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Direct Cost Estimates for the Clean Air Act Second Section 812 Prospective Analysis

Final Report | February 2011

prepared for:

James DeMocker
Office of Air and Radiation
U.S. Environmental Protection Agency

prepared by:

Industrial Economics, Incorporated

2067 Massachusetts Avenue

Cambridge, MA 02140

and

E.H. Pechan & Associates, Inc.
5528-B Hempstead Way
Springfield, VA 22151

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INDUSTRIAL ECONOMICS, INCORPORATED

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ACRONYMS AND ABBREVIATIONS

ACI	activated carbon injection
AIM	architectural and industrial maintenance
ASM	Acceleration Simulation Mode
ATP	anti-tampering
ATV	all-terrain vehicles
BAAQMD	Bay Area Air Quality Management District
BART	best available retrofit technology
BID	background information document
C-I	compression ignition
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CAVR	Clean Air Visibility Rule
CCV	closed crankcase ventilation
CDPF	catalyzed diesel particulate filter
CFFP	Clean Fuel Fleet Program
CFFV	clean fuel fleet vehicle
CFV	clean fuel vehicle
CMV	commercial marine vessel
CNG	compressed natural gas
CO	carbon monoxide
Council	Advisory Council on Clean Air Compliance Analysis
DOT	Department of Transportation
EGR	exhaust gas recirculation
EGU	electricity generating unit
EPA	U.S. Environmental Protection Agency
FCCU	fluid catalytic cracking unit

FCU	fluid coking units
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
g/bhp-hr	grams per brake horsepower hour
g/mi	grams per mile
GDP	gross domestic product
GVW	gross vehicle weight
HC	hydrocarbon
HDDV	heavy-duty diesel vehicle
HDGV	heavy-duty gasoline vehicle
HDV	heavy-duty vehicle
HGB	Houston-Galveston-Brazoria
HRVOC	highly reactive volatile organic compound
I/M	inspection and maintenance
IPM	Integrated Planning Model
km	kilometer
kW	kilowatt
kWHr	kilowatt-hour
L&M	locomotive and marine
LDGT	light-duty gasoline truck
LDGV	light-duty gasoline vehicle
LDT	light-duty truck
LDV	light-duty vehicle
LPG	liquefied petroleum gas
LVW	loaded vehicle weight
MDPV	medium-duty passenger vehicle
mmBtu	million British thermal units
MPO	Metropolitan Planning Organization
MY	model year
NAAQS	National Ambient Air Quality Standards
NCP	Non-Conformance Penalty
NEI	National Emissions Inventory

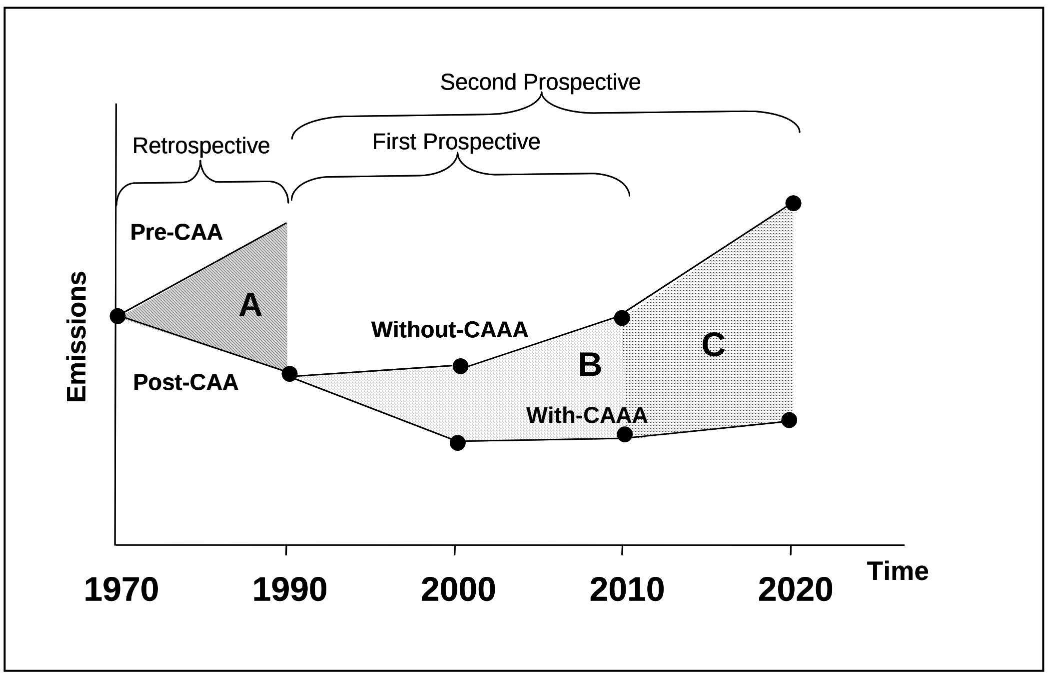
NMHC	nonmethane hydrocarbons
NMOG	nonmethane organic gas
NO_x	oxides of nitrogen
NPV	net present value
NRLM	nonroad, locomotive, marine
O&M	operation and maintenance
OAR	Office of Air and Radiation
OBD	onboard diagnostic
OTC	Ozone Transport Commission
PADD	Petroleum Administration for Defense District
PM_{10}	Particulate matter less than or equal to 10 micrometers
$PM_{2.5}$	Particulate matter less than or equal to 2.5 micrometers
ppm	parts per million
psi	pounds per square inch
RACT	reasonably available control technology
RACM	reasonably available control measure
RFP	reasonable further progress
RIA	regulatory impact analyses
ROG	reactive organic gas
ROI	return on investment
RPE	retail price equivalent
RVP	Reid vapor pressure
S-I	spark ignition
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCC	source classification code
SCR	selective catalytic reduction
SIP	State implementation plan
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
TAC	total annualized costs
TCEQ	Texas Commission on Environmental Quality

