$13
Engine Calibration	DMC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	DMC	$29	$28	$27	$26	$25	$25	$24	$24	$24
Catalyst Loading	IC	$12	$12	$12	$12	$12	$12	$10	$10	$10
Optimized Close-coupled Catalyst	IC	$15	$15	$15	$15	$15	$15	$12	$12	$12
Secondary Air Injection	IC	$24	$24	$24	$24	$24	$24	$19	$19	$19
Hydrocarbon Adsorber	IC	$58	$58	$58	$58	$58	$58	$43	$43	$43
Evaporative Emissions Controls/OBD Upgrades	IC	$4	$4	$4	$4	$4	$4	$3	$3	$3
Engine Calibration	IC	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optimized Thermal Management	IC	$7	$7	$7	$7	$7	$7	$6	$6	$6
Catalyst Loading	TC	$60	$58	$57	$55	$54	$54	$51	$50	$49
Optimized Close-coupled Catalyst	TC	$72	$70	$69	$67	$66	$65	$61	$60	$59
Secondary Air Injection	TC	$119	$116	$113	$111	$109	$107	$101	$99	$97
Hydrocarbon Adsorber	TC	$201	$196	$192	$188	$185	$183	$165	$163	$161
Evaporative Emissions Controls/OBD Upgrades	TC	$20	$20	$19	$19	$18	$18	$17	$17	$16
Engine Calibration	TC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	TC	$36	$35	$34	$33	$32	$32	$30	$30	$30

Notes: $0 values reflect rounding for presentation but are non-zero.

Table 2-10 Technology Costs by Year for I4, V6, V8 & HD Diesel (2010$)

Technology	Cost type	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	DMC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	DMC	$29	$28	$27	$26	$25	$25	$24	$24	$24
SCR Optimization	DMC	$48	$46	$45	$43	$42	$42	$41	$40	$39
Engine Calibration	IC	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optimized Thermal Management	IC	$7	$7	$7	$7	$7	$7	$6	$6	$6
SCR Optimization	IC	$12	$12	$12	$12	$12	$12	$10	$10	$10
Engine Calibration	TC	$2	$2	$2	$2	$2	$2	$2	$2	$2
Optimized Thermal Management	TC	$36	$35	$34	$33	$32	$32	$30	$30	$30
SCR Optimization	TC	$60	$58	$57	$55	$54	$54	$51	$50	$49

Note: $0 values reflect rounding for presentation but are non-zero.

2.2 Vehicle Package Costs

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 proposed 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, for both a V6 and V8 application we anticipate that only 25 percent of the V6 applications will require the technology while 75 percent of the V8 applications will require the technology. This technology penetration rate, or application rate, is the first step in developing our vehicle package costs.

Table 2-11 presents our estimates of application rates of each enabling technology by engine type to meet the proposed standards.

Table 2-11 Technology Application Rates

Technology	Gasoline				Diesel
	I4	V6	V8	HD	All
Catalyst Loading	100%	100%	100%	100%	0%
Optimized Close-coupled Catalyst	50%	60%	75%	0%	0%
Secondary Air Injection	0%	25%	75%	0%	0%
Hydrocarbon Adsorber	0%	0%	15%	0%	0%
Evaporative Emissions Controls/OBD	100%	100%	100%	100%	0%
Engine Calibration	100%	100%	100%	100%	100%
Optimized Thermal Management	25%	25%	25%	25%	25%
SCR Optimization	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 proposed standards.

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 LDT4 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 LDT4s as in many cases identical powertrains and chassis exist between the LDT4 and MDPV platforms.

The next step in developing vehicle package costs is to consider the phase-in rate of the proposed standards. For example, the proposed standards do not reach maximum stringency until the 2025 MY, ramping down from a presumed Tier 2 Bin 5 level in the 2016 MY to the final levels in 2025. Manufacturers would be required to start the phase-in of Tier 3 standards on both LDVs and LDTs in MY 2017. 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 would be required to move from a Tier 2 Bin 5 fleet average in 2016 MY (for vehicles <6,000 lbs GVW) to the proposed standards. This results in a significant step in stringency in 2017. As a result, a large portion of the costs are expected to be incurred in the initial model years. It is also important to note that while we are aligned with CARB on the individual cost of each technology and their application rates, our costs are different from California's estimated LEV III costs due to the fact that the California fleet is currently slightly cleaner than the federal fleet. Finally, manufacturers will have the opportunity in 2015 and 2016 MY 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 proposed standards, moving from 0 percent compliance in the 2016 MY to 100 percent compliance in the 2025 MY (see Section IV of the preamble, which presents the proposed 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 2-12 shows the percentage of vehicles complying with the new standards and, therefore, the percentage of costs being incurred by manufacturers.

Table 2-12 Percentage of Vehicles Complying with the Proposed Standards

MY	Exhaust Standards - Gasoline & Diesel				Evaporative Standards – Gasoline only		
	Passenger Car	Light truck	Class 2b	Class 3	Passenger car	Light truck	HDGV
2016	0%	0%	0%	0%	0%	0%	0%
2017	57%	0%	0%	0%	40%	0%	0%
2018	62%	52%	54%	47%	60%	60%	60%
2019	68%	59%	65%	60%	60%	60%	60%
2020	73%	66%	77%	73%	80%	80%	80%
2021	78%	73%	88%	87%	80%	80%	80%
2022	84%	80%	100%	100%	100%	100%	100%
2023	89%	87%	100%	100%	100%	100%	100%
2024	95%	94%	100%	100%	100%	100%	100%
2025	100%	100%	100%	100%	100%	100%	100%

We then use the application rates shown in Table 2-11 along with the compliance percentages shown in Table 2-12, along with the technology costs shown in Table 2-6 through Table 2-10 to generate the total technology costs for use in our vehicle package cost estimates.

Table 2-13 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Gasoline Passenger Cars (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	I4	$41	$44	$47	$49	$52	$55	$54	$57	$59
Optimized Close-coupled Catalyst	I4	$7	$7	$8	$8	$9	$9	$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/OBD Upgrades	I4	$8	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	I4	$1	$1	$1	$1	$2	$2	$2	$2	$2
Optimized Thermal Management	I4	$5	$5	$6	$6	$6	$7	$7	$7	$8
Catalyst Loading	V6	$54	$58	$62	$64	$68	$72	$71	$75	$78
Optimized Close-coupled Catalyst	V6	$16	$18	$19	$20	$21	$22	$22	$23	$23
Secondary Air Injection	V6	$17	$18	$19	$20	$21	$22	$23	$23	$24
Hydrocarbon Adsorber	V6	$0	$0	$0	$0	$0	$0	$0	$0	$0
Evaporative Emissions Controls/OBD Upgrades	V6	$8	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	V6	$1	$1	$1	$1	$2	$2	$2	$2	$2
Optimized Thermal Management	V6	$5	$5	$6	$6	$6	$7	$7	$7	$8

Catalyst Loading	V8	$68	$72	$76	$81	$86	$90	$90	$94	$97
Optimized Close-coupled Catalyst	V8	$31	$33	$35	$37	$39	$41	$41	$43	$44
Secondary Air Injection	V8	$51	$54	$57	$61	$64	$67	$68	$70	$73
Hydrocarbon Adsorber	V8	$17	$18	$19	$21	$22	$23	$22	$23	$24
Evaporative Emissions Controls/OBD Upgrades	V8	$8	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	V8	$1	$1	$1	$1	$2	$2	$2	$2	$2
Optimized Thermal Management	V8	$5	$5	$6	$6	$6	$7	$7	$7	$8

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-14 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Gasoline Light-duty Trucks (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	I4	$0	$37	$41	$44	$48	$52	$53	$56	$59
Optimized Close-coupled Catalyst	I4	$0	$6	$7	$7	$8	$9	$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/OBD Upgrades	I4	$0	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	I4	$0	$1	$1	$1	$1	$2	$2	$2	$2
Optimized Thermal Management	I4	$0	$5	$5	$5	$6	$6	$7	$7	$8
Catalyst Loading	V6	$0	$49	$54	$58	$64	$69	$70	$74	$78
Optimized Close-coupled Catalyst	V6	$0	$15	$16	$18	$19	$21	$21	$23	$23
Secondary Air Injection	V6	$0	$15	$17	$18	$20	$21	$22	$23	$24
Hydrocarbon Adsorber	V6	$0	$0	$0	$0	$0	$0	$0	$0	$0
Evaporative Emissions Controls/OBD Upgrades	V6	$0	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	V6	$0	$1	$1	$1	$1	$2	$2	$2	$2
Optimized Thermal Management	V6	$0	$5	$5	$5	$6	$6	$7	$7	$8
Catalyst Loading	V8	$0	$61	$67	$73	$80	$86	$88	$93	$97
Optimized Close-coupled Catalyst	V8	$0	$27	$31	$33	$36	$39	$40	$42	$44
Secondary Air Injection	V8	$0	$46	$50	$55	$60	$64	$66	$70	$73
Hydrocarbon Adsorber	V8	$0	$15	$17	$19	$20	$22	$22	$23	$24
Evaporative Emissions Controls/OBD Upgrades	V8	$0	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	V8	$0	$1	$1	$1	$1	$2	$2	$2	$2
Optimized Thermal Management	V8	$0	$5	$5	$5	$6	$6	$7	$7	$8

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-15 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Gasoline Heavy-duty Class 2b Trucks (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	All	$0	$31	$37	$42	$48	$54	$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/OBD Upgrades	All	$0	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	All	$0	$1	$1	$2	$2	$2	$2	$2	$2

Optimized Thermal Management	All	$0	$5	$6	$6	$7	$8	$8	$8	$8

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-16 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Gasoline Heavy-duty Class 3 Trucks (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Catalyst Loading	All	$0	$27	$34	$40	$47	$54	$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/OBD Upgrades	All	$0	$12	$11	$15	$14	$18	$17	$17	$16
Engine Calibration	All	$0	$1	$1	$1	$2	$2	$2	$2	$2
Optimized Thermal Management	All	$0	$4	$5	$6	$7	$8	$8	$8	$8

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-17 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Diesel Passenger Cars (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	$1	$1	$1	$1	$2	$2	$2	$2	$2
Optimized Thermal Management	All	$5	$5	$6	$6	$6	$7	$7	$7	$8
SCR Optimization	All	$34	$36	$39	$40	$42	$45	$46	$47	$49

Table 2-18 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Diesel Light-duty Trucks (2010$)

Technology	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Engine Calibration	All	$0	$1	$1	$1	$1	$2	$2	$2	$2
Optimized Thermal Management	All	$0	$5	$5	$5	$6	$6	$7	$7	$8
SCR Optimization	All	$0	$30	$34	$36	$39	$43	$44	$47	$49

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-19 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Diesel Heavy-duty Class 2b Trucks (2010$)

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	$8
SCR Optimization	All	$0	$31	$37	$42	$48	$54	$51	$50	$49

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-20 Total Technology Costs after Applying Penetration Rates and Proposed Standard Phase-ins – Diesel Heavy-duty Class 3 Trucks (2010$)

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	$4	$5	$6	$7	$8	$8	$8	$8
SCR Optimization	All	$0	$27	$34	$40	$47	$54	$51	$50	$49

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

The final package costs are simply the sum of the costs shown in each of Table 2-13 through Table 2-20. These results are shown in Table 2-21 for gasoline vehicles and Table 2-22 for diesel vehicles. Evaporative system costs associated with heavy heavy-duty gasoline vehicles (HHDGVs, those with GVWR over 14,000 pounds) are not included in these tables. EPA estimates that there are only about 50,000 HHDGVs sold each year, and the evaporative system costs are less than $20 per vehicle (see Table 2-16).

Table 2-21 Vehicle Package Costs by Year for All Gasoline Vehicles (2010$)

Vehicle category	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	I4	$62	$69	$73	$80	$83	$90	$89	$92	$95
Passenger car	V6	$102	$112	$118	$127	$133	$143	$141	$147	$151
Passenger car	V8	$181	$196	$207	$222	$233	$247	$246	$256	$264
Light-duty truck	I4	$0	$60	$65	$74	$78	$87	$87	$92	$95
Light-duty truck	V6	$0	$96	$105	$116	$124	$137	$138	$146	$151
Light-duty truck	V8	$0	$167	$182	$202	$218	$237	$240	$254	$264
Class 2b	V8	$0	$49	$56	$65	$71	$82	$78	$77	$75
Class 3	V8	$0	$44	$52	$63	$70	$82	$78	$77	$75

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

Table 2-22 Vehicle Package Costs by Year for All Diesel Vehicles (2010$)

Vehicle category	Engine	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	I4	$40	$43	$46	$48	$50	$54	$54	$56	$59
Passenger car	V6	$40	$43	$46	$48	$50	$54	$54	$56	$59
Passenger car	V8	$40	$43	$46	$48	$50	$54	$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	$64	$61	$60	$59
Class 3	V8	$0	$32	$41	$48	$55	$64	$61	$60	$59

Note: $0 entries denote zero costs due to a 0 percent application rate (see Table 2-11) and/or compliance rate (see Table 2-12).

2.3 Vehicle Program Costs

With the package costs presented in Table 2-21 and Table 2-22, we can begin to develop vehicle program costs associated with the proposal. The program costs multiply package costs by appropriate vehicle sales per year to estimate the annual costs of the proposed program. The first step to this is determining the sales of each type of vehicle, or package, as presented in Table 2-21 and Table 2-22. To do this, we have started with the baseline database developed in support of the 2012-2016 GHG final rule.[8] That baseline database provides vehicle sales in the years 2017-2025 for each of the vehicle category/engine/fuel combinations listed in Table 2-21 and Table 2-22. However, that baseline database is not reflective of the 2012-2016 GHG final rule which is 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 maintaining vehicle performance. 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 2012-2016 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. Table 2-23 shows the baseline fleet mix—representing the best estimates of the future fleet absent any GHG rules—and Table 2-24 shows the Tier 3 reference fleet—representing the future fleet in the presence of the 2012-2016 GHG final rule. Table 2-26 shows projected sales of light-duty and heavy-duty vehicles excluding sales in the State of California which we have estimated to be 10 percent of nationwide sales.

Table 2-23 Baseline Light-Duty Fleet Mix and Sales

Vehicle category	Engine	Fuel	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger Car	I4	Gas	38%	38%	38%	39%	39%	39%	40%	40%	40%	41%
	I4	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V6	Gas	21%	22%	22%	22%	22%	22%	22%	23%	23%	23%
	V6	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V8	Gas	3.2%	3.1%	3.2%	3.2%	3.2%	3.2%	3.1%	3.1%	3.2%	3.2%
	V8	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	All	All	62%	63%	63%	64%	65%	65%	65%	66%	66%	67%
Light-duty truck	I4	Gas	4.4%	4.0%	3.9%	3.7%	3.6%	3.6%	3.6%	3.5%	3.5%	3.5%
	I4	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	V6	Gas	22%	23%	23%	23%	23%	23%	23%	23%	23%	22%
	V6	Dies	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	V8	Gas	11%	9.3%	9.0%	8.6%	8.5%	8.2%	8.0%	7.5%	7.2%	7.0%
	V8	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	All	All	37%	37%	36%	36%	35%	35%	35%	34%	34%	33%
Electric Vehicle			0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
All Light-duty	All	All	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 2-24 Tier 3 Reference Light-Duty Fleet Mix

Vehicle category	Engine	Fuel	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger Car	I4	Gas	41%	41%	42%	42%	43%	43%	43%	43%	44%	44%
	I4	Dies	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
	V6	Gas	18%	19%	19%	19%	19%	19%	19%	19%	20%	20%
	V6	Dies	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	V8	Gas	2.6%	2.7%	2.7%	2.7%	2.7%	2.7%	2.8%	2.8%	2.8%	2.8%
	V8	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	All	All	62%	63%	63%	64%	65%	65%	65%	66%	66%	67%
Light-duty	I4	Gas	7.8%	7.7%	7.6%	7.5%	7.3%	7.3%	7.2%	7.1%	7.0%	6.9%

Vehicle category	Engine	Fuel	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
truck	I4	Dies	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
	V6	Gas	20%	20%	20%	19%	19%	19%	19%	18%	18%	18%
	V6	Dies	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
	V8	Gas	9.0%	8.9%	8.8%	8.6%	8.5%	8.5%	8.4%	8.2%	8.1%	8.0%
	V8	Dies	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	All	All	37%	37%	36%	36%	35%	35%	35%	34%	34%	33%
Electric Vehicle			0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
All Light-duty	All	All	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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 Heavy-duty GHG rule. Therefore, we are using the baseline fleet mix as the reference fleet mix for this analysis.[9] This fleet mix is shown in Table 2-25.

Table 2-25 Tier 3 Reference Heavy-Duty Fleet Mix

Vehicle category	Engine	Fuel	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Class 2b	V8	Gas	37%	37%	37%	37%	37%	37%	37%	37%	37%	37%
		Dies	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
Class 3	V8	Gas	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
		Dies	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
All HD	All	All	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 2-26 Projected Non-California Sales by Year[a]

Year	Light-duty	Heavy-duty
2016	14,575,658	641,095
2017	14,225,690	637,249
2018	14,018,769	644,894
2019	14,020,792	661,595
2020	14,306,345	689,149
2021	14,570,160	709,140
2022	14,795,795	726,608
2023	14,989,940	739,953
2024	15,240,678	753,308
2025	15,525,414	767,900

[a] Based on AEO 2011.

Using the reference fleet mix and the projected sales, we can calculate the annual costs of the proposed 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 and 3 costs to get the costs for heavy-duty. We have done this separately for the proposed exhaust and evaporative standards and then the combined standards. The results are shown in Table 2-28.

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 we are proposing. For additional information on the test procedure changes we are proposing, see Section IV.F of the preamble.

To determine the appropriate costs for upgrading test facilities for PM measurement we have 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 vehicle manufacturers reflecting estimates for upgrading their internal facilities. The cost estimates ranged from $250,000 to $500,000 per PM test site. 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 2-27. 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. 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 2-27: PM Facility Costs

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	$375,000		$750,000	20	$15,000,000
> 1 million	4			$1,500,000	5	$7,500,000
Fleet					25	$22,500,000

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 $150,000 per year. With 25 manufacturers, the total cost would be $3,750,000 per year every year going forward. In contrast, the PM facility costs shown in Table 2-27 represent one-time costs we expect to be incurred in the year prior to implementation of the proposed standards. These costs are shown in Table 2-28.

Table 2-28 Undiscounted Annual Costs and Costs of the Proposed Program Discounted back to 2012 at 3 and 7 Percent Discount Rates (Millions of 2010 dollars)

	Exhaust			Evaporative			PM Facility & staff	Total
	Light-duty	Heavy-duty	All	Light-duty	Heavy-duty	All		
2016	$0	$0	$0	$0	$0	$0	$22.5	$22.5
2017	$634	$0	$634	$71.4	$0	$71.4	$3.75	$709
2018	$1,150	$23.1	$1,170	$167	$3.86	$171	$3.75	$1,340
2019	$1,240	$28.6	$1,270	$159	$3.76	$162	$3.75	$1,440
2020	$1,350	$34.2	$1,380	$216	$5.22	$221	$3.75	$1,600
2021	$1,470	$40.0	$1,510	$208	$5.09	$213	$3.75	$1,730
2022	$1,580	$46.5	$1,630	$264	$6.52	$271	$3.75	$1,900

	Exhaust			Evaporative			PM Facility & staff	Total
	Light-duty	Heavy-duty	All	Light-duty	Heavy-duty	All		
2023	$1,610	$44.8	$1,660	$253	$6.27	$259	$3.75	$1,920
2024	$1,720	$44.8	$1,770	$257	$6.38	$263	$3.75	$2,040
2025	$1,830	$44.9	$1,870	$246	$6.12	$253	$3.75	$2,130
2030	$1,750	$46.5	$1,790	$246	$6.74	$253	$3.75	$2,050
2040	$1,750	$51.9	$1,800	$246	$7.52	$254	$3.75	$2,060
2050	$1,750	$58.6	$1,810	$246	$8.49	$255	$3.75	$2,070
PV at 3%	$29,900	$814	$30,700	$4,250	$116	$4,360	$89.1	$35,100
PV at 7%	$14,700	$384	$15,100	$2,090	$55.0	$2,150	$52.2	$17,300

Note: Costs shown include costs for the proposed Tier 3 standards on vehicles sold in all states except California.

By then sales weighting the exhaust and evaporative/OBD results by sales in each of the vehicle category/engine/fuel combinations, we can calculate the annual costs for passenger cars, light-duty trucks and heavy-duty trucks. We show these cost per vehicle results for the proposed exhaust standards in Table 2-29, for the proposed evaporative standards in Table 2-30 and for the combined exhaust and evaporative standards in Table 2-31. The costs shown in these three tables include all direct and indirect costs for new vehicle hardware. They also include the effects of learning, and the expected penetration rates and phase-ins of the proposed standards.

Table 2-29 Cost per Vehicle for the Proposed Exhaust Emission Standards (2010$)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	$0	$71	$75	$80	$84	$89	$94	$94	$98	$102
Light-duty truck	$0	$0	$93	$103	$112	$122	$132	$134	$143	$150
All light-duty	$0	$45	$82	$88	$94	$101	$107	$108	$113	$118
Class 2b	$0	$0	$37	$44	$50	$57	$64	$61	$60	$59
Class 3	$0	$0	$32	$41	$48	$55	$64	$61	$60	$59
All heavy-duty	$0	$0	$36	$43	$50	$56	$64	$61	$60	$59
All LD and HD	$0	$43	$80	$86	$92	$99	$105	$105	$110	$115

Note: Costs shown include costs for the proposed Tier 3 standards on vehicles sold in all states except California.

Table 2-30 Cost per Vehicle for the Proposed Evaporative Emission Standards/OBD Upgrades (2010$)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Passenger car	$0	$8	$12	$11	$15	$14	$18	$17	$17	$16
Light-duty truck	$0	$0	$12	$11	$15	$14	$18	$17	$17	$16
All light-duty	$0	$5	$12	$11	$15	$14	$18	$17	$17	$16
Class 2b	$0	$0	$6	$6	$8	$7	$9	$8	$8	$8
Class 3	$0	$0	$6	$6	$8	$7	$9	$8	$8	$8
All heavy-duty	$0	$0	$6	$6	$8	$7	$9	$8	$8	$8
All LD and HD	$0	$5	$12	$11	$15	$14	$17	$16	$16	$15

Note: Costs shown include costs for the proposed Tier 3 standards on vehicles sold in all states except California.

Table 2-31 Cost per Vehicle for the Proposed Exhaust, Evaporative Emission Standards and OBD Upgrades (2010$)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025

Passenger car	$0	$78	$87	$92	$99	$103	$112	$111	$115	$118
Light-duty truck	$0	$0	$105	$114	$127	$136	$150	$151	$159	$165
All light-duty	$0	$50	$94	$100	$109	$115	$125	$124	$130	$134
Class 2b	$0	$0	$43	$50	$58	$64	$73	$69	$68	$66
Class 3	$0	$0	$38	$46	$55	$63	$73	$69	$68	$66
All heavy-duty	$0	$0	$42	$49	$57	$64	$73	$69	$68	$66
All LD and HD	$0	$47	$91	$97	$107	$113	$122	$122	$127	$130

Note: Costs shown include costs for the proposed Tier 3 standards on vehicles sold in all states except California.

References

[1] 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/leviiighg2012/leviiighg2012.htm).

[2] "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.

[3] The 2012-2016 GHG final rule can be found at 75 FR 25374; the 2017-2025 GHG final rule can be found at http://epa.gov/otaq/climate/regs-light-duty.htm.

[4] 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 .

[5] "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.

[6] 76 FR 57106 and http://epa.gov/otaq/climate/regs-light-duty.htm.

[7] 76 FR 57106.

[8] See Chapter 1 of "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis," EPA-420-R-10-009, April 2010.

[9] See Chapter 5 of "Final Rulemaking to Establish Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles: Regulatory Impact Analysis," EPA-420-R-11-901, August 2011.

Chapter 3 Establishing New Emission Test Fuel Parameters

3.1 Assessment of Current Gasoline Properties

In-use gasoline has changed considerably since EPA's emission test fuel specifications were first set and last revised. Gasoline sulfur and benzene have been reduced and, perhaps most importantly, gasoline containing 10 percent ethanol by volume (E10) has replaced clear gasoline (E0) across the country. 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 9.3 percent by volume (vol%) as shown in Figure 3-1.

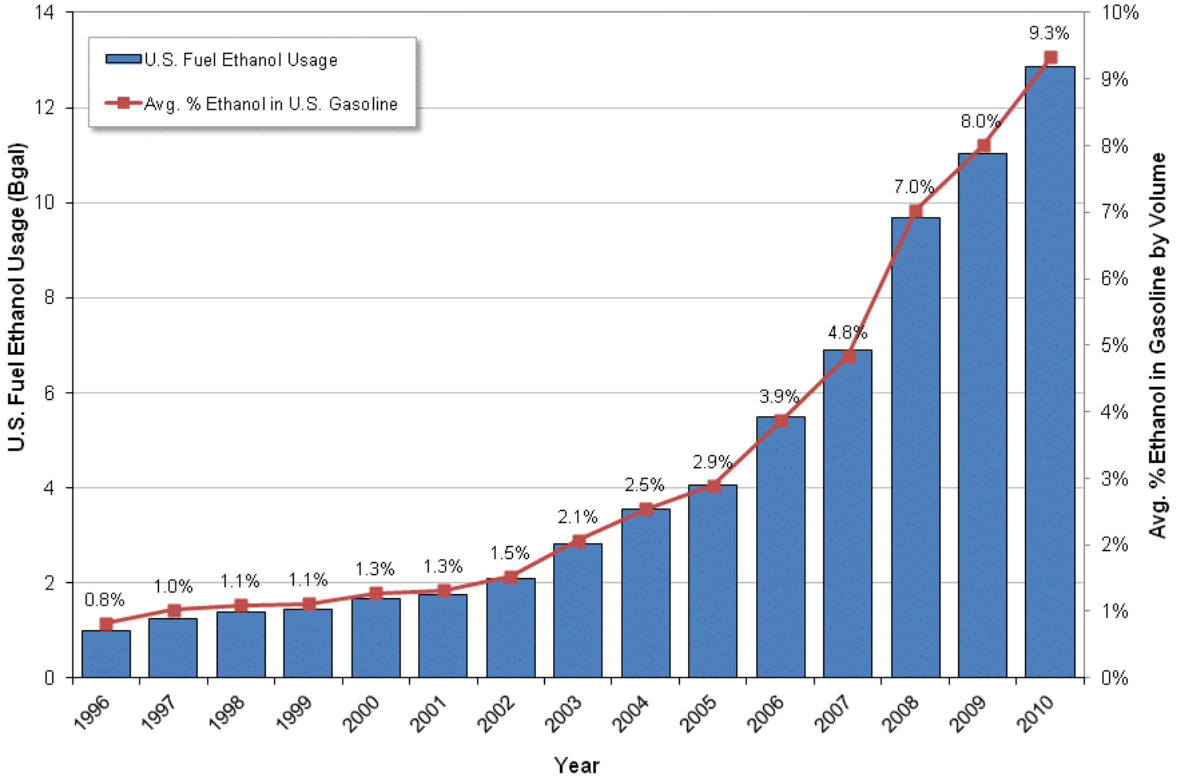

Figure 3-1 Average Gasoline Ethanol Content Over Time[1]

The increase in fuel ethanol has resulted in fuel property changes according to the Alliance of Automobile Manufacturers (AAM) North American Fuel Survey. Each summer and winter, the AAM takes over 300 gasoline samples from 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, we believe it represents a sizeable percentage of the domestic pool and encompasses the major gasoline formulations (conventional and reformulated) and grades (regular and premium) available to consumers. As such, we relied heavily on the AAM North American Fuel Survey trends (as well as refinery compliance data and information provided by CARB) to help inform our proposed vehicle test fuel changes.[A]

3.1.1 Octane

Finished U.S. gasoline has not experienced an increase in average octane (also known as antiknock index or (R+M)/2) due to increased ethanol blending. Denatured fuel ethanol has an average octane rating of 115 (R+M)/2 which is greater than that of conventional regular-grade gasoline, 87 (R+M)/2. With the shift to E10 nationwide, many refiners have backed off on octane production at the refinery in the form of aromatics and olefins. Refiners are currently producing sub-octane blendstocks to avoid giving away expensive octane. We estimate that refiners are currently producing 84 (R+M)/2 blendstocks for 87 octane regular-grade gasoline and 88 (R+M)/2 blendstocks for 91 octane premium-grade gasoline to maintain (but not exceed) minimum octane ratings for E10.

According to AAM summer fuel surveys, the average octane of finished gasoline has remained constant around 89-90 (R+M)/2 over the past decade (refer to Figure 3-2). The reported octane is higher than expected because AAM takes roughly an equal number of regular and premium gasoline samples as part of their North American Fuel Survey. In reality, the majority of consumers fill up on 87 octane regular-grade gasoline based on price and other factors. According to EIA’s Petroleum Marketing Annual, regular-grade gasoline represents over 85 percent of U.S. sales.[2] Accordingly, we believe our proposed 87-88.4 R+M/2 specification for test fuel is representative of in-use gasoline. However, the AAM survey does tell us one important thing about octane – refiners are doing their best not to give it away. We anticipate that this trend will continue into the future as E15 replaces E10.

[A] Since Alaska gasoline varies in fuel properties due to crude oil supply, the manner in which it’s refined, and applicable EPA regulations, we have opted to exclude AAM fuel samples taken from Fairbanks, AK in the average gasoline properties presented in this chapter of the draft RIA.

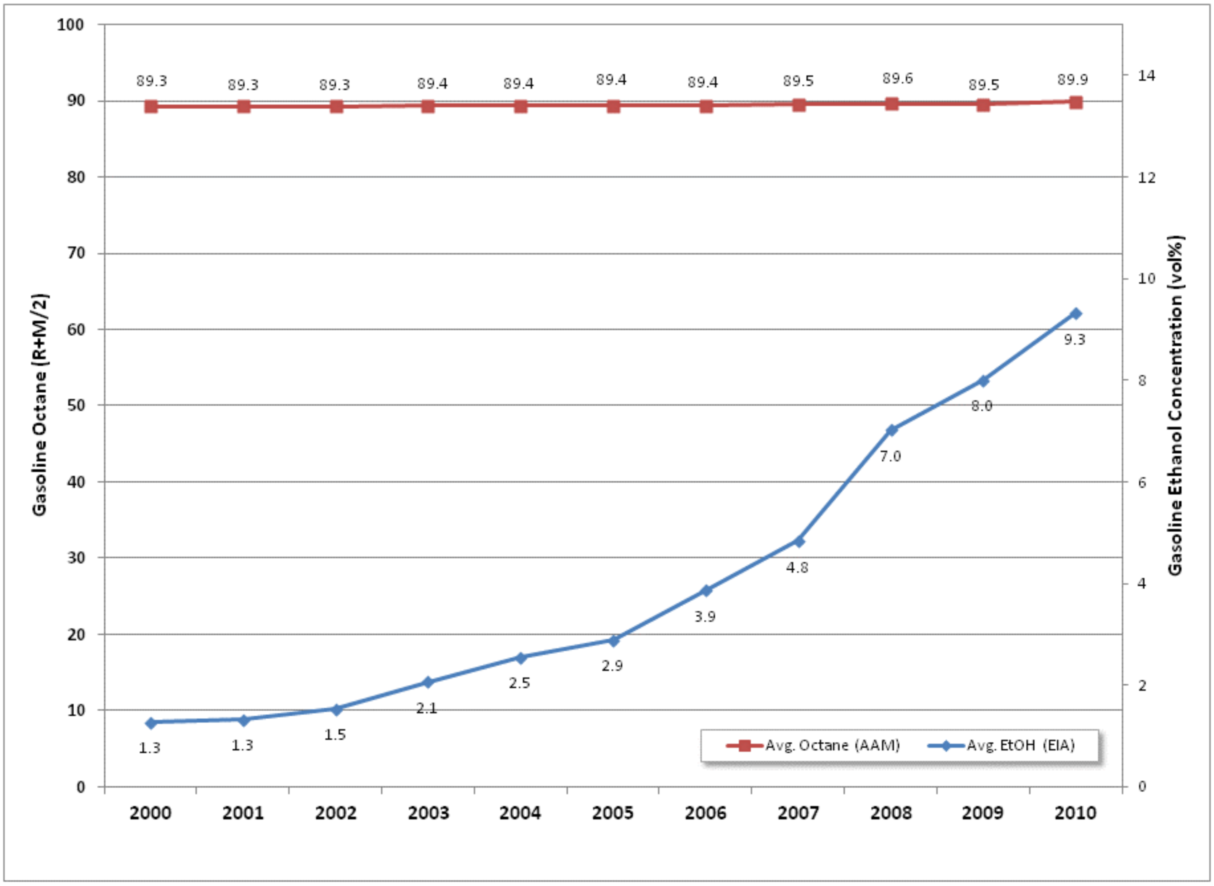

Figure 3-2 Average Gasoline Octane and Ethanol Levels Over Time

3.1.2 Aromatics and Olefins

The increase in fuel ethanol content has resulted in reduced aromatics and olefin levels. According to AAM summer fuel surveys, average aromatics levels have been reduced by 15 percent and olefins levels have been reduced by 19 percent in relative terms over the past decade. In 2010, the average aromatics content of gasoline was measured by AAM at 22.6 vol% and the average olefins content was measured at 7.3 vol%. The average aromatics, olefin, and ethanol levels by year are shown in Figure 3-3.

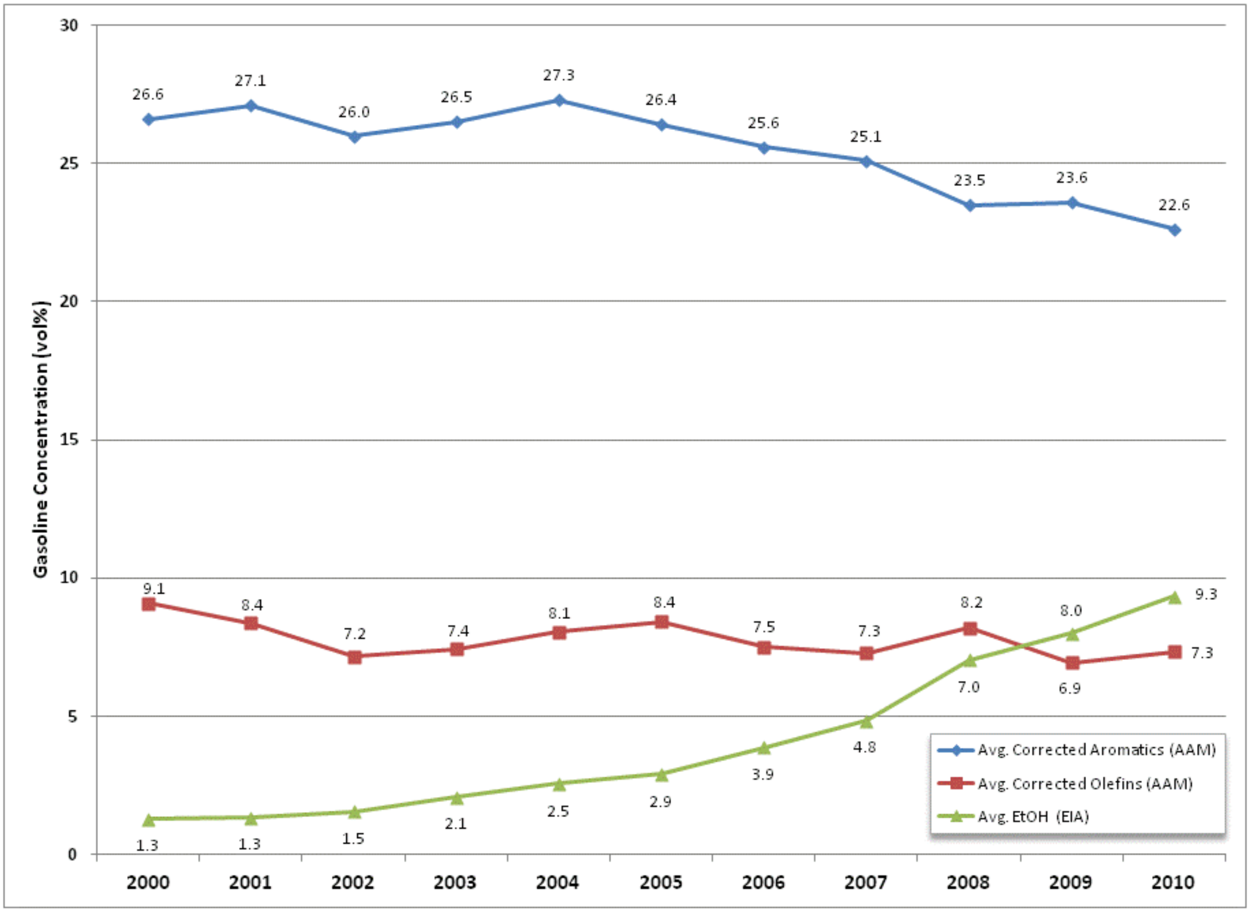

Figure 3-3 Average Gasoline Aromatics, Olefin and Ethanol Levels Over Time

Although aromatics and olefin levels have been reduced over the past decade, there continues to be variation on a batch-by-batch and geographic basis. Our 2009 refinery batch data suggests that gasoline aromatics levels ranged anywhere from 0 to 67 vol% with an average concentration of 23 vol% and olefin levels ranged from 0 to 43 vol% with an average concentration of 11 vol%. The 2009 certification data shown in Figure 3-4 and Figure 3-5 only reflects ethanol that is match blended into reformulated gasoline. It does not account for ethanol that may be blended into conventional gasoline since our existing gasoline regulations do not allow refiners to take advantage of fuel 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 EPA certification data.

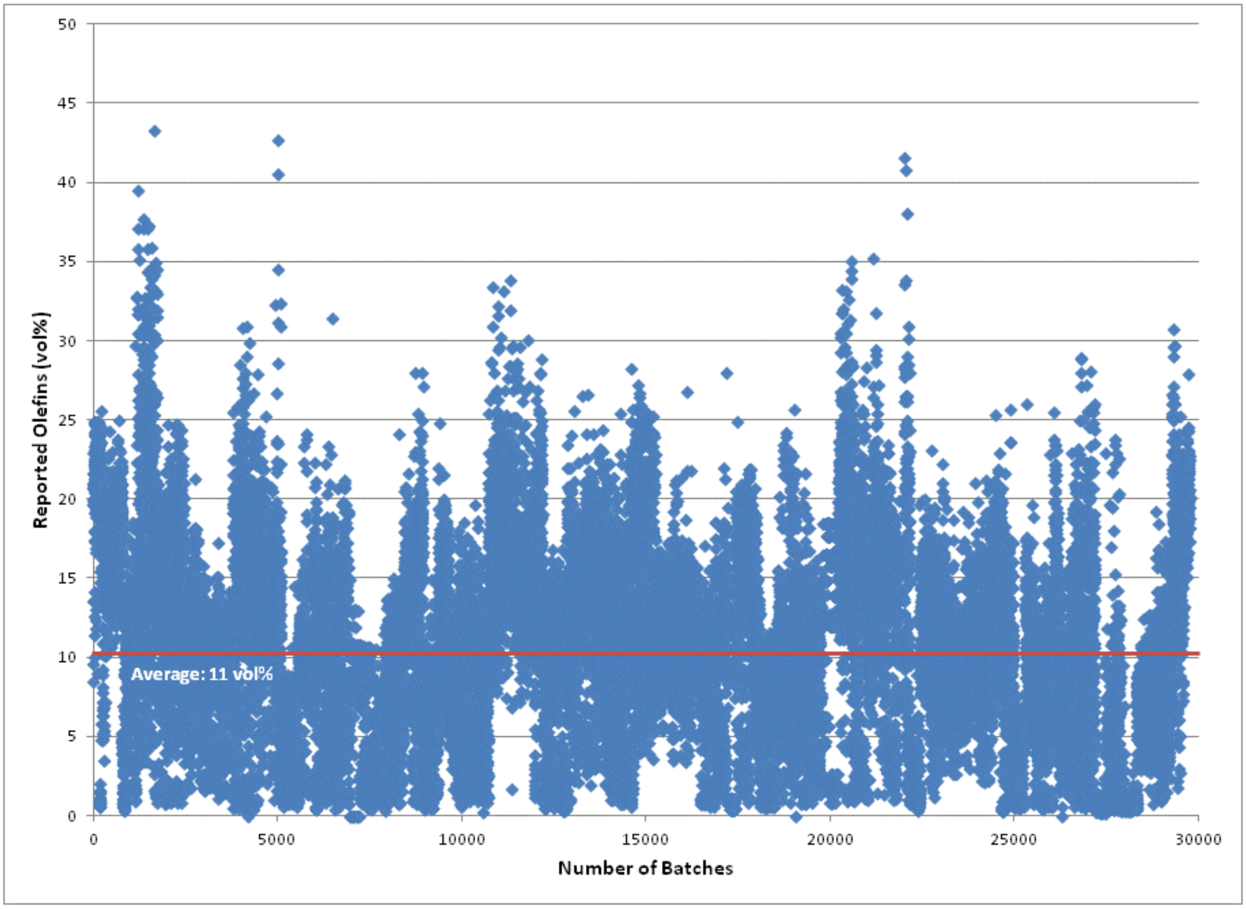

Figure 3-4 Gasoline Aromatics based on 2009 Refinery Batch Data

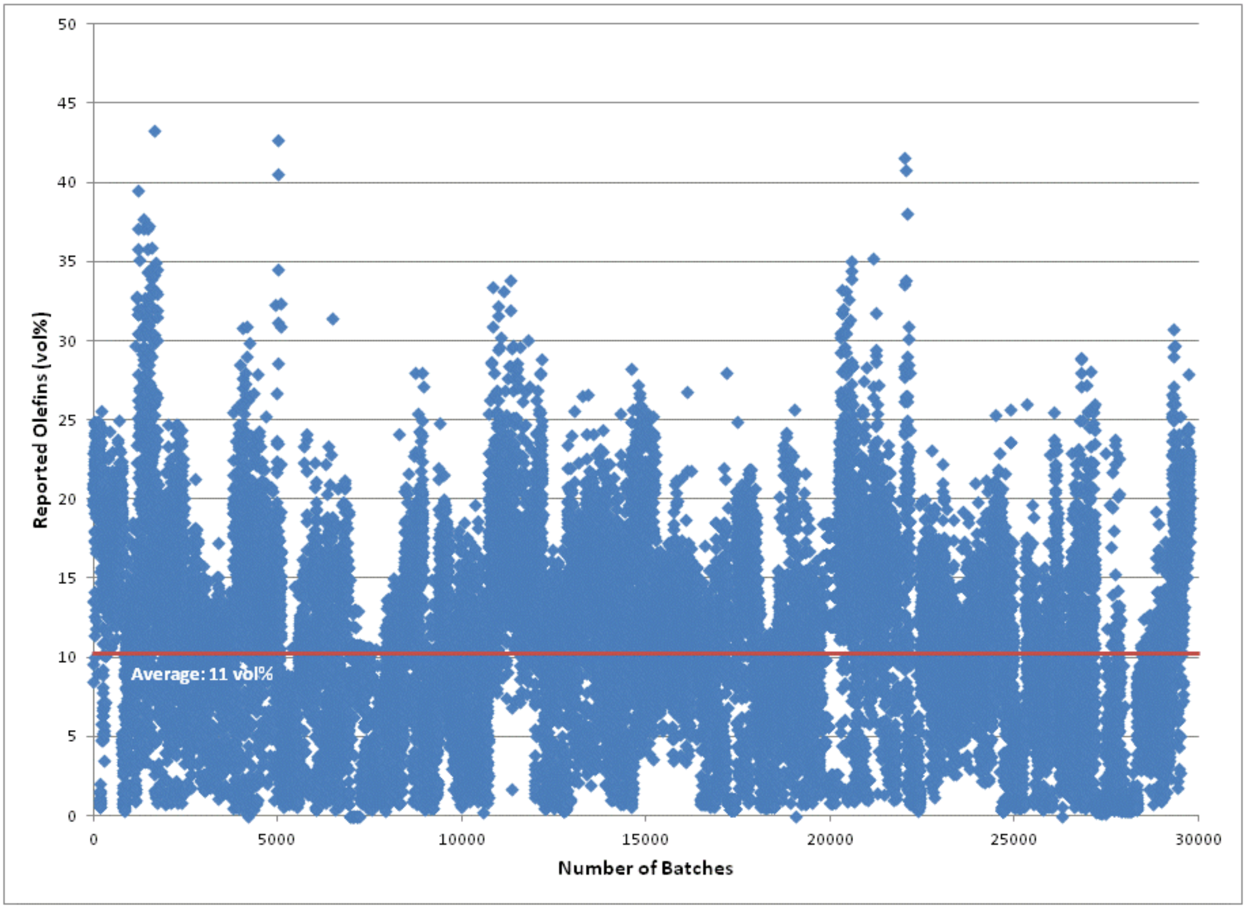

Figure 3-5 Gasoline Olefins based on 2009 Refinery Batch Data

In the summer of 2010, according to the AAM North American Fuel Survey, measured in-use aromatics levels ranged from 3 to 47 vol% (refer to Figure 3-6) while olefin levels ranged from 0.6 to 17 vol% (refer to Figure 3-7). California tends to have lower, tighter in-use gasoline properties based on their existing CaRFG3 regulations. As shown below, gasoline samples taken from Los Angeles and San Francisco, CA had aromatics levels ranging from 10 to 30 vol% and olefin levels ranging from 1 to 8 vol%. Accordingly, the Federal test fuel parameters we're proposing for aromatics and olefins are slightly broader than California's, yet still inclusive of CARB's planned LEV III specs.

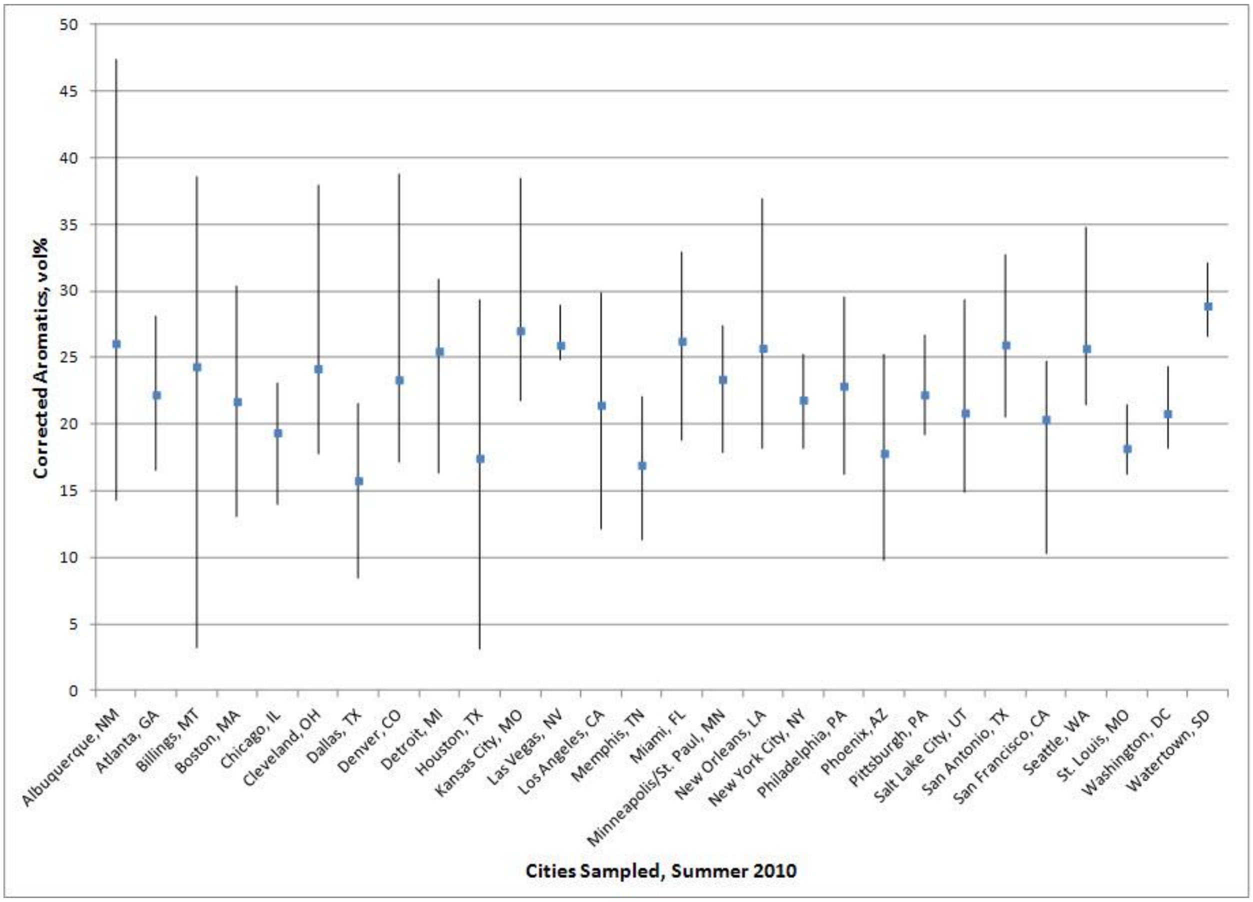

Figure 3-6 Measured Aromatics by AAM City Surveyed, Summer 2010

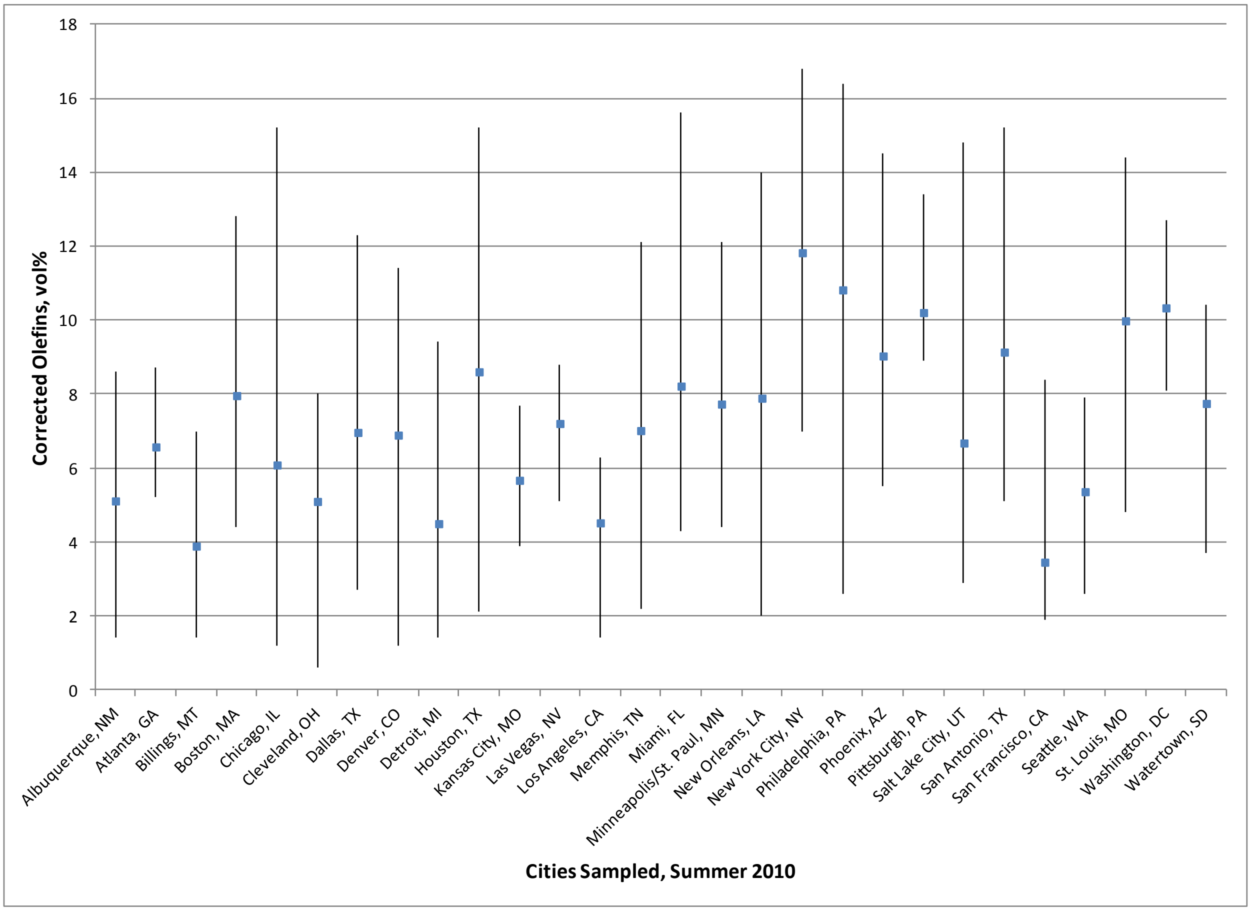

Figure 3-7 Measured Olefins by AAM City Surveyed, Summer 2010

Finished gasoline samples obtained by EPA suggest that gasoline currently contains a wide range of aromatics from basic benzene (C6), and toluene (C7), to larger more complicated aromatics of C10+ hydrocarbons. From August 2007 to September 2011, EPA analyzed 52 fuel samples from various locations throughout the country. Approximately 60 percent of the samples were RFG oversight samples (as part of the RFG rule, every refiner is required to send EPA a sample of every 33rd batch of gasoline) and the remainder were audit samples (collected, mostly from retail, as part of the City Surveys program performed as part of the agreement with API during the regulatory negotiation process that lead to the RFG rule). Total aromatics ranged anywhere from 6 to 39 percent by volume, but the C6, C7, C8, C9 and C10+ contributions were relatively consistent (refer to Figure 3-8). As shown below in Table 3-1, gasoline contained 3.2 percent benzene, 22.5 percent C7 toluene, 28.3 percent C8 aromatic hydrocarbons (xylene and ethyl benzene), 25.5 percent C9 hydrocarbons (trimethylbenzene and other compounds), and 20.6 percent C10+ aromatic hydrocarbons.

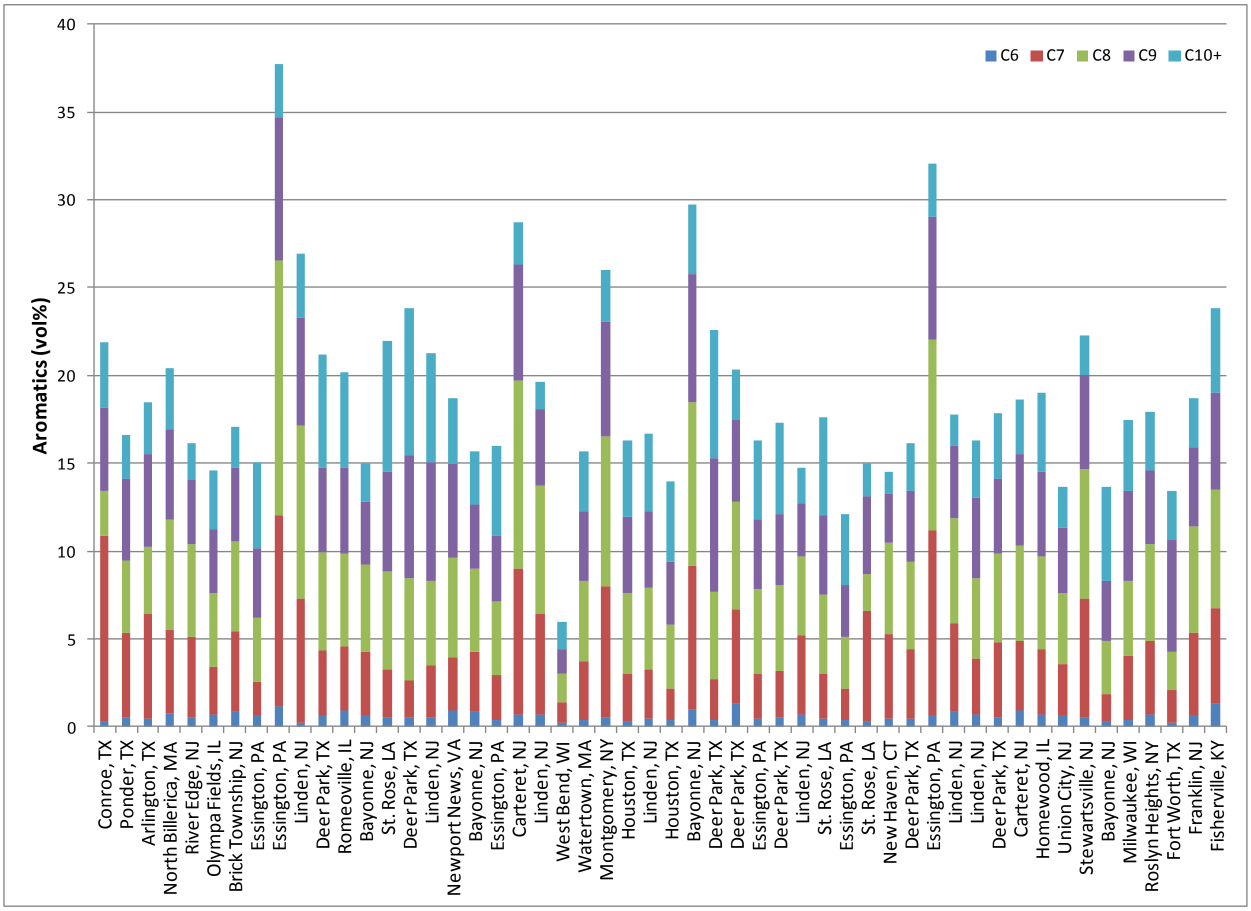

Figure 3-8 Measured Aromatics by EPA Sample Location, 2007-2011

Table 3-1 In-Use Gasoline Aromatics Composition

	Compound	% of Aromatics	Total
C6	Benzene	3.2%	3.2%
C7	Toluene	22.5%	22.5%
C8	m/p-Xylene	16.8%	
	o-Xylene	6.4%	
	Ethylbenzene	5.0%	28.3%
C9	1,2,4-Trimethylbenzene	9.0%	
	3-ethyltoluene	5.6%	
	1,3,5-Trimethylbenzene	2.6%	
	1,2,3-Trimethylbenzene	2.2%	
	1-Methyl-2-ethylbenzene	1.9%	
	n-Propylbenzene	1.6%	
	Indan	1.2%	
	4-ethyltoluene	1.0%	
	Isopropylbenzene	0.5%	25.5%
C10	alkyl indans	7.1%	
	C10 Benzenes	3.6%	
	n-butylbenzene	1.5%	
	1,4-diethylbenzene	1.5%	
	1,2,3,5-tetramethylbenzene	1.3%	
	Naphthalene	0.9%	
	1,2,4,5-tetramethylbenzene	0.9%	
	1,2-diethylbenzene	0.1%	
C11	C11 Benzenes	2.0%	
	2-Methylnaphthalene	0.8%	
	1-Methylnaphthalene	0.3%	
	Pentamethylbenzene	0.1%	
C12	C12 Benzenes	0.5%	20.6%
	Total Aromatics	**100.0%**	**100.0%**

Research by the Japan Petroleum Energy Center (JPEC), Honda, and others have found that larger more complicated aromatic compounds result in greater vehicle particulate matter (PM) emissions. The JPEC study found that PM mass emissions from a light-duty gasoline vehicle increased with increasing carbon number of aromatics in the gasoline.[3] Honda has devised a “PM Index” that correlates PM emissions to the double bond equivalent (DBE) and vapor pressure (V.P) of the fuel components. Their research was published in an SAE paper on October 25, 2010.[4] According to Honda, the PM index of the fuel is a function of all the gasoline components (i) and their respective weight fractions (Wt_i) as shown in Equation 1. DBE is essentially 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). As expected, gasoline containing a large fraction of heavier aromatics compounds with high DBE values result in greater vehicle PM emissions.

Equation 1 Particulate Matter Index

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

Since aromatics do not appear to be created equally in terms of the potential impact on vehicle PM emissions, we believe that it is prudent that our new Tier 3 gasoline emissions test fuel contain both a representative amount and distribution of aromatics. In Section 3.2 we explain how we arrived at the estimated aromatics concentration of our proposed E15 test fuel. We also detail our proposal for ensuring that the contributions of C6, C7, C8, C9, and C10+ aromatic hydrocarbons are representative of in-use gasoline.

3.1.3 Distillation Temperatures

As shown below in Figure 3-9, the transition from E0 to E10 has had little, if any, effect on gasoline distillation temperatures. However, we are proposing modest changes in our test fuel to make distillation temperatures more representative of today's in-use fuel. According to AAM summer fuel surveys, the average temperature at which 10 percent of gasoline is distilled (T10) is at/around 130°F; the average temperature at which 50 percent of gasoline is distilled (T50) is currently at/around 200°F; the average temperature at which 90 percent of gasoline is distilled (T90) is at/around 325°F; and the average temperature at which all gasoline is distilled (final boiling point or FBP) is at/around 400°F. The temperatures reported in Figure 3-9 represent an average of the gasoline formulations (from 9- and 10-psi conventional to 7-psi reformulated) and grades (87 (R+M)/2 regular to 91-93 (R+M)/2 premium) available to consumers and sampled by AAM.

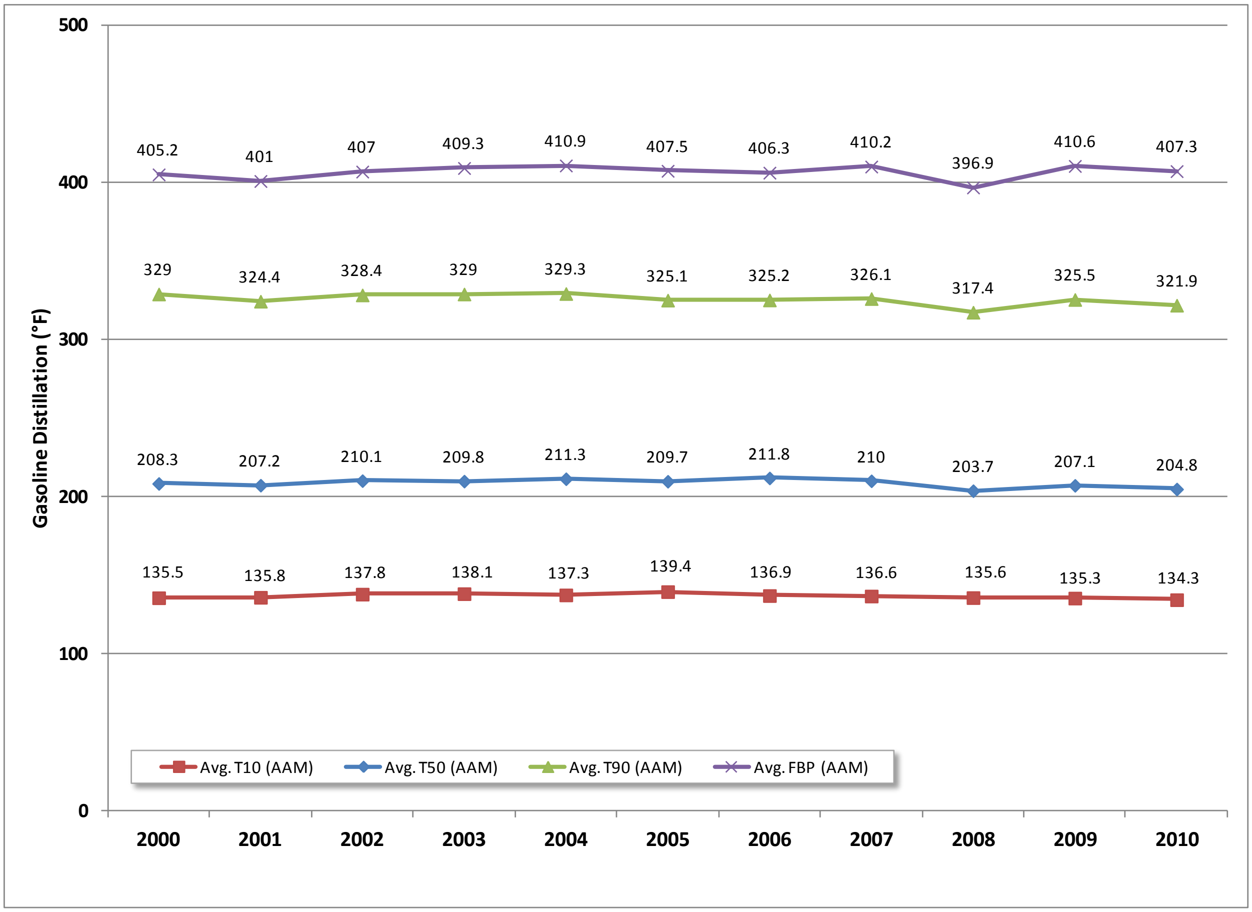

Figure 3-9 Average Gasoline Distillation Temperatures Over Time

The T50 and T90 temperatures from the AAM fuel survey agree with our 2009 refinery compliance data, shown below in Figure 3-10 and Figure 3-11. The shift to E15 is not expected to have major impacts on gasoline distillation temperatures with the exception of T50 (explained in more detail in Section 3.2). Accordingly, we believe our proposed T10, T90 and FBP specifications for gasoline, detailed below in Table 3-3, are representative of in-use fuel and thus appropriate for gasoline vehicle test fuel.

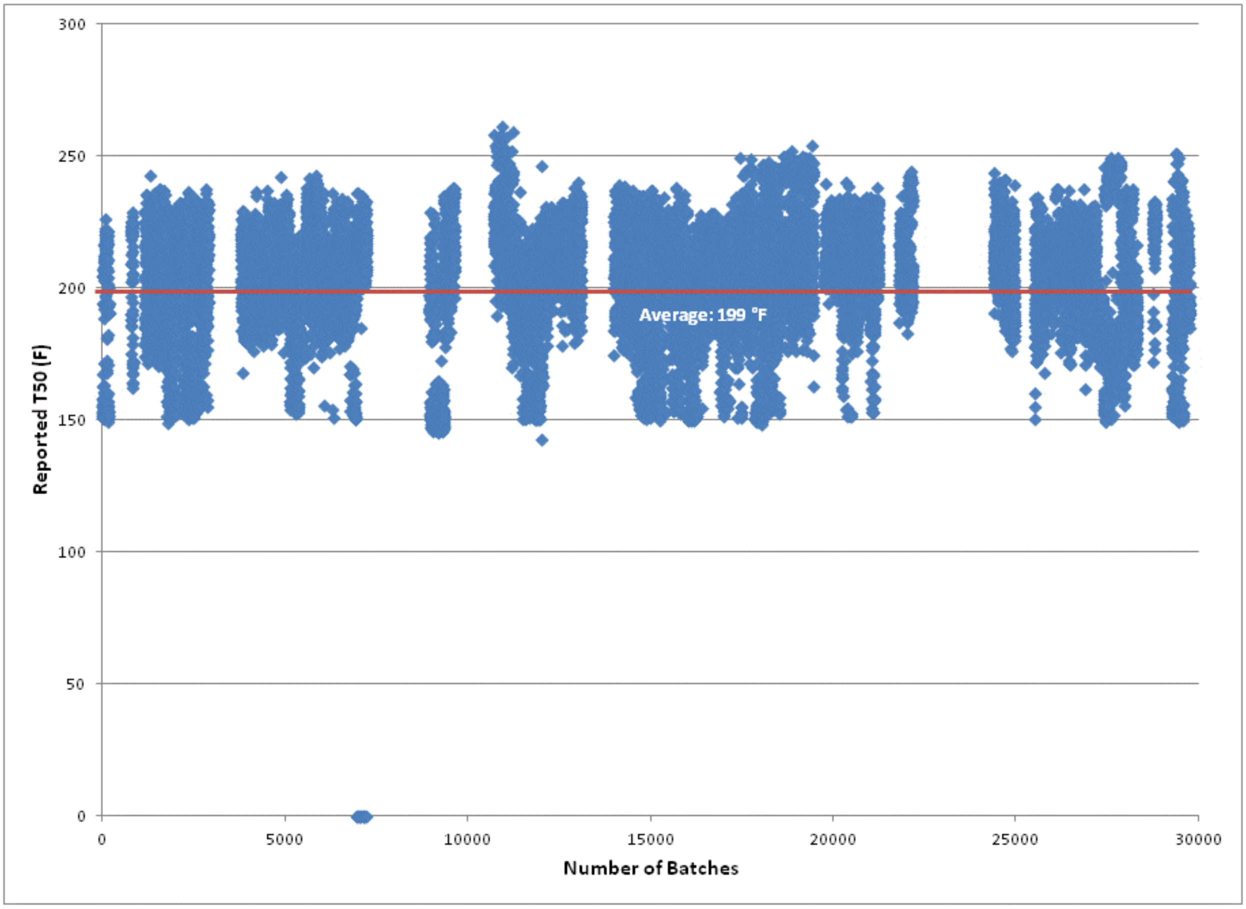

Figure 3-10 Gasoline T50 based on 2009 Refinery Batch Data

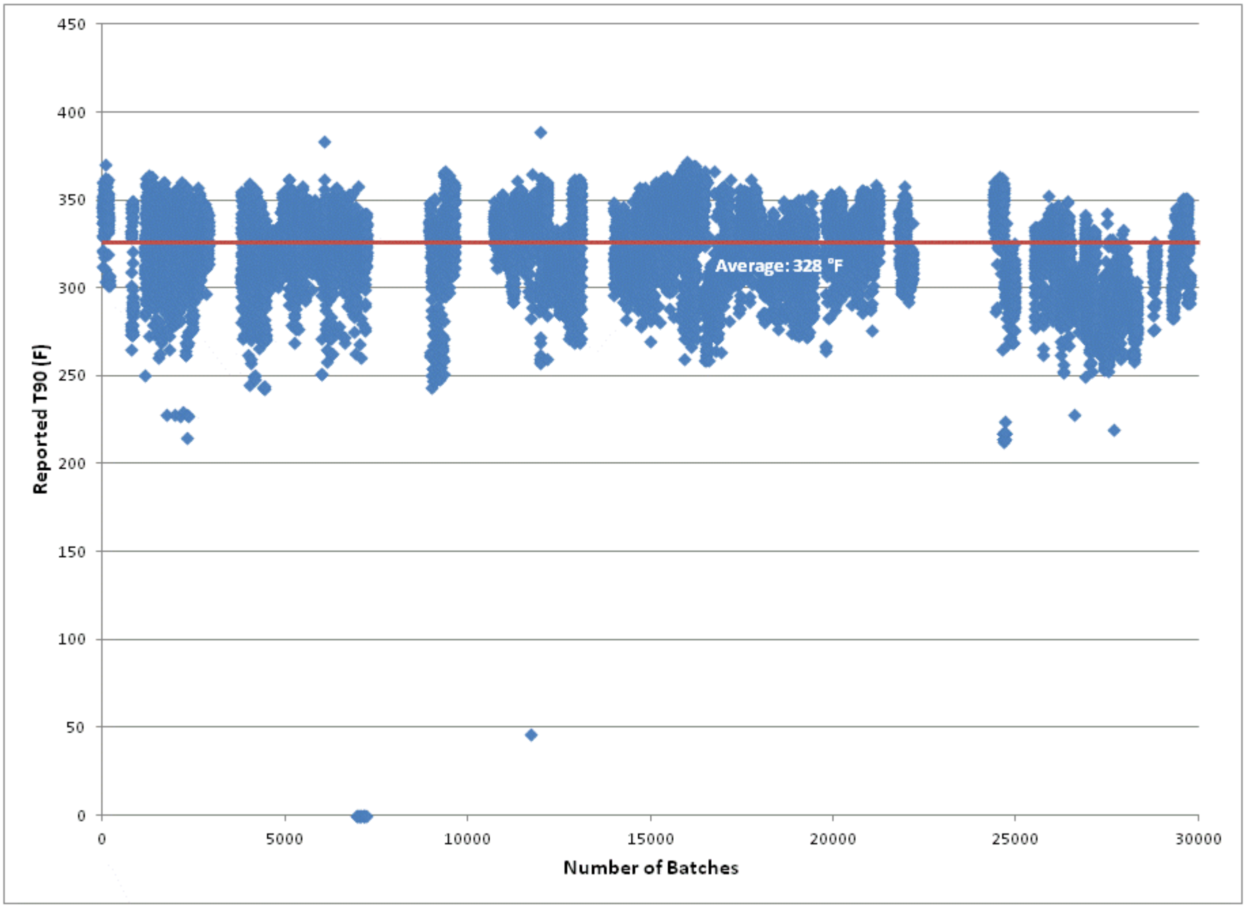

Figure 3-11 Gasoline T90 based on 2009 Refinery Batch Data

As part of our test fuel changes, we are proposing to eliminate our initial boiling point (IBP) specification. The IBP of gasoline is directly correlated to the vapor pressure of gasoline. Since we already limit the vapor pressure of our general testing fuel to 8.7-9.2 psi (and are not planning on changing this under Tier 3), we believe it would be redundant and unnecessary to maintain an IBP specification for emission test fuel. This is consistent with CARB's current LEV II standards and planned LEV III approach.

3.1.4 Sulfur and Benzene

Gasoline sulfur levels have declined significantly over the past decade under the Tier 2 gasoline program. According to AAM summer fuel surveys, average gasoline sulfur has gone from over 150 ppm in 2000 to less than 30 ppm in 2010 (refer to Figure 3-12). However, it's worth noting that The Alliance may not have sampled all the gasoline markets that had higher sulfur during the Tier 2 phase-in as a result of extra lead time given to GPA/Rocky Mountain refineries and small refiners. According to refinery batch reports (refer to Figure 3-13), average gasoline sulfur was still around 37 ppm in 2009. However, refinery certification data does not include ethanol blended into conventional gasoline (CG), so the average downstream sulfur could have been a few ppm lower in 2009. Regardless, since this time, all U.S. refiners (including small refiners) have come into compliance with the Tier 2 30-ppm sulfur standard.

Under today's proposed Tier 3 program, average gasoline sulfur levels are expected to be reduced even further to around 10 ppm by 2017. Accordingly, our proposed Tier 3 test fuel sulfur specification of 8-11 ppm is expected to be representative of future in-use gasoline.

Gasoline benzene levels have also been reduced in recent years due to the MSAT2 program. According to AAM summer fuel surveys, average gasoline benzene content has declined from almost 1 vol% in 2005 to less than 0.8 vol% in 2010 (refer to Figure 3-12). However, The Alliance may not have sampled all the gasoline markets that had higher benzene during the MSAT2 phase-in as a result of extra lead time given to small refiners and early credit provisions. According to refinery batch reports (refer to Figure 3-14), average gasoline benzene was still around 1 vol% in 2009. However, due to unaccounted for CG ethanol blending, average downstream benzene was likely a little lower in 2009. Nevertheless, effective January 1, 2011, all gasoline refiners and importers must be in compliance with the 0.62 vol% annual average benzene standard. So today's gasoline benzene levels are even lower than those reflected in the AAM fuel survey and 2009 compliance data. Accordingly, our proposed Tier 3 test fuel benzene specification of 0.6-0.8 vol% is expected to be representative of future in-use gasoline. These proposed benzene (and sulfur) specifications are consistent with CARB's planned LEV III specifications.

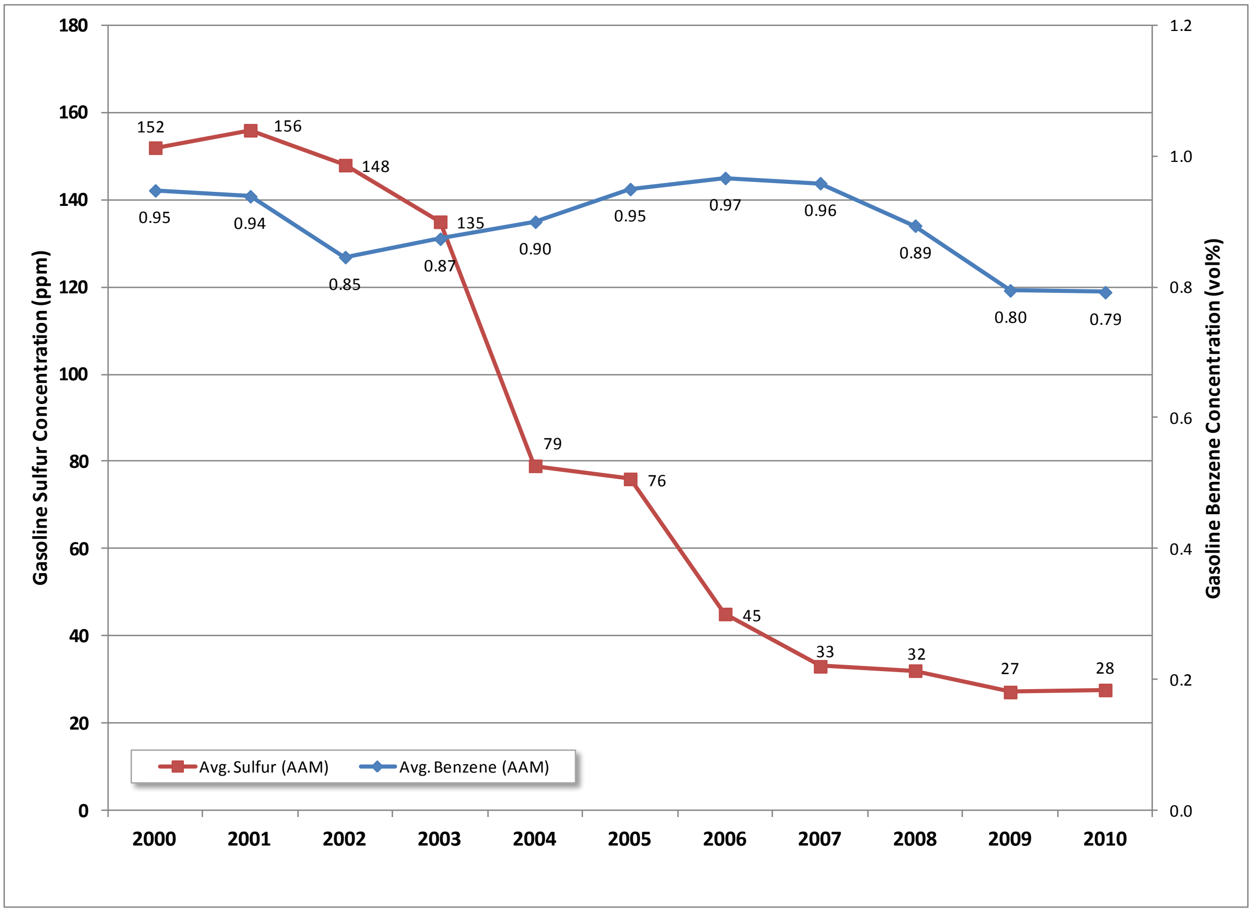

Figure 3-12 Average Gasoline Sulfur and Benzene Levels Over Time

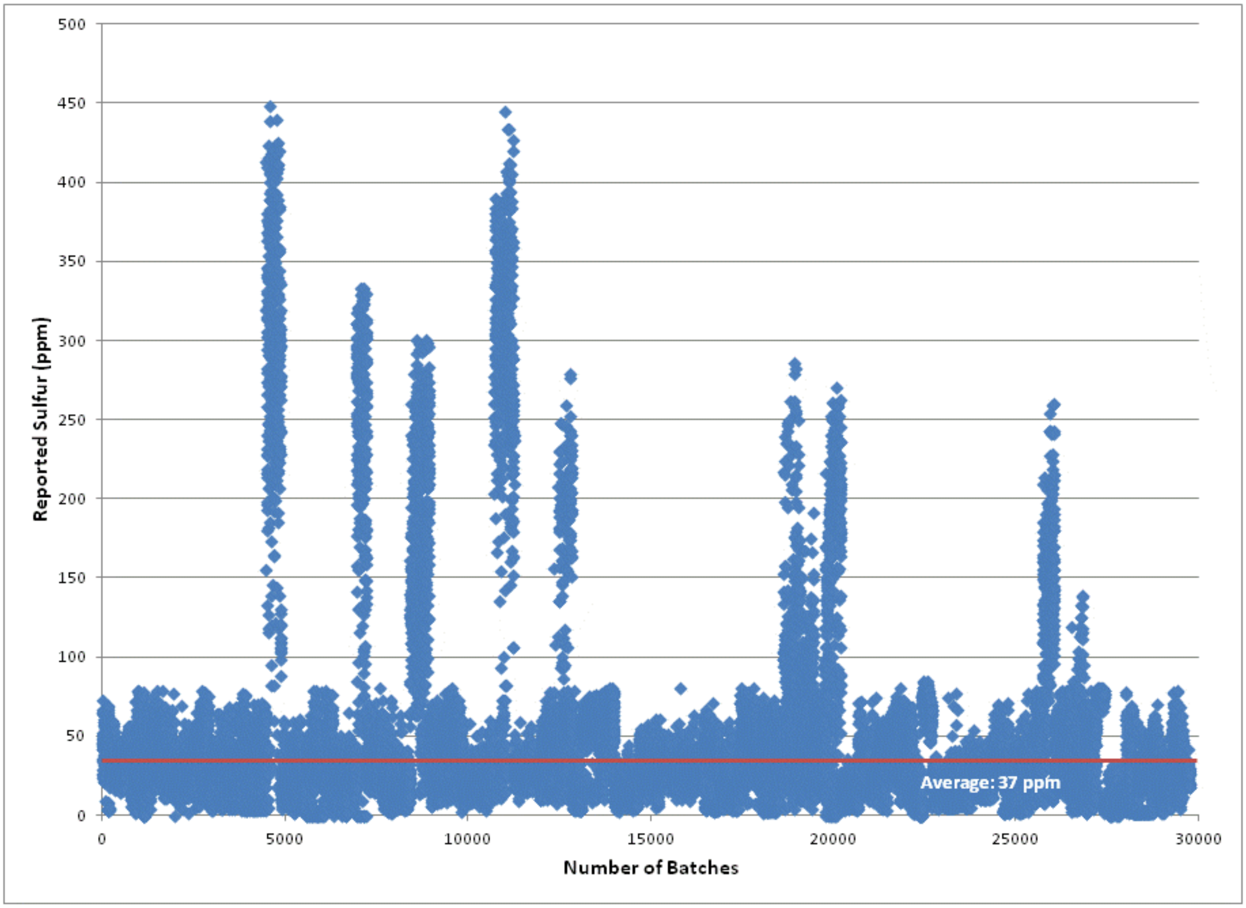

Figure 3-13 Gasoline Sulfur based on 2009 Refinery Batch Data

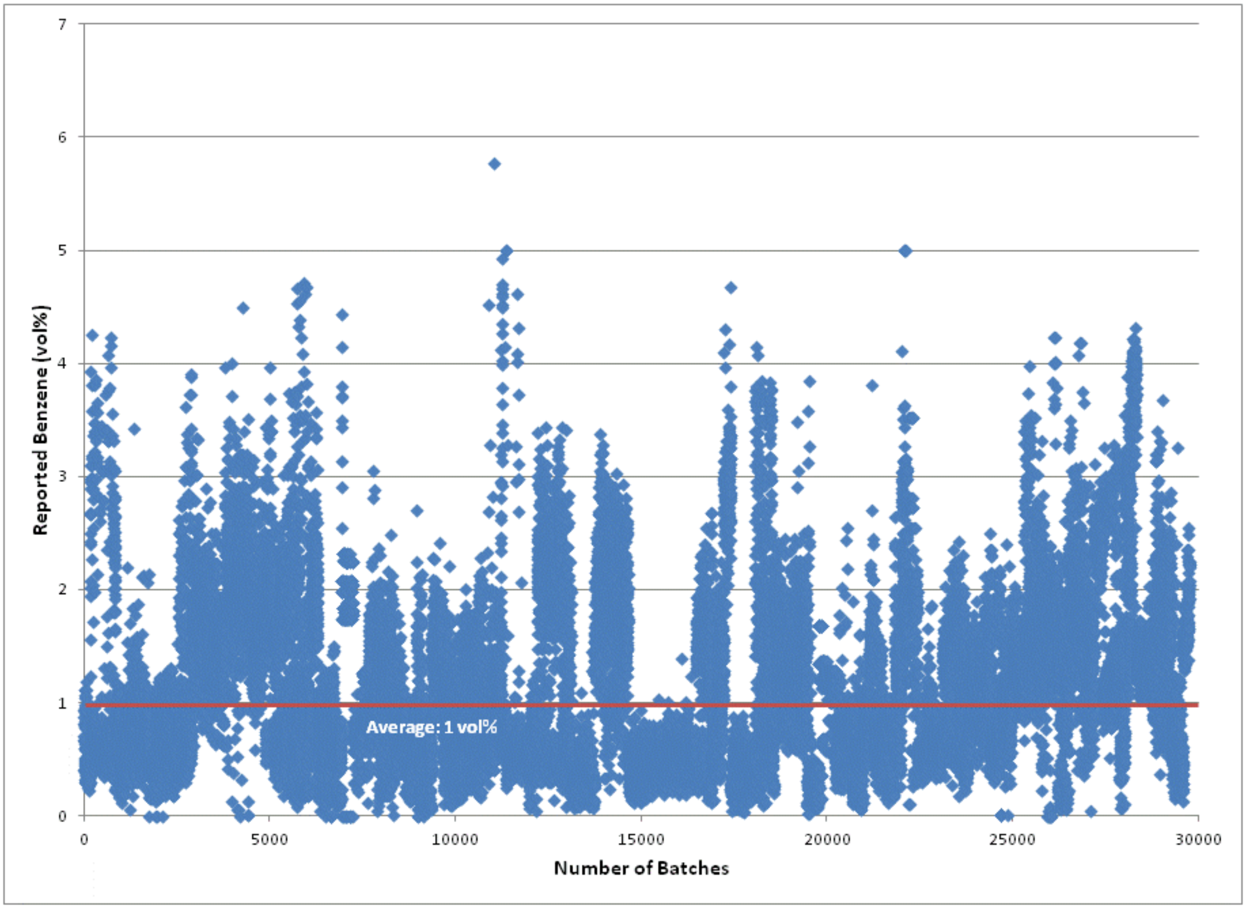

Figure 3-14 Gasoline Benzene based on 2009 Refinery Batch Data

3.2 Projected E15 Implications

In-use gasoline is projected to continue to change with the implementation of the RFS2 program and the further expansion of E15 into the marketplace. As explained in Section IV.D of the preamble, we are proposing to update our Federal emissions test fuel not only to better match today's in-use fuel (average gasoline properties detailed in Section 3.1) but also to be forward looking with respect to future ethanol content. We are proposing to add a 15 vol% ethanol specification to test fuel to be forward-looking with respect to the maximum gasoline ethanol concentration Tier 3 vehicles could expect to encounter. The additional 5 vol% ethanol will have second-order impacts on T50, aromatics, and olefins.

Shifting to E15 test fuel will result in a T50 range that's about 15 percent lower than today's E0 test fuel and about 10 percent lower than today's in-use E10. The proposed 170-190°F T50 range for E15 test fuel was determined by interpolating between the T50 of current E10 market fuel which averages around 195°F (according to AAM[B]) and the estimated T50 of

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[B] Based on our assessment of 60 U.S. fuel samples containing 9.5-10.5 vol% ethanol and 8.5-9.5 psi RVP based on AAM's summer 2010 North American Fuel Survey.

E20 which spans a narrow range of plus or minus several degrees Fahrenheit centered around 165°F (according to our EPAct test program[5]). We believe the proposed T50 range adequately characterizes future 9-psi E15 market fuel.

As explained above in Section 3.1, the commercialization of E10 has already resulted in a 15 percent reduction in aromatics and a 19 percent reduction in olefins in relative terms. Refiners are backing off on expensive aromatics and olefin production in anticipation for downstream ethanol blending. We expect that refiners will continue to back off on octane production once the transition from E10 to E15 has occurred.[C] With that, we can extrapolate to arrive at future aromatics levels in the neighborhood of 21 vol% and olefin levels in the neighborhood of 6.5 vol% for E15. Our Tier 3 sulfur standards should also result in slightly lower olefin production at the refinery. Accordingly, we are proposing an aromatics specification of 19.5-24.5 vol% and an olefins specification of 4-10 vol% (reported as 4.5-11.5 mass% per ASTM D6550) for our proposed E15 test fuel as shown in Table 3-3. We believe that these ranges encompass levels that might be typical for E15 (as well as E10) while still providing flexibility for specialty fuel manufacturers producing Tier 3 test fuel. The proposed aromatics and olefin specifications, although slightly broader to represent the wider range of Federal gasoline properties (detailed in Section 3.1), encompass CARB's planned LEV III emission test fuel specifications.

As explained earlier, in-use gasoline contains a range of aromatic compounds whose contribution to PM emissions seems to increase with carbon number. Accordingly, we are planning on building off the proposed 19.5-24.5 vol% total aromatics spec for E15 and the proposed 0.6-0.8 vol% benzene spec to set test fuel specs for the remaining unspecified aromatic hydrocarbons. For the NPRM, have relied on EPA's 2007-2011 in-use aromatics data (presented in Section 3.1.2) to arrive at the proposed C7, C8, C9 and C10+ specifications presented in Table 3-2. We seek comment on the appropriateness of the proposed aromatics specifications and welcome any additional gasoline aromatics data that others may want to provide us with through notice and comment. We also seek comment on other alternative approaches that would result in a distribution of gasoline aromatics in emissions testing fuel. One such approach might be to set regulations that require equal contributions of C7, C8, C9 and C10+ aromatics in the range of 5 ± 1 vol%.

Table 3-2 Proposed Aromatics Contributions in Tier 3 Cert Fuel

	Aromatics (vol%)
C6 (benzene)	0.6-0.8
C7 (toluene)	4.4-5.5
C8	5.5-6.9
C9	5.0-6.2
C10+	4.0-5.0
Total Aromatics	19.5-24.5

[C] In the interim, while E10 and E15 co-exist, we anticipate that refiners will make E15 using a blendstock similar to today's E10 blendstock. While this may result in a small, temporary octane giveaway, the refinery burden will likely be less than that of producing a separate sub-octane blendstock for E15.

While revisiting emission test fuel parameters, we are taking this opportunity to propose specifications for distillation residue, total content of oxygenates other than ethanol, copper corrosion, solvent-washed gum content, and oxidation stability. The proposed parameters, summarized below in Table 3-3, are consistent with ASTM's D-4814 gasoline specifications and CARB's planned LEV III test fuel requirements.

3.3 Proposed Gasoline Emission Test Fuel Specifications

As explained in Section IV.D of the preamble, we are proposing a consolidation of all gasoline exhaust and evaporative emission test fuels into a single general test fuel. This would be used for all on-highway vehicle testing with the exception of cold CO vehicle testing (which would use higher volatility test fuel) and high-altitude testing (which would be permitted to use lower volatility fuel). 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. The proposed Tier 3 test fuel specifications are summarized in Table 3-3. For more on how we arrived at the proposed ASTM test procedures, refer to Section 3.4.

Table 3-3 Proposed Gasoline Emission Test Fuel Specifications

Property	Unit	SPECIFICATION			ASTM Reference Procedure[a]
		General Testing	Low-Temperature Testing	High Altitude Testing	
Antiknock Index (R+M)/2	-	87.0 - 88.4[b]		87.0 Minimum	D2699-11 and D2700-11
Sensitivity (R-M)	-	7.5 Minimum			
Dry Vapor Pressure Equivalent (*DVPE*)[c]	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)	D5191-10b
Distillation 10% evaporated	°C (°F)	49-60 (120-140)	43-54 (110-130)	49-60 (120-140)	D86-10a
50% evaporated	°C (°F)	77-88 (170-190)			
90% evaporated	°C (°F)	154-166 (310-330)			
Evaporated final boiling point	°C (°F)	193-216 (380-420)			
Residue	milliliter	2.0 Maximum			
Total Aromatic Hydrocarbons	vol. %	19.5-24.5			D5769-10
C6 Aromatics (benzene)	vol. %	0.6-0.8			
C7 Aromatics (toluene)	vol. %	4.4-5.5			
C8 Aromatics	vol. %	5.5-6.9			
C9 Aromatics	vol. %	5.0-6.2			
C10+ Aromatics	vol. %	4.0-5.0			
Olefins[d]	mass %	4.5-11.5			D6550-10

Property	Unit	SPECIFICATION	ASTM Reference Procedure[a]
Ethanol[e]	vol. %	14.6-15.0	D5599-00 (Reapproved 2010)
Total Content of Oxygenates Other than Ethanol[e]	vol. %	0.1 Maximum	
Sulfur	mg/kg	8.0-11.0	D2622-10, D5453-09 or D7039-07
Lead	g/liter	0.0026 Maximum	D3237-06
Phosphorus	g/liter	0.0013 Maximum	D3231-11
Copper Corrosion	-	No. 1 Maximum	D130-10
Solvent-Washed Gum Content	mg/100 ml	3.0 Maximum	D381-09
Oxidation Stability	minute	1,000 Minimum	D525-05

Notes:

[a] ASTM procedures are incorporated by reference in §1065.1010. See §1065.701(d) for other allowed procedures.

[b] Octane specifications apply only for testing related to exhaust emissions. For engines or vehicles that require the use of premium fuel, as described in §1065.710(d), 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.

[c] Calculate dry vapor pressure equivalent, *DVPE*, based on the measured total vapor pressure, pT, in kPa using the following equation: $DVPE = 0.956 \cdot p\mathrm{T} - 2.39$. *DVPE* is intended to be equivalent to Reid Vapor Pressure using a different test method.

[d] The specified olefin concentration range equates to approximately 4 – 10 volume percent when measured according to ASTM D1319.

[e] The reference procedure prescribes measurement of ethanol concentration in mass %. Convert results to volume % as specified in ASTM D4815-09.

3.4 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 of petroleum-fueled Otto-cycle vehicles have been retained in the proposed 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. We are planning to replace this 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. We are planning to replace it 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 currently being used in reformulated gasoline applications. ASTM D1319 does not measure carbon number-specific aromatic hydrocarbon content, which are now specified for the ethanol-blended test fuel in 40 CFR 1065.710. In addition, ASTM D5769 and D6550 are more precise and less labor-intensive than ASTM D1319.

For sulfur measurements, we are planning to replace ASTM D1266 "Standard Test Method for Sulfur in Petroleum Products (Lamp Method)" 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 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. We request comments on the use of three different test methods for the measurement of sulfur content.

References

[1] 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.

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

[3] 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*.

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

[5] U.S. Environmental Protection Agency (2012). Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier-2 Standards (EPAct/V2/E-89: Phase 3), Part I: Program Design and Data Collection. EPA Report Number XX.

Chapter 4 Fuel Program Feasibility

4.1 Overview of Refining Operations

Figure 4-1 shows a process flow diagram for a typical complex refinery, capable of making a wide product slate (shown on the right side of the figure) from crude oil (input on the left). Following the figure is a brief description of key units and streams focusing more on the gasoline producing units.[1] It's important to note that not all refineries have all of these units, which is a key factor in both the variation in their baseline sulfur levels as well as their cost of sulfur control.

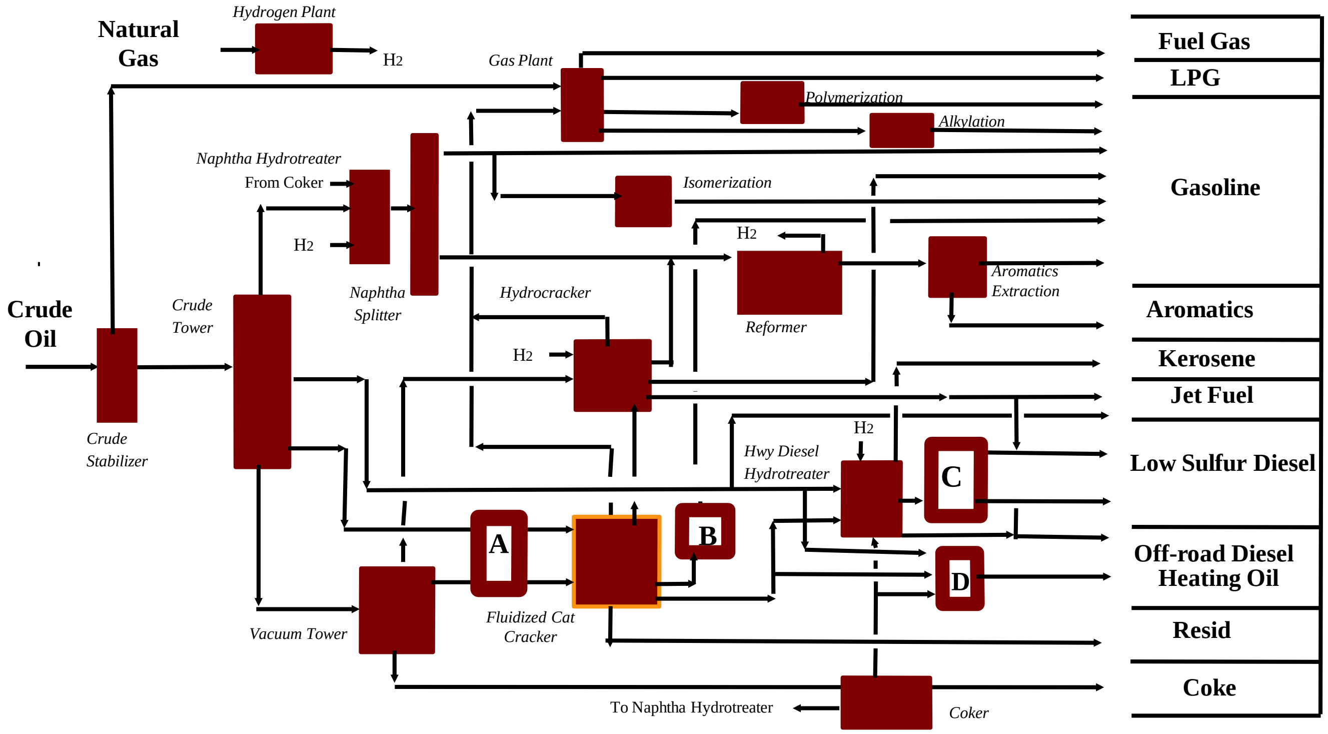

Figure 4-1 Process Flow Diagram for a Typical Complex Refinery

Crude Tower

The purpose of the crude tower is to perform a distillation separation of crude oil into different streams for additional processing in the refinery and for the production of specific products. Crude oil is shipped to the refinery via pipeline, ship, barge, rail, or truck, whereupon it is sampled, tested, and approved for processing. The crude oil is heated to between 650 °F and 700 °F and fed to crude distillation tower. Crude components vaporize and flow upward through the tower. Draw trays are installed at specific locations up the tower from which desired side cuts or fractions are withdrawn. The first side-cut above the flash zone is usually atmospheric gasoil (AGO), then diesel and kerosene/jet fuel are the next side-cuts, in that order. The lightest 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 for 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 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, their gasoline is 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_X 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 Postreat Hydtrotreater "B"

Postreat 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 postreat hydrotreaters resulting in lower octane of the FCC naphtha. Vendor companies have developed postreat hydrotreating technologies which 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.

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 can be made in two ways that it is feasible to comply with the proposed 10-ppm gasoline sulfur standard. First, feasibility can be demonstrated by understanding the technologies currently available which can achieve the necessary reductions in sulfur, and that these technologies are currently being used to achieve significant reductions in gasoline sulfur. The second way to make the case that it is feasible to comply with the proposed 10-ppm gasoline sulfur standard is to highlight that refiners in 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 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 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. When complying 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.[A] The light straight run 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 isomerizaition 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 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

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[A] 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.

between 0 and 10 ppm sulfur. To meet current pipeline and California specifications, denatured ethanol must be 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.[2] 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 only exceptions were western refiners (GPA) and small refiners who were given until 2008. Some small refiners had their gasoline sulfur deadlines extended through 2010 in the highway diesel fuel sulfur rule in exchange for on-time compliance there. 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 those refiners with low gasoline sulfur levels to begin with (i.e., gasoline sulfur levels lower than, perhaps, 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 a fluidized catalytic cracker (FCC) unit, or a coker, which convert heavy boiling stocks to gasoline. As stated above, these units push more sulfur into gasoline and their absence means much less sulfur in gasoline. Alternatively, refiners may use a very low sulfur (sweet) crude oil which can result in a low sulfur gasoline. Or, these refiners may have already installed an FCC feed hydrotreater to improve the operations of their refinery which uses a heavier, higher sulfur (more sour) crude oil. 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 in this first category, 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, those refineries which had sulfur levels above 30 ppm but below some level, such as 50 ppm, probably are meeting the 30-ppm sulfur standard by employing operational changes only and avoided making capital investments. Most of the 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, they probably have an FCC feed hydrotreating unit.

The vast majority of gasoline which was being produced was by refineries with higher sulfur levels, and these refiners had to either adapt some existing hydrotreating capital 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. This desulfurization capital investment can be installed to treat the gas oil feed to the

FCC unit, or treat the gasoline blendstock which 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, the hydrotreating which occurs in the FCC pretreater reacts hydrogen in the feedstock which increases the yield of the FCC unit by increasing the highest profit-making products produced by refineries, such as gasoline and light olefins.[3] 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 postreat hydrotreating as explained below. Another justification for this approach is that it 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 which 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 preateaters 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 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.[4] Because there is no postreating 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, the concentration of contaminants increases and the catalyst may lose its effectiveness.[5]

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 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 units are preceded by FCC pretreaters, the amount of sulfur in the feed which ends up in the FCC naphtha is only about 5 percent, which 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 effect is caused by the additional hydrogen 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 which already had or which installed high pressure FCC pretreaters were able to comply with the 30-ppm sulfur standard without the need to install a FCC naphtha hydrotreater. However, if a refinery had a low pressure, or perhaps even a medium pressure FCC feed hydrotreater, they were generally less able to comply with the 30-ppm gasoline sulfur standard with the FCC hydrotreater by itself, and these refineries were more likely to also install an FCC postreater.

4.2.2.2 Using FCC Naphtha Postreat 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 postreaters). FCC postreaters only treat the gasoline blendstock produced by the FCC unit. Understandably, this unit is much smaller 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 than that as 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 postreaters 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, the feed to the FCC unit has corrosive properties which require that FCC pretreaters use more corrosion-expensive metallurgy, which is not needed for postreaters.[6] For a medium to large-sized refinery, the capital costs are on the order of $70 million for a conventional FCC pretreaters – less than half that of an FCC pretreater.

One drawback of this desulfurization methodology 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.[7] Increased olefin saturation usually means higher hydrogen consumption. There can also be a loss in the gasoline yield caused by mild cracking which breaks some of the gasoline components into smaller fractions which are too light for blending into gasoline. If there is octane loss, two of the ways that the octane loss can be made up is by blending in more ethanol, or by increasing the feed to or the severity of the reformer, the aromatics production unit of the refinery. Sometimes vendors of FCC pretreater technologies design octane increasing capability into their designs, which is discussed below in the section about the individual postreater technologies.

The loss of octane and gasoline yield caused by FCC postreating is lower with technologies which were developed prior to the implementation of the Tier 2 program.[8] These 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 which result in less cracking preserving 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 postreaters 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 postreaters 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. 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.[9] 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 downside 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.

Whatever strategy chosen by the refiner to comply with Tier 2, a critical criterion is that the postreater be capable of cycle lengths that match that of the FCC unit, which typically is 5 years. If the postreater were to require a catalyst changeout before the FCC unit requires a shutdown, either the refiner would have to shutdown the FCC unit early to mirror that of the postreater, or need to store up 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 postreater was started up again and is able to hydrotreat the stored up high sulfur FCC naphtha.

We know of six FCC postreater technologies that refiners used to comply with the Tier 2 gasoline sulfur standards. These are Axens (was IFP) Prime G and Prime G+, Exxon Scanfining, CDTech's CDHydro and HDS, Sinopec's (was Phillips)S-Zorb and UOP's ISAL and Selectfining.

Of the list of FCC postreaters, Axens Prime G+, Exxon Scanfining and UOP's ISAL and Selectfining are fixed bed desulfurization technologies. These processes are called fixed bed because the catalyst resides in a fixed bed reactor.[10] 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 which 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.

Despite the similarities, each of these desulfurization technologies has its differences. Axens Prime G+ desulfurization process largely preserves olefins as its strategy for diminishing octane loss.[11,12 13] 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.

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.

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.[14] [15] [16] [17] [18] [19] 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.[20] 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.[21] 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.[22] [23] The ISAL process is different than 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 licenses its own FCC naphtha desulfurization technology named SelectFining.[24] 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.

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.

Although the CDTech process is significantly different from the fixed bed hydrotreating technologies, it still uses the same type of catalyst. The CDTech process utilizes catalytic distillation.[25,26,27] 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) which 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 off the portion of the FCC naphtha which he wishes not to treat. With the CDTech process, the refiner can choose to treat the entire pool or a portion of the pool, but choosing to treat a part of the pool can be an option in how the CDTech hardware is applied, 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.[28] [29] In 2007, Phillips sold the S-Zorb process to SINOPEC. 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.[30] The untreated FCC naphtha and hydrogen are fed to the reaction vessel where the catalyst catalytically removes the sulfur from the petroleum compound 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 disulfude 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, but our information sources have communicated that only 4 units are actually operating today.

We conducted a literature search or in some cases asked vendors to name which refineries installed their FCC naphtha desulfurization technology 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	1	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 settled on this as the primary strategy we chose for analyzing the compliance costs for Tier 3. The first reason is that, even after refiners used hydrotreating to reduce the sulfur in the FCC naphtha to comply with Tier 2, FCC naphtha is by far the largest contributor of sulfur to the gasoline pool, by virtue of both its volume and sulfur content. 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 situation. By using the refinery-by-refinery model to model today's situation for the typical refinery, we estimate that the FCC naphtha contains about 70 ppm for the typical refinery complying with the 30-ppm Tier 2 sulfur standard and that gasoline blendstock typically contributes to about 40 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 proposed 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 70 ppm to 20 ppm. In fact, for virtually all refineries that have an FCC unit, refiners would not be able to comply with the proposed 10-ppm gasoline sulfur standard without further desulfurizing the FCC naphtha. The second reason why we believe that refiners would address the sulfur in the FCC naphtha is because 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, FCC naphtha hydrotreaters will already be in place that 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	72	36	22
Reformate	23	0.5	22	0.5
Alkylate	13	5	13	5
Isomerate	3	0.5	3	0.5
Butane	4	10	4	10
Light Straight Run Naphtha and Natural Gas Liquids	5	34	5	1
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 70 ppm to 20 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 70 ppm to

20 ppm to enable compliance with Tier 2, there are many refineries which are not typical and so their starting and ending sulfur levels would be different from this example. Despite these differences, we believe that every refinery could technically comply with a 10-ppm gasoline sulfur standard. This is because gasoline sulfur is easy to remove - the challenge is to comply while minimizing the cost of doing so. This challenge is further discussed in Section 4.2.3.5 below which discusses the value of the proposed 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 the 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, butane and natural gas liquids. This is discussed at the end of this section about other gasoline streams.

4.2.3.1 Meeting 10 ppm if Refiners Used an FCC Feed Pretreater to Comply with Tier 2

If a refiner relied on an FCC pretreater to comply with Tier 2 at a refinery, the refiner would likely only be able to achieve 10-ppm sulfur gasoline if their FCC pretreater is a high pressure unit.[31] [32] This is because most refineries which 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 is likely true even if the refiner added reactor volume to its existing low or medium pressure FCC pretreater which does cause additional desulfurization. The problem with the mid and low pressure FCC pretreaters is that they 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. Thus, 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 postreater. Alternatively, refiners in this situation would be in the best situation to take advantage of the averaging aspect 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 need to purchase credits to demonstrate the remainder of its compliance with the 10-ppm gasoline sulfur standard. This scenario would avoid the need for a refiner to install an expensive grassroots FCC postreater.

While they are expensive to install, FCC pretreaters provide important operating cost advantages over postreaters. 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 which 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 or all of the increased operating costs incurred. Perhaps only 5 refineries have high pressure FCC pretreaters in the U.S.

4.2.3.2 Meeting 10 ppm if Refiners Used an FCC Postreater to comply with Tier 2

If a refiner installed an FCC postreater to comply with the Tier 2 gasoline sulfur standard, there are several considerations about the current configuration of the postreater which would affect how a refiner would use this unit to comply with a 10-ppm gasoline sulfur standard. The first issue is what is the degree of desulfurization the postreater is currently facing? It makes sense to work through several examples to understand the types of revamps and associated investments that might occur.

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 postreater is currently removing almost 97 percent of the feed sulfur assuming that the sulfur level of the FCC naphtha exiting postreater is 70 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 postreater. Most all 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 just be turned up and that no additional capital investments would be needed. A Conoco-Phillips hydrotreating specialist we spoke to confirmed that this would be the strategy for their S-Zorb units. Yet one more option, if the refiner is interested in improving its operating margins such as increased gasoline production, and has ample capital dollars to spend, the 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 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 postreaters to achieve lower sulfur without additional capital cost investments. However, many refiners in this situation which invested in an FCC postreater 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 postreater by hydrotreating the full range FCC naphtha. Therefore, the increased severity of the postreater 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 postreater 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 postreater.

The last example of a postreater deserving some discussion is the case where the sulfur level exiting the FCC unit is 800 ppm. This is probably most typical of a refinery refining a 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, a refiner in this position would not likely consider adding a second stage. This is because avoiding the increased octane loss and increased hydrogen consumption for the additional increment of sulfur reduction would probably not justify the capital costs associated with a second stage. Instead of a second stage, a refiner could revamp the existing FCC postreater 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.

Perhaps the most important part of an FCC hydrotreater is 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 minimize 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 out when the postreater is being taken down for regular maintenance, and new and improved catalysts can be used to improve the desulfurization capacity of the unit. If refiners indeed need to comply with a 10-ppm gasoline sulfur standard, 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 catalysts being marketed by the various vendors. We can confirm that Axens and UOP have introduced more active catalysts since the catalysts were loaded into the FCC postreaters to comply with Tier 2, although it is likely that all the vendors now offer improved hydrotreating catalysts.

4.2.3.3 Desulfurizing Other Blendstocks

A more stringent gasoline sulfur standard could require refiners to have to address other gasoline streams that are high enough in sulfur to be a concern to the refiners. This is because without addressing these 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, natural gas liquids and butane.

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 don’t 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. Butane is natural occurring in crude oil and butane is also produced by the FCC unit, and to a lesser degree, hydrocrackers. Refiners separate the butane from these various streams and then blend it back into their gasoline pool depending on the RVP requirements of the gasoline market that the refiner is selling their gasoline into.

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 postreaters 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 won't be as low compared to desulfurization using hydrotreating. 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 postreaters or naphtha hydrotreaters could treat these streams.

Butane is normally treated using mercaptan extraction technologies. We are aware that some refiners have installed at least a few of these units at their refineries to address butane sulfur. Because butane is usually relatively low in sulfur to begin with, refiners are likely to only pursue desulfurizing this gasoline blendstock if their butane is higher than average in sulfur, or if they are considering producing a very low sulfur gasoline, such as 5 ppm.

In summary, to comply with a 10-ppm gasoline sulfur standard, refiners have a range of options available to them, most of which involve reducing the sulfur in the FCC naphtha. If a refinery has a high pressure FCC pretreater, the refiner may be able to just turn up the hydrotreating severity of that unit. If a refinery has a low or medium pressure FCC pretreater and no postreater, the refinery would likely need to install a grassroots FCC postreater to comply with a 10-ppm gasoline sulfur standard, or achieve the most that it can with its current capital and rely on the ABT program. Refiners with FCC postreaters have multiple options. If a refinery is short on octane and hydrogen, the refiner is likely to invest in capital 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 postreater. Refineries with postreaters could always invest in an FCC pretreater (hydrotreater or mild hydrocracker) to improve its refinery's margins or to 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 that continue to have high enough sulfur levels which would be a concern when faced with a more stringent gasoline sulfur standard, and several options exist for addressing the sulfur in these gasoline blendstocks.

4.2.3.4 Demonstrated Compliance with a 10-ppm Gasoline Sulfur Standard

There are multiple cases today where refiners are complying with 10-ppm or lower gasoline sulfur programs. The State of California required 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 poorer quality 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.

4.2.3.5 Improved Feasibility with the Proposed 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. To make the point, it is useful to first understand compliance if the ABT and small refiner and small volume refinery provisions did not exist. Without these provisions, all refineries would have to comply with the 10-ppm gasoline sulfur standard by January 1, 2017. In the approximate 4 years after finalizing this rulemaking, most refiners would have to make capital investments in their refineries to enable compliance with the 10-ppm gasoline sulfur standard. These investments include revamped FCC pretreaters and postreaters, and the installation of grassroots FCC postreaters. As described above, reaching 10 ppm sulfur in the gasoline pool is attainable 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 during a period of time in which 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. Also, the delay allows the small refiners to experience improved margins for a couple of years when other larger refineries are complying with the gasoline sulfur standards.

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 which 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 the refineries which are expected to incur higher costs for reducing their gasoline sulfur levels allowing those refineries to delay investments for lowering their gasoline sulfur. This phasing-in of the gasoline sulfur standard will help spread out the preliminary design demands on the vendor companies which license the desulfurization technology to refiners, spread out the detailed design demands on the engineering companies which provide that service to refiners, spread out the permitting demands on the states which must provide environmental permits to refiners, and spread out the demands on the fabrication shops which 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 to show compliance or help to show compliance at higher cost or financially challenged refineries.

4.2.3.6 Implications of an Average Gasoline Sulfur Standard Less than 10 ppm

While there may be emissions motivations for further reducing gasoline sulfur levels, there are practical reasons for proposing a 10-ppm annual average sulfur standard instead of a more stringent standard, e.g., 5 ppm. The lower the sulfur standard, the more costly it is for refiners to achieve the lower sulfur standard. We identified several reasons why the costs increase so much for more deeply desulfurizing the gasoline pool.

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 even greater capital investments. For example, the most expensive capital investment for an FCC postreater 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 postreater.

There are several other reasons which further increases the desulfurization cost for a gasoline sulfur standard less than 10 ppm beyond the higher FCC postreater cost. Per Table 4-2, other refinery streams contain a very modest amount of sulfur, yet a 5-ppm sulfur standard would likely require desulfurization of some of these streams. For example, we believe that to comply with a 5-ppm gasoline sulfur standard, most refiners would need to treat the butane blended into the gasoline pool. 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 besides butane. Each additional individual gasoline stream that requires desulfurization is incrementally a lot more expensive than addressing the sulfur from the FCC unit because the amount of sulfur reduction is a lot lower, but the capital costs are higher on a per-barrel basis for lower volume gasoline blendstock streams. Furthermore, desulfurizing gasoline down to 5 ppm essentially removes the flexibility offered by the 10-ppm gasoline sulfur standard with 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, this would essentially end the ability of the refiners to average sulfur reductions across their refineries thus significantly increasing the costs while significantly reducing the desulfurization flexibility.

Going lower than 10 ppm would cause control costs to quickly escalate as more challenged refineries would be forced into much larger investments. Our cost estimates for 5 ppm versus 10 ppm with averaging bears this out. We estimate the cost for a 10-ppm gasoline sulfur standard (assuming intra-company credit trading) to be 0.89 ¢/gal compared to 1.38 ¢/gal for the 5-ppm standard. The cost per sulfur reduction for the 10-ppm average standard is 0.89 ¢/gal for the 20 ppm sulfur reduction from Tier 2, or 0.045 ¢/ppm-gal. The cost per sulfur reduction for the 5-ppm standard is 0.49 ¢/gal for the 5-ppm sulfur difference from the 10-ppm average standard, or 0.098 ¢/ppm-gal, 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 appears to be the point which properly balances feasibility with costs.

In much of Europe and Japan, the gasoline sulfur level is capped at 10 ppm. We, however, are not considering a 10-ppm cap for the U.S. The U.S. gasoline distribution system poses contamination challenges that make it difficult to set and enforce tight downstream per-gallon sulfur standards. The U.S. gasoline distribution system poses contamination challenges that make it difficult to set and enforce tight downstream sulfur standards. In Europe, Japan, and California, finished petroleum products are generally shipped short distances directly from the refinery to the terminal with limited susceptibility to contamination. The U.S. has the longest and most complex gasoline distribution system in the world, making it harder to control sulfur contamination than in other countries. Petroleum products are shipped long distances through multi-product pipelines. Further, gasoline goes through the same pipelines and terminals back-to-back with jet fuel (containing up to 2,000 ppm sulfur). Products are often in the custody of a number of separate companies before reaching the terminal. This system is very effective at delivering petroleum products to the bulk of the country, but pipeline transport inevitably introduces the potential for sulfur contamination of the gasoline being shipped through pipelines. Gasoline additives, needed to provide critical fuel performance characteristics (e.g., corrosion control, demulsifiers), also contain varying levels of sulfur which contribute to the overall sulfur content of gasoline. Therefore, we are proposing a 10-ppm average sulfur standard coupled with higher per gallon caps at both the refinery gate and at all points downstream, as 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 considered lowering the 80-ppm cap standard that applies to refiners under the Tier 2 program. If we were to lower the cap standard, we analyzed lowering it to two different possible sulfur levels, either 50 ppm or 20 ppm. If we lowered the refinery cap standard to 20 ppm, then the averaging aspect of the ABT program would essentially not be available to refiners. That is because, under a 20-ppm cap standard, we estimate that refiners would average about 10 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 not have much 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). According to EPA batch data, there were 20 refineries that averaged between 40 and 80 ppm sulfur during 2009. These refineries are using credits to show compliance with the Tier 2 30-ppm gasoline sulfur standard. If the 80-ppm cap were to be reduced to 50 ppm, those refineries that were averaging over 40 ppm would be forced to reduce their sulfur levels below the cap even if their financial situation is more tenable compared to other refineries. However, even if the cap standard were to remain at 80 ppm, most of the 20 refineries that averaged between 40 and 80 ppm under Tier 2 would have to lower their sulfur anyways because of the stringency of the proposed 10-ppm sulfur standard. There would not be sufficient credits available to allow most of those refineries remain at high gasoline sulfur levels. Our cost analysis, which assumes intra-company credit trading, projects that only one refinery would remain just above 40 ppm when the fuels program is fully phased in. For more on our cost analysis, refer to Chapter 5 of the draft RIA.

Another way that a more stringent cap would affect refiners would be to restrict the ability of refiners to process high sulfur FCC naphtha when there is a short term shutdown of the FCC postreater. If the FCC postreater 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 material to other refiners, or hydrotreat the stored up FCC naphtha along with the ongoing production of high sulfur FCC naphtha once the FCC postreater 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 postreater. Without this flexibility, the refiner may have to oversize the FCC postreater and 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 that would result in 10 ppm sulfur in the gasoline pool. If the cap were to be lowered, a 50-ppm cap standard would clearly continue to provide refiners with some flexibility while a 20-ppm cap would not. Even if refiners planned to tolerate some higher sulfur batches when hydrotreating stored FCC naphtha, it could not tolerate much volume of higher sulfur batched because of the need to average 10 ppm over the calendar year. If such outages happen very infrequently, then a small amount of credits could regularly be banked over time that would allow for some longer term higher sulfur batches of gasoline as the stored FCC naphtha was being hydrotreated. Alternatively, the averaging of sulfur credits would help refiners with FCC naphtha hydrotreater outages. Thus, the flexibility of the ABT program coupled with a higher cap standard would provide refiners with some flexibility to handle FCC unit outages.

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 are proposing two potential options for the per-gallon downstream sulfur cap. Under the first option, we are proposing to maintain the current 95-ppm downstream sulfur cap. This option is associated with the proposed maintenance of the current 80-ppm refinery/importer gate sulfur cap and is reflected in the draft regulatory text. Under the second option, we are proposing that the downstream sulfur cap would be reduced to 65 ppm. This option is associated with the proposed reduction in the refinery/importer gate sulfur cap to 50 ppm. Under both of these options, we would be maintaining the current 15-ppm differential between the refinery/importer gate sulfur cap and the downstream sulfur cap.

We are also requesting comment on the potential implementation of a downstream sulfur cap as low as 25 ppm. This scenario is associated with a reduction of the refinery/importer gate sulfur cap to as low as 20 ppm. Under this scenario, the differential between the refinery/importer gate sulfur cap and the downstream sulfur cap might be a little as 5 ppm.

Under all of these potential approaches, the downstream sulfur cap would apply 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 caps under consideration 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 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.

There are currently no direct regulatory controls on the sulfur content of gasoline additives. 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.[33] 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.[B][34]

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 salable 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.[C][35] 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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[B] Aftermarket additives are defined as additives sold to vehicle operators for direct addition to vehicle fuel tanks.

[C] 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.[36] 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 proposed 10-ppm refinery average sulfur standard.

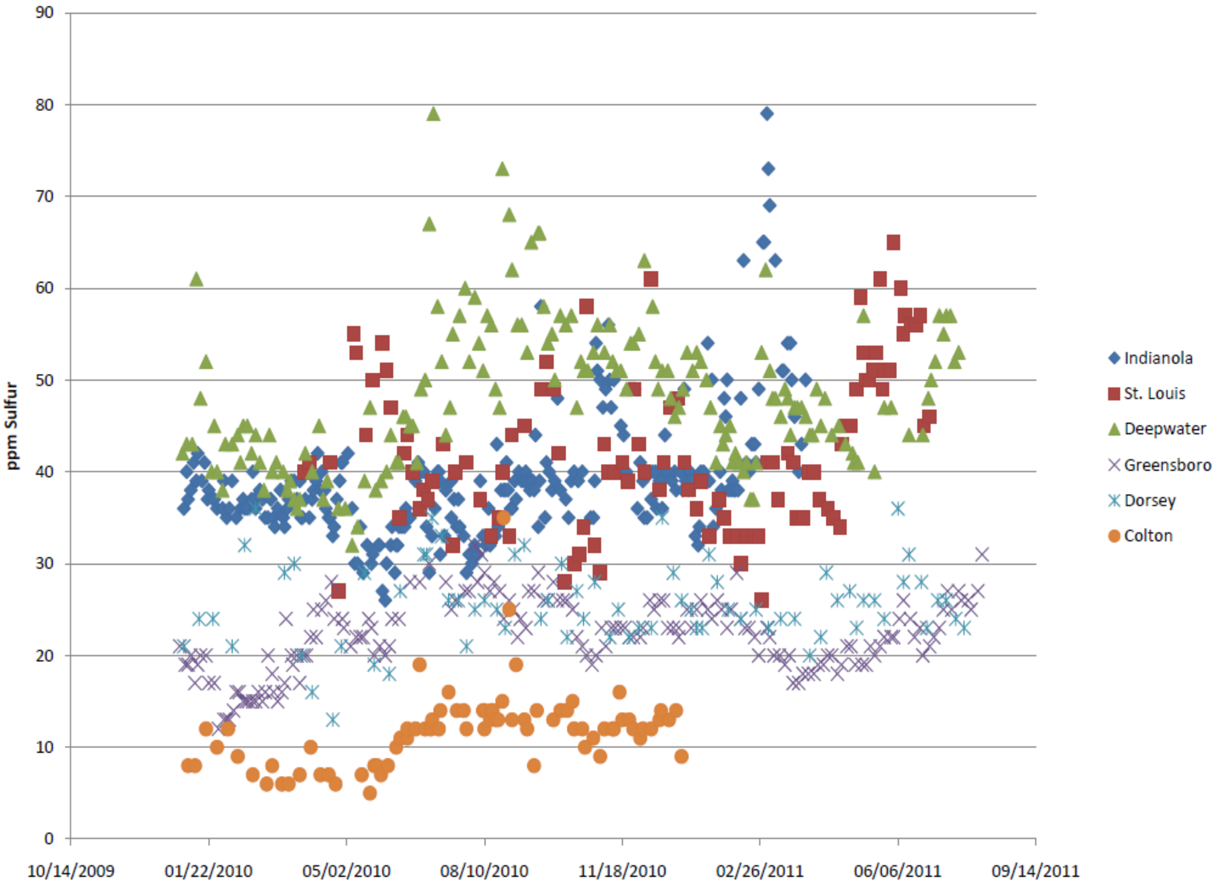

Figure 4-2 Kinder Morgan Transmix Gasoline Product Sulfur Levels

4.2.4.2.2 Maintaining the Current 15-ppm Differential Between the Refinery /Importer Gate and Downstream Sulfur Caps

Under both of the co-proposals for a downstream sulfur cap (95 ppm and 65 ppm), we would be maintaining the current 15-ppm differential between the refinery/importer gate sulfur cap and the downstream sulfur cap.

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

Our co-proposal to maintain the current 95-ppm downstream sulfur cap with an 80-ppm refinery/importer gate sulfur cap represents no change from current requirements. As a result, there would 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.

Our co-proposal to implement a 65-ppm downstream sulfur cap with a 50-ppm refinery gate sulfur cap would also maintain the current 15-ppm differential between these sulfur caps under the Tier 2 program. Since it is this differential that determines the difficulty in complying with the downstream sulfur cap, we expect that there would be no operational changes and additional costs for downstream parties associated with satisfying a 65-ppm cap downstream sulfur cap beyond those that were already incurred under the Tier 2 program to comply with the current 95-ppm downstream sulfur cap.

Under both of the co-proposals, the reduction in the refinery average sulfur standard 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 Potential Reduction in the Differential Between the Refinery/Importer Gate and Downstream Sulfur Caps

We requested comment on the potential implementation of a refinery gate sulfur cap as low as 20 ppm and a corresponding downstream sulfur cap as low as 25 ppm. This was driven by vehicle manufacturers concerns about the potential impacts on emissions performance if vehicles are exposed to gasoline above the proposed 10-ppm refinery average standard.[37] As discussed in Sections 1.2 and 5.2 of this draft RIA, the vehicle emissions benefits associated with today's proposal are driven by the proposed reduction in the average sulfur content of gasoline from 30 to 10 ppm. We believe that the potential benefits from further reductions in the sulfur caps would be minimal. However, further reductions in the sulfur caps could have negative impacts on refiners and downstream parties.

The potential impacts on refiners and additional costs associated with a lower refinery/importer gate sulfur cap discussed in Section 4.2.4.1. A reduction in the differential between the refinery gate sulfur standard and the downstream sulfur standard could also result in negative impacts and additional costs to downstream entities. Reducing the current 15-ppm differential between the refinery/importer gate and downstream sulfur caps could limit the ability of transmix processors to continue to produce finished gasoline, limit the ability of pipeline operators to continue to blend transmix in gasoline, and potentially require the direct regulation of gasoline additive sulfur content which might cause certain gasoline additives to be removed from the market.

Some gasoline additive manufactures relate that it would not be technically possible to reformulate their additives to meet a lower sulfur cap. Hence, the implementation of a sulfur cap for gasoline additives could result in the withdrawal of some necessary and cost-effective gasoline additives (e.g., corrosion inhibitors, and demulsifiers) from the market. Other additive manufactures related that there would be significant costs in reformulating their additives to meet a lower sulfur cap. Some additive manufactures related that they could not justify the cost of reformulation and would need to cease manufacture.

Since gasoline additives may add as much as 3 ppm to the sulfur content of the finished fuel, allowing for further sulfur contamination during distribution and for test variability means that transmix processors must produce gasoline about 5 ppm below the downstream sulfur cap. The sulfur levels in the transmix that processors must cope with would be reduced due to the proposed reduction the gasoline sulfur requirements for refiners/importers. However, the continued presence of high-sulfur jet fuel in transmix would continue to significantly influence the sulfur content of the gasoline produced by transmix processors. Given these considerations, a reduction in the differential between the refinery gate sulfur cap and the downstream sulfur cap might require that the majority of the gasoline produced by transmix processors to be desulfurized, something that is cost-prohibitive to do at transmix processing facilities today. Other options for dealing with transmix, however, are just as impractical, including shipping it back to refineries for reprocessing. Refiners are typically averse to accepting transmix into their facilities for reprocessing due to technical, logistical, and economic constraints. In addition, transmix would typically need to be shipped long distances from the ends of the product distribution by truck to reach a refinery.

If pipeline operators were further limited in their ability to blend small amounts of transmix into gasoline due to a reduction in the differential between the refinery/importer gate and downstream sulfur caps, they could be compelled to install additional transmix storage and shipping facilities at numerous remote locations to facilitate the shipment of small volumes of transmix to transmix processors by truck. One major pipeline operator reported that it has over 100 locations on its system where transmix can be injected into gasoline, some of which do not have tank truck access. Thus, a reduction in the differential between the refinery/importer gate and downstream sulfur caps could result in substantial additional costs and potential changes to transmix operating practices for the pipeline operators.

4.3 Lead Time Assessment

4.3.1 Engineering and Construction Analysis

Given the complexity of gasoline refining, numerous planning and action steps would be required for refiners to complete the refinery changes needed to comply with the proposed Tier 3 sulfur standards. The steps required to implement these changes include: the completion of scoping studies, financing, process design for new or revamped refinery units or subunits, permitting, detailed engineering based upon the process design, field construction of the gasoline sulfur reduction facilities, and start-up and shakedown of the newly installed desulfurization equipment.

We conducted a more thorough lead time analysis in which we sequenced the estimated time to complete scoping studies, process design, permitting, detailed engineering, field construction, and start-up and shakedown in advance of production based upon the methodology used in our recent gasoline and diesel rules.

For the proposed Tier 3 gasoline sulfur program, we estimated refinery lead times required for two general types of refinery projects: the construction of new grassroots FCC postreaters and the revamp of existing pre and postreaters. For each refinery project, we estimated lead times for scoping studies, process design, permitting, detailed engineering, field construction, and start-up and shakedown. Estimated required lead times for scoping studies are six months. Process design ranged from six months for desulfurization equipment revamping to nine months for a grassroots postreater. Based on discussions with refiners, a review of the permitting experience for Tier 2 and our current analysis, we estimate that permitting for desulfurization equipment revamping and the construction of a grassroots postreater would take 9 months. However, we estimate the overall lead-times for Tier-3-related revamps to be considerably shorter, as described below. The estimates for permitting time are consistent with those of EPA's Office of Air Quality Planning and Standards (OAQPS) and our regional offices, both of which have engaged in extensive dialog with potentially affected parties. A discussion of the permitting implications of Tier 3 is contained in Section V.B of the preamble. Detailed engineering efforts were estimated to require six months for desulfurization equipment revamping and nine months for grassroots postreaters. Field construction was estimated to require six months for revamped pre-and postreaters and 12 months for grassroots postreaters. Start-up and shakedown processes were estimated to require six months for revamped FCC treaters and 9 months for grassroots postreaters. There is some degree of overlap among each of these steps as shown in Table 4-3.

To allow refiners to complete all these different steps and comply with the 10 ppm average gasoline sulfur standard, assuming the Tier 3 proposal were to be finalized by the end of 2013, we would be providing three years of lead time. In addition to the three years of lead time, the proposed rulemaking also provides additional flexibility provided by the ABT program, small refinery delays, and hardship provisions. To support this timeline, we conducted several analyses of the expected refinery lead time requirements associated with the proposed Tier 3 standards and found that refinery operators would have more than adequate time to implement the required refinery charges. A justification for proposed timeline appears below.

Complying with Tier 3 is expected to involve some grassroots (new) FCC postreaters, but mostly we believe that refiners will revamp existing FCC postreaters. Revamping of existing FCC postreaters can be accomplished in approximately 2 years, or less (See Table 4-3) Grassroots FCC postreaters are expected to require on average about three-years to install and start-up (See Table 4-3). In comparision to FCC pretreaters, hydrocrackers and distillate hydrotreaters, FCC postreaters are much less costly, low pressure units that take less time to scope out, require shorter lead times for ordering the equipment, and less time to install. Furthermore, the grassroots FCC postreaters to be installed for Tier 3 are expected to be in a moderate to light desulfurization service because the refineries they will be installed in will already be complying with Tier 2 using an FCC pretreater. FCC naphtha from a refinery with an FCC pretreater is expected to only contain about 100 ppm sulfur. To comply with Tier 3, refiners installing these grassroots FCC postreaters would only need to desulfurize the FCC naphtha down to 25 ppm (about a 75% reduction). In comparison, a single-stage FCC postreater would have to desulfurze FCC naphtha from as high as 2400 ppm sulfur down to 25 ppm, a 99% sulfur reduction. The more moderate desulfurization service of the grassroots FCC postreaters needed to comply with Tier 3 would be expected to streamline the scoping and design work.

Table 4-3 Anticipated Compliance Timelines

		Months														
		0-3	3-6	6-9	9-12	12-15	15-18	18-21	21-24	24-27	27-30	30-33	33-36	36-39	39-42	42-45
Revamp Pre- & Postreaters	Scoping Studies	■	■													
	Process Design		■	■												
	Permitting			■	■	■										
	Detailed Engineering				■	■										
	Field Construction						■	■								
	Start-up / Shakedown							■	■							
Grassroots Postreater	Scoping Studies	■	■													
	Process Design		■	■	■											
	Permitting			■	■	■										
	Detailed Engineering					■	■	■								
	Field Construction							■	■	■	■					
	Start-up / Shakedown										■	■	■			

It is useful to compare the proposed lead time for Tier 3 to what was provided for Tier 2. In the case of the Tier 2 standard, we provided a three-year lead time along with an ABT program and other flexibilities to ease compliance. Refiners, though, commented that the three year timeline that we provided was not enough time. For the Tier 2 analysis, we assumed that refiners would solely install low-pressure FCC postreaters, which we believe could be scoped out, designed, installed and started up within a 3 year time period. However, many refiners complied with Tier 2 by installing high-pressure FCC pretreaters which require long lead times for the procurement of the required equipment. Furthermore, those refiners that did not install high-pressure FCC pretreaters instead installed grassroots FCC postreaters, many of which were designed for severe desulfurization service. An additional difference between Tier 3 and Tier 2 is that for Tier 3 we expect the installation of only 16 grassroots units, along with many revamps, but for Tier 2 virtually all refiners installed both grassroots FCC pretreaters and postreaters. The demands on the desulfurization vendors for scoping studies, and on the E & C industry for design and construction, and on the refiners to train their operations staff and start up the new units, was a lot greater for Tier 2 than what we would expect for Tier 3. The total estimated investment cost for Tier 2 versus Tier 3 also highlights the difference in investment demands

The total investment for Tier-2 desulfurization processing units was estimated to be about $6.1 billion, while the total investment for Tier-3 desulfurization processing units is estimated to be about $2.1 billion. This simple comparison indicates that the proposed Tier 3 lead time should be adequate for refineries to obtain necessary permits, secure engineering and construction (E&C) resources, install new desulfurization equipment and make all necessary retrofits to meet the proposed sulfur standards.

We assessed the permitting situation in more detail working in conjunction with the Office of Air Quality, Planning and Standards (OAQPS). On a refinery-by-refinery basis, we provided OAQPS estimates of the additional heating demands for the new and revamped units per the desulfurization vendor submissions. OAQPS was able to project which refineries would likely trigger NOx, particulate matter and greenhouse gas emission permitting limits, which would likely lengthen the permitting process as refiners would need to offset the projected emission increases. As it turns out, only 2 of the 16 refineries which are projected to install grassroots units were projected to exceed particular permitting limits, and these solely did so based on the most conservative assumption that each would produce all the additional hydrogen on site using hydrogen plants (as opposed to using existing reforming capacity) and produce the electricity on site, to satisfy the needs of the new desulfurization equipment. When we provided a second heat demand estimate to OAQPS which assumes that refiners purchase their hydrogen and electricity from third parties, none of the refineries which we projected would install grassroots units was projected to have emission increases which would require offsets. Thus, many of the grassroots units that we project would be installed may end up with a streamlined permitting processe.

The various flexibilities that the proposed Tier 3 rule provides to refiners provide refiners additional time for complying. These flexibilities include the ABT program, the small refiner delay provisions and the hardship provisions. The ABT program allows a refiner, either within its own company or by purchasing credits on the open market, to delay higher investment cost investments, such as the investments in grassroots FCC postreaters, which would provide additional lead time for installing these units. This would occur if refiners would reduce the sulfur levels of their gasoline through operational changes or revamps of their existing FCC pretreaters and postreaters when the ABT Program begins in 2014. Potentially every refinery with either an FCC pretreater or an FCC postreater may be capable of generating early credits. Furthermore, we project that 66 refineries would revamp their existing FCC postreaters to comply with Tier 3. Since revamps can be completed within two years or less, these refiners could potentially begin generating early credits during 2016, or before if refiners begin each of these revamps in early 2014. During the period between 2014 and 2017, these refineries which reduce their gasoline sulfur levels below that required by Tier 2 would generate credits. Refineries with higher cost capital investments, such as the grassroots FCC postreaters, could then delay making those investments through the purchase of credits. We estimate that sufficient credits could be generated early to allow many refineries to delay compliance until as late as

2020. The quantitative early credit analysis that we conducted showed that if refiners with an existing pretreater or postreater would generate early credits by lowering their gasoline sulfur down to 20 ppm starting in 2014 and if revamps were started up in 2016, one year before the program start date, that almost 6 times more credits would be available to offset the early credit demand by the refiners installing grassroots postreater units, assuming that they start up those units in 2018. Even if all grassroots postreaters were assumed to not start up until 2020, there would be almost 4 times more early credits available to those refiners installing grassroots postreaters assuming that the same early credit generation scenario would occur

Additional flexibility is also provided by the small refineries provisions which delays compliance for the refineries which refine less than a net of 75,000 barrels of crude oil per day until 2020. Three of the 16 FCC postreater grassroots units that we project will be installed would be by small refineries. However, small refineries could also decide to comply early and generate credits starting as early as 2014.

As in previous fuel programs, we are proposing hardship provisions to accommodate a refiner's inability to comply with the proposed standard at the start of the Tier 3 program, and to deal with unforeseen circumstances that may occur at any point during the program. These provisions would be available to all refiners, small and non-small, though relief would be granted on a case-by-case basis following a showing of certain requirements; primarily that compliance through the use of credits was not feasible. We are proposing that any hardship waiver would not be a total waiver of compliance; rather, a hardship waiver would be short-term relief that would allow a refiner facing a hardship situation to, for example, receive additional time to comply. This hardship provision would allow a refiner to seek a delay in the case that there was insufficient time to comply.

Finally, we believe that in reality, less leadtime than shown in Table 4-3would actually be necessary. We held discussions with many refiners during most of 2011, and so they have been well aware of Tier 3 and are familiar with the likely requirements. During our subsequent discussions with technology vendors and engineering firms, they explained to us that many refiners have already initiated, and by now, likely completed their scoping studies. Thus, actual time needed for designing, installing and starting of new desulfurization equipment for Tier 3 times would even be less than what we projected because many refineries may have already completed required scoping studies in anticipation of the Tier-3 standards. Moreover, lead times for those refineries that have yet to start the scoping process can also be expected to decrease, since fewer refineries will be competing for the services of the desulfurization vendors.

4.3.2 Permitting Analysis

Our analysis found that GHG emission increases were the most common reason that Prevention of Significant Deterioration (PSD) applicability would be triggered, followed by NO_X emissions. Specifically, 19 refineries appeared likely to have significant emissions for one or more pollutants and thus would trigger major source New Source Review (NSR). Of these 19 refineries, 13 refineries would need permits for NAAQS-related pollutants.

With respect to NAAQS-related pollutants, 6 of these13 refineries were predicted to require both PSD and Nonattainment NSR permits. Of the remaining 7 refineries, 2 required only a Nonattainment NSR permit while the remaining 5 refineries required a PSD permit.

In comparison, for the Tier 2 program, EPA expected the need for NAAQS-related NSR permits might be widespread among refineries. For the proposed Tier 3 gasoline sulfur standard, however, only about 10 refineries would need air permits that address NAAQS pollutants.

This number could be lower if those refineries apply emission controls, such as selective catalytic reduction (SCR) for NO_X, 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.B of the preamble and a supporting memorandum in the docket.[38]

4.3.3 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 proposed 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[39]. 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[a]

Gasoline Refiners	
Number of New Pieces of Equipment per Refinery	60
Number of Revamped Pieces of Equipment per Refinery	15
Job Hours Per Piece of New Equipment[a]	
Front End Design	300
Detailed Design	1,200
Direct and Indirect Construction	9,150

Note:
[a] 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. Very few refineries are expected to require the full 45-month period to complete scoping studies, process design, permitting, detailed engineering, field construction, and start-up/shakedown.

Table 4-5 Maximum Monthly Demand for Personnel

	Front-End Design	Detailed Engineering	Construction
Tier 3 Gasoline Sulfur Program			
Number of Workers	202	809	6,012
Percentage of Current Workforce[a]	11%	9%	4%

Note:
[a] Based on current employment in the U.S. Gulf Coast assuming half of all projects occur in the Gulf Coast

To meet the proposed Tier 3 sulfur standards, refiners are expected to invest $2.2 billion between 2014 and 2019 and utilize approximately 1,000 front-end design and engineering jobs and 6,000 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 four years 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 proposed sulfur standards.

4.3.4 ABT Impacts

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 than would have under 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, 73 refineries would revamp existing pre- and postreaters and 21 would install grassroots postreaters in order to meet the proposed sulfur standards. The remaining 17 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 postreaters and 16 refineries that would install grassroots postreaters in order to meet the proposed sulfur standards under an ABT program.

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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 proposed gasoline sulfur control. 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. We present the results from our energy and supply analyses for our proposed gasoline sulfur program. Finally, we discuss and compare the results of several cost analyses for various sulfur programs.

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.

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, the refinery-by-refinery cost model cannot estimate certain inputs necessary for estimating costs. Because the refinery-specific information is not publicly available, it was necessary to find another way to estimate this information. 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 5.1.3.

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 was subjected to peer review by two refinery industry consultants. Our review of most of the suggested changes recommended by the 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, we anticipate making other improvements to the cost analysis conducted for the final rule, which would necessitate a second round of peer review. Therefore, the peer review comments will be addressed prior to undertaking the cost analysis for the final rulemaking along with the other changes that we will be making to our cost analysis. The peer review comments are contained in two reports submitted to the docket.

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 postreaters) 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 postreater 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 postreaters would have to be installed at those refineries to reduce its gasoline pool down to 10 ppm. However, since adding grassroots FCC postreaters is relatively expensive for the amount of sulfur reduction obtained, the ABT analysis we conducted avoided many of these types of investments. Refineries with both pre and postreaters today could achieve further gasoline sulfur reductions less than 10 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 postreater investments. In addition to addressing the sulfur in the FCC naphtha, we believe that some refineries may need to reduce the sulfur in light straight run (LSR) naphtha. Some refineries might also need to reduce sulfur in butane, although we don't expect refiners to need to address butane sulfur unless they are pursuing a very stringent gasoline sulfur standard, e.g., 5 ppm.

To better understand the desulfurization costs, we evaluated several different scenarios or cases. For a 10-ppm average sulfur standard, we assessed the costs based on each refinery achieving the 10-ppm standard with no averaging among refineries, an averaging program which assumed intra-company transfers of sulfur credits, and an averaging program which assumed nationwide transfers of sulfur credits. To provide credits for averaging and trading under the 10-ppm average standard, we also 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. The costs for the proposed sulfur program are based on a 10-ppm sulfur standard with intra-company credit transfers. These different scenarios are summarized in Table 5-1.

Table 5-1 Sulfur Control Cases Evaluated for the Proposal

10-ppm Standard	5-ppm Standard
No ABT Program	No ABT Program
ABT Program with Intra-Company Credit Transfers (Proposed Rule Costs)	N/A
ABT Program with Nationwide Credit Transfers	N/A

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 to estimate the costs with refinery-by-refinery cost model, and without access to detailed refinery-specific information, we relied on outputs from our LP refinery modeling. Perhaps the most important input is the cost for making up the octane loss that occurs with desulfurization. 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.

Two different sets of refinery modeling runs from two different LP refinery models were used as inputs into the refinery-by-refinery cost model. The refinery-by-refinery cost model already contained the utilization factors and gasoline production volumes for individual refinery units from the analysis conducted by Mathpro for the MSAT2, and we continued to use that information for this cost analysis. The gasoline demand is expected to be fairly flat in the future, so using the previous refinery modeling work for these inputs will likely have little impact on the cost estimate. We plan on updating these inputs for the final rule to reflect more recent refinery modeling work.

Additional refinery modeling was conducted using the Haverly GRTMPS refinery model. The primary reason for conducting new 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. While the gasoline demand and production volumes are not expected to change in the future, the cost of octane is expected to decrease dramatically due to expected much larger use of ethanol under the RFS2 rulemaking.

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 2000 for the Mathpro model and 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 from the Oil and Gas Journal was aggregated by PADD and entered into the LP refinery model. The feedstock volumes, including crude oil and gasoline blendstocks, were obtained from the Energy Information Administration (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 for the Haverly LP refinery modeling, 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 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 year for the Mathpro LP refinery modeling was 2012 while the reference year for the Haverly refinery modeling was 2017 and 2030. We developed two reference cases with the Haverly model to model different control case scenarios. The reference case was created by starting with the base cases 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 change in certain inputs such as product volumes and energy prices need to be accounted for U.S. refinery gasoline, diesel fuel and jet fuel demands are projected year-by-year by EIA in its Annual Energy Outlook (AEO); the projections from the AEO for the reference case are used in the refinery modeling analysis. The Mathpro LP refinery modeling relied on AEO 2006 while the Haverly LP refinery modeling relied on AEO 2011. This growth in demand is used to project refinery production for each PADD to meet that increased demand. This projected growth in 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 the future year being modeled were also entered into the refinery model as well as the estimated 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. For the Mathpro refinery modeling, which was conducted before the nonroad diesel fuel program and MSAT2 benzene control programs were finalized, those fuels control programs were not modeled in the reference case. Also, the implementation of EPAct required a large increase in the amount of ethanol to be blended into gasoline to comply with the renewable fuels standard (RFS), but not RFS2. In its AEO 2006, EIA projected that the volume of ethanol blended into gasoline exceeded the RFS required amounts, resulting in 9.6 billion gallons of ethanol blended into gasoline by 2012. Other provisions of EPAct that were modeled with both the Mathpro and Haverly models included a de facto ban on MTBE and rescinding the RFG oxygenate requirement. The reference case unit throughputs and gasoline blendstock volumes were used in the refinery-by-refinery cost model. For the Haverly refinery modeling work, in addition to the EPAct provisions, the RFS2 renewable fuels volumes were modeled for 2017. For the 2017 reference case, 17.8 billon gallons of ethanol were assumed to be blended into gasoline, and 3.9 billion gallons of renewable and cellulosic diesel fuel and biodiesel were assumed to be blended into diesel fuel for the control case. For gasoline, the ethanol volume beyond the E10 blendwall was assumed to be blended as E15. For the 2030 reference case, we modeled 22.2 billion gallons of corn and cellulosic ethanol, and 8.3 billion gallons of renewable diesel and biodiesel.

The third step in conducting the LP refinery modeling was to run the various 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.

For the Haverly modeling, a control case was run to model the octane loss associated with desulfurization using 2017 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.[A] The octane cost estimated by the LP cost model is 0.76 cents per octane number per gallon of FCC naphtha. Because the octane loss associated with a specific 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 0.38 cents per gallon of FCC naphtha. Table 5-35

[A] 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.

at the end of this chapter summarizes the data output from the refinery modeling from which we calculated the octane cost for using in the refinery-by refinery cost model.

It was necessary to estimate the gasoline qualities for estimating the emissions impact of the proposed Tier 3 program. This was conducted in two separate steps. First it was necessary to estimate the gasoline qualities of the 2017 and 2030 reference cases relative to the gasoline qualities of a revised base case. The sole differences that we modeled between the 2005 revised basecase and the 2017 and 2030 reference cases was the phase out of MTBE and the addition of ethanol. For the 2005 revised basecase we modeled 1.7 billion gallons of MTBE and 4.1 billion gallons of ethanol. For the 2017 and 2030 reference and control cases, we modeled 17.8 and 22.2 billion gallons of ethanol, respectively. In 2017, we estimated that approximately half the gasoline would be 10 percent ethanol and the about the other half would be 15 percent. To model the emissions impact of the different ethanol blends, we modeled two reference cases, one with 100 percent E10 and the other with 100 percent E15. These two ethanol cases were modeled in 2030 and we used the results for 2017 as well. The gasoline qualities for the reference and two ethanol cases are summarized in Table 5-57 to Table 5-61 in the appendix at the end of this chapter. The changes in gasoline quality are summarized in Table 5-2. 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 E10 or E15 gasoline for the emissions analysis.

Table 5-2 Difference in Gasoline Qualities between E10 and E15 Control Cases with the Reference Case

		E10		E15	
		Summer	Winter	Summer	Winter
PADD 1	E200	5.08	2.16	11.08	9.71
	E300	2.41	-1.89	3.58	3.23
	Aromatics	-2.88	-1.20	-5.95	-3.99
	Olefins	-0.92	-1.26	-1.68	-1.75
PADD 2	E200	-3.29	6.96	1.10	11.07
	E300	-2.82	2.10	-4.08	2.68
	Aromatics	-0.17	-2.70	-2.03	-3.22
	Olefins	-0.31	-1.26	-1.55	-1.46
PADD 3	E200	6.06	5.65	12.03	15.76
	E300	3.27	0.76	3.54	8.51
	Aromatics	-4.93	-5.86	-8.43	-9.89
	Olefins	-1.06	-2.56	-2.13	-2.03
PADDs 4 & 5OC	E200	8.78	5.19	11.29	10.88
	E300	0.95	-0.10	1.58	3.81
	Aromatics	-2.92	-5.01	-4.71	-7.62
	Olefins	-1.53	-1.06	-1.87	-1.56
US avg minus CA	E200	3.46	4.65	8.65	11.77
	E300	0.88	0.04	1.08	4.50
	Aromatics	-2.58	-3.19	-5.28	-5.65
	Olefins	-0.87	-1.59	-1.80	-1.73

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 which reflects a 1 octane number loss in the FCC naphtha pool are summarized in Table 5-47 to Table 5-51 at the end of this chapter. The difference in gasoline qualities between the reference and control cases is summarized in Table 5-3. 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. After we integrated the gasoline desulfurization information into the refinery-by-refinery cost model, we estimated that desulfurizing gasoline from 30 ppm down to 10 ppm would result in about a one-half reduction in FCC naphtha octane ((R+M)/2) number. To estimate the changes in gasoline quality from a one-half octane number loss in FCC naphtha that we estimated, we divided the gasoline quality changes for one octane number in the FCC naphtha by a factor of two resulting in half the changes in gasoline quality that we estimated for a one octane number change in FCC naphtha. The second set of columns in Table 5-3 summarizes the gasoline quality changes that we estimated for reducing the gasoline sulfur levels from 30 to 10 ppm.[B]

Table 5-3 Differences in Gasoline Qualities Between the Control and Reference Cases

		2017 minus 1 ON in FCC Naphtha		Adjusted for 1/2 ON	
		Summer	Winter	Summer	Winter
PADD 1	E200	-0.20	-0.27	-0.10	-0.14
	E300	-2.03	-0.63	-1.01	-0.32
	Aromatics	1.14	0.69	0.57	0.34
	Olefins	0.60	0.01	0.30	0.01
PADD 2	E200	-0.19	-0.04	-0.09	-0.02
	E300	-0.06	-0.12	-0.03	-0.06
	Aromatics	0.48	0.27	0.24	0.13
	Olefins	0.09	0.03	0.04	0.01
PADD 3	E200	-1.68	-0.06	-0.84	-0.03
	E300	-1.99	-0.35	-1.00	-0.17
	Aromatics	2.50	0.45	1.25	0.23
	Olefins	0.15	0.04	0.07	0.02
PADD 4 & 5OC	E200	0.50	-0.69	0.25	-0.35
	E300	0.14	-1.67	0.07	-0.84
	Aromatics	0.10	-0.32	0.05	-0.16
	Olefins	0.02	-0.49	0.01	-0.25
US avg minus CA	E200	-1.55	-2.54	-0.78	-1.27
	E300	-1.49	-1.37	-0.75	-0.68
	Aromatics	1.26	0.95	0.63	0.48
	Olefins	0.37	-0.23	0.18	-0.12

[B] Since we completed the LP refinery modeling to estimate the cost for recovering the lost octane and the associated changes in gasoline quality, we found that other Tier 3 refinery modeling studies did not show the same increase in aromatics and decrease in E300 (see also 7.1.3.2). We then discovered that the LP refinery model that we have licensed to use required some improvements in how the refinery model was characterizing both the light-cut and the heavy-cut naphtha from the reformer streams to more accurately estimate the E300 and aromatics content of these streams. We have subsequently worked with a contractor to make these improvements to the LP refinery model and will reassess the changes in gasoline quality for the final rule analysis. Thus, while our modeling results shown in Table 5.3 show a meaningful impact on aromatics and E300, we believe there will in fact be little or no change. Note that these improvements are not expected to have any impact on the cost estimates made by the refinery model.

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 inputs from an LP refinery model case to allow us to better understand the gasoline sulfur control costs to individual refineries. This spreadsheet cost model also allowed us to model how costs would be affected by an ABT program.

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 2009 for modeling the baseline operating conditions for the refineries as it's the latest year we had data for refiner operations and yields. Additionally, EIA projections indicated that gasoline demand is expected to be essentially flat between 2009 and 2017, alleviating the need to adjust refinery operating throughputs and yields for future changes in gasoline demand.[1,C] Because of these factors, the 2009 gasoline production volumes and refinery operating conditions can reasonably be projected to be at the same level in 2017 (the first year of implementation of the Tier 3 program) in estimating costs and refinery impacts. 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.

To estimate the cost for each refiner to lower its gasoline pool down to 10 ppm, we used our refinery-by-refinery model 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 straight run naphtha (LSR) and natural gas liquids (NGL) that require additional hydrotreating, as well as butane volumes that are directly blended into the gasoline pool.

The second step involves 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. Using our refinery-by-refinery model we also estimate that a few refineries will add additional LSR/NGL hydrotreating capacity. We also evaluate each refiner's cost to install new butane Merox extraction equipment to lower the sulfur level of butane that is directly blended to the gasoline pool. Reducing the sulfur content of butane was assumed necessary to meet a 5-ppm sulfur standard for our ABT cases. This assumption is

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[C] Since we conducted the cost analysis for the proposed rulemaking, we put in place an additional round of greenhouse emission reductions (2017 – 2025) for light duty cars and trucks that will reduce future gasoline demand. When we model the costs for the final rulemaking, we will incorporate this reduction in gasoline demand in our costs analyses.

conservative as many refiners may already have this equipment, or may purchase low-sulfur butanes that have already been treated by their supplier.

This allows 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 7 percent return on investment (ROI) before taxes. 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

In order to develop a baseline for our refinery-by-refinery analysis, 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 estimate them. Estimating each refinery's gasoline blendstock volumes was accomplished using actual 2009 refinery specific throughput rates that we obtained from EIA for crude, FCC, cokers and hydrocracking units, and published refinery unit capacity information for the other refinery units. We used this information to estimate the extent that each refinery process unit is utilized, followed by a unit-specific analysis for estimating how each refinery unit produces material for blending into gasoline. After the unit-by-unit estimates are completed, we performed an overall check by comparing our estimated gasoline volumes with reported gasoline volumes for each refinery, using EPA's RFG database

The model requires the total gasoline volume and each gasoline blendstock volume for each refinery as an input. Although the model does estimate this volume of gasoline produced by each refinery based on the estimated volumes of each gasoline blendstock, we chose to use actual 2009 gasoline production data reported by refiners as for the total gasoline volume for each refinery in our cost calculations. To comply with the RFG program, refiners report gasoline production volumes and sulfur levels for reformulated and conventional gasoline to EPA. We used this data and imputed each refiner's 2009 total gasoline production and corresponding sulfur levels into our model.

In the end, our completed refinery-by-refinery modeling estimates of gasoline produced on a national basis, correlated very well with the actual refinery production volume in 2009, with our estimated volumes having an overall error of approximately 0.5 percent relative to the reported refinery production volumes. In order to minimize the impact of this error, we forced the estimated total refinery gate gasoline volume to match actual reported 2009 gasoline production volume across all the refineries. The unadjusted refinery-by-refinery estimates of FCC and LSR gasoline volumes, however, are used for estimating necessary equipment modifications and costs for sulfur removal. This is due to the fact that the refinery by refinery models estimates for each refiner's FCC gasoline are likely to be very close to actual FCC production, as we use actual refinery specific FCC charge throughput rates and account for the effects of FCC feed pretreating on FCC gasoline yields. Additionally, the cost for treating FCC gasoline in our Tier 3 programs, comprise over 85 percent of the total costs, while LSR comprises the bulk of the remaining costs.[D]

5.1.3.1.1 Principal Refinery Unit Volumes

To estimate the production volumes for each of the refinery's gasoline blendstocks, the refinery-by-refinery model needs process capacity information. The Oil and Gas Journal (OGJ) publishes and the EIA reports unit capacities for the principal refinery units for each refinery in the U.S.[2,3] We updated our database from these two sources to reflect capacity that was in place in 2009, the base year for the model. Where differences between the two databases existed, we used the information that was judged best overall from the two sources and entered it into the refinery-by-refinery cost model. These unit capacities indicate the maximum throughput rate for each individual unit, not the actual unit throughput rates for each facility, as this is proprietary business information and not publicly available. In order to enhance our model, we obtained from EIA the actual 2009 annual unit throughput rates for each refiner's crude and major refinery units (FCC, cokers and hydrocracker units). With this information, the refinery-by-refinery model was fine-tuned to reflect each refineries gasoline blendstocks 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's throughputs versus actual capacity that we obtained from EIA for each domestic refinery on a PADD average basis are listed in Table 5-4. This information is presented on a PADD average to protect CBI.

Table 5-4 Process Capacity Utilization[a]

	Crude Throughput	FCC Throughput	Coker Throughput	Hydrocracker Throughput
Total U.S.	0.843	0.840	0.761	0.768
PADD 1[b]	0.779	0.754	0.643	0.707
PADD 2	0.859	0.814	0.810	0.774
PADD 3	0.858	0.880	0.782	0.637
PADDs 4/5 excluding California	0.817	0.794	0.824	0.903

[a]Actual unit throughput rates as a fraction of maximum unit capacity on a PADD basis
[b]PADD 1 data includes Hovensa, VI

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, the Valero Refinery in Norco Louisiana, and the Marathon Refinery in Garyville, Louisiana. 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

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[D] We did not account for any undercutting of the heavy FCC naphtha into jet and diesel fuel, nor did we account for the removal of any pentanes that might be occurring in refineries to comply with stringent summertime RVP standards, therefore our analysis is likely somewhat conservative and overestimates the costs.

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. Refiners that we believe are permanently shutdown in PADD 1 were removed from our analysis but, consistent with recent import/export trends, we allowed PADD 3 to supply any lost capacity to PADD 1 as a result of this lost production. PADD 1 refiners that were presumed to be permanently shutdown are; Giant refinery located in Yorktown, Virginia, Sunoco refinery in Westville, New Jersey, and Shell Oil refinery in Bakersfield, California.

5.1.3.1.2 Other Refinery Unit Volumes

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 these processes feedstocks are primarily supplied by the crude and FCC Units. Since this data is similarly not publicly available we tuned these units to the EIA throughputs rates for crude and FCC units at each facility, with alkylation units running at the same throughput rates as the FCC and the remaining units running at the crude oil throughput ratesThe results of the capacity utilizations of these downstream units are summarized in Table 5-5 below.

Table 5-5 Other Unit Process Capacity Utilization[a]

	Reformer Throughput	Alkylation Throughput	Isomerization Throughput	Poly/Dimersol Throughput
PADD 1	0.774	0.886	0.931	1.000
PADD 2	0.859	0.878	0.859	0.859
PADD 3	0.858	0.880	0.858	0.345
PADDs 4/5 excluding California	0.817	0.794	0.714	0.100

[a] 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, though estimating refinery unit capacity and capacity utilization may or may 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 to each process to convert the process charge rate into the yield of gasoline blendstocks. The process fractional yields that were used in our refinery by refinery model were taken from our MSAT2 final rule LP refinery modeling work, which represented the U.S. refining industry on a PADD basis. The FCC unit process yields of naphtha blendstock are different for units with an FCC feed pretreater, versus those without feed pretreating. In our modeling we accounted for this by adjusting yields and sulfur levels of FCC units with pretreaters and those without a pretreater. The fractional yields of gasoline blendstock for the major process units and the 2009 throughputs for each of these units used in our model are summarized below in Table 5-6 and Table 5-7.

Table 5-6 Gasoline Blendstock Fraction Yields Per Process Unit Charge

	Crude	FCC Units Average	Coker	Hydrocracker
PADD 1	0.190	0.560	0.234	0.369
PADD 2	0.211	0.570	0.234	0.311
PADD 3	0.188	0.554	0.239	0.212
PADDs 4/5 excluding California	0.183	0.565	0.234	0.276

Table 5-7 2009 Refinery Unit Throughputs (1,000 BPSD)

	Crude	FCC Units	Coker	Hydrocracker
PADD 1	1,624	652	<3 [a]	<3 [a]
PADD 2	3,193	1,017	322	223
PADD 3	7,262	2,604	1,043	500
PADDs 4/5 excluding California	1,363	263	130	94

[a] Since there are less than three refiners in this PADD with these units, the data was not reported to protect CBI information.

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 5-6 above, the portion of FCC feedstock converted to naphtha ranged from 55 to 57 percent across the various PADDs. The range among individual refineries can be quite large, but we didn't have access to refinery specific data for this. However, as a group there is expected to be differences between refineries with and without FCC pretreaters. Therefore, rather than simply use the PADD average conversion of FCC feedstock to naphtha for all refineries in a given PADD, the refinery-by-refinery model differentiates between refineries that have an FCC feedstock pretreater and those that do not. We have also quantified the gasoline blendstock fraction yield for FCC units that have both feed pretreater and postreater units.

Historically, refiners have installed FCC feed pretreaters for economic reasons, as pretreaters increase FCC unit conversion to high value gasoline blendstock while decreasing the production of low value light cycle oils and residual material from FCC units. 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 FCC feed pretreating and postreating 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 5-8 below.

Table 5-8 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 Postreater
PADD 1	0.560	0.558	0.638	0.607
PADD 2	0.570	0.533	0.648	0.617
PADD 3	0.554	0.520	0.630	0.600
PADD 4/5 excluding California	0.565	0.548	0.642	0.612

5.1.3.1.2.1 Poly Gas and Alkylate

For the polymerization and alkylation units the capacity of the unit coupled with its estimated utilization rates listed in Table 5-5 is sufficient to establish the volume of gasoline blendstock produced by these units. For example, a particular refinery unit in PADD 1 might have a 10,000 barrel per day alkylation unit. If the alkylation units in PADD 1 are estimated to be operating at 56 percent of its listed capacity in 2017, the alkylate production is projected to be 5,600 barrels per day at that refinery. Each of the refineries within a given PADD was assumed to have the same utilization rate for any alkylation units.

5.1.3.1.2.2 Light Straight Run Naphtha

The remaining gasoline blendstocks, including light straight run naphtha (LSR), coker naphtha and hydrocrackate cannot be estimated simply using the unit capacity and unit utilization rate. In order to determine the volume of gasoline blendstock produced by each of these units, additional steps are required. LSR naphtha is principally comprised of five- and six-carbon hydrocarbons which come directly from crude oil. Thus the volume of LSR for each refinery was based on the volume of crude oil processed by each refinery as determined in Section 5.1.3.1.1, as well as the percentage of that crude oil that is LSR. The fraction of LSR in each refinery's crude oil was estimated on a PADD average basis using the LP refinery model since it is not available on a refinery-by-refinery basis. This percentage is based on the types and quality of crude oil processed by all the refineries in each PADD from our LP model[4]. LSR as a percentage of crude oil is estimated to vary from 4 to 5 percent across the PADDs. These PADD level results are shown in Table 5-9 below.

Table 5-9 LSR as a Percentage of Crude Oil by PADD

	PADD 1	PADD 2	PADD 3	PADDs 4/5[a]
LSR as a Percentage of Crude Oil	4.5%	5.0%	4.4%	4.4%

[a] Excluding California

After we calculated how much LSR is produced at each refinery we determined how much of the LSR is used as a gasoline blendstock. LSR has several possible destinations that vary from refinery to refinery. For each refinery, with the exception of those located in PADD 2, a portion of the LSR is designated to be sold into the petrochemicals market where it is processed into other hydrocarbon compounds. EIA publishes the volume of naphtha which is sold into the petrochemicals market in each PADD[5]. This information is summarized in Table

5-10 below. Since this information is not publicly available on a refinery-by-refinery basis, we assumed that the volume of LSR naphtha sold into the petrochemicals market by each refinery is proportional to the refinery's percentage of the total volume of crude oil processed in the PADD in which the refinery is located. After accounting for the volume of LSR naphtha sold to the petrochemicals market, the balance of LSR naphtha is used as a feedstock for the isomerization unit if the refinery has one. If a refinery does not have an isomerization unit, all of the LSR not sold to the petrochemical market is assumed to be used as a gasoline blendstock. Any volume of LSR at a given refinery that exceeds the capacity of the isomerization unit at the facility is also assumed to be used as a gasoline blendstock. However, if a refiner does not have enough naptha hydrotreating capacity to process all of the refiner's LSR volume, we assumed that the refiner would use excess capacity in their FCC postreater, to reduce the sulfur content of the LSR blendstock.

Table 5-10 Refiner Sales of Naphtha in 2009 (1,000 BPSD)

	PADD 1	PADD 2	PADD 3	PADD 4/5[a]
Naphtha Sold to the Petrochemical Industry	12.2	22.4	161.2	0
Sales of Special Naphtha	0.8	0	31.4	0

[a] Excluding California data

For further clarity on gasoline blendstock yields from the model, the gasoline blendstock volumes of LSR and naphtha from the naphtha splitter overhead tower are adjusted to subtract sales of these blendstocks that are sent to the petrochemicals market.[E] The values listed in Table 5-11 for LSR and naphtha splitter overhead are the volumes sent to gasoline, as a fraction of crude throughput.

Table 5-11 PADD Average Gasoline Blendstock Yields per Fraction of Crude Input

	PADD 1	PADD 2	PADD 3	PADD's 4/5[a]
LSR to Gasoline	0.0309	0.0286	0.0187	0.0381
Naphtha from Light Naphtha Splitter Overhead	0.0021	0.0081	0.0072	0.0093

[a] Excluding California

In refineries with an isomerization unit, much of the LSR is processed into isomerate, the product produced by the isomerization unit. The volume of isomerate produced is dependent on the volume of feedstock processed by the isomerization unit up to its capacity. As described above, all of the LSR that is not assumed to be sold into the petrochemical markets is assumed to be sent to the isomerization unit, up to the maximum capacity of the isomerization unit. The isomerization unit produces a blendstock with a slightly higher energy density and smaller volume compared to the feedstock volume. To account for this effect, the volume of isomerate produced is estimated to be 1.6 percent less than the volume of LSR feedstock to the isomerization unit. Hydrocrackate and Coker Naphtha

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[E] Naphtha Splitter towers separate the naphtha feed stream into a light and heavy streams, whereby the heavy stream is typically reformer feedstock, while the light stream is blend stock lighter than reformer feed.

The hydrocracker and coker units also produce some light naphtha material which is blended into gasoline. Heavy naphtha is also produced in these units, which is feed to the reformer, as discussed in the next section. The light naphtha material produced by the hydrocracker and coker are termed light hydrocrackate and light coker naphtha, respectively. Based on LP refinery modeling work done for the MSAT2 rule we estimated that the portion of the feedstock processed by each of these units converted to light coker naphtha and light hydrocrackate was 5 percent for coker units across all the PADDs, and ranges from 23 to 32 percent for hydrocracker units depending on the PADD. The light coker naphtha is poor in quality and require hydrotreating to removes sulfur, olefins and other impurities, before sending them to an isomerization unit, if a refiner has one. Table 5-12 below summarizes the percentage of the feedstock to these units that is converted to light naphtha and blended into gasoline.

Table 5-12 Isomerization Unit Feed Rates by PADD

	PADD 1	PADD 2	PADD3	PADD 4/5[a]
Light Coker Naphtha (% of Coker Feed)	5.0%	5.0%	5.0%	5.0%
Light Hydrocrackate (% of Hydrocracker Feed)	28.7%	32.0%	23.3%	27.2%

[a] Excluding California

5.1.3.1.2.3 Reformate

The volume of reformate produced by the reformer was estimated based on the volume of feed to the reformer as limited by each unit's capacity. The feed to the reformer comes from various sources depending on the refinery configuration. For virtually all refineries, the heavy part of the straight run naphtha from the atmospheric crude tower is sent to the reformer, while the light naphtha is generally processed in the isomerization unit or blended directly into gasoline as discussed above. Those refineries with a hydrocracker or a coker will send the heavy naphtha from these units to the reformer as well. This reformate feed naphtha contains the six, seven, eight and usually the nine carbon compounds from these various sources. In some cases, the six carbon compounds are separated from the rest of the reformate feedstock to reduce the benzene in the final reformate. The volume of the feed to the reformer is estimated based on a fractions of the material processed in the atmospheric crude tower, hydrocracker and coker on a PADD by PADD basis using information from the LP refinery model.

The fraction of crude oil that is fed to the reformer from the atmospheric crude tower ranges from about 13 to 16 percent of the crude oil input depending on the PADD. About 18 percent of the material processed in the coker unit is estimated to end up as feedstock to the reformer. The percentage of the feedstock processed in the hydrocracker that is fed to the reformer ranges from 30 to 50 percent depending on the PADD in which the refinery is located. The variance in the fraction of hydrocracker material sent to the reformer is due to the significant flexibility that the hydrocracker has for producing either gasoline or diesel fuel. In certain PADDs, such as PADD 4 and 5, there is a higher relative demand for diesel fuel compared to gasoline so there is a lower conversion to naphtha than in other PADDs. The product from the reformer experiences a volume decrease of about 18 percent relative to the volume of feed, due to the conversion of straight chain and cyclical hydrocarbons to energy dense aromatics and other light products. This volume reduction and conversion to lighter products increases with the severity and thus the conversion of the reformer unit. All the refineries in each PADD are assumed to be operating their reformers at the same severity as estimated by the LP refinery model. Each of the values discussed in this paragraph are shown on a PADD by PADD basis in Table 5-13 below.

Table 5-13 Reformer Feed Rates and Volume Loss

	PADD 1	PADD 2	PADD3	PADD 4/5[a]
Medium/Heavy Straight Run Naphtha (% of Crude Input)	13.8%	16.2%	14.0%	13.6%
Medium/Heavy Coker Naphtha (% of Coker Feed)	18.4%	18.4%	18.4%	18.4%
Medium/Heavy Hydrocrackate (% of Hydrocracker Feed)	35.4%	43.4%	50.2%	33.3%
Volume Loss in Reformer	18%	17%	18%	19%

[a] Excluding California

5.1.3.1.2.4 Purchased Blendstocks

Some gasoline blendstocks are purchased and blended into gasoline. The gasoline blendstocks typically purchased include natural gasoline, alkylate, isooctene and ethanol. We did not have information on the volume of these gasoline blendstocks purchased and blended into gasoline by each refinery, so we again relied on the information from EIA, which reports the consumption of these blendstocks on a PADD basis. The EIA information on the amount of pentane plus, naphtha's and NGLs purchased in each PADD are listed in Table 5-14 below. Our RFG database has each refiners amount of ethanol blended into RFG, but does not contain the amount of ethanol that is splash blended into CG at terminals. We accounted for ethanol blended into CG, as well as the purchase of other gasoline blendstocks, by assuming that each refinery purchased a volume of any given gasoline blendstock purchased within their respective PADD proportional to that refinery's crude oil consumption within the PADD. In the 2009 RFG database, the ethanol volumes only averaged 2.7 percent of refiner's gasoline production, which results in an over estimation of our refinery and program costs in this NPRM. In our NPRM analysis, we did not include any desulfurization costs for Pentane plus and naphtha and lighter blendstocks, since we did not know the extent that they were being treated today. However, the addition of these blendstocks, results in very negligible increases in demand for additional naphtha hydrotreating. We will evaluate whether we need to include any costs for treating these streams in the final rule analysis. If there are costs, because the streams are so small, the costs would be negligible.

Table 5-14 Refiner Purchases in 2009 (1,000 BPSD)[c]

	PADD 1	PADD 2	PADD 3	PADD 4/5[a]
Natural Gas Liquids	17.5	115.9	272.4	15.5
Naphtha's and lighter	24.6	39.3	53.7	3.8
Pentanes Plus	0	41.8	94.9	25.7
Ethanol [b]	57.3	66.9	77.3	0.40

Notes:

[a] Excluding California
[b] Ethanol from EPA RFG database, excluding volumes that are splash blended into conventional gasoline
[c] Natural Gas Liquids and Pentanes Plus are different names for the same hydrocarbon stream and we inadvertently found two different volumes for the same hydrocarbon stream and added them both as inputs into our refinery cost model. We will correct this in the final rulemaking analysis.Butane Volumes

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 the 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. 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

$$\text{Butane} = (A*D-B*D)/(C-A)$$

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. To calculate the RVP of the butane used as gasoline blendstock we first had to consider the relative proportion of isobutane versus n-butane being used as a gasoline blendstock as their RVP values differ. This ratio was estimated on a PADD by PADD basis from the LP modeling work. We then used a volume weighted average to calculate the RVP of the mixed butane stream blended into gasoline in each PADD. The information for these calculations is shown in Table 5-15 below. 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 2009 ethanol volumes and taking the sum of all of these values. The RVP value for each of these streams is shown in Table 5-16 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 5-17. 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 5-15 PADD Average Composition of Mixed Butanes Added to Gasoline

	PADD 1	PADD 2	PADD 3	PADD's 4/5[a]
Isobutane %	96%	32%	53%	66%
N-butane %	4%	68%	47%	34%
Mixed Butane RVP (C), psi	71.376	58.192	62.518	65.196

[a] Excluding California

Table 5-16 PADD Average RVP's of Gasoline Blendstocks

	PADD 1	PADD 2	PADD 3	PADD's 4/5[a]
LSR	12.0	12.0	12.0	12.0
Naphtha from Light Naphtha Splitter Overhead	3.0	3.0	3.0	3.0
Reformate	4.5	6.6	5.0	6.2
FCC Naphtha	4.6	4.6	4.6	4.6
Coker Naphtha	13.0	13.0	13.0	13.0
Isomerate C5	13.0	13.0	13.0	13.0
Isomerate C6	7.2	7.2	7.2	7.2
Natural Gasoline (NGL)	12.6	12.6	12.6	12.6
Polymerization Gasoline	2.8	2.8	2.8	2.8
Light Hydrocrackate	9.2	9.2	9.2	9.2
Alkylate, C3	3.6	3.6	3.6	3.6
Alkylate, C4	3.2	3.2	3.2	3.2
Dimersol	5.8	5.8	5.8	5.8
Ethanol	10.7	10.7	10.7	10.7

[a] Excluding California data

Table 5-17 PADD Average Gasoline Data

	PADD 1	PADD 2	PADD 3	PADD's 4/5[a]
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	8.5	9	8	9.1

[a] Excluding California data

5.1.3.2 Calibrating the Blendstock Volumes in the Refinery-By-Refinery Model

After calculating gasoline volume estimates for each refinery in the refinery-by-refinery cost model, we calibrated these values against their reported gasoline blendstock volumes. Refiners report their production volumes for both conventional and reformulated gasoline to EPA to comply with the gasoline reporting requirements. We used these reported volumes from 2009, along with LP modeling results from our MSAT2 Rule, to calibrate the refinery-by-refinery model. Before making any adjustments, the refinery-by-refinery modeling estimates for gasoline produced on a national basis correlated very well with the reported refinery production volume in 2009, with volumes differing by less than 0.5 percent from actual production. In order to eliminate this discrepancy we modified each refiner's yields in our refinery-by-refinery analysis based on the 2009 data as reported by the refineries. The volume of each of the gasoline blendstocks, excluding the light straight run (LSR) and FCC gasoline streams, were increased or decreased proportionally in order to align the aggregated national finished gasoline production volumes in our refinery-by-refinery model with the aggregated national finished gasoline production volume reported by US refineries in 2009.

In making adjustments to the refinery-by-refinery analysis to better align its volumes with the reported gasoline volumes and sulfur levels, we did not make any changes to the production volumes of LSR or FCC gasoline. The LSR and FCC gasoline volumes are left unchanged as these volumes are based on actual refinery-specific FCC charge throughput rates. This accounts for the effects of FCC feed pretreating on FCC gasoline yields and is therefore likely to accurately reflect the production volumes for each individual refinery. Additionally, these volumes are of central importance to our analysis as they are used for estimating the equipment modifications necessary for complying with new Tier 3 sulfur standards and the costs associated with additional sulfur removal.

With these calibrated volumes for each of the gasoline blendstocks, the refinery-by-refinery model can now be used to estimate the sulfur level that refiners must achieve in the FCC naphtha to meet the current sulfur limit under the Tier 2 standards. These volumes also allow us to model what modifications to existing equipment and refinery operations will be required to comply with the new Tier 3 sulfur standards.

5.1.3.3 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 refinery-by-refinery model that represents our estimate for the current operations of each refinery. This allows 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 5-18 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 processers and crude oil drilling operations. The butanes from these sources are produced in downstream units which separate the various hydrocarbon components. Most of these downstream units “sweeten” the butanes using a Merox 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 Merox treatment technology which actually removes the sulfur from the butane stream. This treatment generally lowers the sulfur level of the butanes to under 5ppm. 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 Merox units on site that are capable of removing sulfur from butanes that are either purchased or generated internally from refinery units. We were, however, unable to evaluate existing butane Merox treating capacity at NGL processers, crude drilling operations, or in refineries as there was no information available in the OGJ, from EIA, or other publically available sources. Because we do not know the prevalence of these units, we conservatively assumed in our baseline case that refiners are adding treated butanes with a sulfur content of 10 ppm to their gasoline pool.[F]

For hydrocrackate, dimersol, and poly gas blendstock streams, we used the same sulfur levels that we estimatd for our MSAT2 rulemaking. The sulfur levels for these streams are inherently low due to the dynamics of process reactions in the hydrocracker, 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 15 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 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 a 5-ppm alkylate. 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 5 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

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[F] After we completed our cost analysis, we met with UOP staff, including those who market their Merox technology for removing mercaptans from gasoline streams. The UOP staff said that pretty much all butanes are already being treated by Merox (or similar) extraction units. Thus, there would be no additional cost for treating butanes for complying with Tier 3. We will update our cost analysis to reflect this for the final rule cost analysis.

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. 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 processed 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 has on the order of 100 ppm sulfur before any hydrotreating. LSR that is routed as feedstock to isomerization units has its sulfur lowered to 1 ppm by processing 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. Even cases where there is insufficient capacity in the isomerization units it is still 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 postreaters.

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 processers and crude oil drilling operations and the sulfur content of the NGLs can vary depending on its source, although we estimate that this stream averages about 100. 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 NGLs are treated before arriving at the refinery. For the baseline case in our refinery-by-refinery model we assumed that NGL liquids are purchased with a sulfur content of 100 ppm and hydrotreated based on capacity availability at refineries in a similar manner as LSR. Based on the gasoline blendstock volumes and hydrotreating capacities as discussed in the previous sections, we estimated in the baseline case for our refinery-by-refinery analysis that refiners are hydrotreating 66 percent of the volumes of LSR and NGLs produced and purchased for gasoline blendstock usage on a national average basis. Our hydrotreating capacity evaluation for each refinery is discussed in more detail in Section 5.1.3.4. As a result of the proposed sulfur standards under the Tier 3 program, we anticipate that refiners will revamp existing hydrotreaters and add new hydrotreating capacity to allow them to hydrotreat all of their LSR and NGL material.

We also assumed that all ethanol blended into gasoline has a sulfur content of 5 ppm. Ethanol produced at ethanol plants naturally has 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 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 2009, 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:

$$\text{FCC Naphtha Sulfur ppm} = [(A*B) - (C*D+E*F+G*H+I*J+K*L+M*N+O*P+Q*R+S*T)] / Z$$

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= DimersolSulfur, 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 proposed 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 NGL and LSR streams was 34 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. The remaining 34 percent are untreated and have a sulfur content of approximately 100 ppm. For the Tier 3 control case we assumed that all of the NGLs and LSR were hydrotreated and therefore had an average sulfur content of 1 ppm. 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 5-18 below.

Table 5-18 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[a]	36.0	21[a]	35.0	21[a]
Reformate	22.5	0.5	21.8	0.5	21.2	0.5
Alkylate	12.7	5	12.5	5	12.1	5
Isomerate	3.2	0.5	3.1	0.5	3.1	0.5
Butane	4.0	10	4.0	10	3.8	10
Light Straight Run Naphtha (LSR) and Natural gas Liquids (NGL)	5.2	34	4.9	1	4.8	1
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

[a] 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 postreaters 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 postreaters 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 same delta presented in the table above.[G] The following section discusses our assessment of the desulfurization equipment currently being used in refineries.

5.1.3.4 Assessment of Refineries' Existing Desulfurization Equipment

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 postreater 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 postreaters for each refinery listed in the OGJ and the EIA database. 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.

For refineries that have FCC naphtha postreaters 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 to obtain confidential data from many of them on 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 refiners that 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

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[G] 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.

adjusted based on feedback from the vendor. The aggregated results of this assessment are summarized in Table 5-19 below.

Table 5-19 Postreater Technologies Used By Refineries

	CD Tech	IFP/Axens	Scanfining	UOP ISAL	S-Zorb
Refiners with Existing Postreater	15	40	16	1	4

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 53 refiners are currently using FCC feed pretreaters. Of the 53 refineries with pretreaters, 35 of also have FCC postreaters installed to comply with the Tier 2 gasoline sulfur standard. The technologies used by these 35 refineries are shown in Table 5-20 below. FCC naphtha produced using only 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 postreater 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). 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 5-20 Technologies Used By Refiners with FCC Pre and Postreaters

	CD Tech	IFP/Axens	Scanfining	UOP ISAL	S-Zorb
Refiners with FCC Pretreater and Naphtha Postreater	9	20	5	0	1

Our analysis also showed that there are several refineries that have an FCC unit but have installed neither an FCC naphtha postreater 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 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 reformate, 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 5-21 below.

Table 5-21 Refinery FCC Naphtha Desulfurization Unit Characterization

FCC Treatment Units Installed	Number of Refineries
No FCC Unit	14
FCC Unit, No Pretreater or Postreater	7
FCC Unit With Postreater Only	38
FCC Unit With Pretreater Only	17
FCC Unit With Pretreater and Postreater	35

5.1.3.5 Crude Oil and FCC Feed Sulfur Levels

After we had determined the desulfurization technology in place at each refinery, we sought to calculate the sulfur content of the FCC feedstock. Knowing this is important as it allows us to determine how far the sulfur level of the FCC naphtha, and ultimately the gasoline, produced at any given refinery can be reduced using the units currently in place at each refinery. It also helps us understand the extent to which the existing hydrotreaters are being taxed to comply with the Tier 2 gasoline sulfur standard. 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.

The sulfur level of the FCC feedstock is primarily dependent on the sulfur level of the crude oil being processed by the refinery and whether or not the refinery has an FCC feed pretreater. The first step, therefore, 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 2009. 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 refiners FCC feed charge rate sulfur level would be, using a regression co-relation we built from data on crude sulfur levels and FCC feedstock material, as discussed below. We assumed that refineries today are primarily processing heavy gas oils

(HGO) and vacuum gas oils (VGO) produced from each refinery's crude and coker units. To determine the volume of feedstock processed by the FCC units we assumed that after distillation HGO makes up 20.5 percent (by volume) of the processed crude and VGO makes up an additional 15.6 percent of the crude.[6] Together, these two streams comprise the FCC feed.

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 5-22 below.

Table 5-22 Boiling Ranges of FCC Feedstocks

	TBP Initial	TBP Final
Heavy Gas Oil (HGO)	600°F	800°F
Vacuum Gas Oil (VGO)[a]	800°F	1,000°F

[a] Contains some residual material

For our FCC feed sulfur regression, we used data obtained various crude oil assays that we obtained from Jacobs Engineering for work that Jacobs conducted for us. 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 5-23 below.

Equation 5-3 FCC Feed Sulfur Content Based on Crude Sulfur Content

$$\text{FCC Feed Sulfur Weight Percent} = (\text{Crude Sulfur Weight Percent})^{0.8} * 1.1858 + 0.0409$$

Table 5-23 FCC Feed Sulfur For Various Crude Sulfur Levels

Crude Sulfur Level (Weight %)	FCC 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%

5.1.3.6 Impact of FCC Feed Pretreaters on FCC Feed Sulfur Levels

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 postreated.

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 postreater are producing FCC naphtha that ranges from 200 to 450 ppm before being processed by the postreater. Having a postreater allows these refineries to not have to operate their pretreaters at a high severity as the sulfur will further be reduced to levels necessary to meet the applicable standards in the post-treating units. Refiners 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 postreater 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 postreating units due to a lack of refinery-specific information. For FCC units with a feed pretreater but no postreater we calculated the FCC naphtha sulfur level required by refiner 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 above and shown in Table 5-18. These calculations showed that refiners with FCC feed pretreating units, but no postreaters, 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 must then take into consideration the impact the FCC unit itself has on the sulfur level of the FCC naphtha. We reviewed several literature sources[7,8] and found that the FCC naphtha sulfur level can be accurately determined 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 the sulfur level of the FCC naphtha before any post-treating operations on a refinery-by-refinery basis. The results of this analysis are summarized in Table 5-24 below.

Table 5-24 FCC Naphtha Sulfur Levels for Various Refinery Configurations

	PADD 1	PADD 2	PADD 3	PADD 4/5
No Pretreater or Postreater	N.A.[a]	-<3 [b]	606	784
Pretreater Only	N.A.[a]	73	74	82
Postreater Only	1348	1157	705	1036
Pretreater and Postreater	49	<3 [b]	278	230

[a] N.A. – not applicable, no units of this type in the PADD

[b] Since there are less than three refiners in this PADD with the described configuration, the data was removed to protect potential CBI concerns.

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) allows 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.

5.1.4 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 proposed Tier 3 sulfur standards, the next step in our refinery-by-refinery analysis was to project the changes to refinery units and operations each refinery would have to make in order to comply with the proposed Tier 3 sulfur standard. The first step refiners would take for further gasoline sulfur control would be to desulfurize the light straight run, natural gas liquids, and butane blendstocks. The costs to reduce the sulfur content of these streams is relatively low and would therefore be the most cost effective way to further reduce the sulfur content of the finished gasoline. We also projected in our analysis for RFS2 that 50 percent of all gasoline produced by refiners in 2017 would contain 15 percent ethanol. In 2030 we projected in our analysis for RFS 2 that almost all gasoline contains 15 percent ethanol.[H] Because ethanol tends to be a relatively low sulfur blendstock (assumed to be 5 ppm for our refinery-by-refinery model) increasing the amount of ethanol in the gasoline pool lowers the overall sulfur content of the gasoline. Reducing the sulfur content of the LSR, NGL, and butane streams and increasing the ethanol content, however, would be insufficient to allow refiners to comply with the proposed Tier 3 standards. Refineries with an FCC unit would still have to reduce the sulfur content of their FCC naphtha blendstock in order to meet the Tier 3 standards.

For each refinery we considered two cases. In the first case each refinery had to meet the proposed Tier 3 gasoline sulfur standard of 10 ppm. In order to meet this standard, as discussed in 0, we determined that they would have to reduce the sulfur level of their FCC naphtha stream to 25 ppm. We also considered a case where each refinery would reduce the sulfur level of their gasoline to 5 ppm. We assumed that to meet a 5-ppm sulfur standard, refiners would desulfurize the butane blendstock to 10ppm in addition to further lowering sulfur in the FCC naphtha to 10 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 earn credits for our ABT scenarios discussed in Sections 5.2.1.2 and 5.2.1.3.

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 postreater. In our final rule we may also investigate the ability of refineries with high pressure pretreaters to meet the required standards without the addition of postreaters. For companies that already have an FCC naphtha postreater we assumed that all that would be necessary to meet the proposed sulfur standards was to revamp their existing FCC postreating units. We received cost information from several vendors for revamping FCC postreating 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 not have an FCC postreater would have no choice other than to add a new grass roots FCC postreating unit. We ultimately only received cost information from one vendor for the cost of adding a new grass roots FCC postreating 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, NGL, and butanes as well as the new FCC post-treating units and revamps can be found in the following sections.

[H] In our Tier 3 cost analysis, we inadvertently only accounted for the ethanol volumes that are contained in the 2009 RFG database, not those mandated by RFS 2. For our final rulemaking cost analyiss, we will adjust our model to account for higher ethanol use in the future, which will slightly reduce our Tier 3 cost estimates, due to the dilution effects of ethanol.

5.1.4.1 FCC Naphtha Desulfurization Costs

To estimate the cost for revamping existing FCC postreating units or for adding new postreating 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 postreater 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 postreater, 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 postreater) contained low (0 – 400 ppm) medium (400 – 1,200 ppm) or high (>1,200 ppm) levels of sulfur. Specific cost factors applicable to estimating unit revamps or grass units were also taken into account as described below. The following sections discuss in greater detail how the cost estimates we received from the vendors were used in our refinery-by-refinery analysis.

5.1.4.1.1 Cost to Revamp Existing FCC Naphtha Postreaters

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 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 postreater, 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 an 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 postreater revamps to meet 10 ppm and 5 ppm sulfur levels in gasoline. The aggregated information is summarized in Table 5-26 and Table 5-27.

One of the vendors we contacted for a cost estimate for FCC naphtha desulfurization technology provided information for several potential FCC postreater 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 postreater unit. This ensures that refiners will be able to run their existing FCC postreater at 4 to 5 year catalyst cycle lengths, which is a critical feature for FCC unit operations.

The costs for the FCC postreater 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, 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.

One vendor only submitted information for postreater 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 postreating 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 postreater revamp cost based on the cost differentials between the three FCC naphtha sulfur levels in the other vendors’ revamp estimates. We similarly derived a postreater 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 postreater revamp costs for refiners using this particular technology in our refinery-by-refiner model.

After we had determined cost estimates for the FCC postreater revamps based on information from the vendors the next step was to scale these costs based on the size of the FCC postreating unit present in each refinery. The vendor estimates submitted for revamp costs were based on various FCC postreater 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 its 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. We then increased the size of the FCC postreater by 7.5 percent above each refinery’s maximum FCC gasoline production rate as an over design factor to account for excess capacity that refiners generally design into their unit for processing additional flows of FCC naphtha (i.e, rerunning high sulfur FCC naphtha batches either from that refinery or from neighboring refineries). After sizing the FCC postreater that would be required for each refinery we then scaled the costs given by the vendors using the six-tenths rule as shown below.

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 postreater 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. We estimate that the grassroots offsite cost factors for very modest levels of desulfurization inherent in this analysis are in the 1.2 to 1.3 range, and those for these very simple revamps are in the 1.1 to 1.15 range (the ISBL costs are multiplied by these factors to derive a total cost). These cost factors, as well as the utility prices that we used in our refinery-by-refinery cost model, are shown in Table 5-25 below:

Table 5-25 Cost Factors for Various PADDs

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5[a]
Capital Cost Factor	1.5	1.3	1.0	1.4	1.2
Natural Gas ($/MMBTU)	7.88	7.86	5.64	7.06	7.44
Electricity (¢/kW-hr)	7.98	5.47	5.78	4.69	8.36
Steam ($/1,000 lb)	12.9	12.6	9.20	11.6	11.9
Offsite Capital Cost Factor – New Units	1.26	1.26	1.20	1.30	1.30
Offsite Capital Cost Factor – Unit Revamps	1.13	1.13	1.10	1.15	1.15

[a] Excluding California

The volume-weighted cost estimates for revamping FCC postreaters across the entire refining industry as calculated by our refinery-by-refinery model are shown in Table 5-26 and Table 5-27 below. 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 postreating 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 5-26 Revamp Cost for a 30,000 BPSD FCC Postreater for 10-ppm Standard

FCC Feed Sulfur Level[a]	0 – 400 ppm	400 – 1,200 ppm	>1,200 ppm	Volume Weighted Average [b]
Capital Cost ($/B ISBL)	235	382	505	265
Hydrogen (scf/bbl)	36.8	25.9	25.9	31.3
Fuel Gas (kBTU/bbl)	15.5	15.4	8.51	14.4
Electricity (kWh/bbl)	0.14	0.27	0.52	0.223
Octane Loss (R+M)/2	0.56	0.46	0.42	0.492
Olefin Decrease (vol%)	2.67	2.14	1.97	2.39
Catalyst Cost ($/B)	0.01	0.01	0.01	0.010
Steam (lb/bbl)	0.61	30.88	0.61	13.44

[a] $/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.

[b] Of the refineries that are expected to revamp their FCC naphtha hydrotreater for the no ABT case, 36 have FCC naphtha sulfur levels in the 0 – 400 ppm range, 20 have FCC naphtha sulfur levels in the 400 – 1200 ppm range and 13 have FCC naphtha sulfur levels greater than 1200 ppm.

Table 5-27 Revamp Cost for a 30,000 BPSD FCC Postreater for 5 ppm Standard[a]

FCC Feed Sulfur Level	0 – 400 ppm	400 – 1,200 ppm	>1,200 ppm	Volume Weighted Average
Capital Cost ($/B ISBL)	400	578	600	444
Hydrogen (scf/bbl)	36.2	52.6	56.3	38
Fuel Gas (KBTU/bbl)	22.7	14.6	13.2	17.2
Electricity (kWh/bbl)	0.30	0.52	0.52	0.42?
Octane Loss (R+M)/2	0.60	0.77	0.90	0.62
Olefin Decrease	2.81	3.38	3.96	2.37
Catalyst Cost ($/B)	0.00	0.01	0.00	0.004
Steam (lb/bbl)	23.61	30.88	0.61	26.9

[a] Assumes every refinery is complying with a 5 ppm gasoline sulfur standard

We also found that there were 11 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 expansion needed versus the cost for the 30,000 BPSD grass roots treater used for technology vendor estimates.

5.1.4.1.2 Cost for Grassroots FCC Postreaters

While all refineries that already have FCC postreaters should be able to meet the proposed Tier 3 standards by revamping their existing postreaters, refineries that do not currently have an FCC postreater would have to add a grass roots FCC postreater. To determine the cost of building grass roots FCC postreating units at a refinery we similarly requested cost estimates from vendors. Only one of the vendors that supplied FCC postreating equipment submitted information on the cost of a grass roots FCC postreating 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 postreater 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 postreater 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 postreating 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 postreater and therefore relies on a single vendor's cost estimate for grass roots FCC postreating units for the Tier 3 program. In our FRM analysis we attempt to incorporate additional information from other vendors and literature sources. This one vendor cost estimate seemed reasonable relative to the other cost data that we have for higher levels of desulfurization.

The vendor estimate submitted for a grass roots postreater was based on a postreater 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 postreater revamps. We first determined the appropriate size for each unit based on each refiners maximum FCC naphtha production rate, adding 7.5 percent above each refinery's maximum FCC gasoline production rate as an over design factor. 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 as listed in Table 5-25 to determine the final cost of a grass roots FCC postreater for each refinery. The costs to produce an FCC naphtha with a sulfur level of 25 ppm (corresponding to a 10-ppm gasoline) were estimated based on the grass roots postreater unit that makes FCC naphtha for the 5-ppm standard. These costs are summarized in Table 5-28 and Table 5-29 below.

Table 5-28 Cost for a 30,000 BPSD Grass Roots FCC Postreater for 10-ppm Standard

FCC Feed Sulfur Level	100 ppm
Capital Cost ($/B ISBL)	1500
Hydrogen (scf/bbl)	62.1
Fuel Gas (KBTU/bbl)	4.95
Electricity (kWh/bbl)	1.06
Octane Loss (R+M)/2	0.55
Olefin Decrease	2.65
Catalyst Cost ($/B)	0.04
Steam (lb/bbl)	20.0

Table 5-29 Cost for a 30,000 BPSD Grass Roots FCC Postreater for 5-ppm Standard

FCC Feed Sulfur Level	100 ppm
Capital Cost ($/B ISBL)	1500
Hydrogen (scf/bbl)	133
Fuel Gas (kBTU/bbl)	9
Electricity (kWh/bbl)	1.06
Octane Loss (R+M)/2	1.00
Olefin Decrease	5.15
Catalyst Cost ($/B)	0.04
Steam (lb/bbl)	20.0

5.1.4.2 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, they may be cheaper to desulfurize for refineries that are not already treating these streams. Many refineries can desulfurize some or all of these blendstocks using existing excess capacity in their naphtha hydrotreaters or FCC naphtha postreaters. Further, 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. For our Tier 3 cost estimates, however, we have conservatively used our refinery-by-refinery model to estimate the costs for other refiners to hydrotreat all refiner volumes of LSR and NGL by installing additional hydrotreating equipment. 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 5.1.3.1.2. From this total we then subtracted the volume of LSR processed in the isomerization unit. Because the isomerization units require a low sulfur feedstock we assume all the feed to this unit is treated by the naphtha hydrotreater.

The next step in our assessment of the desulfurization costs of the LSR and NGL blendstocks was to estimate the extent to which these blendstocks are 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 postreaters 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 postreaters 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 assumed that every refinery's production volume of straight run and coker naphthas, as determined in Section 5.1.3.1, are processed in the refinery's reformer feed hydrotreater and that any capacity up to 85 percent of the unit's maximum capacity can be used to treat LSR or NGL. 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 postreater. We allowed LSR and NGL to be processed using excess FCC postreating capacity in refineries where the capacity of the FCC postreater exceeds 120 percent of that required to process a refinery's maximum FCC naphtha yield as determined by the refinery-by-refinery model. Only several refiners had excess FCC postreating capacity available for the treating of LSR or NGL feedstocks, as the capacity of most FCC postreaters 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 postreating units to desulfurize LSR and NGL in response to the Tier 2 sulfur standards. To meet the proposed Tier 3 sulfur standard 10 ppm and the 5 ppm level we considered for the ABT cases, we assumed that refiners would desulfurize all of the LSR and NGL blendstocks. We assumed that LSR and NGL purchased by refiners would be hydrotreated in addition to that processed by the isomerization unit and that blended directly into the gasoline. To determine which of the refineries in our refinery-by-refinery model would need to add hydrotreating capacity, we evaluated each refinery based on their maximum crude processing rate and yields. We used our model to increase each refinery's yield of coker naphtha, reformer naphtha, isomerate, LSR and NGL to correspond to a crude utilization rate of 100 percent. We then used these maximum production volumes to evaluate whether or not each refinery could process all of the LSR and NGL using excess naphtha hydrotreater and FCC postreating capacity. 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. (For our FRM, we will also evaluate if refiners could also use the caustic Merox extraction process to lower the sulfur level in LSR and NGL blendstocks, and if so, are they already doing that today). 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 2009 crude 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 below.

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 rates from the models yields at the 2009 operational crude throughputs as discussed in Section 5.1.3.1. 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 Handework'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 below.

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

5.1.4.3 Butane Desulfurization Costs

After considering the desulfurization of LSR and NGL we then estimated the cost to each refinery for desulfurizing the butane that is blended into gasoline. For the baseline case without ABT where each refinery had to meet the 10-ppm sulfur standard we did not assume any cost associated with butane desulfurization, as we assumed that any refiners likely to reduce the sulfur content of the butane stream already had the necessary equipment. To estimate the costs for each refinery to produce a 5-ppm gasoline for our ABT cases, however, we assumed refineries would reduce the sulfur content of any butane blended into gasoline using extractive desulfurization units (such as Merox or Merichem) which extract mercaptan sulfur (the bulk of sulfur species in butanes) from butane volumes that are added to each refiner's gasoline pool. We accounted for butane treating cost in our refinery-by-refinery model by adding capital to install Merox treating units to each refinery. This is likely a conservative estimate based on our lack of information on which refineries may already have these units. We set up the model to size the Merox treater based on each refinery's maximum addition of butane volume to the gasoline pool, using the amount that is blended in the winter, as winter grade gasoline has the highest seasonal gasoline RVP limits and therefore allows for the highest levels of butane blending. As with some of the LSR and NGL desulfurization units, it is unclear if additional butane desulfurization units will be added to meet the Tier 3 standards. As a conservative estimate, though, we have included the cost of adding these units to our program costs.

To calculate the volume of butanes added to winter grade gasoline we used the refinery-by-refinery model estimate of the full year addition of butane to each refiners CG and RFG gasoline grades which was based on the EPA annual gasoline database. The winter addition of butane volumes was assumed to be 66 percent of the total annual volume of butanes added to a refiner's gasoline pool on a yearly basis. The capital cost we used was for a 10,000 BPSD Merox unit and was listed in 1995 dollars.[9] We multiplied this cost by 1.64 to determine the equivalent cost in 2010 dollars based on the relative increase in the Nelson Refining Construction index from 1995 to 2010. We then multiplied the maximum winter daily butane volume by 1.08 to account for an over design factor to size the equipment. We next 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 in BPSD divided by 10,000 (the size of the unit the cost is based on). Finally, we applied offsite and PADD location factor adjustments as listed in Table 5-25. For the operating cost we assumed that each unit had an annual fixed operating cost of 6.7 percent of the total installed capital cost. To this we added an operating cost of 0.03¢ per gallon based on an operating cost figure from literature listed in 1995 dollars and scaled to 2010 dollars using appropriate factors. Operating costs were presumed to represent all process energy and utility costs, as well as costs associated with purchasing caustic.