TIP	Transportation Improvement Program
TLEV	transitional low emission vehicle
tpy	tons per year
ULEV	ultra-low emission vehicle
VMT	vehicle miles traveled
VOCs	volatile organic compounds
VTEC	Variable Valve Timing and Lift Electronic Control
ZEV	zero-emission vehicle

CHAPTER 1 | INTRODUCTION

Section 812 of the Clean Air Act Amendments of 1990 (CAAA) required the U.S. Environmental Protection Agency (EPA) to perform periodic, comprehensive analyses of the total costs and total benefits of programs implemented pursuant to the Clean Air Act (CAA). The first analysis conducted was a retrospective analysis, addressing the original CAA and covering the period 1970 to 1990. The retrospective was completed in 1997. Section 812 also required performance of prospective cost-benefit analyses, the first of which was completed in 1999. The prospective analyses address the incremental costs and benefits of the CAAA. The First Prospective covered implementation of the CAAA over the period 1990 to 2010. Exhibit 1-1 below outlines the relationship among the Section 812 Retrospective, the First Prospective, and the Second Prospective.

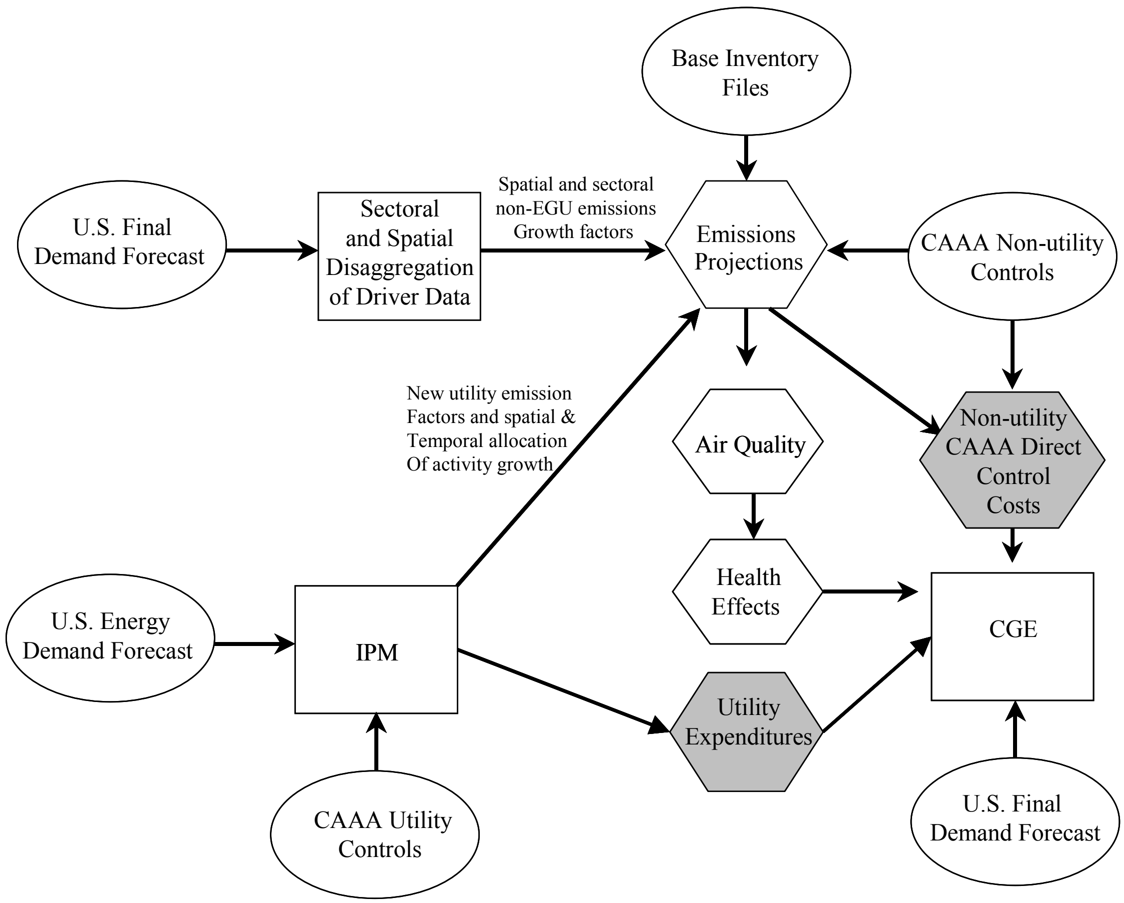
Exhibit 1-1. 812 Scenarios: Conceptual Schematic



EPA's Office of Air and Radiation (OAR) began work on the Second Prospective with the drafting of an analytical plan for the study. This analytical plan was reviewed by a statutorily-mandated external peer review group, the Advisory Council for Clean Air Compliance Analysis (Council). The Council provided comments on the plan, which have been addressed through revisions to the technical analysis planning.

Exhibit 1-2 provides a summary of the key technical steps in the completion of the Second Prospective. The first step in the Second Prospective analysis was the development of base and projection year emission estimates, which were subsequently used to estimate the benefits of CAAA programs. The emission estimates have been published in a separate report (IEc and Pechan, 2010). They were reviewed by the Council's Air Quality Modeling Subcommittee in August 2006 and were subsequently revised.[1]

Exhibit 1-2. May 2003 Analytical Plan - Schematic Flow Chart



This report provides the corresponding direct cost analysis represented by the shaded boxes in Exhibit 1-2 above.[2] It addresses both the utility expenditures that result from the

[1] Industrial Economics, Inc. and E.H. Pechan & Associates, Inc., *Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis – Final Report*, February 2011.