Table 5-32 Merox Treating cost for Sulfur Removal from Butane

Size, BPSD	Capital costs, $ MM	Operating Costs, ¢/gal
10,000	3.28	0.03

5.1.5 Overall Cost Methodology

5.1.5.1 Sulfur Costs without ABT Program

While we are proposing an ABT program as described in Section V.E.1 of the preamble, we also evaluated a scenario with no averaging, banking, or trading between refineries. Under this scenario, every individual refinery would comply with the 10-ppm annual average sulfur standard, and none would lower their annual average sulfur below 10 ppm. This evaluation provided a reference point for determining the impacts of an ABT program on compliance costs.

In complying with the 10-ppm sulfur standard, our refinery-by-refinery analysis concluded that some refineries would do so with revamps to existing equipment while others would need to install new grassroots equipment. Those refineries whose average sulfur levels are already at or below the 10-ppm standard would not need to do anything. Because the most recently available data was for 2009 when some phase-ins under Tier 2 were still effective, we made adjustments to ensure that refinery-specific sulfur levels represented levels after all Tier 2 phase-ins had expired. For instance, if any refinery exhibited an annual average sulfur level above the 80-ppm cap based on 2009 data, we assumed that their current annual average sulfur level was 30 ppm. Further discussion of our refinery-by-refinery analysis can be found in Section 5.1.3.

To determine the impacts on cost of the 10-ppm sulfur standard without ABT, we volume-weighted the refinery-specific ¢/gal costs calculated according to the refinery-by-refinery modeling using 2009 gasoline production data for each refinery. Likewise, we determined nationwide capital costs by summing the individual revamp and/or grassroots equipment costs across all refineries. In these calculations, we assumed that all early credit generation and phase-ins had expired, consistent with our approach to the ABT analysis. The results of our analysis of costs under a scenario without ABT are provided in Section 5.2.1.1 below.

5.1.5.2 Sulfur Costs with ABT Program

As described in Section V.E.1 of the preamble, we are proposing 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 proposed ABT program, refineries that can reduce sulfur below 10 ppm at a relatively low cost can generate credits which can then be sold to refineries for whom the cost of attaining the 10 ppm sulfur standard would be relatively high. The net effect of this credit trading would be expected to reduce the overall cost of the program.

To estimate the impact that the ABT program could have on nationwide average fuel costs, we began with the refinery-by-refinery costs without the benefit of ABT described in Section 5.2.1.1 for sulfur reductions down to 10 ppm, where each and every refinery is assumed to get to 10 ppm. For the ABT analysis we then looked at the projected costs for refineries to get down to 5 ppm (also described in Section 5.2.1.1.). We then determined the lowest cost option among three alternatives for each refinery:

1. The refinery reduces its sulfur to 10 ppm.[I]
2. The refinery reduces its sulfur to 5 ppm and generates credits (in ppm-gal) for the increment between 10 ppm and 5 ppm.
3. The refinery does not lower sulfur, but instead obtains credits to comply with the 10-ppm standard.

A fourth category applied to refineries whose average gasoline sulfur levels are already below 10 ppm. All such refineries were assumed to generate credits for the increment between 10 ppm and their current sulfur level.

This process resulted in an ordering of refineries by their cost to reduce sulfur on a per-ppm basis. Those with the lowest costs were assumed to make the investment. To optimize the nationwide average costs under an ABT program, we determined the credit price at which the total number of credits generated was equal to the total number of credits consumed. This resulted in a list of refineries by their compliance strategy starting from the lowest-cost refinery and increasing to the highest-cost refinery necessary to achieve the cumulative sulfur reduction necessary to average 10 ppm across the gasoline pool. As discussed below, we did this under two different trading assumptions: one where we assumed sulfur credits would be traded freely across companies nationwide, and our primary, more conservative case where we only allowed "trading" across refineries within a company.

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 imports).

Since the cost information available for this NPRM was limited to the costs of reducing sulfur to either 10 ppm or 5 ppm (under which FCC gasoline sulfur levels would be reduced to either 25 or 10 ppm, respectively), we were not able to estimate refinery-specific costs of reducing sulfur to other levels. As a result, our ABT modeling could not account for scenarios in which a refinery makes some capital investments to lower sulfur to some interim level, such as 20 ppm, and then obtains credits in order to demonstrate compliance with the 10-ppm standard.

[I] No refinery compliance margins were included in this analysis.

Our ABT analysis also could not account for credit generation at sulfur levels other than 5 ppm. Our ABT analysis, then, most likely underestimates the cost savings that could occur due to ABT since the greatest efficiencies are achieved when every refinery has the option of using any combination of capital investments and credits generation or use. For the final rule, we may investigate methods for expanding our ABT analysis to examine these types of scenarios.

We evaluated two ABT scenarios designed to bound the likely outcomes. In the first scenario, we assumed perfect nationwide credit trading in which all credit generators make their credits available to any refinery that needs them, regardless of their ownership. As described in Section V.E.1 of the preamble, the proposed ABT program is designed such that it could operate in this way. However, such perfect nationwide trading may not be realistic. Under Tier 2 today, there is still a considerable amount of inter-company trading occurring, but a significant fraction of Tier 2 sulfur credits are bought and sold within companies.[J] Under Tier 3, it will be more difficult to generate credits, and also more difficult to make up for deficits. Consequently, we also investigated a second ABT scenario in which trading between companies does not occur and averaging would only occur within companies that own more than one refinery. Under this second scenario, individual companies might decide to bank credits for their own use, declining to make credits that they generate at one of their facilities available to other companies. They might do this, for instance, to address unplanned equipment downtime or other circumstances that could make future compliance more difficult. While we do anticipate some trading to occur between companies, we believe that this second, more limited scenario more closely represents how our proposed ABT program might actually operate. As a result, the within-company credit trading scenario is the primary scenario that we used to estimate overall costs for our proposed program. It represents a somewhat conservative scenario with respect to estimation of costs. The results of both scenarios are described in Sections 5.2.1.2 and 5.2.1.3 below.

Since an ABT program would allow some refineries to continue producing gasoline with an average sulfur level above 10 ppm, we also investigated whether any areas of the country might experience inordinately high sulfur levels as a result, and if so whether those higher sulfur levels might be problematic in terms of either vehicle performance or local air quality. While we were not able to model the distribution of all gasoline from the point of production to the point of consumption, we did compare average sulfur levels at each refinery's location to the location of nearby ozone nonattainment areas (based on the designation status with respect to the 1997 ozone NAAQS). A discussion of our analysis of sulfur levels by refinery and location can be found in Section 5.2.1 below.

[J] Based on Tier 2 sulfur compliance data, of the 26 companies that purchased sulfur credits in 2010, eight bought credits only from their own company, and another five bought credits both from their own company and from other companies. The remainder bought credits only from other companies.

5.2 Estimated Tier 3 Sulfur Control Costs

5.2.1 Sulfur Cost Results

5.2.1.1 Cost of the Sulfur Program without ABT

Without ABT, all refineries would be required to meet the 10-ppm annual average sulfur standard. We estimate that 13 refineries are already at or below 10 ppm, and thus their costs of compliance would be zero. The remaining refineries would incur ¢/gal costs at various levels depending on their particular configurations and the steps they would need to take. While we estimate that the nationwide average cost of compliance would be 0.97 ¢/gal under this scenario, two refineries would incur costs above 6 ¢/gal. The distribution of costs is shown in Figure 5-1 as a function of the number of refineries.

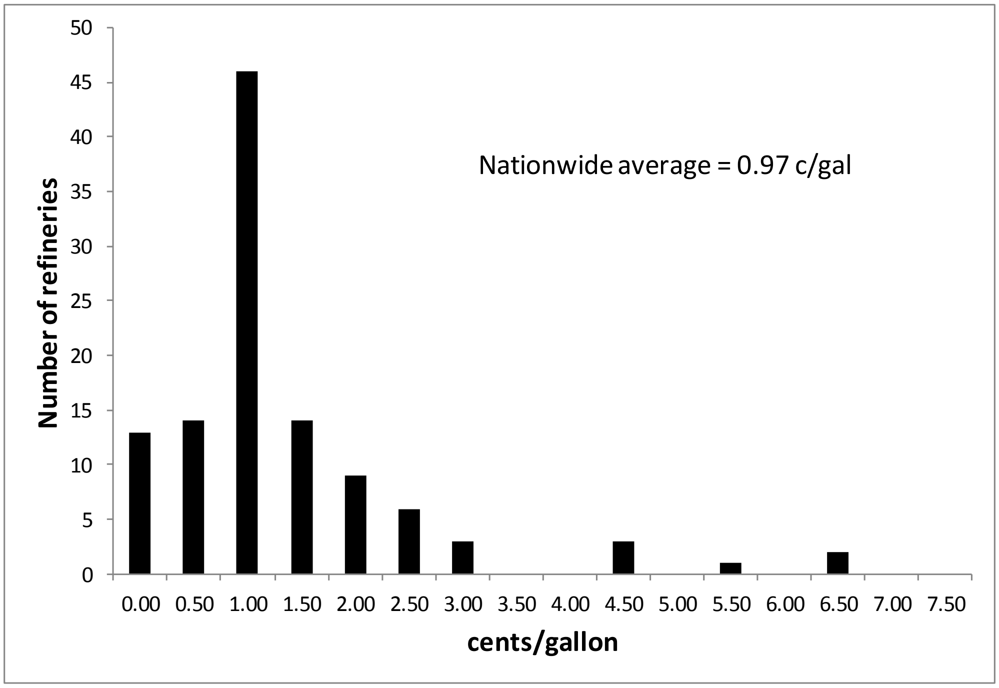

Figure 5-1 Distribution of Compliance Costs by Refinery for 10 ppm without ABT Program

In order to enable evaluation of the costs of the program with ABT, we also needed to estimate the costs for each refiner to reach 5 ppm. The distribution of costs for this scenario is shown below.

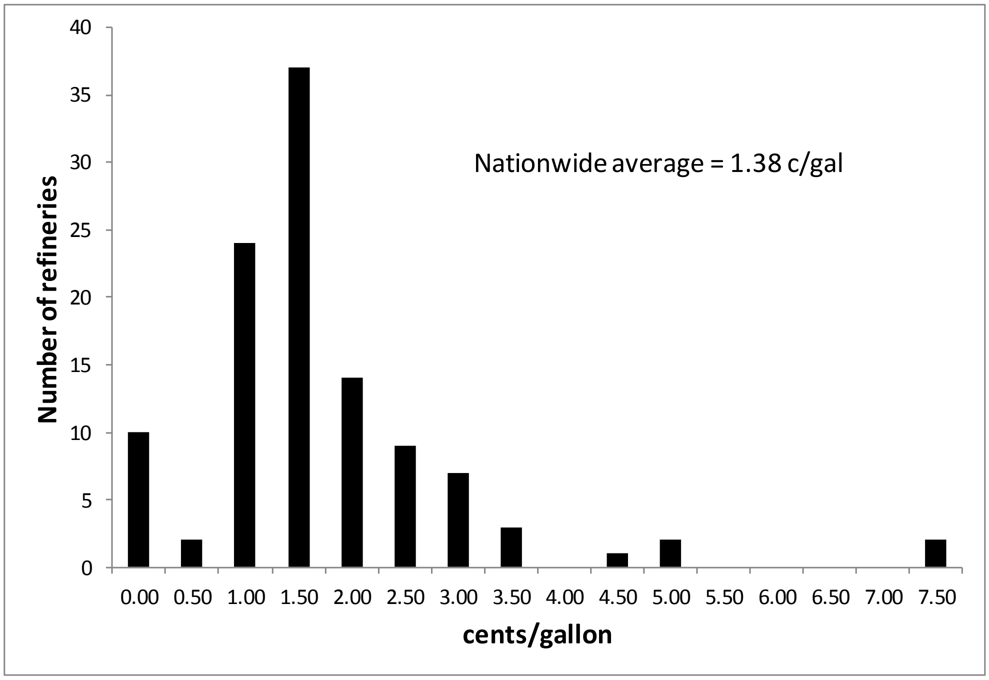

Figure 5-2 Distribution of Compliance Costs by Refinery for 5 ppm without ABT Program

5.2.1.2 Cost of Sulfur Control Program with ABT

Under a scenario in which credit trading only occurs between refineries within the same company, we determined that about 23 percent of refineries would be involved in either generating or consuming credits. Table 5-33 summarizes our estimate of the amount of credit trading that would occur under this scenario.

Table 5-33 Impacts of ABT Program with Intra-Company Credit Transfers

Number of refineries whose sulfur is already below 10 ppm, and which generate credits[a]	3
Number of refineries which lower their sulfur to 5 ppm and generate credits	15
Number of refineries that do not lower their sulfur but instead consume credits	8
Number of refineries that lower sulfur to 10 ppm and neither generate nor consume credits	85

[a] Additional refineries also have sulfur levels below 10 ppm, but do not generate credits under this scenario.

The nationwide average cost of compliance with the 10-ppm sulfur standard would be reduced from 0.97 ¢/gal without ABT to 0.89 ¢/gal under company-only trading.[K] However, there would continue to be a significant variation in costs by refinery as illustrated in Figure 5-3.

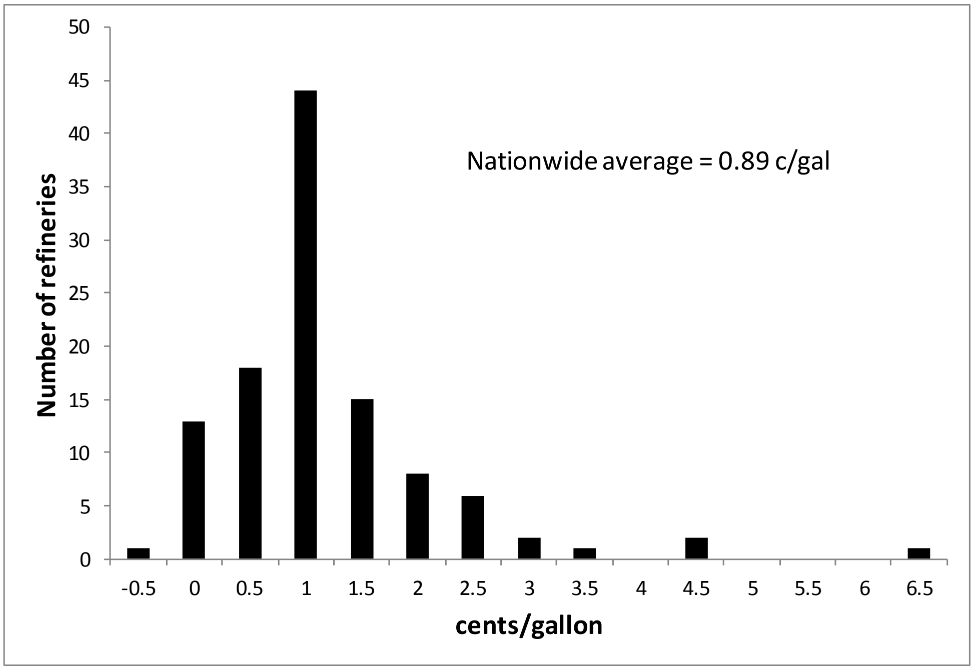

Figure 5-3 Distribution of Compliance Costs by Refinery for 10-ppm Average Standard with ABT Program and Intra-Company Credit Transfers

In this figure, refineries with negative costs are those whose sulfur levels were already below 10 ppm and who would generate and sell credits. While there are several refineries with costs above 3 ¢/gal in this scenario, in practice we would expect such refineries to incur lower costs by pursuing some combination of lowering their gasoline sulfur to some level above 10 ppm and also purchasing credits to cover the remaining sulfur reductions needed to reach 10 ppm. The analysis we conducted for this draft RIA was unable to capture such nuances, but we will be investigating them for the final rule.

Figure 5-4 illustrates how the cumulative distribution of costs by volume would change under this scenario. In general, the distribution would shift downward slightly in comparison to a scenario in which there was a 10 ppm average standard but no ABT program.

[K] Approximately 55% of this desulfurization cost is comprised of the variable cost, and the majority of that is due to the cost of recovering the octane lost when the hydrotreater unit saturates the octane-rich olefins contained in the FCC naphtha. Another 30% of the cost is due to the capital cost amortized over the volume of gasoline. Finally, about 15% of the cost is due to the fixed operating cost which includes the maintenance of the new equipment and taxes.

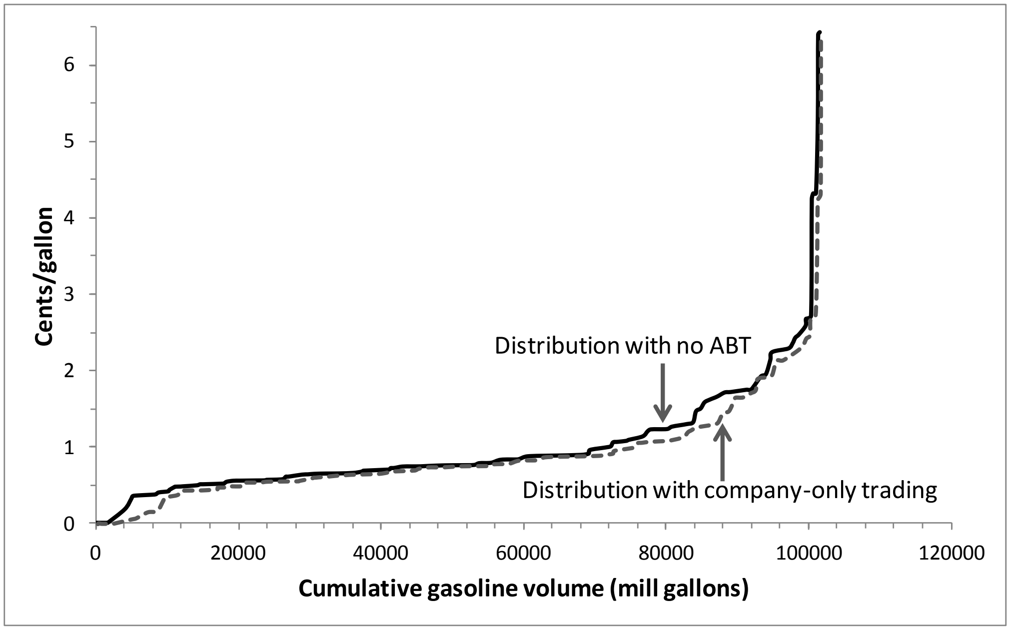

Figure 5-4 Distribution of Costs by Volume for 10-ppm Average Standard with ABT Program and Intra-Company Credit Transfers

Since we estimate that 85 out of 111 refineries would meet the 10-ppm sulfur standard without the use of credits under the intra-company trading scenario, only about 5 percent of gasoline would continue to have an annual average sulfur level above 10 ppm. These refineries tend to be smaller than average. The distribution of sulfur levels under this scenario is shown in Figure 5-5.

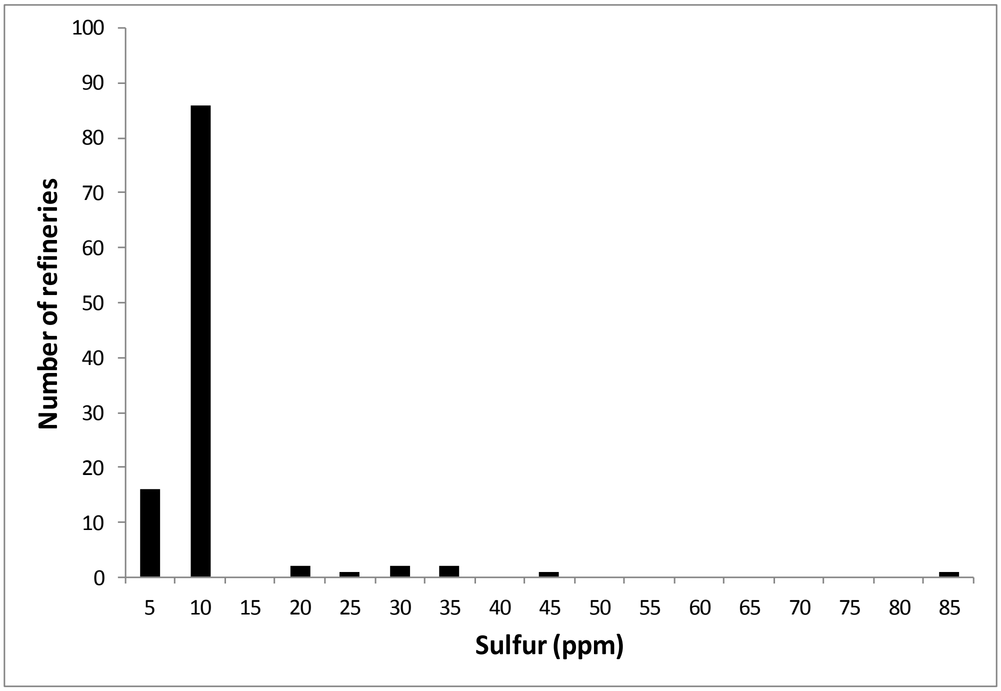

Figure 5-5 Distribution of Sulfur Levels by Refinery with ABT Program and Intra-Company Credit Transfers

Of the 5 percent of gasoline volume that would have average sulfur levels above 10 ppm under this scenario, nearly half would be below 20 ppm, and a majority would be below 30 ppm. Moreover, as noted above, we would expect refineries with the highest sulfur levels to pursue some combination of lowering their gasoline sulfur to some level above 10 ppm and also purchasing credits to cover the remaining sulfur reductions needed to attain the 10-ppm standard.

We also investigated whether the existence of refineries producing gasoline with average sulfur levels higher than 10 ppm after 2020 might contribute to local areas where the average sulfur level is higher than 10 ppm, and whether this might be problematic in terms of either vehicle performance/emissions or local air quality. To do this, we compared the location of refineries with sulfur levels higher than 10 ppm to the location of other refineries serving similar areas. We also compared the location of refineries to areas that have historically been in nonattainment for ozone.

As shown above in Table 5-33, we estimated that eight refineries would have annual average sulfur levels above 10 ppm under company-only credit trading. Three of these refineries serve areas that are, at a minimum, several hundred miles away from historical ozone nonattainment areas. The remaining five refineries with average sulfur levels above 10 ppm supply areas that are also supplied by other refineries whose average sulfur levels would be 10 ppm or lower. As a result, gasoline with higher sulfur levels would likely be diluted by gasoline with lower sulfur levels, and we would not expect any ozone non-attainment area to receive gasoline with an average sulfur level higher than 20 ppm.

5.2.1.3 Cost of Sulfur Control Program with ABT and Nationwide Credit Transfers

Although we believe that credit trading will occur primarily between refineries within the same company, we also investigated a scenario in which credit transfers would occur between all refineries regardless of location or company. For this scenario, we determined that more than 60 percent of refineries would be involved in either generating or consuming credits. Table 5-34 summarizes our estimate of the amount of credit trading that would occur under this scenario.

Table 5-34 Impacts of ABT Program with Nationwide Credit Transfers

Number of refineries whose sulfur is already below 10 ppm, and which generate credits	12
Number of refineries which lower their sulfur to 5 ppm and generate credits	34
Number of refineries that do not lower their sulfur but instead consume credits	25
Number of refineries that lower sulfur to 10 ppm and neither generate nor consume credits	40

The nationwide average cost of compliance with the 10-ppm sulfur standard would be reduced from 0.97 ¢/gal without any ABT program to 0.79 ¢/gal under nationwide trading. There would continue to be some variation in costs by refinery as illustrated in Figure 5-6, though the distribution would not be as wide as under the intra-company credit transfer scenario.

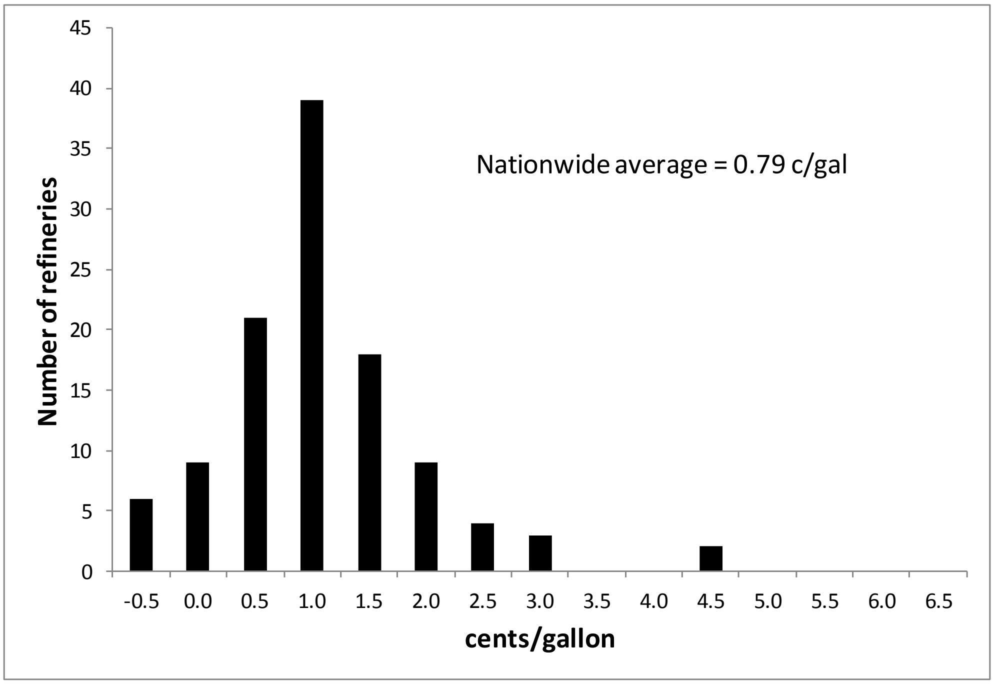

Figure 5-6 Distribution of Refinery Compliance Costs with ABT Program and Nationwide Credit Transfers

Figure 5-7 illustrates how the cumulative distribution of costs by volume would change under this scenario. In comparison to a scenario wherein credit trading occurs only between refineries within the same company, the downward shift in the distribution would be more pronounced.

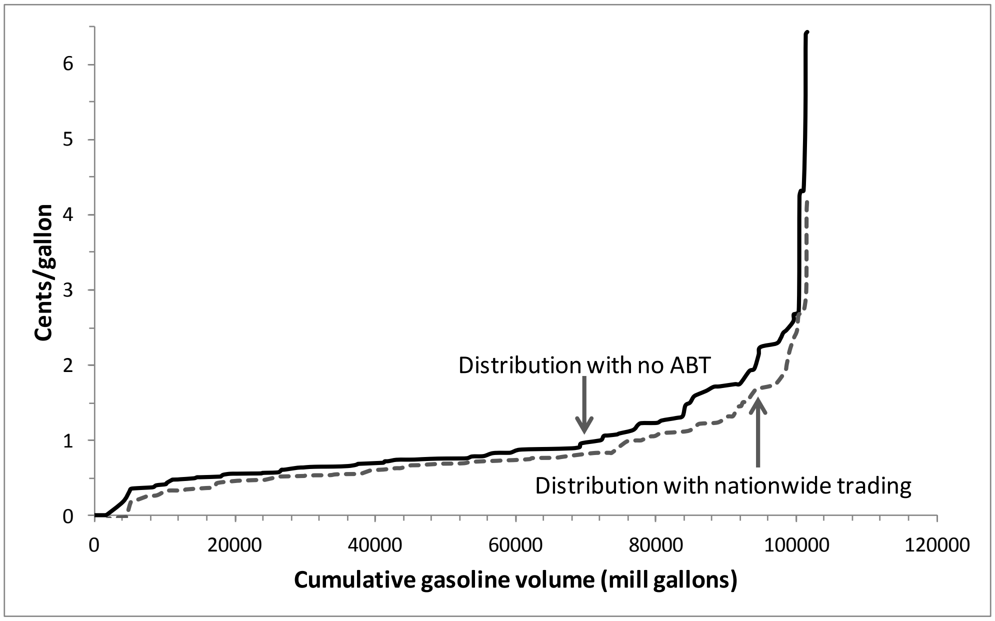

Figure 5-7 Distribution of Compliance Costs by Volume with ABT Program and Nationwide Credit Transfers

Under a scenario in which credit transfers occur nationwide, we estimate that 25 out of 111 refineries, or about 23 percent, would not lower their sulfur levels and would instead obtain credits. These refineries tend to be smaller than average, and represent about 17 percent of gasoline volume. The distribution of sulfur levels under this scenario is shown in Figure 5-8.

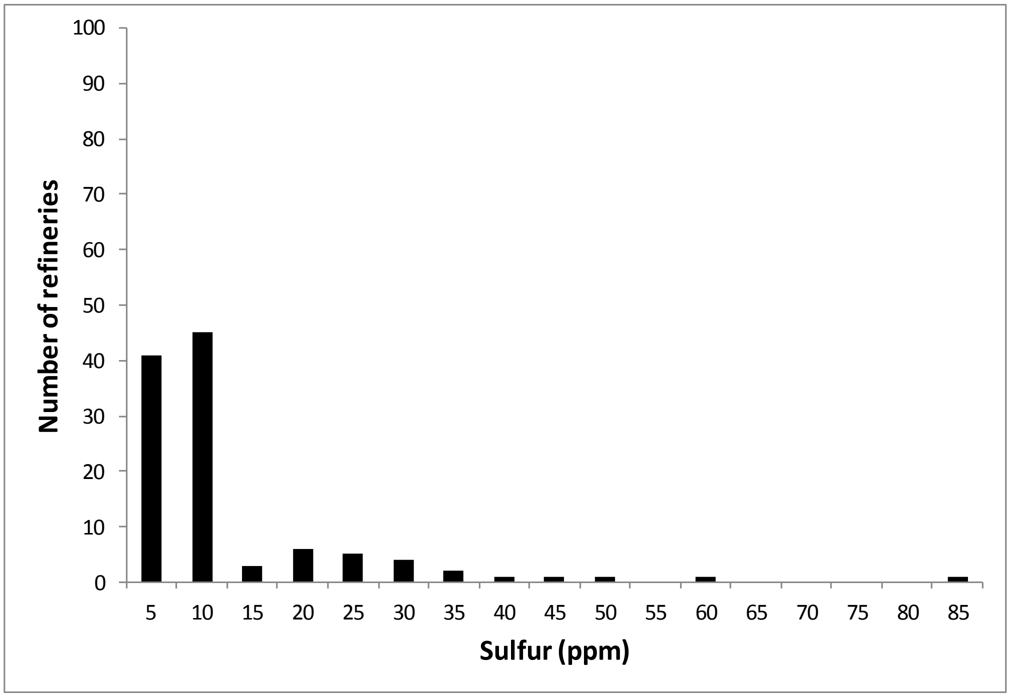

Figure 5-8 Distribution of Sulfur Levels by Refinery with ABT Program and Nationwide Credit Transfers

Of the 17 percent of gasoline volume that would have average sulfur levels above 10 ppm under this scenario, the vast majority would be below 30 ppm.

As for the previous scenario under which credit transfers would occur only within companies, we investigated the localized impact of higher sulfur levels under a scenario in which credit transfers occur nationwide and thus there are more refineries with average sulfur levels above 10 ppm. Under this scenario, most refineries with average sulfur levels higher than 10 ppm supply areas that are also supplied by refineries with sulfur levels at 10 ppm or below. We expect the dilution of higher sulfur with lower sulfur in such areas to result in annual average sulfur levels no higher than about 20 ppm. Of those refineries projected to have average sulfur levels higher than 10 ppm under this scenario and which are the primary or only suppliers of gasoline to a particular area, none of the affected areas have historically been in nonattainment for ozone.

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.

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.[10] 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. This cost reflects an assumption that the capital cost for revamps of FCC postreaters is 30 percent of the capital costs for a grassroots FCC postreater . Mathpro also analyzed costs assuming that the capital cost for revamps of FCC postreaters are 50 percent of a grassroots FCC postreaters, 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.

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).[11] 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.

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 1.38 ¢/gal.

In response to the Alliance study, API retained Baker and O'Brien (BOB) in 2010 to study the cost of additional gasoline sulfur control and an increase in RVP using a refinery-by-refinery cost approach with BOB's Prism model.[12] 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 and 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 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 postreater (see below). Like the original study, API did not report average costs, but reported 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 sets the gasoline price in the gasoline market 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 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 is provided by API about what hardware comprises their desulfurization units, the inside battery limits (ISBL) and total capital costs for the FCC postreaters 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 postreater 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 postreater 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 postreater is $1500/bbl-day for a 30,000 bbl/day grassroots unit, which increases to $1875/bbl/day when the offsite costs are added on. Thus, the API capital costs are about 3 ½ times higher than the capital costs that we are using for a grassroots FCC postreater. To check our capital costs, we found other capital cost estimates to which we could compare our costs, including the capital costs used by the National Petroleum Council when it studied the cost of gasoline desulfurization prior to Tier 2.[L] Table 5-35 contains a cost comparison of ISBL, and ISBL and OSBL FCC postreater capital costs.

Table 5-35 Capital Cost Comparison

Technology	EPA (Tier 3)	API	Mathpro (ICCT)	Jacobs	Exxon Scanfining (NPC)	IFP Prime G (NPC)	CDTech (NPC)	Phillips S-Zorb (NPC)
ISBL Capital Cost ($/bbl/day)	1500	-	-	2440	1045	1410	960	860
ISBL and OSBL Capital Cost ($/bbl/day)	1875	6540	1800	3538	1360	1833	1248	1118

Table 5-35 shows that, compared to the average of the rest of the capital cost estimates, the API capital cost for FCC postreater is about four times higher. Compared to the next highest

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[L] The capital costs that the vendors provided to the National Petroleum Council were adjusted from year 2000 dollars, which was the year that the NPC analysis was conducted, to year 2011 dollars, which is the base year of the Tier 3 analysis. To make this adjustment we used the Nelson-Farrar capital cost index which increased the NPC capital costs by 55% over the year 2000 costs.

cost estimate, which is the FCC postreater capital cost from the Jacobs data base in the Haverly refinery cost model that we use,[M] 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 Table 5-27. For complying with the Tier 2 gasoline sulfur standard (Jacobs and NPC costs), 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

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[M] 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.

a percentage of the capital cost for a grassroots unit. API estimates that revamping an FCC postreater would cost 30 to 70 percent of the capital cost for a grassroots FCC unit. Our capital cost estimate for revamping an FCC naphtha postreaters 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.

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.[13] 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 and 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. Because API's addendums to its original report came out many months after its original report, we originally assessed the most similar case to our proposal from API's original study. This was sensitivity case 3, which studied a 10-ppm average gasoline sulfur standard with a 7.8-psi RVP limit on all conventional gasoline with a 1-psi waiver. One of the most important conclusions by API with respect to sensitivity case 3 was the projected 623 thousand barrels per day (about 6.5 percent of total gasoline demand) reduction in U.S. gasoline production due to reduced blending of light hydrocarbons in response to RVP control and the closure of 4 refineries caused by the investment hurdle of complying with both the sulfur and RVP standards evaluated. Because of API's significant projected impacts, which differed from those made by the Alliance and by ECTA in their studies, we looked closely at this projected impact. We found that this projection for a large shortfall in supply is similar to previous projections made by API for earlier rulemakings. Baker and O'brien made a very dire projection for diesel fuel supply when analyzing the final highway and proposed nonroad diesel fuel sulfur regulations for the proposed nonroad diesel rulemaking back in 2003.[14] API's projection was that 12 refineries would be shutdown and that U.S. refiners would exit the diesel market resulting in a shortage of diesel fuel supply of 639 thousand barrels per day and to make up the shortfall, the distillate market would need to be supplied by imports. Since that projection was made back in 2003 and the highway diesel fuel program is fully implemented and the nonroad diesel fuel program is mostly implemented, we can look at the impacts to see how well API's projection played out.

First, with respect to imports, the distillate import/export market was fairly stable at about 200 thousand barrels per day of net imports during the period 2003 to 2005, before the highway and nonroad programs started. If we add the expected increase in imports estimated by API caused by the ULSD highway rule, API projected the imports to increase to 549 thousand barrels per day in 2006. When the temporary compliance option of the ULSD highway rule ended in 2010 and nonroad diesel (excluding locomotive and marine diesel because those requirements don't start until 2012) must comply with the ULSD nonroad diesel rule in 2010, API estimated that imports will increase to 829 thousand barrels per day including the baseline imports. However, what actually occurred is that imports not only did not increase, but they actually decreased to the point that the U.S. became net exporters of 428 thousand barrels per day of distillate.[15] [16] Thus, API was off by over 1200 thousand barrels per day in its estimate of distillate production in 2010 by U.S. refiners. Figure 5-9 summarizes the imports and exports of diesel fuel and gasoline during the period when the clean fuels regulations were being phased in.

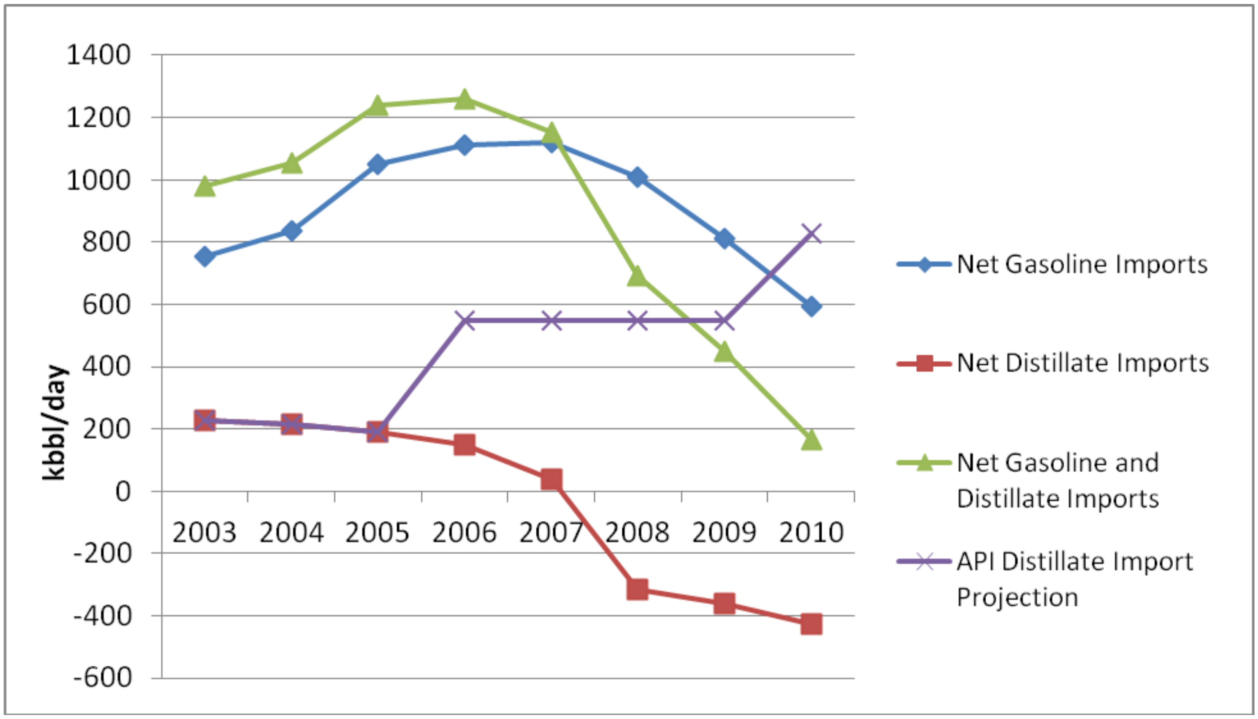

Figure 5-9 Petroleum Product Imports and Exports During the Implementation of Clean Fuels Regulations

One reason why API was so far off in its projection that U.S. distillate supply would decrease significantly is that it had projected that 12 refineries would shut down due to the highway and nonroad rulemakings, but, in fact, there were very few refinery shutdowns.[17] [18] Between 2003 and 2011 when the highway and nonroad diesel fuel ULSD programs were phasing in (as well as Tier 2, MSAT2, RFS1 and RFS2), there was a total of 5 refinery shutdowns of refineries which produce transportation fuels. However, also during this time period there were reactivations of three previously shutdown transportation fuel producing refineries. Considering both the shutdown refineries and reactivated refineries, there was a net shutdown of two transportation fuel producing refinery closures. It is unclear why those 5 transportation fuel producing refineries shutdown, but there is no evidence to suggest they were caused by the diesel rules. There are many factors which cause refinery shutdowns.

To understand these factors it is necessary to revisit the history of the U.S. refining industry.[19] During the second crude oil embargo which occurred during the Carter Administration, subsidies were established that incentivized the construction of many small refineries. After crude oil prices dropped, those subsidies ended and many of those refineries were not economically competitive with larger refineries. Over time the number of refineries decreased and the remaining refineries were expanded to supply the U.S. market. This is part of a rationalization that most any industry experiences as the industry matures. Figure 5-10 and Table 5-36 summarize the changes in the number of refineries, the average size of refineries, and the total production capacity of the U.S. refining industry based on data from the Energy Information Administration (EIA).

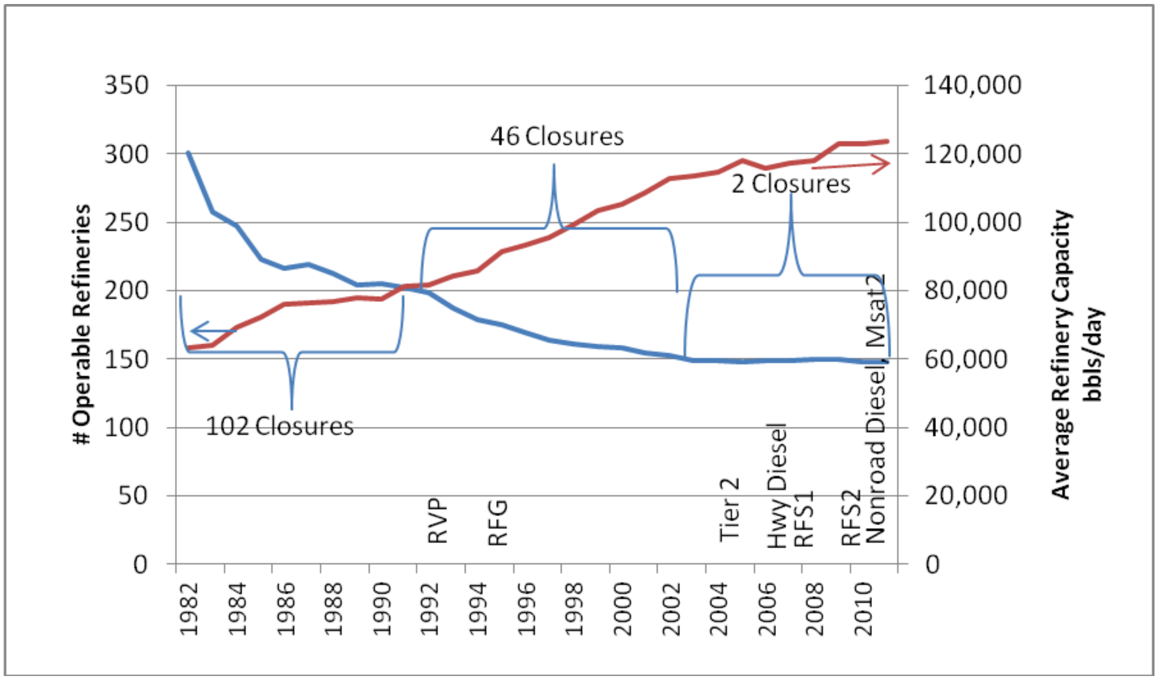

Figure 5-10 Refining Industry Statistics

Table 5-36 U.S. Refinery Industry Statistics

Year	1982 - 1992	1993 – 2002	2003 - 2011
Net Change in the Number of Operable Refineries	-102	-50	-2
Change in Average Refinery Size (kbbl/day)	+18,400	+31,800	+11,000
Change in Total U.S. Operating Refinery Capacity (MMbbl/day)	-1.2	+1.6	+0.4

Figure 5-10 and Table 5-36 show that there were many refinery closures during the 1980s and 1990s, although over time the number of refinery closures was diminishing. Therefore, the refinery closures which occurred during the 2003 to 2011 time frame could very well be due to this rationalization process reflecting a maturing industry. In fact, examining the trend, the number of net refinery shutdowns is virtually flat during the 2003 to 2011 time frame relative to the previous periods. This is clearly a rationalization of the refining industry because as refineries were closing, the average refinery size increased over each of the periods. Finally, the total U.S. refinery capacity decreased and increased back to its 1982 levels during the 1980s and early 90s (decrease was likely due to the corporate average fuel economy standards), but showed a modest increase from the late 1990's through 2011.

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 CO2 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, hydrogen, and gasoline octane 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 111 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 gasoline octane demand results from refineries having to replace octane that is lost due to increased FCC naphtha hydrotreating. Increased SRU loading results from the increased fuel desulfurization and associated H2S 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, electricity and gasoline octane based on the desulfurization technology used by each refinery for any FCC postreating and LSR hydrotreating. To determine the FCC postreating demands the model considers each refinery's volume of FCC naphtha under normal operations, the FCC naphtha sulfur level at the refinery prior to postreating, and the process requirements of the FCC postreater 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 postreating technology. Table 5-26 through Table 5-29 show the FCC postreater 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 postreating.

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, on a national average basis, are listed in Table 5-31. The normal case demands for FCC postreating and LSR hydrotreating were then summed to determine the increase in energy, hydrogen, and octane 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 2009 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 postreating 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 refineries projected to install a new FCC postreater 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 new FCC postreaters, 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 projects 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, rather than 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, as well as make up for all of the lost octane at their refinery. Others may choose to purchase some or all of the hydrogen, electricity, and high octane blendstocks 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 while making up for any gasoline octane loss at their refinery. In the low impact scenarios we assume that all the necessary hydrogen, electricity, and high octane blendstocks 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 while replacing the lost octane in their gasoline. We consulted literature sources to determine the conversion factors from MBTU fuel gas to 1,000 standard cubic feet (scf) of hydrogen[20] and 1,000 pounds of steam[21] that are typical for refineries. We also assumed a standard conversion efficiency from fuel gas to electricity for our modeling. These conversion factors are shown in Table 5-37 below.

Table 5-37 Fuel Gas Required to Produce Hydrotreater Utilities

Utility	Fuel Gas Required (M BTU)
Hydrogen (1,000 SCF)	239
Steam (1,000 lbs)	1530
Electricity (1 kWh)	5.1

We also had to determine the fuel gas demands that would be required to make up for lost octane in our high impacts scenario. For this analysis we assumed that all lost octane in the gasoline that results from increased FCC postreating to meet the proposed Tier 3 standards would be recovered by running the reformers at the refineries at a higher severity as opposed to sourcing it from ethanol or other means. This would increase the octane of the reformate and offset the octane losses from the FCC naphtha, resulting in no change in the octane of the overall gasoline pool. Running the reformer at a higher severity requires a higher reactor processing temperature and an increased volumetric rate for the pumps and compressors. These changes further increase the fuel gas and electricity demands of the refinery. We estimated these demands using information we obtained from our Jacob's refinery LP modeling analysis. The estimates we used for the fuel gas and electricity demands for increasing gasoline octane are shown in Table 5-38 below. These demand increases were only used for the high impact scenarios. For the low impact scenarios we assumed that lost octane was recovered by purchasing high octane blendstocks resulting in no fuel gas or electricity demand increases at the refinery.

Table 5-38 Energy Required to Increase Gasoline Octane

Utility	Amount Required to Increase Octane[a] 1 Point (per barrel gasoline)
Fuel Gas (M BTU)	1.87
Electricity (kWh)	0.057

Note:
[a] (R + M)/2 method

5.4.3 Refinery Demand Impacts

Using our refinery-by-refinery model, along with the technology vendor data for new and revamped FCC postreating and LSR hydrotreating data (shown in Table 5-26 through Table 5-29 and Table 5-31) we were able to calculate the increases in refinery 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 5-39 and Table 5-40 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 data provided, OAQPS determined that under the proposed Tier 3 gasoline sulfur standard primary ABT scenario "high case" at most only about 19 refineries would be expected to need New Source Review (NSR) permits. This equates to approximately 17% of the 111 refineries projected to be affected by the proposed Tier 3 standards. Of these 19 refineries, about 13 refineries would need permits for NAAQS-related pollutants and their precursors and for GHGs. In addition to these 13 refineries, the analysis estimated that 6 other refineries may require a permit addressing only GHG emissions. A technical memorandum describing the OAQPS analysis and results is in the public docket for this proposal.[22]

Table 5-39 Tier 3 Refinery Energy, Hydrogen and Sulfur Plant Demand Increases (10 ppm, No ABT Cases)

	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production Increase (Tons Sulfur/Day)	Sulfur Plant Capacity Increase (Percent of Existing Facility)	Hydrogen Demand Increase (million scf/year)
Refinery Number	Normal Volumes	Maximum Volumes	Normal Volumes	Maximum Volumes			
1	117,423	117,423	243,241	243,241	0.28	0.02	426
2	0	0	0	0	0.00	0.00	0
3	2,239,110	2,739,637	2,566,562	3,140,286	0.00	0.00	863
4	173,672	173,672	569,009	569,009	0.43	0.03	1,628
5	46,380	58,279	261,528	328,624	0.13	0.04	655
6	4,433	7,291	14,523	23,888	0.04	1.96	42
7	60,923	69,776	199,605	228,609	0.10	0.03	571
8	23,941	29,792	134,995	167,988	0.17	0.07	338
9	107,543	135,777	222,775	281,262	0.20	0.18	390
10	25,924	29,812	146,179	168,106	0.10	0.08	366
11	13,984	16,250	78,855	91,630	0.09	0.05	198
12	76,663	92,786	251,175	303,997	0.43	0.07	719
13	51,432	51,432	168,509	168,509	0.47	1.18	482
14	0	0	6,444	6,444	0.00	0.00	27
15	16,876	16,876	89,463	89,463	0.07	0.13	219
16	831,027	1,244,900	899,341	1,347,235	0.26	0.22	218
17	31,964	31,964	82,442	82,442	2.19	0.96	206
18	150,568	150,568	311,900	311,900	0.22	0.03	547
19	27,087	44,061	152,736	248,452	0.26	[a]	383
20	43,909	46,106	143,861	151,058	0.37	0.08	412
21	165,539	212,719	343,091	440,875	0.17	0.04	538
22	14,886	16,690	38,395	43,048	0.01	0.02	96
23	83,222	83,222	272,663	272,663	0.41	0.12	780
24	190,870	210,535	206,560	227,841	0.33	0.29	50
25	702,808	702,808	798,012	798,012	0.10	0.09	256
26	20,503	22,001	67,175	72,082	0.90	0.60	192
27	0	0	0	0	0.00	0.00	0
28	3,145,454	3,528,532	3,223,899	3,616,532	0.31	0.07	201
29	0	0	0	0	0.00	0.00	0
30	64,080	66,959	165,279	172,703	0.15	0.01	414
31	0	0	0	0	0.00	0.00	0
32	62,002	62,002	159,918	159,918	0.35	3.46	400
33	1,693,620	1,948,219	1,832,841	2,108,370	0.27	0.03	444
34	16,574	24,879	93,456	140,290	0.15	0.21	234
35	10,469	10,469	12,340	12,340	0.04	0.96	6
36	337,961	411,915	365,743	445,776	0.15	[a]	89
37	5,175	5,175	29,180	29,180	0.13	3.30	73
38	0	0	2,907	2,907	0.00	0.00	12

Refinery Number	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production	Sulfur Plant Capacity	Hydrogen Demand
39	21,773	21,773	71,336	71,336	0.58	0.93	204
40	19,171	23,883	91,207	113,621	0.04	0.01	214
41	177,093	203,657	636,542	732,024	0.30	0.03	1,288
42	3,288	4,683	10,773	15,343	0.03	0.97	31
43	41,705	43,146	107,567	111,284	0.52	0.26	269
44	3,609,133	4,265,613	3,905,818	4,616,262	0.66	0.22	946
45	27,946	41,431	105,829	156,897	0.06	[a]	221
46	6,846	8,054	38,603	45,416	0.05	0.55	97
47	1,416,139	1,416,139	1,532,550	1,532,550	0.25	0.03	371
48	21,918	41,206	45,403	85,358	0.02	0.01	80
49	7,024	7,191	18,116	18,547	0.19	2.16	45
50	2,170,692	2,170,692	2,349,131	2,349,131	0.61	0.23	569
51	0	0	0	0	0.00	0.00	0
52	3,945,526	3,984,109	4,269,863	4,311,617	0.61	0.03	1,034
53	102,473	124,044	264,305	319,941	0.46	[a]	662
54	40,155	51,299	108,185	138,209	0.11	0.09	236
55	21,405	26,758	120,695	150,884	0.16	0.13	302
56	26,807	28,515	70,005	74,463	0.04	0.13	144
57	91,964	107,033	518,563	603,534	0.00	0.03	1,299
58	0	0	0	0	0.00	0.00	0
59	52,160	62,683	108,050	129,848	0.10	0.03	189
60	109,050	109,050	357,285	357,285	0.62	0.11	1,022
61	23,773	23,773	36,151	36,151	0.04	0.00	52
62	9,233	9,655	30,251	31,632	0.04	1.96	87
63	136,167	175,790	282,068	364,148	0.08	0.01	494
64	54,151	60,794	165,033	185,278	0.24	0.12	221
65	360,695	402,762	390,346	435,870	0.05	0.19	95
66	8,113	8,589	20,926	22,152	0.04	0.39	52
67	26,289	34,157	67,806	88,100	0.19	0.17	170
68	89,955	103,448	507,237	583,323	0.20	0.02	1,271
69	30,259	33,479	99,139	109,690	0.14	0.14	284
70	9,369	20,299	61,521	133,298	0.20	0.03	103
71	37,188	37,188	121,841	121,841	1.31	0.44	349
72	1,079,231	1,299,822	1,167,948	1,406,672	0.09	0.14	283
73	15,845	17,618	51,915	57,724	0.03	0.00	149
74	38,525	40,291	101,764	106,429	0.09	0.04	215
75	0	0	0	0	0.00	0.00	0
76	14,588	14,588	47,795	47,795	0.03	0.00	137
77	16,875	20,135	43,524	51,932	0.13	0.70	109
78	139,558	139,558	289,093	289,093	0.16	0.02	507
79	0	0	0	0	0.00	0.00	0
80	64,517	76,071	65,729	77,500	0.07	0.10	234
81	2,009,982	2,009,982	2,280,122	2,280,122	0.24	0.05	729
82	58,475	60,441	191,583	198,026	0.26	[a]	548

	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
Refinery Number	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production	Sulfur Plant Capacity	Hydrogen Demand
83	2,008,357	2,021,700	2,173,451	2,187,891	0.48	0.09	526
84	0	0	0	0	0.00	0.00	0
85	23,472	27,526	132,354	155,214	0.27	0.14	332
86	20,570	24,731	115,988	139,454	0.00	0.00	291
87	97,698	112,353	363,505	418,031	0.35	0.10	752
88	4,171	5,743	27,391	37,710	0.08	0.12	46
89	147,823	147,823	306,331	306,331	0.13	0.01	495
90	786,104	984,013	850,725	1,064,903	0.30	0.18	206
91	786,104	984,013	850,725	1,064,903	0.41	1.47	206
92	25,608	25,608	53,152	53,152	0.03	0.08	56
93	35,993	47,565	36,669	48,459	0.05	[a]	131
94	4,151,496	4,231,505	4,606,346	4,695,121	0.65	0.08	1,307
95	1,232	2,692	8,090	17,675	0.01	0.03	14
96	2,457	3,308	13,417	18,060	0.02	[a]	33
97	28,695	28,695	74,012	74,012	0.52	[a]	185
98	0	0	0	0	0.00	0.00	0
99	46,468	50,408	152,246	165,155	0.26	0.66	436
100	2,591,010	2,708,025	2,804,001	2,930,635	0.83	0.13	679
101	0	0	0	0	0.00	0.00	0
102	32,339	57,437	111,894	198,734	0.12	0.06	221
103	0	0	0	0	0.00	0.00	0
104	74,538	74,538	154,710	154,710	0.00	0.00	162
105	5,400	5,668	35,458	37,218	0.00	0.00	59
106	139,029	139,029	455,507	455,507	0.25	0.02	1,303
107	0	0	11,540	11,540	0.05	[a]	48
108	8,314	8,879	17,223	18,393	0.00	0.00	30
109	1,485,414	1,704,414	1,607,521	1,844,524	0.32	0.05	389
110	122,762	122,762	279,765	279,765	0.22	0.06	515
111	27,548	33,475	155,338	188,757	0.10	0.07	389

[a] The refinery did not have published information on the capacity of the existing sulfur plant.

Table 5-40 Tier 3 Refinery Energy, Hydrogen and Sulfur Plant Demand Increase (10 ppm, ABT Cases)

Refinery Number	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production Increase (Tons Sulfur/Day)	Sulfur Plant Capacity Increase (Percent of Existing Facility)	Hydrogen Demand Increase (million scf/day)
	Normal Volumes	Maximum Volumes	Normal Volumes	Maximum Volumes			
1	20,503	22,001	67,175	72,082	0.90	0.60	192
2	64,080	66,959	229,725	240,045	0.22	0.02	467
3	323,504	388,955	476,338	572,710	0.00	0.00	528
4	89,955	103,448	507,237	583,323	0.20	0.02	1,271
5	0	0	0	0	0.00	0.00	0
6	426,001	692,966	627,257	1,020,346	0.29	[a]	696
7	0	0	0	0	0.00	0.00	0
8	26,807	28,515	70,005	74,463	0.04	0.13	144
9	117,423	117,423	243,241	243,241	0.28	0.02	426
10	5,400	5,668	35,458	37,218	0.00	0.00	59
11	1,525,387	1,525,387	1,558,831	1,558,831	0.51	1.28	64
12	8,113	8,589	20,926	22,152	0.04	0.39	52
13	7,024	7,191	18,116	18,547	0.19	2.16	45
14	74,538	74,538	154,710	154,710	0.00	0.00	162
15	0	0	0	0	0.00	0.00	0
16	2,591,010	2,708,025	2,804,001	2,930,635	0.83	0.13	679
17	177,093	203,657	636,542	732,024	0.30	0.03	1,288
18	0	0	0	0	0.00	0.00	0
19	19,171	23,883	91,207	113,621	0.04	0.01	214
20	26,289	34,157	67,806	88,100	0.19	0.17	170
21	2,239,110	2,739,637	2,566,562	3,140,286	0.00	0.00	863
22	83,222	83,222	272,663	272,663	0.41	0.12	780
23	147,823	147,823	306,331	306,331	0.13	0.01	495
24	0	0	2,907	2,907	0.00	0.00	12
25	2,273,706	2,751,864	2,323,556	2,812,199	0.50	0.08	96
26	0	0	0	0	0.00	0.00	0
27	107,543	135,777	222,775	281,262	0.20	0.18	390
28	16,875	20,135	43,524	51,932	0.13	0.70	109
29	150,568	150,568	311,900	311,900	0.22	0.03	547
30	0	0	0	0	0.00	0.00	0
31	30,259	33,479	99,139	109,690	0.14	0.14	284
32	0	0	0	0	0.00	0.00	0
33	139,558	139,558	289,093	289,093	0.16	0.02	507
34	9,369	20,299	61,521	133,298	0.20	0.03	103
35	0	0	6,444	6,444	0.00	0.00	27
36	0	0	0	0	0.00	0.00	0
37	109,050	109,050	357,285	357,285	0.62	0.11	1,022
38	0	0	0	0	0.00	0.00	0

Refinery Number	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production	Sulfur Plant Capacity	Hydrogen Demand
39	10,469	10,469	12,340	12,340	0.04	0.96	6
40	210,772	269,511	319,729	408,832	0.07	0.00	379
41	173,672	173,672	569,009	569,009	0.43	0.03	1,628
42	21,773	21,773	71,336	71,336	0.58	0.93	204
43	3,145,454	3,528,532	3,223,899	3,616,532	0.31	0.07	201
44	337,961	411,915	365,743	445,776	0.15	[a]	89
45	3,945,526	3,984,109	4,269,863	4,311,617	0.61	0.03	1,034
46	97,698	112,353	363,505	418,031	0.35	0.10	752
47	1,416,139	1,416,139	1,532,550	1,532,550	0.25	0.03	371
48	16,876	16,876	89,463	89,463	0.07	0.13	219
49	433,258	526,468	637,943	775,189	0.14	0.09	707
50	4,433	7,291	14,523	23,888	0.04	1.96	42
51	58,475	60,441	191,583	198,026	0.26	[a]	548
52	2,170,692	2,170,692	2,349,131	2,349,131	0.61	0.23	569
53	8,497	8,497	12,247	12,247	0.00	0.00	16
54	31,964	31,964	82,442	82,442	2.19	0.96	206
55	336,635	420,834	495,673	619,649	0.19	0.15	550
56	32,339	57,437	111,894	198,734	0.12	0.06	221
57	38,525	40,291	101,764	106,429	0.09	0.04	215
58	54,151	60,794	165,033	185,278	0.24	0.12	221
59	0	0	0	0	0.00	0.00	0
60	23,773	23,773	36,151	36,151	0.04	0.00	52
61	190,870	210,535	206,560	227,841	0.33	0.29	50
62	3,288	4,683	10,773	15,343	0.03	0.97	31
63	0	0	0	0	0.00	0.00	0
64	2,008,357	2,021,700	2,173,451	2,187,891	0.48	0.09	526
65	2,457	3,308	13,417	18,060	0.02	[a]	33
66	41,705	43,146	149,509	154,676	0.63	0.31	304
67	46,468	50,408	152,246	165,155	0.26	0.66	436
68	1,079,231	1,299,822	1,167,948	1,406,672	0.09	0.14	283
69	3,071	3,325	7,294	7,896	0.00	0.00	17
70	4,123,377	4,123,377	4,213,781	4,213,781	0.38	0.03	174
71	786,104	984,013	850,725	1,064,903	0.30	0.18	206
72	37,188	37,188	121,841	121,841	1.31	0.44	349
73	0	0	0	0	0.00	0.00	0
74	40,155	51,299	108,185	138,209	0.11	0.09	236
75	1,485,414	1,704,414	1,607,521	1,844,524	0.32	0.05	389
76	122,762	122,762	279,765	279,765	0.22	0.06	515
77	102,473	124,044	264,305	319,941	0.46	[a]	662
78	0	0	0	0	0.00	0.00	0
79	3,609,133	4,265,613	3,905,818	4,616,262	0.66	0.22	946
80	43,909	46,106	143,861	151,058	0.37	0.08	412
81	1,693,620	1,948,219	1,832,841	2,108,370	0.27	0.03	444
82	0	0	0	0	0.00	0.00	0

Refinery Number	Demand Estimates						
	Fuel Gas Demands				Sulfur Plant Production		Hydrogen
	Low Impact Cases (Million BTU/Yr)		High Impact Cases (Million BTU/Yr)		Sulfur Production	Sulfur Plant Capacity	Hydrogen Demand
83	60,923	69,776	199,605	228,609	0.10	0.03	571
84	4,171	5,743	27,391	37,710	0.08	0.12	46
85	4,151,496	4,231,505	4,606,346	4,695,121	0.65	0.08	1,307
86	8,314	8,879	17,223	18,393	0.00	0.00	30
87	5,175	5,175	29,180	29,180	0.13	3.30	73
88	96,113	113,326	98,454	116,085	0.13	0.17	543
89	988,379	1,480,617	1,109,185	1,661,587	0.31	0.26	412
90	0	0	0	0	0.00	0.00	0
91	9,233	9,655	30,251	31,632	0.04	1.96	87
92	21,918	41,206	45,403	85,358	0.02	0.01	80
93	14,886	16,690	38,395	43,048	0.01	0.02	96
94	35,993	47,565	36,669	48,459	0.05	[a]	131
95	202,851	261,880	506,929	654,442	0.15	0.01	1,146
96	786,104	984,013	850,725	1,064,903	0.41	1.47	206
97	25,924	29,812	146,179	168,106	0.10	0.08	366
98	1,232	2,692	8,090	17,675	0.01	0.03	14
99	369,152	432,912	543,551	637,434	0.30	0.15	603
100	0	0	0	0	0.00	0.00	0
101	28,695	28,695	74,012	74,012	0.52	[a]	185
102	828,747	828,747	965,965	965,965	0.13	0.11	412
103	0	0	11,540	11,540	0.06	[a]	48
104	13,984	16,250	78,855	91,630	0.09	0.05	198
105	62,002	62,002	159,918	159,918	0.35	3.46	400
106	260,661	391,286	383,805	576,142	0.17	0.25	426
107	194,048	194,048	294,359	294,359	0.07	0.00	349
108	0	0	0	0	0.00	0.00	0
109	428,992	479,023	481,425	537,572	0.08	0.27	179
110	52,160	62,683	108,050	129,848	0.10	0.03	189
111	0	0	0	0	0.00	0.00	0

[a] The refinery did not have published information on the capacity of the existing sulfur plant.

Chapter 5 Appendix

LP Refinery Modeling Output Tables

Table 5-41 Volume and Cost Information Used for Estimating the Cost of Octane

	PADD	PADD 1	PADD 2	PADD 3	PADD 4/5	USA
FCC Naphtha Volume (kbbl)	Summer	33,001	90,996	248,651	20,296	392,943
	Winter	33,692	137,617	302,644	29,719	503,671
	Total	66,693	228,613	551,294	50,015	896,614
Obj Function ($000)	Reference	10,021,915	19,715,175	51,232,848	11,926,884	92,896,822
	Control	9,961,128	19,662,097	51,072,893	11,913,432	92,609,550
	Difference					-287,272
Cost	($/bbl)					-0.3203965
	(c/gal)					-0.7628488

Table 5-42 PADD 1 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 1	Actual Capacity in 2009	2017 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,260	1,982	2,791	1,982	2,792	0	1
Vacuum Tower	492	788	1,159	788	1,159	0	0
Sats Gas Plant	0	110	120	109	120	-1	0
Unsats Gas Plant	0	157	93	157	93	0	0
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	490	490	291	490	291	0	0
FCC Splitter	0	0	0	21	0	21	0
Hydrocracker	22	69	69	69	69	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	44	153	292	153	292	0	0
Visbreaker	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	18	35	18	35	0	0
CRU Reformer	223	281	337	284	337	3	0
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	29	36	25	36	-4	0
C4 Isomerization	32	32	32	32	32	0	0
C5/C6 Isomerization	7	126	149	133	158	7	9
HF Alkylation	40	40	20	40	20	0	0
H2SO4 Alkylation	29	47	44	49	44	3	0
Dimersol	0	0	0	0	0	0	0
Cat Poly	5	1	1	1	1	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	334	299	530	299	530	0	0
DHT 2nd RCT - Total	0	240	460	240	460	0	0
DHT Arom Saturation	0	0	0	0	0	0	0
NHT - Total Fd	274	571	650	590	651	19	0
CGH - Generic	119	158	158	158	158	0	0
CGH - Olefin Sat'n	119	0	0	0	0	0	0
FCCU Fd HDT	44	1,459	1,459	1,459	1,459	0	0
LSR Splitter	0	87	51	100	50	13	-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	32,600	33	33	33	33	0	0
MTBE	3	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	64	974	1,007	974	1,008	0	1
Lube Unit	146	53	53	53	53	0	0
Sulfur Plant	1,434	1	2	1	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	13	11	13	11	13	0	0
BTX Reformer - Extract feed	23	23	23	23	23	0	0
Toluene Dealkyation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

Table 5-43 PADD 2 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 2	Actual Capacity in 2009	2017 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	3,612	2,996	3,831	2,996	3,840	0	10
Vacuum Tower	1,452	1,326	1,660	1,326	1,664	0	4
Sats Gas Plant	0	167	171	169	175	2	4
Unsats Gas Plant	0	255	301	255	302	0	1
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	1,144	852	1,036	852	1,039	0	3
FCC Splitter	0	500	594	500	596	0	2
Hydrocracker	234	216	216	216	216	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	375	280	329	280	329	0	0
Visbreaker	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	34	40	34	40	0	0
CRU Reformer	807	516	529	540	542	24	13
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	42	54	42	54	0	0
C4 Isomerization	15	65	60	65	63	0	3
C5/C6 Isomerization	157	168	125	170	141	2	16
HF Alkylation	156	126	78	126	78	0	0
H2SO4 Alkylation	81	81	40	81	40	0	0
Dimersol	3	0	0	0	0	0	0
Cat Poly	4	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	1,056	691	577	691	577	0	0
DHT 2nd RCT - Total	0	512	528	512	529	0	0
DHT Arom Saturation	6	0	0	0	0	0	0
NHT - Total Fd	1,038	818	929	823	932	5	3
CGH - Generic	282	127	176	133	177	5	1
CGH - Olefin Sat'n	282	0	0	0	0	0	0
FCCU Fd HDT	521	521	521	521	521	0	0
LSR Splitter	0	71	100	75	100	4	0
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	32,600	0	36	0	36	0	0
MTBE	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	799,200	1,004	1,066	985	1,058	-19	-7
Lube Unit	66	24	24	24	24	0	0
Sulfur Plant	1,434	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	18	16	18	16	18	0	0
BTX Reformer - Extract feed	34	34	34	34	34	0	0
Toluene Dealkyation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

Table 5-44 PADD 3 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 3	Actual Capacity in 2009	2017 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	8,735	5,576	5,706	5,589	5,706	13	0
Vacuum Tower	3,963	2,587	2,647	2,593	2,647	6	0
Sats Gas Plant	0	534	522	541	523	8	0
Unsats Gas Plant	0	839	728	839	730	0	3
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	2,808	2,808	2,411	2,808	2,422	0	11
FCC Splitter	0	1,636	1,207	1,636	1,218	0	11
Hydrocracker	523	1,416	1,416	1,397	1,397	-19	-19
H-Oil Unit	0	144	144	144	144	0	0
Delayed Coker	1,350	625	648	628	649	2	2
Visbreaker	51	0	51	0	49	0	-2
Thermal Naphtha Splitter	0	74	79	74	79	0	0
CRU Reformer	1,765	524	410	613	454	89	44
SRU Reformer	0	0	0	0	0	0	0
BTX Reformer	0	381	383	385	383	4	0
C4 Isomerization	50	133	133	133	133	0	0
C5/C6 Isomerization	199	47	0	75	0	28	0
HF Alkylation	295	235	148	235	148	0	0
H2SO4 Alkylation	290	290	267	290	270	0	3
Dimersol	19	0	0	0	0	0	0
Cat Poly	23	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	2,606	2,080	2,032	2,086	2,038	5	6
DHT 2nd RCT - Total	0	1,592	1,565	1,599	1,570	6	6
DHT Arom Saturation	4	0	0	0	0	0	0
NHT - Total Fd	2,284	1,177	1,041	1,206	1,049	30	8
CGH - Generic	905	173	18	196	26	23	8
CGH - Olefin Sat'n	905	0	0	0	0	0	0
FCCU Fd HDT	1,375	1,559	1,559	1,559	1,559	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	32,600	263	263	263	263	0	0
MTBE	28	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	1,569,400	5,345	5,487	5,217	5,414	-129	-73
Lube Unit	1,169	506	506	506	506	0	0
Sulfur Plant	1,434	15	13	15	13	0	0
Merox Jet	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	146	146	146	146	146	0	0
BTX Reformer - Extract feed	318	318	318	318	318	0	0
Toluene Dealkyation	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0

Table 5-45 PADD 4 and PADD 5OC Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 4 and 5OC	Actual Capacity in 2009	2017 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,796	1,518	1,558	1,518	1,558	0	0
Vacuum Tower	599	559	541	559	541	0	0
Sats Gas Plant	0	71	71	71	68	0	-3
Unsats Gas Plant	0	66	70	66	70	0	0
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	344	224	224	224	224	0	0
FCC Splitter	0	132	140	132	140	0	0
Hydrocracker	91	144	194	144	194	0	0
H-Oil Unit	0	0	0	0	0	0	0
Delayed Coker	143	133	133	133	133	0	0
Visbreaker	56	41	20	41	20	0	0
Thermal Naphtha Splitter	0	17	16	17	16	0	0
CRU Reformer	0	0	0	0	0	0	0
SRU Reformer	287	214	211	236	248	0	37
BTX Reformer	0	0	0	0	0	0	0
C4 Isomerization	19	19	19	19	19	0	0
C5/C6 Isomerization	43	2	0	2	0	0	0
HF Alkylation	37	19	36	19	36	0	0
H2SO4 Alkylation	38	38	38	38	38	0	0
Dimersol	1	1	0	1	0	0	0
Cat Poly	10	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	404	492	483	492	483	0	0
DHT 2nd RCT - Total	0	331	331	331	331	0	0
DHT Arom Saturation	0	0	0	0	0	0	0
NHT - Total Fd	326	426	435	434	434	0	-1
CGH - Generic	66	0	0	0	0	0	0
CGH - Olefin Sat'n	66	0	0	0	0	0	0
FCCU Fd HDT	89	89	89	89	89	0	0
LSR Splitter	0	100	100	100	100	0	0
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	10	4	1	1	0	-3
Reformate Splitter	0	30	11	3	3	0	-8
SDA	32,600	14	28	14	28	0	0
MTBE	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	373,900	518	619	499	603	0	-16
Lube Unit	0	0	0	0	0	0	0
Sulfur Plant	1,434	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 Dealkyation	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 U.S. (except CA) Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADDs 1 -4 and 5OC	Actual Capacity in 2009	2017 Ref case		Control Case Minus 1 ON		Control Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	15,403	12,071	13,886	12,084	13,897	13	11
Vacuum Tower	6,505	5,260	6,007	5,266	6,012	6	5
Sats Gas Plant	0	882	885	890	886	9	1
Unsats Gas Plant	0	1,317	1,192	1,317	1,196	0	3
FCC DeC5 Tower	0	0	0	0	0	0	0
FCC	4,786	4,373	3,962	4,373	3,976	0	13
FCC Splitter	0	2,267	1,941	2,288	1,954	20	12
Hydrocracker	869	1,845	1,895	1,826	1,876	-20	-20
H-Oil Unit	0	144	144	144	144	0	0
Delayed Coker	1,912	1,190	1,401	1,193	1,403	2	2
Visbreaker	107	41	71	41	70	0	-2
Thermal Naphtha Splitter	0	143	170	144	171	0	0
CRU Reformer	2,794	1,321	1,276	1,437	1,333	115	57
SRU Reformer	287	214	211	236	248	0	37
BTX Reformer	0	452	473	452	473	1	0
C4 Isomerization	116	250	245	249	247	-1	2
C5/C6 Isomerization	406	343	275	380	299	37	25
HF Alkylation	528	420	281	420	281	0	0
H2SO4 Alkylation	438	455	389	458	392	3	3
Dimersol	23	1	0	1	0	0	0
Cat Poly	42	1	1	1	1	0	0
Isooctane	0	0	0	0	0	0	0
DHT - Total	4,400	3,562	3,622	3,567	3,628	5	6
DHT 2nd RCT - Total	0	2,676	2,885	2,682	2,891	6	6
DHT Arom Saturation	10	0	0	0	0	0	0
NHT - Total Fd	3,921	2,992	3,056	3,054	3,066	53	10
CGH - Generic	1,373	459	352	487	361	28	9
CGH - Olefin Sat'n	1,373	0	0	0	0	0	0
FCCU Fd HDT	2,029	3,628	3,628	3,628	3,628	0	0
LSR Splitter	0	259	252	276	251	17	-1
LSR Bz Saturator	0	0	0	0	0	0	0
Reformate Saturator	0	22	7	13	4	0	-3
Reformate Splitter	0	66	20	39	12	0	-8
SDA	130,400	310	359	310	359	0	0
MTBE	31	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	2,742,564	7,841	8,178	7,675	8,084	-147	-95
Lube Unit	1,380	582	582	582	582	0	0
Sulfur Plant	5,736	22	22	22	22	0	0
Merox Jet	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0
BTX Reformer - Tower feed	177	173	177	173	177	0	0
BTX Reformer - Extract feed	375	375	375	375	375	0	0
Toluene Dealkyation	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 1 Gasoline Qualities Estimated by LP Refinery Modeling

Gasoline Qualities and Volume	2017 Ref Case						2017 minus 1 ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.84	4.96	4.85	4.87	4.82	4.85	4.84	4.95	4.88	4.87	4.81	4.85
Density (lb/bbl)	254.7	261.9	255.3	255.7	258.1	256.7	255.0	261.7	257.6	255.7	258.2	256.7
Sulfur (ppm)	23.6	22.0	23.5	22.2	24.9	23.3	23.4	21.2	22.6	22.6	24.9	23.6
% at 200	45.9	45.5	45.9	48.7	52.2	50.2	45.3	46.2	45.7	48.4	52.0	49.9
% at 300	81.8	75.8	81.2	81.5	79.1	80.5	81.0	76.5	79.2	80.8	78.6	79.9
RVP (psi)	9.11	7.00	8.92	12.15	11.93	12.06	9.11	7.00	8.28	12.17	11.94	12.07
T10 (F)	124	137	125	104	106	105	124	137	129	104	106	105
T50 (F)	208	209	208	202	195	199	209	208	209	203	196	200
T90 (F)	335	362	338	336	347	341	339	359	347	339	349	344
Driveability	1145	1195	1150	1100	1092	1097	1152	1187	1166	1105	1095	1101
Vapor Lock	137.4	148.8	138.4	120.1	120.1	120.1	137.6	148.6	141.9	120.1	120.1	120.1
Aromatics (vol%)	20.8	22.0	20.9	21.5	21.2	21.3	22.1	22.0	22.0	22.3	21.7	22.0
Benzene (vol%)	0.42	0.42	0.42	0.50	0.63	0.55	0.45	0.51	0.47	0.51	0.63	0.56
Olefins (vol%)	9.17	11.48	9.38	8.61	8.30	8.48	9.09	11.35	9.98	8.74	8.15	8.50
Alcohol (vol%)	11.2	13.8	11.4	11.1	13.7	12.2	11.2	13.8	12.2	11.1	13.7	12.2
Oxygen (wt%)	4.23	5.06	4.31	4.19	5.12	4.57	4.22	5.07	4.56	4.19	5.12	4.57
Volumes (kbbl/day)	1,693,907	169,974	1,863,881	345,786	240,886	586,672	1,709,571	1,118,250	2,827,821	1,623,409	1,130,922	2,754,331

Table 5-48 PADD 2 Gasoline Qualities Estimated by LP Refinery Modeling

Gasoline Qualities and Volume	2017 Ref Case						2017 minus 1 ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.91	4.97	4.92	4.89	4.84	4.88	4.91	4.97	4.92	4.88	4.83	4.88
Density (lb/bbl)	259.9	262.4	260.3	259.1	258.4	259.1	260.0	262.1	260.3	259.3	258.4	259.2
Sulfur (ppm)	27.4	20.3	26.3	25.2	22.7	25.1	26.5	18.9	25.3	25.2	22.4	25.0
% at 200	56.2	52.4	55.6	58.0	59.2	58.1	56.0	52.4	55.5	57.9	59.3	58.0
% at 300	82.9	80.0	82.4	81.7	82.9	81.8	82.8	80.2	82.4	81.6	82.9	81.7
RVP (psi)	9.03	7.00	8.72	11.55	11.47	11.55	9.03	7.00	8.72	11.56	11.47	11.55
T10 (F)	124	137	126	108	109	108	124	137	126	108	109	108
T50 (F)	187	195	188	184	181	183	188	195	189	184	181	183
T90 (F)	330	343	332	335	330	335	331	342	332	336	330	335
Driveability	1077	1133	1086	1048	1036	1047	1079	1132	1088	1049	1036	1048
Vapor Lock	134.2	146.4	136.1	120.1	120.1	120.1	134.3	146.4	136.2	120.1	120.1	120.1
Aromatics (vol%)	21.2	21.2	21.2	22.1	20.1	21.9	21.8	21.2	21.7	22.4	20.0	22.2
Benzene (vol%)	0.77	0.88	0.79	0.49	0.67	0.50	0.76	0.88	0.78	0.50	0.65	0.51
Olefins (vol%)	8.66	5.44	8.16	9.10	8.50	9.06	8.83	5.08	8.25	9.14	8.40	9.08
Alcohol (vol%)	11.2	13.8	11.6	11.2	12.0	11.3	11.2	13.8	11.6	11.2	12.0	11.3
Oxygen (wt%)	4.17	5.06	4.31	4.18	4.48	4.20	4.16	5.07	4.31	4.18	4.48	4.20
Volumes (kbbl/day)	1,799,149	334,626	2,133,775	1,710,734	139,111	1,849,845	1,799,149	334,626	2,133,775	1,710,734	139,111	1,849,845

Table 5-49 PADD 3 Gasoline Qualities Estimated by LP Refinery Modeling

Gasoline Qualities and Volume	2017 Ref Case						2017 minus 1 ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	5.06	4.90	5.01	4.99	4.98	4.98	5.02	5.00	5.01	4.99	4.96	4.98
Density (lb/bbl)	259.5	254.7	258.2	254.8	255.8	255.1	258.6	261.2	259.3	255.0	255.6	255.2
Sulfur (ppm)	28.0	27.2	27.8	28.0	28.0	28.0	28.0	27.2	27.8	28.0	28.0	28.0
% at 200	59.0	59.4	59.1	59.6	61.4	60.1	59.5	51.8	57.4	59.3	62.0	60.0
% at 300	83.6	88.2	84.9	85.1	85.3	85.2	84.0	80.0	82.9	84.6	85.4	84.8
RVP (psi)	9.07	7.00	8.49	11.45	11.33	11.42	9.07	7.00	8.49	11.47	11.29	11.42
T10 (F)	124	137	128	109	110	109	124	137	128	109	110	109
T50 (F)	182	181	181	180	177	179	180	196	185	181	175	179
T90 (F)	327	306	321	320	319	320	325	343	330	322	319	321
Driveability	1057	1053	1056	1024	1013	1021	1052	1137	1075	1028	1009	1023
Vapor Lock	133.1	144.0	136.1	120.1	120.1	120.1	132.9	146.6	136.7	120.1	120.1	120.1
Aromatics (vol%)	20.8	6.5	16.9	15.0	15.2	15.1	19.8	18.3	19.4	15.6	15.3	15.5
Benzene (vol%)	0.62	0.61	0.61	0.58	0.52	0.56	0.61	0.61	0.61	0.58	0.61	0.58
Olefins (vol%)	13.42	1.72	10.18	10.82	10.90	10.84	13.07	3.17	10.33	10.90	10.82	10.88
Alcohol (vol%)	11.2	13.7	11.9	11.2	13.7	11.8	11.2	13.7	11.9	11.2	13.7	11.8
Oxygen (wt%)	4.15	5.20	4.44	4.23	5.17	4.47	4.16	5.07	4.42	4.22	5.18	4.47
Volumes (kbbl/day)	1,276,784	488,041	1,764,825	1,400,642	497,125	1,897,767	1,276,784	488,041	1,764,825	1,400,642	497,125	1,897,767

Table 5-50 PADD 4 and 5OC Gasoline Qualities Estimated by LP Refinery Modeling

Gasoline Qualities and Volume	2017 Ref Case						2017 minus 1 ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.96	0.00	4.96	4.95	0.00	4.95	4.96	0.00	4.96	4.95	0.00	4.95
Density (lb/bbl)	263.3	0.0	263.3	261.2	0.0	261.2	263.5	0.0	263.5	261.1	0.0	261.1
Sulfur (ppm)	25.0	0.0	25.0	28.0	0.0	28.0	24.6	0.0	24.6	28.0	0.0	28.0
% at 200	58.5	0.0	58.5	58.6	0.0	58.6	59.0	0.0	59.0	57.9	0.0	57.9
% at 300	85.5	0.0	85.5	84.7	0.0	84.7	85.7	0.0	85.7	83.0	0.0	83.0
RVP (psi)	9.34	0.00	9.34	11.52	0.00	11.52	9.34	0.00	9.34	11.55	0.00	11.55
T10 (F)	122	0	122	108	0	108	122	0	122	108	0	108
T50 (F)	182	0	182	182	0	182	181	0	181	184	0	184
T90 (F)	318	0	318	322	0	322	317	0	317	329	0	329
Driveability	1048	0	1048	1031	0	1031	1045	0	1045	1042	0	1042
Vapor Lock	131.8	0.0	131.8	120.0	0.0	120.0	131.6	0.0	131.6	120.1	0.0	120.1
Aromatics (vol%)	24.4	0.0	24.4	23.8	0.0	23.8	24.5	0.0	24.5	23.4	0.0	23.4
Benzene (vol%)	0.84	0.00	0.84	1.09	0.00	1.09	0.86	0.00	0.86	1.10	0.00	1.10
Olefins (vol%)	5.70	0.00	5.70	5.47	0.00	5.47	5.72	0.00	5.72	4.98	0.00	4.98
Alcohol (vol%)	11.3	0.0	11.3	11.1	0.0	11.1	11.3	0.0	11.3	11.3	0.0	11.3
Oxygen (wt%)	4.15	0.00	4.15	4.08	0.00	4.08	4.14	0.00	4.14	4.18	0.00	4.18
Volumes (kbbl/day)	701,850	0	701,850	734,023	0	734,023	701,850	0	701,850	744,898	0	744,898

Table 5-51 U.S. (except CA) Gasoline Qualities Estimated by Refinery Modeling

Gasoline Qualities and Volume	2017 Ref Case						2017 minus 1 ON in FCC naphtha					
	Summer			Winter			Summer			Winter		
	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool	CG	RFG	Pool
Energy (MMBTU/bbl)	4.93	4.93	4.93	4.93	4.91	4.93	4.92	4.96	4.93	4.91	4.85	4.90
Density (lb/bbl)	258.6	258.5	258.6	257.8	256.9	257.6	258.6	261.7	259.4	257.4	257.5	257.4
Sulfur (ppm)	26.1	24.0	25.8	26.4	26.3	26.4	25.7	22.3	24.8	25.5	25.6	25.5
% at 200	54.0	54.7	54.1	57.9	58.5	58.0	53.9	48.7	52.5	55.4	55.4	55.4
% at 300	83.1	83.3	83.1	83.3	83.2	83.3	82.9	78.0	81.6	82.3	80.8	82.0
RVP (psi)	9.10	7.00	8.78	11.56	11.52	11.55	9.10	7.00	8.55	11.71	11.72	11.72
T10 (F)	124	137	126	108	108	108	124	137	127	107	107	107
T50 (F)	192	190	191	184	182	184	192	202	195	189	189	189
T90 (F)	329	328	329	328	328	328	330	352	336	333	339	334
Driveability	1090	1104	1092	1041	1038	1041	1091	1165	1111	1059	1066	1061
Vapor Lock	134.6	145.7	136.3	120.1	120.1	120.1	134.6	147.7	138.1	120.1	120.1	120.1
Aromatics (vol%)	21.4	14.1	20.3	20.0	17.6	19.6	21.8	20.9	21.5	20.8	19.8	20.5
Benzene (vol%)	0.63	0.67	0.64	0.63	0.57	0.62	0.64	0.60	0.63	0.60	0.62	0.61
Olefins (vol%)	9.55	4.65	8.80	9.00	9.81	9.14	9.50	8.21	9.16	8.91	8.92	8.91
Alcohol (vol%)	11.2	13.8	11.6	11.2	13.4	11.6	11.2	13.8	11.9	11.2	13.6	11.8
Oxygen (wt%)	4.18	5.13	4.33	4.18	5.05	4.33	4.18	5.07	4.41	4.19	5.08	4.41
Volumes (kbbl/day)	5,471,690	992,641	6,464,331	4,191,185	877,122	5,068,307	5,487,354	1,940,917	7,428,271	5,479,683	1,767,158	7,246,841

Table 5-52 PADD 1 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 1	Actual Capacity in 2009	Reference 2005 in 2030		100% E10 Case in 2030		E10 Case Relative to Ref Case		100% E15 Case in 2030		E15 Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,260	1,156	1,716	757	1,267	-400	-449	757	1,267	-400	-449
Vacuum Tower	492	507	738	332	550	-175	-187	332	550	-175	-187
Sats Gas Plant	0	104	62	70	50	-34	-12	72	47	-32	-15
Unsats Gas Plant	0	185	226	156	191	-29	-36	156	191	-29	-36
FCC DeC5 Tower	0	0	0	0	0	0	0	0	0	0	0
FCC	490	678	827	565	691	-113	-136	565	691	-113	-136
FCC Splitter	0	387	467	324	391	-63	-76	324	391	-63	-76
Hydrocracker	22	52	82	52	82	0	0	52	82	0	0
H-Oil Unit	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	44	22	94	22	82	0	-12	22	82	0	-12
Visbreaker	0	0	0	0	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	3	11	3	10	0	-1	3	10	0	-1
CRU Reformer	223	138	223	90	154	-48	-70	134	154	-3	-70
SRU Reformer	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer	0	36	36	36	36	0	0	36	36	0	0
C4 Isomerization	32	53	0	32	0	-21	0	32	0	-21	0
C5/C6 Isomerization	7	51	95	32	32	-19	-63	17	8	-34	-87
HF Alkylation	40	40	20	40	20	0	0	40	20	0	0
H2SO4 Alkylation	29	125	68	94	20	-31	-48	77	20	-48	-48
Dimersol	0	0	0	0	0	0	0	0	0	0	0
Cat Poly	5	1	31	1	32	0	1	8	32	7	1
Isooctane	0	0	0	0	0	0	0	0	0	0	0
DHT - Total	334	431	742	300	572	-130	-170	310	572	-121	-170
DHT 2nd RCT - Total	0	0	0	0	0	0	0	0	0	0	0
DHT Arom Saturation	0	0	0	0	0	0	0	0	0	0	0
NHT - Total Fd	274	263	397	165	286	-98	-111	152	286	-111	-111
CGH - Generic	119	161	158	159	158	-2	0	158	158	-3	0
CGH - Olefin Sat'n	119	0	0	0	0	0	0	0	0	0	0
FCCU Fd HDT	44	460	460	396	396	-63	-63	396	396	-63	-63
LSR Splitter	0	1	51	1	24	0	-27	1	40	0	-11
LSR Bz Saturator	0	0	0	0	0	0	0	0	0	0	0
Reformate Saturator	0	21	1	19	1	-2	0	10	1	-11	0
Reformate Splitter	0	63	3	57	3	-6	0	30	3	-33	0
SDA	0	33	33	33	33	0	0	33	33	0	0
MTBE	3	0	0	0	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	63,700	645	935	538	788	-107	-147	518	795	-127	-140
Lube Unit	146	53	53	53	53	0	0	53	53	0	0
Sulfur Plant	1,434	1	1	1	1	0	0	1	1	0	0
Merox Jet	0	0	0	0	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Tower feed	13	13	13	13	13	0	0	13	13	0	0
BTX Reformer - Extract feed	23	23	23	23	23	0	0	23	23	0	0
Toluene Dealkyation	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0

Table 5-53 PADD 2 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 2	Actual Capacity in 2009	Reference 2005 in 2030		100% E10 Case in 2030		E10 Case Relative to Ref Case		100% E15 Case in 2030		E15 Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	3,612	2,638	4,141	2,494	3,972	-145	-169	2,206	3,830	-432	-311
Vacuum Tower	1,452	1,092	1,770	1,026	1,711	-66	-58	905	1,656	-186	-114
Sats Gas Plant	0	162	137	136	144	-26	7	107	120	-55	-18
Unsats Gas Plant	0	248	332	204	319	-44	-13	166	302	-82	-31
FCC DeC5 Tower	0	0	0	0	0	0	0	0	0	0	0
FCC	1,144	864	1,144	666	1,080	-197	-64	569	1,031	-295	-113
FCC Splitter	0	503	653	6	628	-496	-24	0	595	-503	-58
Hydrocracker	234	234	234	234	234	0	0	234	234	0	0
H-Oil Unit	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	375	153	395	129	375	-24	-21	86	355	-67	-40
Visbreaker	0	0	0	0	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	19	48	16	45	-3	-3	10	43	-8	-5
CRU Reformer	807	393	613	376	515	-18	-98	329	496	-64	-116
SRU Reformer	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer	0	42	54	42	54	0	0	42	54	0	0
C4 Isomerization	15	50	0	27	27	-23	27	10	15	-40	14
C5/C6 Isomerization	157	157	300	157	129	0	-171	100	0	-57	-300
HF Alkylation	156	121	78	78	92	-44	14	78	78	-44	0
H2SO4 Alkylation	81	81	71	79	81	-2	10	40	65	-40	-6
Dimersol	3	0	0	0	0	0	0	0	0	0	0
Cat Poly	4	0	29	0	3	0	-26	0	8	0	-21
Isooctane	0	0	0	0	0	0	0	0	0	0	0
DHT - Total	1,056	827	644	874	610	47	-34	762	581	-66	-63
DHT 2nd RCT - Total	0	0	0	0	0	0	0	0	0	0	0
DHT Arom Saturation	6	0	0	0	0	0	0	0	0	0	0
NHT - Total Fd	1,038	621	1,007	597	966	-24	-41	495	924	-125	-83
CGH - Generic	282	242	233	1	183	-241	-49	0	179	-242	-54
CGH - Olefin Sat'n	282	0	0	0	0	0	0	0	0	0	0
FCCU Fd HDT	521	521	521	650	650	129	129	521	521	0	0
LSR Splitter	0	100	100	93	100	-7	0	77	71	-23	-29
LSR Bz Saturator	0	0	0	0	0	0	0	0	0	0	0
Reformate Saturator	0	2	10	1	1	-1	-9	1	1	-1	-9
Reformate Splitter	0	5	30	3	3	-2	-27	3	3	-2	-27
SDA	0	36	36	36	36	0	0	36	36	0	0
MTBE	0	0	0	0	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	799,200	1,149	1,149	1,197	1,224	48	75	1,086	1,086	-63	-63
Lube Unit	66	24	24	24	24	0	0	24	24	0	0
Sulfur Plant	1,434	4	5	4	5	0	0	3	5	-1	0
Merox Jet	0	0	0	0	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Tower feed	18	16	18	16	18	0	0	16	18	0	0
BTX Reformer - Extract feed	34	34	34	34	34	0	0	34	34	0	0
Toluene Dealkyation	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0

Table 5-54 PADD 3 Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 3	Actual Capacity in 2009	Reference 2005 in 2030		100% E10 Case in 2030		E10 Case Relative to Ref Case		100% E15 Case in 2030		E15 Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	8,735	7,741	7,111	7,477	7,036	-264	-75	7,203	6,648	-538	-464
Vacuum Tower	3,963	3,514	3,210	3,381	3,264	-133	54	3,275	3,022	-239	-188
Sats Gas Plant	0	635	427	624	471	-11	44	612	423	-23	-4
Unsats Gas Plant	0	679	675	690	612	10	-63	607	571	-73	-104
FCC DeC5 Tower	0	0	0	0	0	0	0	0	0	0	0
FCC	2,808	2,075	2,154	2,103	1,901	28	-252	1,820	1,794	-255	-360
FCC Splitter	0	6	1,153	161	435	155	-719	0	848	-6	-305
Hydrocracker	667	1,797	1,797	2,020	2,020	223	223	1,937	1,937	140	140
H-Oil Unit	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	1,350	992	853	933	881	-59	28	886	769	-106	-85
Visbreaker	51	0	0	0	0	0	0	0	0	0	0
Thermal Naphtha Splitter	0	120	103	113	107	-7	3	107	93	-13	-10
CRU Reformer	1,765	1,517	1,140	1,130	904	-387	-236	1,149	863	-368	-277
SRU Reformer	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer	0	265	261	261	261	-4	0	261	261	-4	1
C4 Isomerization	50	50	0	50	0	0	0	50	0	0	0
C5/C6 Isomerization	199	130	58	229	50	99	-7	134	0	4	-58
HF Alkylation	295	148	148	148	148	0	0	148	148	0	0
H2SO4 Alkylation	290	234	235	252	197	18	-38	197	179	-37	-56
Dimersol	19	0	0	0	0	0	0	0	0	0	0
Cat Poly	23	0	0	0	0	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0	0	0	0	0
DHT - Total	2,606	2,159	1,867	1,726	1,689	-434	-178	1,872	1,675	-288	-192
DHT 2nd RCT - Total	0	0	0	0	0	0	0	0	0	0	0
DHT Arom Saturation	4	0	0	0	0	0	0	0	0	0	0
NHT - Total Fd	2,284	1,648	1,198	1,474	1,076	-174	-122	1,828	1,300	180	102
CGH - Generic	905	1	1	26	1	25	0	1	1	0	0
CGH - Olefin Sat'n	905	0	0	0	0	0	0	0	0	0	0
FCCU Fd HDT	1,375	1,844	1,844	1,850	1,630	6	-213	1,562	1,559	-282	-285
LSR Splitter	0	1	1	100	1	99	0	1	1	0	0
LSR Bz Saturator	0	0	0	0	0	0	0	0	0	0	0
Reformate Saturator	0	327	76	91	10	-236	-65	330	272	3	196
Reformate Splitter	0	980	227	273	31	-707	-196	989	815	9	588
SDA	0	263	263	263	263	0	0	263	263	0	0
MTBE	28	0	0	0	0	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	1,569,400	5,529	5,529	5,931	5,931	402	402	5,670	5,670	141	141
Lube Unit	1,169	440	440	440	440	0	0	440	440	0	0
Sulfur Plant	1,434	15	13	14	14	-1	1	13	12	-1	0
Merox Jet	0	0	0	0	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Tower feed	0	96	94	94	94	-2	0	94	94	-2	0
BTX Reformer - Extract feed	0	211	208	208	208	-3	0	208	208	-3	0
Toluene Dealkyation	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0

Table 5-55 PADD 4 and 5OC Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADD 4 and 5OC	Actual Capacity in 2009	Reference 2005 in 2030		100% E10 Case in 2030		E10 Case Relative to Ref Case		100% E15 Case in 2030		E15 Case Relative to Ref Case	
Refinery Units		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	1,796	1,513	1,547	1,418	1,442	-95	-104	1,400	1,400	-113	-146
Vacuum Tower	599	655	632	607	578	-48	-55	588	560	-67	-73
Sats Gas Plant	0	92	57	82	53	-10	-4	75	39	-17	-18
Unsats Gas Plant	0	113	115	104	105	-9	-10	101	100	-12	-14
FCC DeC5 Tower	0	0	0	0	0	0	0	0	0	0	0
FCC	344	392	382	360	345	-32	-37	344	331	-47	-51
FCC Splitter	0	218	222	202	204	-15	-18	182	196	-35	-26
Hydrocracker	91	141	191	141	191	0	0	141	191	0	0
H-Oil Unit	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	143	162	162	137	137	-25	-25	133	129	-29	-33
Visbreaker	56	0	0	7	3	7	3	26	8	26	8
Thermal Naphtha Splitter	0	19	19	16	16	-3	-3	17	15	-2	-3
CRU Reformer	0	0	0	0	0	0	0	0	0	0	0
SRU Reformer	287	129	201	95	73	-33	-128	69	27	-60	-174
BTX Reformer	0	0	0	0	0	0	0	0	0	0	0
C4 Isomerization	19	45	0	40	8	-5	8	40	6	-5	5
C5/C6 Isomerization	43	78	2	0	0	-78	-2	3	0	-75	-2
HF Alkylation	37	37	37	37	37	0	0	37	37	0	0
H2SO4 Alkylation	38	74	74	64	64	-10	-10	60	60	-14	-14
Dimersol	1	0	1	1	1	0	0	1	1	1	0
Cat Poly	10	0	0	0	0	0	0	0	0	0	0
Isooctane	0	0	0	0	0	0	0	0	0	0	0
DHT - Total	404	575	578	528	527	-48	-51	518	507	-57	-71
DHT 2nd RCT - Total	0	0	0	0	0	0	0	0	0	0	0
DHT Arom Saturation	0	0	0	0	0	0	0	0	0	0	0
NHT - Total Fd	326	313	349	292	297	-21	-53	288	287	-25	-62
CGH - Generic	66	78	74	66	60	-11	-14	65	60	-12	-14
CGH - Olefin Sat'n	66	0	0	0	0	0	0	0	0	0	0
FCCU Fd HDT	89	139	189	139	189	0	0	139	177	0	-12
LSR Splitter	0	100	100	89	88	-11	-12	85	100	-15	0
LSR Bz Saturator	0	0	0	0	0	0	0	0	0	0	0
Reformate Saturator	0	2	10	1	1	-1	-9	1	1	-1	-9
Reformate Splitter	0	5	30	3	3	-2	-27	3	3	-2	-27
SDA	0	28	28	28	28	0	0	28	28	0	0
MTBE	0	0	0	0	0	0	0	0	0	0	0
TAME	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	373,900	705	785	679	826	-26	40	688	809	-18	23
Lube Unit	0	0	0	0	0	0	0	0	0	0	0
Sulfur Plant	1,434	2	2	2	2	0	0	2	2	0	0
Merox Jet	0	0	0	0	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Tower feed	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Extract feed	0	0	0	0	0	0	0	0	0	0	0
Toluene Dealkyation	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0

Table 5-56 U.S. (except CA) Unit Capacity and Throughput Volumes from LP Refinery Modeling (Thousand bbl/day)

PADDs 1 -4 and 5OC	Actual Capacity in 2009	Reference 2005 in 2030		100% E10 Case in 2030		E10 Case Relative to Ref Case		100% E15 Case in 2030		E15 Case Relative to Ref Case	
Refinery Unit		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Crude Tower	15,403	13,049	14,515	12,146	13,717	-903	-798	11,567	13,145	-1,482	-1,370
Vacuum Tower	6,505	5,768	6,350	5,346	6,104	-422	-246	5,100	5,788	-668	-562
Sats Gas Plant	0	993	683	912	718	-81	35	865	629	-128	-54
Unsats Gas Plant	0	1,225	1,348	1,153	1,227	-72	-122	1,030	1,163	-195	-185
FCC DeC5 Tower	0	0	0	0	0	0	0	0	0	0	0
FCC	4,786	4,008	4,506	3,694	4,018	-314	-489	3,298	3,846	-710	-660
FCC Splitter	0	1,114	2,494	694	1,658	-420	-837	506	2,030	-608	-464
Hydrocracker	1,013	2,223	2,303	2,446	2,526	223	223	2,363	2,443	140	140
H-Oil Unit	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	1,912	1,329	1,505	1,222	1,475	-108	-30	1,127	1,334	-202	-171
Visbreaker	107	0	0	7	3	7	3	26	8	26	8
Thermal Naphtha Splitter	0	159	181	147	178	-12	-3	137	161	-23	-20
CRU Reformer	2,794	2,048	1,976	1,596	1,572	-453	-404	1,613	1,513	-436	-463
SRU Reformer	287	129	201	95	73	-33	-128	69	27	-60	-174
BTX Reformer	0	344	351	340	351	-4	0	340	351	-4	1
C4 Isomerization	116	199	0	149	35	-49	34	132	20	-67	20
C5/C6 Isomerization	406	415	455	418	212	2	-244	253	8	-162	-447
HF Alkylation	528	346	283	302	297	-44	14	302	282	-44	0
H2SO4 Alkylation	438	513	448	488	363	-25	-85	374	324	-139	-124
Dimersol	23	0	1	1	1	0	0	1	1	1	0
Cat Poly	42	1	60	1	35	0	-25	8	40	7	-20
Isooctane	0	0	0	0	0	0	0	0	0	0	0
DHT - Total	4,400	3,993	3,831	3,428	3,398	-565	-432	3,462	3,336	-531	-495
DHT 2nd RCT - Total	0	0	0	0	0	0	0	0	0	0	0
DHT Arom Saturation	10	0	0	0	0	0	0	0	0	0	0
NHT - Total Fd	3,921	2,844	2,952	2,527	2,625	-317	-327	2,763	2,797	-81	-155
CGH - Generic	1,373	481	466	252	402	-229	-64	225	398	-257	-68
CGH - Olefin Sat'n	1,373	0	0	0	0	0	0	0	0	0	0
FCCU Fd HDT	2,029	2,964	3,014	3,035	2,866	71	-148	2,619	2,653	-345	-360
LSR Splitter	0	202	252	283	213	81	-39	164	212	-38	-40
LSR Bz Saturator	0	0	0	0	0	0	0	0	0	0	0
Reformate Saturator	0	351	97	112	13	-239	-83	342	275	-10	178
Reformate Splitter	0	1,054	290	337	40	-717	-250	1,025	824	-29	534
SDA	0	359	359	359	359	0	0	359	359	0	0
MTBE	31	0	0	0	0	0	0	0	0	0	0
TAME	3	0	0	0	0	0	0	0	0	0	0
Hydrogen Plant - Total MSCF	1,238,369	8,029	8,399	8,346	8,769	317	370	7,962	8,360	-67	-38
Lube Unit	1,380	516	516	516	516	0	0	516	516	0	0
Sulfur Plant	5,736	21	21	20	22	-1	0	19	20	-2	-1
Merox Jet	0	0	0	0	0	0	0	0	0	0	0
Merox Diesel	0	0	0	0	0	0	0	0	0	0	0
BTX Reformer - Tower feed	127	124	125	123	125	-2	0	123	125	-2	0
BTX Reformer - Extract feed	268	268	265	265	265	-3	0	265	265	-3	0
Toluene Dealkyation	0	0	0	0	0	0	0	0	0	0	0
Cumene	0	0	0	0	0	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0	0	0	0	0	0

Table 5-57 PADD 1 Gasoline Qualities for the E10 and E15 Cases relative to the Reference Case

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	Pool
Energy (MMBTU/bbl)	5.18	5.09	5.14	5.11	4.93	5.02	5.05	5.04	5.04	5.02	4.91	4.98	4.93	4.93	4.93	4.87	4.82	4.85
Density (lb/bbl)	257.70	259.91	258.80	255.81	252.05	253.91	257.59	260.94	258.89	255.60	255.72	255.65	259.60	260.61	260.01	257.91	255.72	257.01
Sulfur (ppm)	27.5	23.3	25.4	22.4	16.9	19.6	23.7	23.6	23.7	20.9	18.0	19.8	28.0	28.0	28.0	12.6	17.6	14.7
% at 200	45.8	50.8	48.3	44.6	62.4	53.6	54.8	51.1	53.3	53.3	59.4	55.7	59.8	58.7	59.4	60.9	66.7	63.3
% at 300	76.6	81.4	79.0	75.8	89.2	82.6	81.6	81.2	81.4	78.1	84.6	80.7	81.5	84.1	82.6	83.0	89.8	85.8
RVP (psi)	7.92	6.54	7.23	12.61	13.19	12.90	9.27	7.00	8.39	13.78	13.39	13.62	8.27	7.00	7.75	13.29	12.92	13.14
T10 (F)	131.2	140.0	135.6	101.4	97.7	99.6	122.6	137.1	128.2	94.0	96.5	95.0	129.0	137.1	132.3	97.1	99.5	98.1
T50 (F)	208.5	198.2	203.3	210.9	174.5	192.5	190.1	197.5	193.0	193.0	180.5	188.1	179.8	182.1	180.7	177.5	165.7	172.7
T90 (F)	358.5	336.6	347.6	362.1	301.3	331.4	336.0	337.6	336.7	351.6	322.1	340.0	336.3	324.3	331.4	329.5	298.3	316.7
Driveability	1180.7	1141.2	1161.0	1147.0	971.4	1058.2	1090.3	1135.7	1107.9	1071.7	1008.4	1046.8	1069.1	1076.0	1072.0	1007.7	944.7	981.9
Vapor Lock	143.8	149.5	146.6	119.1	109.7	114.3	133.4	146.9	138.7	109.7	109.7	109.7	137.1	144.3	140.0	109.7	109.7	109.7
Aromatics (vol%)	27.9	20.2	24.1	27.0	14.8	20.8	22.0	20.0	21.2	20.3	18.5	19.6	18.5	17.6	18.1	18.8	14.0	16.8
Benzene (vol%)	0.58	0.57	0.58	0.61	0.56	0.59	0.51	0.57	0.53	0.52	0.58	0.54	0.73	0.89	0.79	0.46	0.55	0.50
Olefins (vol%)	11.0	10.4	10.7	10.6	16.8	13.8	9.1	10.9	9.8	10.2	16.0	12.5	8.5	9.8	9.0	7.9	17.9	12.0
Alcohol (vol%)	0.50	4.89	2.68	0.00	4.94	2.50	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	15.00
Oxygen (wt%)	0.74	2.56	1.65	0.15	2.50	1.34	3.74	3.69	3.72	3.77	3.77	3.77	5.57	5.55	5.56	5.61	5.65	5.63
Volumes (kbbl/day)	1,399,252	1,387,051	2,786,303	1,338,953	1,368,062	2,707,015	1,760,831	1,121,463	2,882,294	1,698,176	1,106,878	2,805,054	1,736,796	1,204,323	2,941,119	1,619,601	1,125,767	2,745,368

Table 5-58 PADD 2 Gasoline Qualities for the E10 and E15 Cases relative to the Reference Case

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	Pool
Energy (MMBTU/bbl)	5.18	5.02	4.97	4.99	4.75	4.95	4.99	5.03	4.99	4.87	4.89	4.88	4.94	4.93	4.94	4.83	4.81	4.83
Density (lb/bbl)	257.79	258.55	259.05	255.20	251.15	254.54	258.09	259.13	258.25	256.71	256.01	256.59	260.15	259.67	260.07	258.46	256.91	258.20
Sulfur (ppm)	27.4	9.7	20.7	25.0	16.9	23.7	23.3	17.9	22.4	24.1	24.1	24.1	28.0	28.0	28.0	26.8	26.7	26.8
% at 200	45.7	53.7	56.1	48.8	68.4	51.9	53.4	49.7	52.8	58.9	59.0	58.9	57.5	55.8	57.2	62.7	64.8	63.0
% at 300	76.6	85.0	84.6	79.7	93.7	82.0	81.7	82.2	81.7	83.9	84.9	84.1	80.3	81.3	80.5	84.2	86.7	84.6
RVP (psi)	7.91	7.00	8.73	13.97	12.70	13.76	9.28	7.00	8.92	13.31	13.31	13.31	8.28	7.00	8.08	13.07	12.93	13.05
T10 (F)	131.2	137.1	126.0	92.8	100.9	94.1	122.6	137.1	124.9	97.0	97.0	97.0	128.9	137.1	130.2	98.5	99.4	98.6
T50 (F)	208.6	192.3	187.4	202.3	162.3	195.8	192.9	200.4	194.1	181.7	181.5	181.6	184.6	188.0	185.1	173.9	169.6	173.2
T90 (F)	358.7	320.2	322.3	344.5	280.8	334.2	335.6	333.0	335.2	325.4	320.8	324.6	341.6	337.2	340.9	323.8	312.8	322.0
Driveability	1181.5	1102.5	1073.5	1090.7	918.9	1062.8	1098.0	1139.7	1104.7	1015.8	1010.7	1015.0	1088.7	1106.7	1091.6	993.4	970.6	989.7
Vapor Lock	143.9	146.0	135.9	110.3	110.3	110.3	133.9	147.4	136.0	110.3	110.3	110.3	137.8	145.3	139.0	110.3	110.3	110.3
Aromatics (vol%)	27.9	18.9	22.2	24.7	12.3	22.7	22.5	19.5	22.0	20.4	18.2	20.0	20.3	19.2	20.2	20.0	16.9	19.5
Benzene (vol%)	0.58	0.56	0.54	0.58	0.57	0.58	0.51	0.56	0.52	0.50	0.55	0.51	0.55	0.76	0.58	0.67	0.65	0.67
Olefins (vol%)	11.5	3.8	8.8	13.0	6.8	12.0	8.8	6.7	8.5	10.7	11.2	10.7	7.3	7.0	7.2	10.5	10.6	10.6
Alcohol (vol%)	0.42	10.00	8.80	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	15.00
Oxygen (wt%)	0.40	3.73	3.27	0.00	3.84	0.62	3.74	3.72	3.73	3.76	3.77	3.76	5.56	5.57	5.56	5.60	5.63	5.60
Volumes (kbbl/day)	1,772,351	329,642	1,759,558	1,685,250	326,672	2,011,922	1,802,319	342,519	2,144,838	1,751,081	339,433	2,090,514	1,841,582	342,519	2,184,101	1,751,081	339,433	2,090,514

Table 5-59 PADD 3 Gasoline Qualities for the E10 and E15 Cases relative to the Reference Case

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	Pool
Energy (MMBTU/bbl)	5.18	5.16	5.18	5.13	5.18	5.14	5.07	5.11	5.08	5.07	5.00	5.05	4.95	4.95	4.95	4.91	4.84	4.89
Density (lb/bbl)	258.31	258.54	258.37	256.15	254.74	255.78	258.18	259.96	258.66	256.90	255.26	256.48	260.34	260.35	260.35	258.80	254.37	257.67
Sulfur (ppm)	27.6	24.8	26.8	25.7	22.4	24.7	24.1	24.9	24.3	22.8	23.1	22.9	27.8	26.0	27.3	13.1	21.6	15.3
% at 200	44.8	51.4	46.6	43.7	56.5	45.8	54.0	49.0	52.7	50.7	53.7	51.4	58.8	58.3	58.6	59.9	66.5	61.6
% at 300	75.9	82.7	77.8	75.5	83.3	76.8	81.1	80.8	81.0	76.8	79.8	77.6	80.6	83.1	81.3	83.4	90.9	85.3
RVP (psi)	7.94	6.54	7.55	12.47	11.65	12.34	8.85	7.00	8.35	12.02	11.83	11.97	7.85	7.00	7.61	11.43	11.00	11.32
T10 (F)	131.1	140.0	133.5	102.3	107.5	103.2	125.3	137.1	128.5	105.2	106.4	105.5	131.7	137.1	133.1	108.9	111.6	109.6
T50 (F)	210.4	197.0	206.7	212.6	186.6	208.4	191.6	201.8	194.4	198.4	192.3	196.9	181.9	182.8	182.2	179.7	166.2	176.2
T90 (F)	361.9	330.7	353.3	363.6	328.2	357.6	338.1	339.4	338.4	357.6	343.9	354.1	340.3	328.9	337.2	327.5	293.7	318.9
Driveability	1189.8	1131.7	1173.7	1154.8	1049.1	1137.5	1100.8	1150.5	1114.2	1110.6	1080.5	1102.9	1083.6	1082.8	1083.4	1029.9	959.7	1012.0
Vapor Lock	144.0	149.3	145.5	120.1	120.1	120.1	135.9	147.6	139.1	120.1	120.1	120.1	139.7	144.4	141.0	120.1	120.1	120.1
Aromatics (vol%)	29.2	19.7	26.6	27.6	20.0	26.1	22.4	19.5	21.6	20.8	18.4	20.2	19.1	15.6	18.1	17.9	11.0	16.2
Benzene (vol%)	0.59	0.58	0.59	0.59	0.58	0.58	0.52	0.51	0.52	0.50	0.57	0.52	0.73	0.90	0.77	0.40	0.59	0.45
Olefins (vol%)	11.5	1.1	8.6	11.5	9.8	11.0	9.4	2.7	7.6	8.4	8.5	8.5	7.9	2.8	6.5	7.5	13.5	9.0
Alcohol (vol%)	0.90	5.00	2.03	0.00	4.00	0.63	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	15.00
Oxygen (wt%)	0.67	2.54	1.19	0.00	2.50	0.40	3.73	3.71	3.73	3.75	3.78	3.76	5.55	5.55	5.55	5.59	5.68	5.61
Volumes (kbbl/day)	1,257,764	480,771	1,738,535	1,400,629	489,720	1,890,349	1,306,897	479,961	1,786,858	1,492,196	508,849	2,001,045	1,306,897	499,552	1,806,449	1,433,678	488,895	1,922,573

Table 5-60 PADD 4 and 5OC Gasoline Qualities for the E10 and E15 Cases relative to the Reference Case

Gasoline Qualities and Volume for PADDs 4 & 5OC	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	Pool
Energy (MMBTU/bbl)	5.06	0.00	5.06	5.00	0.00	5.00	4.95	0.00	4.95	4.89	0.00	4.89	4.89	0.00	4.89	4.80	0.00	4.80
Density (lb/bbl)	258.41	0.00	258.41	253.46	0.00	253.46	258.55	0.00	258.55	254.99	0.00	254.99	260.44	0.00	260.44	256.45	0.00	256.45
Sulfur (ppm)	24.8	0.0	24.8	24.4	0.0	24.4	28.0	0.0	28.0	28.0	0.0	28.0	28.0	0.0	28.0	25.8	0.0	25.8
% at 200	53.3	0.0	53.3	59.2	0.0	59.2	62.1	0.0	62.1	64.4	0.0	64.4	64.6	0.0	64.6	70.1	0.0	70.1
% at 300	90.7	0.0	90.7	92.2	0.0	92.2	91.6	0.0	91.6	92.1	0.0	92.1	92.2	0.0	92.2	96.0	0.0	96.0
RVP (psi)	8.07	0.00	8.07	13.00	0.00	13.00	9.08	0.00	9.08	12.96	0.00	12.96	8.08	0.00	8.08	12.59	0.00	12.59
T10 (F)	130.3	0.0	130.3	99.0	0.0	99.0	123.8	0.0	123.8	99.2	0.0	99.2	130.2	0.0	130.2	101.5	0.0	101.5
T50 (F)	193.0	0.0	193.0	181.1	0.0	181.1	175.1	0.0	175.1	170.5	0.0	170.5	170.0	0.0	170.0	158.9	0.0	158.9
T90 (F)	294.6	0.0	294.6	287.8	0.0	287.8	290.3	0.0	290.3	288.3	0.0	288.3	287.5	0.0	287.5	270.5	0.0	270.5
Driveability	1069.1	0.0	1069.1	979.5	0.0	979.5	1001.4	0.0	1001.4	948.5	0.0	948.5	992.8	0.0	992.8	899.4	0.0	899.4
Vapor Lock	140.4	0.0	140.4	111.9	0.0	111.9	131.9	0.0	131.9	110.3	0.0	110.3	136.4	0.0	136.4	110.3	0.0	110.3
Aromatics (vol%)	20.4	0.0	20.4	20.3	0.0	20.3	17.4	0.0	17.4	15.3	0.0	15.3	15.7	0.0	15.7	12.7	0.0	12.7
Benzene (vol%)	1.17	0.00	1.17	1.12	0.00	1.12	1.19	0.00	1.19	1.18	0.00	1.18	1.19	0.00	1.19	0.73	0.00	0.73
Olefins (vol%)	9.7	0.0	9.7	8.8	0.0	8.8	8.1	0.0	8.1	7.8	0.0	7.8	7.8	0.0	7.8	7.3	0.0	7.3
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	15.00
Oxygen (wt%)	0.01	0.00	0.01	0.00	0.00	0.00	3.73	0.00	3.73	3.78	0.00	3.78	5.55	0.00	5.55	5.64	0.00	5.64
Volumes (kbbl/day)	889,157	0	889,157	733,803	0	733,803	718,402	0	718,402	762,467	0	762,467	718,402	0	718,402	762,467	0	762,467

Table 5-61 U.S. (except CA) Gasoline Qualities for the E10 and E15 Cases relative to the Reference Case

Gasoline Qualities and Volume for PADDs 1 - 4 & 5OC	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	Pool
Energy (MMBTU/bbl)	5.16	5.10	5.10	5.06	4.96	5.03	5.02	5.06	5.03	4.97	4.93	4.96	4.93	4.93	4.93	4.86	4.82	4.85
Density (lb/bbl)	257.99	259.40	258.71	255.37	252.52	254.52	258.01	260.38	258.62	256.20	255.65	256.06	260.06	260.39	260.15	258.11	255.59	257.45
Sulfur (ppm)	27.1	21.6	24.5	24.4	18.1	22.5	24.2	22.9	23.9	23.3	20.4	22.6	28.0	27.5	27.8	19.0	20.2	19.3
% at 200	46.8	51.4	50.4	47.8	62.0	51.7	55.1	50.4	53.9	55.8	57.9	56.3	59.4	58.1	59.1	62.5	66.3	63.5
% at 300	78.8	82.2	81.5	79.3	88.5	81.9	82.8	81.3	82.4	81.4	83.4	81.9	82.3	83.4	82.6	85.3	89.5	86.4
RVP (psi)	7.95	6.61	7.78	13.07	12.77	13.00	9.15	7.00	8.60	13.07	12.97	13.04	8.15	7.00	7.84	12.65	12.44	12.59
T10 (F)	131.0	139.5	132.1	98.5	100.4	98.9	123.4	137.1	126.9	98.5	99.2	98.7	129.7	137.1	131.7	101.2	102.5	101.5
T50 (F)	206.4	197.0	199.0	204.3	175.4	196.4	189.4	199.1	191.9	187.9	183.8	186.9	180.6	183.2	181.3	174.4	166.5	172.3
T90 (F)	348.7	332.9	336.2	346.2	304.3	334.5	330.5	337.3	332.2	336.7	327.5	334.3	332.7	327.6	331.3	319.1	299.7	314.1
Driveability	1164.5	1133.3	1131.2	1106.9	981.0	1072.0	1083.8	1140.1	1098.3	1048.3	1027.6	1043.0	1069.2	1082.8	1072.8	994.1	953.0	983.4
Vapor Lock	143.3	148.9	142.9	115.4	112.1	114.5	134.0	147.2	137.4	112.7	112.5	112.6	137.8	144.5	139.6	112.6	112.4	112.6
Aromatics (vol%)	27.0	19.9	23.8	25.5	15.6	22.6	21.7	19.8	21.2	19.8	18.4	19.4	18.9	17.4	18.5	18.1	13.8	17.0
Benzene (vol%)	0.68	0.57	0.64	0.67	0.56	0.64	0.60	0.55	0.59	0.60	0.57	0.59	0.73	0.87	0.77	0.55	0.58	0.56
Olefins (vol%)	11.1	7.4	9.6	11.4	13.7	12.1	8.9	8.1	8.7	9.6	13.2	10.5	7.9	7.6	7.8	8.5	15.5	10.4
Alcohol (vol%)	0.48	5.68	3.69	0.00	5.49	1.53	10.00	10.00	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	15.00
Oxygen (wt%)	0.49	2.73	1.73	0.04	2.70	0.77	3.74	3.70	3.73	3.76	3.77	3.76	5.56	5.55	5.56	5.60	5.66	5.62
Volumes (kbbl/day)	5,318,524	2,197,464	7,173,553	5,158,635	2,184,454	7,343,089	5,588,449	1,943,943	7,532,392	5,703,920	1,955,160	7,659,080	5,603,677	2,046,394	7,650,071	5,566,827	1,954,095	7,520,922

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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

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^{-9} meter) to over 100 micrometer (µm, or 10^{-6} meter) in diameter (for reference, a typical strand of human hair is 70 um 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 $PM_{2.5}$ and inhalable or thoracic coarse particles are measured as $PM_{10-2.5}$, corresponding to their size (diameter) range in micrometers and referring to total particle mass under 2.5 and between 2.5 and 10 micrometers, respectively. The EPA currently has standards that measure $PM_{2.5}$ and PM_{10}.[A]

Particles span many sizes and shapes and 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 pollution also varies by time of year and location and 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_X), nitrogen oxides (NO_X) and volatile organic compounds (VOCs)) in the atmosphere. The chemical and physical properties of $PM_{2.5}$ may vary greatly with time, region, meteorology and source category. Thus, $PM_{2.5}$ 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.[1]

[A] 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.

6.1.1.2 Health Effects of PM

This section provides a summary of the health effects associated with exposure to ambient concentrations of PM.[B] The information in this section is based on the information and conclusions in the Integrated Science Assessment (ISA) for Particulate Matter (December 2009) prepared by EPA's Office of Research and Development (ORD).[C]

The ISA concludes that ambient concentrations of PM are associated with a number of adverse health effects.[D] The ISA characterizes the weight of evidence for different health effects associated with three PM size ranges: $PM_{2.5}$, $PM_{10\text{-}2.5}$, and UFPs. The discussion below highlights the ISA's conclusions pertaining to these three size fractions of PM, considering variations in health effects associated with both short-term and long-term exposure periods.

6.1.1.2.1 Effects Associated with Short-term Exposure to $PM_{2.5}$

The ISA concludes that cardiovascular effects and premature mortality are causally associated with short-term exposure to $PM_{2.5}$.[2] It also concludes that respiratory effects are likely to be causally associated with short-term exposure to $PM_{2.5}$, including respiratory emergency department (ED) visits and hospital admissions for chronic obstructive pulmonary disease (COPD), respiratory infections, and asthma; and exacerbation of respiratory symptoms in asthmatic children.

6.1.1.2.2 Effects Associated with Long-term Exposure to $PM_{2.5}$

The ISA concludes that there are causal associations between long-term exposure to $PM_{2.5}$ and cardiovascular effects, such as the development/progression of cardiovascular disease (CVD), and premature mortality, particularly from cardiovascular causes.[3] It also concludes that long-term exposure to $PM_{2.5}$ is likely to be causally associated with respiratory effects, such as reduced lung function growth, increased respiratory symptoms, and asthma development. The ISA characterizes the evidence as suggestive of a causal relationship for associations between long-term $PM_{2.5}$ exposure and reproductive and developmental outcomes, such as low birth weight and infant mortality. It also characterizes the evidence as suggestive of a causal relationship between $PM_{2.5}$ and cancer incidence, mutagenicity, and genotoxicity.

[B] Personal exposure includes contributions from many different types of particles, from many sources, and in many different environments. Total personal exposure to PM includes both ambient and nonambient components and collectively these components may contribute to adverse health effects.

[C] The ISA is available at http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546

[D] The ISA evaluates the health evidence associated with different 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 definitions of these levels of evidence, please refer to Section 1.5 of the ISA.

6.1.1.2.3 Effects Associated with $PM_{10-2.5}$

The ISA summarizes evidence related to short-term exposure to $PM_{10-2.5}$. $PM_{10-2.5}$ is the fraction of PM_{10} particles that is larger than $PM_{2.5}$.[4] The ISA concludes that available evidence is suggestive of a causal relationship between short-term exposures to $PM_{10-2.5}$ and cardiovascular effects. It also concludes that the available evidence is suggestive of a causal relationship between short-term exposures to $PM_{10-2.5}$ and respiratory effects, including respiratory-related ED visits and hospitalizations. The ISA also concludes that the available literature suggests a causal relationship between short-term exposures to $PM_{10-2.5}$ and mortality. Data are inadequate to draw conclusions regarding health effects associated with long-term exposure to $PM_{10-2.5}$.[5]

6.1.1.2.4 Effects Associated with Ultrafine Particles

The ISA concludes that the evidence is suggestive of a causal relationship between short-term exposures to UFPs and cardiovascular effects, including changes in heart rhythm and vasomotor function (the ability of blood vessels to expand and contract).[6]

The ISA also concludes that there is suggestive evidence of a causal relationship between short-term UFP exposure and respiratory effects. The types of respiratory effects examined in epidemiologic studies include respiratory symptoms and asthma hospital admissions, the results of which are not entirely consistent. There is evidence from toxicological and controlled human exposure studies that exposure to UFPs may increase lung inflammation and produce small asymptomatic changes in lung function. Data are inadequate to draw conclusions regarding health effects associated with long-term exposure to UFPs.[7]

6.1.2 Ozone

6.1.2.1 Background

Ground-level ozone pollution is typically formed through reactions involving VOCs and NO_X 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 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_X emissions.

The highest levels of ozone are produced when both VOC and NO_X emissions are present in significant quantities on clear summer days. Relatively small amounts of NO_X enable ozone to form rapidly when VOC levels are relatively high, but ozone production is quickly limited by removal of the NO_X. Under these conditions NO_X reductions are highly effective in reducing ozone while VOC reductions have little effect. Such conditions are called "NO_X-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_X-limited.

Ozone concentrations in an area also can be lowered by the reaction of nitric oxide (NO) with ozone, forming nitrogen dioxide (NO_2); as the air moves downwind and the cycle continues, the NO_2 forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of NO_X, VOC, and ozone, all of which change with time and location. When NO_X levels are relatively high and VOC levels relatively low, NO_X 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_X reductions can actually increase local ozone under certain circumstances. Even in VOC-limited urban areas, NO_X reductions are not expected to increase ozone levels if the NO_X reductions are sufficiently large. Rural areas are usually NO_X-limited, due to the relatively large amounts of biogenic VOC emissions in such areas. Urban areas can be either VOC- or NO_X-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

Exposure to ambient ozone contributes to a wide range of adverse health effects.[E] These health effects are well documented and are critically assessed in the EPA ozone air quality criteria document (ozone AQCD) and EPA staff paper.[8,9] We are relying on the data and conclusions in the ozone AQCD and staff paper, regarding the health effects associated with ozone exposure.

Ozone-related health effects include lung function decrements, respiratory symptoms, aggravation of asthma, increased hospital and emergency room visits, increased asthma medication usage, and a variety of other respiratory effects. Cellular-level effects, such as inflammation of lungs, have been documented as well. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and highly suggestive evidence that short-term ozone exposure directly or indirectly contributes to non-accidental and cardiopulmonary-related mortality, but additional research is needed to clarify the underlying mechanisms causing these effects. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council (NRC), 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.[10] People who appear to be more susceptible to effects associated with exposure to ozone include children, asthmatics and the elderly. Those with greater exposures to ozone, for instance due to time spent outdoors (e.g., children and outdoor workers), are also of concern.

[E] 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.

Based on a large number of scientific studies, EPA has identified several key health effects associated with exposure to levels of ozone found today in many areas of the country. Short-term (1 to 3 hours) and prolonged exposures (6 to 8 hours) to ambient ozone concentrations have been linked to lung function decrements, respiratory symptoms, increased hospital admissions and emergency room visits for respiratory problems.[11, 12, 13, 14, 15, 16] Repeated exposure to ozone can increase susceptibility to respiratory infection and lung inflammation and can aggravate preexisting respiratory diseases, such as asthma.[17, 18, 19, 20, 21] Repeated exposure to sufficient concentrations of ozone can also cause inflammation of the lung, impairment of lung defense mechanisms, and possibly irreversible changes in lung structure, which over time could affect premature aging of the lungs and/or the development of chronic respiratory illnesses, such as emphysema and chronic bronchitis.[22, 23, 24, 25]

Children and outdoor workers tend to have higher ozone exposure because they typically are active outside, working, playing and exercising, during times of day and seasons (e.g., the summer) when ozone levels are highest.[26] For example, summer camp studies have reported statistically significant reductions in lung function in children who are active outdoors.[27, 28, 29, 30, 31, 32, 33, 34] Further, children are more at risk of experiencing health effects from ozone exposure than adults because their respiratory systems are still developing. These individuals (as well as people with respiratory illnesses, such as asthma, especially asthmatic children) can experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during prolonged periods of moderate exertion.[35, 36, 37, 38]

6.1.3 Nitrogen Oxides and Sulfur Oxides

6.1.3.1 Background

Sulfur dioxide (SO_2), a member of the sulfur oxide (SO_X) 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_2) is a member of the nitrogen oxide (NO_X) family of gases. Most NO_2 is formed in the air through the oxidation of nitric oxide (NO) emitted when fuel is burned at a high temperature. SO_2 and NO_2 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_X 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_2. Additional information on the health effects of SO_2 can be found in the EPA Integrated Science Assessment for Sulfur Oxides.[39] 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_2. The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. In laboratory studies involving controlled human exposures to SO_2, respiratory effects have consistently been observed following 5-10 min exposures at SO_2 concentrations ≥ 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_2 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_2 levels range from 1 to 30 ppb, with maximum 1 to 24-hour average SO_2 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_2 concentrations and respiratory symptoms in children, particularly those with asthma. Generally consistent associations also have been observed between ambient SO_2 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_2 effect estimates, the effect of SO_2 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_2 on respiratory endpoints occur independent of the effects of other ambient air pollutants.

Consistent associations between short-term exposure to SO_2 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_2 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_2 and mortality. Significant associations between short-term exposure to SO_2 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_2 exposure and cardiovascular morbidity.

6.1.3.3 Health Effects of Nitrogen Oxides

Information on the health effects of NO_2 can be found in the EPA Integrated Science Assessment (ISA) for Nitrogen Oxides.[40] The EPA has 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_2 exposure. The ISA concludes that the strongest evidence for such a relationship comes from epidemiologic studies of respiratory effects including symptoms, emergency department visits, and hospital admissions. Based on both short- and long-term studies, the ISA concludes that associations of NO_2 with respiratory health effects are stronger among a number of groups; these include individuals with preexisting pulmonary conditions (e.g., asthma or COPD), children and older adults. The ISA also draws two broad conclusions regarding airway responsiveness following NO_2 exposure. First, the ISA concludes that NO_2 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 asthmatics to NO_2 concentrations as low as 0.26 ppm. Second, exposure to NO_2 has been found to enhance the inherent responsiveness of the airway to subsequent nonspecific challenges in controlled human exposure studies of asthmatic subjects. Small but significant increases in non-specific airway hyperresponsiveness were reported following 1-hour exposures of asthmatics to 0.1 ppm NO_2. Enhanced airway responsiveness could have important clinical implications for asthmatics since transient increases in airway responsiveness following NO_2 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_2 exposures and an array of adverse health effects that range from the onset of respiratory symptoms to hospital admission.

Although the weight of evidence supporting a causal relationship is somewhat less certain than that associated with respiratory morbidity, NO_2 has also been linked to other health endpoints. These include all-cause (nonaccidental) mortality, hospital admissions or emergency department visits for cardiovascular disease, and decrements in lung function growth associated with chronic exposure.

6.1.4 Health Effects of Carbon Monoxide

Information on the health effects of carbon monoxide (CO) can be found in the EPA Integrated Science Assessment (ISA) for Carbon Monoxide.[41] The ISA concludes that ambient concentrations of CO are associated with a number of adverse health effects.[F] This section provides a summary of the health effects associated with exposure to ambient concentrations of CO.[G]

Human clinical 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 hospital admissions and emergency room visits for congestive heart failure and cardiovascular disease as a whole. The 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.

[F] The ISA evaluates the health evidence associated with different 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 definitions of these levels of evidence, please refer to Section 1.6 of the ISA.

[G] Personal exposure includes contributions from many sources, and in many different environments. Total personal exposure to CO includes both ambient and nonambient components; and both components may contribute to adverse health effects.

Animal studies show various neurological effects with in-utero CO exposure. Controlled human exposure studies report inconsistent neural and behavioral effects following low-level CO exposures. The 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 epidemiologic and animal toxicological studies cited in the ISA have evaluated associations between CO exposure and 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 associations between perinatal CO exposure and decrements in birth weight, as well as other developmental outcomes. The ISA concludes these studies are suggestive of a causal relationship between long-term exposures to CO and developmental effects and birth outcomes.

Epidemiologic studies provide evidence of effects on respiratory morbidity such as changes in pulmonary function, respiratory symptoms, and hospital admissions associated with ambient CO concentrations. A limited number of epidemiologic studies considered copollutants such as ozone, SO_2, 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 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 ISA concludes that the epidemiologic evidence is suggestive of a causal relationship between short-term exposures to 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 ISA also concludes that there is not likely to be a causal relationship between relevant long-term exposures to CO and mortality.

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.[42,43,44] 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 x 10^{-6} to 7.8 x 10^{-6} as the unit risk estimate (URE) for benzene.[H,45] 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.[46,47]

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.[48,49] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[50,51] EPA's inhalation reference concentration (RfC) for benzene is 30 µg/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.[52,53,54,55] 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 µg/m^3 for 1-14 days exposure.[56,I]

6.1.5.2 1,3-Butadiene

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.[57,58] 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.[59,60,61] 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 3×10^{-5} per µg/m^3.[62] 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.[63] Based on this critical effect and the benchmark concentration methodology, an RfC for chronic health effects was calculated at 0.9 ppb (approximately 2 µg/m^3).

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

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[H] A unit risk estimate is defined as the increase in the lifetime risk of an individual who is exposed for a lifetime to 1 µg/m3 benzene in air.

[I] A minimal risk level (MRL) is defined as an estimate of the daily human exposure to a hazardous substance that is likely to be without appreciable risk of adverse noncancer health effects over a specified duration of exposure.

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.[64] 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.[65,66,67]

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.[68,69,70] 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.[71] 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.[72] Finally, a study of embalmers reported formaldehyde exposures to be associated with an increased risk of myeloid leukemia but not brain cancer.[73]

Health effects of formaldehyde in addition to cancer were reviewed by the Agency for Toxics Substances and Disease Registry in 1999[74] and supplemented in 2010,[75] and by the World Health Organization.[76] 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.[77] 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[78] (http://www.nap.edu/catalog.php?record_id=13142). The EPA is currently revising the draft assessment in response to this review.

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.[79] The URE in IRIS for acetaldehyde is 2.2×10^{-6} per µg/m^3.[80] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 12th Report on

Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[81,82] 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.[83] In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.[84,85] Data from these studies were used by EPA to develop an inhalation reference concentration of 9 µg/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.[86] 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.[87] The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.[88]

Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein.[89] The Agency has developed an RfC for acrolein of 0.02 µg/m^3 and an RfD of 0.5 µg/kg-day.[90] 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.[91] 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.[92] Studies in humans indicate that levels as low as 0.09 ppm (0.21 mg/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[93]) 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 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 µg/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 µg/m^3 and 0.7 µg/m^3, respectively.[94]

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.[95]

Effects of ground-level smog causing intense eye irritation have been attributed to photochemical oxidants, including PAN.[96] 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.[97]

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.[9899] 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.[100] 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.[101] 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).[102,103] 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 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.[104] Chronic (long term) exposure of workers and rodents to naphthalene has been reported to cause cataracts and retinal damage.[105] EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.[106] The draft reassessment completed external peer review.[107] 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.[108] 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.[109]

Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.[110] 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 µg/m^3.[111] 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.[J]

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.[K,112] Other systematic reviews of relevant literature are cited were appropriate.

[J] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

[K] It should be noted that there are no peer reviewed EPA-authored reviews of traffic-related health studies. The HEI panel primarily used epidemiology studies for inferring whether there was sufficient evidence of a causal association exists between a particular health effect and traffic-related air pollution, In its weight-of-evidence determinations, the panel also placed "considerable weight" on controlled human exposure studies. However, it restricted consideration of other toxicological studies to whether or not the studies provided "general mechanistic support" for the inferences of causality made on the basis of epidemiology.

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 or 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. 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.

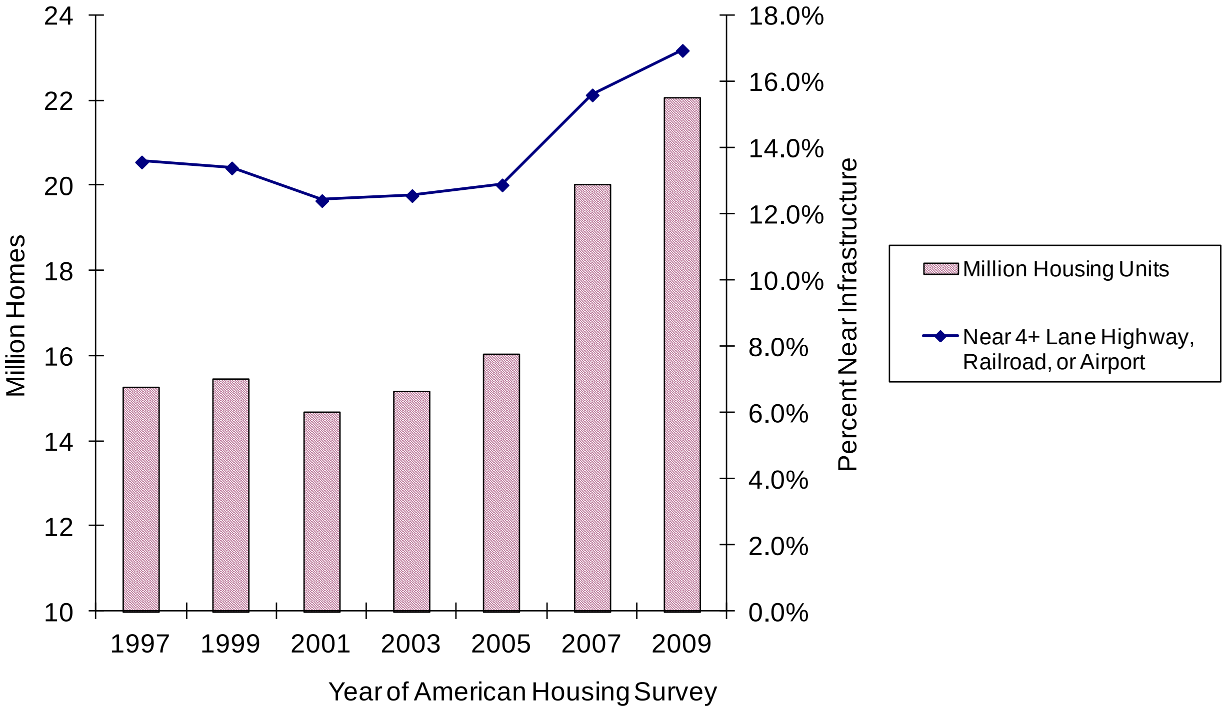

Figure 6-1 Trends in Populations Near Large Highways, Railroads, and Airports

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.[113] Although the ATUS does not indicate their mode of travel, the majority of trips undertaken nationally is by motor vehicle.[114] 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 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.[L] 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.[115,116]

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.[117]

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

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[L] The autonomic nervous system (ANS) consists of sympathetic and parasympathetic components. The sympathetic ANS signals body systems to "fight or flight." The parasympathetic ANS signals the body to "rest and digest." In general, HRV is indicative of parasympathetic control of the heart.

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, 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 $\mu g/m^3$ 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.[118,119,120] 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_1. FEV_1 and PEF reflect the function of the large airways. FVC and FEV_1, along with their ratio (FVC/FEV_1) 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_{75}) reflects the status of small airways, which asthma and COPD affect.

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.[121] 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.[122]

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.[123] 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.[124]

EPA is pursuing a two-part strategy to address visibility impairment. First, EPA developed the regional haze program (64 FR 35714) which was put in place in July 1999 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. Second, EPA has 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 $PM_{2.5}$. Figure 6-2 shows the location of the 156 Mandatory Class I Federal areas.

* Rainbow Lake, WI and Bradwell Bay, FL are Class 1 Areas where visibility is not an important air quality related value

Produced by NPS Air Resources Division

Figure 6-2 Mandatory Class I Federal Areas in the U.S.

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, 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 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.[125]

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 Integrated Science Assessment for Oxides of Nitrogen and Sulfur- Ecological Criteria.[126,127,128]

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. Excesses of nitrogen or sulfur can lead to acidification, nutrient enrichment, and eutrophication of aquatic ecosystems.[129]

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 and sediments, 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 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.[130] 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. 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.[131] 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.[132]

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.

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 NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms – an indication that eutrophication is well developed in more than half of U.S. estuaries.[133]

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.[134] 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. Little research has been conducted on the effects associated with mixtures of contaminants found in ambient PM. 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 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.[135] 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.[136,137] 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.[138]

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 is it 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.[139,140] Over fifty percent of the mercury in the Chesapeake Bay has been attributed to atmospheric deposition.[141] Overall, the National Science and Technology Council identifies atmospheric deposition as the primary source of mercury to aquatic systems.[142] 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.[143,144] 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.[145] 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.[146] Polycyclic aromatic hydrocarbons (PAHs) are a class of POM that contains compounds which are known or suspected carcinogens.

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 µm 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.[147]

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.[148,149] Analyses of PAH deposition in Chesapeake and Galveston Bay indicate that dry deposition and gas exchange from the atmosphere to the surface water predominate.[150,151] 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.[152] 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.[153] 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.[154] 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.[155]

Cousins et al. estimate that more than ninety percent of semi-volatile organic compound (SVOC) emissions in the United Kingdom deposit on soil.[156] An analysis of PAH concentrations near a Czechoslovakian roadway indicated that concentrations were thirty times greater than background.[157]

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

There are a number of environmental or public welfare effects associated with the presence of ozone in the ambient air.[158] In this section we discuss the impact of ozone on plants, including trees, agronomic crops and urban ornamentals.

The Air Quality Criteria Document for Ozone and related Photochemical Oxidants notes that, "ozone affects vegetation throughout the United States, impairing crops, native vegetation, and ecosystems more than any other air pollutant."[159] Like carbon dioxide (CO_2) and other gaseous substances, ozone enters plant tissues primarily through apertures (stomata) in leaves in a process called "uptake."[160] Once sufficient levels of ozone (a highly reactive substance), or its reaction products, reaches the interior of plant cells, it can inhibit or damage essential cellular components and functions, including enzyme activities, lipids, and cellular membranes, disrupting the plant's osmotic (i.e., water) balance and energy utilization patterns.[161,162] If enough tissue becomes damaged from these effects, a plant's capacity to fix carbon to form carbohydrates, which are the primary form of energy used by plants, is reduced,[163] while plant respiration increases. With fewer resources available, the plant reallocates existing resources away from root growth and storage, above ground growth or yield, and reproductive processes, toward leaf repair and maintenance, leading to reduced growth and/or reproduction. Studies have shown that plants stressed in these ways may exhibit a general loss of vigor, which can lead to secondary impacts that modify plants' responses to other environmental factors. Specifically, plants may become more sensitive to other air pollutants, more susceptible to disease, insect attack, harsh weather (e.g., drought, frost) and other environmental stresses. Furthermore, there is evidence that ozone can interfere with the formation of mycorrhiza, essential symbiotic fungi associated with the roots of most terrestrial plants, by reducing the amount of carbon available for transfer from the host to the symbiont.[164,165]

This ozone damage may or may not be accompanied by visible injury on leaves, and likewise, visible foliar injury may or may not be a symptom of the other types of plant damage described above. When visible injury is present, it is commonly manifested as chlorotic or necrotic spots, and/or increased leaf senescence (accelerated leaf aging). Because ozone damage can consist of visible injury to leaves, it can also reduce the aesthetic value of ornamental vegetation and trees in urban landscapes, and negatively affects scenic vistas in protected natural areas.

Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even lower concentrations experienced for a longer duration have the potential to create chronic stress on sensitive vegetation. Not all plants, however, are equally sensitive to ozone. Much of the variation in sensitivity between individual plants or whole species is related to the plant’s ability to regulate the extent of gas exchange via leaf stomata (e.g., avoidance of ozone uptake through closure of stomata)[166,167,168] Other resistance mechanisms may involve the intercellular production of detoxifying substances. Several biochemical substances capable of detoxifying ozone have been reported to occur in plants, including the antioxidants ascorbate and glutathione. After injuries have occurred, plants may be capable of repairing the damage to a limited extent.[169]

Because of the differing sensitivities among plants to ozone, ozone pollution can also exert a selective pressure that leads to changes in plant community composition. Given the range of plant sensitivities and the fact that numerous other environmental factors modify plant uptake and response to ozone, it is not possible to identify threshold values above which ozone is consistently toxic for all plants. The next few paragraphs present additional information on ozone damage to trees, ecosystems, agronomic crops and urban ornamentals.

Assessing the impact of ground-level ozone on forests in the United States involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as “biomass loss.” Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, though the magnitude of the effect may be higher or lower depending on the tree species.[170]

Some of the common tree species in the United States that are sensitive to ozone are black cherry (*Prunus serotina*), tulip-poplar (*Liriodendron tulipifera)*, and eastern white pine (*Pinus strobus)*. Ozone-exposure/tree-response functions have been developed for each of these tree species, as well as for aspen (*Populus tremuliodes*), and ponderosa pine (*Pinus ponderosa*). Other common tree species, such as oak (*Quercus* spp.*)* and hickory (*Carya* spp.), are not nearly as sensitive to ozone. Consequently, with knowledge of the distribution of sensitive species and the level of ozone at particular locations, it is possible to estimate a "biomass loss" for each species across their range.

Ozone also has been conclusively shown to cause discernible injury to forest trees.[171,172] In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts. Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function.[173,174]

Because plants are at the base of the food web in many ecosystems, changes to the plant community can affect associated organisms and ecosystems (including the suitability of habitats that support threatened or endangered species and below ground organisms living in the root zone). Ozone impacts at the community and ecosystem level vary widely depending upon numerous factors, including concentration and temporal variation of tropospheric ozone, species composition, soil properties and climatic factors.[175] In most instances, responses to chronic or recurrent exposure in forested ecosystems are subtle and not observable for many years. These injuries can cause stand-level forest decline in sensitive ecosystems.[176,177,178] It is not yet possible to predict ecosystem responses to ozone with much certainty; however, considerable knowledge of potential ecosystem responses has been acquired through long-term observations in highly damaged forests in the United States.

Air pollution can have noteworthy cumulative impacts on forested ecosystems by affecting regeneration, productivity, and species composition.[179] In the U.S., ozone in the lower atmosphere is one of the pollutants of primary concern. Ozone injury to forest plants can be diagnosed by examination of plant leaves. Foliar injury is usually the first visible sign of injury to plants from ozone exposure and indicates impaired physiological processes in the leaves.[180] However, not all impaired plants will exhibit visible symptoms.

Laboratory and field experiments have also shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN) examined 15 species and numerous cultivars. The NCLAN results show that "several economically important crop species are sensitive to ozone levels typical of those found in the United States."[181] In addition, economic studies have shown reduced economic benefits as a result of predicted reductions in crop yields associated with observed ozone levels.[182,183,184]

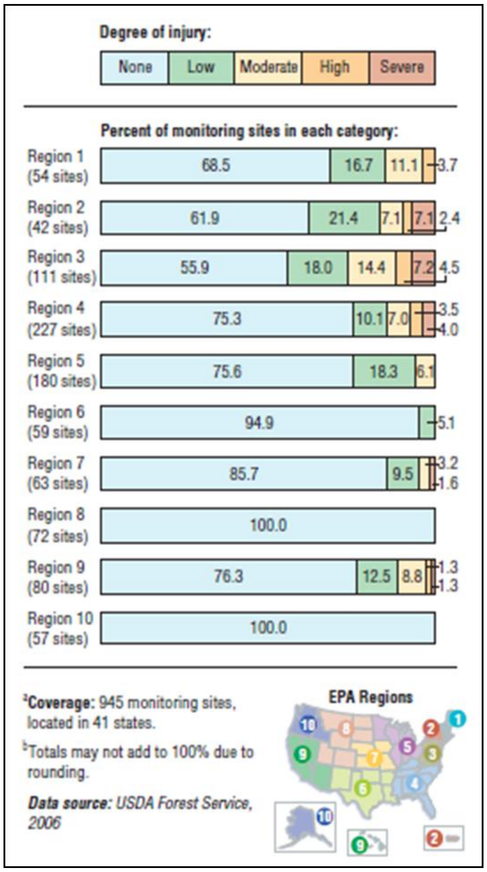
Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. It is estimated that more than $20 billion (1990 dollars) are spent annually on landscaping using ornamentals, both by private property owners/tenants and by governmental units responsible for public areas.[185] This is therefore a potentially costly environmental effect. However, in the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative analysis has been conducted.

6.2.3.1 Recent Ozone Visible Foliar Injury Data for the U.S

In the U.S. the national-level visible foliar injury indicator is based on data from the U.S. Department of Agriculture (USDA) Forest Service Forest Inventory and Analysis (FIA) program. As part of its Phase 3 program, formerly known as Forest Health Monitoring, FIA examines ozone injury to ozone-sensitive plant species at ground monitoring sites in forest land across the country. For this indicator, forest land does not include woodlots and urban trees. Sites are selected using a systematic sampling grid, based on a global sampling design.[186,187] At each site that has at least 30 individual plants of at least three ozone-sensitive species and enough open space to ensure that sensitive plants are not protected from ozone exposure by the forest canopy, FIA looks for damage on the foliage of ozone-sensitive forest plant species. Because ozone injury is cumulative over the course of the growing season, examinations are conducted in July and August, when ozone injury is typically highest. Monitoring of ozone injury to plants by the USDA Forest Service has expanded over time from monitoring sites in 10 states in 1994 to nearly 1,000 monitoring sites in 41 states in 2002.

There is considerable regional variation in ozone-related visible foliar injury to sensitive plants in the U.S. The U.S. EPA has developed an environmental indicator based on data from the USDA FIA program which examines ozone injury to ozone-sensitive plant species at ground monitoring sites in forest land across the country. The data underlying the indicator in Figure 6-3 are based on averages of all observations collected in 2002, the latest year for which data are publicly available at the time the study was conducted, and is broken down by U.S. EPA Region. Ozone damage to forest plants is classified using a subjective five-category biosite index based on expert opinion, but designed to be equivalent from site to site. Ranges of biosite values translate to no injury, low or moderate foliar injury (visible foliar injury to highly sensitive or moderately sensitive plants, respectively), and high or severe foliar injury, which would be expected to result in tree-level or ecosystem-level responses, respectively.[188,189]

The highest percentages of observed high and severe foliar injury, those which are most likely to be associated with tree or ecosystem-level responses, are primarily found in the Mid-Atlantic and Southeast regions. In EPA Region 3 (which comprises the States of Pennsylvania, West Virginia, Virginia, Delaware, Maryland and Washington D.C.), 12 percent of ozone-sensitive plants showed signs of high or severe foliar damage, and in Region 2 (States of New York, New Jersey), and Region 4 (States of North Carolina, South Carolina, Kentucky, Tennessee, Georgia, Florida, Alabama, and Mississippi) the values were 10 and 7 percent, respectively. The sum of high and severe ozone injury ranged from 2 to 4 percent in EPA Region 1 (the six New England States), Region 7 (States of Missouri, Iowa, Nebraska and Kansas), and Region 9 (States of California, Nevada, Hawaii and Arizona). The percentage of sites showing some ozone damage was about 45 percent in each of these EPA Regions.



[a]Coverage: 945 monitoring sites, located in 41 states.

[b]Totals may not add to 100% due to rounding.

Data source: USDA Forest Service, 2006

Figure 6-3 Ozone Injury to Forest Plants in U.S. by EPA Regions, 2002[ab]

6.2.3.2 Indicator Limitations

The categories for the biosite index are subjective and may not necessarily be directly related to biomass loss or physiological damage to plants in a particular area. Ozone may have other adverse impacts on plants (e.g., reduced productivity) that do not show signs of visible foliar injury.[190] The presence of diagnostic visible ozone injury on indicator plants does provide evidence that ozone is having an impact in an area. However, absence of ozone injury in an area does not necessarily mean that there is no impact from ozone exposure.

Field and laboratory studies were reviewed to identify the forest plant species in each region that are sensitive to ozone air pollution and exhibit diagnostic injury. Other forest plant species, or even genetic variants of the same species, may not show symptoms at ozone levels that cause effects on the selected ozone-sensitive species.

Because species distributions vary regionally, different ozone-sensitive plant species were examined in different parts of the country. These target species could vary with respect to ozone sensitivity, which might account for some of the apparent differences in ozone injury among regions of the U.S. Ozone damage to foliage may be reduced under conditions of low soil moisture, but most of the variability in the index (70 percent) was explained by ozone concentration.[191]

Though FIA has extensive spatial coverage based on a robust sample design, not all forested areas in the U.S. are monitored for ozone injury. Even though the biosite data have been collected over multiple years, most biosites were not monitored over the entire period, so these data cannot provide more than a baseline for future trends.

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.[192] In laboratory experiments, a wide range of tolerance to VOCs has been observed.[193] 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.[194]

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.[195,196,197] 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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Chapter 7 Impacts of the Proposed Rule on Emissions and Air Quality

This chapter presents the overall emissions and air quality impacts of the proposed Tier 3 standards. Section 7.1 describes national average impacts on criteria and toxic emissions resulting from the Tier 3 proposal. Section 7.2 describes the air quality effects of the proposed 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 proposed 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 the Tier 3 proposal on criteria and toxic air pollutants for selected calendar years, and the methodology used to estimate these reductions. The proposed fuel and vehicle standards will directly reduce emissions of nitrogen oxides (NO_X), including nitrogen dioxide (NO_2), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter ($PM_{2.5}$), air toxics, and sulfur dioxide (SO_2). The implementation of lower sulfur gasoline will reduce criteria and air toxic emissions from the existing gasoline fleet, and cause some reductions in SO_2 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 are presenting emission reductions in calendar year 2017, near the beginning of the proposed fuel program.

The proposed vehicle standards will incur reductions as the cleaner cars and trucks begin to enter the fleet in model year 2017. 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 through calendar year 2030, when 2017 and later model year cars and trucks comprise 80 percent of the light-duty fleet, and travel 90 percent of vehicle miles travelled (VMT). 2030 is a standard out-year for evaluation; it is used for air quality modeling in this proposal as well as recent EPA rules. However, the full impact of the vehicle program would 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 proposed vehicle standards. As explained in Section 7.2, air quality modeling was done only for 2017 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 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 continuation of the Tier 2 vehicle program indefinitely and an average gasoline sulfur level of 30 ppm (10 ppm in California).

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.

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 2017 and 2030. Both scenarios reflect the renewable fuel volumes mandated in the Energy Policy Act of 2005 (EPAct) and Energy Independence and Security Act of 2007 (EISA). We thus refer to this renewable fuel level as "post-EPAct/EISA". A key update in the analysis of renewable fuel volumes from that performed for the RFS2 final rule is the inclusion of gasoline containing 15 percent ethanol by volume (E15) in the fuel pool, per the approval in 2011 of a waiver which allows E15 to be used in model year 2001 and later cars and trucks. We estimated the market shares for E15 and gasoline containing 10 percent ethanol by volume (E10) in the market in 2017 and 2030, as discussed in Section 7.1.3.2.1.

Table 7-1 Overview of Reference and Control Scenarios

	Reference Scenario	Control Scenario
2017	Renewable Fuels: RFS2 program[a] 21.6 B gallons renewable fuels (24 B ethanol-equivalent gallons): 17.8 B gallons ethanol: E10 [b], E15[c] Fuel Sulfur Level: 30 ppm (10 ppm California) Fleet: 100 percent Tier 2 and older vehicles	Renewable Fuels: RFS2 program[a] 21.6 B gallons renewable fuels (24 B ethanol-equivalent gallons): 17.8 B gallons ethanol: E10 [b], E15[c] Fuel Sulfur Level: 10 ppm Fleet:[d] 93 percent Tier 2 and older vehicles 7 percent Tier 3 vehicles
2030	Renewable Fuels: RFS2 program[a] 30.5 B gallons renewable fuels (36 B ethanol-equivalent gallons): 22.2 B gallons ethanol: E15[c] Fuel Sulfur Level: 30 ppm (10 ppm California) Fleet: 100 percent Tier 2 and older vehicles	Renewable Fuels: RFS2 program[a] 30.5 B gallons renewable fuels (36 B ethanol-equivalent gallons): 22.2 B gallons ethanol: E15[c] Fuel Sulfur Level: 10 ppm Fleet:[d] 20 percent Tier 2 and older vehicles 80 percent Tier 3 vehicles

[a] RFS2 primary mid-ethanol scenario, 75 FR 14670 (March 26, 2010)
[b] Gasoline containing 10 percent ethanol by volume
[c] Gasoline containing 15 percent ethanol by volume
[d] 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 proposed Tier 3 program, federal gasoline would 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. Our Tier 3 control scenario modeled the suite of exhaust and evaporative emission standards proposed 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:

- Fleet average Federal Test Procedure (FTP) NMOG+NO_X standards of 30 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2025

- Fleet average Supplemental Federal Test Procedure (SFTP) $NMOG+NO_X$ standards of 50 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2025

- Per-vehicle FTP PM standard of 3 mg/mi for LDVs, LDTs and MDPVs, phasing in from MYs 2017 to 2022

- Per-vehicle US06-only PM standard of 10 mg/mi for LDVs through LDT2s and 25 mg/mi for LDT3s and LDT4s, phasing in for MYs 2017 to 2022

- New standards for Class 2b and 3 trucks phasing in by MY 2022 including $NMOG+NO_X$ declining fleet average, more stringent PM standards, and a regulatory useful life of 150,000 miles

- More stringent evaporative emission standards for diurnal plus hot soak emissions, a new canister bleed test and emissions standard, a new requirement to measure emissions using 9 RVP E15 certification test fuel, and new requirements addressing evaporative leaks on in-use vehicles.

The Tier 3 standards are expected to reduce onroad criteria and toxic emissions, and to a much smaller extent, nonroad SO_2 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 proposed Tier 3 standards is aligned with the model year 2017-2025 Light-Duty GHG standards[1] to achieve significant criteria pollutant and GHG emissions reductions while providing regulatory certainty and compliance efficiency to the auto and oil industries. The LD GHG standards were still in a preliminary state of development (pre-proposal) at the time we developed our assumptions for the Tier 3 emissions, air quality, and cost analyses presented here, so we were not able to reflect them in these analyses. However, our analyses for the final Tier 3 rule will include the final LD GHG standards in both the reference and control scenarios, and will thus account for their impacts on the future vehicle fleet and future fuel consumption. We do not anticipate that this change will substantially modify our results or conclusions. Improved fuel efficiency does not have a direct impact on criteria pollutant emissions, because non-GHG emissions standards for light-duty vehicles are expressed as grams per mile driven; thus, non-GHG emissions are a function of the emission control systems rather than the amount of fuel burned. As a result, we do not believe that changes to vehicle efficiency as a result of the LD GHG standards will affect the emissions benefits of the Tier 3 rule, but we will include the LD GHG requirement in our analysis for the final rule. 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)

- 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)

The analysis also accounts for many other national rules and standards. 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. See the Tier 3 emissions modeling TSD for more detail.

Decisions on the emissions and other elements used in the air quality modeling were made early in the analytical process for this proposal. For this reason, the Tier 3 emission control scenario used in the air quality modeling includes emission reductions from Tier 3 across the nation, assuming no reductions associated with California's LEV III program (as opposed to including California's LEV III program and its associated emission reductions in the baseline scenario). We will conduct new air quality modeling for the final rule that will include emission reductions from California's LEV III program, both in California and in states that by that time have adopted the LEV III program, in the baseline scenario.[A]

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.[2] A version of MOVES2010a, 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 2017 through 2030, and 2050.[B]

The MOVES model updates affecting reference and control case emissions were extensive, and are documented in a separate memorandum to the Tier 3 docket.[3] Updates made to MOVES2010a for this analysis primarily incorporated major new research in three areas. The

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[A] The California Air Resources Board (CARB) approved the LEV III program in January 2012. Several states have adopted the LEV III program under Section 177 of the Clean Air Act. These states include Connecticut, Maryland, Maine, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, Washington, and Vermont.

[B] The MOVES updates are reflected in a version of the MOVES model code (April 14, 2011 Version a) and a concurrently updated version of the MOVES default database (May 12, 2011), available in the Tier 3 docket As these updates are still draft, this code and/or database are not approved for official use in SIP and conformity analyses.

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 effects of changes in fuel properties on exhaust emissions of Tier 2 vehicles, which comprise the majority of the fleet by 2017, were assessed through the results of the EPAct Phase-3 Program. 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.[4] Improvements in estimating and projecting evaporative emissions are described in this document (see 7.1.3.3.7). Finally, because the updates to fuel sulfur effects are critical for estimating reductions from the Tier 3 program, they are also presented in detail in Section 7.1.3.4.

Other than sulfur, these changes had more bearing on updating reference case emissions than on the projected reductions from the Tier 3 standards. One key exception to this, however, were updates made to $PM_{2.5}$ fuel effects that result in an increase in emissions with increases in aromatics and T90 (reduction in E300). As discussed in Section 7.1.3.2.2, this update had an impact on control case emissions, as changes in aromatics and E300 were projected by refinery modeling as sulfur levels were reduced from 30 ppm to 10 ppm. However, other recent studies suggest that the PM emission increases observed are likely linked to the impacts of heavier hydrocarbons, and in particular heavy aromatics.[5,6,7] More study is needed to understand these relationships, and whether the changes in refinery operation to make up for lost octane, should it occur, would be likely to impact heavy aromatics or not.

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.[8] HC, CO and NO_X 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 MOVES2010a emission rates for NH_3, NO and NO_2.[C, 9]

The MOVES version used for this analysis also includes an added capability to model many hazardous air pollutants. And other changes were made to the MOVES2010a 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 addressing MOVES updates.

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

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[C] The changes to the NO and NO_2 rates did not impact the total NO_X emissions, but facilitated the output of separate results for nitric oxide and nitrogen dioxide.

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 air quality modeling, because the abbreviated approach enabled analysis for calendar years in addition to 2017 and 2030, and makes the analysis easier for stakeholders and other commenters to replicate. National emission inventories were developed using the pre-aggregation feature of MOVES. For criteria pollutants, the default pre-aggregation level of 'hour' was selected, which condenses the county-level temperatures into a single national average temperature by hour of the day.[D] 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 this difference in temperature resolution (national average vs. gridded hourly temperature), the national emission inventory analysis also used information contained in the MOVES2010a default database for vehicle miles travelled, fleet age distributions, activity inputs (e.g., speeds), temperatures, emission standards, and inspection/maintenance programs. As discussed in Section 7.2, this contrasts with the air quality modeling inventory methodology, which used data supplied by state and regional modelers for many of these inputs, employed hourly meteorological data, and accounts for Section 177 states adoption of California LEV standards in the modeling baseline.

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 7.5 was applied to July and 4.3 to January; these factors were determined based on analysis of annual PM emissions during modeling for the RFS2 rule.[10] 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 national 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

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[D] For air toxics, pre-aggregation level of 'month' was used instead to improve the model run time. Monthly pre-aggregation averages the temperatures of all selected days and hours into a national average hourly temperature for the month.

development of fuel supply database tables that reflected the difference between the reference and control scenarios, discussed in the following sections.

7.1.3.2.1 Reference Scenario

The reference scenario was developed to reflect updated assumptions regarding the ethanol blends used to meet the EISA-mandated volumes. For simplicity, we assumed the same biofuel volumes analyzed in the RFS2 final rule, referred to in that rule as the primary "mid-ethanol" case.[11] The RFS2 analysis also considered a "low-ethanol" and a "high-ethanol" scenario; the difference being an increase in cellulosic ethanol and a decrease in cellulosic diesel going from the low-ethanol to the high-ethanol scenario. We believe that the RFS2 renewable fuel volumes still bracket the realm of realistic potential fuel scenarios assuming the EISA mandate is met. However, given the practical limitations of conducting air quality modeling for all three scenarios, we focused our Tier 3 modeling on the primary mid-ethanol case.

We relied on biofuel volumes taken directly from the RFS2 mid-ethanol case, which made projections for every year between 2010 and 2022. We assumed that renewable fuel production/consumption would remain constant after EISA reaches full implementation in 2022. Accordingly, for 2030, we relied on 2022 biofuel volumes from the RFS2 primary mid-ethanol case.

In the RFS2 final rule, we assumed that all ethanol would be consumed as either E10 or E85. Since then, EPA issued a waiver permitting 15 volume percent ethanol blends (E15) to be used in 2001 and newer model year light-duty vehicles.[E] While E15 has only limited commercial availability currently, EPA believes it may compete favorably with E85 in the marketplace and could become a major gasoline blend in the future to meet the mandated RFS2 volumes. Accordingly, the reference scenario assumes an increasing utilization of E15 over time as infrastructure ramps up and owners become more aware of their vehicle's ethanol usage potential.

To estimate future E15 fuel consumption, we started by estimating the fraction of vehicles capable of legally refueling on E15 (or higher ethanol blends) in the future. To do this, we relied on many vehicle assumptions made under the RFS2 final rule.[F] For flexible fuel vehicles (FFVs), we started with EPA certification data and assumed that the "Detroit 3" (GM, Ford and Chrysler) would follow through with their voluntary commitment to produce 50 percent FFVs by 2012.[G] We also assumed that the Detroit 3 would continue to comprise approximately 45 percent of total light-duty vehicle sales. In addition, we relied on total light-duty vehicle sales projections from EIA's Annual Energy Outlook (AEO). Factoring in EPA's projected vehicle scrappage rates, vehicle miles traveled (VMT) by model year (MY), and fuel economy assumptions based on EPA's 2012-2016 Light-Duty Greenhouse Gas Rule,[H] we

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[E] On Nov. 4 2010, EPA issued a partial waiver for MY2007 and newer light-duty vehicles (75 FR 68094). On January 26, 2011, EPA extended the waiver to MY 2001-2006 light-duty vehicles (76 FR 4662).

[F] Refer to Section 1.7 of the RFS2 RIA for more on our FFV/vehicle assumptions.

[G] We assumed that non-domestic automakers would produce around 2 percent FFVs in current and future years.

[H] 75 FR 25324 (May 7, 2010).

estimate that by 2017, 13.6 percent of gasoline demand would come from FFVs, 68.7 percent would come from 2001 and later model year non-FFVs, and 17.7 percent would come from legacy vehicles, nonroad, motorcycles and other small engines not approved for E15. By 2030, the contributions would be 22.0, 66.8, and 11.2 percent, respectively. A graph of the projected gasoline fuel fractions over time is provided in Figure 7-1.

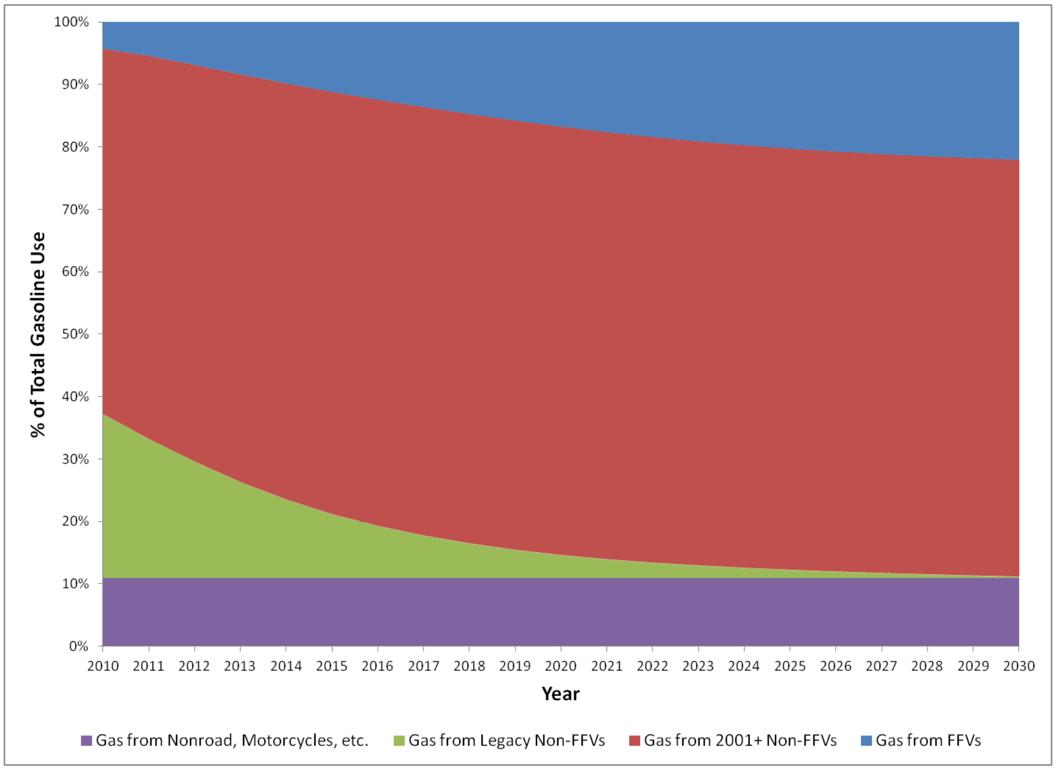


Figure 7-1 Gasoline Fuel Fraction by Vehicle Type

The next step was to estimate how often E15-capable vehicles would fill up on E15. E15 utilization is a function of how accessible E15 is to consumers (i.e., number of stations offering it) and how often E15-capable vehicles choose to fill up on it (based on retail pricing and other factors). We assumed that E15 utilization for 2001 and later model year vehicles would ramp up to 50 percent by 2017, increasing to almost 100 percent utilization by 2030. We assumed that new nonroad equipment (and other small engines not covered by the waiver) would be designed for and/or certified on E15 in the future. As such, we assumed that E15 utilization in nonroad equipment would ramp up from zero percent in 2017 to almost 100 percent by 2030. This resulted in a very small amount of E85 needing to be used in 2017 and 2030 to reach the RFS2 primary mid-ethanol volumes. FFV owners were assumed to utilize E15 at the same rate as 2001 and later model year conventional vehicles when not refueling on E85. When not refueling on E15 (or E85), all E15-capable vehicles were assumed to refuel on E10. As a simplifying assumption, we assumed E0 usage was negligible. Figure 7-2 shows the E15 and E85 utilization assumptions and Figure 7-3shows the resulting fuel volumes by year. Total fuel volumes were computed based on motor gasoline energy projections provided in the Annual Energy Outlook (AEO) 2011 early release.

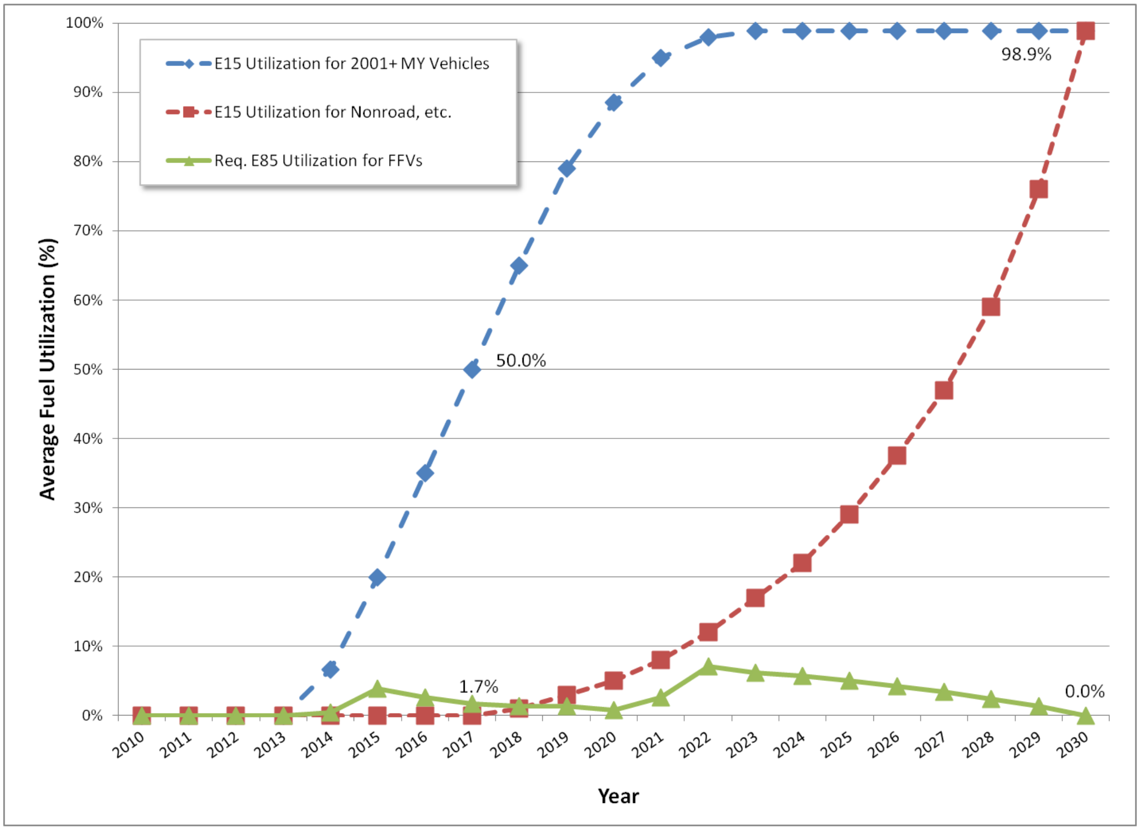


Figure 7-2 Post-EPAct/EISA Fuel Utilization Assumptions/Results

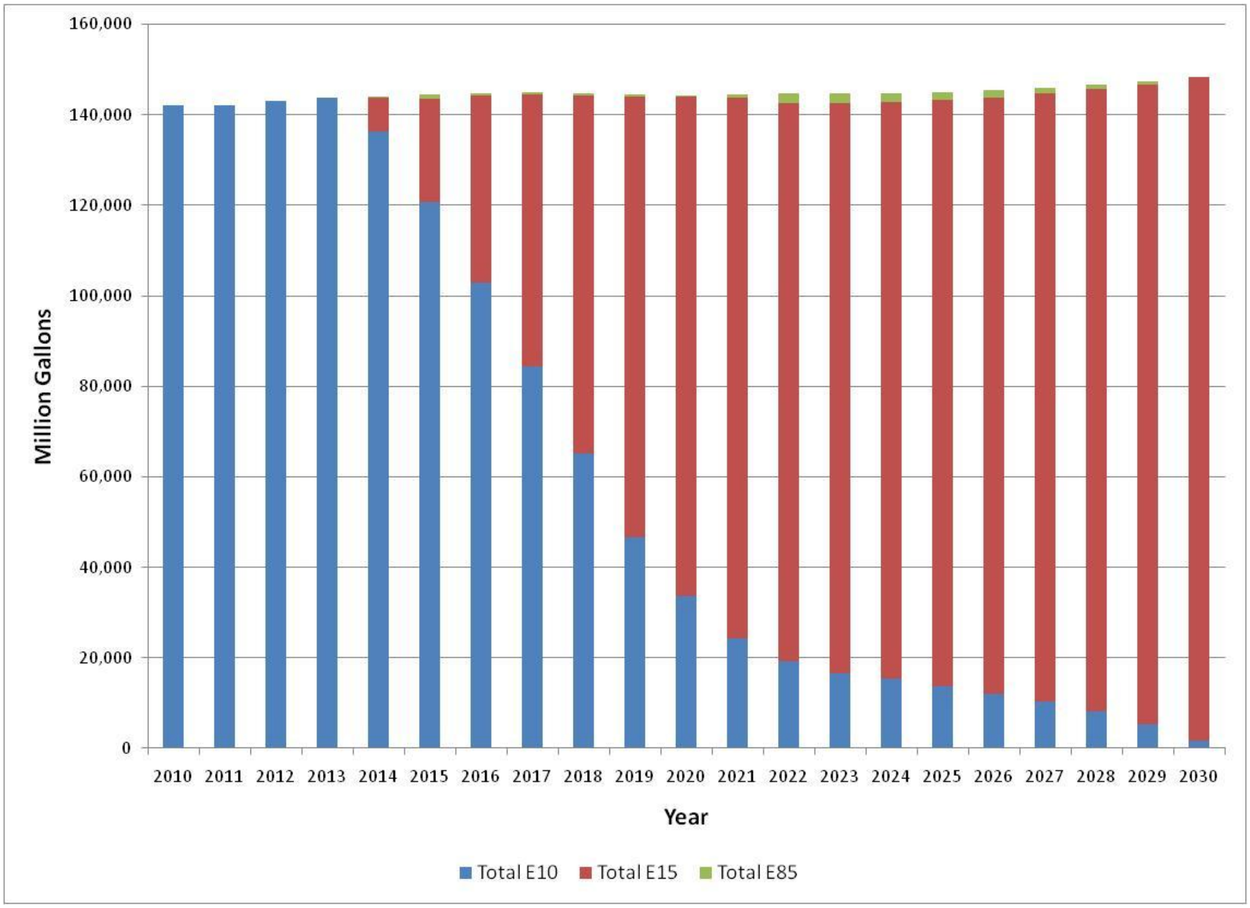


Figure 7-3 Assumed Post-EPAct/EISA Gasoline Fuel Volumes by Calendar Year

As shown above, our post-EPAct/EISA ethanol blend assumptions (i.e., ramp up of E15) are capable of meeting the RFS2 primary mid-ethanol scenario with little to no E85 needed – especially in our 2017 and 2030 modeling years. Therefore, for emissions and air quality modeling, we made the simplifying assumption that E85 use would be negligible. While E85 used in FFVs could be part of the future biofuel picture, we believe that given EPA's waiver decision and the ability for E15 to compete in today's gasoline marketplace, E15 is a viable ethanol blend for meeting the RFS2 volumes.

These projected fuel scenarios do not reflect the impact of the LD GHG standards, as the rule was still in a preliminary state at the time we needed to finalize our assumptions for these Tier 3 analyses. The LD GHG standards will reduce gasoline demand in 2017 and beyond which has two impacts on our analysis. First, the reduced fuel consumption associated with the LD GHG standards will likely result in somewhat lower costs for sulfur control, because less gasoline will need to be desulfurized. Second, if ethanol volumes are constant but gasoline demand is reduced due to the LD GHG standards, perhaps as much as five percent of the fuel pool could be E85 or other higher-level ethanol blends by 2030. However, we do not expect this to significantly impact criteria pollutant reference or control case emissions because recent data on NMOG and NO_X emissions do not show significant differences when run on E85,[12,13] and the percentage of the fleet impacted is small. There could be a small impact on sulfur related costs and emission reductions due to an effect of E85 on overall fuel pool sulfur concentrations, depending on what could be assumed for future E85 (or other higher level ethanol blend) sulfur levels. An increase in E85 volumes could also lead to changes in toxic emissions, with increases in acetaldehyde emissions from ethanol combustion, but decreases in most other toxics due to dilution. However, EPA air quality modeling suggests that changes in ambient levels of acetaldehyde are likely to be much smaller than changes in direct emissions.[14,15] This is because emissions of acetaldehyde precursors, particularly alkenes, are lower in E85 emissions. For the Tier 3 final rule's analysis, we will be including the impact of the LD GHG standards, and we will revisit our assumed future fuel scenarios accordingly, including higher-level ethanol blends as appropriate.

For this analysis we assumed that E15 would first appear in significant volumes in reformulated gasoline (RFG) areas. All RFG is subject to a de facto 7-psi RVP standard. And since neither E10 nor E15 can take advantage of the 1-psi waiver in RFG areas, the two fuels are essentially the same with respect to vapor pressure limits. In conventional gasoline (CG) areas, E15 is held to a 9-psi standard whereas E10 is allowed to be 10-psi in-use (through the use of a 1-psi waiver). As a result, in order for E15 to enter into CG areas, refiners would need to remove butanes/pentanes to make an 8-psi blendstock to account for the 1-psi increase associated with ethanol blending. Conversely, refiners could keep their CG blendstocks around 9-psi to blend up 10-psi E10 which is eligible for the 1-psi waiver and thus is considered 9-psi for compliance purposes. Due to the additional actions needed to market E15 during the summer in CG areas, it makes sense that more E15 would be used in RFG areas, at least in the near term. Accordingly, we assumed that in 2017, 75 percent of RFG would be E15 and the balance of E15 would be used in CG (resulting in 25 percent E15 utilization and 75 percent E10 utilization in those areas). By 2030, since we modeled a much larger volume of ethanol, E15 was assumed to be used virtually everywhere.

Converting these assumptions into post-EPAct/EISA fuel properties on a county-by-county basis required an assessment of fuel properties prior to the EPAct/EISA requirements for 2017 and 2030, termed “pre-EPAct/EISA”. We developed these starting with 2005 fuel volumes as the baseline for our analysis of renewable fuel impacts because these volumes were in use immediately before EPAct was enacted, creating volume requirements for 2006, and because they provide consistency with the base case used for air quality modeling described in Section 7.2. In 2005, gasoline contained over 4 billion gallons of ethanol. In 2005, gasoline also contained approximately 2 billion gallons of MTBE.

For translation into the fuel supply inputs needed by MOVES, the MOVES2010a default fuel supply for 2005 (based on the National Emission Inventory[16]) was updated to serve as a better basis for the other modeling cases. These updates are detailed below.

- In 2005, California fuel was required to have an ethanol level of 5.7 percent for all fuel. The MOVES2010a default fuel supply listed California counties with a 57 percent market share of E10 and a 43 percent market share of E0. The fuel supplies for these counties were refined to indicate E5.7 at 100 percent market share. Also, Alameda County, California, had anomalous fuel property data. The fuel properties for this county were replaced with an average of the fuel properties of the neighboring counties.

- Counties in the southeast Michigan fuel program area erroneously had been assigned higher sulfur and benzene levels than the rest of the state of Michigan. Sulfur and benzene for these counties were corrected to an average of all other Michigan counties. Some Michigan counties also had very low levels of MTBE (<0.3 percent), despite an MTBE ban in Michigan in 2005. These fuels have been corrected to a 0 percent MTBE conventional fuel to properly reflect the absence of MTBE in Michigan.

- Many counties in the 2005 default fuel supply had fuel RVP levels that were drastically inconsistent with the mandated level for RVP in that county for a given summer month. Summer RVP levels for all counties were corrected to their mandated level (including a 0.25psi compliance margin) based on knowledge of fuel programs in place for 2005. Winter RVP levels remain unchanged from the 2005 default fuel supply.

- The corrections above were applied to the months of January (winter fuel properties) and July (summer fuel properties) for the 2005 base case. The fuel properties for these two months were then duplicated to other months to complete the 2005 fuel supply for all months. The corrected January fuel supply was duplicated to February, March, April, October, November and December; the corrected July fuel supply was duplicated to May, June, August and September. Although this duplication eliminates fuel property changes during the shoulder seasons in April and September, these intermediate month fuel properties were used only when modeling refueling for the air quality inventories; we expect that this simplification will not significantly impact the modeling run results. Diesel fuel properties were not adjusted in the 2005 fuel supply.

The 2017 pre-EPACT/EISA base was developed using the corrected 2005 fuel supply discussed above as a foundation. From this fuel supply, benzene and sulfur levels for all counties were further 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 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 7-2 below:

Table 7-2- MSAT2 Downstream Fuel Benzene Levels

PADD	**CG**	**RFG**
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 2005 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 a significant 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:

1) A “high sulfur” aromatics level was determined using the following equation:

$$high\ sulfur\ aromatics\ level = \left(\frac{1}{sulfur\ level} * 0.479\right) + 24.60$$

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 2005 fuel supply

Diesel fuel sulfur levels were also adjusted to 30ppm to reflect low sulfur diesel levels. There were no other changes from the 2005 base case to the 2017 base case. The fuel properties for the 2030 base case were identical to the 2017 base case for every county; the only modification made to create the 2030 pre-EPAct/EISA base case is a change in the year of the fuel supply.

The post-EPAct/EISA cases used as a reference for Tier 3 were developed using the pre-EPAct/EISA cases for 2017 and 2030 as a foundation, and were then created by inserting the ethanol market share assumptions for each county discussed at the beginning of this section. Fuel properties for all counties were then adjusted based on relationships found in refinery modeling for this additional ethanol. The process used for adjusting ethanol market shares and fuel properties for every county is described below:

1) Counties with multiple fuels were aggregated to one set of temporary fuel properties using the market shares of these fuels. Counties with only one fuel remain unchanged in this step.

2) Two new fuels, a 10 percent ethanol blend and a 15 percent ethanol blend, were created from the temporary fuel properties by raising the ethanol level from the temporary aggregate to the appropriate new ethanol level.

3) For each new fuel, other fuel properties were adjusted based on refinery modeling to reflect changes due to increased ethanol use. These fuel property changes (on a percent ethanol basis) are shown in Table 7-3 below:

Table 7-3- Reference Case Fuel Property Changes

	Summer		Winter	
Fuel Property[a]	**E10**	**E15**	**E10**	**E15**
E200	0.54834	0.76481	0.73693	1.04067
E300	0.13946	0.09549	0.00634	0.39788
Aromatics	-0.40887	-0.46684	-0.50555	-0.49956
Olefins	-0.13788	-0.15915	-0.25198	-0.15296

Note:

[a] These fuel property changes are listed as a per-ethanol percent change.

4) Market shares for the E10 and E15 fuels were adjusted to reflect RFS2 level ethanol use. As explained above, in RFG counties, E10 was added to the fuel supply at a 25 percent market share, E15 was added to the fuel supply at a 75 percent market share. For counties not using RFG, E10 was added to the fuel supply at a 75 percent market share, and E15 was added at a 25 percent market share. In 2030, the E10 market share is set at 1 percent and E15 market share set at 99 percent, regardless of fuel program.

5) RVP levels for the new E10 and E15 fuels were corrected to reflect E15 fuel not receiving a 1psi waiver for maximum RVP level. As discussed for the base case fuel supplies in the previous section, RVP levels were adjusted to within a 0.25 psi compliance margin depending on county fuel programs.

The result of this effort was two alternate fuel supply databases tables for use in MOVES, reflecting the reference case fuels in 2017 and 2030 – these tables were used for the development of national emissions inventory as well as air quality modeling. New fuel formulations were also required for MOVES, and were created for each of the new E10 and E15 fuels created for the 2017 and 2030 reference case.

7.1.3.2.2 Control Scenario

The Tier 3 control fuel scenarios for the years 2017 and 2030 used the fuel supplies constructed for the 2017 and 2030 reference cases described in the previous section as a foundation. To develop the control scenario fuel supplies, we modified the reference fuel supplies to reflect the sulfur program proposed in the Tier 3 control case by reducing sulfur from 30 ppm to 10 ppm for all gasoline.[I] Associated fuel properties determined by refinery modeling were also adjusted to reflect the implications of sulfur reductions on other fuel properties, such as an increase in aromatics and decrease in olefins and distillation properties, as shown in Table 7-4

[I] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases.

below. These changes were made to every county with fuel exceeding a sulfur level of 10ppm. No changes were made to the diesel fuel supply for the control scenario.

Table 7-4 Tier 3 Control Case Sulfur Fuel Property Changes

Fuel Property	Summer	Winter
E200 (%)	-0.78	-1.27
E300 (%)	-0.75	-0.68
Aromatics (%)	0.63	0.48
Olefins (%)	-0.82	-1.12

The result of this effort was two additional alternate fuel supply databases tables for use in MOVES, reflecting the control case fuels in 2017 and 2030; these tables were used for the development of national emissions inventory as well as air quality modeling. For the national emission inventories the 2017 fuel supply was applied to 2018 through 2021 as well, to approximate the fuel supply prior to full RFS2 implementation; the 2030 fuel supplies were applied to 2022 through 2029, reflecting full RFS2 implementation. New fuel formulations were also required for MOVES, and were created for the low sulfur versions of the E10 and E15 fuels created for the 2017 and 2030 reference case.

Upon further analysis, we believe that the increase in aromatics and reduction in E300 shown in Table 7-4 is unlikely. The process of hydrotreating in the fluid catalytic cracking (FCC) of gasoline to reduce sulfur tends to saturate olefins formed by the FCC unit and which are present in FCC gasoline, thus reducing its octane. Because refiners have historically been pressed to make as much octane as possible to supply market needs, various technologies and catalyst formulations have been developed for hydrotreating FCC gasoline to avoid and/or minimize this loss of octane. Nevertheless, our analysis estimated that desulfurizing gasoline to an average of 10 ppm would result in about a half number loss in the octane of FCC gasoline, and we also conservatively assumed that this octane loss would need to be compensated for with other changes to gasoline, such as increased reformate (an aromatic rich stream), isomerate and alkylate. These assumptions are conservative and not consistent with more recent trends. For example, there is less demand for octane due to the dramatic rise in the use of ethanol (which has very high octane), and the declining demand for gasoline. It is not clear that the loss in octane resulting from gasoline desulfurization would need to be compensated for. In fact, there is considerable “give away” of octane in the gasoline pool today as ethanol is still often splash blended on top of finished gasoline instead of blending it with a sub-octane gasoline blendstock. Nevertheless, for our Tier 3 analysis, we conservatively assumed that the full half number loss in the octane of FCC gasoline would have to be compensated for by the refinery and not made up by blending in more ethanol. In particular, in running the refinery model to make up for the lost octane, we conservatively constrained the refinery model such that the only options for additional octane were changes within the refinery. Additional ethanol was not a modeled option, despite the fact that ethanol will be providing additional octane to the gasoline pool as ethanol use continues to rise through 2017 and beyond.

Furthermore, the increase in aromatics and decrease in E300 may simply be a function of additional assumptions in the refinery modeling. We did not model any revamps in FCC feed hydrotreaters. For some refineries, revamping FCC pretreaters is expected to realize the decrease in FCC gasoline sulfur levels without any decrease in FCC gasoline octane levels. Furthermore, when refiners are faced with tighter sulfur standards, one strategy for compliance would be to undercut the heaviest portion of the FCC naphtha, which is also the portion highest in sulfur, into either jet fuel or diesel fuel. By doing so, refiners would not only reduce the hydrotreating severity of their FCC posttreaters (reducing olefin saturation and some of the octane loss), but they would be increasing E300 (lightening up the gasoline pool). One check of our refinery modeling output, which shows increasing aromatics and decreasing E300, would be to compare the output of our refinery modeling with that of other studies. Our refinery modeling estimated a 0.48 volume percent increase in the aromatic content and 0.68 percent reduction in the E300 of gasoline in the winter, and a 0.63 volume percent increase in the aromatic content and 0.75 percent reduction in the E300 of gasoline in the summer. Recent modeling performed by Mathpro for the International Council on Clean Transportation (ICCT) showed a 0.1 volume percent increase in aromatic content and a 0.2 volume percent decrease in E300 in the summer, and a 0.3 volume percent decrease in aromatics and 0.8 percent volume percent increase in E300 in the winter.[17] Overall, the Mathpro refinery modeling showed an annual average decrease in aromatics and increase in E300. Recent modeling by Baker & O'Brien for API (Sensitivity Case 3) showed about half the increase in aromatics that our analysis showed, however the API study also included the octane impacts of lower RVP, so we could not determine whether modeling by API would show an increase in aromatics or not if it solely modeled sulfur control.[18] API's addendum to its original study which added an additional control case that solely modeled a 10 ppm gasoline sulfur standard (no change in RVP), showed a 0.2 volume percent decrease in aromatics during the summertime (no wintertime fuel quality data was presented, nor was any distillation data presented either summer or winter). Furthermore, after we completed this analysis for the NPRM, we discovered that the LP refinery cost model that we licensed to use required some improvements to correctly characterize the qualities of the light and heavy naphtha streams from the reformer to improve its estimation of E300 and aromatics content. Thus, unlike our modeling results shown in Table 7-4, which show a meaningful impact on aromatics and E300, we believe, consistent with the Mathpro and Baker and O'Brien refinery modeling studies, that there will be little to no change. Note that these improvements are not expected to have any impact on the cost estimates made by the refinery model.

The air quality analysis included the changes to aromatics and E300 shown in Table 7-4. However, because of the concerns above, we did not reflect these changes in the national emission inventories presented in Section 7.1.5.

7.1.3.3 Vehicle Program Inputs

Modeling the controls introduced by the Tier 3 vehicle program required the development of another set of alternate MOVES database tables to reflect each aspect of the proposed Tier 3 program. These database tables included:

- Gaseous exhaust emissions rates (HC/CO/NO_X) for light duty cars, trucks, and light-heavy trucks (gas and diesel) to reflect the proposed 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 trucks (gas and diesel) to reflect the proposed Tier 3 FTP and US06 PM standards and phase-in.

- Evaporative HC permeation emission rates to reflect the proposed diurnal test standard, certification fuel, and phase-in.

- Leak prevalence rates for tank vapor venting and liquid leaks to reflect proposed requirements for evaporative leak detection.

The development of these alternative emission rates is discussed below by pollutant, fuel and vehicle regulatory class.

7.1.3.3.1 Gasoline LD HC/CO/NO_X Exhaust

Gaseous emission rates in MOVES are contained in a database table (EmissionRateByAge) that expresses emission rates as mass per time, 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, vehicle soak time for start). Developing these rates on Tier 3 vehicles required accounting for expected changes in each of these dimensions.

The development of Tier 3 emission rates followed the same procedures used to develop National LEV (NLEV, covering model years 2001-2003) and Tier 2 rates (covering model years 2004 and later) in the default MOVES database, as described in the documentation for development of light-duty exhaust emission rates for MOVES2010 (known as the “MOVES Light-Duty report”).[19] 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 MOVES 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 proposed standards. For Tier 3, we developed estimates of FTP results for Tier 3 vehicles based on IUVP data from Tier 2 Bin 2 and 3 vehicles, including composite results, “cold-start” emissions” (Bag1 minus Bag3) and “hot-running” emissions (Bag 2 FTP 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.

3. *Merge FTP results and Phase-in assumptions*. For running emissions, calculate weighted ratios of emissions in each model year relative to those for cars (LDV) in MY2000, which represent Tier 1 LDV (as discussed in the MOVES Light Duty report, default MOVES rates were projected forward based on model year 2000 data from state I/M data, in conjunction with IUVP data for later model years).

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 120K miles, 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. Addition information is available in a separate memo available in the docket.[20]

7.1.3.3.1.1 Average FTP Results (Step 1) (Standard)

Our projected emissions for Tier 3 vehicles are driven by the proposed NMOG+NO_X standard, set at 30 mg/mi. However, because MOVES projects NO_X and THC emissions separately, we apportioned the aggregate standard into NMOG and NO_X 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_X control. Accordingly, we assumed “effective standards” for NMOG and NO_X would be 20 mg/mi and 10 mg/mi, respectively. To implement this assumption, we further assumed that for NO_X, 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 7-5, 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.

$$\mathrm{T3} = 0.775 \cdot \mathrm{B2} + 0.225 \cdot \mathrm{B3}$$

Equation 7-2

Table 7-5 Hydrocarbons (HC): Useful-Life FTP Standards and Associated Cold-Start and Hot-Running Results on the FTP and US06 Cycles. Values for the FTP and US06 represent NMOG and NMHC, respectively.

Bin	Useful-life Standard (mg/mi)	FTP Composite[a] (mg/mi)	FTP Cold Start[a] (mg)	FTP hot Running[a] (Bag 2) (mg/mi)	US06[b] (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[c]	20	9.2	142	0.7	10.0

[a] Values represent "non-methane organic gases" (NMOG).
[b] Values represent "non-methane hydrocarbons" (NMHC).
[c] 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 7-6.

Table 7-6 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[a]	2,100	286	2,040	81	1,390

[a] Values for Tier 3 calculated using Equation 7-2.

Corresponding results for $\mathrm{NO_X}$ are presented in Table 7-7. 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 7-7 NO_X: 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 $NMOG+NO_X$ 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.

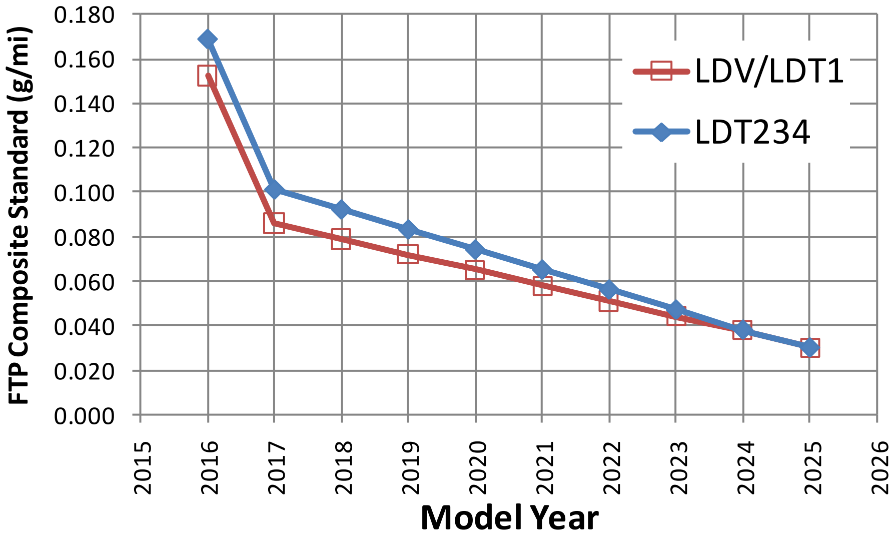


Figure 7-4 $NMOG+NO_X$ FTP Fleet Average Requirements during Phase-In of the Tier 3 Exhaust Emissions Standards for Light-Duty Vehicles.

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.