[2] In almost all cases, except where noted below, the cost estimates presented in this report reflect the same economic growth assumptions, intermediate data inputs, rule effective dates, rule-effectiveness assumptions, and other key assumptions and inputs used in the emissions analysis.

Integrated Planning Model (IPM), and the non-utility CAAA control costs. The estimates presented here represent a key stand-alone output of the Second Prospective. In addition, based on the direct cost estimates presented in the main body of this report, the Project Team has generated estimates of CAAA-related private costs that served as inputs in its computable general equilibrium modeling analysis of the CAAA.[3] The Project Team also incorporated certain benefits-side expenditure effects in the CGE analysis, such as avoided health costs and the labor force impacts of the CAAA.

Note also that the cost estimates presented in this report represent direct expenditures associated with CAAA-related compliance. As such, they do not reflect how the Amendments may interact with existing distortions in the economy. For example, the peer-reviewed literature suggests that environmental regulations such as those issued pursuant to the CAAA may exacerbate the economic distortions associated with the income tax.[4] Industries that incur costs to meet the requirements of the Amendments may pass such costs on to consumers in the form of higher prices. This increase in the price level results in a reduction in the real wage (i.e., the purchasing power of labor income), which may induce workers to contribute less to the labor force. The magnitude of the resulting welfare loss, known as the tax interaction effect, depends significantly on the marginal income tax rate; the higher the marginal tax rate, the more significant the loss.[5] Because of this effect, the social costs of the Amendments may exceed the direct CAAA-related costs incurred by regulated industries. The literature also suggests, however, that a benefit-side tax interaction effect associated with a CAAA-related increase in labor productivity may offset the cost-side tax interaction effect. The expenditure-based cost estimates presented in this report do not reflect the tax interaction effect. The Project Team addresses the tax interaction effect and the broader social costs and benefits of the CAAA in the CGE analysis referred to above.

The remainder of this introductory chapter summarizes the overall approach used to estimate direct costs, and provides a description of the model sets, and summarizes direct costs by source category.

SUMMARY OF DIRECT COST APPROACH

The scope of this analysis is to estimate the incremental direct costs for all criteria and hazardous air pollutant regulations issued under CAAA programs. The increment of

[3] Private costs differ from the direct cost estimates presented in the main body of this report in two important ways: (1) they reflect private interest rates rather than the 5 percent social discount rate used throughout this report and (2) they reflect transfers (e.g., excise taxes on fuel) not included in the Project Team's direct cost estimates. Appendix J presents the Project Team's estimates of the private costs associated with the Amendments.

[4] For a review of tax interaction effects see, Lawrence H. Goulder, Ian W.H. Parry, Roberton C. Williams, and Dallas Burtraw, " The cost-effectiveness of alternative instruments for environmental protection in a second-best setting," *Journal of Public Economics*, Vol. 72 (1999), 329-360; Roberton C. Williams III, " Revisiting the cost of protectionism: The role of tax distortions in the labor market," *Journal of International Economics*, Vol. 47, (1999), 429-447; and Roberton C. Williams III, Environmental Tax Interactions when Pollution Affects Health or Productivity," *Journal of Environmental Economics and Management*, Vol. 44, (2002), 261-270.

[5] More specifically, this loss is estimated as the difference between the pre-tax wage rate and the wage received by workers multiplied by the reduction in labor supply.

interest corresponds to the difference in costs incurred under two scenarios, depicted in schematic form in Exhibit 1-1 above:

1. An historical, "*with-CAAA*" scenario control case that reflects expected or likely future measures implemented since 1990 to comply with rules promulgated through September 2005[6]; and
2. A counterfactual "*without-CAAA*" scenario baseline case that freezes the scope and stringency of emissions controls at their 1990 levels, while allowing for changes in population and economic activity and, therefore, in emissions attributable to economic and population growth.

As a result of our adopting an incremental approach to cost estimation, a single cost estimate is presented for each relevant rule, rather than total costs for the two primary scenarios.

While the emissions analysis addressed only criteria pollutant emissions, the direct cost analysis addressed CAAA provisions issued to control emissions of criteria pollutants and hazardous air pollutants (HAPs).

We estimate direct costs in projection years 2000, 2010, and 2020 using control assumptions consistent with those of the emissions and benefits analysis. The costs summarized in this analysis reflect the most appropriate cost data and/or methodologies available for CAAA-based regulations issued to date. This report presents the results of EPA's analysis of the projected costs associated with implementation of the CAAA programs to control air emissions from the following sectors: non-EGU point sources, EGUs, nonroad engines/vehicles, onroad vehicles, and nonpoint (area) sources.

The control measures for which costs are estimated in this analysis are consistent with the control assumptions modeled in the second section 812 emission projections analysis. For each source category, unit cost information was developed in a form that can be applied to the point, nonpoint, nonroad, and onroad vehicle emission inventories in 2000, 2010, and 2020. This report describes the cost information used in AirControlNET, the Integrated Planning Model, and other control cost tools to generate estimates of CAAA costs in 2000, 2010, and 2020 by control measure and source category. In general, key cost and cost input information was obtained from regulatory impact analyses (RIAs), background information documents (BIDs), regulatory support documents, and *Federal Register* notices.