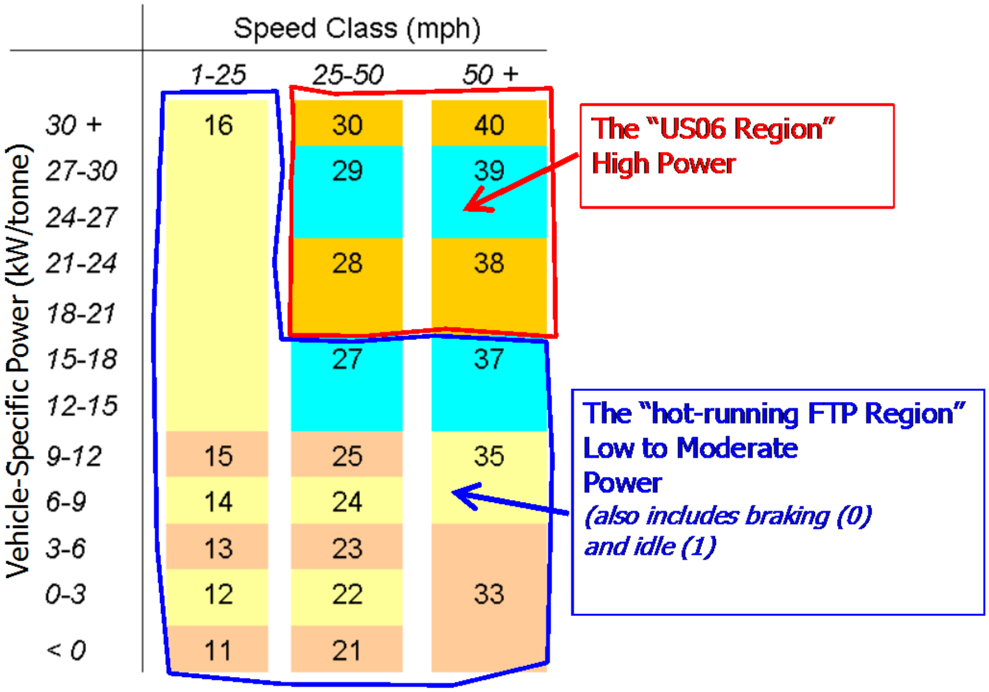
Start and running emissions in each model year are simply calculated as weighted averages of the emissions estimates and the phase-in fractions. The resulting weighted start estimates are used directly to represent cold-start emissions for young vehicles in each model year (ages 0-3). For running emissions, 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 standards (< ~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). Data measured on the SC03 cycle did not play a role in emission rate development.

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 2016 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 7-5 through Table 7-7. For HC and CO, we used Equation 7-2, as before. For NO_X, 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 7-3 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.



	1-25	25-50	50 +
30 +	16	30	40
27-30		29	39
24-27			
21-24		28	38
18-21			
15-18		27	37
12-15			
9-12	15	25	35
6-9	14	24	
3-6	13	23	
0-3	12	22	33
< 0	11	21	

Figure 7-5 Operating modes for running Exhaust Emissions, divided broadly into "hot-running FTP" and "US06" regions.

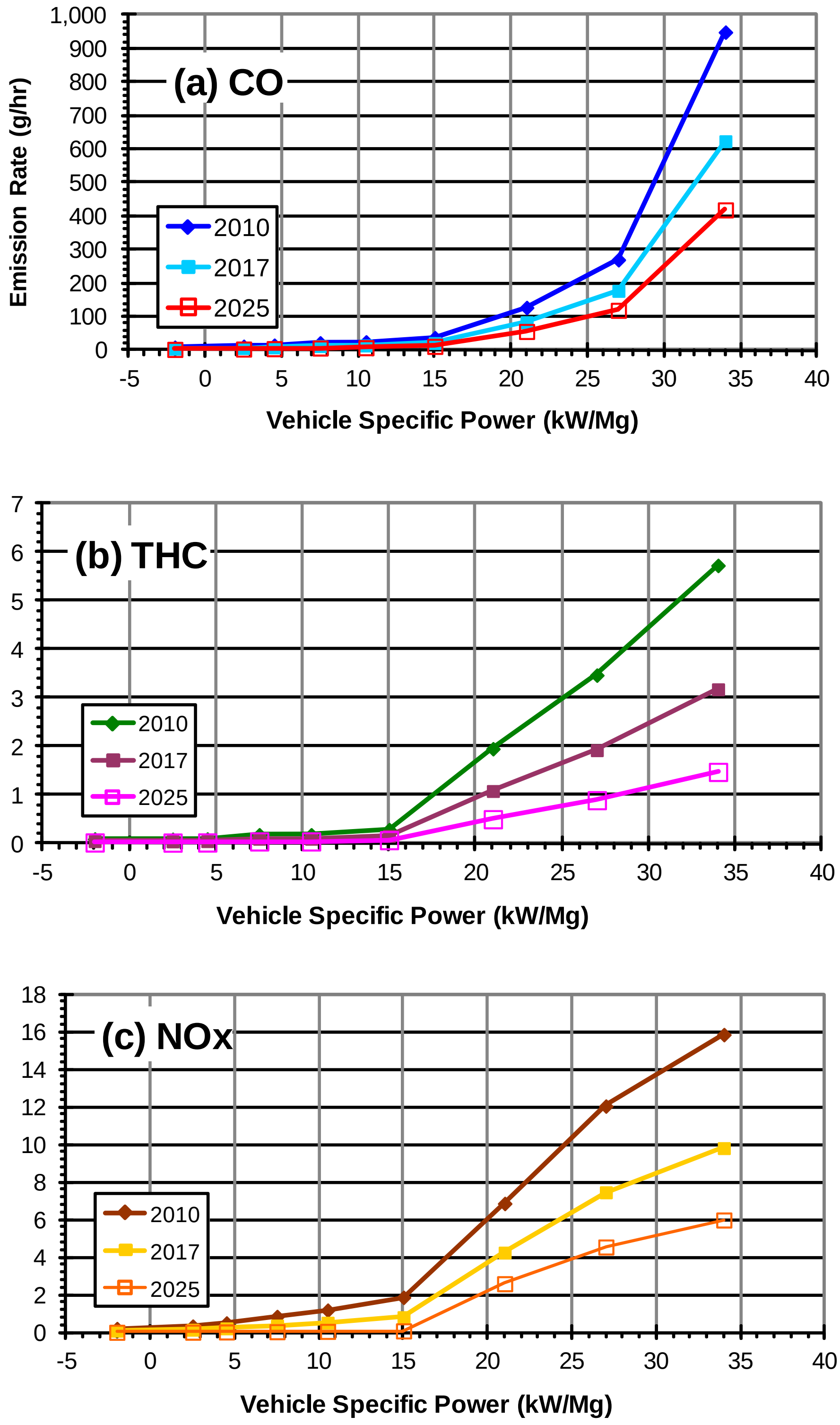


Figure 7-6 Projected Emission Rates for Cars in Operating modes 21-30, vs. VSP, in ageGroup 0-3 years, for three model years, for (a) CO, (b) THC and (c) NO$_X$ (LINEAR SCALE).

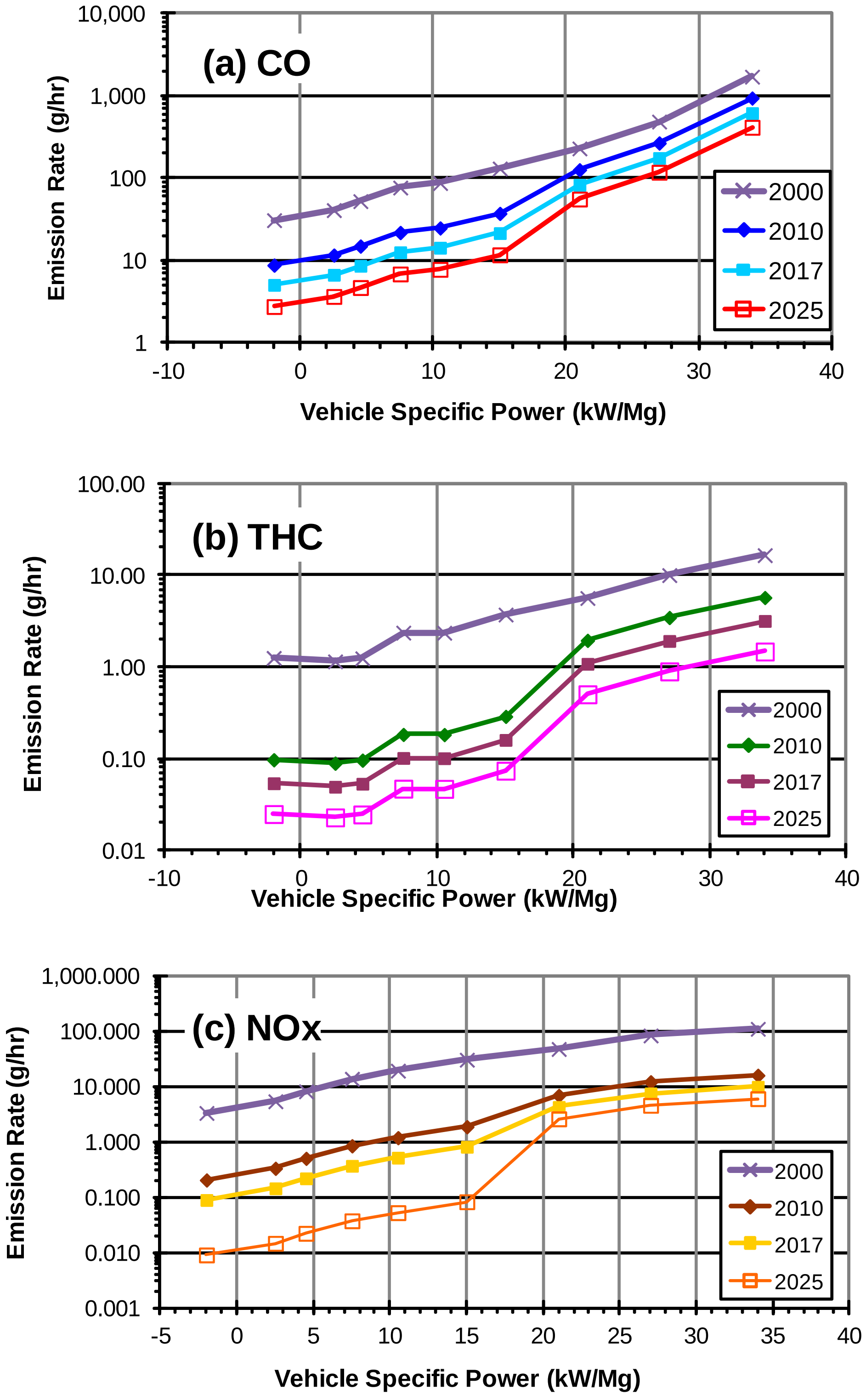


Figure 7-7 Projected Emission Rates for Cars in Operating modes 21-30, vs. VSP, in ageGroup 0-3 years, for Four Model Years, for (a) CO, (b) THC and (c) NO_X (LOGARITHMIC SCALE).

7.1.3.3.1.5 Apply Deterioration (Step 5)

Based on our extensive emissions analysis during MOVES2010 development, we assume that deterioration for different technologies is best represented by a multiplicative model, in which different technologies, represented by successive model-year groups, show 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 2017 and later model year vehicles, the deterioration assumptions were modified to represent the extension of the full useful life (FUL), which is increased from 120,000 mi to 150,000 mi. However, we did not extrapolate the 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 proposed Tier 3 standards, emissions can be constructed for FTP composite and US06 from MOVES emission rates for the Tier 2 (labeled as model year 2010) and Tier 3 (labeled as model year 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.

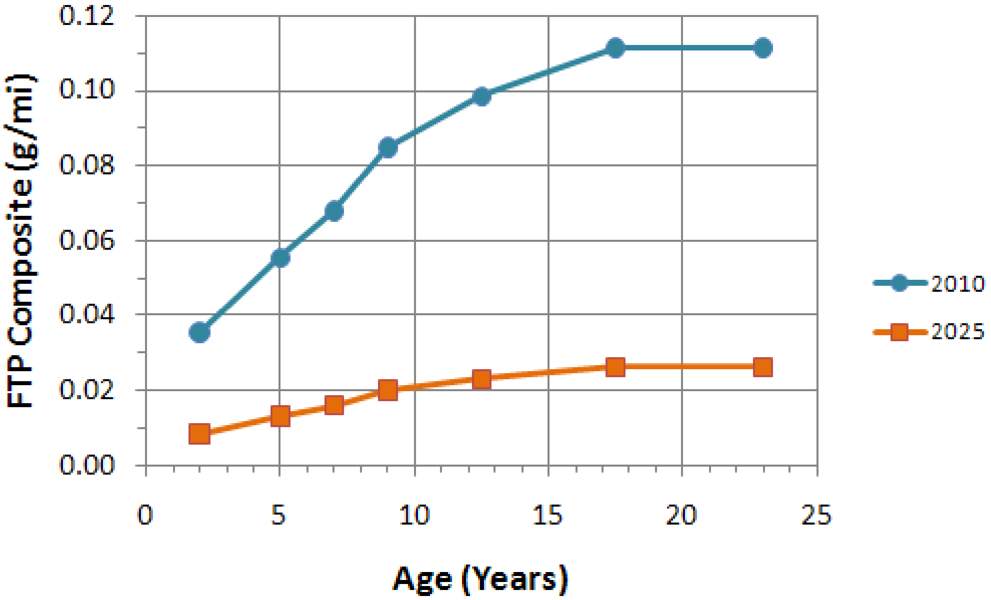


Figure 7-8 FTP Composite NO_X emissions for reference (2010) and Tier 3 (2025) constructed from MOVES rates

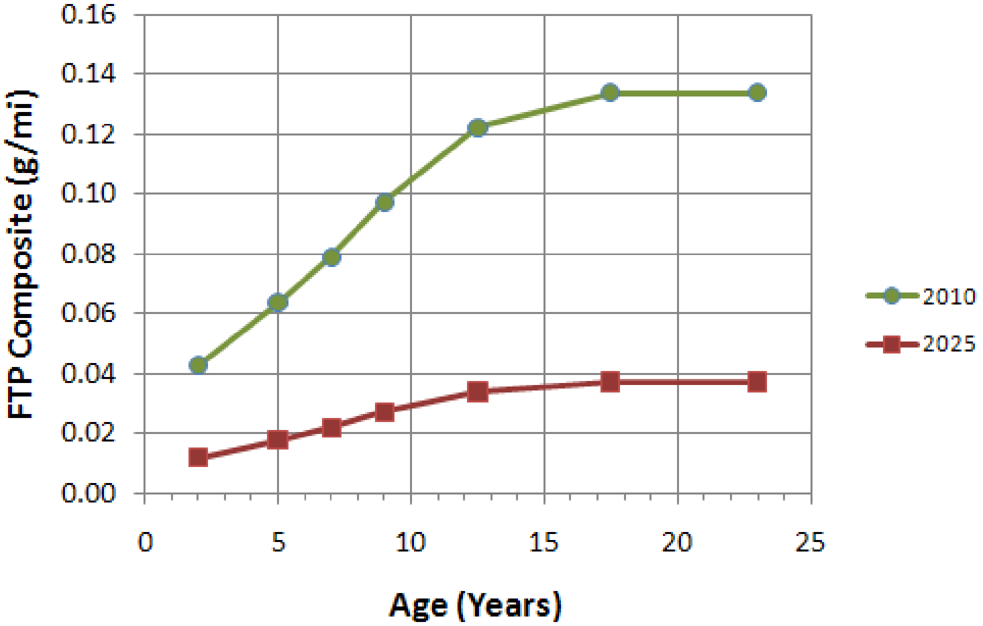


Figure 7-6 FTP Composite THC emissions constructed from MOVES rates

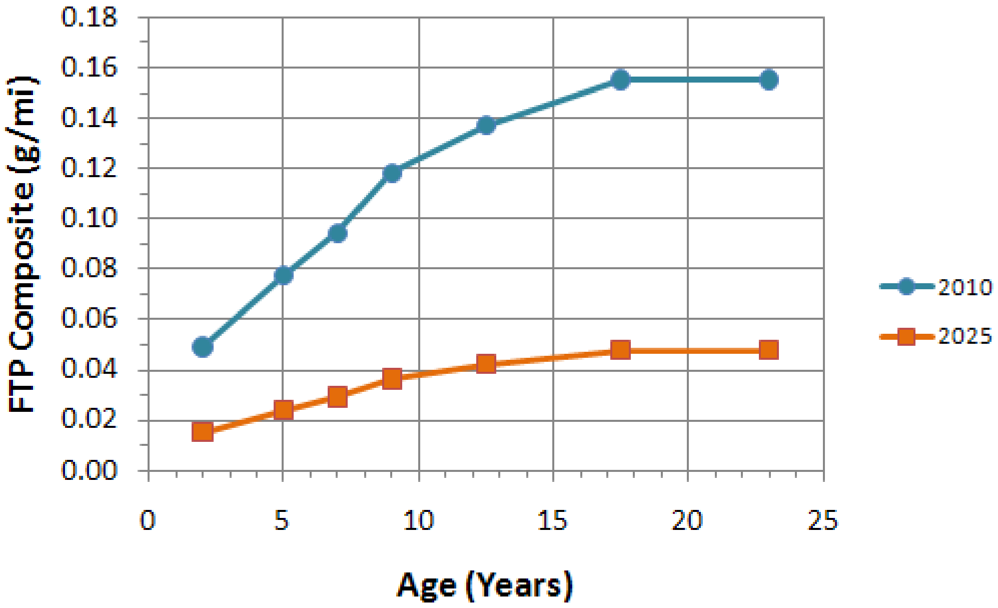


Figure 7-7 US06 NO_X emissions constructed from MOVES rates

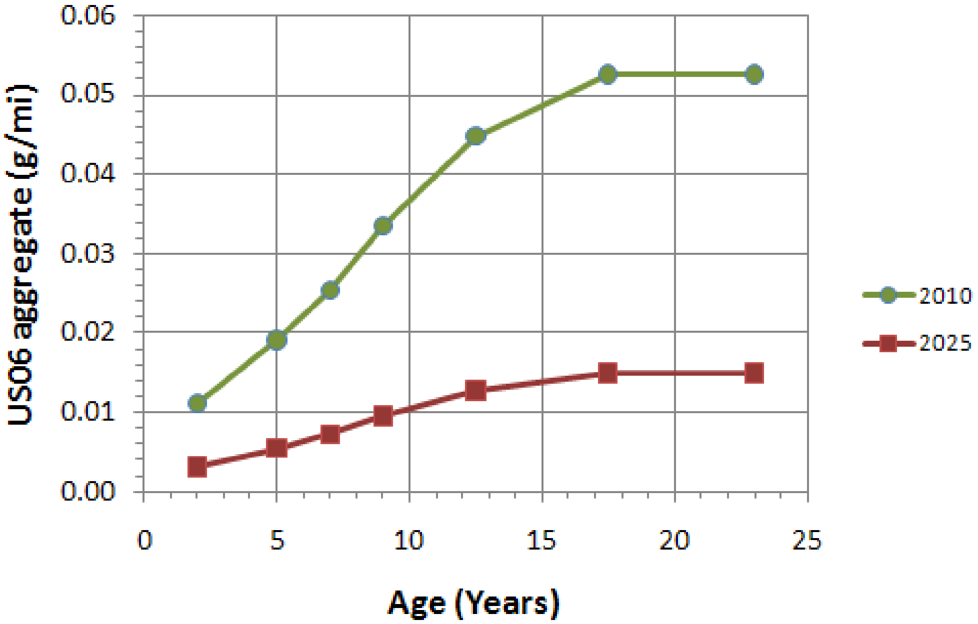


Figure 7-8 US06 THC emissions constructed from MOVES rates

7.1.3.3.2 Diesel LD HC/CO/NO_X 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_X 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_X were set at 10 and 20 mg/mi, respectively. As mentioned, all remaining steps were conducted as described in 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 MD HC/CO/NO_X

The proposed Tier 3 program will affect not just light duty vehicles (below 8,500 pounds GVW), but also chassis certified vehicles between 8,500 and 14,000 pounds. These vehicles are referred to here as medium duty vehicles, but are also commonly known as Class 2b and 3 heavy trucks. In MOVES, these vehicles are designated regulatory class 41. Regulatory class 41 also captures certain other vehicles, namely engine certified trucks and medium duty passenger vehicles, which are not regulated underneath the proposed medium duty standards. As described in the reference case medium duty updates to MOVES,[21] we assumed that during this timeframe engine certified vehicles and medium-duty passenger vehicles (MDPV) are five percent and fifteen percent of the regulatory class respectively.

Table 7-8 Population Percentage

Category	Percent of Reg Class 41
MDPV	15%
Class 2B	60%
Class 3	20%
Engine Certified	5%

The Class 2b and Class 3 vehicle program was modeled to begin in model year 2017 and fully phase in during the 2022 model year (Figure 7-9). This yields an aggregate standard of 0.178 g/mile NMOG+NO_X for Class 2b vehicles and 0.247 gram/mile for Class 3 vehicles in 2022.

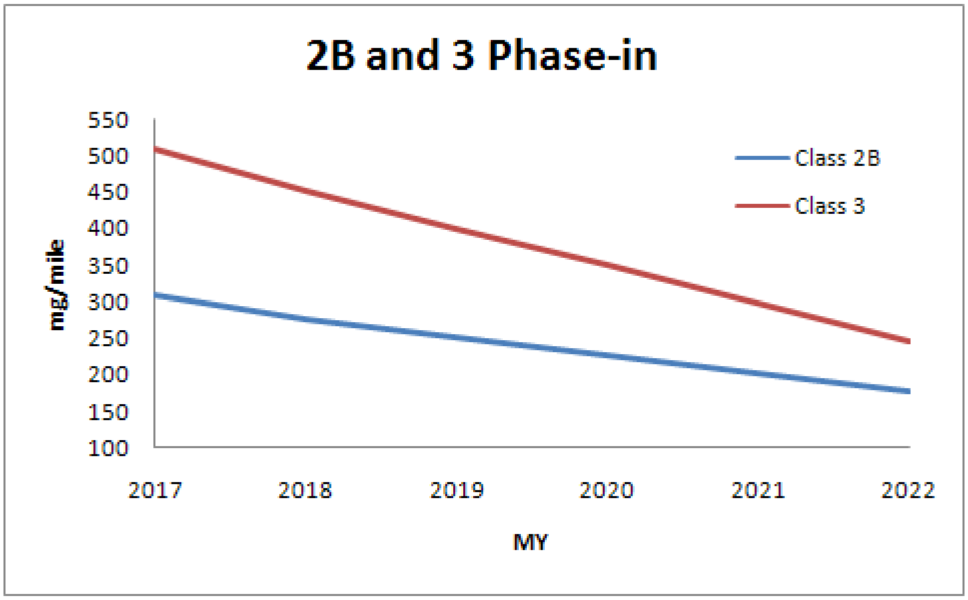


Figure 7-9 Class 2B and 3 Standard Phase-in

We combined the proposed Tier 3 phase-in for Class 2b and 3 vehicles with the existing emission standards 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 1.2x their standard on the chassis FTP.[22] Calculated using Table 7-8, the weighted average of the Class 2b, Class 3, MDPV, and engine standards is 0.181.[J] To account for the real world performance of these vehicles, we related this average back to Tier 2 light duty vehicles, for which we have a significant amount of data from EPA's in-use verification program. Using the same tool that was used for developing the Tier 2 and Tier 3 light duty emission rates, we modeled MOVES Regulatory Class 41 in 2022 as 90 percent Bin 5 and 10 percent Bin 8 vehicles.[K] For the phase-in years of 2017-2021, we calculated new MOVES rates as a weighted average of the Tier 3 rates and the existing MOVES rates for regulatory class 41 such that the appropriate weighted composite was calculated each year Table 7-9.

[J] Due to a calculation error, an NMOG+ NO_X standard of 0.177 was used for Regulatory Class 41. As a result, a slightly different phase-in of the NMOG+NO_X and CO rates was used in the proposal modeling. This error overstates the NMOG+ NO_X reductions for this vehicle class by approximately 2.5% in 2022.

[K] 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.

Table 7-9 Phase-in of MD Tier 3 Rates

Model Year	Tier 3 Rate	MOVES DB Rates	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 grams per bhp multiplied by 1.2),[23] and for the Tier 3 MD vehicles, the standard ranges from 4.2 to 7.3 g/mile. Using the same weighted averages as before, we calculated an aggregate CO standard of 4.4 grams/mile, 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.

Like in the light duty vehicles, deterioration 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 MD HC/CO/NO$_X$

For medium duty diesel vehicles, the emission rates currently in MOVES are significantly below the proposed 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$_X$ standard will produce a reduction in diesel Class 2b and Class 3 NO$_X$ emissions. Because data on current NO$_X$ emissions are limited, as there is little in-use data on MY 2010 and 2011 vehicles which use selective catalytic reduction as a NO$_X$ control strategy, we used a proportional approach to estimate the Tier 3 effect, reducing NO$_X$ in proportion to the change in the emission standard. Because emission standards 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 7-10. Also, to account for the change in “useful life”, we duplicated the Tier 3 age 0-3 NO$_X$ rates to the 4-5 year age-group.

Table 7-10 Phase-in of MD Diesel Tier 3 NO_X Rates

Model Year	Tier 3 Phase In	Reduction in NO_X Running Emission Rate	Reduction in NO_X 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 $PM_{2.5}$

Tier 3 will reduce direct particulate matter ($PM_{2.5}$) emissions from light-duty vehicles through a full-useful life (FUL) PM standard on the FTP of 3 mg/mi. Additionally, the Tier 3 standards will include more stringent SFTP PM standards for light-duty vehicles, with a 10 mg/mi standard on the US06 for light-duty passenger vehicles, and 20 mg/mi on the US06 for light-duty trucks. These standards are targeting several processes that contribute to particulate matter in light-duty gasoline vehicles: cold starts, high-power operation, and deterioration of engine and emission control technology over the life of the vehicle.

To achieve the FUL PM standards without sacrificing fuel economy, it is anticipated that manufacturers may try a variety of strategies including reducing lubrication oil consumption over the life of the vehicle.[L] For our analysis, we projected that reductions in lube oil consumption would reduce the organic carbon (OC) fraction of PM by 30 percent for both cold start and running emissions. These reductions are based on an analysis of the Kansas City Light-duty Vehicle Emissions Study, which collected PM emissions from a randomly recruited sample of vehicles in the Kansas City area in 2005. Using chemical tracers found in both the lube oil and the particulate samples, the lube oil contribution to PM was estimated to be 25 percent of the PM emissions, primarily from the OC fraction of PM. The 25 percent reduction is estimated by weighting the sample to represent the distribution of vehicle ages and vehicle types in the Kansas City Metropolitan Area in 2004.

From this analysis, a 30 percent OC reduction is projected in Tier 3 gasoline vehicles due to decreased lube oil consumption, which represents approximately a 25 percent PM reduction for gasoline vehicles during cold start and running emission processes. The modeling assumptions and overview of the Kansas City analysis are located in the *Supporting Technical*

[L] Since high oil consumption leads directly to elevated PM emissions, it is unlikely that manufacturers would be able to meet the proposed Tier 3 PM standards without addressing oil consumption over the full useful life of the vehicle.

Document: Estimated Reductions in Particulate Matter Emissions from Light-duty and Medium-duty Gasoline Vehicles through Implementation of Tier 3 Regulations.[24]

For the modeling runs described here, the OC reductions are anticipated to be phased-in over a four year period, with the full-implementation occurring in 2020. The OC reductions are 7.5 (2017), 15 (2018), 22.5 (2019), and 30 percent (2020). The percent reductions are applied to cold-start and running emission processes, to passenger car and truck sources, and to PM emissions as the vehicles age.

7.1.3.3.6 Diesel PM

The Tier 3 controls were modeled as having no impact on light duty diesel PM emissions.

7.1.3.3.7 Gasoline Evaporative Emissions

The proposed Tier 3 evaporative program, requiring lower emissions on the diurnal test procedure on E15 certification fuel and strengthened in-use detection of vapor leaks, is projected to cause a significant reduction in evaporative hydrocarbon emissions. For this analysis, tighter diurnal standards in conjunction with E15 certification fuel were attributed to reductions in evaporative permeation emissions, since the current certification standards are aimed at not allowing any vented vapor emissions during the test. The new requirements for in-use leak detection were modeled as resulting in a reduced prevalence (frequency rate) of fuel system vapor and liquid leaks.[M]

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 from 0.50 g/test to 0.300 g/test, approximately a 40 percent reduction.

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 E15 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 rate is developed by estimating permeation emissions over one day of diurnal activity (65F-105F) on an ethanol-containing fuel using various reductions in the base rate. 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).

[M] One of the updates to MOVES for this analysis was to enable direct input of the leak prevalence rates.

Table 7-11 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.[25,26] The proposed evaporative leak provisions grew from this work, and informed 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. Because the Colorado study was not able to distinguish leaks from other high evaporative emission sources in the broader population, we analyzed data from CRC's E-77 program and found that insufficient canister purge is also contributing to high evaporative emissions, as this causes the canisters to become oversaturated, venting vapor into the atmosphere.

Because the Colorado data suggested high evaporative emissions on newer vehicles as well as old, we assumed that the leak prevalence rates from the Colorado study included a degree of emissions from insufficient purge. Because insufficient purge would not be a function of age, we assume most (all but 1 percent) of the Colorado prevalence rates at age 0-3 are due to insufficient purge, which is assumed constant with age. The increase in high evaporative emissions incidence with age was then attributed to an increasing prevalence of leaks. This is illustrated in the chart to the left in Figure 7-10.

To model the control scenario, because the proposed leak requirement would only address leaks and not insufficient purge, only the leak portion of high evaporative emissions were reduced. Colorado data on a subset of vehicles that were selected for more detailed observation and testing suggested that 70 percent of the evaporative leaks detected were due to durability of the evaporative and/or fuel system – e.g. problems like corroded fuel lines, filler neck, cracked hoses etc. that could be addressed with improved durability (the other 30 percent were due to issues beyond the manufacturers control, such as improper maintenance or missing gas caps). We estimated that the leak program would lead to a 70 percent reduction in the occurrence of vapor leaks. This is reflected in the chart on the right in Figure 7-10; note that the emissions attributed to insufficient purge were not changed from the reference case.

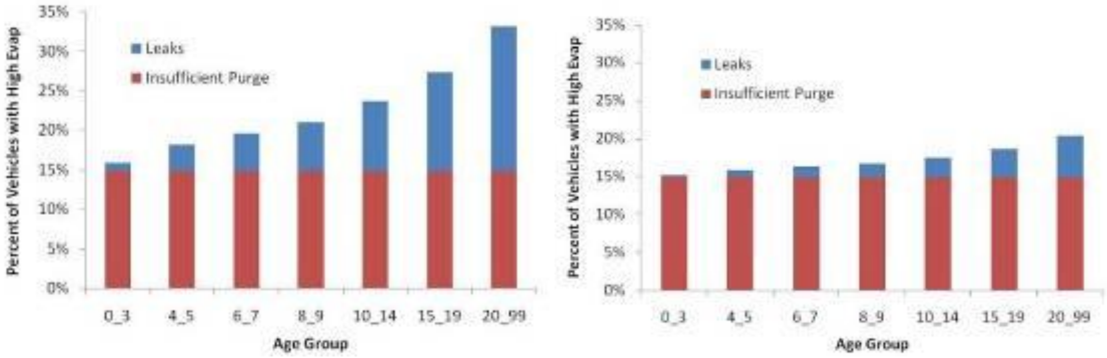


Figure 7-10 Vapor Leak Occurrence Assumed for Reference (Left) and Tier 3 (Right)

7.1.3.3.7.1 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 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 7-12 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 proposed sulfur standards, the version of MOVES used for this analysis made significant updates to the effect of fuel sulfur levels below 30ppm on exhaust emissions. In MOVES2010a these effects were based on extrapolation of data on sulfur levels above 30 ppm.[27] The updates made for this analysis were based on significant new data generated from EPA research conducted in 2010-11, summarized below. A draft report on this research is available in the docket.[28]

7.1.3.4.1 EPA Sulfur Research Program

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. 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.[29]

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_X, CO and total HC when the vehicles were tested on low sulfur fuel, relative to 32 ppm fuel.[30] In particular, the study found a nearly 50 percent increase in NO_X when sulfur was increased from 6 ppm to 32 ppm. Another recent study by Umicore showed reductions of 41 percent for NO_X and 17 percent for HC on a PZEV operating on fuel with 33 ppm and 3 ppm sulfur.[31] 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 the state of sulfur loading for the typical vehicle in field. In response, 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 81 cars and light trucks recruited from owners in southeast Michigan, covering model years 2007-9 with approximately 20,000-40,000 odometer miles. 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 fuel, one at a sulfur level of 5 ppm and the other at 28 ppm. A nominal concentration of approximately 25 ppm was targeted for the high level to be representative of retail fuel available to the public in the vehicle recruiting area. 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, and then 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_X and hydrocarbons (Table 7-11), suggesting that reversible sulfur loading exists in the in-use fleet and has a measurable effect on aftertreatment performance; for example, Bag 2 NO_X emissions dropped 32 percent between the pre- and post-cleanout tests on 28 ppm fuel.

Table 7-11 Average Clean-out Effect on In-use Emissions using 28 ppm Test Fuel

	NO_x (p-value)	THC (p-value)	CO (p-value)	NMHC (p-value)	CH_4 (p-value)	PM (p-value)
Bag 1	–	–	4.7% (0.0737)	–	–	15.4% (< 0.0001)
Bag 2	31.9% (0.0009)	16.5% (0.0024)	–	17.8% (0.0181)	15.3% (0.0015)	–
Bag 3	38.3% (<0.0001)	21.4% (<0.0001)	19.5% (0.0011)	27.8% (<0.0001)	12.0% (<0.0001)	24.5% (<0.0001)
FTP Composite	11.4% (<0.0001)	4.1% (0.0187)	7.6% (0.0008)	3.0% (0.0751)	6.9% (0.0003)	13.7% (<0.0001)
Bag 1 – Bag 3	–	–	4.2% (0.0714)	–	–	–

Where no reduction estimate is provided, the clean-out effect is not significant at $\alpha = 0.10$.

To assess the impact of lower sulfur fuel on in-use emissions, a representative subset of vehicles was kept to conduct testing on 28 ppm and 5 ppm fuel with accumulated mileage. A first step in this portion of the study was to assess differences in the effectiveness of the clean-out procedure when done using different fuel sulfur levels. Table 7-12 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_X emissions were 47 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.

Table 7-12 Reduction in emissions from 28 ppm to 5 ppm immediately following clean-out

	NO_x (p-value)	THC (p-value)	CO (p-value)	NMHC (p-value)	CH_4 (p-value)	PM[‡]
Bag 1	5.9% (0.0896)	5.4% (0.0118)	7.3% (0.0023)	4.6% (0.0465)	11.1% (<0.0001)	–
Bag 2	47.3% (0.0010)	40.2% (<0.0001)	–[‡]	34.4% (0.0041)	53.6% (<0.0001)	–
Bag 3	51.2% (<0.0001)	35.0% (<0.0001)	10.1% (0.0988)	45.0% (<0.0001)	25.4% (<0.0001)	–
FTP Composite	17.7% (0.0001)	11.2% (<0.0001)	8.3% (0.0003)	8.8% (0.0003)	21.4% (<0.0001)	–
Bag 1 – Bag 3	–[‡]	–[‡]	5.8% (0.0412)	–[‡]	–[‡]	–

[‡] Sulfur level 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 7-13; reductions for Bag 2 NO_X were particularly high, estimated at 59 percent between 28ppm and 5ppm overall For some pollutants, such as Bag 2 NO_X, 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. Other results, such as Bag 1 hydrocarbons, did show a significant miles-by-sulfur interaction. In this case, determination of a sulfur level effect for the in-use fleet required estimation of a miles-equivalent level of sulfur loading, which can be gleaned from the cleanout results obtained from the baseline testing on the vehicles as-received.

Table 7-13: In-use emission reductions from 28 to 5 ppm sulfur

	NO_X **(p-value)**	**THC (p-value)**	**CO (p-value)**	**NMHC (p-value)**	**CH_4 (p-value)**	**NO_x+NMOG (p-value)**	**PM** ‡
Bag 1	10.7% (0.0033)	8.5%† (0.0382)	7.5%† (0.0552)	7.5% (< 0.0001)	13.9%† (< 0.0001)	N/A	–
Bag 2	59.2% (< 0.0001)	48.8% (< 0.0001)	– ‡	44.8%† (0.0260)	49.9% (< 0.0001)	N/A	–
Bag 3	62.1% (< 0.0001)	40.2% (< 0.0001)	20.1% (< 0.0001)	49.9% (< 0.0001)	29.2% (< 0.0001)	N/A	–
FTP Composite	23.0%† (0.0180)	13.0%† (0.0027)	11.9%† (0.0378)	10.6%† (0.0032)	25.8%† (< 0.0001)	17.3% (0.0140)	–
Bag 1 – Bag 3	– ‡	5.2% (0.0063)	4.3% (0.0689)	5.1% (0.0107)	4.6% (0.0514)	N/A	–

† Model with significant sulfur and mileage interaction term. ‡ Sulfur level not significant at $\alpha = 0.10$. For THC Bag 1 and CH_4 Bag 1, because the effect of clean-out was not statistically significant, the reduction estimates are based on the estimates of least squares means.

Major findings from this study include:

- Reversible sulfur loading is occurring in the in-use fleet of Tier 2 vehicles and has a measureable effect on emissions of NO_X, 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 28 to 5 ppm is expected to achieve significant reductions in emissions of NO_X, hydrocarbons, and other pollutants of interest in the in-use fleet.

The overall reductions found in this study are in agreement with other low sulfur studies conducted on Tier 2 vehicles. The magnitude of NO_X and HC reductions found in this study when switching from 28 ppm to 5 ppm fuel are consistent with those found in MSAT and Umicore studies mentioned above.

7.1.3.4.2 Implementation in MOVES

The results shown in Table 7-13 were applied in MOVES for model year 2004 and later gasoline vehicles (the nominal start of the Tier 2 phase-in) to estimate sulfur effects below 30 ppm. The sulfur fuel effect applies multiplicatively to other gasoline fuel effects in MOVES, and applies only for sulfur levels below 30ppm. For sulfur levels above 30 ppm, and for all pre-

2004 model year vehicles, the sulfur effect originally used in MOVES remains in place. Equation 7-3 shows the generic form of the new sulfur correction; Table 7-14 shows the specific values for the sulfur coefficients by pollutant, process, and vehicle type.

$$sulfur\ effect = \left[1.0 - Coeff_{sulfur} * (30 - sulfurLevel)\right]$$

Equation 7-3 Low Sulfur Effect

Table 7-14 Low Sulfur Coefficients by Vehicle Type, Process and Pollutant

Vehicle Type	**THC**		**CO**		**NO_X**		**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	0.002237	0.020336	0.001866	0	0	0.024459	0	0
All other Vehicle Types	0	0.015488	0	0.009436	0	0.027266	0	0

These equations were then used to fill in the database table that houses fuel effect equations in the MOVES database (“GeneralFuelRatioExpression”). This table allows the MOVES model to compute fuel effects based on the fuel properties of any fuel contained in the fuel supply and fuel formulation database tables.

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 proposed Tier 3 regulation are the emissions from gasoline-powered equipment such as lawn-mowers, recreational boats and all-terrain vehicles. Their SO_2 emissions are reduced with the proposed decrease in gasoline sulfur levels. As with onroad, reference and control case emissions were generated using the fuel supply inputs reflecting the post-EISA/EPAct renewable fuel volumes.

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).[32] The fuels in the NMIM database, NCD2010201Tier 3, were developed from the reference and control fuels used for onroad vehicles, as described in Section 7.1.3. In 2005, onroad and nonroad gasoline formulations are assumed to be identical. In 2017, E10 and E15 ethanol blends are available in every county, but nonroad equipment is assumed to use E10 only. In 2030, we assume almost all nonroad equipment can use either E10 or E15, so onroad and nonroad gasoline formulations are again assumed to be identical. For all years, the reference case included the higher sulfur reference gasoline and the control case met the proposed sulfur limits.

Since aircraft, locomotive and commercial marine emission sources do not burn gasoline, their emission factors are unaffected by the 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 they were for the Heavy-Duty Greenhouse Gas Rule (2011)[33]. The procedures for calculating emissions from locomotives and C1/C2 commercial marine were developed for the Locomotive Marine Rule (2008) and are detailed in the RIA for that rule.[34] The procedures used for calculating C3 commercial marine emissions are those developed in the recent C3 Rule (2010).[35]

7.1.5 Criteria and Toxic Emission Impact Results

The proposed Tier 3 rule will reduce NO_X (including NO_2), VOC, CO, and SO_2 from all gasoline-powered on road vehicles immediately upon implementation of lower sulfur fuel, and will further reduce these emissions as well as $PM_{2.5}$ 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_2 emissions from the nonroad gasoline fleet as a result of sulfur standards. The reductions are summarized in this section for each pollutant.

NO_X reductions are shown in Table 7-15 for Calendar Years 2017 through 2030, and 2050 when the fleet will have turned over completed to Tier 3 standards. We project significant reductions immediately upon implementation of the program, growing to a nearly 30 percent reduction in onroad emissions by 2030, and nearly 40 percent reduction in onroad emissions with full fleet turnover by 2050.

Table 7-15 Tier 3 NO_X Reductions by Calendar Year (Annual U.S. Short Tons)

Year	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2017	3,452,314	3,167,934	284,381	8.2%
2018	3,179,942	2,890,474	289,469	9.1%
2019	2,942,238	2,646,150	296,088	10.1%
2020	2,732,380	2,429,517	302,863	11.1%
2021	2,557,573	2,241,209	316,364	12.4%
2022	2,427,305	2,091,971	335,335	13.8%
2023	2,304,619	1,950,687	353,932	15.4%
2024	2,196,463	1,823,335	373,128	17.0%
2025	2,115,326	1,717,083	398,244	18.8%
2026	2,040,468	1,617,809	422,659	20.7%
2027	1,989,071	1,540,270	448,801	22.6%
2028	1,942,891	1,469,181	473,710	24.4%
2029	1,913,717	1,413,482	500,234	26.1%
2030	1,890,403	1,365,613	524,790	27.8%
2050	2,410,373	1,507,204	903,170	37.5%

Table 7-16 shows the reduction in NO_X emissions, in annual short tons, projected in calendar years 2017 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 2017 over 90 percent of the program reductions are coming from lower sulfur gasoline on the fleet already on the road. By 2030, nearly 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.[N] We project that about one tenth of the reductions from the Tier 3 fleet in 2030 are attributable to the proposed Tier 3 heavy-duty emission standards.

Table 7-16 Projected NO_X Reductions from Tier 3 Program (Annual U.S. Short Tons)

	2017	**2030**
Total reduction	**284,381**	**524,790**
Reduction from pre-Tier 3 fleet due to sulfur standard	*264,653*	*66,286*
Reduction from Tier 3 fleet due to vehicle and sulfur standards	*19,728*	*458,504*

VOC reductions are shown in Table 7-17 for Calendar Years 2017 through 2030, and 2050 when the fleet will have turned over completed to Tier 3 standards. We project reductions of over 40,000 tons (3 percent of the onroad fleet emissions) immediately upon implementation of the program, growing to a 23 percent reduction in onroad emissions by 2030, and 36 percent reduction in onroad emissions with full fleet turnover by 2050.

[N] This is an approximate breakdown, as there will be some NO_X 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

Table 7-17 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
2017	1,614,384	1,569,603	44,782	2.8%
2018	1,506,001	1,456,342	49,659	3.3%
2019	1,411,787	1,356,874	54,913	3.9%
2020	1,333,867	1,272,497	61,370	4.6%
2021	1,266,250	1,195,112	71,138	5.6%
2022	1,211,710	1,128,740	82,970	6.8%
2023	1,163,986	1,067,208	96,778	8.3%
2024	1,123,476	1,012,446	111,029	9.9%
2025	1,084,012	955,680	128,332	11.8%
2026	1,045,808	899,298	146,509	14.0%
2027	1,025,657	858,927	166,730	16.3%
2028	1,004,922	818,008	186,913	18.6%
2029	988,529	781,665	206,863	20.9%
2030	977,067	751,040	226,028	23.1%
2050	1,151,908	735,548	416,361	36.1%

Table 7-18 shows the VOC reductions in 2017 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 proposed exhaust and evaporative standards. In 2017 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 about one quarter of the Tier 3 fleet reductions in 2030.

Table 7-18 Projected VOC Reductions from Tier 3 Program (Annual U.S. Short Tons)

	2017	**2030**
Total reduction	**44,782**	**226,028**
Reduction from pre-Tier 3 fleet due to sulfur standard	39,561	13,739
Reduction from Tier 3 fleet due to vehicle and sulfur standards	5,222	212,289
Exhaust	*41,433*	*168,264*
Evaporative	*3,349*	*57,764*

CO reductions are shown in Table 7-19 for Calendar Years 2017 through 2030, and 2050 when the fleet will have turned over completed to Tier 3 standards. We project significant reductions immediately upon implementation of the program, growing to a 30 percent reduction in onroad emissions by 2030, and 46 percent reduction in onroad emissions with full fleet turnover by 2050.

Table 7-19 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
2017	20,915,593	20,168,910	746,683	3.6%
2018	20,297,089	19,454,190	842,899	4.2%
2019	19,782,476	18,830,656	951,820	4.8%
2020	19,374,712	18,295,010	1,079,702	5.6%
2021	19,122,796	17,747,325	1,375,471	7.2%
2022	18,830,157	17,119,383	1,710,775	9.1%
2023	18,736,417	16,610,543	2,125,874	11.3%
2024	18,647,649	16,095,479	2,552,170	13.7%
2025	18,647,177	15,584,593	3,062,585	16.4%
2026	18,621,982	15,054,696	3,567,286	19.2%
2027	18,699,029	14,558,766	4,140,263	22.1%
2028	18,745,355	14,047,003	4,698,352	25.1%
2029	18,850,303	13,594,884	5,255,420	27.9%
2030	18,951,626	13,186,263	5,765,362	30.4%
2050	24,839,365	13,339,791	11,499,574	46.3%

Table 7-20 shows the reductions for CO, broken down by pre- and post-Tier 3 in the manner described for NO_X and VOC above. The immediate reductions in the onroad fleet from sulfur control comprise about 80 percent of total reductions in 2017. By 2030, the proposed vehicle standard, enabled by low sulfur fuel, are accounting for 98 percent of program reductions. Of the Tier 3 vehicle standard reductions in 2030, we estimate that about 5 percent are contributed by the proposed heavy-duty tailpipe standards.

Table 7-20 CO Reductions from Tier 3 Program (Annual U.S. Short Tons)

	2017	**2030**
Total reduction	**746,683**	**5,765,362**
Reduction from pre-Tier 3 fleet due to sulfur standard	608,502	139,074
Reduction from Tier 3 fleet due to vehicle and sulfur standards	138,181	5,626,288

Direct $PM_{2.5}$ impacts are shown in Table 7-21 for calendar years 2017 through 2030, and 2050 when the fleet will have turned over completed to Tier 3 standards. For direct PM, the impact shown is solely from the proposed 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 7,500 tons annually, which represents approximately 10 percent of the onroad direct $PM_{2.5}$ inventory. However, since the PM standards are mainly focused on improving engine durability through the end of a vehicle's useful life, the relative reduction in onroad emissions is projected to grow to 17 percent with full fleet turnover in 2050.

As discussed in Section 7.2.1.1, the control scenario emissions inventory prepared for air quality modeling included the impact of an increase in aromatics as sulfur is reduced from 30 ppm to 10 ppm fuel. While this assumption had a minor effect on control case emissions for several pollutants, the effect was more visible for direct $PM_{2.5}$ emissions, as it resulted in a projected increase in emissions (roughly 700 tons nationwide) in 2017. As discussed in Section 7.1.3.2.2, this emissions increase results from a series of conservative assumptions and uncertainties related to fuel parameters in 2017, and is not expected to occur in reality. As a result, we have not included the PM emissions increase from sulfur reduction in the emission inventory impacts shown in Table 7-21.

Table 7-21 Tier 3 $PM_{2.5}$ Reductions by Calendar Year (Annual U.S. Short Tons)

CY	Onroad mobile reference	Onroad mobile with control	Reduction	Percent reduction in onroad
2017	115,098	114,977	121	0.1%
2018	107,295	106,932	362	0.3%
2019	100,885	100,162	724	0.7%
2020	95,192	93,992	1,200	1.3%
2021	90,480	88,767	1,713	1.9%
2022	85,144	82,943	2,201	2.6%
2023	81,859	79,081	2,778	3.4%
2024	78,955	75,561	3,393	4.3%
2025	76,935	72,890	4,045	5.3%
2026	75,204	70,502	4,702	6.3%
2027	73,880	68,496	5,384	7.3%
2028	72,504	66,431	6,073	8.4%
2029	71,990	65,210	6,780	9.4%
2030	71,554	64,096	7,458	10.4%
2050	92,895	77,279	15,616	16.8%

Emissions of air toxics also would be reduced by the proposed 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 7-22 presents reductions for certain gaseous air toxics and polycyclic aromatic hydrocarbons (PAHs)[O], reflecting reductions of a few percent in 2017, and 20 to 40 percent of onroad emissions, depending on the individual pollutant, in 2030.

Table 7-22 Reductions for Certain Individual Compounds (Annual U.S. Short Tons)

	2017	Percent reduction	2030 Reduction	Percent reduction

[O] PAHs represents the sum of the following 15 PAH compounds: acenaphthene, acenaphthalene, anthracene, benz(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benze(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).

	Reduction	in onroad		in onroad
Acetaldehyde	762	3%	4,414	26%
Formaldehyde	727	3%	2,707	12%
Acrolein	23	1%	184	15%
1,3-Butadiene	322	5%	1,087	37%
Benzene	1,625	4%	8,581	36%
Naphthalene	96	2%	420	17%
Ethanol	2,684	2%	27,821	24%
2,2,4-Trimethylpentane	840	2%	5,616	18%
Ethyl Benzene	724	3%	3,204	22%
Hexane	857	3%	3,525	30%
Propionaldehyde	29	2%	102	20%
Styrene	98	4%	755	38%
Toluene	3,504	3%	16,965	22%
Xylene	2,856	3%	14,238	22%
PAHs	7	1%	67	17%

The totals shown in Table 7-23 represent the sum of all toxic species in Table 7-22. As shown, in 2030 the overall on-road inventory of total toxics would be reduced by over 20 percent, with nearly one third of the vehicle program reductions coming from the proposed evaporative standards.

Table 7-23 Reductions in Total Mobile Source Air Toxics (Annual U.S. Short Tons)

	2017	**2030**
Total reduction	**15,156**	**89,685**
Reduction from pre-Tier 3 fleet due to sulfur standard	13,184	5,022
Reduction from Tier 3 fleet due to vehicle and sulfur standards	1,972	84,663
Exhaust	*13,748*	*64,144*
Evaporative	*1,408*	*25,541*

SO_2 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_2 from the on and off-road fleet. The reductions, shown in Table 7-24, represent a roughly 50 percent reduction in onroad SO_2 emissions. The breakdown of the relative contribution of on-road 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.[36]

Table 7-24 Projected SO_2 Reductions from Tier 3 Program (Annual U.S. Short Tons)

	2017	**2030**
Total reduction	**16,261**	**17,267**
Reduction from onroad vehicles due to sulfur standard	15,494	16,370
Reduction from off-road equipment due to sulfur standard	767	897
Percent reduction in onroad SO_2 emissions	**51%**	**51%**

7.2 Criteria and Toxic Pollutant Air Quality Impacts

7.2.1 Emission Inventories for Air Quality Modeling

To estimate the benefits of the proposed Tier 3 rule, we performed air quality modeling for the years 2017 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.[37]

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. While modeling at this level is time-consuming and resource intensive, this 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 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.

We used the same approach to model both the reference and the control cases, except, for the Tier 3 control case, we used the Tier 3 emission rates and fuels developed for the national inventories and described in Section 7.1.3.

Because of differences in methodology, particularly the treatment of vehicle speed distributions and the 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. The two sets of results are compared in Table 7-25 below.

Table 7-25 Comparison of Calendar Year 2030 Onroad Emission National Inventories and Inventories Used for Air Quality Modeling [U.S. Short tons]

	Reference			Control		
Pollutant	National Inventory	Air Quality Inventory	Difference AQ vs. NI	National Inventory	Air Quality Inventory	Difference AQ vs. NI
NO_X	1,890,403	1,846,571	-2%	1,365,613	1,371,925	0%
VOC	977,067	911,513	-7%	751,040	699,592	-7%
CO	18,951,626	17,021,674	-10%	13,186,263	11,984,061	-9%
$PM_{2.5}$	71,554	88,516	24%	64,917	83,842	29%
Benzene	23,654	22,221	-6%	15,073	14,352	-5%
Ethanol	107,912	116,762	8%	80,091	89,574	12%
Acrolein	1,223	863	-29%	1,039	699	-33%
1,3-Butadiene	2,915	2,932	1%	1,828	1,955	7%
Formaldehyde	21,967	14,810	-33%	19,260	12,270	-36%
Acetaldehyde	16,757	13,926	-17%	12,343	9,946	-19%
SO_2	31,983	30,526	-5%	15,613	15,068	-3%

The differences between the national inventories and air quality inventories reflect the non-linear response to the more detailed handling of temperature and other local variables such as speed in the air quality inventory; this is pronounced in pollutants with strong temperature sensitivities in MOVES, such as $PM_{2.5}$, where the finer temperature resolution in the air quality approach produced significantly higher emissions than the aggregate national inventory approach.

Because the reference and control case emissions rates were the same for the national inventory and air quality inventory runs, the percent reductions due to the proposed Tier 3 rule are very similar, as shown in Table 7-26. The exception is $PM_{2.5}$, where the air quality inventory shows a slight increase in emissions in 2017. As discussed in Section 7.1.3.2.2, this increases resulted from a series of conservative assumptions and uncertainties related to fuel parameters in 2017 which we do not expect to occur in reality.

Table 7-26 Comparison of Emission Reductions from Reference to Control Case in "National" and "Air Quality" Onroad Inventories

	2017		2030	
Pollutant	National Inventory Reduction	Air Quality Inventory Reduction	National Inventory Reduction	Air Quality Inventory Reduction
NO_X	-8%	-7%	-28%	-26%
VOC	-3%	-3%	-25%	-23%
CO	-4%	-3%	-30%	-30%
$PM_{2.5}$	-0.1%	1%	-10%	-5%
Benzene	-4%	-4%	-36%	-35%
Ethanol	-3%	-2%	-26%	-23%
Acrolein	-1%	-1%	-15%	-19%
1,3-Butadiene	-5%	-5%	-37%	-33%
Formaldehyde	-2%	-3%	-12%	-17%
Acetaldehyde	-3%	-3%	-26%	-29%
SO_2	-51%	-50%	-51%	-51%

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 rare. 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 done detailed modeling for some counties and less detailed estimates for the other counties.

In this approach, we group counties that have similar properties that would result in similar emission rates. 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.

More specifically, the representing counties are chosen so they can be used to compute g/mi factors that will be representative across the group of counties. To assure this, the counties are grouped based on 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 7-27 below.

Table 7-27 Characteristics for Representing County Groupings

County Grouping Characteristic	Description
PADD	Petroleum Administration for Defense Districts (PADDs). PADD 1 is divided into three sub-PADD groupings and each sub-group is treated as a separate PADD (1a, 1b and 1c). Each state belongs to a PADD and all counties in any state are within the same PADD.
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).

The result is a set of 106 county groups with similar fuel, emission standards, altitude and I/M programs. For each group, the county with the highest VMT was chosen as the representing county. Of these, only 103 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.[38]

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.[39] 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 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,[40]

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. For a given scenario, this resulted in over 16,000 run specification files. A series of post-processing scripts were developed to take the raw MOVES emission rate table results and translate it 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. Note, an update to these post-processing scripts was made between the reference case and control case runs, which inadvertently introduced a small inconsistency in emission rates between reference and control for about one-third of the counties. Specifically, there were 1,218 counties, out of 3,109 total counties, which were impacted. The result was that for some counties, control case emission rates were a few percent higher than they should have been; fixing this error would increase the magnitude of reduction in the air quality analysis.[41]

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.

7.2.1.1.1 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, age distributions, and inspection-maintenance programs for each of the representing counties. The source data for each of these inputs is described below.

7.2.1.1.1.1 Temperature and Humidity

Ambient temperature can have a large impact on emissions. Cold 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. And, of course, the interaction between emissions and ambient temperatures is an important consideration in air quality modeling. Thus accurately accounting for ambient temperatures was important for our air quality modeling work.

The gridded meteorological input data for the entire year of 2005 were derived from simulations of the Pennsylvania State University / National Center for Atmospheric Research Mesoscale Model.[42] This model, commonly referred to as MM5, is a limited-area, nonhydrostatic, terrain-following system that solves for the full set of physical and thermodynamic equations which govern atmospheric motions. A description of how this tool was used to determine temperatures is found in the documentation for the recent Heavy-Duty Greenhouse Gas rule.[43]

SMOKE-MOVES uses the MM5 temperatures and the county groups described in Section 7.2.1.1.1 to generate a list of all the possible temperatures and temperature profiles that are needed in the lookup tables. (Temperature profiles are vectors of 24 temperatures that describe how temperatures change over a day. They are needed to estimate vapor venting emissions.) To do this, SMOKE-MOVES determines the minimum and maximum temperatures in the county group for January and for July, and the minimum and maximum temperatures for each hour of the day. It then generates a list of all possible temperatures between these limits, using a five degree Fahrenheit interval. The model also uses these temperatures (using a 10 degree interval) to develops a collection of possible temperature profiles.

SMOKE-MOVES then runs MOVES for each of the listed temperatures and temperature profiles, generating emission rate look-up tables that cover the desired temperature ranges. Finally, the original grid cell temperatures are used to find the appropriate emission rate for each cell. The 2005 temperatures were used for all scenarios.

The treatment of humidity is simpler. SMOKE-MOVES calculates an average day-time (6am to 6pm) relative humidity for the county group for July and for January. The appropriate (July or January) humidity is used for all runs of the county group.

7.2.1.1.1.2 Vehicle Population Inputs

Vehicle population data is a required input for MOVES when modeling on a county basis. Using the technical guidance provided to states by EPA, a contractor generated appropriate estimates for vehicle populations 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" (EPA-420-B-10-023, April 2010), which is available on the EPA web site at: http://www.epa.gov/otaq/models/moves/index.htm

7.2.1.1.1.3 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 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 NEI.[44] These inputs were then converted to a format consistent with MOVES.

7.2.1.1.2 Parallel Processing on the "Cloud"

Providing the level of detail desired for the air quality modeling required an enormous amount of data. Even with the "representing county" approach, we ran MOVES over 83,000 times to support Tier3 rule making. Processing just one of the Tier 3 scenarios required 16,604 runs, which if run serially would take over 200 days. Early on, we recognized that this would be infeasible, even with the fastest computers available to us. Therefore, we developed a Linux-based environment at Amazon Web Services that enabled us to process the Tier 3 base case in less than 48 hours. We split the 16,604 runs into 206 batches (103 representative counties, for January and July). We then ran 206 Linux processor instances in parallel, with each instance processing 80 - 120 individual MOVES runs.

7.2.1.1.3 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.

VMT by county and Source Classification Code (SCC) was developed using MOVES2010a and the National County Database. MOVES2010a has the EPA's most recent projections of VMT growth at the national level, based on estimates from the Annual Energy Outlook[45]. The National County Database (NCD20101201)[46] has our most recent estimates of 2005 VMT and our best estimates of allocation of VMT from national to the county level. Accordingly, for the 2005 base year, our estimates of VMT by county and SCC were taken directly from the NCD. For the 2017 and 2030 inventories, we ran MOVES2010a with default inputs to generate total national VMT by SCC. But, because MOVES uses a static (1999) default allocation of VMT to county, we did not use MOVES for these allocations. Instead, the 2017 county VMT was created by interpolating between the NCD VMT values for 2015 and those for 2020 and computing the NCD fraction for each county, then multiplying these fractions by the MOVES VMT. The 2030 county allocation was computed similarly, using the NCD VMT for 2030. The VMT was also adjusted to account for increased onroad transportation of ethanol fuels and the resulting increase in travel by large tanker trucks. For both the reference and control scenarios, impacts of this activity on emissions from tank trucks (Class 8) are accounted by adjusting VMT used in SMOKE-MOVES.[47] The VMT adjustments were derived from the Oak Ridge National Laboratory analysis of ethanol transport, scaled to account for the ethanol volumes. Nationwide impacts of this adjustment on VMT are small – less than 0.03 percent of total diesel truck VMT in 2017, and less than 0.05 percent in 2030.

Vehicle populations by county and SCC were developed similarly to the VMT, using MOVES to generate national totals for each year and using the NCD to allocate to county. However, the NCD does not include population estimates, so we used MOVES to generate the 2005 national population and we assumed that, for each calendar year (2005, 2017 and 2030) and for each SCC, the allocation of national vehicle population to county was proportional to the allocation of VMT (summed across roadtypes).

The average speeds provided to SMOKE for each county were derived from the default national average speed distributions found in the default MOVES2010a database AvgSpeedDistribution table. These average speeds are the average speeds developed for the previous EPA highway vehicle emission factor model, MOBILE6.[48] 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.[49]

Table 7-28 Comparison of Calendar Year 2030 Nonroad Emission National Inventories and Inventories Used for Air Quality Modeling [U.S. Short tons]

	Reference			Control		
Pollutant	National Inventory	Air Quality Inventory	Difference	National Inventory	Air Quality Inventory	Difference
NO_X	765,026	765,026	0.0%	765,026	765,026	0.0%
VOC	1,209,534	1,209,534	0.0%	1,209,452	1,209,452	0.0%
CO	12,921,772	12,921,772	0.0%	12,921,772	12,921,772	0.0%
$PM_{2.5}$	68,308	68,308	0.0%	68,308	68,308	0.0%
Benzene	23,246	23,390	0.6%	23,245	23,389	0.6%
Acrolein	571	570	-0.2%	571	570	-0.2%
1,3-Butadiene	1,772	1,774	0.1%	1,772	1,774	0.1%
Formaldehyde	13,580	13,522	-0.4%	13,580	13,522	-0.4%
Acetaldehyde	7,899	7,888	-0.1%	7,899	7,888	-0.1%
SO_2	3,154	3,154	0.0%	2,257	2,257	0.0%

7.2.1.3 Refueling

7.2.1.3.1 Methodology

This section describes how the emission inventories for refueling from on-road vehicles in calendar years 2017 and 2030 for Tier 3 reference and control cases were generated for air quality modeling. The refueling inventory includes emissions from spillage loss and displacement vapor loss. The displacement emissions vary from scenario to scenario depending on the RVP of the modeled fuels. For this analysis, the refueling emissions were estimated using the revised version of EPA's Motor Vehicle Emissions Simulator (MOVES2010a) at the county level for all twelve months. We used the same fuel supply inputs as we used for the onroad inventories described in Section 7.1.3.2.

As for onroad emissions, described above, we used a "representing county" approach to reduce MOVES runtime. Additional information on the use of representing counties to model refueling emissions is available in a technical support document.[50]

7.2.1.3.2 Emission Inventory Results

The annual refueling emission inventories for air quality modeling for the lower 48 states are shown in Table 7-29, along with the percent changes between the two scenarios. The Tier 3 proposal to eliminate the RVP waiver for E10 fuels reduces refueling emissions in 2017, but has no impact in 2030, where we model E15 as the only gasoline available for onroad vehicles in both the reference and control cases.

Table 7-29 Refueling Emissions for Tier 3 reference and control (U.S. Short Tons)

	2017			**2030**		
	Reference	**Control**	**Percent Reduction**	**Reference**	**Control**	**Percent Reduction**
VOC	75,397	74,235	-1.5%	56,405	56,402	0.0%
Benzene	158	160	1.6%	90	90	0.0%
Ethanol	8,582	8,426	-1.8%	7,143	7,142	0.0%

7.2.1.4 Portable Fuel Container and Upstream Emissions

The Tier 3 proposed rule has no impact on portable fuel container (PFC) emissions. The proposed 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 proposed 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 proposed Tier 3 standards on upstream or PFC emissions a significant number of modifications were made to the 2005v.4.2 platform inventory to account for impacts of renewable fuel requirements under EISA in the reference case air quality inventory. These modifications are described in detail in a memorandum to the docket.[51] Modifications to point and nonpoint inventories include adjustments to agricultural emissions, 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 increased 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.[P] 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. We recently created a number of new hydrocarbon speciation profiles for vehicle exhaust and evaporative emissions and headspace vapor. These profiles were created using data from the EPAct test program,[52] CRC's E-77 series of evaporative emissions programs described in Section 7.2 above,[53,54] and recent measurements of speciated gasoline headspace vapors collected by EPA's Office of Research and Development (ORD).[55] Mobile source hydrocarbon speciation profiles used in this analysis are listed in a memo to the docket.[56]

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) 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 $PM_{2.5}$ concentrations, 24-hour $PM_{2.5}$ concentrations, annual NO_2 concentrations, air toxics concentrations, visibility levels and nitrogen and sulfur deposition levels for 2017 and 2030. The 2005-based CMAQ modeling platform was used as the basis for the air quality modeling for this proposed rule. This platform represents a structured system of connected modeling-related tools and data that provide a consistent and transparent basis for

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[P] For more information, please see the website for SMOKE: http://www.smoke-model.org/index.cfm.

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 2005. 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.[57,58,59] The CMAQ model version 4.7 was most recently peer-reviewed in February of 2009 for the U.S. EPA.[Q] The CMAQ model is a well-known and well-respected tool and has been used in numerous national and international applications.[60,61,62] This 2005 multi-pollutant modeling platform used the most recent CMAQ code available at the time of air quality modeling (CMAQ version 4.7.1[R]) with a minor internal change made by the U.S. EPA CMAQ model developers intended to speed model runtimes when only a small subset of toxics species are of interest.

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 v4.7.1 which reflects updates to version 4.7 to improve the underlying science. These include aqueous chemistry mass conservation improvements, improved vertical convective mixing and lowered CB05 mechanism unit yields for acrolein from 1,3-butadiene tracer reactions which were updated to be consistent with laboratory measurements. Section 7.2.3 of this draft 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 two 12 km grids (an Eastern U.S. and a Western U.S. domain), as shown in Figure 7-11. The modeling domain contains 14 vertical layers with the top of the modeling domain at about 16,200 meters, or 100 millibars (mb) of atmospheric pressure.

[Q] Allen, D., Burns, D., Chock, D., Kumar, N., Lamb, B., Moran, M. (February 2009). Report on the Peer Review of the Atmospheric Modeling and Analysis Division, NERL/ORD/EPA. U.S. EPA, Research Triangle Park, NC., http://www.epa.gov/amad/peer/2009_AMAD_PeerReviewReport.pdf.

[R] CMAQ version 4.7 was released on December, 2008. It is available from the Community Modeling and Analysis System (CMAS) as well as previous peer-review reports at: http://www.cmascenter.org.

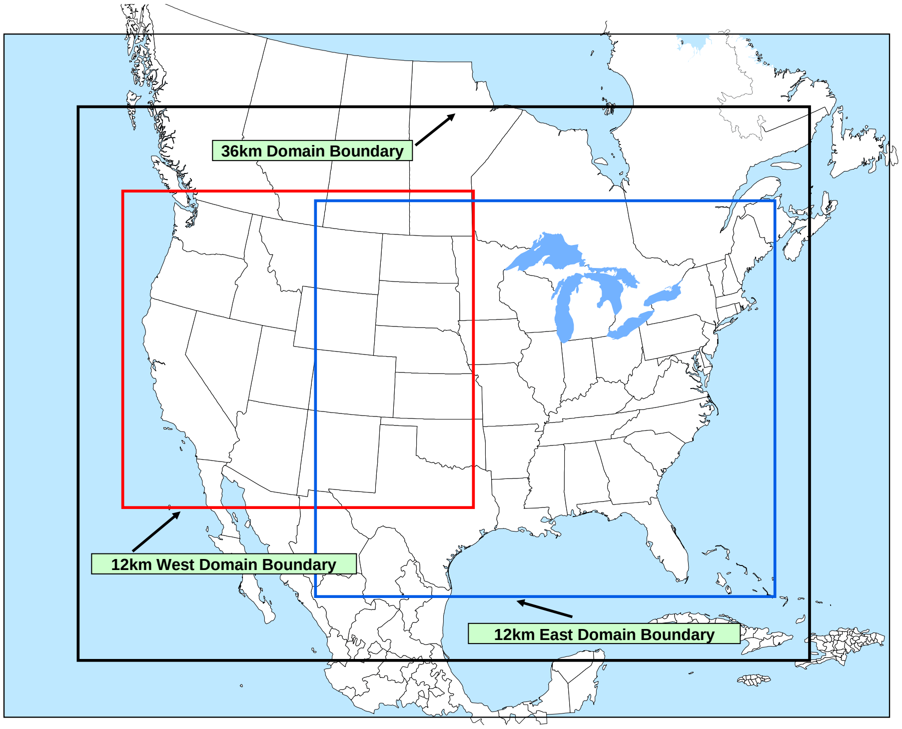

Figure 7-11 Map of the CMAQ Modeling Domain

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 Pennsylvania State University/National Center for Atmospheric Research Mesoscale Model[63] for the entire year of 2005 over model domains that are slightly larger than those shown in Figure 7-11. This model, commonly referred to as MM5, is a limited-area, nonhydrostatic, terrain-following system that solves for the full set of physical and thermodynamic equations which govern atmospheric motions.[64] The meteorology for the national 36 km grid and the two 12 km grids were developed by EPA and are described in more detail within the AQM TSD. The meteorological outputs from MM5 were processed to create model-ready inputs for CMAQ using the Meteorology-Chemistry Interface Processor (MCIP) version 3.4. 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.[65]

The lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry model, the GEOS-CHEM model.[66] 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 2005 with a grid resolution of 2 degree x 2.5 degree (latitude-longitude) and 20 vertical layers. 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 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 2005 base year and each of the future year base cases and control scenarios analyzed for this rule are summarized in Section 7.2.1 of this draft RIA.

7.2.2.4 CMAQ Evaluation

An operational model performance evaluation for ozone, $PM_{2.5}$ 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 2005 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 the following geographic groupings: domain wide, Eastern vs. Western (divided along the 100th meridian), and each Regional Planning Organization (RPO) region.[S] The "acceptability" of model performance was judged by comparing our results to those found in recent regional $PM_{2.5}$ model applications for other, non-EPA studies.[T] Overall, the performance for the 2005 modeling platform is within the range or close to that of these other applications. The performance of the CMAQ modeling was evaluated over a 2005 base case. The model was able to reproduce historical concentrations of ozone and $PM_{2.5}$ 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 2005 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 $PM_{2.5}$ concentrations, annual NO_2 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:

- 2005 base year
- 2017 Tier 3 reference case
- 2017 Tier 3 control case
- 2030 Tier 3 reference case

[S] Regional Planning Organization regions include: Mid-Atlantic/Northeast Visibility Union (MANE-VU), Midwest Regional Planning Organization – Lake Michigan Air Directors Consortium (MWRPO-LADCO), Visibility Improvement State and Tribal Association of the Southeast (VISTAS), Central States Regional Air Partnership (CENRAP), and Western Regional Air Partnership (WRAP).

[T] 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.

- 2030 Tier 3 control case

The emission inventories used in the air quality and benefits modeling are different from the proposed 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 draft 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 2005 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 $PM_{2.5}$ concentrations, annual NO_2 concentrations and visibility impairment for each of the 2017 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., 2003-2007).

The projected daily and annual $PM_{2.5}$ 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 $PM_{2.5}$ and its non-carbon components. This characterization of $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ species components: sulfates, nitrates, ammonium, organic carbon mass, elemental carbon, crustal, water, and blank mass (a fixed value of 0.5 $\mu g/m^3$). More complete details of the SMAT procedures can be found in the report "Procedures for Estimating Future $PM_{2.5}$ Values for the CAIR Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT)".[67] 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.[68] The projected 8-hour ozone design values were calculated using the approach identified in EPA's guidance on air quality modeling attainment demonstrations.[69]

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, and acrolein, as well as 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_X, VOC, CO, $PM_{2.5}$, SO_2, NH_3, and seven air toxics: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, ethanol, naphthalene and acrolein. The air toxics are explicit model species in the CMAQv4.7 model with carbon bond 5 (CB05) mechanisms.[70] 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 EPAct data.[71] 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.[72]

Complete combustion of ethanol in fuel produces carbon dioxide (CO_2) and water (H_2O). 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_2 and formation of nitric acid (HNO_3) without PAN formation.[U]

$$NO_2 + \cdot OH + M \rightarrow HNO_3 + M \qquad k = 1.19 \times 10^{-11}\ cm^3 molecule^{-1} s^{-1}$$ [73]

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

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[U] All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

alkenes, alkanes, and aromatics. Alternate reactions of acetyl peroxy radical, such as oxidation of NO to form NO_2, which again leads to ozone formation, are also included.

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_2 to form the acetyl peroxy radical [$CH_3C(O)OO\cdot$].[V] When NO_X 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_2), to produce PAN [$CH_3C(O)OONO_2$]. An overview of these reactions and the corresponding reaction rates are provided below.[W]

$\mathbf{CH_3CHO} + \cdot OH \rightarrow CH_3C\cdot O + H_2O$ $k = 1.5 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [74]

$CH_3C\cdot O + O_2 + M \rightarrow \mathbf{CH_3C(O)OO\cdot} + M$

$\mathbf{CH_3C(O)OO\cdot} + \boldsymbol{NO} \rightarrow CH_3C(O)O\cdot + \boldsymbol{NO_2}$ $k = 2.0 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [75]

$CH_3C(O)O\cdot \rightarrow \cdot CH_3 + CO_2$

$\cdot CH_3 + O_2 + M \rightarrow CH_3OO\cdot + M$

$CH_3OO\cdot + NO \rightarrow CH_3O\cdot + NO_2$

$CH_3O\cdot + O_2 \rightarrow \mathbf{HCHO} + HO_2$

$\mathbf{CH_3C(O)OO\cdot} + NO_2 + M \rightarrow \mathbf{CH_3C(O)OONO_2} + M$ $k = 1.0 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [76]

Acetaldehyde can react with the NO_3 radical, ground state oxygen atom (O_3P) and chlorine, although these reactions are much slower. Acetaldehyde can also photolyze (hν), which predominantly produces $\cdot CH_3$ (which reacts as shown above to form $CH_3OO\cdot$) and HCO (which rapidly forms HO_2 and CO):

$\mathbf{CH_3CHO} + h\nu + 2\ O_2 \rightarrow CH_3OO\cdot + HO_2 + CO$ $\lambda = 240\text{-}380\ nm$ [77]

As mentioned above, $CH_3OO\cdot$ 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

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[V] 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).

[W] All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

atmospheric lifetimes of approximately 3 hours and 13 hours, respectively.[78] Formaldehyde can also react with NO_3 radical, ground state oxygen atom (O_3P) and chlorine, although these reactions are much slower. Formaldehyde is removed mainly by photolysis whereas the higher 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_2), which can lead to ozone formation and regenerate OH radicals.

$$\mathbf{HCHO} + h\nu + 2\,O_2 \rightarrow 2\,HO_2 + CO \qquad \lambda = 240\text{-}360\text{ nm}$$ [79]

$$HO_2 + NO \rightarrow NO_2 + OH$$

Photolysis of HCHO can also proceed by a competing pathway which makes only stable products: H_2 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[80,81] 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.[82]

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 ($O^3(P)$), hydroxyl radical (OH), or nitrate radicals. The reaction rates are based on expert recommendations,[83] and the photolysis rate is from IUPAC recommendations.

In CMAQ v4.7, 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_3). 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. 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 peroxyproprional 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_3CH_2OH) 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).[84] This reaction produces acetaldehyde (CH_3CHO) with a 90 percent yield.[85] 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. [X]

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_2), and the remainder of the reaction occurs at the –CH3 and –OH groups, creating formaldehyde (HCHO), oxidizing NO to NO_2 (represented by model species XO_2) and creating glycoaldehyde, which is represented as ALDX:

$$CH_3CHOH + OH \rightarrow HO_2 + 0.90\ CH_3CHO + 0.05\ ALDX + 0.10\ HCHO + 0.10\ XO_2$$

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 4.7, based on recommendations of Edney et al. and the recent work of Carlton et al.[86, 87] In previous versions of CMAQ, all SOA was semivolatile and resulted from the oxidation of compounds emitted entirely in the gas-phase. In CMAQ v4.7, parameters in existing pathways were revised and new formation mechanisms were added. Some of the new pathways, such as low-NO_X oxidation of aromatics and particle-phase oligomerization, result in nonvolatile SOA.

Organic aerosol 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 organic aerosol (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 $PM_{2.5}$ during the summer (but less in the winter).[88,89] A wide range of laboratory studies conducted over the past twenty years show that anthropogenic aromatic hydrocarbons and long-chained alkanes, along with biogenic isoprene, monoterpenes, and sesquiterpenes, contribute to SOA formation.[90,91,92,93,94] Modeling studies, as well as carbon isotope measurements, indicate that a significant fraction of SOA results from the oxidation of biogenic hydrocarbons.[95,96] 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.[97]

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

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[X] All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

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, currently accounting for almost 40 percent of anthropogenic VOC,[98] mobile sources are also an important source of SOA, particularly in populated areas.

Toluene is an important contributor to anthropogenic SOA. Mobile sources are the most significant contributor to ambient toluene concentrations as shown by analyses done for the 2005 National Air Toxics Assessment (NATA)[99] and the Mobile Source Air Toxics (MSAT) Rule.[100] The 2005 NATA indicates that onroad and nonroad mobile sources accounted for almost 60 percent (1.46 $\mu g/m^3$) of the total average nationwide ambient concentration of toluene (2.48 $\mu g/m^3$), 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-NO_X pathways is expected to be less volatile and be produced in higher yields than SOA from high-NO_X conditions. [101] Alkanes form SOA with higher yields resulting from the oxidation of longer chain as well as cyclic alkanes.[102]

It is unlikely that ethanol would form directly from SOA or affect SOA formation indirectly through changes in the radical populations from 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.[103] The experiments were conducted under conditions where peroxy radical reactions would dominate over reaction with NO (i.e., irradiations performed in the absence of 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 would be potentially made. As expected, no SOA was produced. From these experiments, the upper limit for the aerosol yield would have been less than 0.01 percent based on scanning mobility particle sizer (SMPS) data. Given the expected negative result based on these initial smog chamber experiments, these data were not published.

In general, measurements of organic aerosol 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.[104,105] 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 primary organic aerosol (POA) from the measured OC concentration.[106] 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 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 compositional data from the precursors has largely prevented the identification of aromatically-derived SOA in ambient samples which, in turn, has prevented observation-based measurements of the aromatic and other SOA contributions to ambient PM levels.

As a first step in determining the ambient SOA concentrations, EPA has developed a tracer-based method to estimate such concentrations.[107,108] 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_X, 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.[109,110,111,112]

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 $PM_{2.5}$ samples are two tracer compounds that have been identified in smog chamber aromatic SOA samples.[113] 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 this way. It is possible that these unstudied compounds produce SOA species which are being used as tracers for other VOCs. This means that the present work could overestimate 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 biogenic hydrocarbons. 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 also been used to estimate monthly ambient aromatic SOA concentrations from March 2004 to February 2005 in five U.S. Midwestern cities.[114] The annual tracer-based SOA concentration estimates were 0.15, 0.18, 0.13, 0.15, and 0.19 μg 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 μg/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.[115]

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.[116, 117, 118, 119, 120,121,122] Studies have indicated that ambient OC levels may be underestimated by current model parameterizations.[123] While the treatment of new precursors has likely reduced the model/measurement bias, underestimates can persist.[124] 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.[125,126]

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 NO_X sources. PAN is a reservoir and carrier of NO_X and is the product of acetyl radicals reacting with 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.[Y] PAN can undergo thermal decomposition with a lifetime of approximately 1 hour at 298K or 148 days at 250K.[Z]

[Y] 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

$\mathbf{CH_3C(O)OONO_2} + M \rightarrow CH_3C(O)OO\cdot + \mathbf{NO_2} + M$ $k = 3.3 \times 10^{-4}\ s^{-1}$ [127]

The reaction above shows how NO_2 is released in the thermal decomposition of PAN, along with a peroxy radical which can oxidize NO to NO_2 as previously shown in Section 7.2.3.1. NO_2 can also be formed in photodegradation reactions where NO is converted to NO_2 (see OH radical reaction of acetaldehyde in Section 7.2.3.1). In both cases, NO_2 further photolyzes to produce ozone (O_3).

$\mathbf{NO_2} + h\nu \rightarrow NO + O(^3P)$ $\lambda = 300\text{-}800\ nm$ [128]

$O(^3P) + O_2 + M \rightarrow \mathbf{O_3} + M$

The temperature sensitivity of PAN allows it to be stable enough at low temperatures to be transported long distances before decomposing to release NO_2. NO_2 can then participate in ozone formation in regions remote from the original NO_X source.[129] A discussion of CB05 mechanisms for ozone formation can be found in Yarwood et al. (2005).[130]

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 two molecules of either hydroperoxy radical or methylperoxy radical, both of which oxidize NO to NO_2 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 4.7.1. Pollutants such as ozone, PM, acetaldehyde, formaldehyde, acrolein, and 1,3-butadiene 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. 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.[131]

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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.).

[Z] All rate coefficients are listed at 298 K and, if applicable, 1 bar of air.

7.2.4 Impacts of the Proposed Rule on Air Quality

Air quality modeling performed for this proposed rule estimates the changes in ambient concentrations of $PM_{2.5}$, ozone and NO_2, as well as changes in ambient concentrations of ethanol and the following air toxics: acetaldehyde, acrolein, benzene, 1,3-butadiene, and formaldehyde. The air quality modeling results also include changes in deposition of nitrogen and sulfur and changes in visibility levels due to this proposed rule.

This section describes current ambient levels of the modeled pollutants and presents the projected future ambient levels resulting from the proposed rule.

7.2.4.1 Ozone

As described in Section 6.2.1 of this draft 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 Levels of Ozone

Figure 7-12 shows a snapshot of measured ozone concentrations in 2010. The highest ozone concentrations were located in California.

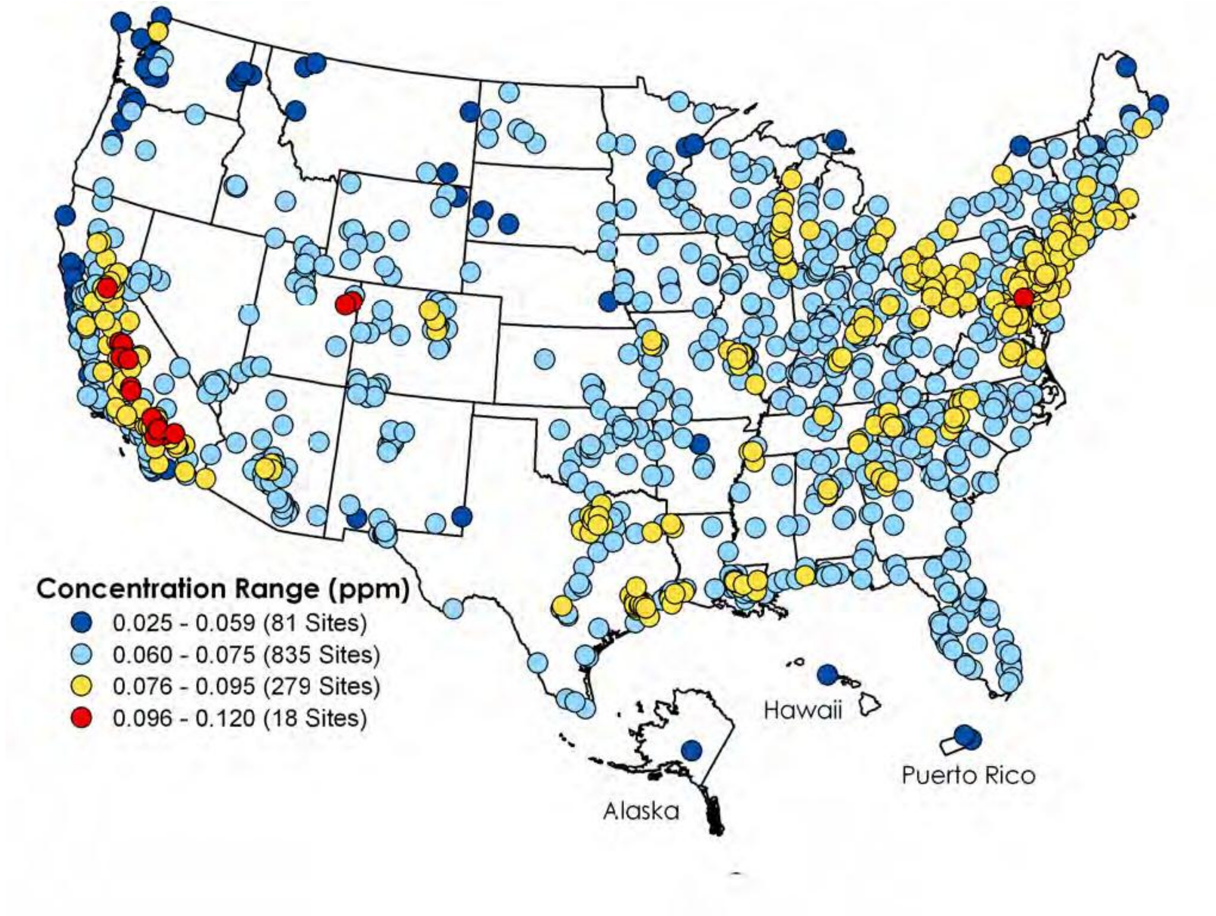


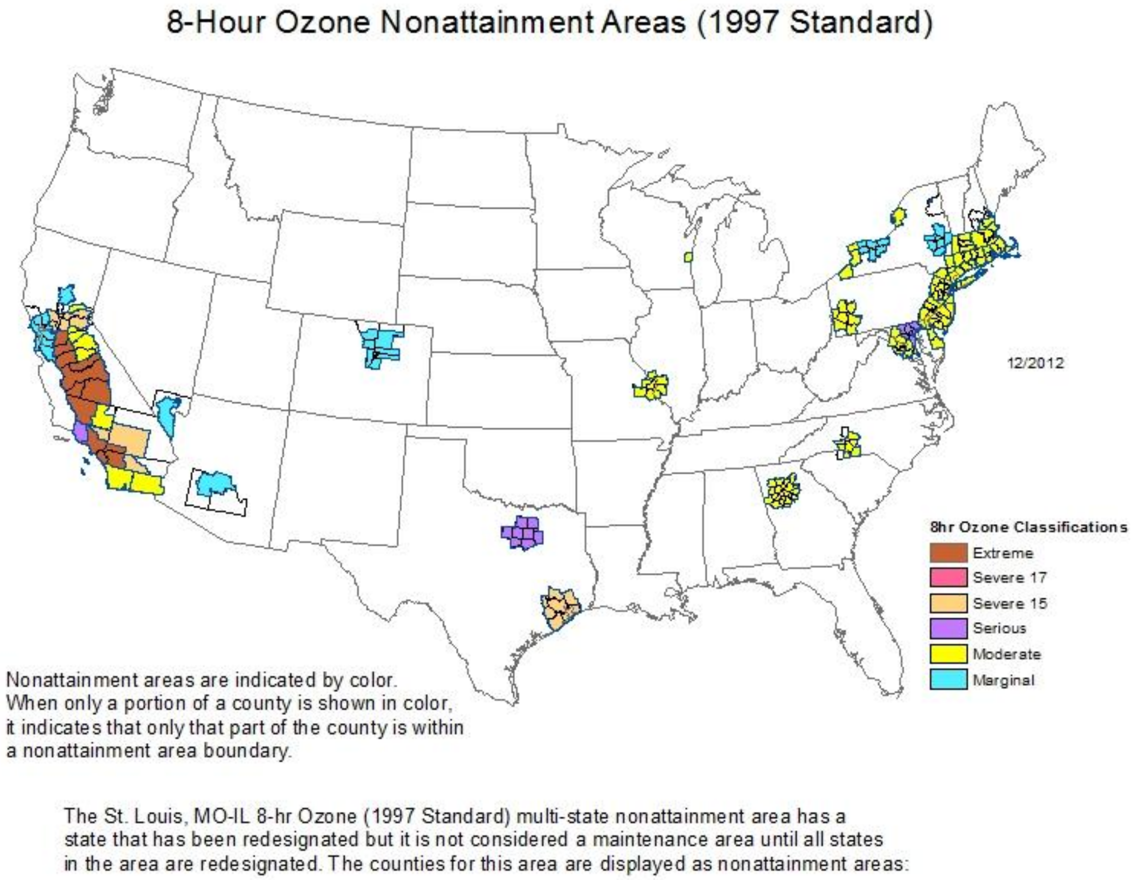
Figure 7-12 Ozone Concentrations (fourth highest daily maximum 8-hour concentration) in ppm for 2010[AA]

The primary and secondary NAAQS for ozone are 8-hour standards set at 0.075 ppm. The most recent revision to the ozone standards was in 2008; the previous 8-hour ozone standards, set in 1997, had been set at 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).[BB] As of December 14, 2012, there were 41 8-hour ozone nonattainment areas for the 1997 ozone NAAQS, composed of 221 full or partial counties, with a total population of over 129 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.[132] These designations include 46 areas, composed of 227 full or partial counties, with a population of over 123 million. Nonattainment areas for the 2008 ozone NAAQS are pictured in Figure 7-14. As of December 14, 2012, over 138 million people are living in ozone nonattainment areas.[CC]

[AA] 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/.

[BB] 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.

[CC] The 138 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



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 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:

Figure 7-13 1997 8-hour Ozone Nonattainment Areas

(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.

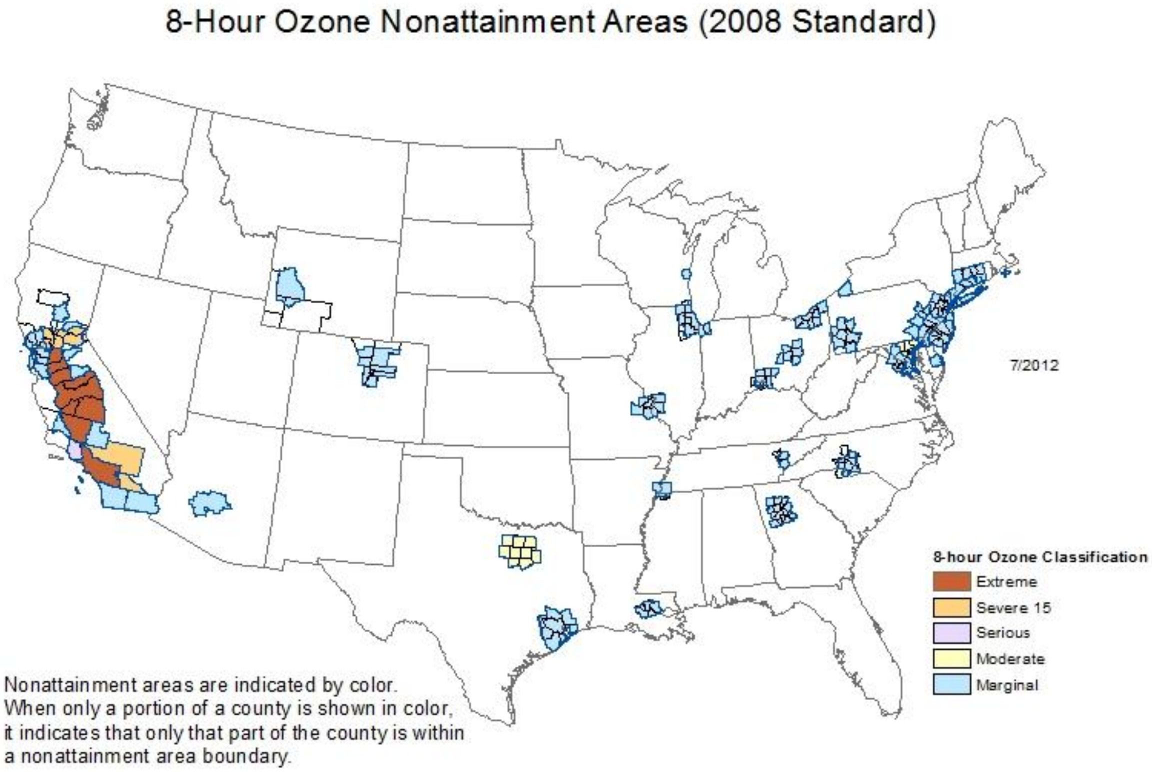


Figure 7-14 2008 8-hour Ozone Nonattainment Areas

States with ozone nonattainment areas are required to take action to bring those areas into attainment in the future. The attainment date assigned to an ozone nonattainment area is based on the area's classification. Most ozone nonattainment areas are required to attain the 1997 8-hour ozone NAAQS in the 2007 to 2013 time frame and then to maintain it thereafter.[DD] 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 working to complete the current review of the ozone NAAQS by mid-2014. If EPA revises the ozone standards in 2014 pursuant to that review, the attainment dates associated with areas designated nonattainment for that NAAQS would likely be in the 2019 to 2036 timeframe, depending on the severity of the problem in each area.

7.2.4.1.2 Projected Levels of Ozone Without this Proposed Rule

EPA has already adopted many mobile source emission control programs that are expected to reduce ambient ozone levels. These control programs include the New Marine

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[DD] 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.

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 2017, with all current controls in effect but excluding the emissions changes expected to occur as a result of this proposed action or any other additional controls, at least 40 counties, with a projected population of almost 50 million people, would 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 12 counties with a population of almost 32 million people that would 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 proposal 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 proposed standards.

7.2.4.1.1 Projected Levels of Ozone With this Proposed Rule

This section summarizes the results of our modeling of ozone air quality impacts in the future with the proposed standards. Specifically, for the years 2017 and 2030 we compare a reference scenario (a scenario without the proposed standards) to a control scenario that includes the proposed standards. Our modeling indicates that ozone design value concentrations will decrease dramatically in many areas of the country as a result of this proposal and in some places those decreases will be enough to move the projected design values from being above the NAAQS to being below the NAAQS. Additional information on the emissions reductions that are projected with this final action is available in Section 7.2.1 of this draft RIA.

Figure 7-15 and Figure 7-16 present the changes in 8-hour ozone design value concentrations in 2017 and 2030 respectively. Note that the projected results for 2017 do not include California, while the projected results for 2030 do.[EE] This issue does not have a significant impact on the AQ modeling results for the rest of the country.

[EE] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-

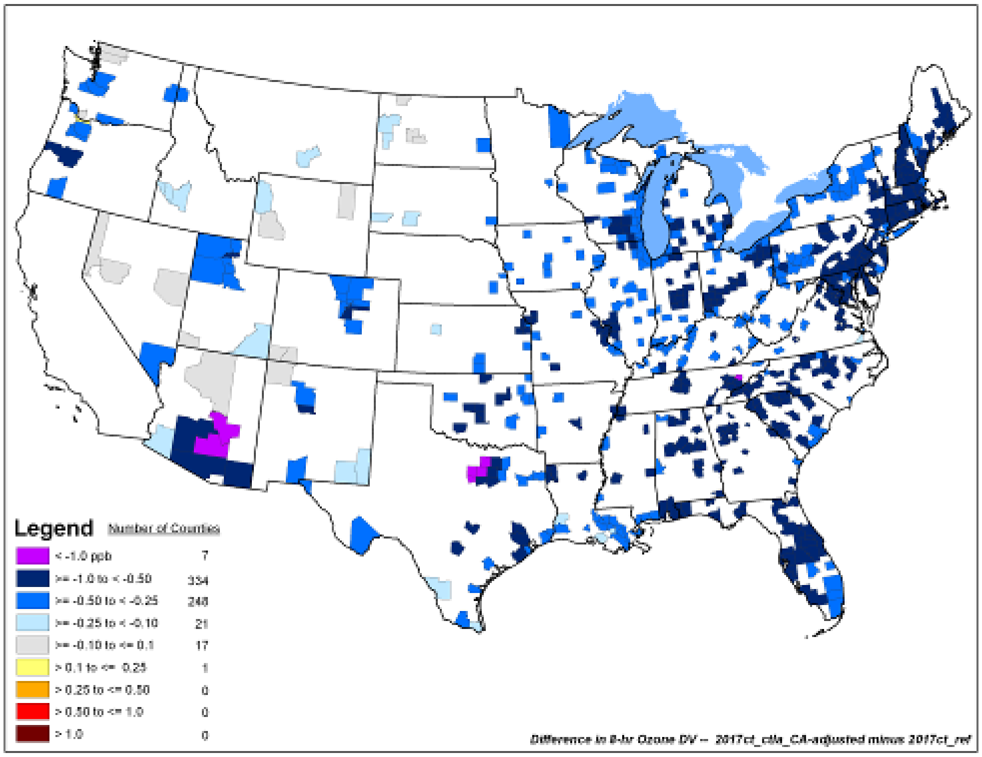

Figure 7-15 Projected Change in 2017 8-hour Ozone Design Values Between the Reference Case and Control Case

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19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases..

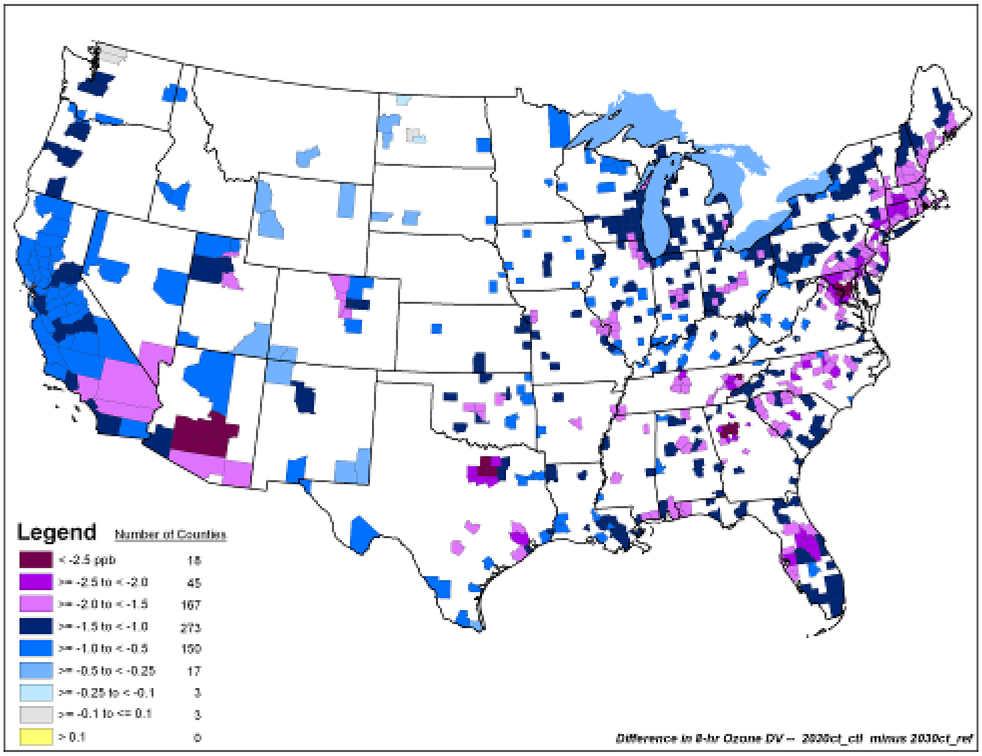


Figure 7-16 Projected Change in 2030 8-hour Ozone Design Values Between the Reference Case and Control Case

As can be seen in Figure 7-15, the majority of the design value decreases in 2017 are between 0.5 and 1.0 ppb. The projected population-weighted average design value concentration without the proposed rule is 71.3 ppb in 2017. There are also 7 counties with projected 8-hour ozone design value decreases of more than 1 ppb; these counties are in Arizona, Texas and Tennessee. The maximum projected decrease in an 8-hour ozone design value in 2017 is 1.09 ppb in Tarrant County, Texas near Dallas, which is projected to be above the ozone standard. Figure 7-16 presents the ozone design value changes for 2030. The projected population-weighted average design value concentration without the proposed rule is 66.7 ppb in 2030. In 2030 the ozone design value decreases are larger than in 2017; most decreases are projected to be between 1.0 and 1.5 ppb, and over 200 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 3.2 ppb in Maricopa County, Arizona, where Phoenix is located.

Table 7-30 and Table 7-31 show the average change, due to this proposed rule, in 2017 and 2030 8-hour ozone design values for: (1) all counties with 2005 baseline design values, (2) counties with 2005 baseline design values that exceeded the 2008 ozone standard, (3) counties with 2005 baseline design values that did not exceed the 2008 standard, but were within 10 percent of it, (4) counties with 2017/2030 design values that exceeded the 2008 ozone standard, and (5) counties with 2017/2030 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 2017 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 0.47 ppb in 2017 and 1.55 ppb in 2030. On a population-weighted basis, design values in those counties that are projected to be above the 2008 ozone standard in 2017 and 2030 are projected to decrease by 0.30 and 1.62 ppb respectively due to the proposed standards.