The summary direct cost measures presented at the end of this chapter and the end of each of the emission sector chapters are expressed in 2006 dollars. Within each of the sector chapters, however, and in order to adequately document our source data, we often present estimates in the year's dollars of the original source. Conversions to 2006 dollars

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[6] The lone exception is the Coke Ovens Residual Risk rulemaking, promulgated under Title III of the Act in March 2005. We omitted this rule because it has a very small impact on criteria pollutant emissions (less than 10 tons per year VOCs) and because the costs of the rule are negligible relative to the overall costs of the Amendments. The primary MACT rule for coke oven emissions, however, involves much larger emission reductions and costs and therefore is included in the *with-CAAA* scenario.

use the GDP implicit price deflator series.[7] For the purposes of annualizing capital investments, a discount rate of 5 percent is used wherever possible.[8]

THE IMPACT OF LEARNING ON COSTS

A significant body of literature suggests that the per unit cost of producing or using a given technology declines as experience with that technology increases over time.[9] The mechanism through which these reductions occur is not well understood, as decreases in costs may reflect several different effects, including returns to research and development, productivity spillovers from outside an industry, economies of scale, or efficiency improvements associated with increased experience with a given technology (i.e., learning-curve impacts). Given the multitude of factors that may lead to cost reductions over time, it is unclear whether such reductions should be modeled as learning-curve effects or as some other form of technological change. Nordhaus (2008) suggests that it is difficult to distinguish learning-curve effects from exogenous technological change and that learning effects, as estimated separately from technological change, will typically be overestimated.[10] Nevertheless, the most detailed peer-reviewed empirical studies examining these cost reductions quantify a "learning rate" for different technologies and industries that represents the percentage reduction in costs associated with each doubling in the cumulative production of a technology. Based on the strength of the evidence in this literature, the Project Team incorporated the concept of the learning effect into its assessment of CAAA costs.

Where possible, the Project Team based its learning curve adjustments on learning rates presented in the empirical literature, but this was not possible for each sector affected by the Amendments. Through a detailed review of several learning curve studies, the Project Team identified learning rates for EGU applications of flue gas desulfurization, selective catalytic reduction, and selective noncatalytic reduction (capital costs only) which were then used for the present analysis. In addition, the Project Team identified learning curve studies for vehicle production that served as the basis for its learning curve

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[7] The series we relied on is the GDP implicit price deflator, found in Table B-3 on page 284 of the *Economic Report of the President*, Transmitted to Congress February 2006, United States Government Printing Office: Washington, DC. Note that some components of the analysis that rely on the AirControlNET tool made use of a slightly different price index to reflect price inflation for non-EGU point and non-point controls.

[8] In a few cases, the source for cost estimates either does not include a statement of the discount rate assumption or does not include enough information to standardize the cost to a 5 percent discount rate. These exceptions are noted in the text.

[9] These studies include John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, 1984, Vol. 9, No. 2, 235-247; Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," *Organizational Science*, Vol. 2, No. 1, February 1991; International Energy Agency, *Experience Curves for Energy Technology Policy*, 2000; and Paul L. Joskow and Nancy L. Rose, "The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units," *RAND Journal of Economics*, Vol. 16, Issue 1, 1-27.

[10] William Nordhaus, "The Perils of the Learning Model For Modeling Endogenous Technological Change," unpublished working paper, December 15, 2008.

adjustments for motor vehicle engine controls. For other technologies and industries affected by the Amendments, we found no estimates of learning curve impacts in the empirical literature. For such technologies/industries, the Project Team applied a default learning rate of 10 percent, consistent with the recommendation of the EPA Science Advisory Board's Advisory Council on Clean Air Compliance Analysis that the Project Team apply a default learning rate of 5 to 10 percent to sectors for which no empirical data are available.[11,12] We chose 10 percent as a default learning rate because this value is more consistent with the learning rates presented in the empirical literature than the low end of the Council's recommended range.[13] In addition, because this literature estimates a learning rate of approximately 20 percent for many technologies, our assumption of a 10 percent learning rate may be conservative.[14] Exhibit 1-3 presents the learning rates that the Project Team selected by sector and technology.[15] Note that for onroad and nonroad sources, we limited our learning curve adjustments to the first two doublings of cumulative production, consistent with EPA practice in its regulatory impact analyses for regulations affecting these sources.