Table 7-30 Average Change in Projected 8-hour Ozone Design Value in 2017

Average[a]	Number of U.S. Counties	2020 Population	Change in 2017 design value (ppb)
All	676	238,026,106	-0.50
All, population-weighted			-0.47
Counties whose 2005 base year is violating the 2008 8-hour ozone standard	393	176,910,535	-0.56
Counties whose 2005 base year is violating the 2008 8-hour ozone standard, population-weighted			-0.51
Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard	201	40,516,171	-0.47
Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.42
Counties whose 2017 control case is violating the 2008 8-hour ozone standard	37	47,659,433	-0.35
Counties whose 2017 control case is violating the 2008 8-hour ozone standard, population-weighted			-0.30
Counties whose 2017 control case is within 10 percent of the 2008 8-hour ozone standard	124	68,625,934	-0.51
Counties whose 2017 control case is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-0.49

Notes:

[a] Averages are over counties with 2005 modeled design values.

[b] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

Table 7-31 Average Change in Projected 8-hour Ozone Design Value in 2030

Average[a]	Number of U.S. Counties	2030 Population	Change in 2030 design value (ppb)
All	676	261,497,900	-1.35
All, population-weighted			-1.55
Counties whose 2005 base year is violating the 2008 8-hour ozone standard	393	194,118,748	-1.54
Counties whose 2005 base year is violating the 2008 8-hour ozone standard, population-weighted			-1.69
Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard	201	44,436,103	-1.18
Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-1.25
Counties whose 2030 control case is violating the 2008 8-hour ozone standard	10	30,619,714	-1.49
Counties whose 2030 control case is violating the 2008 8-hour ozone standard, population-weighted			-1.62
Counties whose 2030 control case is within 10 percent of the 2008 8-hour ozone standard	40	21,541,863	-1.37
Counties whose 2030 control case is within 10 percent of the 2008 8-hour ozone standard, population-weighted			-1.50

Notes:

[a] Averages are over counties with 2005 modeled design values

[b] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

There are still 12 counties, most of them in California, that are projected to have 8-hour ozone design values above the 2008 NAAQS in 2030 without the proposed standards or any other additional controls in place. Table 7-32 below presents the changes in design values for these counties.

Table 7-32 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[a]
San Bernardino, California	-1.91	2,784,490
Riverside, California	-1.68	2,614,198
Los Angeles, California	-1.68	10,742,722
Kern, California	-1.00	981,806
Orange, California	-1.13	4,431,071
Harris, Texas	-2.05	5,268,889
Tulare, California	-1.00	528,663
Suffolk, New York	-1.33	1,705,822
Fresno, California	-1.15	1,196,950
Harford, Maryland	-1.91	365,103
Brazoria, Texas	-1.96	364,257
Hudson, New Jersey	-0.88	747,407

Note:

[a] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

The proposed rule would also reduce ozone design values in some counties from above the level of the standard to below it. In 2017, ozone design values in three counties (Bucks County in Pennsylvania, Arlington County in Virginia and St Louis County in Missouri) move from being above the standard to below. The projected population in these three counties in 2017 is almost 2 million people. There are two more counties whose design values would be reduced from above the standard to below by the proposed rule in 2030. These counties are Hudson County in New Jersey and Brazoria County in Texas. The projected population in these two counties in 2030 is over 1 million people.

In terms of modeling accuracy, the count of modeled nonattainment counties is much less certain than the average changes in air quality. For example, actions by states to meet their SIP obligations would not be expected to significantly change the overall concentration changes induced by this final rule, but they could substantially change the number of counties in or out of attainment. If state actions resulted in an increase in the number of areas that are very close to, but still above, the NAAQS, then this rule might bring many of those counties down sufficiently to change their attainment status. On the other hand, if future state actions brought several counties we project to be very close to the standard into attainment status, then the air quality improvements from this rule might change the actual attainment status of very few counties. Bearing this limitation in mind, our modeling indicates that the emission reductions from this proposed rule will decrease the number of ozone nonattainment counties by 3 in 2017 and by 2 in 2030, without consideration of new state or local programs.

As described in Section 6.1.2.1 of this draft 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 proposed fuel and vehicle standards. This change in ozone results from interactions between photochemistry, background concentrations of VOC and NO_X, local emissions and meteorology.

There is one county in 2017 that is projected to have an increase in modeled ozone design value concentration (Multnomah County, Oregon, where Portland is located). When NO_X levels are relatively high and VOC levels relatively low, NO_X forms inorganic nitrates (*i.e.*, particles) but relatively little ozone. Such conditions are called "NO_X-saturated." Under these conditions, VOC reductions are effective in reducing ozone, but NO_X reductions can actually increase local ozone under certain circumstances. We believe that this is the case in Multnomah County, Oregon in 2017. In 2030, when the fleet would be composed of vehicles meeting the new standards and the NO_X 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 6.2.2 of this draft 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 Levels of PM

Figure 7-17 and Figure 7-18 respectively show a snapshot of annual and 24-hour $PM_{2.5}$ concentrations in 2010. In 2010, the highest annual average $PM_{2.5}$ concentrations were in California, Indiana, Pennsylvania and Hawaii and the highest 24-hour $PM_{2.5}$ concentrations were in California and Alaska.

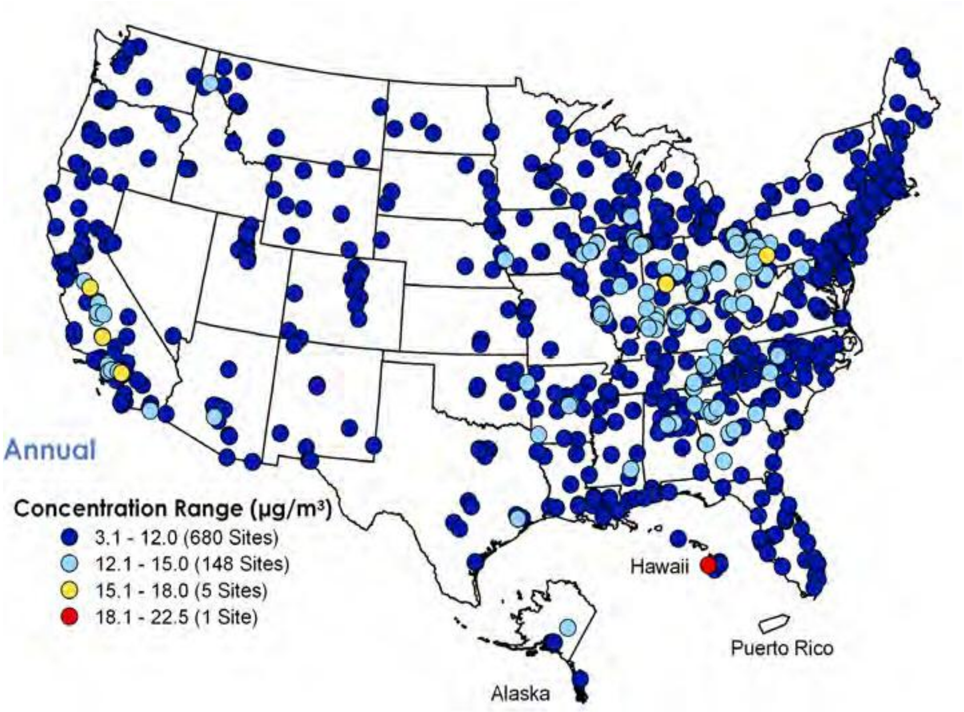


Figure 7-17 Annual Average $PM_{2.5}$ Concentrations in µg/m^3 for 2010[FF]

[FF] 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/.

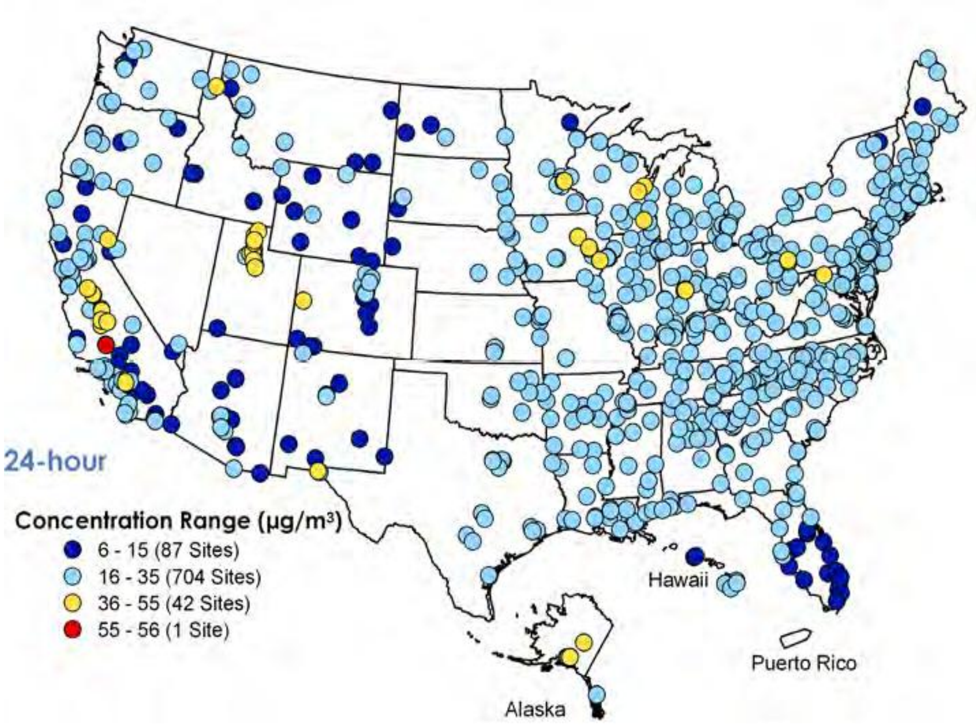


Figure 7-18 24-hour (98th percentile 24- hour concentrations) $PM_{2.5}$ Concentrations in µg/m³ for 2010[GG]

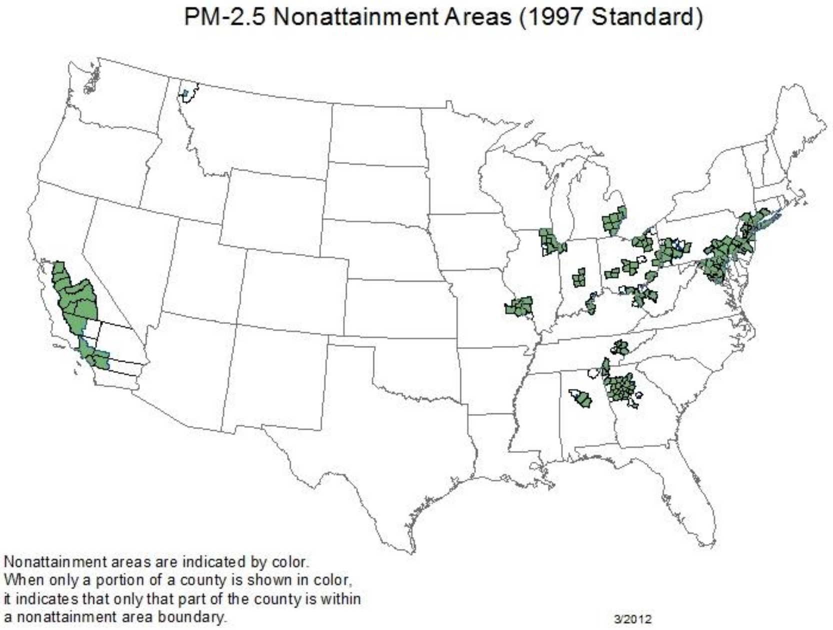
There are two NAAQS for $PM_{2.5}$: an annual standard (12.0 µg/m³) and a 24-hour standard (35 µg/m³). The most recent revisions to these standards were in 1997, 2006 and in December 2012. The December 2012 rule revised the level of the annual $PM_{2.5}$ standard from 15 µg/m³ to 12 µg/m³.[133]

In 2005 the U.S. EPA designated nonattainment areas for the 1997 $PM_{2.5}$ NAAQS (70 FR 19844, April 14, 2005). As of December 14, 2012, over 91 million people lived in the 35 areas that are designated as nonattainment for the 1997 $PM_{2.5}$ NAAQS. These $PM_{2.5}$ nonattainment areas are comprised of 191 full or partial counties. Nonattainment areas for the 1997 $PM_{2.5}$ NAAQS are pictured in Figure 7 19. EPA anticipates making attainment/nonattainment designations for the 2012 $PM_{2.5}$ NAAQS by December 2014, with those designations likely becoming effective in early 2015.[134] On October 8, 2009, the EPA issued final nonattainment area designations for the 2006 24-hour $PM_{2.5}$ NAAQS (74 FR 58688, November 13, 2009). These designations include 32 areas composed of 121 full or partial counties, with a population of over 70 million. Nonattainment areas for the 2006 $PM_{2.5}$ NAAQS are pictured in Figure 7 20. In total, there are 50 $PM_{2.5}$ nonattainment areas with a population of over 105 million people.[HH]

[GG] 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/.

[HH] Data come from Summary Nonattainment Area Population Exposure Report, current as of December 14, 2012 at: http://www.epa.gov/oar/oaqps/greenbk/popexp.html and contained in Docket EPA-HQ-OAR-2011-0135.

States with $PM_{2.5}$ nonattainment areas will be required to take action to bring those areas into attainment in the future. Most 1997 $PM_{2.5}$ nonattainment areas are required to attain the 1997 $PM_{2.5}$ NAAQS in the 2009 to 2014 time frame and then required to maintain the 1997 $PM_{2.5}$ NAAQS thereafter.[135] The 2006 24-hour $PM_{2.5}$ nonattainment areas will be required to attain the 2006 24-hour $PM_{2.5}$ NAAQS in the 2015 to 2019 time frame and then be required to maintain the 2006 24-hour $PM_{2.5}$ NAAQS thereafter.[136] 2012 $PM_{2.5}$ nonattainment areas will likely be required to attain the 2012 $PM_{2.5}$ NAAQS in the 2021 to 2025 time frame, depending on the severity of an area's fine particle pollution problems and the availability of pollution controls.



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.

3/2012

Figure 7-19 1997 $PM_{2.5}$ Nonattainment Areas

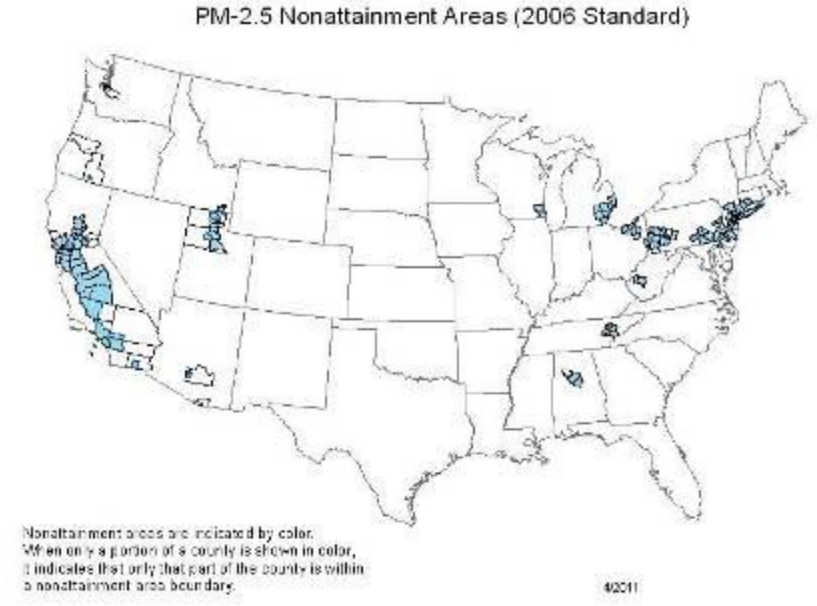


Figure 7-20 2006 $PM_{2.5}$ Nonattainment Areas

As of December 14, 2012, over 29 million people live in the 46 areas that are designated as nonattainment for the PM_{10} NAAQS. There are 39 full or partial counties that make up the PM_{10} nonattainment areas. Nonattainment areas for the PM_{10} NAAQS are pictured in Figure 7-21.

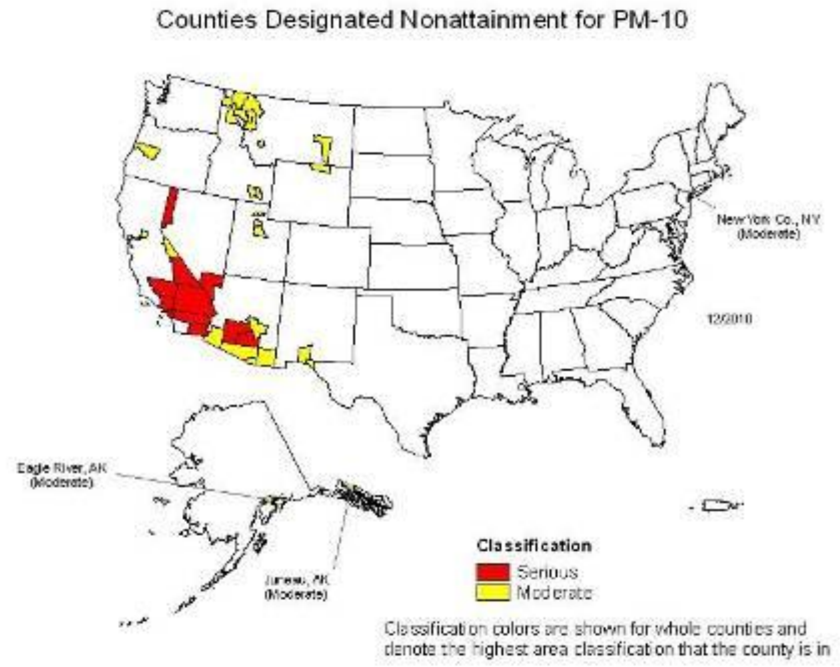


Figure 7-21 PM_{10} Nonattainment Areas

7.2.4.2.2 Projected Levels of $PM_{2.5}$ Without this Proposed 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 conducted for this proposal projects that in 2030, with all current controls in effect but excluding the emissions changes expected to occur as a result of this proposal or any other additional controls, at least 14 counties, with a projected population of over 28 million people, would have projected design values above the level of the annual standard of 12.0 µg/m^3 and at least 21 counties, with a projected population of over 31 million people, would have projected design values above the level of the 2006 24-hour standard of 35 µg/m^3.[II] Since the emission changes from this proposed action would go into effect during the period when some areas are still working to attain the $PM_{2.5}$ NAAQS, the projected emission changes will help state and local agencies in their effort to attain and maintain the $PM_{2.5}$ standard. In the following section we discuss projected $PM_{2.5}$ reductions from these proposed standards.

7.2.4.2.3 Projected Annual Average Levels of $PM_{2.5}$ With this Proposed Rule

This section summarizes the results of our modeling of annual average $PM_{2.5}$ air quality impacts in the future due to the standards proposed in this action. Specifically, for the years 2017 and 2030 we compare a reference scenario (a scenario without the proposed standards) to a control scenario that includes the proposed standards. Our modeling indicates that by 2030 annual $PM_{2.5}$ design values in the majority of the modeled counties would decrease due to the proposed standards. The decreases in annual $PM_{2.5}$ design values are likely due to the projected reductions in primary $PM_{2.5}$, NO_X, SO_X and VOC emissions. Additional information on the emissions reductions that are projected with this proposed action is available in Section 7.2.1 of this draft RIA.

It is important to note that, as discussed in Section 7.1.5 and 7.2.1.1, the control scenario emissions inventory prepared for air quality modeling included direct $PM_{2.5}$ vehicle emissions increases that we do not expect to occur in reality. These increases resulted from a series of conservative assumptions and uncertainties related to fuel parameters in 2017, and also an emissions processing issue which erroneously increased direct PM emissions in about one third of modeled counties (see Section 7.2.1.1.2 for more detail). Because our air quality modeling assumes this increase, our air quality results overestimate ambient PM and underestimate the reductions that would result from the proposed Tier 3 standards.

Figure 7-22 and Figure 7-23 present the changes in annual $PM_{2.5}$ design values in 2017 and 2030 respectively.[JJ] Note that the projected results for 2017 do not include California, while the projected results for 2030 do.[KK] This issue does not have a significant impact on the AQ modeling results for the rest of the country.

[II] The projections from the modeling analysis for the Tier 3 proposal differ from what was presented in the recent PM NAAQS RIA (http://www.epa.gov/pm/actions.html). The differences in modeling between the analyses stem primarily from the difference in modeling platform (Tier 3 used the 2005 modeling platform, while the PM NAAQS used the 2007 modeling platform), and the different years being evaluated (2020 vs. 2030).

[JJ] An annual $PM_{2.5}$ design value is the concentration that determines whether a monitoring site meets the annual NAAQS for $PM_{2.5}$. The full details involved in calculating an annual $PM_{2.5}$ design value are given in appendix N of 40 CFR part 50.

[KK] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there

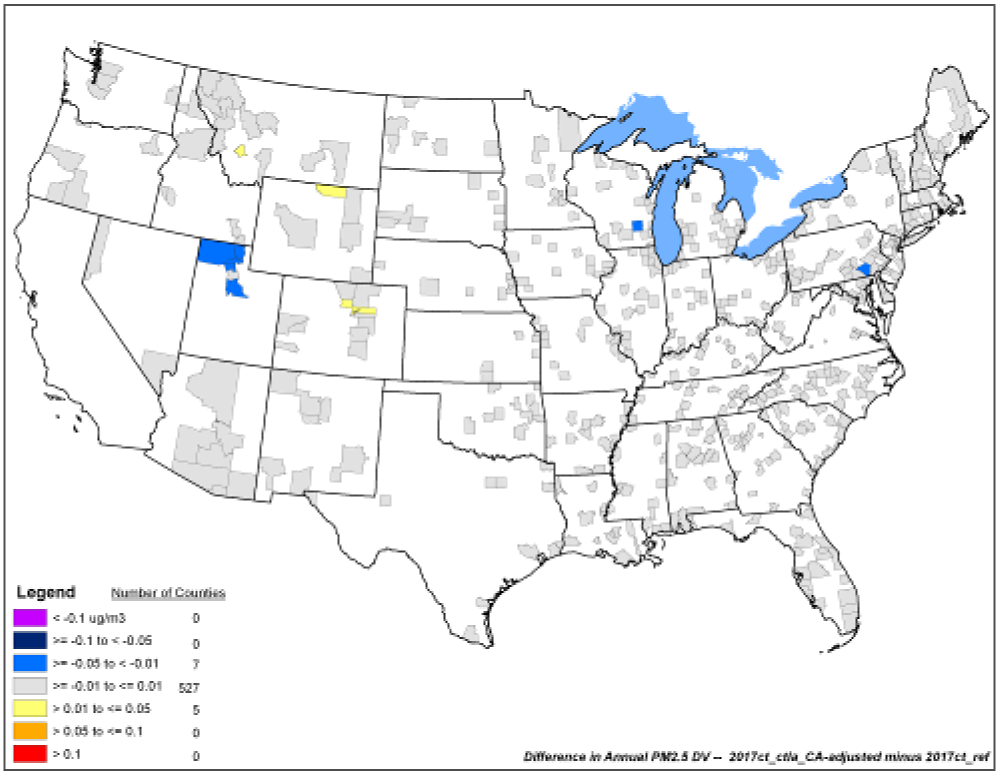


Figure 7-22 Projected Change in 2017 Annual PM$_{2.5}$ Design Values Between the Reference Case and Control Case

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should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases.

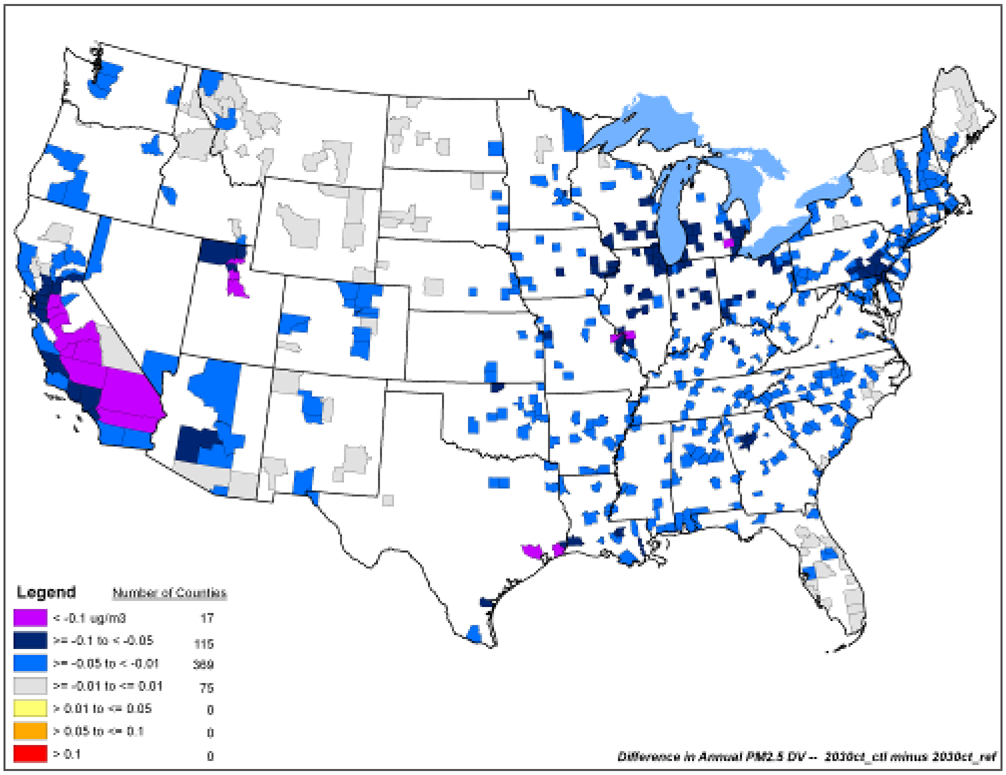

Figure 7-23 Projected Change in 2030 Annual $PM_{2.5}$ Design Values Between the Reference Case and Control Case

The projected population-weighted average design value concentration without the proposed rule is 9.3 µg/m^3 in 2017. As shown in Figure 7-22, we project that in 2017 seven counties will have design value decreases of between 0.01 µg/m^3 and 0.05 µg/m^3. These counties are in Utah, Pennsylvania and Wisconsin. The maximum projected decrease in a 2017 annual $PM_{2.5}$ design value is 0.03 µg/m^3 in Weber County, Utah. As mentioned above the decreases in ambient annual $PM_{2.5}$ concentrations are due to reductions in NO_X, SO_X and VOCs and the subsequent reductions in secondarily formed PM due to this proposed rule in 2017, which offset the small increases in direct PM emissions that were modeled but we do not expect to occur (see Section 7.1.5 and Section 7.2.1.1.2 of this draft RIA for more detail). As a result, the projected decreases in design values are underestimates of the actual effects of the proposed rule. There are a few counties with projected small increases in annual $PM_{2.5}$ in 2017, but as explained, we do not expect that these localized small increases will actually happen.

The projected population-weighted average design value concentration without the proposed rule is 9.5 µg/m^3 in 2030. Figure 7-23 presents the annual $PM_{2.5}$ design value changes in 2030. In 2030 all the modeled counties have decreases in annual $PM_{2.5}$ design values. The annual $PM_{2.5}$ design value decreases in 2030 are larger than the decreases in 2017; most design values are projected to decrease between 0.01 and 0.05 µg/m^3 and over 100 additional counties have projected design value decreases greater than 0.05 µg/m^3. The maximum projected decrease in an annual $PM_{2.5}$ design value in 2030 is 0.20 µg/m^3 in Tulare County, California.

Table 7-33 and Table 7-34 show the average change in 2017 and 2030 annual $PM_{2.5}$ design values for: (1) all counties with 2005 baseline design values, (2) counties with 2005 baseline design values that exceeded the 2012 annual $PM_{2.5}$ standard, (3) counties with 2005 baseline design values that did not exceed the 2012 standard, but were within 10 percent of it, (4) counties with 2017/2030 design values that exceeded the 2012 annual $PM_{2.5}$ standard, and (5) counties with 2017/2030 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 $PM_{2.5}$ as they work to ensure long-term maintenance of the annual $PM_{2.5}$ NAAQS. All of these metrics show either no change or a small increase or decrease in 2017 and show a decrease in 2030; these results are underestimates for the reasons explained above. The rows in Table 7-33 that compare the 2017 control case to the standard do not include California as we were not able to model design value changes in CA due to an inventory error.[LL] On a population-weighted basis, there is no change (0.00 $\mu g/m^3$) in the average modeled future-year annual $PM_{2.5}$ design values in 2017 and a 0.06 $\mu g/m^3$ decrease in 2030. On a population-weighted basis design values in those counties that are projected to be above the annual $PM_{2.5}$ standard in 2030 would decrease by 0.11 $\mu g/m^3$ due to the proposed standards.

[LL] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases.

Table 7-33 Average Change in 2017 Annual $PM_{2.5}$ Design Value as a Result of the Proposed Rule

AVERAGE	Number of U.S. Counties	2020 Population	Change in 2017 design value (µg/m^3)
All	576	226,563,544	0.00
All, population-weighted			0.00
Counties whose 2005 base year is violating the annual $PM_{2.5}$ standard	314	140,706,274	0.00
Counties whose 2005 base year is violating the annual $PM_{2.5}$ standard, population-weighted			0.00
Counties whose 2005 base year is within 10 percent of the annual $PM_{2.5}$ standard	83	29,253,128	-0.01
Counties whose 2005 base year is within 10 percent of the annual $PM_{2.5}$ standard, population-weighted			0.00
Counties whose 2017 control case is violating the annual $PM_{2.5}$ standard	6	5,227,380	0.01
Counties whose 2017 control case is violating the annual $PM_{2.5}$ standard, population-weighted			0.00
Counties whose 2017 control case is within 10 percent of the annual $PM_{2.5}$ standard	20	20,338,215	-0.01
Counties whose 2017 control case is within 10 percent of the annual $PM_{2.5}$ standard, population-weighted			0.00

Notes:

[a] Averages are over counties with 2005 modeled design values

[b] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

Table 7-34 Average Change in 2030 Annual $PM_{2.5}$ Design Value as a Result of the Proposed Rule

AVERAGE	Number of U.S. Counties	2030 Population	Change in 2030 design value ($\mu g/m^3$)
All	576	247,415,381	-0.05
All, population-weighted			-0.06
Counties whose 2005 base year is violating the annual $PM_{2.5}$ standard	314	152,109,569	-0.05
Counties whose 2005 base year is violating the annual $PM_{2.5}$ standard, population-weighted			-0.07
Counties whose 2005 base year is within 10 percent of the annual $PM_{2.5}$ standard	83	31,863,376	-0.05
Counties whose 2005 base year is within 10 percent of the annual $PM_{2.5}$ standard, population-weighted			-0.05
Counties whose 2030 control case is violating the annual $PM_{2.5}$ standard	14	28,624,758	-0.11
Counties whose 2030 control case is violating the annual $PM_{2.5}$ standard, population-weighted			-0.10
Counties whose 2030 control case is within 10 percent of the annual $PM_{2.5}$ standard	28	23,840,272	-0.07
Counties whose 2030 control case is within 10 percent of the annual $PM_{2.5}$ standard, population-weighted			-0.09

Notes:

[a] Averages are over counties with 2005 modeled design values

[b] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

There are fourteen counties, mostly in California, that are projected to have annual $PM_{2.5}$ design values above the NAAQS in 2030 without the proposed standards or any other additional standards in place. Table 7-35 below presents the changes in design values for these counties.

Table 7-35 Change in Annual $PM_{2.5}$ Design Values ($\mu g/m^3$) for Counties Projected to be Above the Annual $PM_{2.5}$ NAAQS in 2030

County Name	Change in Annual $PM_{2.5}$ Design Value ($\mu g/m^3$)	Population in 2030[a]
Riverside County, California	-0.14	2,614,198
San Bernardino County, California	-0.11	2,784,489
Kern County, California	-0.19	981,806
Tulare County, California	-0.2	528,662
Fresno County, California	-0.16	1,196,949
Kings County, California	-0.17	195,067
Los Angeles County, California	-0.09	10,742,722
Allegheny County, Pennsylvania	-0.05	1,234,930
Lincoln County, Montana	-0.02	20,454
Jefferson County, Alabama	-0.05	697,239
Wayne County, Michigan	-0.09	1,838,269
Santa Cruz County, Arizona	-0.03	55,393
Orange County, California	-0.06	4,431,070
Cuyahoga, Ohio	-0.07	1,303,510

Note:

[a] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

7.2.4.2.4 Projected 24-hour Average Levels of $PM_{2.5}$ With this Proposed Rule

This section summarizes the results of our modeling of 24-hour $PM_{2.5}$ air quality impacts in the future due to the proposed rule. Specifically, for the years 2017 and 2030 we compare a reference scenario (a scenario without the proposed standards) to a control scenario that includes the proposed standards. Our modeling indicates that by 2030 24-hour $PM_{2.5}$ design values in the majority of the modeled counties would decrease due to the proposed standards. The decreases in 24-hour $PM_{2.5}$ design values are likely due to the projected reductions in primary $PM_{2.5}$, NO_X, SO_X and VOCs. Additional information on the emissions reductions that are projected with this proposed action is available in Section 7.2.1 of this draft RIA.

It is important to note that, as discussed in Section 7.1.5 and 7.2.1.1, the control scenario emissions inventory prepared for air quality modeling included direct $PM_{2.5}$ vehicle emissions increases that we do not expect to occur in reality. These increases resulted from a series of conservative assumptions and uncertainties related to fuel parameters in 2017, and also an emissions processing issue which erroneously increased direct PM emissions in about one third of modeled counties (see Section 7.2.1.1.2 for more detail). Because our air quality modeling assumes this increase, our air quality results overestimate ambient PM and underestimate the reductions that would result from the proposed Tier 3 standards.

Figure 7-24 and Figure 7-25 present the changes in 24-hour $PM_{2.5}$ design values in 2017 and 2030 respectively.[MM] Note that the projected results for 2017 do not include California, while the projected results for 2030 do.[NN] This issue does not have a significant impact on the AQ modeling results for the rest of the country.

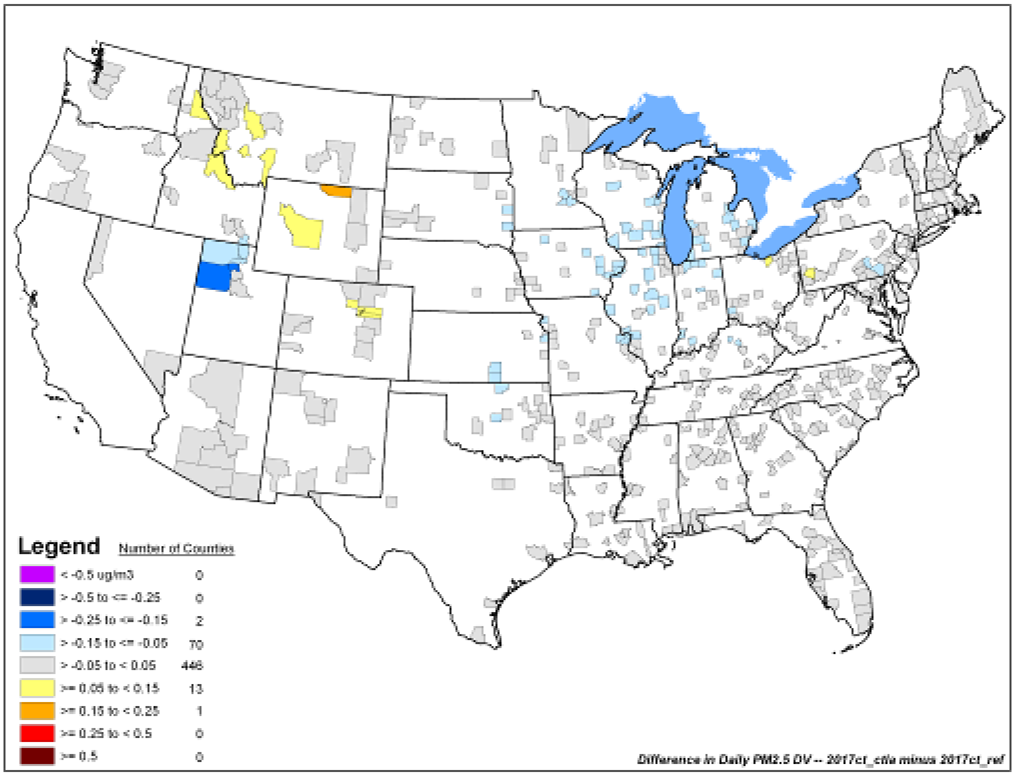

Figure 7-24 Projected Change in 2017 24-hour $PM_{2.5}$ Design Values Between the Reference Case and the Control Case

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[MM] A 24-hour $PM_{2.5}$ design value is the concentration that determines whether a monitoring site meets the 24-hour NAAQS for $PM_{2.5}$. The full details involved in calculating a 24-hour $PM_{2.5}$ design value are given in appendix N of 40 CFR part 50.

[NN] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases.

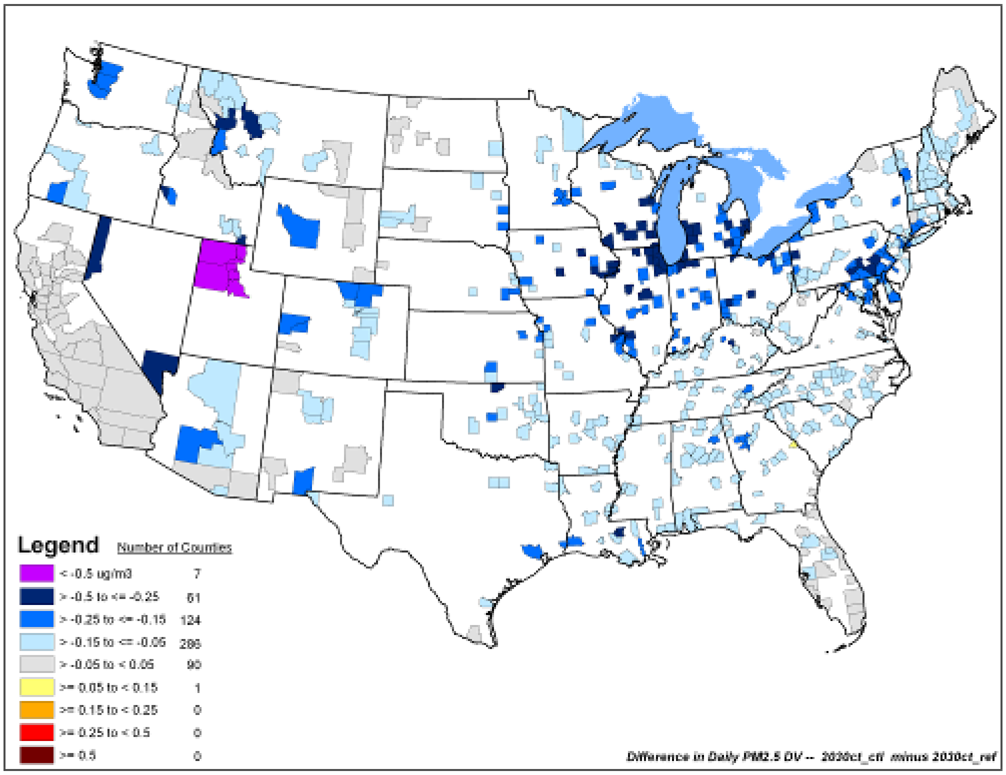

Figure 7-25 Projected Change in 2030 24-hour $PM_{2.5}$ Design Values Between the Reference Case and the Control Case

The projected population-weighted average design value concentration without the proposed rule is 23.4 $\mu g/m^3$ in 2017. As shown in Figure 7-24, in 2017 there are 72 counties with projected 24-hour $PM_{2.5}$ design value decreases greater than 0.05 $\mu g/m^3$. These counties are in Utah, Pennsylvania and scattered throughout the Midwest. The maximum projected decrease in a 2017 24-hour $PM_{2.5}$ design value is 0.20 $\mu g/m^3$ in Tooele County, Utah. As mentioned above, the decreases in ambient annual $PM_{2.5}$ concentrations are due to reductions in NO_X, SO_X and VOCs and the subsequent reductions in secondarily formed PM due to this proposed rule in 2017, which offset the small increases in direct PM emissions that were modeled but we do not expect to occur (see Section 7.1.5 and Section 7.2.1.1.2 of this draft RIA for more detail). As a result, the projected decreases in design values are underestimates of the actual effects of the proposed rule. There are some counties with projected small increases in 24-hour $PM_{2.5}$ in 2017, but as explained, we do not expect that these localized small increases will actually happen.

The projected population-weighted average design value concentration without the proposed rule is 24.3 $\mu g/m^3$ in 2030. Figure 7-25 presents the 24-hour $PM_{2.5}$ design value changes in 2030. In 2030 the 24-hour $PM_{2.5}$ design value decreases are larger; most design values are projected to decrease between 0.05 and 0.15 $\mu g/m^3$ and over 200 counties have projected design value decreases greater than 0.15 $\mu g/m^3$. The maximum projected decrease in a 24-hour $PM_{2.5}$ design value in 2030 is 1.28 $\mu g/m^3$ in Kings County, California. As shown in Figure 7-25, design values in 93 counties would decrease by more than 0.25 $\mu g/m^3$. These counties are in Idaho, Nevada, California, Montana, Louisiana, northern Utah, and the upper

Midwest. The decreases in 24-hour $PM_{2.5}$ design values that are projected in some counties are likely due to emission reductions related to reductions in $PM_{2.5}$ precursor emissions (NO_X, SO_X, and VOCs). There is one county, Richmond County, Georgia, with a projected 24-hour $PM_{2.5}$ design value increase of less than 0.15 μg/m^3. Additional information on the emissions reductions that are projected with this proposed action is available in Section 7.2.1.

Table 7-36 shows the average change in 2030 24-hour $PM_{2.5}$ design values for: (1) all counties with 2005 baseline design values, (2) counties with 2005 baseline design values that exceeded the 24-hour $PM_{2.5}$ standard, (3) counties with 2005 baseline design values that did not exceed the standard, but were within 10 percent of it, (4) counties with 2030 design values that exceeded the 24-hour $PM_{2.5}$ standard, and (5) counties with 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 $PM_{2.5}$ as they work to ensure long-term maintenance of the 24-hour $PM_{2.5}$ NAAQS. On a population-weighted basis, the average modeled future-year 24-hour $PM_{2.5}$ design values are projected to decrease by 0.20 μg/m^3 due to the proposed standards. On a population-weighted basis, 24-hour $PM_{2.5}$ design values in those counties that are projected to be above the 24-hour $PM_{2.5}$ standard in 2030 would decrease by 0.32 μg/m^3.

Table 7-36 Average Change in Projected 24-hour $PM_{2.5}$ Design Values in 2030

Average[a]	Number of U.S. Counties	2030 Population[b]	Change in 2030 design value (μg/m^3)
All	569	245,111,480	-0.16
All, population-weighted			-0.20
Counties whose 2005 base year is violating the 2006 24-hour $PM_{2.5}$ standard	108	91,474,036	-0.29
Counties whose 2005 base year is violating the 2006 24-hour PM2.5 standard, population-weighted			-0.27
Counties whose 2005 base year is within 10 percent of the 2006 24-hour $PM_{2.5}$ standard	140	53,990,060	-0.18
Counties whose 2005 base year is within 10 percent of the 2006 24-hour $PM_{2.5}$ standard, population-weighted			-0.21
Counties whose 2030 control case is violating the 2006 24-hour $PM_{2.5}$ standard	21	31,002,272	-0.50
Counties whose 2030 control case is violating the 2006 24-hour $PM_{2.5}$ standard, population-weighted			-0.32
Counties whose 2030 control case is within 10 percent of the 2006 24-hour $PM_{2.5}$ standard	7	4,212,913	-0.37
Counties whose 2030 control case is within 10 percent of the 2006 24-hour $PM_{2.5}$ standard, population-weighted			-0.50

Note:
[a] Averages are over counties with 2005 modeled design values
[b] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

There are 21 counties that are projected to have 24-hour $PM_{2.5}$ design values above the NAAQS in 2030 without the proposed standards or any other additional controls in place. Table 7-37 below presents the changes in design values for these counties.

Table 7-37 Change in 24-hour $PM_{2.5}$ Design Values ($\mu g/m^3$) for Counties Projected to be Above the 24-hour $PM_{2.5}$ NAAQS in 2030

County Name	Change in 24-hour $PM_{2.5}$ Design Value ($\mu g/m^{3)}$	Population in 2030[a]
Riverside County, California	-0.59	2,614,198
Kern County, California	-1.22	981,806
San Bernardino County, California	-0.35	2,784,490
Fresno County, California	-1.06	1,196,950
Sacramento County, California	-0.81	1,856,971
Cache County, Utah	-0.43	141,446
Kings County, California	-0.12	195,067
Lane County, Oregon	-0.01	460,993
Los Angeles County, California	-1.28	10,742,722
Allegheny County, Pennsylvania	-0.11	1,234,931
Tulare County, California	-0.07	528,663
Lake County, Montana	-1.25	40,126
Stanislaus County, California	-0.19	688,246
Ravalli County, Montana	-1.08	63,914
Missoula County, Montana	-0.27	141,264
Klamath County, Oregon	-0.13	77,200
Salt Lake County, Utah	-0.59	1,431,946
Lincoln County, Montana	-0.12	20,454
Butte County, California	-0.26	287,236
Pierce County, Washington	-0.24	1,082,579
Orange County, California	-0.13	4,431,071

Note:
[a] Population numbers based on Woods & Poole data. Woods & Poole Economics, Inc. 2001. Population by Single Year of Age CD.

7.2.4.3 Nitrogen Dioxide

As described in Section 6.2.3 of this draft RIA, NO_2 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_2 levels.

7.2.4.3.1 Current Levels of NO_2

Between 2003 and 2005, national mean concentrations of NO_2 were about 15 ppb for averaging periods ranging from a day to a year.[OO] There are two NAAQS for NO_2: an annual standard (53 ppb) and a 1-hour standard (100 ppb). The primary NAAQS for NO_2 was revised in January 2010. EPA completed area designations in January 2012 and there are currently no nonattainment areas. The designations were based on the existing community-wide monitoring network. Once the expanded network of NO_2 monitors is fully deployed and three years of air quality data have been collected, EPA intends to redesignate areas, as appropriate, based on the air quality data from the new monitoring network.[137,138]

7.2.4.3.2 Projected Levels of NO_2 without this Proposed Rule

EPA has already adopted many mobile source emission control programs that are expected to reduce ambient NO_2 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_2 in the future are expected to decrease. However, even with the implementation of all current state and federal regulations, there are projected to be parts of the country with elevated NO_2 concentrations in the future. The emission changes from this proposal would go into effect during the period when any NO_2 nonattainment areas would be working to attain the NO_2 NAAQS.

7.2.4.3.3 Projected Levels of NO_2 with this Proposed Rule

This section summarizes the results of our modeling of annual average NO_2 air quality impacts in the future due to the proposed standards. Specifically, for the years 2017 and 2030 we compare a reference scenario (a scenario without the proposed standards) to a control scenario that includes the proposed standards. Figure 7-26 and Figure 7-27 present the changes in annual NO_2 concentrations in 2017 and 2030 respectively.

[OO] EPA, 2010. Final Regulatory Impact Analysis (RIA) for the NO2 National Ambient Air Quality Standards (NAAQS). http://www.epa.gov/ttn/ecas/regdata/RIAs/FinalNO2RIAfulldocument.pdf

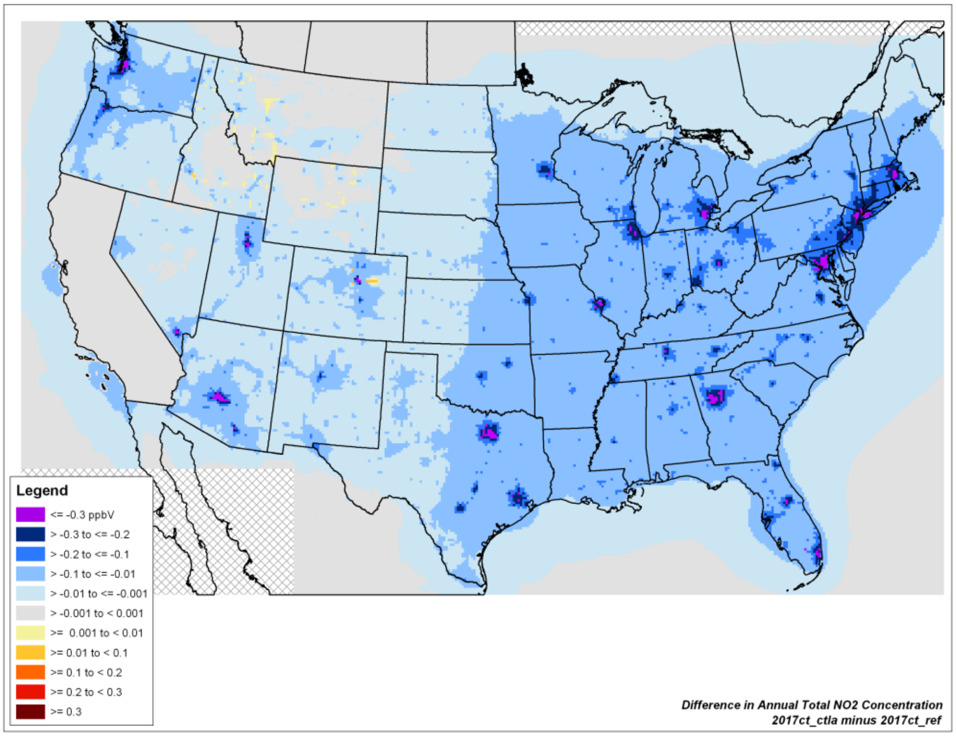

Figure 7-26 Projected Change in 2017 Annual NO_2 Concentrations Between the Reference Case and Control Case

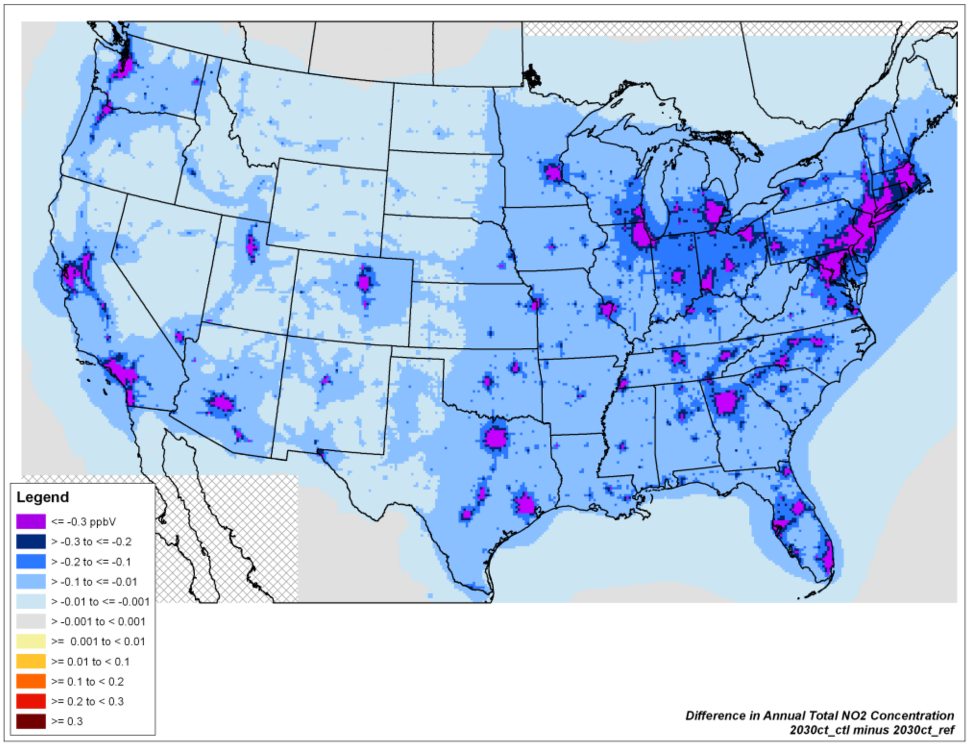

Figure 7-27 Projected Change in 2030 Annual NO_2 Concentrations Between the Reference Case and Control Case

As shown in Figure 7-27, our modeling indicates that by 2030 annual NO_2 concentrations in the majority of the country would decrease less than 0.1 ppb due to this proposal. However decreases in annual NO_2 concentrations are greater than 0.3 ppb in most urban areas. These emissions reductions would also likely decrease 1-hour NO_2 concentrations and help any potential nonattainment areas to attain and maintain the standard. Note that the projected results for 2017 do not include California, while the projected results for 2030 do. [PP] This issue does not have a significant impact on the AQ modeling results for the rest of the country.

7.2.4.4 Air Toxics

As described in Section 6.2.5 of this draft 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 Levels 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.[139] 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.[140] 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.[141] 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

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[PP] An inconsistency in our approaches for estimating California fuel sulfur levels led us to model an increase in sulfur in California. More specifically, for the reference case, we used MOVES default fuels for California. These were developed based on a mix of survey data and other sources, which resulted in a range of sulfur levels from 8-19 ppm. However, the control case assumed 10 ppm sulfur throughout California. As a result, although there should have been no change in California fuel properties due to Tier 3, some areas had small modeled increases or decreases.

to direct emissions from mobile and stationary sources.[QQ,RR,142] 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.

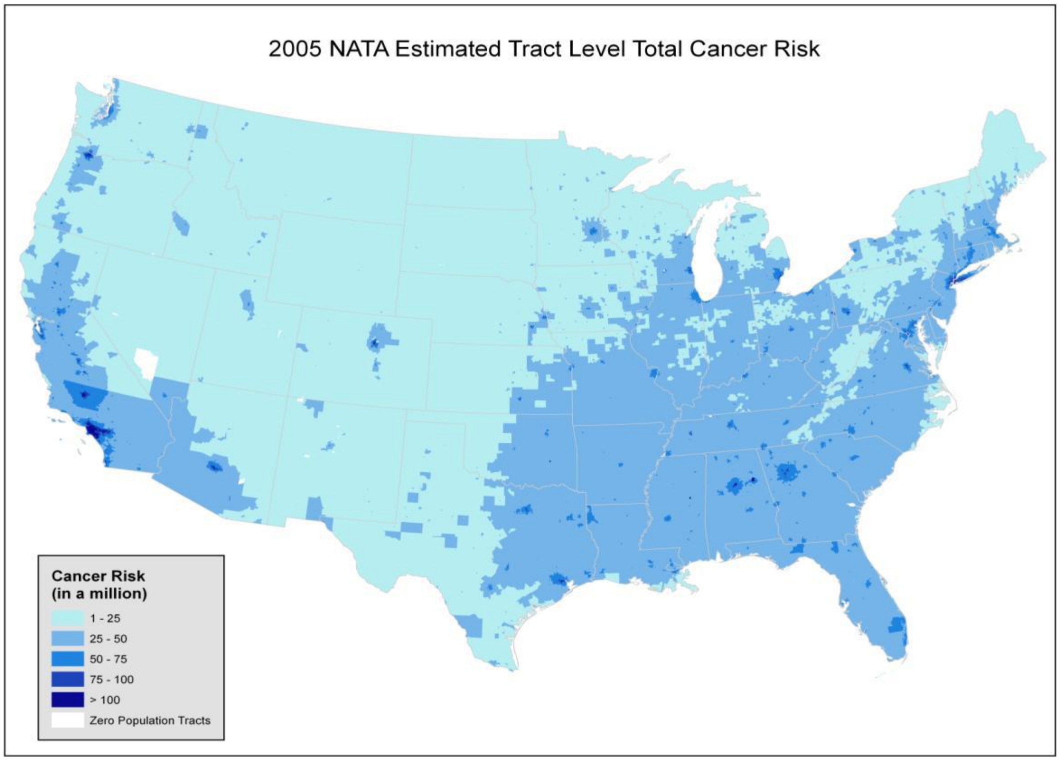


Figure 7-28 Tract Level Average Carcinogenic Risk, 2005 NATA

[QQ] 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.

[RR] NATA relies on a Guassian 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.

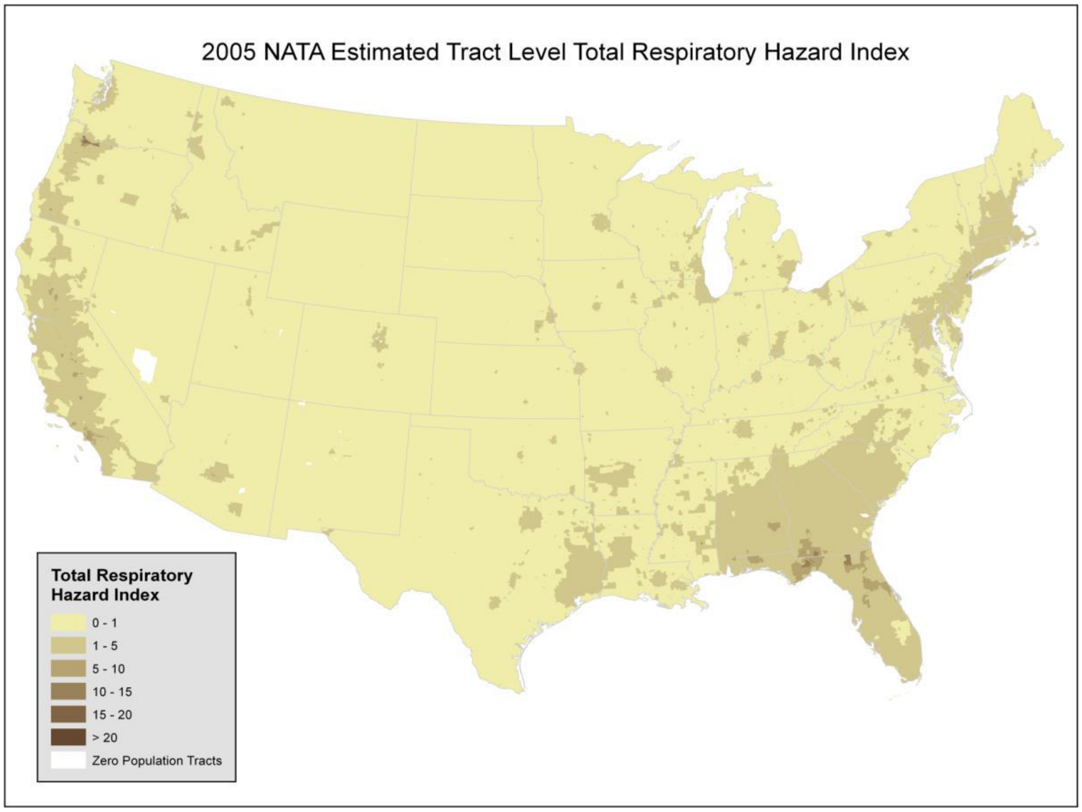


Figure 7-29 County Level Average Noncancer Hazard Index, 2005 NATA

7.2.4.4.2 Projected Levels of Air Toxics

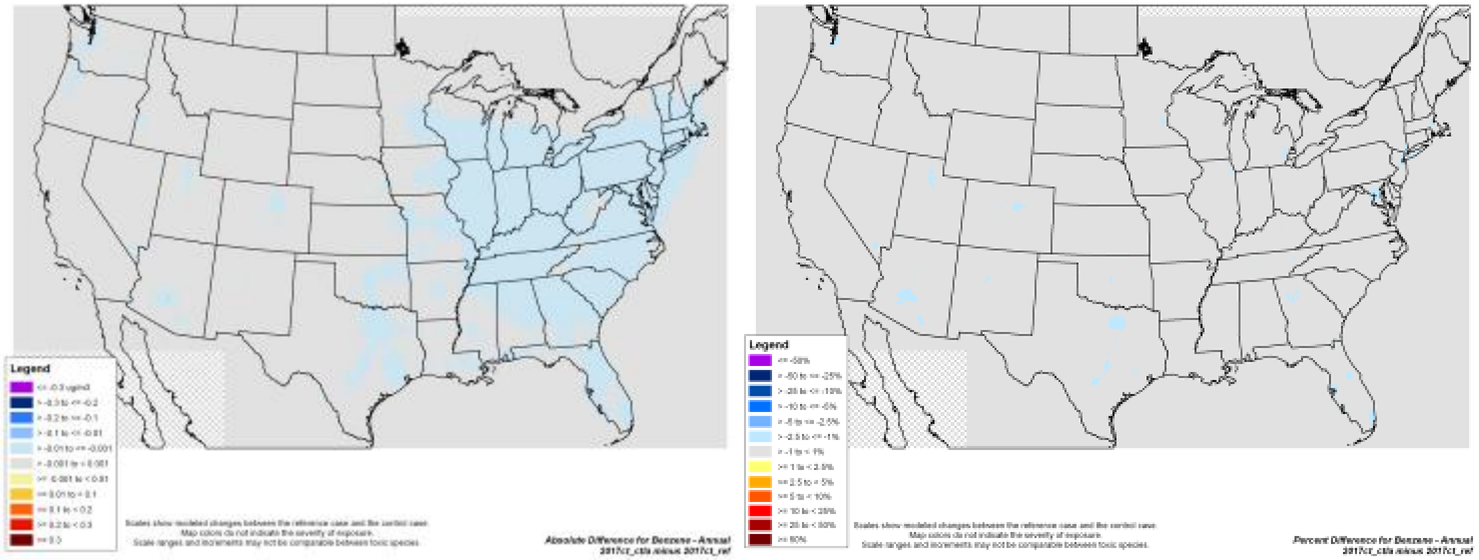
In the following sections, we describe results of our modeling of air toxics levels in the future with the proposed standards. Although there are a large number of compounds which are considered air toxics, we focused on those which were identified as national and regional-scale cancer and noncancer 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 2017, 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 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 proposed 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 2017 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 2017, which is the first year of the proposed program. However, our modeling projects there would be small immediate reductions in ambient concentrations of air toxics due to the proposed sulfur controls 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.

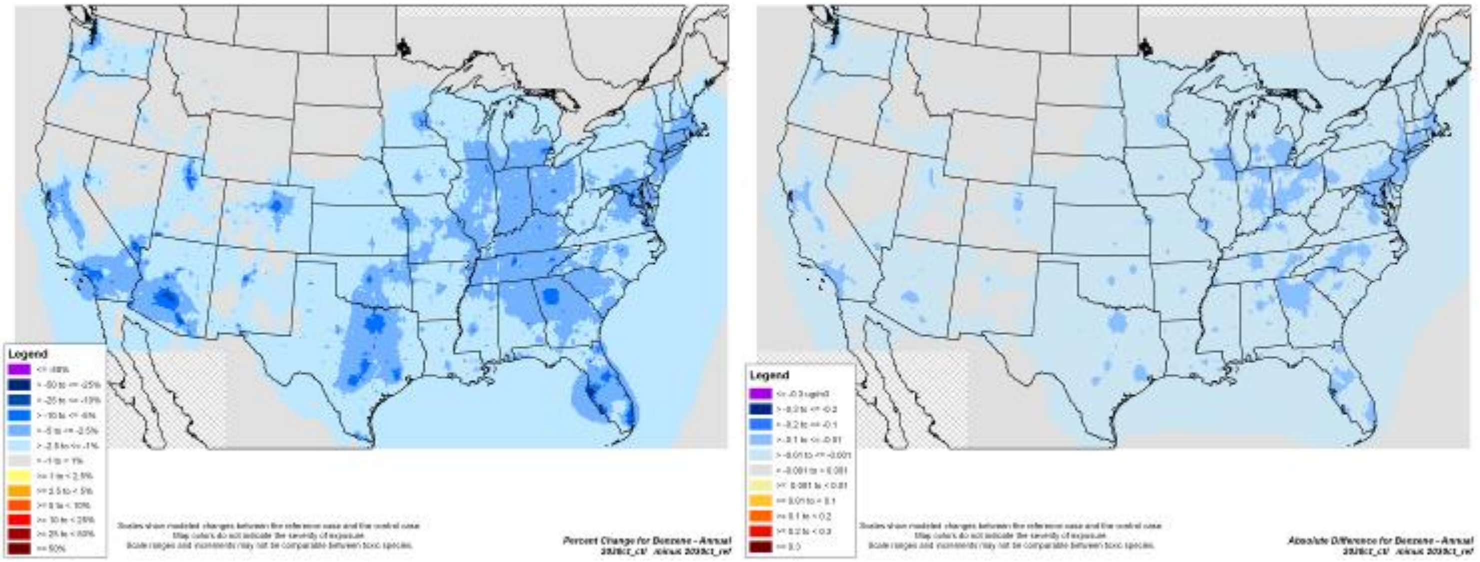
Benzene

Our modeling projects that the proposed standards would have a notable impact on ambient benzene concentrations. In 2017, the first year the proposed Tier 3 standards take effect, ambient benzene reductions are generally between 0.001 and 0.01 µg/m³, or between 1 and 2.5 percent in some areas (Figure 7-30). In 2030, our modeling projects that the proposal would 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 µg/m³ in rural areas and as much as 0.1 µg/m³ in urban areas (Figure 7-31).



Scales show modeled changes between the reference case and the control case.
Map colors do not indicate the severity of exposure.
Scale ranges and increments may not be comparable between toxic species.

Figure 7-30 Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)



Scales show modeled changes between the reference case and the control case.
Map colors do not indicate the severity of exposure.
Scale ranges and increments may not be comparable between toxic species.

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 µg/m³ (right)

1,3-Butadiene

Our modeling also shows reductions of ambient 1,3-butadiene concentrations in 2017 and 2030. Figure 7-32 shows that in 2017, ambient concentrations of 1,3-butdiene generally decrease between 1 and 5 percent across the country, corresponding to small decreases in absolute concentrations (less than 0.001 µg/m³). In 2030, reductions of 1,3-butadiene concentrations range between 1 and 25 percent, with decreases of at least 0.005 µg/m³ in urban areas (Figure 7-33).

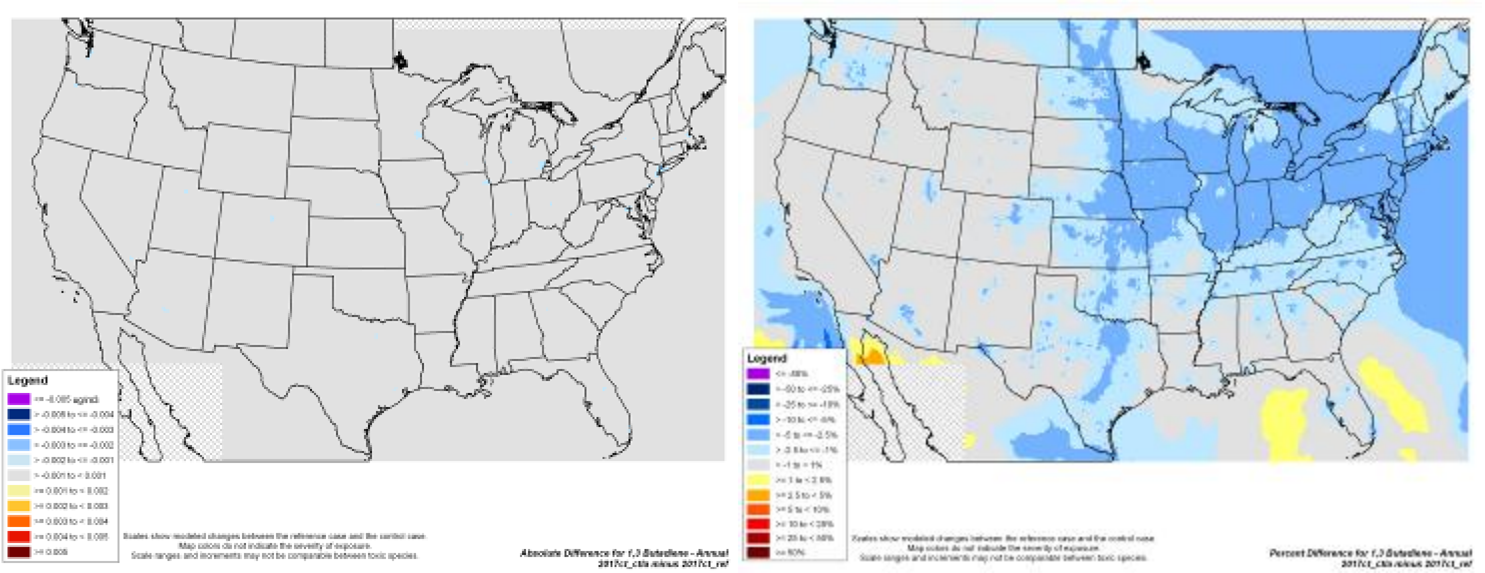


Figure 7-32 Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

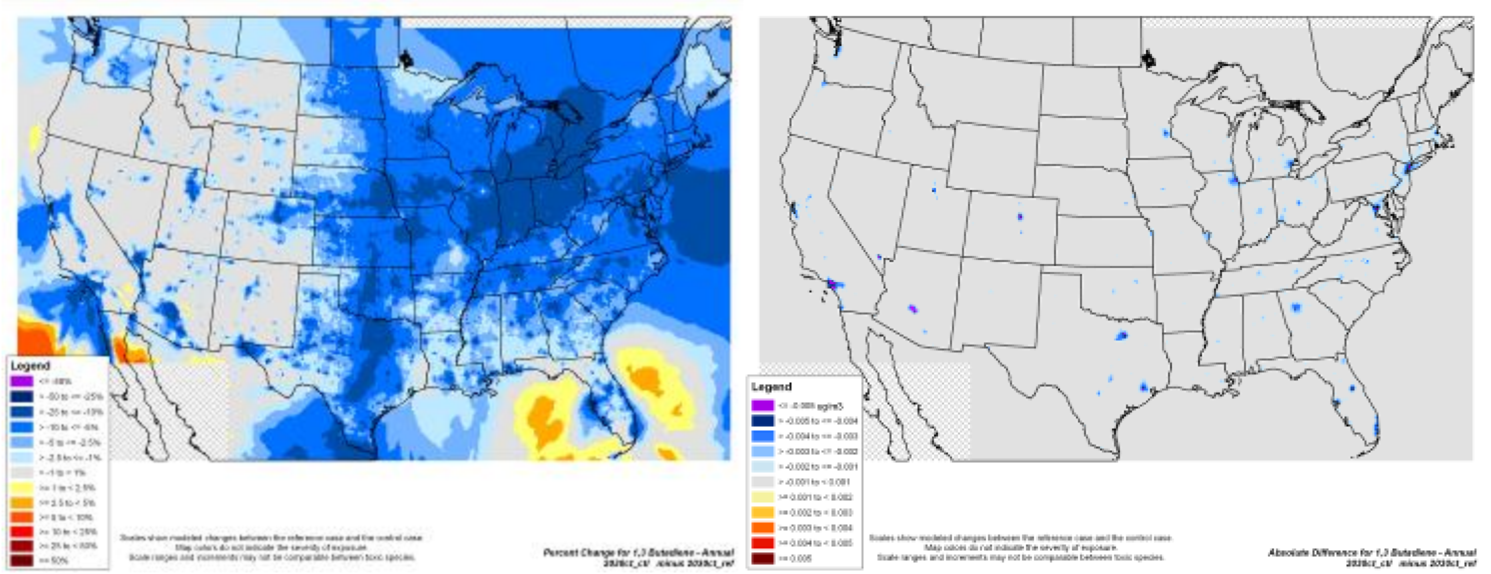


Figure 7-33 Changes in 1,3-Butadiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Acrolein

Our modeling indicates the proposed standards would reduce ambient concentrations of acrolein in 2017 and 2030. Figure 7-34 shows decreases in ambient concentrations of acrolein generally between 1 and 2.5 percent across the parts of the country in 2017, corresponding to small decreases in absolute concentrations (less than 0.001 µg/m³). Reductions of acrolein concentrations in 2030 range between 1 and 25 percent, with decreases as high as 0.003 µg/m³ in a few urban areas.

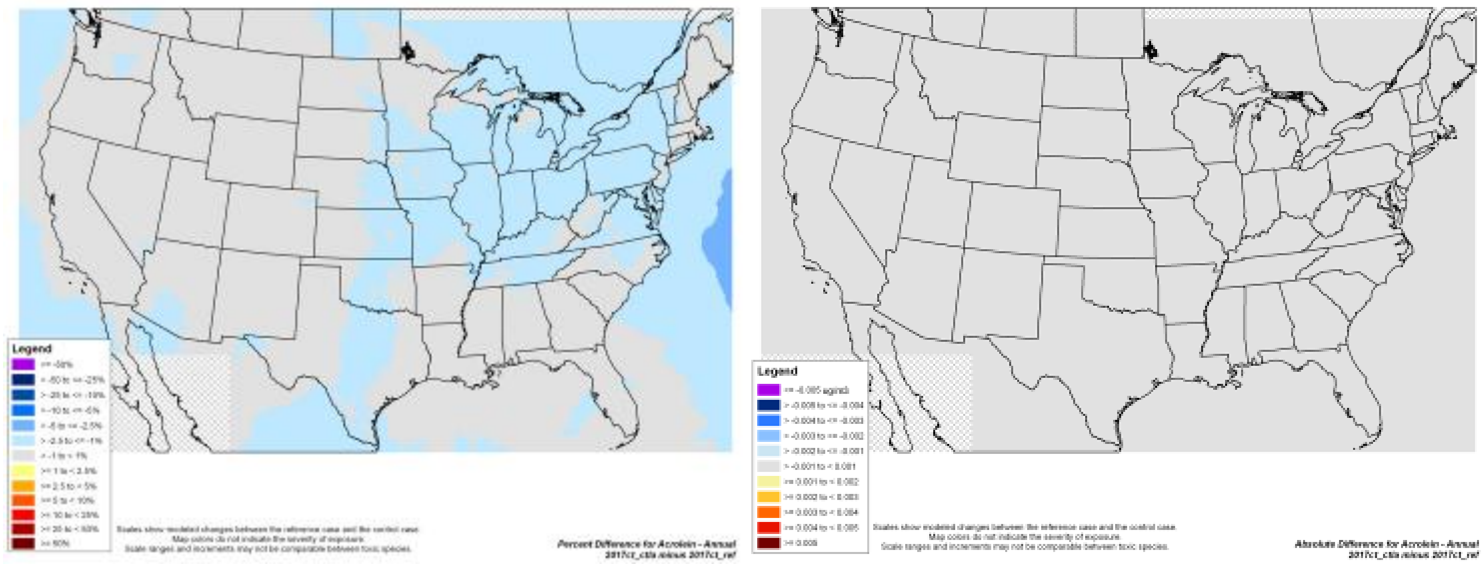


Figure 7-34 Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

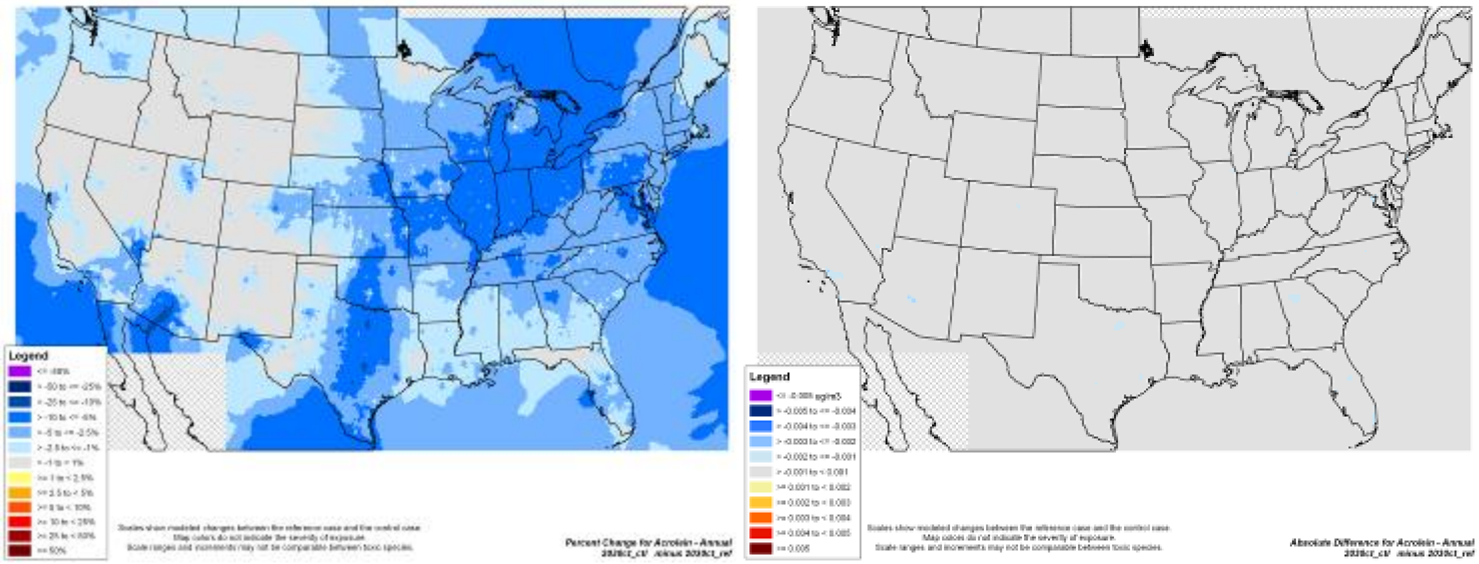


Figure 7-35 Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Ethanol

Our modeling projects that the proposed standards would slightly decrease ambient ethanol concentrations in 2030, with negligible impact in 2017. As shown in Figure 7-36, in 2017, annual percent changes in ambient concentrations of ethanol are less than 1 percent across the country, with absolute concentrations of ± 0.01 ppb. In 2030, some parts of the country, especially urban areas, are projected to have reductions in ethanol concentrations on the order of 1 to 5 percent as a result of the proposal (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.

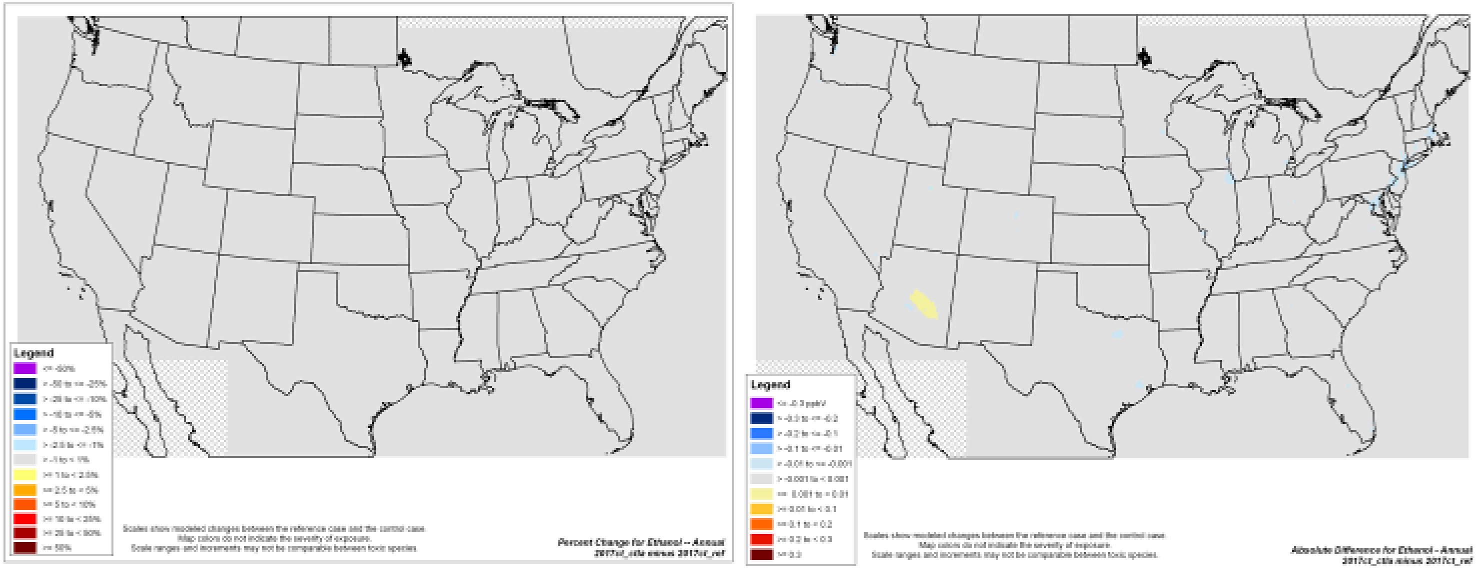


Figure 7-36 Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

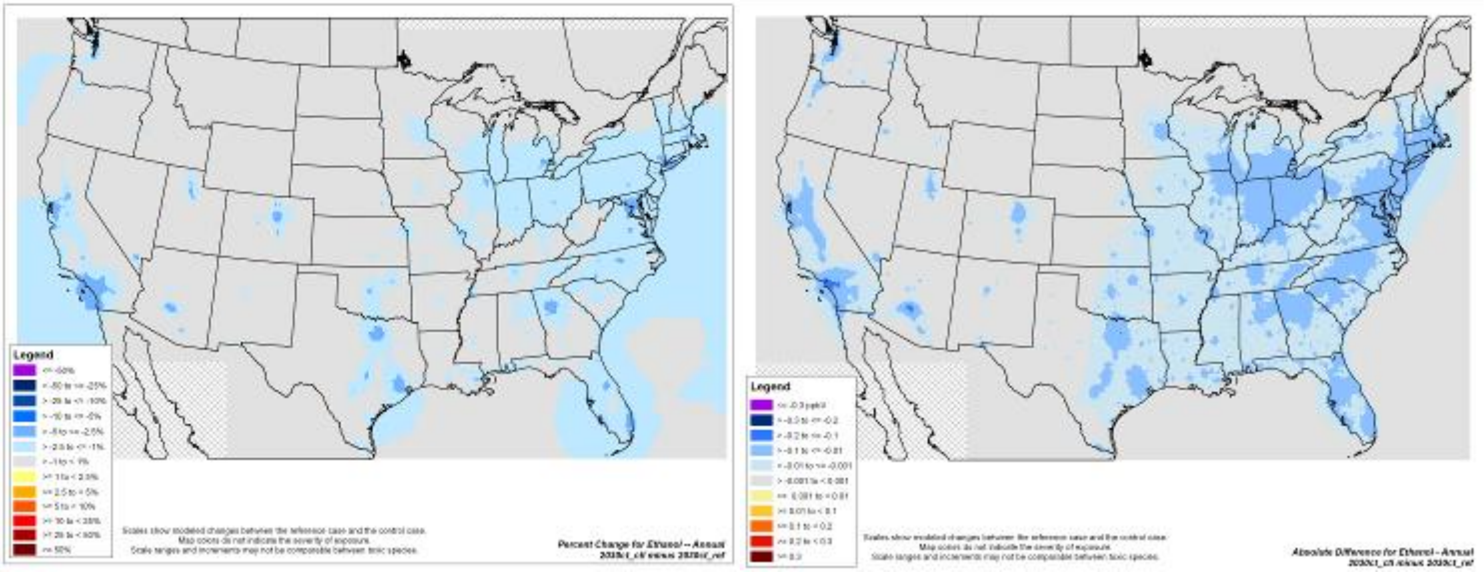


Figure 7-37 Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Formaldehyde

Our modeling projects that formaldehyde concentrations would slightly decrease in parts of the country (mainly urban areas) as a result of the proposal. 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 2017 but are on the order of 1 to 5 percent in 2030 in some urban areas as a result of the proposal. 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 µg/m³ in both years, with some areas as high as 0.1 µg/m³ in 2030.

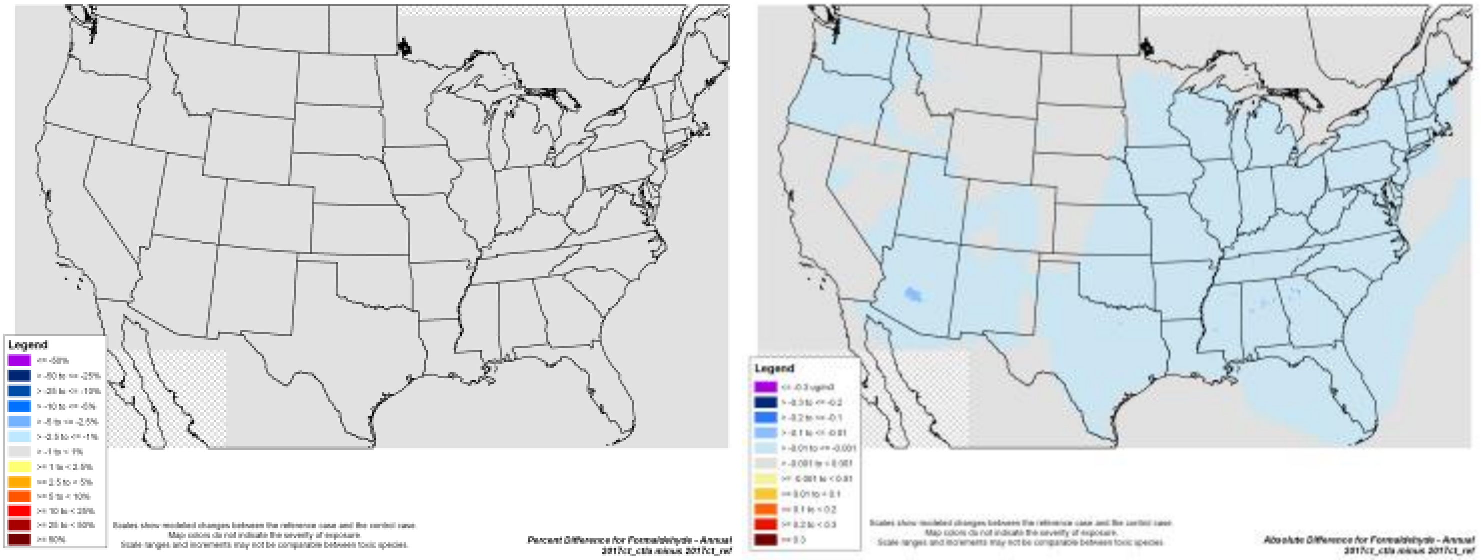


Figure 7-38 Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

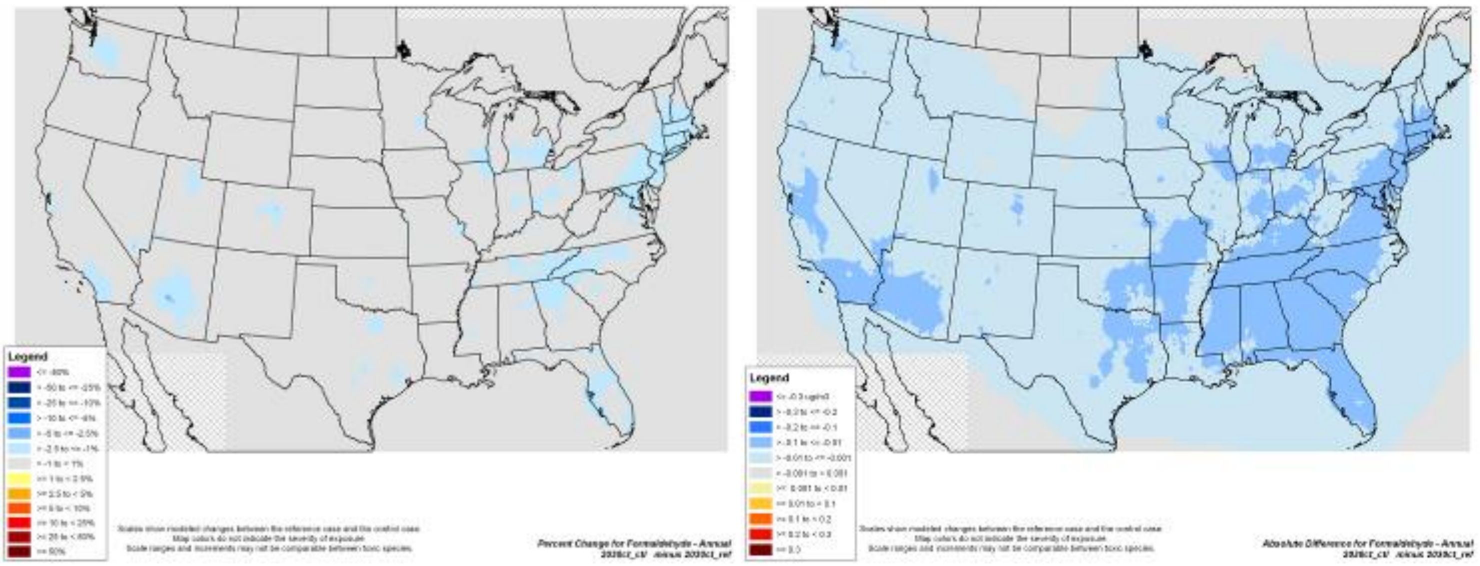


Figure 7-39 Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

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 proposal 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

µg/m³ to -0.01 µg/m³ with decreases happening in the more populated areas and increases happening in more rural areas (Figure 7-40).

The complex photochemistry associated with 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 NO_X to form peroxyacylnitrate (PAN). Reducing NO_X allows acetaldehyde precursors to be available to form acetaldehyde instead. This phenomenon is more prevalent in rural areas where 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.[143]

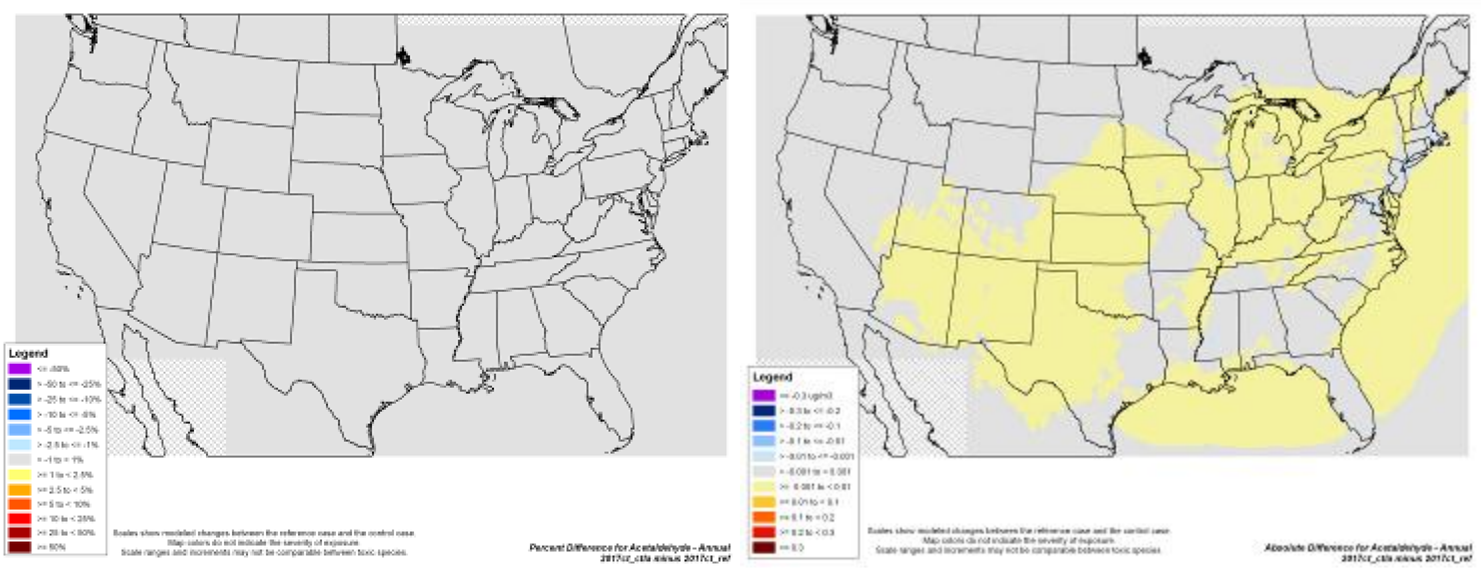


Figure 7-40 Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

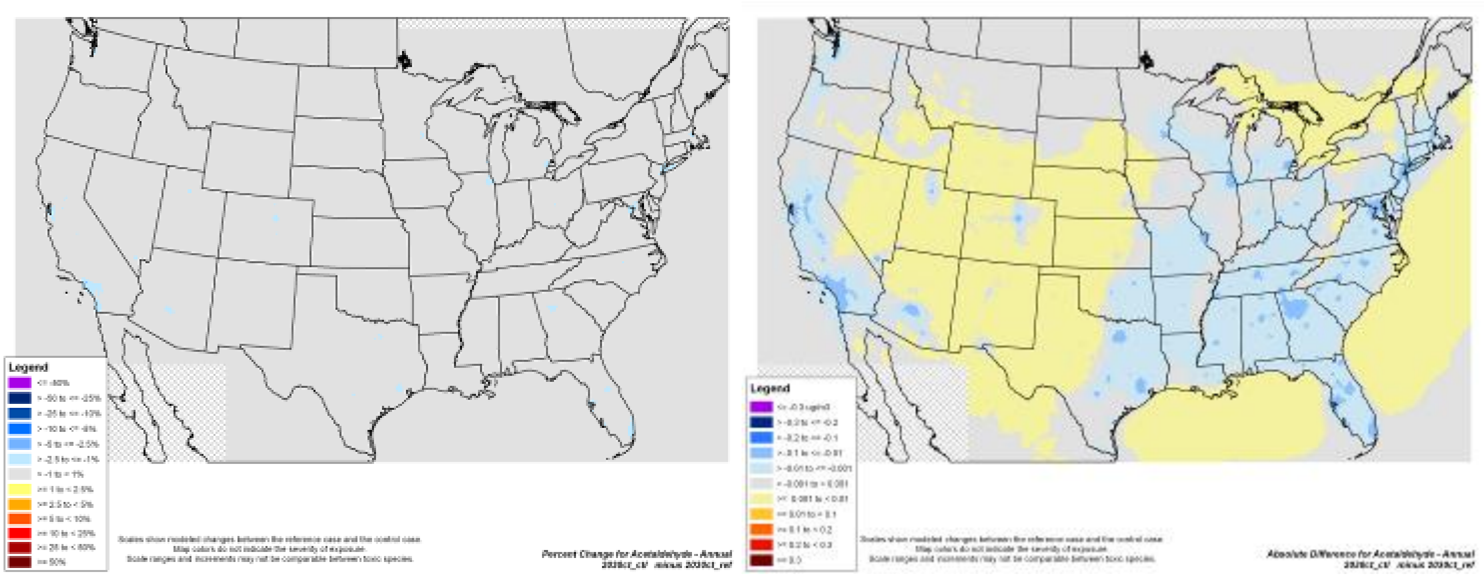


Figure 7-41 Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in μg/m³ (right)

Population Metrics

Although the reductions in ambient air toxics concentrations expected from the proposed Tier 3 standards are generally small, they are projected to benefit the majority of the U.S. population. As shown in Table 7-38, over 80 percent of the total U.S. population is projected to experience a decrease in ambient benzene and acrolein concentrations of at least 2.5 percent. More than 85 percent of the population is projected to experience decrease in 1,3-butadiene concentrations of at least 5 percent. Table 7-38 also shows that over 80 percent of the U.S population is projected to experience at least a 1 percent decrease in ambient ethanol concentrations, and over a 60 percent would experience a similar decrease in ambient formaldehyde concentrations with the proposed standards.

Table 7-38 Percent of Total Population Experiencing Changes in Annual Ambient Concentrations of Toxic Pollutants in 2030 as a Result of the Proposed Standards

Percent Change	Benzene	Acrolein	1,3-Butadiene	Formaldehyde	Ethanol	Acetaldehyde
≤ -50						
> -50 to ≤ -25			0.1%			
> -25 to ≤ -10	2.8%	0.7%	56.8%			
> -10 to ≤ -5	23.7%	36.8%	30.8%			
> -5 to ≤ -2.5	54.5%	43.7%	7.1%	1.2%	33.0%	0.3%
> -2.5 to ≤ -1	17.7%	15.3%	3.4%	63.2%	55.3%	25.1%
> -1 to < 1	1.4%	3.5%	1.7%	35.6%	11.6%	74.6%

≥ 1 to < 2.5			0.0%			
≥ 2.5 to < 5						
≥ 5 to < 10						
≥ 10 to < 25						
≥ 25 to < 50						
≥ 50						

Of note, the proposed 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/m³) for over 5 million people in 2030, meaning that as a result of the proposed 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 6.3.1 of this draft 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 $PM_{2.5}$ nonattainment areas indicate that, as of July 20, 2012, over 105 million people live in nonattainment areas for the $PM_{2.5}$ 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.[144] 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.[145,146,147] 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 139 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 proposed rule would improve visibility in all these areas.[SS] The average visibility on the 20 percent worst days at all modeled Mandatory Class I Federal areas is projected to improve by 0.04 deciviews, or 0.28 percent, in 2030. The greatest improvement in visibilities will be seen in Joshua Tree National Monument, where visibility is projected to improve by 0.99 percent (0.16 DV) in 2030 due to the proposed standards. Table 7-39 contains the full visibility results from 2030 for the 139 analyzed areas.

Table 7-39 Visibility Levels (in Deciviews) for Mandatory Class I Federal Areas on the 20 Percent Worst Days with and without this Proposed Rule

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Sipsey Wilderness	AL	29.03	21.67	21.80	21.84	21.76	11.39
Caney Creek Wilderness	AR	26.36	21.00	21.03	21.10	21.02	11.33
Upper Buffalo Wilderness	AR	26.27	21.24	21.30	21.35	21.28	11.28
Chiricahua NM	AZ	12.89	12.29	12.28	12.23	12.21	6.92
Chiricahua Wilderness	AZ	12.89	12.27	12.27	12.22	12.20	6.91
Galiuro Wilderness	AZ	12.89	12.37	12.35	12.21	12.15	6.88
Grand Canyon NP	AZ	11.86	11.03	11.02	10.89	10.86	6.95
Mazatzal Wilderness	AZ	13.95	12.87	12.84	12.61	12.55	6.91
Mount Baldy Wilderness	AZ	11.32	10.91	10.91	10.85	10.84	6.95
Petrified Forest NP	AZ	13.56	12.90	12.89	12.75	12.72	6.97
Pine Mountain Wilderness	AZ	13.95	12.81	12.78	12.54	12.48	6.92

[SS] 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.

Class 1 Area (20% worst days)	**State**	**2005 Baseline Visibility (dv)[a]**	**2017 Reference**	**2017 Tier 3 Control**	**2030 Reference**	**2030 Tier 3 Control**	**Natural Background**
Saguaro NM	AZ	14.39	13.72	13.71	13.57	13.55	6.84
Sierra Ancha Wilderness	AZ	14.45	13.55	13.53	13.33	13.28	6.92
Superstition Wilderness	AZ	14.15	13.15	13.13	12.99	12.93	6.88
Sycamore Canyon Wilderness	AZ	15.45	14.83	14.81	14.70	14.67	6.96
Agua Tibia Wilderness	CA	22.36	18.87	18.87	18.19	18.09	7.17
Ansel Adams Wilderness (Minarets)	CA	15.24	14.48	14.48	14.29	14.25	7.12
Caribou Wilderness	CA	13.65	12.75	12.75	12.61	12.57	7.29
Cucamonga Wilderness	CA	18.44	15.83	15.83	15.42	15.32	7.17
Desolation Wilderness	CA	12.87	11.89	11.88	11.76	11.73	7.13
Emigrant Wilderness	CA	16.87	15.86	15.85	15.69	15.65	7.14
Hoover Wilderness	CA	11.61	11.05	11.05	10.95	10.94	7.12
John Muir Wilderness	CA	15.24	14.41	14.42	14.25	14.22	7.14
Joshua Tree NM	CA	18.90	16.74	16.72	16.14	15.98	7.08
Kaiser Wilderness	CA	15.24	14.21	14.21	13.99	13.95	7.13
Kings Canyon NP	CA	23.73	22.29	22.29	21.99	21.91	7.13
Lassen Volcanic NP	CA	13.65	12.78	12.77	12.61	12.56	7.31
Lava Beds NM	CA	14.13	13.14	13.13	13.20	13.17	7.49
Mokelumne Wilderness	CA	12.87	12.04	12.03	11.91	11.88	7.14
Pinnacles NM	CA	17.90	15.64	15.61	15.43	15.31	7.34

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Point Reyes NS	CA	22.40	20.89	20.87	21.08	20.99	7.39
Redwood NP	CA	18.55	17.99	17.97	17.77	17.73	7.81
San Gabriel Wilderness	CA	18.44	15.86	15.86	15.37	15.26	7.17
San Gorgonio Wilderness	CA	21.43	19.50	19.50	19.01	18.89	7.10
San Jacinto Wilderness	CA	21.43	18.70	18.71	17.67	17.52	7.12
San Rafael Wilderness	CA	19.43	17.63	17.61	17.30	17.21	7.28
Sequoia NP	CA	23.73	21.90	21.88	21.52	21.42	7.13
South Warner Wilderness	CA	14.13	13.34	13.33	13.30	13.27	7.32
Thousand Lakes Wilderness	CA	13.65	12.76	12.75	12.60	12.55	7.32
Ventana Wilderness	CA	17.90	16.48	16.45	16.21	16.07	7.32
Yosemite NP	CA	16.87	15.87	15.86	15.71	15.67	7.14
Black Canyon of the Gunnison NM	CO	10.00	9.32	9.32	9.29	9.28	7.06
Eagles Nest Wilderness	CO	8.82	8.27	8.26	8.22	8.20	7.08
Flat Tops Wilderness	CO	8.82	8.43	8.43	8.39	8.38	7.07
Great Sand Dunes NM	CO	11.82	11.34	11.34	11.31	11.30	7.10
La Garita Wilderness	CO	10.00	9.59	9.59	9.54	9.54	7.06
Maroon Bells-Snowmass Wilderness	CO	8.82	8.38	8.38	8.36	8.35	7.07

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Mesa Verde NP	CO	12.14	11.46	11.45	11.48	11.46	7.09
Mount Zirkel Wilderness	CO	9.72	9.29	9.29	9.28	9.27	7.08
Rawah Wilderness	CO	9.72	9.29	9.29	9.26	9.25	7.08
Rocky Mountain NP	CO	12.85	12.37	12.36	12.34	12.32	7.05
Weminuche Wilderness	CO	10.00	9.58	9.58	9.51	9.51	7.06
West Elk Wilderness	CO	8.82	8.35	8.35	8.33	8.32	7.07
Everglades NP	FL	22.31	19.30	19.06	19.10	19.04	11.15
Okefenokee	GA	27.13	21.29	21.44	21.47	21.40	11.45
Wolf Island	GA	27.13	21.10	21.12	21.18	21.12	11.42
Craters of the Moon NM	ID	14.06	13.30	13.30	13.10	13.05	7.13
Sawtooth Wilderness	ID	14.97	14.75	14.74	14.75	14.75	7.15
Selway-Bitterroot Wilderness	ID	17.11	16.83	16.83	16.86	16.85	7.32
Mammoth Cave NP	KY	31.37	22.87	23.09	23.14	23.07	11.53
Acadia NP	ME	22.89	18.51	18.80	18.83	18.80	11.45
Moosehorn	ME	21.72	17.81	18.01	18.03	18.01	11.36
Roosevelt Campobello International Park	ME	21.72	17.68	17.95	17.96	17.94	11.36
Isle Royale NP	MI	20.74	18.69	18.64	18.74	18.68	11.22
Seney	MI	24.16	21.32	21.33	21.44	21.35	11.37
Boundary Waters Canoe Area	MN	20.20	17.13	17.05	17.16	17.10	11.21

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Voyageurs NP	MN	19.27	17.03	16.95	17.05	16.99	11.09
Hercules-Glades Wilderness	MO	26.75	21.92	21.99	22.04	21.97	11.27
Anaconda-Pintler Wilderness	MT	17.11	16.73	16.72	16.77	16.77	7.28
Bob Marshall Wilderness	MT	16.13	15.71	15.71	15.74	15.73	7.36
Cabinet Mountains Wilderness	MT	14.31	13.74	13.74	13.79	13.78	7.43
Gates of the Mountains Wilderness	MT	11.94	11.56	11.56	11.57	11.57	7.22
Glacier NP	MT	19.62	18.81	18.82	18.81	18.81	7.56
Medicine Lake	MT	18.21	17.65	17.65	17.58	17.57	7.30
Mission Mountains Wilderness	MT	16.13	15.57	15.57	15.62	15.61	7.39
Red Rock Lakes	MT	11.19	10.78	10.78	10.74	10.72	7.14
Scapegoat Wilderness	MT	16.13	15.68	15.68	15.70	15.70	7.29
UL Bend	MT	15.49	15.17	15.17	15.13	15.12	7.18
Linville Gorge Wilderness	NC	28.77	20.85	21.23	21.24	21.19	11.43
Shining Rock Wilderness	NC	28.54	20.47	20.78	20.81	20.73	11.45
Lostwood	ND	19.57	18.48	18.28	18.39	18.36	7.33
Theodore Roosevelt NP	ND	17.74	16.71	16.51	16.61	16.58	7.31
Great Gulf Wilderness	NH	22.82	16.73	17.01	17.05	17.01	11.31

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Presidential Range-Dry River Wilderness	NH	22.82	16.68	16.97	17.00	16.96	11.33
Brigantine	NJ	29.01	21.56	21.88	21.93	21.84	11.28
Bandelier NM	NM	11.97	10.89	10.88	10.77	10.75	7.02
Bosque del Apache	NM	13.81	12.78	12.76	12.63	12.61	6.97
Carlsbad Caverns NP	NM	17.19	14.93	15.00	15.03	15.00	7.02
Gila Wilderness	NM	13.12	12.57	12.56	12.53	12.52	6.95
Pecos Wilderness	NM	9.60	9.08	9.07	9.01	8.99	7.04
Salt Creek	NM	18.27	16.70	16.70	16.67	16.64	6.99
San Pedro Parks Wilderness	NM	10.42	9.87	9.87	9.78	9.77	7.03
Wheeler Peak Wilderness	NM	9.60	8.92	8.92	8.82	8.80	7.07
White Mountain Wilderness	NM	13.01	12.16	12.16	12.20	12.19	6.98
Jarbidge Wilderness	NV	12.26	11.98	11.98	11.98	11.97	7.10
Wichita Mountains	OK	23.81	19.38	19.18	19.29	19.18	11.07
Crater Lake NP	OR	13.21	12.52	12.51	12.62	12.60	7.71
Diamond Peak Wilderness	OR	13.21	12.45	12.44	12.56	12.54	7.77
Eagle Cap Wilderness	OR	17.34	16.36	16.36	16.51	16.48	7.34
Gearhart Mountain Wilderness	OR	13.21	12.69	12.68	12.68	12.66	7.46

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Hells Canyon Wilderness	OR	19.00	18.00	18.00	17.82	17.76	7.32
Kalmiopsis Wilderness	OR	16.38	15.48	15.46	15.60	15.56	7.71
Mount Hood Wilderness	OR	14.68	13.33	13.30	13.53	13.46	7.77
Mount Jefferson Wilderness	OR	15.80	14.96	14.95	15.12	15.09	7.81
Mount Washington Wilderness	OR	15.80	14.95	14.93	15.12	15.09	7.89
Mountain Lakes Wilderness	OR	13.21	12.44	12.43	12.57	12.55	7.57
Strawberry Mountain Wilderness	OR	17.34	16.66	16.65	16.55	16.51	7.49
Three Sisters Wilderness	OR	15.80	15.02	15.01	15.18	15.15	7.87
Cape Romain	SC	26.48	20.61	20.72	20.76	20.69	11.36
Badlands NP	SD	17.14	15.56	15.50	15.56	15.54	7.30
Wind Cave NP	SD	15.84	14.81	14.72	14.77	14.75	7.24
Great Smoky Mountains NP	TN	30.28	22.32	22.57	22.62	22.52	11.44
Joyce-Kilmer-Slickrock Wilderness	TN	30.28	22.03	22.29	22.34	22.25	11.45
Big Bend NP	TX	17.30	15.76	15.71	15.75	15.72	6.93
Guadalupe Mountains NP	TX	17.19	14.95	15.03	15.06	15.03	7.03

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
Arches NP	UT	10.77	10.13	10.13	10.20	10.18	6.99
Bryce Canyon NP	UT	11.62	10.95	10.95	10.93	10.93	6.99
Canyonlands NP	UT	10.77	10.15	10.13	10.24	10.21	7.01
Capitol Reef NP	UT	10.86	10.46	10.46	10.53	10.52	7.03
James River Face Wilderness	VA	29.12	20.45	20.61	20.65	20.56	11.24
Shenandoah NP	VA	29.31	20.24	20.67	20.69	20.61	11.25
Lye Brook Wilderness	VT	24.45	17.72	17.75	17.80	17.67	11.25
Alpine Lake Wilderness	WA	16.99	15.59	15.55	15.35	15.22	7.86
Glacier Peak Wilderness	WA	13.29	12.26	12.25	12.26	12.24	7.80
Goat Rocks Wilderness	WA	12.67	11.54	11.52	11.60	11.56	7.82
Mount Adams Wilderness	WA	12.67	11.57	11.56	11.65	11.61	7.78
Mount Rainier NP	WA	17.07	15.77	15.75	15.80	15.75	7.90
North Cascades NP	WA	13.29	12.24	12.23	12.18	12.17	7.78
Olympic NP	WA	15.83	14.63	14.61	14.71	14.65	7.88
Pasayten Wilderness	WA	15.35	14.34	14.32	14.48	14.46	7.77
Dolly Sods Wilderness	WV	29.05	20.23	20.82	20.84	20.79	11.32
Otter Creek Wilderness	WV	29.05	20.34	20.90	20.93	20.87	11.33
Bridger Wilderness	WY	10.73	10.38	10.38	10.39	10.39	7.08
Fitzpatrick Wilderness	WY	10.73	10.38	10.38	10.38	10.38	7.09
Grand Teton NP	WY	11.19	10.73	10.72	10.68	10.66	7.09

Class 1 Area (20% worst days)	State	2005 Baseline Visibility (dv)[a]	2017 Reference	2017 Tier 3 Control	2030 Reference	2030 Tier 3 Control	Natural Background
North Absaroka Wilderness	WY	11.30	10.99	10.99	10.97	10.97	7.09
Teton Wilderness	WY	11.19	10.81	10.80	10.77	10.75	7.09
Washakie Wilderness	WY	11.30	10.99	10.99	10.97	10.96	7.09
Yellowstone NP	WY	11.19	10.76	10.76	10.70	10.69	7.12

[a] 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 6.3.2.1 of this draft 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.

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.[TT] 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

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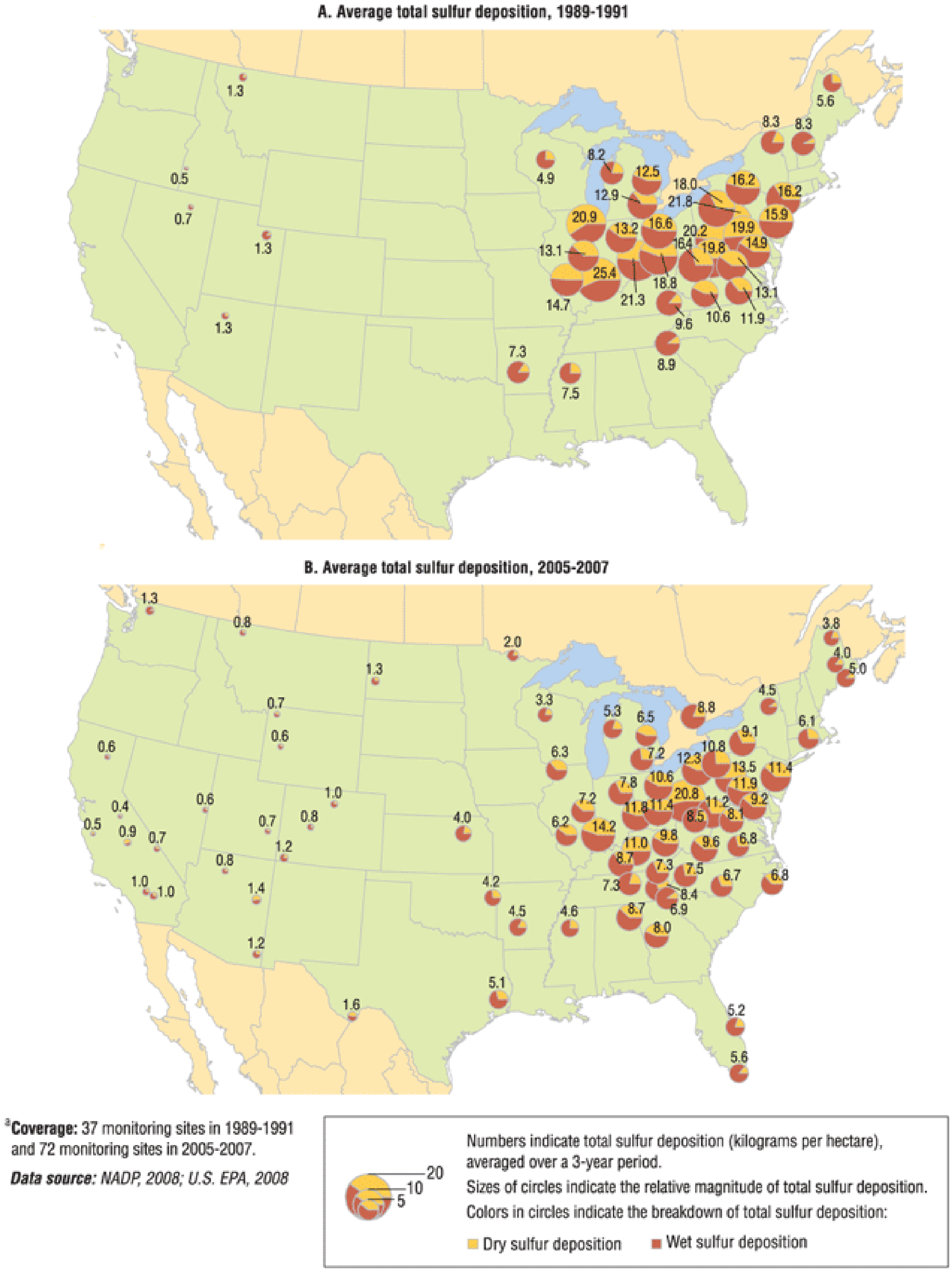
[TT] U.S. EPA. (2012). U.S. EPA's Report on the Environment. Data accessed online February 15, 2012 at: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewPDF&ch=46&lShowInd=0&subtop=341&lv=list.listByChapter&r=216610 and contained in Docket EPA-HQ-OAR-2011-0135.

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.[UU]

[UU] 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.


A. Average total sulfur deposition, 1989-1991

B. Average total sulfur deposition, 2005-2007

[a]**Coverage:** 37 monitoring sites in 1989-1991 and 72 monitoring sites in 2005-2007.

Data source: *NADP, 2008; U.S. EPA, 2008*

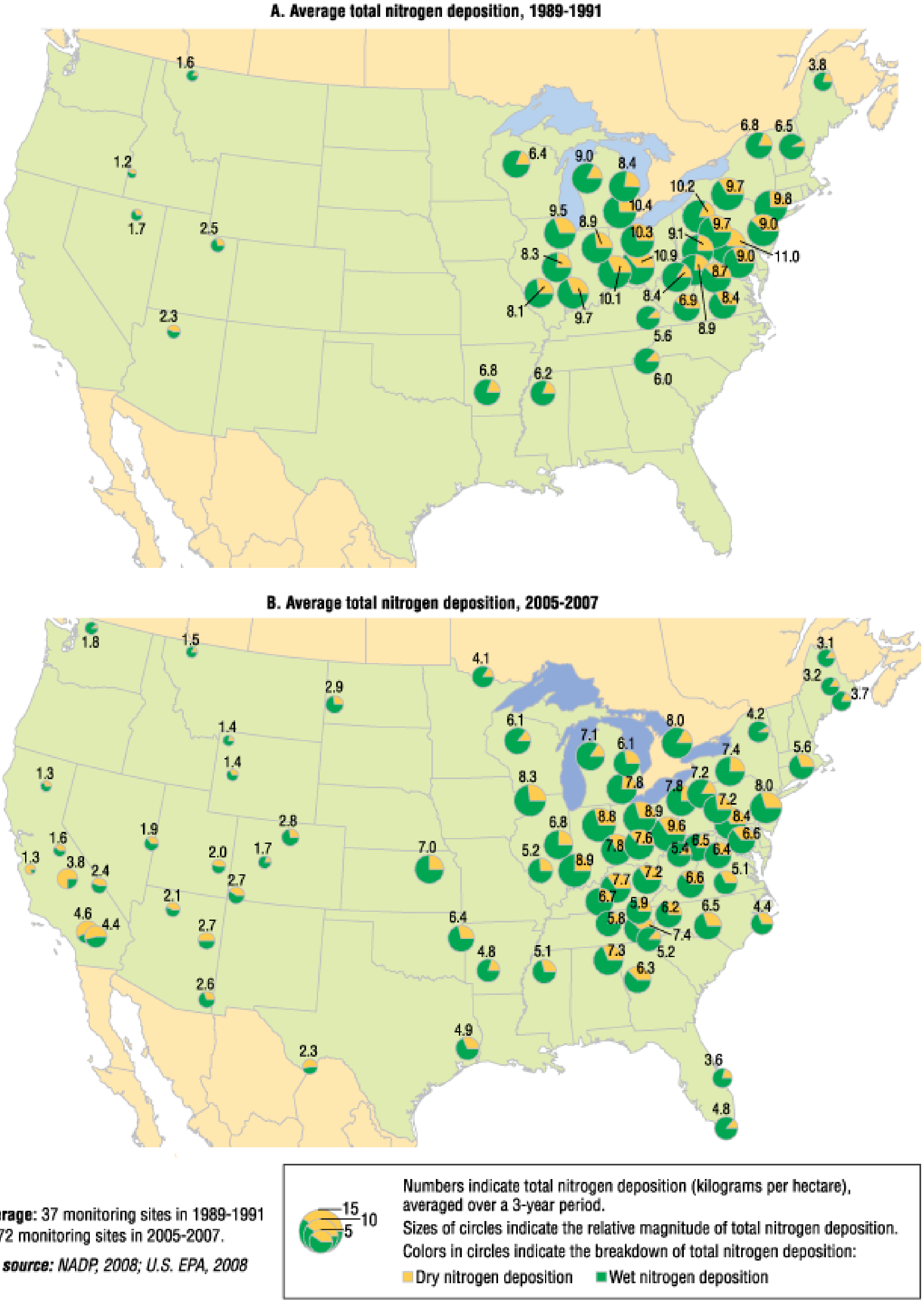
Numbers indicate total sulfur deposition (kilograms per hectare), averaged over a 3-year period.

Sizes of circles indicate the relative magnitude of total sulfur deposition.

Colors in circles indicate the breakdown of total sulfur deposition:

🟨 Dry sulfur deposition 🟥 Wet sulfur deposition

Figure 7-42 Total Sulfur Deposition in the Contiguous U.S., 1989-1991 and 2005 -2007



[a] **Coverage:** 37 monitoring sites in 1989-1991 and 72 monitoring sites in 2005-2007.

Data source: *NADP, 2008; U.S. EPA, 2008*

Numbers indicate total nitrogen deposition (kilograms per hectare), averaged over a 3-year period.
Sizes of circles indicate the relative magnitude of total nitrogen deposition.
Colors in circles indicate the breakdown of total nitrogen deposition:
🟨 Dry nitrogen deposition 🟩 Wet nitrogen deposition

Figure 7-43 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 proposed rule. Figure 7-44 shows that for nitrogen deposition by 2030 the proposed standards would result in annual percent decreases of more than 5 percent in most urban areas with decreases of more than 7 percent in urban areas in Nevada, Arizona and Florida. In addition, smaller decreases, in the 1 to 1.5 percent range, would occur over most of the rest of the country.

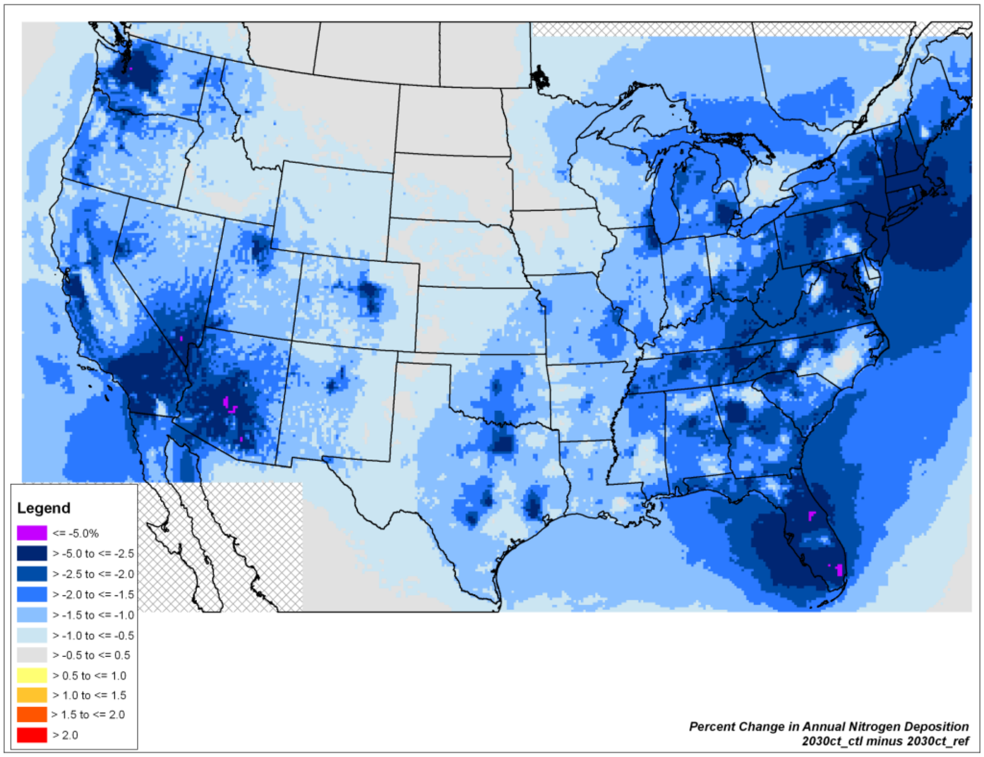


Figure 7-44 Percent Change in Annual Total Nitrogen over the U.S. Modeling Domain as a Result of the Proposed Standards

Figure 7-45 shows that for sulfur deposition the proposed standards will result in annual percent decreases of more than 2 percent in some 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.

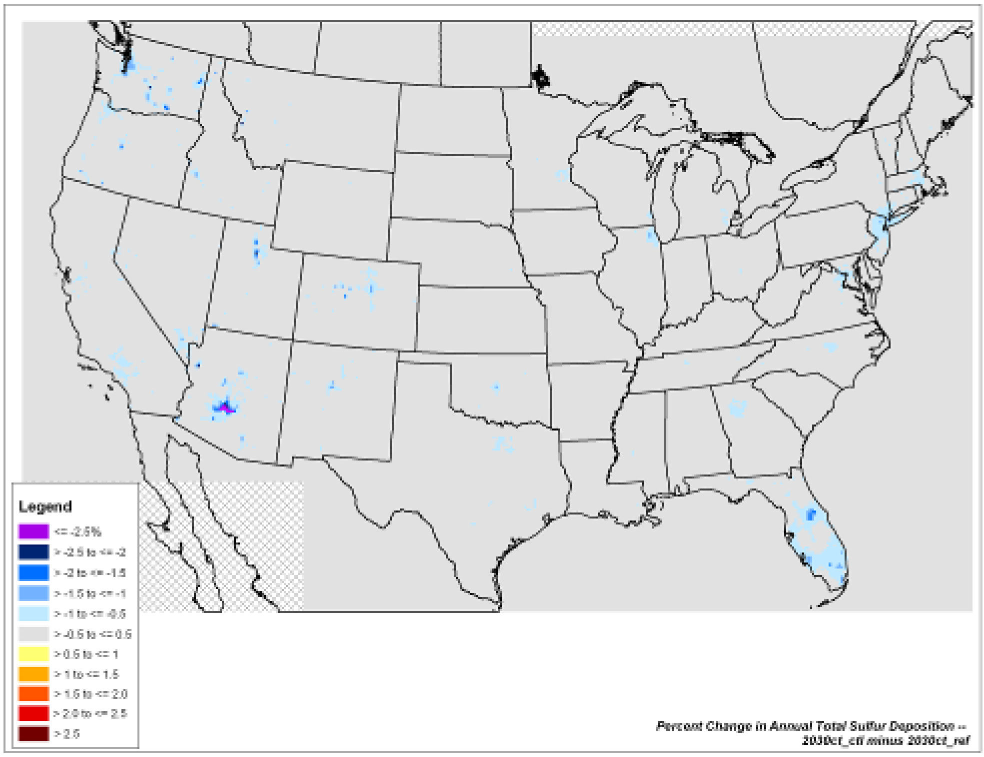


Figure 7-45 Percent Change in Annual Total Sulfur over the U.S. Modeling Domain as a Result of the Proposed Standards

7.3 Greenhouse Gas Emission Impacts

Reductions in nitrous oxide (N_2O) emissions and methane (CH_4) emissions, both potent greenhouse gas emissions (with global warming potentials 298 and 25 times greater than CO_2, respectively), are projected for gasoline cars and trucks due to the proposed sulfur and tailpipe standards. These projections are based on studies that provide a basis for reductions in N_2O and CH_4 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_2O emissions over the FTP and a 50 percent reduction over the US06 when sulfur was reduced from 30 to 5 ppm.[148] EPA's sulfur study, detailed in Section 7.2, found a 25 percent reduction in CH_4 emissions when sulfur was reduced from 28 to 5 ppm (the EPA study did not measure N_2O emissions).

Several studies have also established that reductions in tailpipe standards for NO_X and HC results in reductions in and N_2O and CH_4, respectively. N_2O is unique in that it is not formed primarily 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_2O formation. Studies conducted by EPA and Environment Canada found that N_2O emission are lower on vehicles certified to more stringent NO_X emission standards.[149,150] A study by Meffert, et al. established a strong correlation between improvements in NO_X catalytic conversion efficiency and reductions in N_2O

emissions.[151] A study published by Behrentz, et al. in 2004 examined the relationship between N_2O and NO_X from data collected by the California Air Resources Board on cars and light trucks ranging from the mid-1980s through early 2000's Low Emission Vehicle (LEV) technology.[152] The study reported an N_2O: NO_X ratio of 0.095±0.035 (with the lower end of the range comprised of older oxidation catalyst technologies, and the higher end of the range comprised of modern three-way catalyst technologies), and supported the application of N_2O: NO_X ratios to NO_X emissions as a reasonable method for estimating N_2O emission inventories. Subsequent analysis of this dataset by Meszler also found that for vehicles equipped with more modern controls, N_2O emissions increased with vehicle mileage, suggesting deterioration in N_2O emissions as vehicles age. [153]

The Meszler and Environment Canada studies cited above also established that vehicles certified to more stringent HC standards emit less CH_4, 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_4 and HC emissions. MOVES estimates methane as a function of total HC emissions, so the CH_4 emission inventories account for effects such as deterioration, temperature, aggressive driving, and reductions in tailpipe emission standards. Because of this, CH_4 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_4 from using low sulfur fuel is about double that for total HC (Table 7-13)). The MOVES results are shown in Table 7-40.

Table 7-40: Estimated Reduction in CH_4 from Tier 3 Program ($MMTCO_2eq$)

	2017	**2030**
Reference case onroad mobile emissions	2.1	2.5
Control case onroad mobile emissions	2.0	2.0
Reduction	**0.1**	**0.5**

MOVES N_2O emissions are based directly on a limited sample of N_2O emission data, rather than linking N_2O emissions to NO_X emissions as suggested by Behrentz; as a result, the model does not estimate potential N_2O reduction concurrent with the Tier 3 program. Because of this, the MOVES-based inventories are significantly lower than inventories that take into account the N_2O:NO_X link, because they do not account for factors affecting light-duty NO_X emissions, like deterioration or aggressive driving, and lower NO_X standards. To estimate N_2O reductions, we have calculated N_2O reductions due to vehicle standards on the Tier 3 fleet (2017 and later model year vehicles), using the 0.095 N_2O:NO_X factor from Behrentz. For the pre-Tier 3 fleet, we then bounded the N_2O reductions due to sulfur control using two methods: 1) applying the 0.095 N_2O: NO_X ratio directly to the sulfur-related NO_X reductions reported in Section 7.2; and 2) applying the percent reduction in N_2O from the UC Riverside study to current MOVES inventory estimates for onroad gasoline vehicles. These two methods are outlined in Table 7-41, along with the range of reductions that result.

Table 7-41: Estimated Reduction in N_2O from the Tier 3 Program

	2017	**2030**
Reduction from Tier 3 fleet		
NO_X reduction from Tier 3 fleet due to vehicle and sulfur standards (U.S. Short Tons)	19,728	458,504
N_2O reduction based on N_2O:NO_X ratio of 0.095 ($MMTCO_2eq^a$)	0.5	11.8
Reduction from pre-Tier 3 fleet		
Method 1		
Reference case onroad gasoline NO_X emissions (U.S. Short Tons)	1,844,772	980,679
Reference case onroad gasoline N_2O emissions based on N_2O:NO_X ratio of 0.095 ($MMTCO_2eq^a$)	47.4	25.2
Reduction from pre-Tier 3 fleet due to sulfur standard (U.S. Short Tons)	264,653	66,286
N_2O reduction based on N_2O:NO_X ratio of 0.095 ($MMTCO_2eq^a$)	6.8	1.7
Method 2		
U.S. onroad gasoline N_2O emissions from pre-Tier 3 fleet using MOVES ($MMTCO_2e$)	10.3	2.0
Percent reduction in N_2O going from 30 to 10 ppm	23% [b]	23%
N_2O reduction ($MMTCO_2eq$)	2.4	0.5
Total Range of N_2O Reduction ($MMTCO_2eq$)	**2.9 –7.3**	**12.3-13.5**

[a] Using GWP of 298 [VV]

[b] 29 percent from 25ppm sulfur reduction in UC Riverside study scaled to 20ppm reduction

Summing the results from Tables 7-40 and 7-41, the range of reductions calculated for CH_4 and N_2O is from 3.0 to 7.4 million metric tons of carbon dioxide equivalent ($MMTCO_2eq$) in 2017, growing to 12.8 to 14.0 $MMTCO_2eq$ in 2030. These reductions would be offset to some degree by CO_2 emissions associated with higher energy use required in the process of removing sulfur. To assess refinery permitting implications, EPA has conducted an analysis of these refinery impacts, and estimates an increase of up to 4.6 $MMTCO_2eq$ million metric tons of carbon dioxide equivalent ($MMTCO_2e$) in 2017 with the implementation of the lower sulfur standards.[154] The actual increase will be lower, since refineries will not be operating at their permit capacity. The actual increase will also be a function of several factors, including

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[VV] 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). At this time, the 1996 IPCC Second Assessment Report (SAR) 100-year GWP values are used in the official U.S. greenhouse gas inventory submission to the United Nations Framework Convention on Climate Change (per the reporting requirements under that international convention, which were last updated in 2006) . N_2O has a 100-year GWP of 298 and CH_4 has a 100-year GWP of 25 according to the 2007 IPCC AR4.

technology options selected by the refineries and the projected use of averaging, banking and trading in avoiding the need for investments at some refineries. As a result, 4.6 MMTCO_2e represents an upper-bound estimate of the possible increase in refinery CO_2 emissions due to the need for additional process heat and hydrogen production to enable additional hydrotreating.

In 2017, the range of potential decrease in CH_4 and N_2O emissions overlaps with the range of projected increase in CO_2 from refinery processes, suggesting that a net increase or decrease in GHG emissions cannot be quantified with certainty. However, we estimate the program would result in net GHG reductions as the program continues into the future, as shown by our 2030 estimates.

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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 2017

The following section presents maps of seasonal changes in ambient concentrations of modeled air toxics in 2017.

Benzene

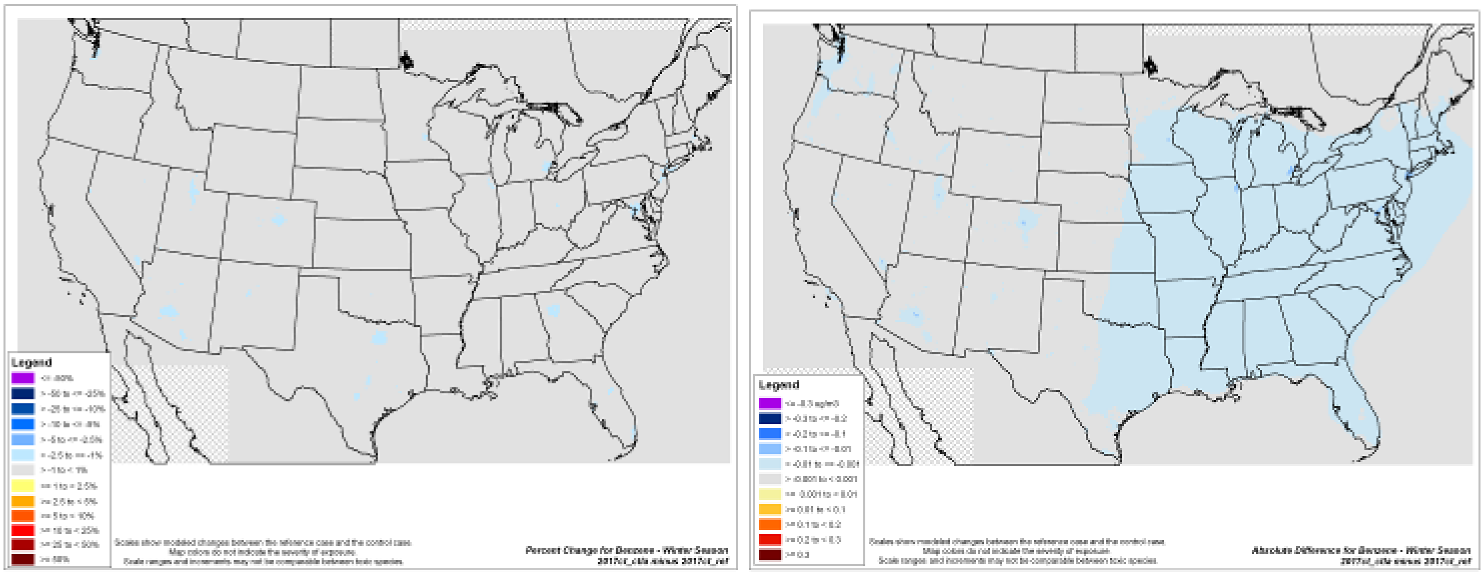

Figure 7A-1 Winter Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

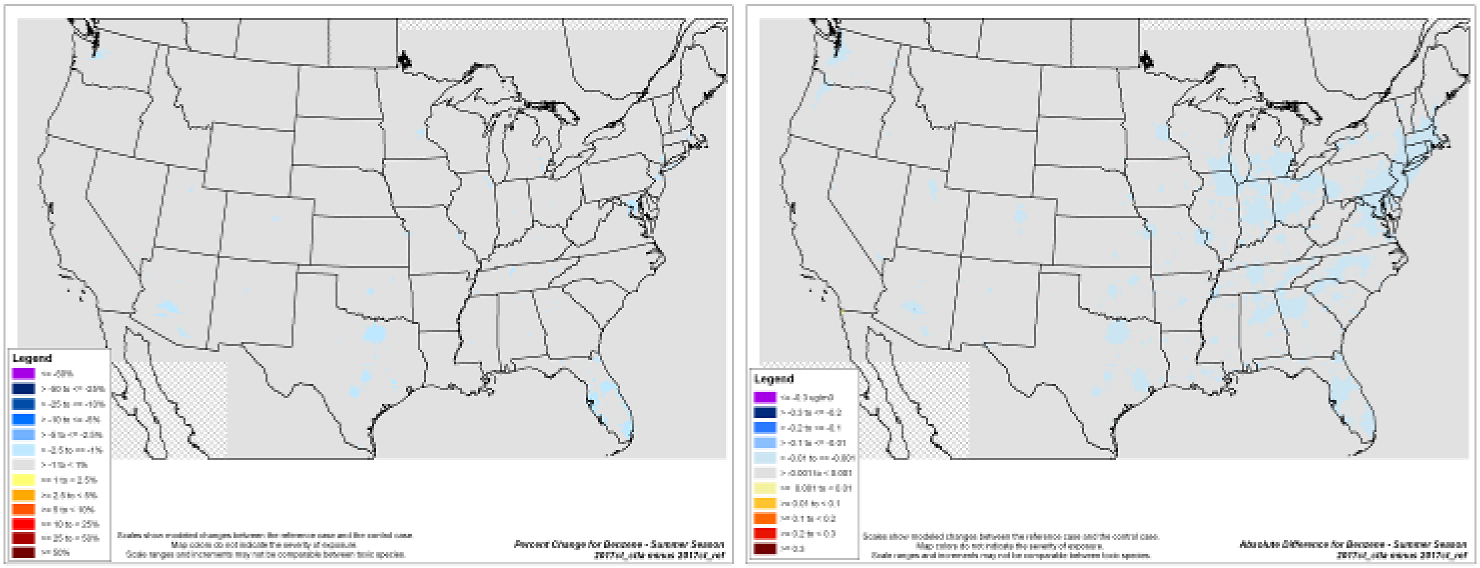

Figure 7A-2 Summer Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

1,3-Butadiene

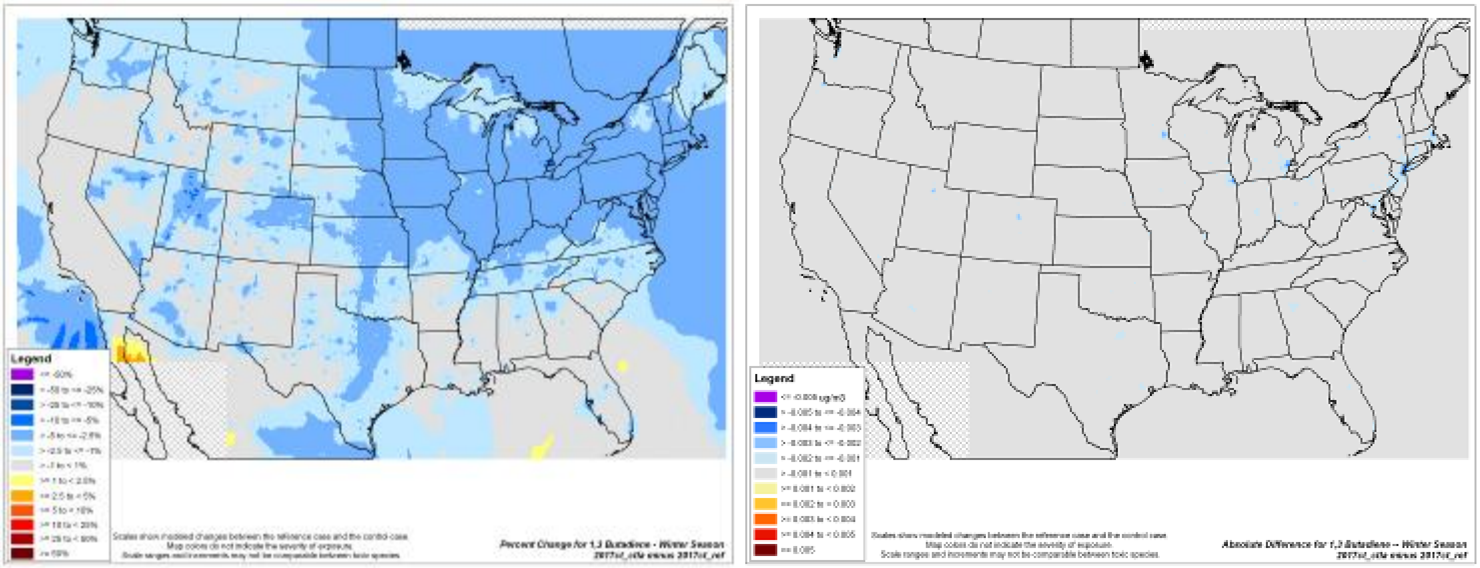

Figure 7A-3 Winter Changes in 1,3-Buatdiene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

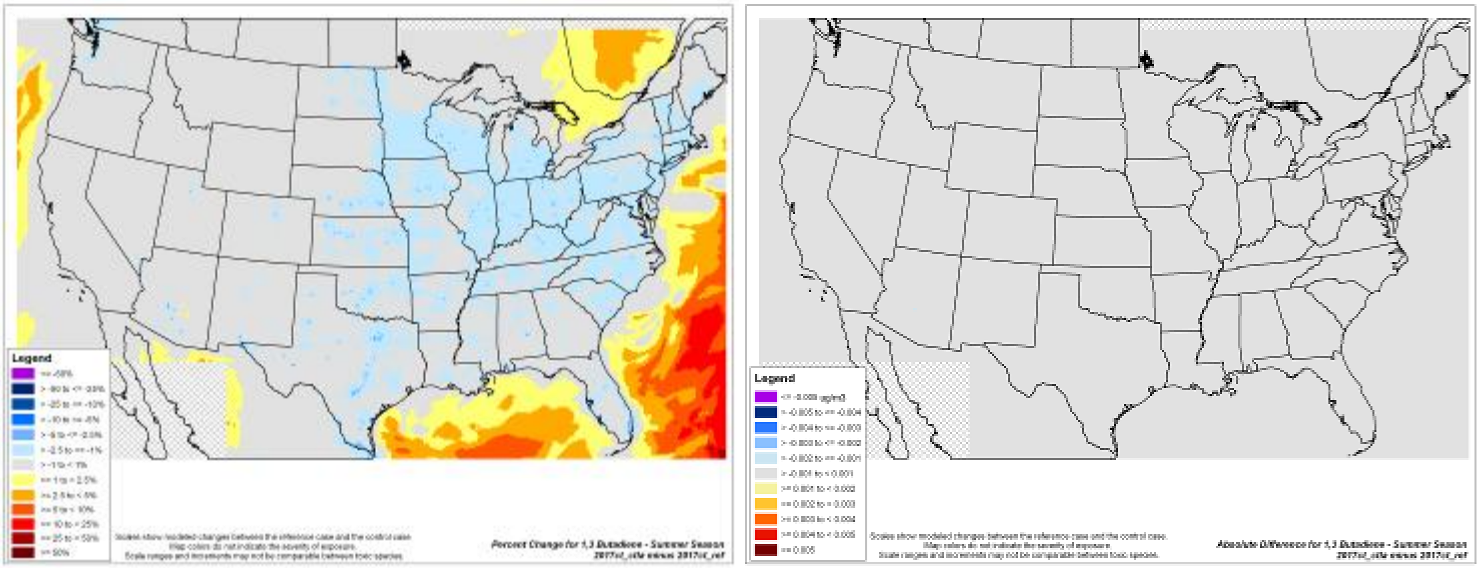

Figure 7A-4 Summer Changes in 1,3-Buatdiene Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Acrolein

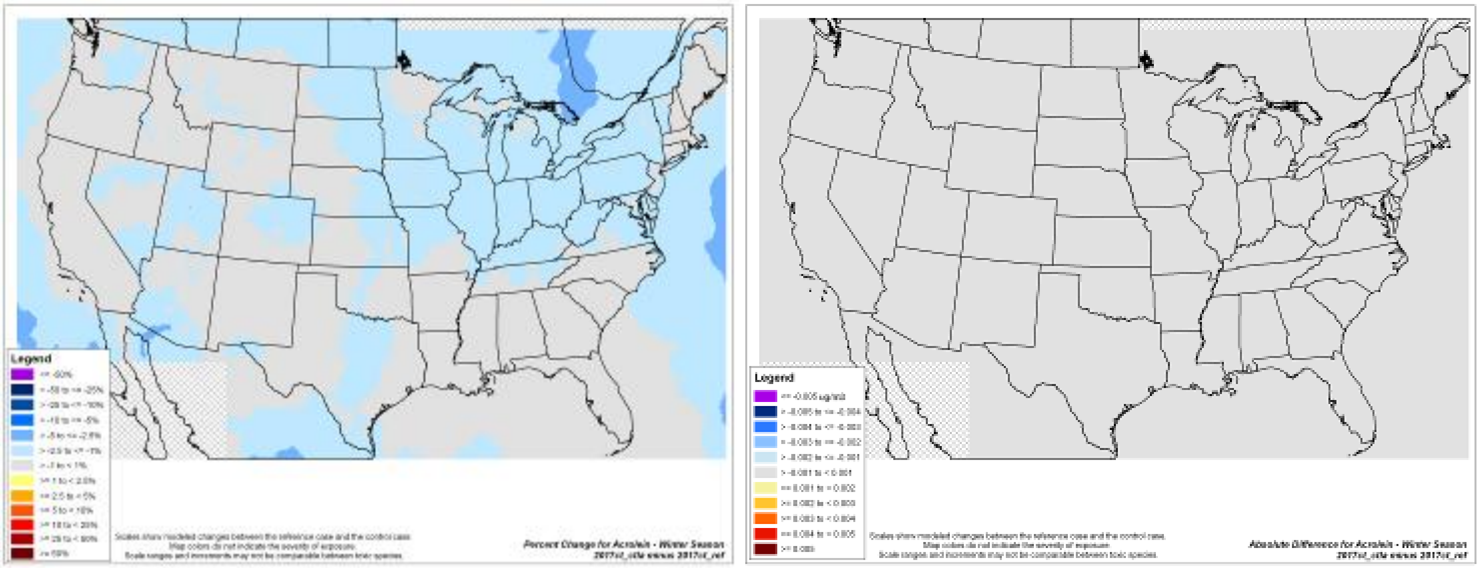

Figure 7A-5 Winter Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

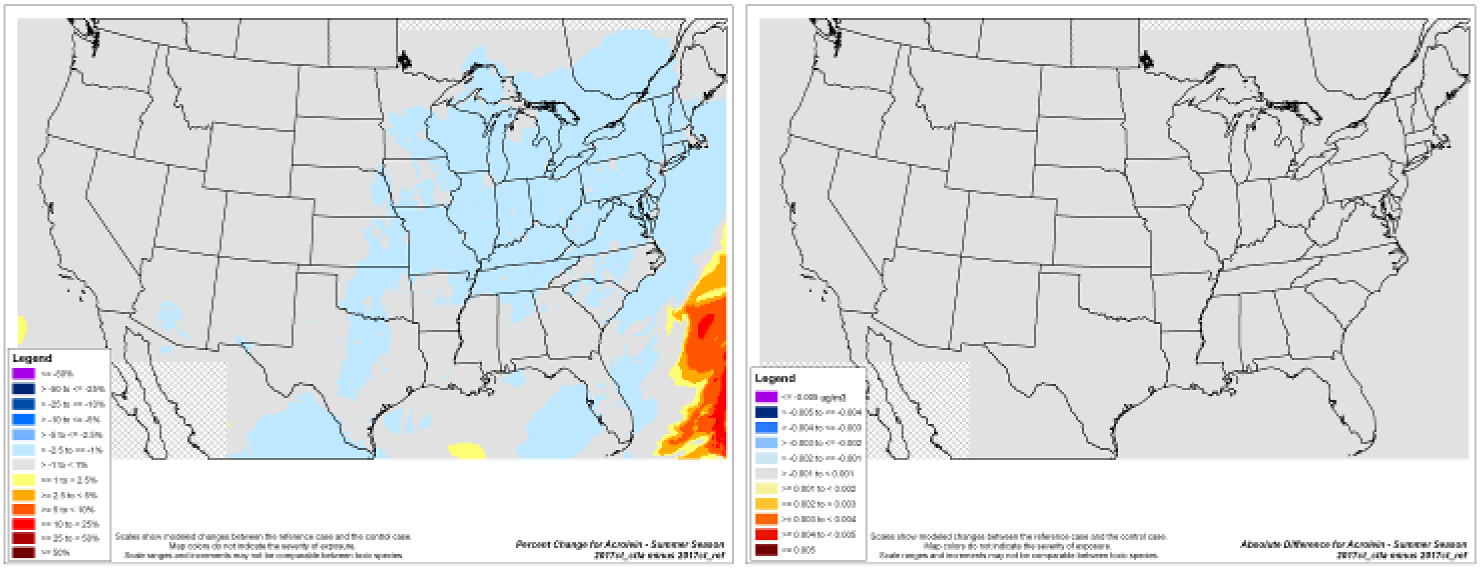

Figure 7A-6 Summer Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Ethanol

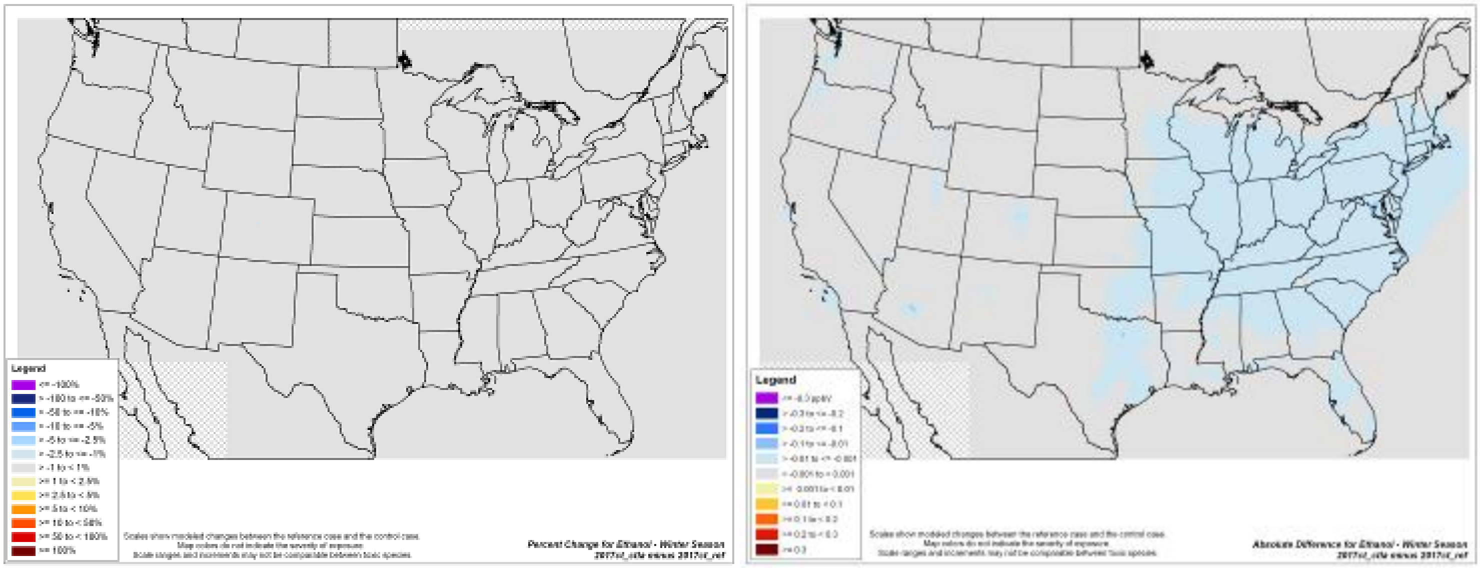

Figure 7A-7 Winter Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

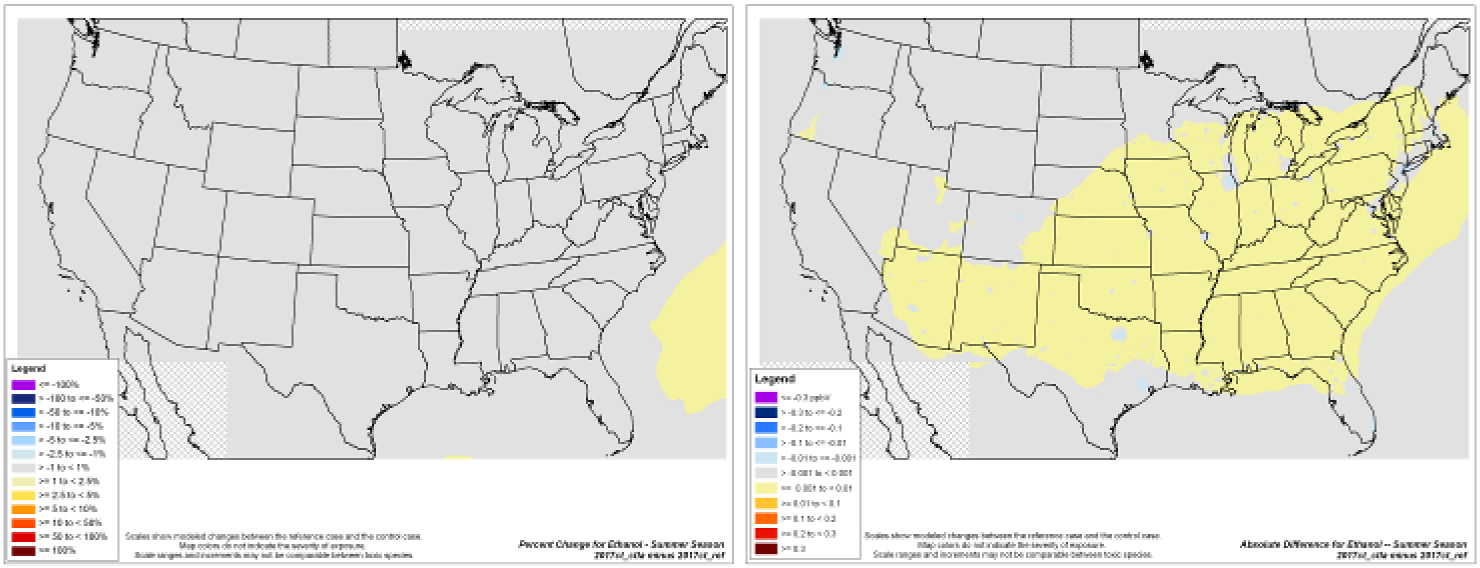

Figure 7A-8 Summer Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Formaldehyde

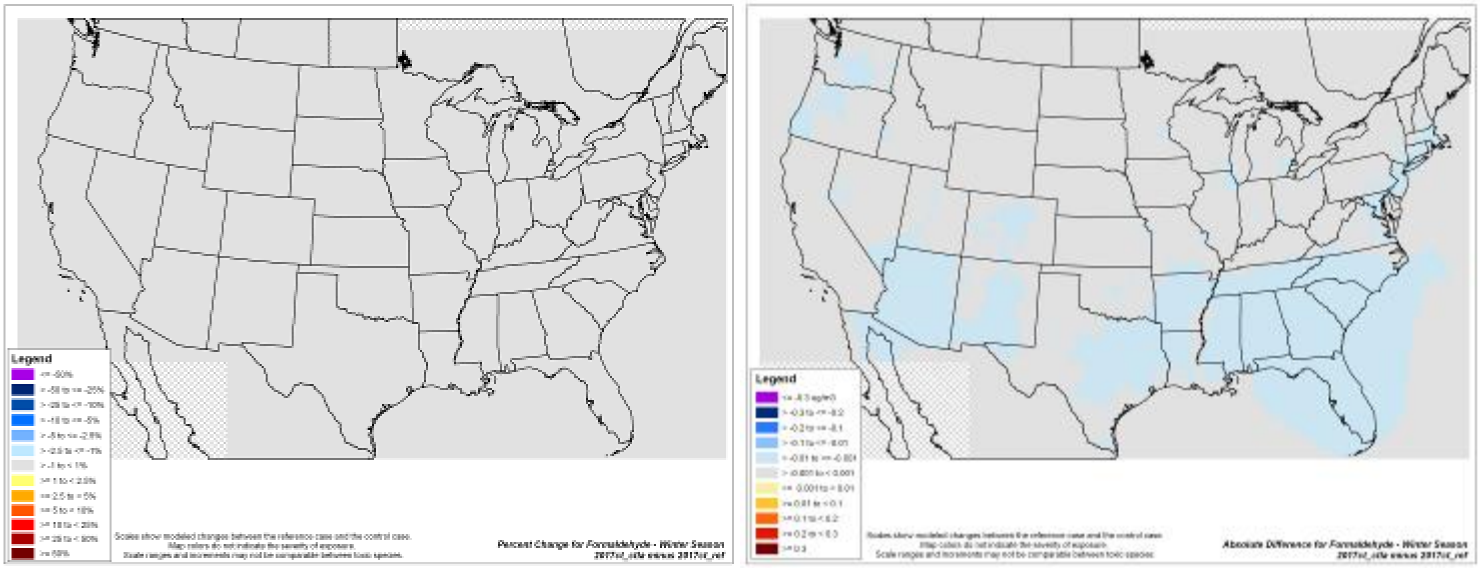

Figure 7A-9 Winter Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

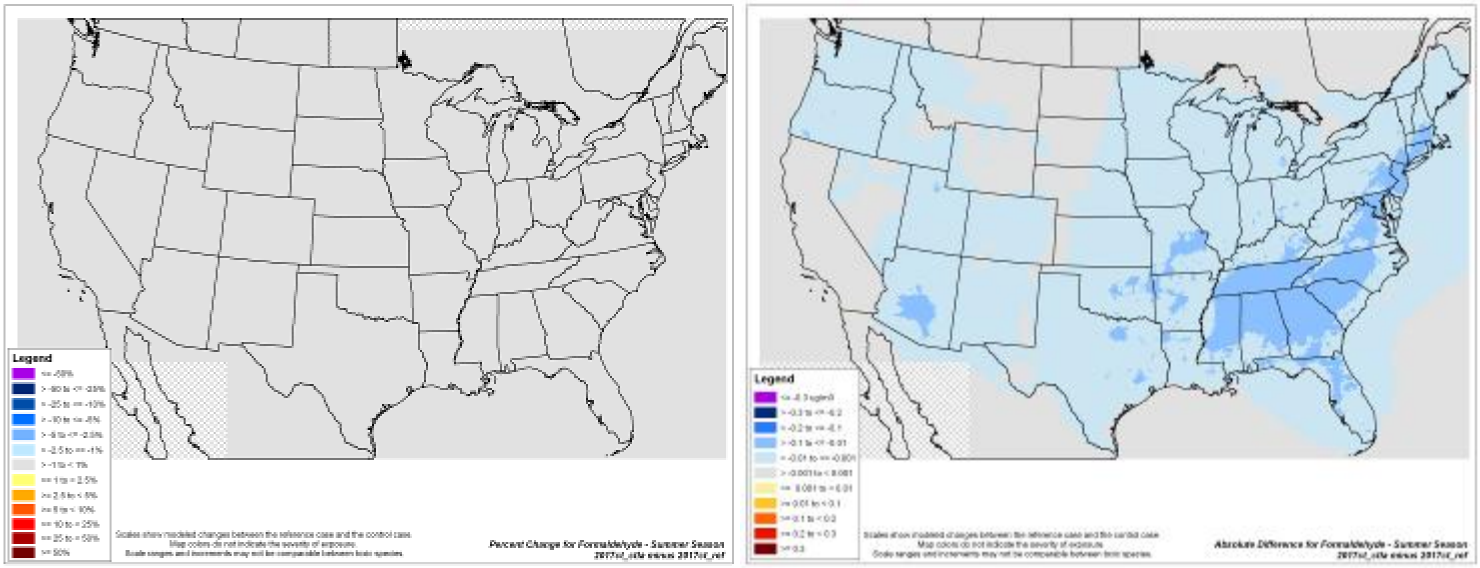

Figure 7A-10 Summer Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Acetaldehyde

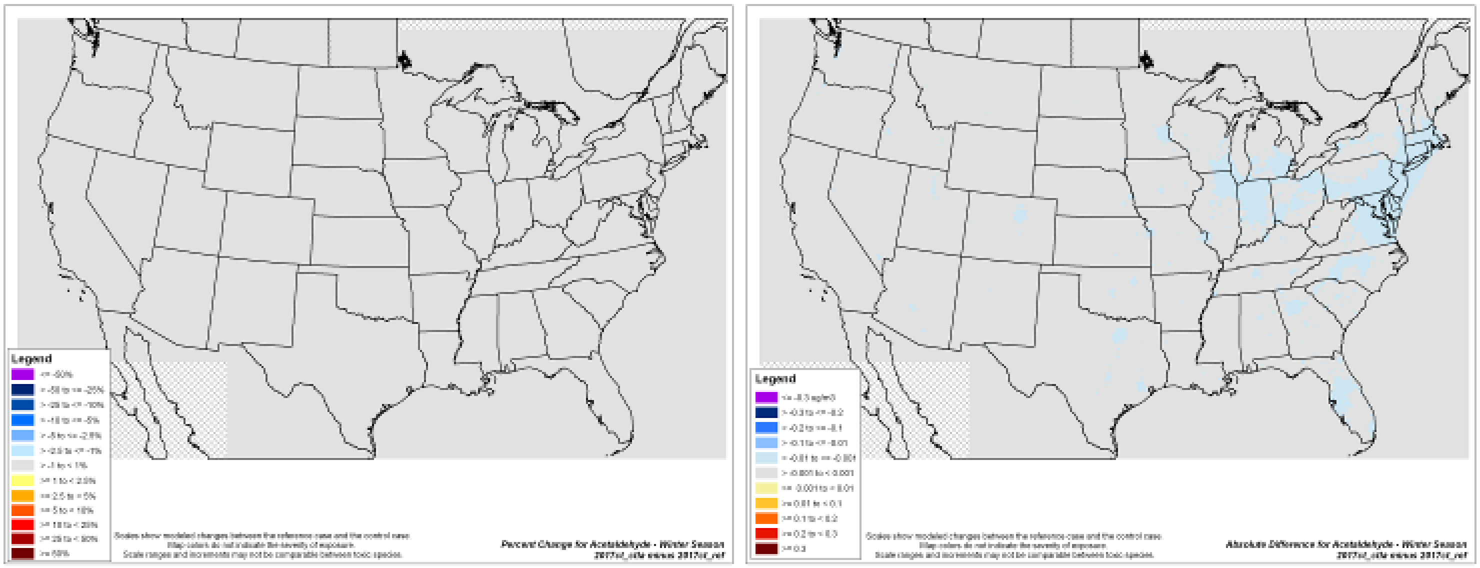

Figure 7A-11 Winter Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

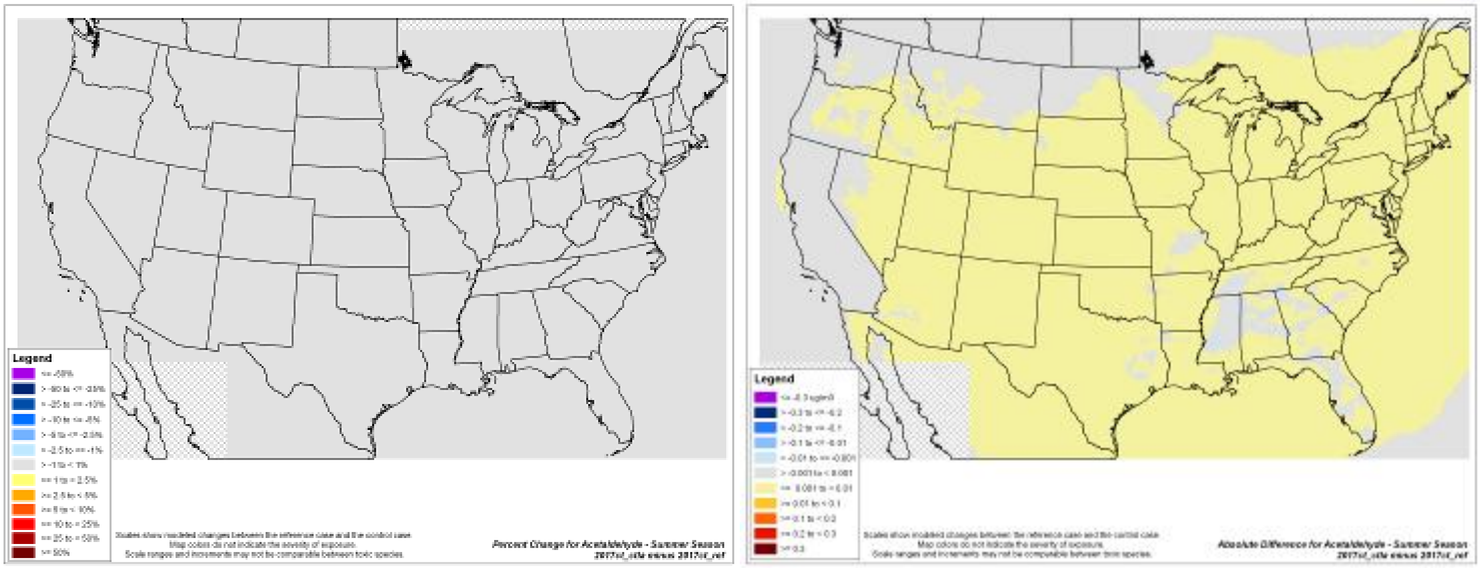

Figure 7A-12 Summer Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2017: Percent Changes (left) and Absolute Changes in µg/m³ (right)

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

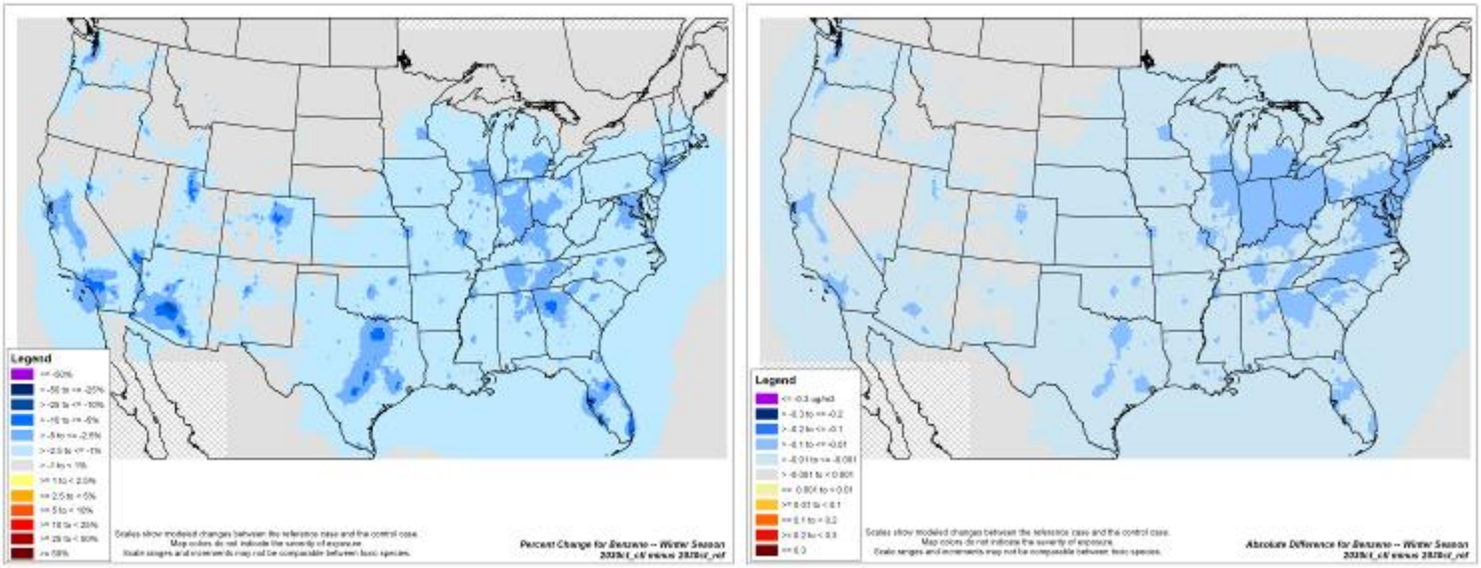

Figure 7A-13 Winter Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

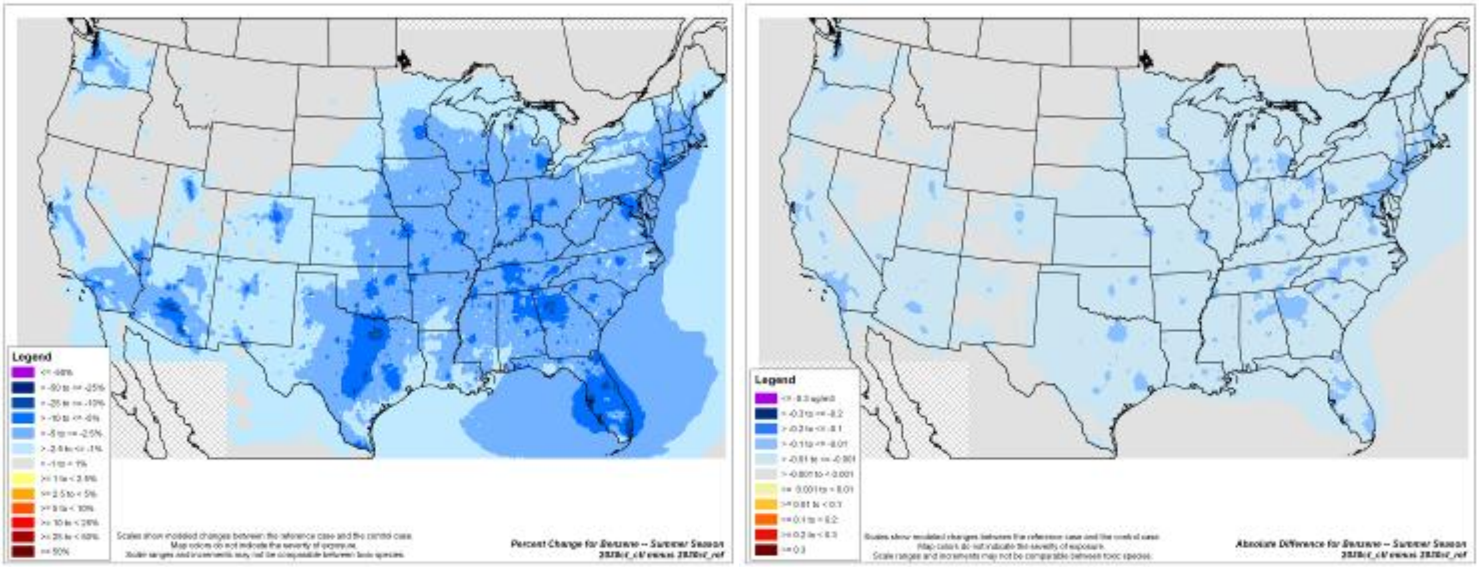

Figure 7A-14 Summer Changes in Benzene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

1,3-Butadiene

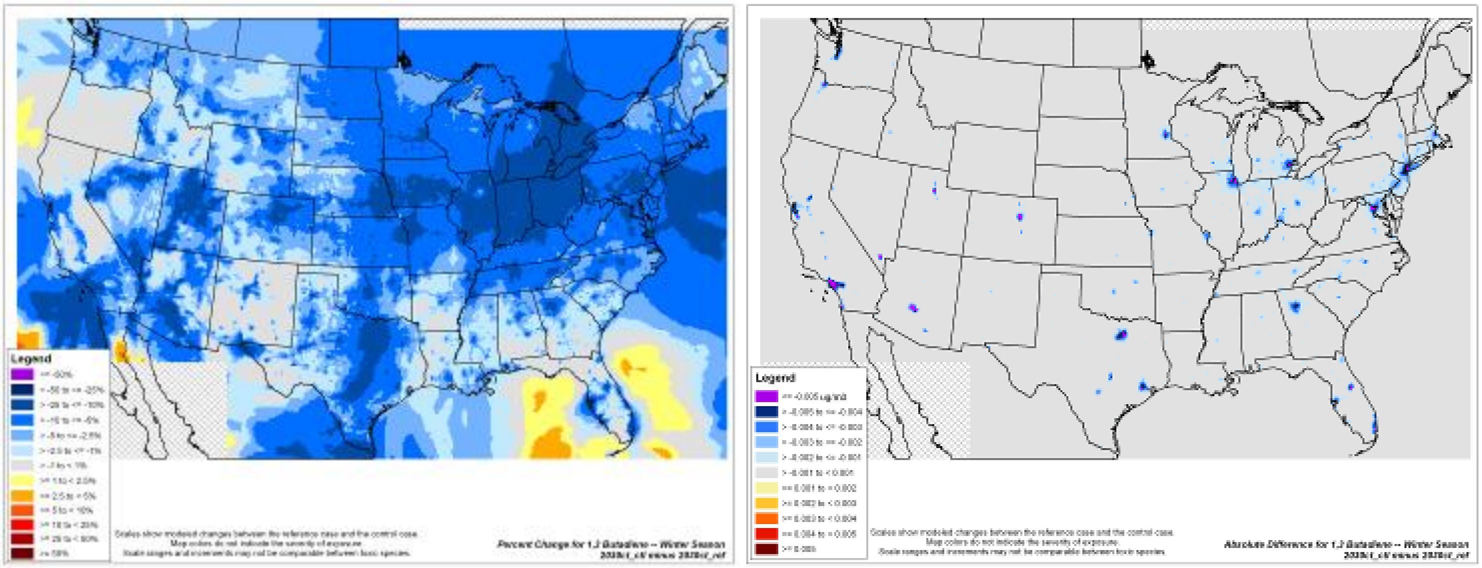

Figure 7A-15 Winter Changes in 1,3-Buatdiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

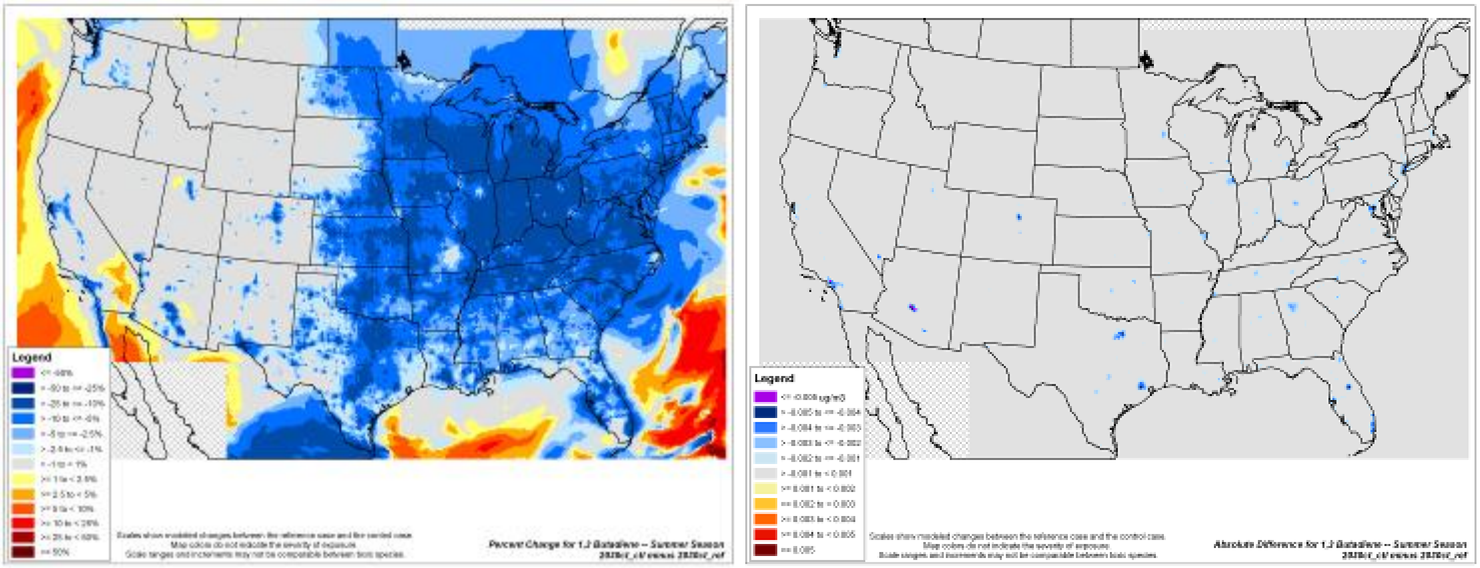

Figure 7A-16 Summer Changes in 1,3-Buatdiene Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Acrolein

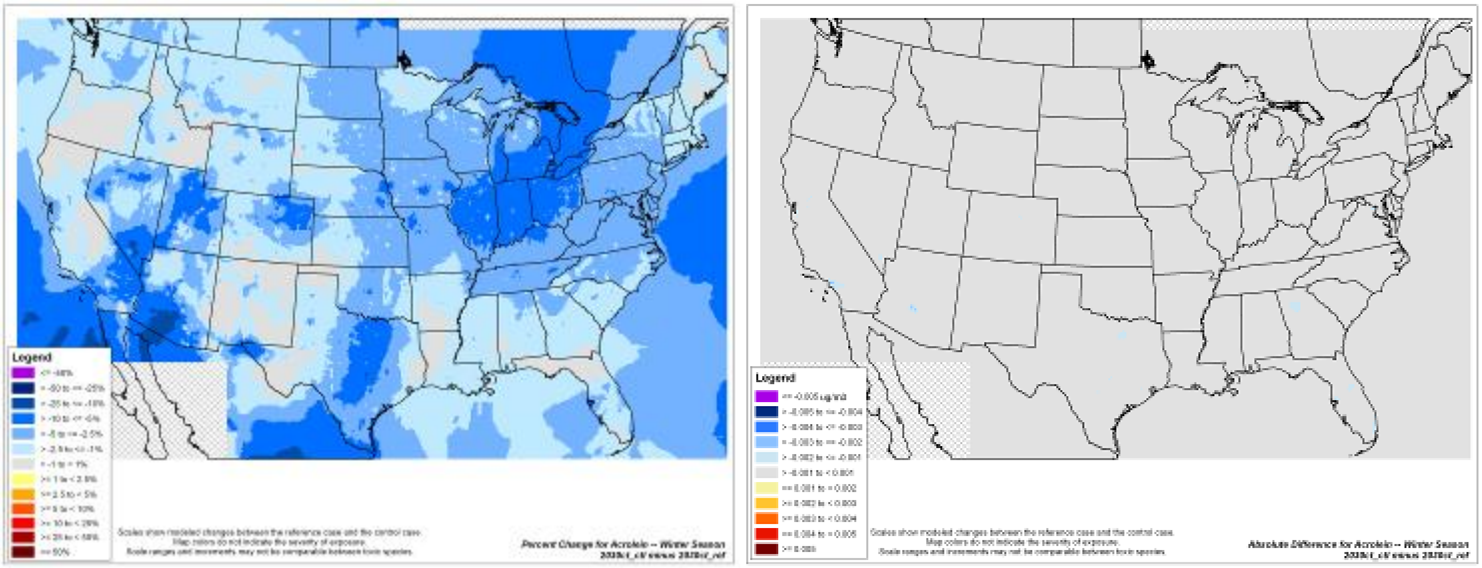

Figure 7A-17 Winter Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

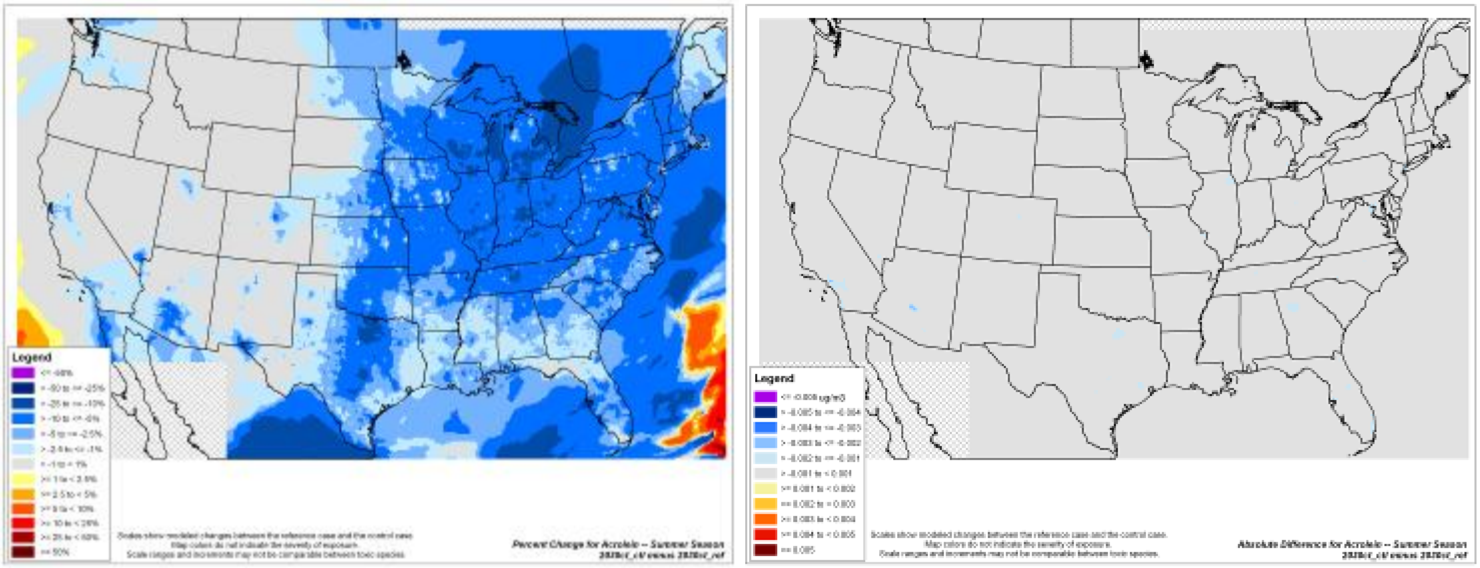

Figure 7A-18 Summer Changes in Acrolein Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Ethanol

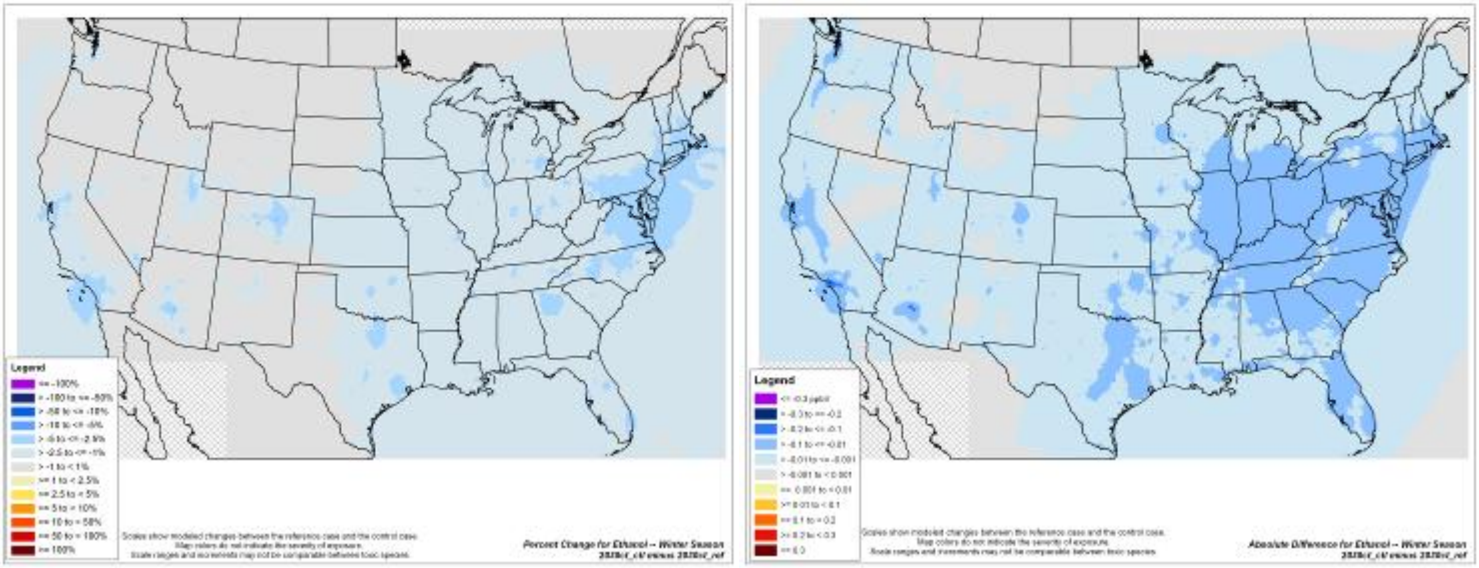

Figure 7A-19 Winter Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

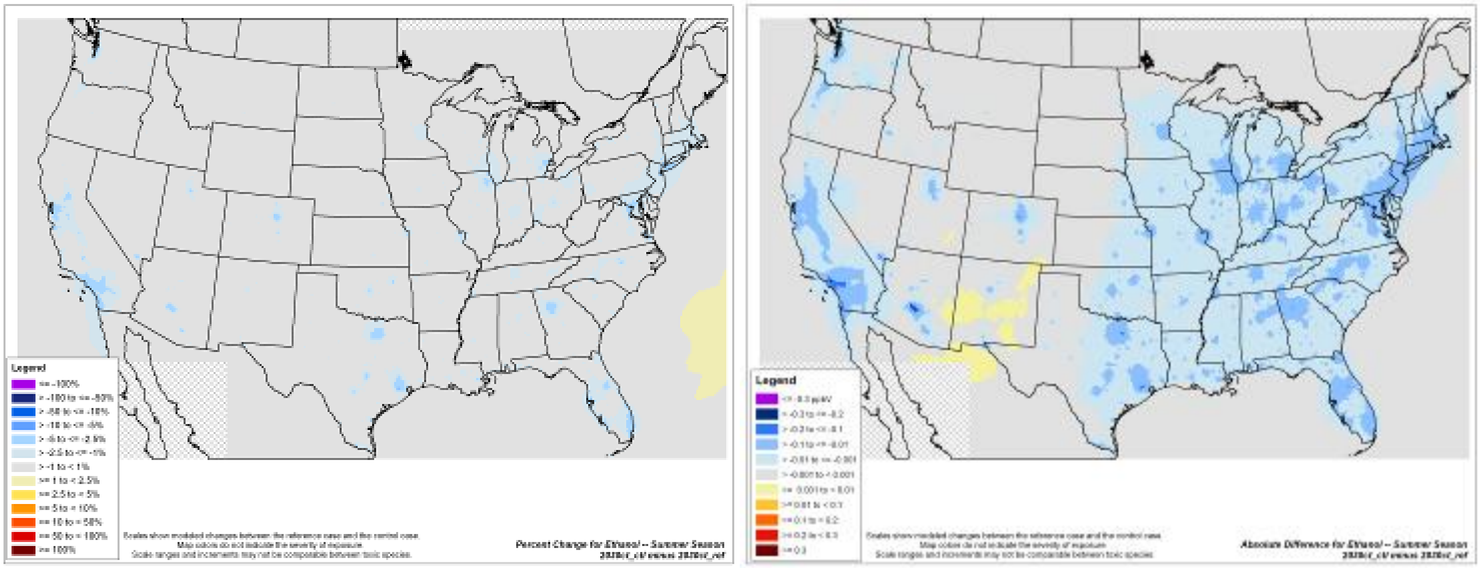

Figure 7A-20 Summer Changes in Ethanol Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Formaldehyde

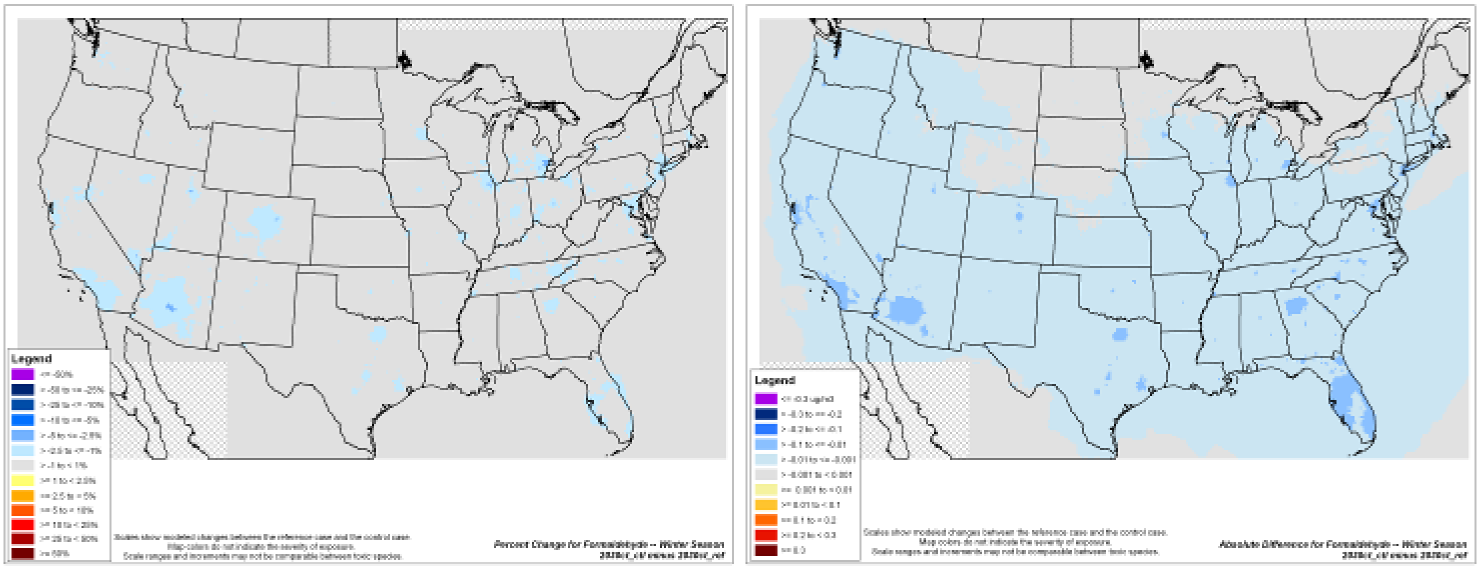

Figure 7A-21 Winter Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

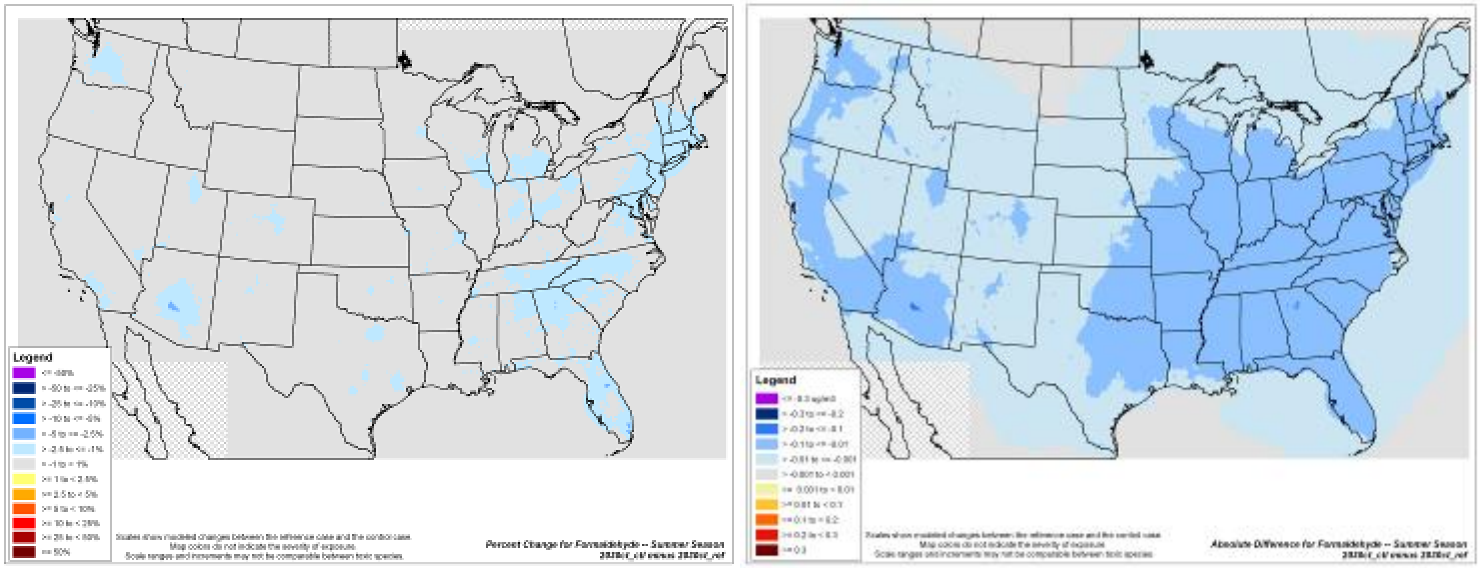

Figure 7A-22 Summer Changes in Formaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in µg/m³ (right)

Acetaldehyde

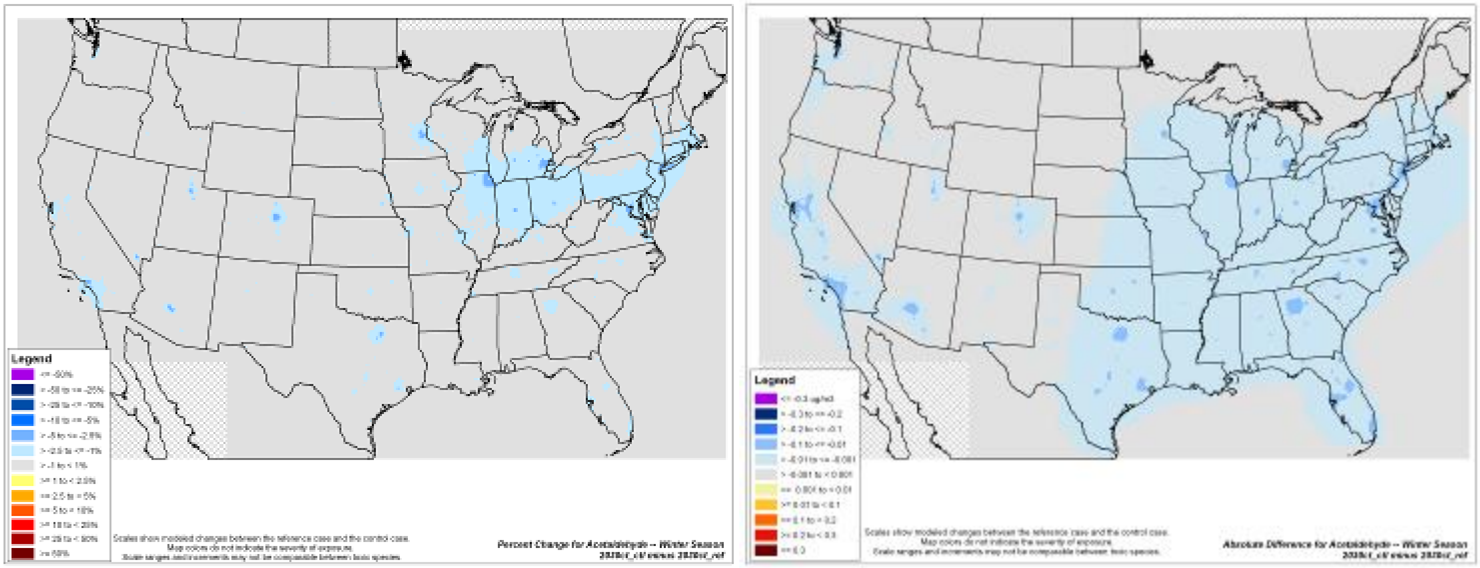

Figure 7A-23 Winter Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in μg/m³ (right)

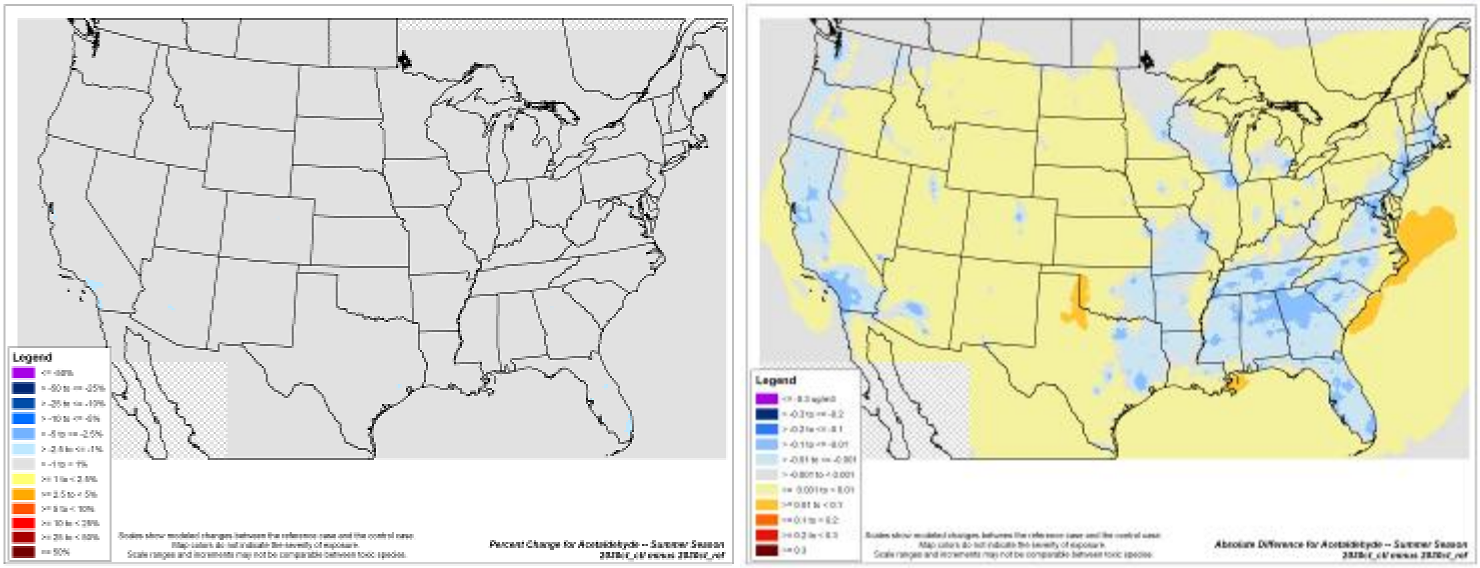

Figure 7A-24 Summer Changes in Acetaldehyde Ambient Concentrations Between the Reference Case and the Control Case in 2030: Percent Changes (left) and Absolute Changes in μg/m³ (right)

Chapter 8 Comparison of Program Costs to Program Emission Reductions and Air Quality Benefits

EPA traditionally evaluates the effectiveness of a proposal in terms of net benefits and in terms of cost per ton of emissions reduced. Section 8.1 below presents the cost-benefit analysis of the proposal, while Section 8.2 presents the cost per ton of emissions reduced.

8.1 Cost-Benefit Analysis

The net benefits of the proposed 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 would be incurred from our proposed 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 proposed program.

All costs represent the fleet-weighted average of light-duty vehicles and trucks. All costs are represented in 2010 dollars.

8.1.1.1 Vehicle Costs

The vehicle costs include the technology costs projected to meet the proposed exhaust and evaporative standards, as detailed in draft 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 2016 MY fleet used in the 2012-2016MY light-duty GHG final rulemaking.

Table 8-1: Annual Vehicle Technology Costs, 2010$

Year	Vehicle Exhaust Emission Control Costs ($Million)	Vehicle Evaporative Emission Control Costs ($Million)	Facility Costs ($Million)	Total Proposed Vehicle Program Costs ($Million)[a]
2016	$0	$0	$22.5	$22.5
2017	$634	$71.4	$3.75	$709
2018	$1,170	$171	$3.75	$1,340
2019	$1,270	$162	$3.75	$1,440
2020	$1,380	$221	$3.75	$1,600
2021	$1,510	$213	$3.75	$1,730
2022	$1,630	$271	$3.75	$1,900
2023	$1,660	$259	$3.75	$1,920
2024	$1,770	$263	$3.75	$2,040
2025	$1,870	$253	$3.75	$2,130

Year	Vehicle Exhaust Emission Control Costs ($Million)	Vehicle Evaporative Emission Control Costs ($Million)	Facility Costs ($Million)	Total Proposed Vehicle Program Costs ($Million)[a]
2030	$1,790	$253	$3.75	$2,050

[a] These estimates include costs associated with the proposed Tier 3 vehicle standards in all states except California.

8.1.1.2 Fuel Costs

The fuel costs consist of the additional operating costs and capital costs to the refiners to meet the proposed sulfur average of 10 ppm. The sulfur control costs, as described in detail in draft RIA Chapter 5, assume a cost of 0.89 cents per gallon which includes the refinery operating and capital costs. The projected annual fuel consumption and annual fuel costs of the proposed program are listed in Table 8-2.

Table 8-2: Annual Fuel Costs, 2010$

Year	Annual Fuel Consumption (million gallons)	Fuel Sulfur Control Costs ($Million)[a]
2016	36,208	$ 322
2017	144,878	$ 1,289
2018	144,710	$ 1,288
2019	144,435	$ 1,285
2020	144,324	$ 1,284
2021	144,562	$ 1,287
2022	144,838	$ 1,289
2023	144,774	$ 1,288
2024	144,812	$ 1,289
2025	145,057	$ 1,291
2030	148,295	$ 1,320

[a] These estimates include costs associated with the proposed 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 proposed program, as shown in Table 8-3.

Table 8-3: Total Annual Vehicle and Fuel Control Costs, 2010$

Year	Total Proposed Vehicle Program Costs ($Million)	Fuel Sulfur Control Costs ($Million)	Total Proposed Program Costs ($Million)[a]
2016	$22.5	$322	$345
2017	$709	$1,289	$1,998
2018	$1,340	$1,288	$2,628
2019	$1,440	$1,285	$2,725
2020	$1,600	$1,284	$2,884
2021	$1,730	$1,287	$3,017
2022	$1,900	$ 1,289	$3,189
2023	$1,920	$1,288	$3,208
2024	$2,040	$1,289	$3,329
2025	$2,130	$1,291	$3,421
2030	$2,050	$1,320	$3,370

[a] These estimates include costs associated with the proposed Tier 3 vehicle and fuel standards in all states except California.

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 proposed Tier 3 standards. The vehicles and fuels subject to the proposed standards are significant sources of mobile source air pollution such as direct PM, NO_X, SO_X, VOCs and air toxics. The standards would affect exhaust and evaporative emissions of these pollutants from vehicles. Emissions of NO_X (a precursor to ozone formation and secondarily-formed $PM_{2.5}$), SO_X (a precursor to secondarily-formed $PM_{2.5}$), VOCs (a precursor to ozone formation and, to a lesser degree, secondarily-formed $PM_{2.5}$) and directly-emitted $PM_{2.5}$ contribute to ambient concentrations of $PM_{2.5}$ and ozone. Exposure to ozone and $PM_{2.5}$ 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 proposed standard by answering two key questions:

1. What are the health and welfare effects of changes in ambient particulate matter ($PM_{2.5}$) and ozone air quality resulting from reductions in precursors including NO_X and SO_2?

2. What is the economic value of these effects?

For the proposal, we have quantified and monetized the health and environmental impacts in 2030, representing impacts associated with a year when the program is fully implemented and most of the fleet is turned over. Overall, we estimate that the proposed standards would lead to a net decrease in $PM_{2.5}$- and ozone-related health impacts in 2030. The decrease in population-weighted national average $PM_{2.5}$ exposure results in a net decrease in adverse PM-related human health impacts (the decrease in national population-weighted annual average $PM_{2.5}$ is 0.05 μg/m^3 in 2030).[A] The 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 0.52 ppb in 2030).

Using the lower end of EPA's range of preferred premature mortality estimates (Pope et al., 2002 for $PM_{2.5}$ and Bell et al., 2004 for ozone),[B,C] we estimate that by 2030, implementation of the proposed standards would reduce approximately 970 premature mortalities annually and yield approximately $9.5 billion in total annual benefits. The upper end of the range of avoided premature mortality estimates associated with the proposed standards (based on Laden et al., 2006 for $PM_{2.5}$ and Levy et al., 2005 for ozone)[D,E] results in approximately 2,800 premature mortalities avoided in 2030 and yields approximately $27 billion in total benefits. Thus, even using the lower end of the range of premature mortality estimates, the health impacts of the proposed standards presented in this rule are clearly 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 this proposal. For this reason, the Tier 3 emission control scenario used in the air quality and benefits modeling includes emission reductions from Tier 3 across the nation, assuming no reductions associated with California's LEV III program (as opposed to including California's LEV III program and its associated emission reductions in the baseline scenario). This was because EPA had not granted California a waiver of preemption under CAA section 209 for the LEV III program at the time EPA conducted the air quality modeling. EPA did include California's fuel program, which independent of LEV III was already resulting in average gasoline sulfur levels of 10 ppm, in the baseline scenario. Since then, EPA granted a waiver for California's LEV III program (78 FR 2112, January 9, 2013) and several states have adopted the LEV III program under Section 177 of the Clean Air Act. Based on this change in circumstances, we will conduct new air quality modeling for the final rule that will include emission reductions from California's LEV III program, both in California and in states that by that time have adopted the LEV III program, in the baseline scenario.

[A] Note that the national, population-weighted $PM_{2.5}$ 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 $PM_{2.5}$ and ozone design value metrics presented in Chapter 7, which represent the average for areas with a current air quality monitor.

[B] Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. (2002). Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution. *Journal of the American Medical Association,* 287, 1132-1141.

[C] Bell, M.L., et al. (2004). Ozone and short-term mortality in 95 US urban communities, 1987-2000.*Journal of the American Medical Association*, *292(19)*, 2372-2378.

[D] Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. (2006). Reduction in Fine Particulate Air Pollution and Mortality. *American Journal of Respiratory and Critical Care Medicine*. *173*, 667-672.

[E] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. (2005). Ozone exposure and mortality: an empiric bayes metaregression analysis. *Epidemiology. 16(4),* 458-68.

Had we modeled the California LEV III emission impacts in the Tier 3 air quality baseline, we estimate that benefits would decrease by approximately 12-16 percent, depending on the particular health impact functions used to characterize both PM- and ozone-related premature mortality.[F] As a result, we estimate that in 2030, using the lower end of EPA's range of preferred premature mortality estimates (Pope et al., 2002 for $PM_{2.5}$ and Bell et al., 2004 for ozone),[G,H] the proposed standards would reduce approximately 820 premature mortalities annually and yield approximately $8.0 billion in total annual benefits. The upper end of the range of avoided premature mortality estimates associated with the proposed standards (based on Laden et al., 2006 for $PM_{2.5}$ and Levy et al., 2005 for ozone)[I,J] results in approximately 2,400 premature mortalities avoided in 2030 and yields approximately $23 billion in total benefits. These are rough estimates since, without new photochemical air quality modeling to reflect the revised baseline and control scenarios, we are unable to account for cross-state transport of pollution into or out of California or Section 177 states. However, we believe this is a reasonable characterization of the small reduction in benefits had we modeled the emission reductions of the LEV III program in California and other states that adopt the LEV III program in the baseline. We believe our overall cost-benefit conclusions do not materially change with or without the inclusion of emission reductions from California and in other states that adopt the LEV III program in our analysis. We will conduct new air quality modeling for the final rule that will include emission reductions from the LEV III program in California, and in states that have adopted the program, in the baseline scenario. The rest of this Chapter presents benefits that include emission reductions from the LEV III program.

8.1.2.1 Overview

This analysis reflects the impacts of the proposed Tier 3 rule in 2030 compared to a future-year reference scenario without the program in place. Overall, we estimate that the proposed rule would lead to a net decrease in $PM_{2.5}$-related health and environmental impacts (see Section 7.2.5 for more information about the air quality modeling results). The decrease in population-weighted national average $PM_{2.5}$ exposure results in a net decrease in adverse PM-

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[F] To conduct this sensitivity analysis, we simply assumed no air quality change in the California portion of the CMAQ domain. We then exported the reference and control air quality surfaces to be used as inputs to BenMAP. Note that this simple approach is unable to account for legitimate emissions impacts related to cross-state transport of pollution. It was also not possible to do this adjustment for the several states that have also adopted the LEV III program. First, the interstate transport of pollutants is a much larger issue in states other than California where states are smaller and populations are denser. Second, such an adjustment would not capture the interstate travel of Tier 3 vehicles within a LEV III state. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

[G] Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. (2002). Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution. *Journal of the American Medical Association,* 287, 1132-1141.

[H] Bell, M.L., et al. (2004). Ozone and short-term mortality in 95 US urban communities, 1987-2000.*Journal of the American Medical Association*, *292(19)*, 2372-2378.

[I] Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. (2006). Reduction in Fine Particulate Air Pollution and Mortality. *American Journal of Respiratory and Critical Care Medicine*. *173*, 667-672.

[J] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. (2005). Ozone exposure and mortality: an empiric bayes metaregression analysis. *Epidemiology. 16(4)*, 458-68.

related human health and environmental impacts (the decrease in national population weighted annual average $PM_{2.5}$ is 0.05 µg/m3 in 2030).

The air quality modeling also projects decreases in ozone concentrations (see Section 7.2.5). 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 0.52 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.[1,2] Our benefits methods are also consistent with rulemaking analyses such as the final 2012-2016 MY Light-Duty Vehicle Rule, [3] the final Portland Cement National Emissions Standards for Hazardous Air Pollutants (NESHAP) RIA,[4], and the final 2017-2025 MY Light-Duty Vehicle Rule.[5] To model the ozone and PM air quality impacts of the proposal, we used the Community Multiscale Air Quality (CMAQ) model (see Section 7.2.2). The modeled ambient air quality data serves as an input to the Environmental Benefits Mapping and Analysis Program version 4.0.43 (BenMAP).[K] 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 in 2030 is presented in Table 8-4. We present total benefits based on the PM- and ozone-related premature mortality function used. The benefits ranges therefore reflect the addition of each estimate of ozone-related premature mortality (each with its own row in) to estimates of PM-related premature mortality. The analysis of the proposed standards reflects EPA's work to characterize benefits prior to the most recent PM NAAQS.[L] EPA will update its benefits analysis, and related uncertainty analysis, to be consistent with the final PM NAAQS for the final Tier 3 regulatory impact analysis.

Table 8-4: Estimated 2030 Monetized PM-and Ozone-Related Health Benefits[a,b,d]

2030 Total Ozone and PM Benefits – PM Mortality Derived from American Cancer Society Analysis and Six-Cities Analysis[b]			
Premature Ozone Mortality Function	Reference	Total Benefits (Billions, 2010$, 3% Discount Rate)[c,d]	Total Benefits (Billions, 2010$, 7% Discount Rate) [c,d]
Multi-city analyses	Bell et al., 2004	Total: $9.5 - $21 PM: $7.7 - $19 Ozone: $1.8	Total: $8.7 - $19 PM: $7.0 - $17 Ozone: $1.8
	Huang et al., 2005	Total: $10 - $21 PM: $7.7 - $19	Total: $9.5 - $20 PM: $7.0 - $17

[K] Information on BenMAP, including downloads of the software, can be found at http://www.epa.gov/ttn/ecas/benmodels.html.

[L] US EPA (2012). National Ambient Air Quality Standards for Particulate Matter. http://www.epa.gov/PM/2012/finalrule.pdf

		Ozone: $2.6	Ozone: $2.6
	Schwartz, 2005	Total: $10 - $22 PM: $7.7 - $19 Ozone: $2.7	Total: $9.6 - $20 PM: $7.0 - $17 Ozone: $2.7
Meta-analyses	Bell et al., 2005	Total: $13 - $24 PM: $7.7 - $19 Ozone: $5.5	Total: $12 - $23 PM: $7.0 - $17 Ozone: $5.5
	Ito et al., 2005	Total: $15 - $26 PM: $7.7 - $19 Ozone: $7.5	Total: $15 - $25 PM: $7.0 - $17 Ozone: $7.5
	Levy et al., 2005	Total: $15 - $27 PM: $7.7 - $19 Ozone: $7.7	Total: $15 - $25 PM: $7.0 - $17 Ozone: $7.7

Notes:
[a] Benefits presented in this table include California emission reductions from the LEV III program. Had we modeled the California LEV III emission impacts in the Tier 3 air quality baseline, we estimate that benefits would decrease by approximately 12-16 percent, depending on the particular health impact functions used to characterize both PM- and ozone-related premature mortality. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.[b]Total includes premature mortality-related and morbidity-related ozone and $PM_{2.5}$ benefits. Range was developed by adding the estimate from the ozone premature mortality function to the estimate of $PM_{2.5}$-related premature mortality derived from either the ACS study (Pope et al., 2002) or the Six-Cities study (Laden et al., 2006).
[c] Note that total benefits presented here do not include a number of unquantified benefits categories. A detailed listing of unquantified health and welfare effects is provided in Table 8-5.
[d] 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 in Table 8-4 include all of the human health impacts we are able to quantify and monetize at this time. However, the full complement of human health and welfare 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). Additionally, we are unable to quantify a number of known welfare effects, including reduced acid and particulate deposition damage to cultural monuments and other materials, and environmental benefits due to reductions of impacts of eutrophication in coastal areas. These are listed in Table 8-5. As a result, the health benefits quantified in this section are likely underestimates of the total benefits attributable to the proposed program.

Table 8-5: Human Health and Welfare Effects of Pollutants Affected by the Proposed Tier 3 Program

Pollutant/ Effect	*Quantified and monetized in primary estimate*	*Unquantified*
PM: health[a]	Premature mortality based on cohort study estimates[b] and expert elicitation estimates Hospital admissions: respiratory and cardiovascular Emergency room visits for asthma Nonfatal heart attacks (myocardial infarctions) Lower and upper respiratory illness Minor restricted activity days Work loss days Asthma exacerbations (among asthmatic populations Respiratory symptoms (among asthmatic populations) Infant mortality	Low birth weight, pre-term birth and other reproductive outcomes Pulmonary function Chronic respiratory diseases other than chronic bronchitis Non-asthma respiratory emergency room visits UVb exposure (+/-)[c]
PM: welfare		Visibility in Class I areas in SE, SW, and CA regions Household soiling Visibility in residential areas Visibility in non-class I areas and class 1 areas in NW, NE, and Central regions UVb exposure (+/-)[c] Global climate impacts[c]
Ozone: health	Premature mortality based on short-term study estimates Hospital admissions: respiratory Emergency room visits for asthma Minor restricted activity days School loss days	Chronic respiratory damage Premature aging of the lungs Non-asthma respiratory emergency room visits UVb exposure (+/-)[c]
Ozone: welfare	Decreased outdoor worker productivity	Yields for: --Commercial forests --Fruits and vegetables, and --Other commercial and noncommercial crops Damage to urban ornamental plants Recreational demand from damaged forest aesthetics Ecosystem functions UVb exposure (+/-)[c] Climate impacts
CO: health		Behavioral effects
Nitrate Deposition: welfare		Commercial fishing and forestry from acidic deposition effects Commercial fishing, agriculture and forestry from nutrient deposition effects Recreation in terrestrial and estuarine ecosystems from nutrient deposition effects Other ecosystem services and existence values for currently healthy ecosystems Coastal eutrophication from nitrogen deposition effects

Pollutant/ Effect	*Quantified and monetized in primary estimate*	*Unquantified*
Sulfate Deposition: welfare		Commercial fishing and forestry from acidic deposition effects Recreation in terrestrial and aquatic ecosystems from acid deposition effects Increased mercury methylation
HC/Toxics: health[d]		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)
HC/Toxics: welfare		Direct toxic effects to animals Bioaccumulation in the food chain Damage to ecosystem function Odor

Notes:

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Cohort estimates are designed to examine the effects of long term exposures to ambient pollution, but relative risk estimates may also incorporate some effects due to shorter term exposures (see Kunzli et al., 2001 for a discussion of this issue).[6] While some of the effects of short term exposure are likely to be captured by the cohort estimates, there may be additional premature mortality from short term PM exposure not captured in the cohort estimates included in the primary analysis.

[c] May result in benefits or disbenefits.

[d] Many of the key hydrocarbons related to this action are also hazardous air pollutants listed in the CAA.

While there would be impacts associated with air toxic pollutant emission changes that result from the proposed 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.[7] While

EPA has since improved these tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act,[8] EPA conducted a case study analysis of the 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."[9] 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 proposed program.[M]

8.1.2.1.1 Human Health Impacts

Table 8-6 and Table 8-7 present the core estimates of annual $PM_{2.5}$ and ozone health impacts in the 48 contiguous U.S. states associated with the proposed 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 proposed program would result in between 800 and 2,100 cases of avoided $PM_{2.5}$-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 the range of expert opinion is used, we estimate between 270 and 2,700 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) (Bell et al., 2004; Huang et al., 2005; Schwartz, 2005) and from a series of meta-analyses (Bell et al., 2005, Ito et al., 2005, and Levy et al., 2005). 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

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[M] In April, 2009, EPA hosted a workshop on estimating the benefits or 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.

as in the NMMAPS, without excluding consideration of meta-analyses of previously published studies."[10] For ozone-related premature mortality in 2030, we estimate a range of between 170 to 770 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 $PM_{2.5}$-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 (Pope et al., 2002) and the Six-Cities study (Laden et al., 2006). 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 $PM_{2.5}$-Related Health Impacts[a,b]

Health Effect	2030 Annual Reduction in Incidence (5th - 95th percentile)
Premature Mortality – Derived from epidemiology literature[c]	
Adult, age 30+, ACS Cohort Study (Pope et al., 2002)	800 (310 – 1,300)
Adult, age 25+, Six-Cities Study (Laden et al., 2006)	2,100 (1,100 – 3,000)
Infant, age <1 year (Woodruff et al., 1997)	3 (0 – 8)
Chronic bronchitis (adult, age 26 and over)	560 (100 – 1,000)
Non-fatal myocardial infarction (adult, age 18 and over)	980 (360 – 1,600)
Hospital admissions - respiratory (all ages)[d]	160 (77 – 230)
Hospital admissions - cardiovascular (adults, age >18)[e]	380 (270 – 440)
Emergency room visits for asthma (age 18 years and younger)	600 (350 – 850)
Acute bronchitis, (children, age 8-12)	1,300 (0 – 2,500)
Lower respiratory symptoms (children, age 7-14)	16,000 (7,700 – 24,000)
Upper respiratory symptoms (asthmatic children, age 9-18)	12,000 (3,800 – 20,000)
Asthma exacerbation (asthmatic children, age 6-18)	27,000 (3,000 – 74,000)
Work loss days	100,000 (88,000 – 110,000)

Minor restricted activity days (adults age 18-65)	600,000 (500,000 – 690,000)

Notes:

[a] Benefits presented in this table include California emission reductions from the LEV III program. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

[b] Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.

[c] PM-related adult mortality based upon the American Cancer Society (ACS) Cohort Study (Pope et al., 2002) and the Six-Cities Study (Laden et al., 2006). 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).[N]

[d] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

[e] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 8-7: Estimated Ozone-Related Health Impacts[a,b]

Health Effect	2030 Annual Reduction in Incidence (5th - 95th percentile)
Premature Mortality, All ages[c]	
Multi-City Analyses	
Bell et al. (2004) – Non-accidental	170 (73 – 260)
Huang et al. (2005) – Cardiopulmonary	250 (120 – 380)
Schwartz (2005) – Non-accidental	260 (110 – 410)
Meta-analyses:	
Bell et al. (2005) – All cause	540 (300 – 780)
Ito et al. (2005) – Non-accidental	750 (500 – 1,000)
Levy et al. (2005) – All cause	770 (560 – 970)
Hospital admissions- respiratory causes (adult, 65 and older)[d]	1,200 (160 – 2,200)
Hospital admissions -respiratory causes (children, under 2)	550 (290 – 810)
Emergency room visit for asthma (all ages)	580 (0 – 1,500)
Minor restricted activity days (adults, age 18-65)	970,000 (490,000 – 1,500,000)
School absence days	350,000 (150,000 – 490,000)

Notes:

[N] 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.

[a] Benefits presented in this table include California emission reductions from the LEV III program. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.
[b] Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous U.S.
[c] 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.
[d] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

Table 8-8: Results of Application of Expert Elicitation: Annual Reductions in Premature Mortality in 2030 Associated with the Proposed Program[a]

Source of Mortality Estimate	2030 Tier 3 Control		
	5th Percentile	Mean	95th Percentile
Pope et al. (2002)	310	800	1,300
Laden et al. (2006)	1,100	2,100	3,000
Expert A	400	2,200	4,000
Expert B	170	1,600	3,600
Expert C	300	1,700	3,600
Expert D	240	1,200	1,900
Expert E	1,400	2,700	4,100
Expert F	1,000	1,500	2,100
Expert G	0	960	1,800
Expert H	4	1,200	2,800
Expert I	260	1,600	2,900
Expert J	390	1,300	2,900
Expert K	0	270	1,300
Expert L	65	1,000	2,300

Notes:
[a] Benefits presented in this table include California emission reductions from the LEV III program. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

8.1.2.1.2 Monetized Estimates of Human Health and Environmental Impacts

Table 8-9 presents the estimated monetary value of changes in the incidence of ozone and $PM_{2.5}$-related health and environmental effects. Total aggregate monetized benefits are presented in Table 8-10. All monetized estimates are presented in 2010$. Where appropriate, estimates account for growth in real gross domestic product (GDP) per capita between 2000 and 2030.[O] The monetized value of $PM_{2.5}$-related mortality also accounts for a twenty-year

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[O] 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 segmented cessation lag.[P] 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).[Q]

In addition to omitted benefits categories such as air toxics and various welfare effects, not all known $PM_{2.5}$- 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 $PM_{2.5}$- 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 proposed program, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, is between $9.5 and $27 billion, assuming a 3 percent discount rate, or between $8.7 and $25 billion, assuming a 7 percent discount rate. As the results indicate, total benefits are driven primarily by the reduction in $PM_{2.5}$- 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 chronic illness (chronic bronchitis and 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.

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reader to the PM NAAQS regulatory impact analysis.[9] 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.

[P] 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.

[Q] 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.

Table 8-9: Estimated Monetary Value of Changes in Incidence of Health and Welfare Effects (millions of 2010$) [a,b,c]

		2030
PM$_{2.5}$-Related Health Effect		(5th and 95th Percentile)
Premature Mortality – Derived from Epidemiology Studies[d]	Adult, age 30+ - ACS study (Pope et al., 2002)	
	3% discount rate	$7,200 ($920 – $18,000)
	7% discount rate	$6,500 ($830 - $17,000)
	Adult, age 25+ - Six-Cities study (Laden et al., 2006)	
	3% discount rate	$18,000 ($2,600 - $45,000)
	7% discount rate	$17,000 ($2,300 - $41,000)
	Infant Mortality, <1 year – (Woodruff et al. 1997)	$27 ($0 - $100)
Chronic bronchitis (adults, 26 and over)		$310 ($25 - $1,000)
Non-fatal acute myocardial infarctions		
3% discount rate		$110 ($24 - $260)
7% discount rate		$90 ($19 - $210)
Hospital admissions for respiratory causes		$2.5 ($1.2 – $3.6)
Hospital admissions for cardiovascular causes		$5.5 ($1.2 - $10)
Emergency room visits for asthma		$0.24 ($0.13 - $0.36)
Acute bronchitis (children, age 8–12)		$0.61 ($0.00 - $1.5)
Lower respiratory symptoms (children, 7–14)		$0.34 ($0.13 - $0.63)
Upper respiratory symptoms (asthma, 9–11)		$0.40 ($0.12 - $0.89)
Asthma exacerbations		$1.6 ($0.17 - $4.4)
Work loss days		$16 ($14 - $19)
Minor restricted-activity days (MRADs)		$41 ($24 - $59)
Ozone-related Health Effect		
Premature Mortality, All ages – Derived from Multi-city analyses	Bell et al., 2004	$1,700 ($220 - $4,200)
	Huang et al., 2005	$2,500 ($340 - $6,200)
	Schwartz, 2005	$2,600 ($330 - $6,500)
Premature Mortality, All ages – Derived from Meta-analyses	Bell et al., 2005	$5,400 ($760 - $13,000)
	Ito et al., 2005	$7,400 ($1,100 - $18,000)

	Levy et al., 2005	$7,600 ($1,100 - $18,000)
Hospital admissions- respiratory causes (adult, 65 and older)		$32 ($4.2 - $56)
Hospital admissions- respiratory causes (children, under 2)		$6.0 ($3.1 - $8.9)
Emergency room visit for asthma (all ages)		$0.23 ($0.0 - $0.57)
Minor restricted activity days (adults, age 18-65)		$67 ($31 - $110)
School absence days		$34 ($15 - $48)

Notes:

[a] Benefits presented in this table include California emission reductions from the LEV III program. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

[b] Monetary benefits are rounded to two significant digits for ease of presentation and computation. PM and ozone benefits are nationwide.

[c] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2030).

[d] 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.

Table 8-10: Total Monetized Ozone and PM-related Benefits Associated with the Proposed Program in 2030[a]

Total Ozone and PM Benefits (billions, 2010$) – PM Mortality Derived from the ACS and Six-Cities Studies					
3% Discount Rate			**7% Discount Rate**		
Ozone Mortality Function	Reference	Mean Total Benefits	Ozone Mortality Function	Reference	Mean Total Benefits
Multi-city	Bell et al., 2004	$9.5 - $21	Multi-city	Bell et al., 2004	$8.7 - $19
	Huang et al., 2005	$10 - $21		Huang et al., 2005	$9.5 - $20
	Schwartz, 2005	$10 - $22		Schwartz, 2005	$9.6 - $20
Meta-analysis	Bell et al., 2005	$13 - $24	Meta-analysis	Bell et al., 2005	$12 - $23
	Ito et al., 2005	$15 - $26		Ito et al., 2005	$15 - $25
	Levy et al., 2005	$15 - $27		Levy et al., 2005	$15 - $25
Total Ozone and PM Benefits (billions, 2010$) – PM Mortality Derived from Expert Elicitation (Lowest and Highest Estimate)					
3% Discount Rate			**7% Discount Rate**		
Ozone Mortality Function	Reference	Mean Total Benefits	Ozone Mortality Function	Reference	Mean Total Benefits
Multi-city	Bell et al., 2004	$4.6 - $27	Multi-city	Bell et al., 2004	$4.4 - $24
	Huang et al.,	$5.4 - $27		Huang et al.,	$5.2 - $25

	2005			2005	
	Schwartz, 2005	$5.5 - $28		Schwartz, 2005	$5.3 - $25
Meta-analysis	Bell et al., 2005	$8.3 - $30	Meta-analysis	Bell et al., 2005	$8.1 - $28
	Ito et al., 2005	$10 - $32		Ito et al., 2005	$10 - $30
	Levy et al., 2005	$11 - $33		Levy et al., 2005	$10 - $30

Notes:

[a] Benefits presented in this table include California emission reductions from the LEV III program. Had we modeled the California LEV III emission impacts in the Tier 3 air quality baseline, we estimate that benefits would decrease by approximately 12-16 percent, depending on the particular health impact functions used to characterize both PM- and ozone-related premature mortality. We will account for emissions in states that have adopted California's LEV III program in the baseline air quality modeling for the final rule.

8.1.2.1.3 Methodology

8.1.2.1.3.1 Human Health Impact Functions

Health impact functions measure the change in a health endpoint of interest, such as hospital admissions, for a given change in ambient ozone or PM concentration. Health impact functions are derived from primary epidemiology studies, meta-analyses of multiple epidemiology studies, or expert elicitations. A standard health impact function has four components: (1) an effect estimate from a particular study; (2) a baseline incidence rate for the health effect (obtained from either the epidemiology study or a source of public health statistics such as the Centers for Disease Control); (3) the size of the potentially affected population; and (4) the estimated change in the relevant ozone or PM summary measures.

A typical health impact function might look like:

$$\Delta y = y_0 \cdot \left(e^{\beta \cdot \Delta x} - 1\right),$$

where y_0 is the baseline incidence (the product of the baseline incidence rate times the potentially affected population), β is the effect estimate, and Δx is the estimated change in the summary 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; $PM_{2.5}$ and ozone effect estimates; and baseline incidence rates. We also describe the treatment of potential thresholds in PM-related health impact functions. Section 8.2 describes the ozone and PM air quality inputs to the health impact functions.

8.1.2.1.3.2 Potentially Affected Populations

The starting point for estimating the size of potentially affected populations is the 2000 U.S. Census block level dataset.[11] Benefits Modeling and Analysis Program (BenMAP) incorporates 250 age/gender/race categories to match specific populations potentially affected by ozone and other air pollutants. The software constructs specific populations matching the populations in each epidemiological study by accessing the appropriate age-specific populations from the overall population database. BenMAP projects populations to 2030 using growth factors based on economic projections.[12]

8.1.2.1.3.3 Effect Estimate Sources

The most significant quantifiable benefits of reducing ambient concentrations of ozone and PM are attributable to reductions in human health risks. EPA's Ozone and PM Criteria Documents[13,14] and the World Health Organization's 2003 and 2004[15,16] reports outline numerous human health effects known or suspected to be linked to exposure to ambient ozone and PM. EPA evaluated the ozone and PM literature for use in the benefits analysis for the final 2008 Ozone NAAQS and final 2006 PM NAAQS analyses. We use the same literature in this analysis; for more information on the studies that underlie the health impacts quantified in this RIA, please refer to those documents.

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 8-11 lists the health endpoints included in this analysis.

Table 8-11: Health Impact Functions Used in BenMAP to Estimate Impacts of $PM_{2.5}$ and Ozone Reductions

ENDPOINT	*POLLUTANT*	*STUDY*	*STUDY POPULATION*
Premature Mortality			
Premature mortality – daily time series	O_3	Multi-city Bell et al (2004) (NMMAPS study)[17] – Non-accidental Huang et al (2005)[18] - Cardiopulmonary Schwartz (2005)[19] – Non-accidental Meta-analyses: Bell et al (2005)[20] – All cause Ito et al (2005)[21] – Non-accidental Levy et al (2005)[22] – All cause	All ages
Premature mortality —cohort study, all-cause	$PM_{2.5}$	Pope et al. (2002)[23] Laden et al. (2006)[24]	>29 years >25 years
Premature mortality, total exposures	$PM_{2.5}$	Expert Elicitation (IEc, 2006)[25]	>24 years
Premature mortality — all-cause	$PM_{2.5}$	Woodruff et al. (1997)[26]	Infant (<1 year)
Chronic Illness			
Chronic bronchitis	$PM_{2.5}$	Abbey et al. (1995)[27]	>26 years
Nonfatal heart attacks	$PM_{2.5}$	Peters et al. (2001)[28]	Adults (>18 years)

ENDPOINT	*POLLUTANT*	*STUDY*	*STUDY POPULATION*
Hospital Admissions			
Respiratory	O_3	Pooled estimate: Schwartz (1995) - ICD 460-519 (all resp)[29] Schwartz (1994a; 1994b) - ICD 480-486 (pneumonia)[30,31] Moolgavkar et al. (1997) - ICD 480-487 (pneumonia)[32] Schwartz (1994b) - ICD 491-492, 494-496 (COPD) Moolgavkar et al. (1997) – ICD 490-496 (COPD)	>64 years
		Burnett et al. (2001)[33]	<2 years
	$PM_{2.5}$	Pooled estimate: Moolgavkar (2003)—ICD 490-496 (COPD)[34] Ito (2003)—ICD 490-496 (COPD)[35]	>64 years
	$PM_{2.5}$	Moolgavkar (2000)—ICD 490-496 (COPD)[36]	20–64 years
	$PM_{2.5}$	Ito (2003)—ICD 480-486 (pneumonia)	>64 years
	$PM_{2.5}$	Sheppard (2003)—ICD 493 (asthma)[37]	<65 years
Cardiovascular	$PM_{2.5}$	Pooled estimate: Moolgavkar (2003)—ICD 390-429 (all cardiovascular) Ito (2003)—ICD 410-414, 427-428 (ischemic heart disease, dysrhythmia, heart failure)	>64 years
	$PM_{2.5}$	Moolgavkar (2000)—ICD 390-429 (all cardiovascular)	20–64 years
Asthma-related ER visits	O_3	Pooled estimate: Peel et al (2005)[38] Wilson et al (2005)[39]	 All ages All ages
Asthma-related ER visits (cont'd)	$PM_{2.5}$	Norris et al. (1999)[40]	0–18 years
Other Health Endpoints			
Acute bronchitis	$PM_{2.5}$	Dockery et al. (1996)[41]	8–12 years
Upper respiratory symptoms	$PM_{2.5}$	Pope et al. (1991)[42]	Asthmatics, 9–11 years
Lower respiratory symptoms	$PM_{2.5}$	Schwartz and Neas (2000)[43]	7–14 years
Asthma exacerbations	$PM_{2.5}$	Pooled estimate: Ostro et al. (2001)[44] (cough, wheeze and shortness of breath) Vedal et al. (1998)[45] (cough)	6–18 years[a]
Work loss days	$PM_{2.5}$	Ostro (1987)[46]	18–65 years
School absence days	O_3	Pooled estimate: Gilliland et al. (2001)[47] Chen et al. (2000)[48]	5–17 years[b]
Minor Restricted Activity Days (MRADs)	O_3	Ostro and Rothschild (1989)[49]	18–65 years
	$PM_{2.5}$	Ostro and Rothschild (1989)	18–65 years

Notes:

[a] The original study populations were 8 to 13 for the Ostro et al. (2001) study and 6 to 13 for the Vedal et al. (1998) study. Based on advice from the Science Advisory Board Health Effects Subcommittee (SAB-HES), we extended the applied population to 6 to 18, reflecting the common biological basis for the effect in children in the broader age group. See: U.S. Science Advisory Board. 2004. Advisory Plans for Health Effects Analysis in the Analytical Plan for EPA's Second Prospective Analysis –Benefits and Costs of the Clean Air Act, 1990—2020. EPA-SAB-COUNCIL-ADV-04-004. See also National Research Council (NRC). 2002. *Estimating the Public Health Benefits of Proposed Air Pollution Regulations*. Washington, DC: The National Academies Press.

[b] 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.

In selecting epidemiological studies as sources of effect estimates, we applied several criteria to develop a set of studies that is likely to provide the best estimates of impacts in the U.S. To account for the potential impacts of different health care systems or underlying health status of populations, we give preference to U.S. studies over non-U.S. studies. In addition, due to the potential for confounding by co-pollutants, we give preference to effect estimates from models including both ozone and PM over effect estimates from single-pollutant models.[50,51]

8.1.2.1.3.4 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 100 ppb decrease in daily ozone levels might, in turn, decrease hospital admissions by 3 percent. The baseline incidence of the health effect is necessary to convert this relative change into a number of cases. 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 100,000 people, that number must be multiplied by the number of 100,000s in the population.

Table 8-12 summarizes the sources of baseline incidence rates and provides average incidence rates for the endpoints included in the analysis. 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 8-13 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. 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. Regional incidence rates are available for hospital admissions, and county-level data are available for premature mortality. We have projected mortality rates such that future mortality rates are consistent with our projections of population growth.[52]

Table 8-12: Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population

Endpoint	*Parameter*	*Rates*	
		Value	*Source*
Mortality	Daily or annual mortality rate projected to 2020	Age-, cause-, and county-specific rate	CDC Wonder (2006–2008)[53] U.S. Census bureau
Hospitalizations	Daily hospitalization rate	Age-, region-, state-, county- and cause-specific rate	2007 HCUP data files[a,54]
Asthma ER Visits	Daily asthma ER visit rate	Age-, region-, state-, county- and cause-specific rate	2007 HCUP data files[a]
Chronic Bronchitis	Annual prevalence rate per person		1999 NHIS (American Lung Association, 2002, Table 4)[55]
	Aged 18–44	0.0367	
	Aged 45–64	0.0505	
	Aged 65 and older	0.0587	
	Annual incidence rate per person	0.00378	Abbey et al. (1993, Table 3)
Nonfatal Myocardial Infarction (heart attacks)	Daily nonfatal myocardial infarction incidence rate per person, 18+	Age-, region-, state-, and county- specific rate	2007 HCUP data files[a]; adjusted by 0.93 for probability of surviving after 28 days (Rosamond et al., 1999)
Asthma Exacerbations	Incidence among asthmatic African-American children		Ostro et al. (2001)
	daily wheeze	0.076	
	daily cough	0.067	
	daily dyspnea	0.037	
Acute Bronchitis	Annual bronchitis incidence rate, children	0.043	American Lung Association (2002, Table 11)[56]
Lower Respiratory Symptoms	Daily lower respiratory symptom incidence among children[b]	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)		1996 HIS (Adams, Hendershot, and Marano, 1999, Table 41);[57] U.S. Bureau of the Census (2000)[58]
	Aged 18–24	0.00540	
	Aged 25–44	0.00678	
	Aged 45–64	0.00492	
School Loss Days	Rate per person per year, assuming 180 school days per year	9.9	National Center for Education Statistics (1996)[59] 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:

[a] 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.

[b] Lower respiratory symptoms are defined as two or more of the following: cough, chest pain, phlegm, and wheeze.

Table 8-13: Asthma Prevalence Rates Used for this Analysis

Population Group	*Asthma Prevalence Rates*	
	Value	*Source*
All Ages	0.0780	American Lung Association (2010, Table 7)[60]
< 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[a]

Notes:
[ab] Calculated by ALA for U.S. EPA, based on NHIS data (CDC, 2008).[61]

8.1.2.1.3.5 PM$_{2.5}$-Related Premature Mortality "Lowest Measured Level" (LML) Assessment

Based on our review of the current body of scientific literature, EPA estimated PM-related mortality without applying an assumed concentration threshold. EPA's Integrated Science Assessment for Particulate Matter (U.S. EPA, 2009),[62] which was reviewed by EPA's Clean Air Scientific Advisory Committee (U.S. EPA-SAB, 2009; U.S. EPA-SAB, 2009),[63,64] concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function. Consistent with this finding, we have conformed the threshold sensitivity analysis to the current state of the PM science and improved upon our previous approach for estimating the sensitivity of the benefits estimates to the presence of an assumed threshold by incorporating a new "Lowest Measured Level" (LML) assessment.

This approach summarizes the distribution of avoided PM mortality impacts according to the baseline (*i.e.* pre-Tier 3 Program) PM$_{2.5}$ levels experienced by the population receiving the PM$_{2.5}$ mortality benefit (see Figure 8-1). We identify on this figure the lowest air quality levels measured in each of the two primary epidemiological studies EPA uses to quantify PM-related mortality. This information allows readers to determine the portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the estimated PM mortality decreases as we consider air quality levels further below the LML in the two epidemiological studies. While the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

The large proportion of the avoided PM-related impacts we estimate in this analysis occur among populations exposed at or above the LML of each study (Figure 8-1), increasing our confidence in the PM mortality analysis. Approximately 25 percent of the avoided impacts occur at or above an annual mean PM$_{2.5}$ level of 10 µg/m^3 (the LML of the Laden et al. 2006 study); about 81 percent occur at or above an annual mean PM$_{2.5}$ level of 7.5 µg/m^3 (the LML of the Pope et al. 2002 study). As we model mortality impacts among populations exposed to levels of PM$_{2.5}$ that are successively lower than the LML of each study our confidence in the results diminishes. However, the analysis above confirms that the great majority of the impacts occur at or above the Pope et al. LML.

As an example, when considering mortality impacts among populations living in areas with an annual mean PM level of 8 µg/m^3, we would place greater confidence in estimates drawn from the Pope et al. 2002 study, as this air quality level is above the LML of this study. Conversely, we would place equal confidence when estimating mortality impacts among populations living in locations where the annual mean PM levels are above 10 µg/m^3 because this value is at or above the LML of each study.

While the LML of each study is important to consider when characterizing and interpreting the overall level PM-related benefits, EPA believes that both cohort-based mortality estimates are suitable for use in air pollution health impact analyses. When estimating PM mortality impacts using risk coefficients drawn from the Laden et al. analysis of the Harvard Six Cities and the Pope et al. analysis of the American Cancer Society cohorts there are innumerable other attributes that may affect the size of the reported risk 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.

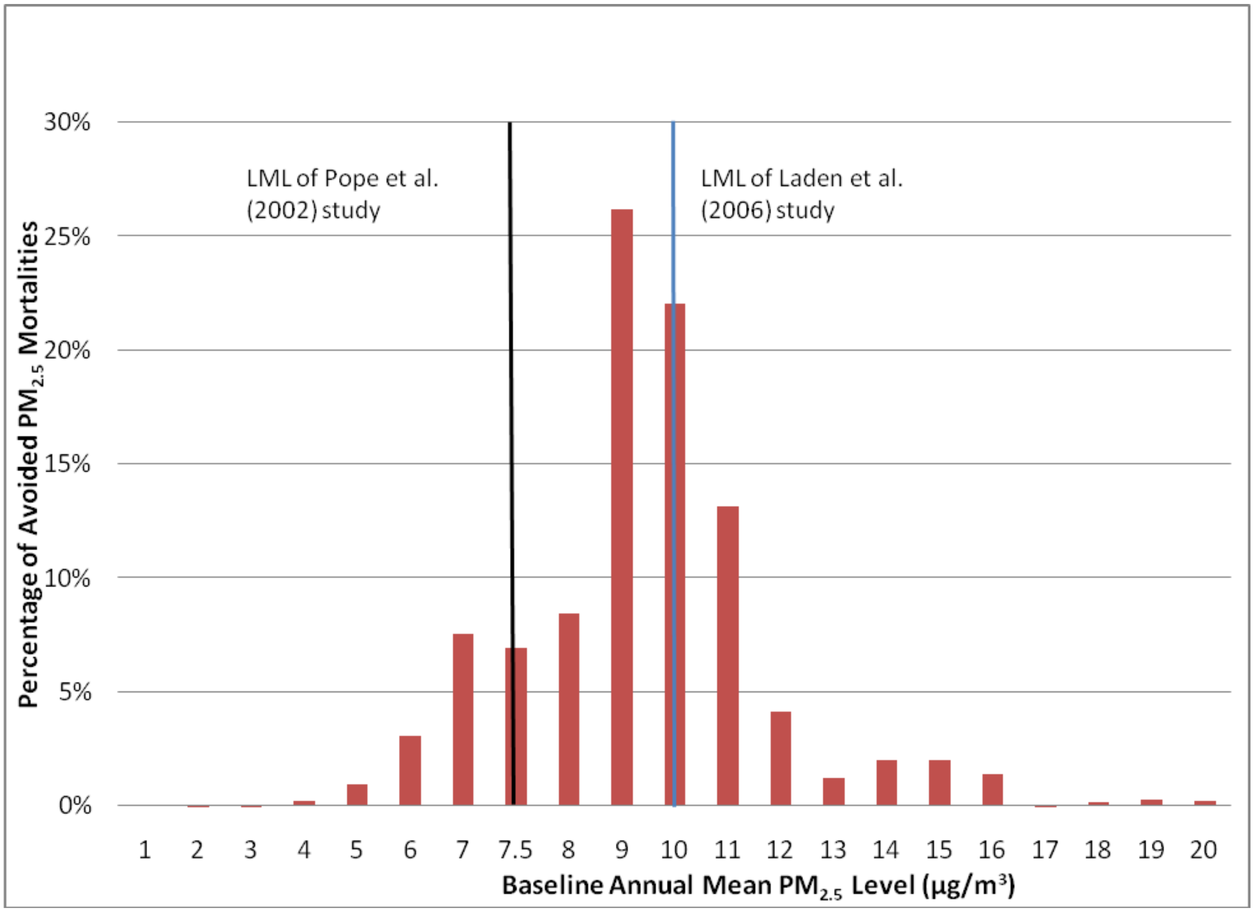

Figure 8-1 Percentage of Total PM-related Mortalities Avoided by Baseline Air Quality Level

8.1.2.1.3.6 Economic Values for Health Outcomes

Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects for a large population. Therefore, the appropriate economic measure is willingness-to-pay (WTP) for changes in risk of a health effect rather than WTP for a health effect that would occur with certainty (Freeman, 1993).[65] Epidemiological studies generally provide estimates of the relative risks of a particular health effect that is avoided because of a reduction in air pollution. We converted those to units of avoided statistical incidence for ease of presentation. We calculated the value of avoided statistical incidences by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a pollution-reduction regulation 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 death is $1 million ($100/0.0001 change in risk).

WTP estimates generally are not available for some health effects, such as hospital admissions. In these cases, we used the cost of treating or mitigating the effect as a primary estimate. These cost-of-illness (COI) estimates generally understate the true value of reducing the risk of a health effect, because they reflect the direct expenditures related to treatment, but not the value of avoided pain and suffering (Harrington and Portney, 1987; Berger, 1987).[66,67] We provide unit values for health endpoints (along with information on the distribution of the unit value) in Table 8-14. All values are in constant year 2010 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 2006 PM NAAQS RIA.[68] For details on valuation estimates for ozone-related endpoints, see the 2008 Ozone NAAQS RIA.[69]

Table 8-14: Unit Values for Economic Valuation of Health Endpoints (2010$)

Health Endpoint	**Central Estimate of Value Per Statistical Incidence**		
	2000 Income Level	**2030 Income Level[a]**	**Derivation of Distributions of Estimates**
Premature Mortality (Value of a Statistical Life)	$8,000,000	$9,900,000	EPA currently recommends a central VSL of $6.3m (2000$) 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, 2000).

Chronic Bronchitis (CB)	$450,000	$550,000	The WTP to avoid a case of pollution-related CB is calculated as where x is the severity of an average CB case, WTP_{13} is the WTP for a severe case of CB, and $ is the parameter relating WTP to severity, based on the regression results reported in Krupnick and Cropper (1992). The distribution of WTP for an average severity-level case of CB was generated by Monte Carlo methods, drawing from each of three distributions: (1) WTP to avoid a severe case of CB is assigned a 1/9 probability of being each of the first nine deciles of the distribution of WTP responses in Viscusi et al. (1991); (2) the severity of a pollution-related case of CB (relative to the case described in the Viscusi study) is assumed to have a triangular distribution, with the most likely value at severity level 6.5 and endpoints at 1.0 and 12.0; and (3) the constant in the elasticity of WTP with respect to severity is normally distributed with mean = 0.18 and standard deviation = 0.0669 (from Krupnick and Cropper [1992]). This process and the rationale for choosing it is described in detail in the Costs and Benefits of the Clean Air Act, 1990 to 2010 (U.S. EPA, 1999).
Nonfatal Myocardial Infarction (heart attack)			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). Direct medical costs are based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990). Lost earnings: Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings: age of onset: at 3% at 7% 25–44 $8,774 $7,855 45–54 $12,932 $11,578 55–65 $74,746 $66,920 Direct medical expenses: An average of: 1. Wittels et al. (1990) ($102,658—no discounting) 2. Russell et al. (1998), 5-year period ($22,331 at 3% discount rate; $21,113 at 7% discount rate)
<u>3% discount rate</u>			
Age 0–24	$89,373	$89,373	
Age 25–44	$100,690$1	$100,690	
Age 45–54	06,053	$106,053	
Age 55–65	$185,785	$185,785	
Age 66 and over	$89,373	$89,373	
<u>7% discount rate</u>			
Age 0–24	$88,547	$88,547	
Age 25–44	$98,680	$98,680	
Age 45–54	$103,481	$103,481	
Age 55–65	$174,866	$174,866	
Age 66 and over	$88,548	$88,548	
Hospital Admissions			
Chronic Obstructive Pulmonary Disease (COPD)	$17,996	$17,996	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 COPD category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Asthma Admissions	$11,957	$11,957	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 (2000) (www.ahrq.gov).
All Cardiovascular	$30,256	$30,256	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 (2000) (www.ahrq.gov).
All respiratory (ages 65+)	$25,413	$25,413	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, 2000 (www.ahrq.gov).
All respiratory (ages 0–2)	$10,943	$10,943	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, 2000 (www.ahrq.gov).
Emergency Room Visits for Asthma	$405	$405	No distributional information available. Simple average of two unit COI values: (1) $311.55, from Smith et al. (1997) and (2) $260.67, from Stanford et al. (1999).
Respiratory Ailments Not Requiring Hospitalization			
Upper Respiratory Symptoms (URS)	$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 (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. In the absence of information surrounding the frequency with which each of the seven types of URS occurs within the URS symptom complex, we assumed a uniform distribution between $9.2 and $43.1.
Lower Respiratory Symptoms (LRS)	$20	$21	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 (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS. In the absence of information surrounding the frequency with which each of the 11 types of LRS occurs within the LRS symptom complex, we assumed a uniform distribution between $6.9 and $24.46.
Asthma Exacerbations	$55	$57	Asthma exacerbations are valued at $45 per incidence, based on the mean of average WTP estimates for the four severity definitions of a “bad asthma day,” described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a “bad asthma day,” as defined by the subjects. For purposes of valuation, an asthma exacerbation is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. The value is assumed have a uniform distribution between $15.6 and $70.8.
Acute Bronchitis	$452	$494	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.
Work Loss Days (WLDs)	Variable (U.S. median = $137)	Variable (U.S. median = $137)	No distribution available. Point estimate is based on county-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5—to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.

Minor Restricted Activity Days (MRADs)	$64	$69	Median WTP estimate to avoid one MRAD from Tolley et al. (1986). Distribution is assumed to be triangular with a minimum of $22 and a maximum of $83, with a most likely value of $52. 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	$95	$95	No distribution available

Note:

[a] 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.

8.1.2.1.3.7 Manipulating Air Quality Modeling Data for Health Impacts Analysis

In Section 7.2, 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 $PM_{2.5}$ related to emission reductions estimated to occur due to the implementation of the program. We estimate ambient $PM_{2.5}$ 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.[R,S] 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 observations and modeled ozone predictions to interpolate hourly ozone concentrations to a grid

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[R] The ozone season for this analysis is defined as the 5-month period from May to September.

[S] 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).

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.[T,U]

For $PM_{2.5}$, 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). $PM_{2.5}$ is calculated as the sum of the primary fine fraction and all of the secondarily formed particles. Future-year estimates of $PM_{2.5}$ were calculated using relative reduction factors (RRFs) applied to 2005 ambient $PM_{2.5}$ and $PM_{2.5}$ species concentrations. A gridded field of $PM_{2.5}$ concentrations was created by interpolating Federal Reference Monitor ambient data and IMPROVE ambient data. Gridded fields of $PM_{2.5}$ 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 $PM_{2.5}$ standard (EPA, 2001).[70] The guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. The procedure for calculating future-year $PM_{2.5}$ design values is called the "Speciated Modeled Attainment Test (SMAT)." EPA used this procedure to estimate the ambient impacts of the final program.

Table 8-15 provides those ozone and $PM_{2.5}$ 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 8-15: Summary of CMAQ-Derived Population-Weighted Ozone and $PM_{2.5}$ Air Quality Metrics for Health Benefits Endpoints Associated with the Proposed Tier 3 Program

	2030	
Statistic[a]	Baseline	Change[b]
Ozone Metric: National Population-Weighted Average (ppb)[c]		
Daily Maximum 8-Hour Average Concentration	42.8652	0.5235
$PM_{2.5}$ Metric: National Population-Weighted Average (μg/m³)		
Annual Average Concentration	8.3941	0.0479

Notes:

[T] The 12-km grid squares contain the population data used in the health benefits analysis model, BenMAP.

[U] 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.

[a] Ozone and $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ and ozone design value metrics presented in Chapter 7, which represent the average for areas with a current air quality monitor.

[b] The change is defined as the base-case value minus the control-case value.

[c] 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 proposed program. Please refer to Section 7.2.1 for more information about the inventories used in the air quality modeling that supports the health impacts analysis.

8.1.2.1.4 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 and this analysis is no exception. As outlined both in this and preceding chapters, many inputs were used to derive the estimate of benefits for the proposal, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological health effect estimates, estimates of values (both from WTP and COI studies), population estimates, income estimates, and estimates of the future state of the world (*i.e.*, regulations, technology, and human behavior). Each of these inputs may be uncertain and, depending on its role in the benefits analysis, may have a disproportionately large impact on estimates of total benefits. For example, emissions estimates are used in the first stage of the analysis. As such, any uncertainty in emissions estimates will be propagated through the entire analysis. When compounded with uncertainty in later stages, small uncertainties in emission levels can lead to large impacts on total benefits.

The National Research Council (NRC) (2002, 2008)[71,72] highlighted the need for EPA to conduct rigorous quantitative analysis of uncertainty in its benefits estimates and to present these estimates to decision makers in ways that foster an appropriate appreciation of their inherent uncertainty. In general, the NRC concluded that EPA's general methodology for calculating the benefits of reducing air pollution is reasonable and informative in spite of inherent uncertainties. Since the publication of these reports, EPA's Office of Air and Radiation (OAR) continues to make progress toward the goal of characterizing the aggregate impact of uncertainty in key modeling elements on both health incidence and benefits estimates in two key ways: Monte Carlo analysis and expert-derived concentration-response functions. In this analysis, we use both of these two methods to assess uncertainty quantitatively, as well as provide a qualitative assessment for those aspects that we are unable to address quantitatively.

First, 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. Monte Carlo simulation uses random sampling from distributions of parameters to characterize the effects of uncertainty on output variables, such as incidence of premature mortality. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and dollar benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates.

Second, because characterization of random statistical error omits important sources of uncertainty (*e.g.*, in the functional form of the model—*e.g.*, whether or not a threshold may exist), we also incorporate the results of an expert elicitation on the relationship between premature mortality and ambient $PM_{2.5}$ concentration (Roman et al., 2008).[73] Use of the expert elicitation and incorporation of the standard errors approaches provide insights into the likelihood of different outcomes and about the state of knowledge regarding the benefits estimates. However, there are significant unquantified uncertainties present in upstream inputs including emission and air quality. Both approaches have different strengths and weaknesses, which are fully described in Chapter 5 of the PM NAAQS RIA (U.S. EPA, 2006).

In benefit analyses of air pollution regulations conducted to date, the estimated impact of reductions in premature mortality has accounted for 85 to 95 percent of total monetized benefits. Therefore, it is particularly important to attempt to characterize the uncertainties associated with reductions in premature mortality. The health impact functions used to estimate avoided premature deaths associated with reductions in ozone have associated standard errors that represent the statistical errors around the effect estimates in the underlying epidemiological studies. In our results, we report credible intervals based on these standard errors, reflecting the uncertainty in the estimated change in incidence of avoided premature deaths. We also provide multiple estimates, to reflect model uncertainty between alternative study designs.

For premature mortality associated with exposure to PM, we follow the same approach used in the RIA for 2006 PM NAAQS (U.S. EPA, 2006), presenting two empirical estimates of premature deaths avoided, and a set of twelve estimates based on results of the expert elicitation study. Even these multiple characterizations, including confidence intervals, omit the contribution to overall uncertainty of uncertainty in air quality changes, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. 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.

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 (NRC, 2008) and issued a series of recommendations to EPA, including that the Agency should:

1. 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.

2. Report additional risk metrics, including the percentage of baseline mortality attributable to short-term exposure.

3. Remove reference to a no-causal relationship between ozone exposure and premature mortality.

The quantification and presentation of ozone-related premature mortality in this chapter is responsive to these NRC recommendations.

Some key sources of uncertainty in each stage of both the PM and ozone health impact assessment are the following:

- gaps in scientific data and inquiry;
- variability in estimated relationships, such as epidemiological effect estimates, introduced through differences in study design and statistical modeling;
- errors in measurement and projection for variables such as population growth rates;
- errors due to misspecification of model structures, including the use of surrogate variables, such as using PM_{10} when $PM_{2.5}$ is not available, excluded variables, and simplification of complex functions; and
- biases due to omissions or other research limitations.

In Table 8-16 we summarize some of the key uncertainties in the benefits analysis.

Table 8-16: Primary Sources of Uncertainty in the Benefits Analysis

1. Uncertainties Associated with Impact Functions
- The value of the ozone or PM effect estimate in each impact function. - Application of a single impact function to pollutant changes and populations in all locations. - Similarity of future-year impact functions to current impact functions. - Correct functional form of each impact function. - Extrapolation of effect estimates beyond the range of ozone or PM concentrations observed in the source epidemiological study. - Application of impact functions only to those subpopulations matching the original study population.
2. Uncertainties Associated with CMAQ-Modeled Ozone and PM Concentrations
- Responsiveness of the models to changes in precursor emissions from the control policy. - Projections of future levels of precursor emissions, especially ammonia and crustal materials. - Lack of ozone and $PM_{2.5}$ monitors in all rural areas requires extrapolation of observed ozone data from urban to rural areas.
3. Uncertainties Associated with PM Mortality Risk
- Limited scientific literature supporting a direct biological mechanism for observed epidemiological evidence. - Direct causal agents within the complex mixture of PM have not been identified. - The extent to which adverse health effects are associated with low-level exposures that occur many times in the year versus peak exposures. - The extent to which effects reported in the long-term exposure studies are associated with historically higher levels of PM rather than the levels occurring during the period of study. - Reliability of the $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.
4. Uncertainties Associated with Possible Lagged Effects

- The portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels that would occur in a single year is uncertain as well as the portion that might occur in subsequent years.
5. Uncertainties Associated with Baseline Incidence Rates
- Some baseline incidence rates are not location specific (*e.g.*, those taken from studies) and therefore may not accurately represent the actual location-specific rates. - Current baseline incidence rates may not approximate well baseline incidence rates in 2030. - Projected population and demographics may not represent well future-year population and demographics.
6. Uncertainties Associated with Economic Valuation
- Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them. - Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates because of differences in income or other factors.
7. Uncertainties Associated with Aggregation of Monetized Benefits
- Health and welfare benefits estimates are limited to the available impact functions. Thus, unquantified or unmonetized benefits are not included.

8.1.3 Comparison of Costs and Benefits

This section presents the cost-benefit comparison related to the expected impacts of the proposed 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 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 8-17 contains the estimated social costs and the estimated monetized benefits of the program.

The results in Table 8-17 suggest that the 2030 monetized benefits of the proposed standards are greater than the expected costs. Specifically, the annual benefits of the total program will range between $8.0 to $23 billion annually in 2030 using a three percent discount rate, or between $7.4 to $21 billion assuming a 7 percent discount rate, compared to estimated social costs of approximately $3.4 billion in that same year. Though there are a number of health and environmental effects associated with the proposed standards that we are unable to quantify or monetize (see Table 8-5), the benefits of the proposed standards outweigh the projected costs.

Using a conservative benefits estimate, the 2030 benefits outweigh the costs by a factor of 2.2. Using the upper end of the benefits range, the benefits could outweigh the costs by a factor of 6.8. Thus, even taking the most conservative benefits assumptions, benefits of the proposed standards clearly outweigh the costs.

Table 8-17: Summary of Annual Benefts and Costs Associated with the Proposed Tier 3 Program (Billions, 2010$)[a]

Description	**2030**
Vehicle Program Costs	$2.1
Fuels Program Costs	$1.3
Total Estimated Costs[b]	$3.4
Total Estimated Health Benefits[c,d,e,f]	
3 percent discount rate	$8.0 - $23
7 percent discount rate	$7.4 - $21
Annual Net Benefits (Total Benefits – Total Costs)	
3 percent discount rate	$4.6 - $20
7 percent discount rate	$4.0 - $18

Notes:

[a] 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.

[b] 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 draft RIA for more information on vehicle costs, Chapter 5 for fuel costs, and Section 8.1.1 for a summary of total program costs).

[c] Total includes ozone and $PM_{2.5}$ benefits. Range was developed by adding the estimate from the Bell et al., 2004 ozone premature mortality function to $PM_{2.5}$-related premature mortality derived from the American Cancer Society cohort study (Pope et al., 2002) for the low estimate and ozone premature mortality derived from the Levy et al., 2005 study to $PM_{2.5}$-related premature mortality derived from the Six-Cities (Laden et al., 2006) study for the high estimate.

[d] 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.

[e] 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).

[f] 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 Quantified and Monetized Impacts Associated with the Proposal in 2017

For illustrative purposes, this section presents the quantified and monetized impacts associated with the proposed standards in 2017. As presented in Section 7.1.5, the emissions impacts of the proposed standards in 2017 are primarily due to the effects of sulfur on the existing (pre-Tier 3) fleet. For reasons explained in Section 7.1.3.2.2, our analysis of the air quality impacts in 2017 reflects an increase in direct PM emissions from vehicles (along with reductions in NO_X, VOCs and other pollutants). This emissions increase results from a series of conservative assumptions and uncertainties related to fuel parameters in 2017, and is not expected to occur in reality. Because our air quality modeling assumes this increase, as well as increased direct PM emissions due to an emissions processing error (see Section 7.2.1.1.2), our illustrative benefits analysis in 2017 overestimates ambient concentrations of PM and underestimates the benefits of the proposed Tier 3 standards. Note also that the benefit estimates presented in this section do not include the effects of any emissions reductions or air quality changes in California.

This analysis reflects the impacts of the proposed Tier 3 rule in 2017 compared to a future-year reference scenario without the program in place. Overall, we estimate that the proposed rule would lead to a net decrease in $PM_{2.5}$-related health and environmental impacts in 2017 (see Section 7.2.5 for more information about the air quality modeling results). The decrease in population-weighted national average $PM_{2.5}$ exposure results in a net decrease in adverse $PM_{2.5}$-related human health and environmental impacts (the decrease in national population-weighted annual average $PM_{2.5}$ is 0.003 $\mu g/m^3$ in 2017). 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 0.17 ppb in 2017).

Table 8-18 and Table 8-19 present the annual $PM_{2.5}$ and ozone health impacts in the 48 contiguous U.S. states associated with the proposed Tier 3 program. For each endpoint presented in Table 8-18 and Table 8-19, 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 proposed standards would result in between 57 and 150 cases of avoided $PM_{2.5}$-related premature mortalities annually in 2017. For ozone-related premature mortality in 2017, we estimate a range of between 49 to 230 fewer premature mortalities.

Table 8-20 presents the estimated monetary value of changes in the incidence of ozone and $PM_{2.5}$-related health and environmental effects. Total aggregate monetized benefits are presented in Table 8-21. All monetized estimates are presented in 2010$. Where appropriate, estimates account for growth in real gross domestic product (GDP) per capita between 2000 and 2017. The monetized value of $PM_{2.5}$-related mortality also accounts for a twenty-year segmented cessation lag.[V] 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 $PM_{2.5}$-related nonfatal heart attacks (myocardial infarctions).[W]

In addition to omitted benefits categories such as air toxics and various welfare effects, not all known $PM_{2.5}$- and ozone-related health and welfare effects could be quantified or monetized. The estimate of total monetized health benefits of the proposed program is thus equal to the subset of monetized $PM_{2.5}$- and ozone-related health impacts we are able to quantify

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[V] 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.

[W] 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.

plus the sum of the nonmonetized health and welfare benefits. Our estimate of total monetized benefits associated with the proposed standards in 2017, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, is between $1.0 and $3.4 billion, assuming a 3 percent discount rate, or between $1.0 and $3.3 billion, assuming a 7 percent discount rate. Had our ambient air quality modeling of $PM_{2.5}$ not included the increase in direct PM emissions, we estimate that benefits would increase by a range of $400 to $970 million (assuming a 3 percent discount rate) or increase by a range of $360 to $880 million (assuming a 7 percent discount rate), using current EPA benefit-per-ton estimates for direct PM.[X]

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. Accounting for the removal of the increase in direct PM emissions in the 2017 air quality modeling, total monetized benefits increase even more, to between $1.4 and $4.3 billion, assuming a 3 percent discount rate, or between $1.3 and $4.2 billion, assuming a 7 percent discount rate. The benefits increase substantially after 2017, as the vehicle standards phase in after 2017 and as the fleet turns over.

Table 8-18: Estimated $PM_{2.5}$-Related Health Impacts[a]

Health Effect	2017 Annual Reduction in Incidence (5th - 95th percentile)
Premature Mortality – Derived from epidemiology literature[b]	
Adult, age 30+, ACS Cohort Study (Pope et al., 2002)	57 (9 – 110)
Adult, age 25+, Six-Cities Study (Laden et al., 2006)	150 (54 – 240)
Infant, age <1 year (Woodruff et al., 1997)	0 (0 – 1)
Chronic bronchitis (adult, age 26 and over)	38 (-7 – 84)
Non-fatal myocardial infarction (adult, age 18 and over)	64 (7 – 120)
Hospital admissions - respiratory (all ages)[c]	10 (3 – 17)
Hospital admissions - cardiovascular (adults, age >18)[d]	23 14 – 28)
Emergency room visits for asthma (age 18 years and younger)	40 (15 – 64)
Acute bronchitis, (children, age 8-12)	87 (-45 – 220)

[X] The $PM_{2.5}$-related benefit-per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of directly emitted $PM_{2.5}$. The benefit per-ton technique has been used in previous analyses, including the 2012-2016 Light-Duty Greenhouse Gas Rule (U.S. EPA, 2010. Regulatory Impact Analysis, Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards. Office of Transportation and Air Quality. April. Available at http://www.epa.gov/otaq/climate/regulations/420r10009.pdf. EPA-420-R-10-009). The benefits-per-ton values are available at http://www.epa.gov/oaqps001/benmap/bpt.html. Note that the values on the website are presented in year 2006$; the values underlying the estimates here have been adjusted to 2010$ using the CPI-U "all" index.

Health Effect	2017 Annual Reduction in Incidence (5th - 95th percentile)
Lower respiratory symptoms (children, age 7-14)	1,100 (270 – 1,900)
Upper respiratory symptoms (asthmatic children, age 9-18)	830 (0 – 1,700)
Asthma exacerbation (asthmatic children, age 6-18)	1,800 (-360 – 5,100)
Work loss days	7,300 (5,900 – 8,700)
Minor restricted activity days (adults age 18-65)	43,000 (33,000 – 53,000)

Notes:
[a] Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.
[b] PM-related adult mortality based upon the American Cancer Society (ACS) Cohort Study (Pope et al., 2002) and the Six-Cities Study (Laden et al., 2006). 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).[Y]
[c] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.
[d] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 8-19: Estimated Ozone-Related Health Impacts[a]

Health Effect	2017 Annual Reduction in Incidence (5th - 95th percentile)
Premature Mortality, All ages[b]	
Multi-City Analyses	
Bell et al. (2004) – Non-accidental	49 (21 – 77)
Huang et al. (2005) – Cardiopulmonary	71 (33 – 110)
Schwartz (2005) – Non-accidental	75 (31 – 120)
Meta-analyses:	
Bell et al. (2005) – All cause	160 (88 – 230)
Ito et al. (2005) – Non-accidental	220 (140 – 290)
Levy et al. (2005) – All cause	230 (160 – 290)
Hospital admissions- respiratory causes (adult, 65 and older)c	290 (37 – 520)
Hospital admissions -respiratory causes (children, under 2)	170 (85 – 250)
Emergency room visit for asthma (all ages)	170 (-3 – 441)

[Y] 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	2017 Annual Reduction in Incidence (5th - 95th percentile)
Minor restricted activity days (adults, age 18-65)	300,000 (150,000 – 440,000)
School absence days	98,000 (43,000 – 140,000)

Notes:

[a] Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous U.S.

[b] 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.

[c] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

Table 8-20: Estimated Monetary Value of Changes in Incidence of Health and Welfare Effects (millions of 2010$) [a,b]

		2017
$PM_{2.5}$-Related Health Effect		(5th and 95th Percentile)
Premature Mortality – Derived from Epidemiology Studies[c,d]	Adult, age 30+ - ACS study (Pope et al., 2002)	
	3% discount rate	$490 ($41 - $1,300)
	7% discount rate	$440 ($37 - $1,200)
	Adult, age 25+ - Six-Cities study (Laden et al., 2006)	
	3% discount rate	$1,300 ($160 - $3,200)
	7% discount rate	$1,100 ($140 - $2,900)
	Infant Mortality, <1 year – (Woodruff et al. 1997)	$2.5 (-$3.3 - $11)
Chronic bronchitis (adults, 26 and over)		$20 (-$2.6 - $70)
Non-fatal acute myocardial infarctions		
3% discount rate		$7.4 ($0.80 - $20)
7% discount rate		$5.9 ($0.60 - $15)
Hospital admissions for respiratory causes		$0.16 ($0.05 - $0.23)
Hospital admissions for cardiovascular causes		$0.38 ($0.01 - $0.74)
Emergency room visits for asthma		$0.016 ($0.006 - $0.026)
Acute bronchitis (children, age 8–12)		$0.041 (-$0.021 - $0.12)
Lower respiratory symptoms (children, 7–14)		$0.023 ($0.005 - $0.047)
Upper respiratory symptoms (asthma, 9–11)		$0.028 ($0 - $0.070)
Asthma exacerbations		$0.10 (-$0.02 - $0.30)

Work loss days		$1.2 ($0.96 - $1.4)
Minor restricted-activity days (MRADs)		$2.9 ($1.7 - $4.3)
Ozone-related Health Effect		
Premature Mortality, All ages – Derived from Multi-city analyses	Bell et al., 2004	$460 ($60 - $1,200)
	Huang et al., 2005	$670 ($90 - $1,700)
	Schwartz, 2005	$700 ($91 - $1,800
Premature Mortality, All ages – Derived from Meta-analyses	Bell et al., 2005	$1,500 ($210 - $3,700)
	Ito et al., 2005	$2,100 ($300 - $4,900)
	Levy et al., 2005	$2,100 ($320 - $5,000)
Hospital admissions- respiratory causes (adult, 65 and older)		$7.6 ($0.97 - $14)
Hospital admissions- respiratory causes (children, under 2)		$1.8 ($0.93 - $2.7)
Emergency room visit for asthma (all ages)		$0.07 ($0 - $0.17)
Minor restricted activity days (adults, age 18-65)		$20 ($9.0 - $34)
School absence days		$9.4 ($4.1 - $13)

Notes:

[a] Monetary benefits are rounded to two significant digits for ease of presentation and computation. PM and ozone benefits are nationwide.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2017).

[c] 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.

Table 8-21: Total Monetized Ozone and PM-related Benefits Associated with the Proposed Program in 2017

Total Ozone and PM Benefits (billions, 2010$) – PM Mortality Derived from the ACS and Six-Cities Studies					
3% Discount Rate			**7% Discount Rate**		
Ozone Mortality Function	Reference	Mean Total Benefits	Ozone Mortality Function	Reference	Mean Total Benefits
Multi-city	Bell et al., 2004	$1.0 - $1.8	Multi-city	Bell et al., 2004	$0.96 - $1.7
	Huang et al., 2005	$1.2 - $1.9		Huang et al., 2005	$1.2 - $1.9
	Schwartz, 2005	$1.3 - $2.0		Schwartz, 2005	$1.2 - $1.9
Meta-analysis	Bell et al., 2005	$2.1 - $2.8	Meta-analysis	Bell et al., 2005	$2.0 - $2.7

	Ito et al., 2005	\$2.6 - \$3.4		Ito et al., 2005	\$2.6 - \$3.3
	Levy et al., 2005	\$2.7 - \$3.4		Levy et al., 2005	\$2.6 - \$3.3

8.2 Cost Per Ton of Emissions Reduced

This section will present the cost per ton of emissions reduced analysis we completed for the proposed combined Tier 3 vehicle and fuel standards. This analysis relies in part on cost information from draft RIA Chapters 2 and 5 and emissions information from draft RIA Chapter 8 to estimate the dollars per ton (\$/ton) of total NO_X + NMOG emission reductions after the proposed Tier 3 standards would have been fully implemented. We have calculated the cost per ton on an aggregate basis to provide a comprehensive means for capturing the effectiveness of the proposed program on vehicles and fuels.

8.2.1 Overview

We have calculated the aggregate cost per ton which uses the costs and emission reductions for calendar years 2017 and 2030, consistent with the years that we evaluated for air quality and the cost-benefit analysis. All of our results are presented and discussed in Section 8.2.5 below.

8.2.2 Baselines

An average approach to cost per ton of emissions reduced analysis requires that we compare the costs and emission reductions associated with the proposed standards to those for the previous set of standards that are being met by manufacturers. In this case, the \$/ton values represent the full range of control from the last applicable standard to our proposed standards.

Since today's program includes both proposed fuel standards and proposed vehicle standards, it was necessary for us to define a baseline for both fuels and vehicles from which to calculate reductions in emissions and increases in costs. For sulfur content of fuel and vehicle emissions, the previous standards were set under the Tier 2 program. The baseline sulfur level in the fuel is therefore 30 ppm and the baseline vehicle exhaust standard is 0.07 g/mi NO_X. The baseline vehicle evaporative standards are listed below in Table 8-22.

Table 8-22: Light-Duty Vehicle, Light-Duty Truck, and Medium-Duty Passenger Vehicle Evaporative Standards[a]

Vehicle Type	3 Day Diurnal + Hot Soak (g/test)	2 Day Diurnal + Hot Soak (g/test)
LDV	0.50	0.65
LLDT	0.65	0.85
MDPV	1.00	1.25

[a] 72 Federal Register at 8471 (February 26, 2007)

8.2.3 Costs

Costs that would be incurred from our proposed program would be due to the proposed Tier 3 exhaust standards, Tier 3 evaporative standards, and reductions in sulfur content of gasoline, as discussed above in Section 8.1.1. 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, are as shown in Table 8-23. All costs represent the fleet-weighted average of light-duty vehicles and trucks. All costs are represented in 2010 dollars.

Table 8-23: Total Annual Vehicle and Fuel Control Costs, 2010$

	Total Vehicle and Fuel Control Costs ($Million)[a]
2017	$1,999
2030	$3,367

[a] These estimates include costs associated with the proposed Tier 3 vehicle and fuel standards in all states except California.

8.2.4 Emission Reductions

In order to determine the overall cost per ton of emissions reduced due to the standards we are proposing, it was necessary to calculate the tons of each pollutant reduced on an aggregate basis. Our proposed standards are intended primarily to reduce emissions of NO_X and NMOG. As a result, we have determined that the cost per ton of emissions reduced of our standards should be determined for both NO_X and NMOG. It is true that our program does include new proposed standards for PM. However, as discussed in Chapter 2, we believe that the efforts manufacturers make to meet the NO_X+NMOG standards will also result in sufficient PM reductions to meet our proposed PM standards. Thus we estimate that manufacturers would incur no additional costs to comply with the Tier 3 PM standard and a cost per ton of emissions reduced analysis of the PM standards is therefore unnecessary.

8.2.4.1 NO_X and NMOG

Several past rulemakings which produced reductions in both NO_X and NMOG have taken an approach to cost per ton of emissions reduced that sums the NO_X and NMOG emission reductions. This approach leads to $/ton NO_X+NMOG. In addition, many standards for mobile sources have been established in terms of NO_X+NMOG caps, including the previous Tier 2 vehicle standards. Thus we believe that this approach to cost per ton of emissions reduced is appropriate for our Tier 3 standards as well.

The projected annual reductions in NO_X and NMOG in 2017 and 2030 are included in Table 8-24.

Table 8-24: Annual NO_X and VOC Reductions (tons) in 2017 and 2030

	NO_X Reductions (tons)	VOC Reductions (tons)	Total NO_X+VOC Reductions (tons

2017	284,381	44,782	329,162
2030	524,790	226,028	750,818

8.2.5 Results

The results of our cost per ton of emissions reduced analysis are provided in Table 8-25. Costs are provided above in Table 8-23. The tons reduced are from the values in Table 8-24 as the difference between our Tier 2 baseline at our baseline fuel sulfur level of 30 ppm, and our Tier 3 standards at our fuel sulfur standard of 10 ppm.

The costs of the proposed program would be higher immediately after it is implemented than they would be after several years, since both vehicle manufacturers and refiners can take advantage of decreasing capital and operating costs over time. In addition, the reductions in NO_X and VOC emissions will become greater as a greater percentage of the fleet contains the technologies required to meet the proposed standards.

Table 8-25 Cost Per Ton of Emissions Reduced of the Proposed Vehicle and Fuel Standards

	Total Proposed Program Cost ($million, 2010$)	Total NO_X + VOC Reductions (tons)	Cost Per Ton of Emissions Reduced ($/ton)
2017	$1,999	329,162	$6,072
2030	$3,367	750,818	$4,484

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Chapter 9 Economic Impact Analysis

9.1 Introduction

The proposed rule 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 proposed rule, 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. The recently issued 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 this proposal on employment in the regulated sectors.

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 proposed standards at the aggregate market level. Light-duty vehicle manufacturers are expected to comply with the proposed 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 proposed standards. These costs differ across years and range from $71 to $102 for cars, $93 to $150 for trucks and $36 to $59 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.[A] We do not quantify the expected level of cost pass-through or the ultimate vehicle price increase consumers

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[A] 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), 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.

are expected to face, apart from noting that prices are expected to increase by an amount up to the increased manufacturers' costs.

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 this rule 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 rule on fleet-wide emissions. Because we do not estimate the effect of the rule 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 rule 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.[1] 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 proposed in a study by Morgenstern, Pizer, and Shih[2] of the impacts of regulation in employment in the regulated sectors. In particular, Morgenstern et al. identify three separate ways that employment levels may change in the regulated industry in response to a new or more stringent regulation.

- Demand effect: higher production costs due to the regulation will lead to higher market prices; higher prices in turn reduce demand for the good, reducing the demand for labor to make that good. In the authors' words, the "extent of this effect depends on the cost increase passed on to consumers as well as the demand elasticity of industry output."
- Cost effect: as costs go up, plants add more capital and labor (holding other factors constant), with potentially positive effects on employment; in the authors' words, as "production costs rise, more inputs, including labor, are used to produce the same amount of output."
- Factor-shift effect: post-regulation production technologies may be more or less labor-intensive (i.e., more/less labor is required per dollar of output). In the authors' words, "environmental activities may be more labor intensive than conventional production," meaning that "the amount of labor per dollar of output will rise," though it is also possible that "cleaner operations could involve automation and less employment, for example."

The authors note that the demand effect is expected to have a negative effect on employment, the cost effect to have a positive effect on employment, and the factor-shift effect to have an ambiguous effect on employment. Without more information with respect to the magnitudes of these competing effects, it is not possible to predict the total effect environmental regulation will have on employment levels in a regulated sector.

Morgenstern et al. estimated the effects on employment of spending on pollution abatement for four highly polluting/regulated industries (pulp and paper, plastics, steel, and petroleum refining) using data for six years between 1979 and 1991. They conclude that increased abatement expenditures generally have not caused a significant change in employment in those sectors. More specifically, their results show that, on average across the industries studied, each additional $1 million (1987$) spent on pollution abatement results in a (statistically insignificant) net increase of 1.5 jobs. In the petroleum refining industry in particular, they found statistically significant and positive cost and factor shift effects and an insignificant demand effect, for a net (statistically significant) increase of 2.17 jobs per $1 million (1987$).

Following the Morgenstern et al. framework for the impacts of regulation on employment in the regulated sector, we consider three effects for the auto sector: the demand effect, the cost effect, and the factor shift effect.

9.2.2.1 The Demand Effect

The demand effect depends on the effects of this proposal 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 proposed 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 demand effect to be small as well.

9.2.2.2 The Cost Effect

The demand effect, above, measures the effect due to new vehicle sales only. The cost effect measures the impacts due to the changes in technologies for vehicles that would have been sold in the absence of the rule.

One way to estimate the cost 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, as the factor-shift effect indicates. For instance, the ratio for the motor vehicle manufacturing sector represents the ratio for all vehicle manufacturing, not just for emissions reductions. 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.

Some of the costs of this proposal 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),[3] 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).

The Census Bureau provides both the Annual Survey of Manufacturers[4] (ASM) and the Economic Census. The ASM is a subset of the Economic Census, based on a sample of 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).

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.[B]

Table 9-1 provides the values, either given (BLS) or calculated (ASM, Economic Census) for employment per $1 million of expenditures, all based on 2010 dollars, though the underlying data come from different years (which may account for some of the differences). 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 $1 Million Expenditures (2010$) in the Motor Vehicle Manufacturing Sector[a]

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	0.770	0.514
ASM	Motor Vehicle Mfg	0.655	0.437
ASM	Light Duty Vehicle Mfg	0.609	0.406
Economic Census	Motor Vehicle Mfg	0.665	0.443
Economic Census	Light Duty Vehicle Mfg	0.602	0.402
BLS ERM	Motor Vehicle Parts Mfg	2.614	1.743
ASM	Motor Vehicle Parts Mfg	2.309	1.540
Economic Census	Motor Vehicle Parts Mfg	2.712	1.809

Note:

[a] 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$).[5] 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

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[B] 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.

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 2010$) 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 2010 (the base year for the ASM) to determine how many workers will be needed per $1 million of 2010$; 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 2.1 of the draft 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 1.809 in 2010 if all the additional costs are in the parts sector; the minimum value is 0.402 in 2010, if all the additional costs are in the light-duty vehicle manufacturing sector. Increased costs of vehicles and parts would, by itself, be expected to increase employment between 2017 and 2025 by somewhere between a few hundred to a few thousand jobs.

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.

Table 9-2 Employment Effects due to Increased Costs of Vehicles and Parts, in job-years

Year	Costs (Millions of 2010$)	Maximum Employment Due to Cost Effect (if all expenditures are in the Parts Sector)	Minimum Employment Due to Cost Effect (if all expenditures are in the Light Duty Vehicle Mfg Sector)
2016	$ 23	0	0
2017	$ 709	900	200
2018	$ 1,340	1,700	400
2019	$ 1,440	1,800	400
2020	$ 1,600	1,900	400
2021	$ 1,730	2,000	400
2022	$ 1,900	2,100	400
2023	$ 1,920	2,000	400
2024	$ 2,040	2,100	400
2025	$ 2,130	2,100	400

9.2.2.3 The Factor Shift Effect

The factor shift effect looks at the changes in labor intensity associated with a regulation. As noted above, the estimates of the cost effect assume constant labor per $1 million in expenditures, though the new technologies may be either more or less labor-intensive than the existing ones. We have no evidence on the factor shift effect for the compliance technologies and therefore do not quantify it. An estimate of the factor shift effect would either increase or decrease the estimate used for the cost effect.

9.2.2.4 Summary of Employment Effects in the Auto Sector

The overall effect of the proposed rule on auto sector employment depends on the relative magnitude of the cost effect, the demand effect and the factor shift effect. Because we do not have quantitative estimates of the demand and factor shift effects we cannot reach a quantitative estimate of the overall employment effects of the proposed rule on auto sector employment or even whether the total effect would 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 these effects will be small as well. Additionally, the cost and demand effects are expected to work in opposite directions. Thus while we do not have an estimate of the direction of the overall effect of the proposed rule on auto sector employment, we expect it will be imperceptible.

The proposed rule is not expected to provide incentives for manufacturers to shift employment between domestic and foreign production. This is because the proposed standards would 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 proposal, there may be some initial incentive for foreign production, but the opportunity for the U.S. to sell in other markets might increase. To the extent that the requirements of this proposal 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 would 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 proposed standards would be more stringent sulfur requirements. This change to fuels is expected to increase manufacturers' costs of gasoline production by about 0.9 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."[6] Thus the assumption of competitive markets has some foundation in this industry. We do not estimate the price increase that consumers are likely to face, though we note that it 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. 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 proposed 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 Morgenstern et al. framework of demand effects, cost effects and factor shift effects can also be applied to the impact of the proposed rule on employment in the refinery sector.[7] 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 demand effect on refining sector employment is expected to be negative. The discussion in Chapter 9.3.1 above suggested that the proposed rule would 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 would 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 would be lower in the long run than in the short run, leading to a greater reduction in employment due to the demand effect over time. While we do not quantify the level of job losses that could be expected here, recall that the quantity of gasoline sold as a result of the standards proposed here is expected to decrease by only a very small amount over any time horizon.

The cost effect of the proposed rule on employment in the refining sector is expected to be positive as usual in the Morgenstern et al. framework. In order to satisfy the requirements of the proposed 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. Section V.A.2.c of the Preamble discusses the expected employment needed to reduce the sulfur content of fuels; as noted there, to meet the proposed Tier 3 sulfur standards, refiners are expected to invest $2.2 billion between 2014 and 2019 and utilize approximately 1,000 front-end design and engineering jobs and 6,000 construction jobs. As the petroleum sector employed approximately 65,000 workers in 2009, this increase in employment would be comparable to an increase of over 10 percent when compared to 2009 levels.

As with our analysis of the vehicle manufacturing sector, we do not have information on the direction the factor shift effect might take. It is unclear whether the refining industry would become more or less capital intensive as a result of the proposed rule. Thus the direction of the factor shift effect is ambiguous.

This rule is not expected to provide incentives to shift employment between domestic and foreign production. First, the proposed standards would 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.[C] In this 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 would be 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 demand effect would lower employment, the cost effect would raise employment, and the factor shift effect would have an ambiguous effect on employment. As a whole then, it is not evident whether the proposed rule would increase or decrease employment in the refining sector. However, given the small anticipated reduction in quantity sold, it appears that the rule would not have major employment consequences for this sector.

The petroleum industry is one of the four industries studied by Morgenstern et al. (2002) when they looked at the effect of environmental expenditures on employment. They found a small but statistically significant increase in employment in this sector (2.17 jobs per million dollars of expenditures, using 1987$). Using this factor (adjusted to 2010$), the estimated sulfur fuel control costs in 2017 of $1,289 million would imply an increase of approximately 1,600 jobs in the refinery sector. We note that the regulations that this estimate is derived from are not

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[C] 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).

directly comparable to the current proposed rule; it is based on the costs of reductions in refinery emissions instead of changing fuel properties, and therefore may not be applicable for the standards proposed 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 net 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 proposed 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 proposed rule is 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 need to revamp their current treatment units and others will need to add additional treatment units. Producers of this equipment would be 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 cost 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 demand effect would not start until 2017, when compliance would be 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.

References

[1] 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.

[2] 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.

[3] http://www.bls.gov/emp/ep_data_emp_requirements.htm

[4] http://www.census.gov/manufacturing/asm/index.html

[5] 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."

[6] 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.

[7] 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.

Chapter 10 Initial Regulatory Flexibility Analysis

10.1 Introduction

This chapter discusses our Initial Regulatory Flexibility Analysis (IRFA) 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. 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 IRFA. A summary of the Panel's recommendations is presented in the preamble of this proposed rulemaking. Further, a detailed discussion of the Panel's advice and recommendations is found in the Final Panel Report contained in the docket for this proposed rulemaking.[1]

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 IRFA under section 603 of the Regulatory Flexibility Act. Key elements of an IRFA are:

- A description of the reasons why action by the agency is being considered;
- A succinct statement of the objectives of, and legal basis for, the proposed rule;
- A description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- Projected reporting, record keeping, and other compliance requirements of the proposed 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;
- An identification to the extent practicable, of all other relevant Federal rules which may duplicate, overlap, or conflict with the proposed rule;

- Any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities.

The Regulatory Flexibility Act was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. Although we are not required by the Clean Air Act to provide special treatment to small businesses, the Regulatory Flexibility Act requires us to carefully consider the economic impacts that our rules will have on small entities. The recommendations made by the Panel may serve to help lessen these economic impacts on small entities when consistent with Clean Air Act requirements.

10.3 Need for the Rulemaking and Rulemaking Objectives

As presented in Chapter 9 of this Draft 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 proposed 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) refinery average, 80 ppm per-gallon cap, and 95 ppm downstream cap; beginning in 2004 and phasing in through 2008.

The proposed 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 proposal will establish 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_X 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 proposed 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 the proposed 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[A]; (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. The regulatory revisions being considered by EPA for this proposed rulemaking are expected to affect a variety of small businesses, but would not affect any small governments or small organizations. Table 10-1 provides an overview of the primary SBA small business categories potentially affected by this proposed regulation.

Table 10-1 Industry Sectors Potentially Affected by Proposed Rule

Industry Sector	2007 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 325998 424690	1,000 employees 500 employees 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 GVWR) manufacturers	333618, 336120, 336211 336312	1,000 employees 750 employees
Independent commercial importers	811111, 811112, 811198	$7 million (annual receipts)
Alternative fuel converters	335312	1,000 employees

[A] 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.

	336312, 336322, 336399 811198	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 rule 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-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 the proposed Tier 3 rule under are the Tier 2 Vehicle/Gasoline Sulfur rulemaking, the Light-duty Greenhouse Gas (GHG) proposed rule, and the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards proposed rule (RTR/NSPS).

The Tier 2 vehicle/gasoline sulfur rulemaking was adopted by EPA in February 2000.[B] The Light-duty GHG National Program is a coordinated effort by EPA and the National Highway Traffic Safety Administration (NHTSA) taking steps to enable the production of a new generation of clean vehicles, though reduced GHG emissions and improved fuel efficiency from on-road vehicles and engines. On August 28, 2012 , EPA and NHTSA finalized a rulemaking which further strengthens GHG and CAFE standards for light-duty vehicles of model years 2017 and beyond.[C]

The proposed rules to address Petroleum Refinery Sector Risk and Technology Review (RTR) and New Source Performance Standards (NSPS) will focus on developing updated emissions standards for petroleum refineries for multiple pollutants. The proposed rules are based on results of the RTR analyses for both Maximum Achievable Control Technology standards (MACT 1 and 2). The technology review will be conducted to identify any new practices, processes, or control technologies for the industry and cost-effective emission control options. EPA is developing uniform standards for some emission sources in the petroleum refining sector that may serve as the basis for these technology reviews. The proposed rules will also review the standards and rule provisions to determine whether other changes may be needed during periods of start-up, shutdown, and malfunction to ensure the standards are consistent with recent court opinions and other CAA programs. With regard to NSPS, the proposed rules will address NSPS issues under reconsideration from the promulgation of existing NSPS and other NSPS rules affecting the refining sector.

[B] See 65 FR 6698, February 10, 2000.

[C] See 77 FR 62624 October 15, 2012.

10.7 Projected 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. EPA expects that the recordkeeping, reporting, and compliance provisions of the proposed rule will be fairly consistent with those in place today for other fuel programs. Further, we expect to use existing registration and reporting systems that parties in the fuel production and distribution industry are already familiar with.

For any motor vehicle emission control program, EPA must have assurances that the regulated products will meet the standards. The program that EPA is considering for manufacturers subject to this proposal will include testing, reporting, and record keeping requirements for manufacturers of vehicles covered by the proposed Tier 3 regulations. Testing requirements for these manufacturers could include certification emission (including deterioration factor) testing and in-use testing. Reporting requirements would likely include emission test data and technical data on the vehicles. Manufacturers would have to keep records of this information.

10.8 Regulatory Alternatives

The Panel developed a wide range of regulatory alternatives to mitigate the impacts of the proposed rulemaking on small businesses, and recommended that we propose and seek comment on the flexibilities. The Panel's findings and discussions are based on the information that was available during the term of the Panel and issues that were raised by the SERs during the outreach meetings and in their written comments. 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. Alternatives discussed throughout the Panel process include those offered in the development of the upcoming rule. Though some of the recommended flexibilities may be appropriate to apply to all entities affected by the rulemaking, the Panel's discussions and recommendations are focused mainly on the impacts, and ways to mitigate adverse impacts, on small businesses. A summary of the Panel's recommendations, along with those provisions that we are actually proposing in this action, are detailed below. A full discussion of the regulatory alternatives and hardship provisions discussed and recommended by the Panel, all written comments received from SERs, and summaries of the two outreach meetings that were held with the SERs can be found in the SBREFA Final Panel Report.[2] In addition, all of the flexibilities that are being proposed in the rulemaking for small businesses, as well as those for all entities that may be affected by the rulemaking, are described in the preamble to the proposed rule.

10.8.1 Fuel-related Alternatives

Described below are the flexibility options recommended by the Panel and our proposed regulatory alternatives related to the proposed gasoline requirements.

10.8.1.1 SBAR Panel Recommendations

10.8.1.1.1 Lead Time—Sulfur

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). 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.

10.8.1.1.2 Provisions for Additive Manufacturers

The Panel recommended that EPA provide flexibilities for gasoline additive manufacturers. Following discussion with EPA, the Panel suggested that EPA propose the following flexibilities:

- For additives used downstream of the refiner: Differentiating bulk additives based on whether they meet a 20 or 25 ppm sulfur standard.
- For aftermarket consumer additives: Allow for aftermarket additives to meet either a 20 ppm or 25 ppm sulfur cap.
- For additives not meeting a 10, 20, or 25 ppm sulfur limit: Allow for the use of volume accounting reconciliation (VAR) records for additives that would not be able to meet a 25 ppm sulfur cap to show that use of the additive would not cause the sulfur level of the finished fuel to exceed 10 ppm (similar to EPA's Nonroad Diesel Rulemaking[D]), and require product labeling for aftermarket additives.

10.8.1.1.3 Refinery Gate and Downstream Caps

With regard to the 20 ppm refinery gate cap discussed in Section 3 of the Panel Report, 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

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[D] See 69 FR 39088, June 29, 2004

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 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. Thus, the SBA and OMB Panel members recommend that EPA propose retaining the 80 ppm and 95 ppm caps.

The Panel also 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.

10.8.1.1.4 Hardship Provisions

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.

10.8.1.2 EPA's Proposed Regulatory Flexibility Options

In general, we have chosen to propose many of the Panel's recommended regulatory flexibility provisions where applicable. The following is a discussion of the proposed provisions.

10.8.1.2.1 Delayed Standards for Small Refiners

As explained in Sections V.E.2.a.i and XII.C of the preamble to the proposed rule, we are proposing an option that would allow small refiners to postpone their compliance with the Tier 3 program for up to three years. This delayed compliance schedule for small refiners is not intended as an opportunity for those refiners to greatly expand their production of gasoline with a sulfur content higher than 10 ppm, but rather would help small refiners with compliance with the program. Since the compliance costs for their competitors would rise during these three years and since their gasoline would all be sold into the same fungible market, this delay would not only provide them flexibility, but also financial support towards later compliance. 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. 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 their refinery average 30 ppm sulfur standard (however, these credits may not be used for compliance with the proposed Tier 3 10 ppm average sulfur standard).

10.8.1.2.2 Refinery Gate and Downstream Caps

Consistent with the Panel recommendations, as discussed above and in Section XII.C of the preamble to the proposed rule, we are proposing to either maintain the current 80/95 ppm caps or to lower them to 50/65 ppm. Should we lower the caps to 50/65 ppm (given the stringency of the 10 ppm average standard), we anticipate that these caps would provide the same level of flexibility for refiners, pipelines, terminals, transmix processors, and gasoline additive manufacturers as the current 80/95 ppm cap. Also, if we were to lower the caps to 50/65, we are proposing to allow the current Tier 2 80 ppm refinery gate cap to remain in place until through December 31, 2019. Compliance with the 50 ppm refinery gate cap would begin on January 1, 2020, when the 10-ppm average sulfur standard is required for all refiners. Similarly, we are proposing to allow the Tier 2 95 ppm downstream cap to remain in effect through February 29, 2020; compliance with the 65 ppm downstream cap would begin on March 1, 2020. For more information on the proposed cap provisions, refer to Section V.A.3 of the preamble to the proposed rule.

10.8.1.2.3 Credit-related Flexibilities

As described in detail in Section V.E.1 of the preamble to the proposed rule, we are proposing a credit trading program. Refiners and importers would be able to generate early sulfur credits from January 1, 2014 through December 31, 2016 relative to the current 30-ppm Tier 2 average sulfur standard (i.e., credits may be generated for any reductions below 30 ppm prior to the start of the general Tier 3 program). Beginning January 1, 2017 standard credits may be generated for over-compliance with the proposed 10-ppm Tier 3 sulfur standard. In addition, small refiners and small volume refineries would be able to generate “early standard credits” from January 1, 2017 through December 31, 2019 for reductions below 10 ppm prior to their proposed program start date of January 1, 2020.

In previous EPA fuel programs, importers have generally been treated as refiners, except for the purposes of early credit generation. Refiners have historically been required to establish a baseline in order to generate early credits. Importers generally do not have a specific baseline or amount of fuel that they import in a given year, so participation in the early credit market would not have been feasible under those programs. Under the proposed Tier 3 sulfur program, refiners and importers are not required to establish baselines—the existing 30-ppm Tier 2 standard is the “baseline.” Therefore, we are also proposing to allow importers to participate in the early credit program as well as the ongoing standard credit program.

10.8.1.2.4 Gasoline Additive Manufacturers

During the SBREFA Panel process, some gasoline additive manufacturing SERs raised the concern that they would have difficulty meeting a 25-ppm sulfur cap, and the Panel recommended that EPA request comment on whether or not gasoline additives should be allowed to remain at levels above 25 ppm sulfur, and on potential methods for ensuring that bulk additives do not increase the level of the resultant fuel blend. However, as discussed above and in Section V.A.3 of the preamble to the proposed rule, we are co-proposing retaining the current 80/95 ppm caps and moving to 50/65 ppm caps. Both of these options would have the same 15-ppm differential between the refinery gate and downstream caps, thus we are not proposing any additional provisions for gasoline additives beyond what already exists under the current Tier 2 program.

10.8.2 Vehicle-related Alternatives

Described below are the flexibility options recommended by the Panel and our proposed regulatory alternatives related to the proposed exhaust and evaporative emission standards.

10.8.2.1 SBAR Panel Recommendations

10.8.2.1.1 Lead Time for Exhaust and Evaporative Emission Standards

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_X 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.

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.

10.8.2.1.2 Assigned Deterioration Factors

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.

10.8.2.1.3 Reduced Testing Burden

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_2 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_2 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 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.

10.8.2.1.4 Hardship Provisions

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.)

10.8.2.1.5 Applicability of Flexibilities

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_2 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 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.

10.8.2.2 EPA's Proposed Regulatory Flexibility Options

We have chosen to propose the Panel's recommended regulatory flexibility provisions along with a few additional flexibilities identified below. The following is a discussion of the proposed provisions.

10.8.2.2.1 Lead Time for Exhaust and Evaporative Emission Standards

EPA is proposing that small businesses be given additional leadtime to comply with the potential Tier 3 exhaust and evaporative emission 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.) 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. 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.

While EPA is proposing the same standards for all manufacturers starting with model year 2022, EPA is requesting 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 requesting comment on the standards recommended by the SER. The SER-recommended relaxed $NMOG+NO_X$ 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.

10.8.2.2.2 Assigned Deterioration Factors

EPA is proposing 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, EPA should 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. EPA recognizes 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.

10.8.2.2.3 Reduced Testing Burden

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 is proposing 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, EPA is proposing new PM standards and will 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, EPA is proposing to continue the waiver for PM testing in the Tier 3 timeframe for small businesses. Small businesses will not be required to measure PM emissions when they certify to the Tier 3 emission standards. In lieu of testing, small businesses will 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.

With the Tier 3 proposal, EPA is proposing new OBD requirements for vehicles certifying to the Tier 3 standards. The proposed OBD requirements are 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 are therefore proposing 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 current regulations. With the Tier 3 proposal, EPA is proposing 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. With the Tier 3 proposal, we are proposing that the categories of vehicles newly subject to the SFTP standards, including alternative-fuel converters, have the option to substitute the FTP emissions levels for the SC03 emissions results for purposes of compliance when calculating the SFPT emissions. 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 expect the SFTP emissions should be similarly low, and therefore the added SC03 testing burden is unnecessary.

10.8.2.2.4 Hardship Provisions

EPA is proposing hardship provisions for small businesses subject to 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 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 hardship 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 we are proposing that such a limit is not needed as part of the Tier 3 hardship provisions.

10.8.2.2.5 Applicability of Flexibilities

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 current 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.

With the Tier 3 proposal, EPA is proposing 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, EPA is proposing 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_2 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.[E] EPA is proposing 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. EPA believes 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.

10.9 Projected Economic Effects of the Proposed Rulemaking

The following section summarizes the economic impact on small businesses of the proposed Tier 3 exhaust and evaporative emission standards and the proposed fuel requirements. As noted earlier, the types of companies that will be affected by the proposed Tier 3 exhaust and evaporative emissions include vehicle manufacturers, ICIs, and alternative fuel converters.

[E] See 75 FR 25324, May 7, 2010.

Similarly, the types of companies that will be affected by the proposed fuel requirements include gasoline refiners and importers, ethanol producers, gasoline additive manufacturers, transmix processors, and terminal operators.

To gauge the impact of the proposed 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 analysis for the proposed in-use gasoline requirements are based on the cost estimates developed in Chapter 5 of this Draft RIA. The costs used in this analysis for the proposed Tier 3 exhaust and evaporative emission standards are based on the cost estimates developed in Chapter 2 of this Draft 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.[3]

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. Our proposal to retain the 80 ppm refinery gate cap and 95 ppm downstream cap should mean that downstream parties such as transmix processors, gasoline additive manufacturers, and terminal operators would not incur additional costs as a result of this program. Further, the co-proposal of a 50 ppm refinery gate cap and a 65 ppm downstream cap has the same 15 ppm differential for downstream parties, so we do not anticipate increased costs for downstream parties with this proposal either.

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 this proposed program. Of the 10 refiners that EPA believes would be considered small refiners for the proposed program, it is projected that the majority of these refiners will experience costs less than one percent of their sales, two refiners will experience costs between one and three percent of their sales, and one refiner 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 a vehicle geared toward the handicap market in both a gasoline-powered and CNG-powered version. 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 proposed 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 proposed regulations on small businesses impacted by the proposed fuel requirements and the proposed Tier 3 exhaust and evaporative emission standards.

Table 10-2 Summary of Impacts on Small Businesses

Industry Sector	0-1 Percent	1-3 Percent	>3 Percent
Gasoline fuel refiners and importers	7	2	1
Vehicle manufacturers	4	0	0
Alternative fuel converters	2	3	4
Independent commercial importers	0	8	0
Totals	13	13	5

For a complete discussion of the economic impacts of the proposed rulemaking, see Chapter 9, the Economic Impact Analysis chapter, of this draft Regulatory Impact Analysis.

References

[1] 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

[2] 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

[3] "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.