As indicated above, the learning rate for a given technology represents the percent reduction in unit costs associated with each doubling in cumulative production or experience. The cumulative production metrics selected by the Project Team vary by industry and technology, but for those technologies where the Project Team relied upon learning rates presented in the empirical literature, we used the same metric of cumulative production as the underlying studies. For other sectors, we used sales as the metric of cumulative production, with two exceptions: non-EGU point and nonpoint sources. Due to resource constraints, the Project Team was not able to obtain historical sales information for the control technologies used by these sources. In the absence of such information, the Project Team used the cumulative emissions reductions achieved as a result of the original Clean Air Act (CAA) and the Amendments combined as its metric of cumulative production. These reductions represent the difference between emissions with the 1990 Amendments and emissions without the original CAA (or the Amendments). Because learning for non-EGU point and nonpoint sources has been occurring since the 1970s, when the original Clean Air Act was implemented, we believe

[11] EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.

[12] The Project Team makes no learning curve adjustments for motor vehicle inspection and maintenance programs. Because most states either run centralized inspection centers themselves or regulate the fees charged by decentralized inspection centers, it is unclear whether the learning curve impacts for I&M programs would be significant.

[13] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," Academy of Management Review, Vol 9, No. 2, 1984.

[14] *Ibid.*

[15] Although innovation may lead to the development of new technologies that would reduce costs even further, we do not attempt to capture such effects in the cost estimates presented in this report. The learning rates presented in Exhibit 1-3 only reflect the cost-reducing impact of firms' growing experience with existing technologies.

this metric would be more appropriate than cumulative emissions reductions associated with the Amendments alone.

Exhibit 1-3. Learning Rates and Cumulative Production Metrics for EGU Emission Control Technologies and Motor Vehicle Emission Controls

Control Technology/ Source Category	Learning Rates	Cumulative Production Metric
EGUs - Flue Gas Desulfurization[1]	Capital Costs: 11% O&M Costs: 22%	Cumulative FGD capacity
EGUs - Selective Catalytic Reduction[2]	Capital Costs: 14% O&M Costs: 21%	Cumulative SCR capacity
EGUs - Selective Non-catalytic Reduction	Capital Costs: 15%[3] O&M Costs: 10%[4]	Cumulative number of plants with SNCR
EGUs - Activated Carbon Injection[4]	Capital and O&M Costs: 10%	Cumulative ACI capacity
Motor Vehicle Engine Controls[5]	Fixed Costs: No Adjustment Variable Production Costs: 13% (limited to two doublings of cumulative production) Vehicle Operating Costs: No adjustment	Cumulative vehicle production
Motor Vehicle Fuel Rules[4]	All Costs: 10%(limited to two doublings of cumulative production)	Cumulative sales of affected fuel
Motor Vehicle Inspection & Maintenance Programs	No adjustments for learning	Not applicable
Nonroad Engine Controls[4]	All Costs: 10% (limited to two doublings of cumulative production)	Cumulative sales of affected engines
Non-EGU Point Source Controls[4]	All Costs: 10%	Cumulative non-EGU point source reductions of NO_x, SO_2, VOCs, and PM emissions since enactment of the original Clean Air Act
Nonpoint Source Controls[4]	All Costs: 10%	Cumulative nonpoint source reductions of NO_x, SO_2, VOCs, and PM emissions since enactment of the original Clean Air Act
Local Controls i. EGUs[4]	i. All Costs: 10%	Cumulative EGU reductions of NO_x, SO_2, and PM emissions since enactment of the original Clean Air Act
ii. Non-EGU Point Sources[4]	ii. All Costs: 10%	Cumulative non-EGU point source reductions of NOx, SO2, VOCs, and PM emissions since enactment of the original Clean Air Act
iii. Nonpoint Sources[4] iv. On-road vehicles v. Non-road engines	iii. All Costs: 10% iv. No adjustments for learning v. No adjustments for learning	Cumulative nonpoint source reductions of NOx, SO2, VOCs, and PM emissions since enactment of the original Clean Air Act Not applicable Not applicable

Exhibit 1-3. Learning Rates and Cumulative Production Metrics for EGU Emission Control Technologies and Motor Vehicle Emission Controls

Control Technology/ Source Category	Learning Rates	Cumulative Production Metric

Notes:
1. Estimates for FGD from Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," International Journal of Energy Technology and Policy, Vol. 2, Nos. 1/2, 2004.
2. Estimates for SCR derived from Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," Journal of the Air & Waste Management Association, Vol. 55, December 2005.
3. Estimate for SNCR capital costs derived from Cynthia Manson, Matthew B. Nelson, and James E. Neumann. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," unpublished working paper, July 2002.
4. Based on the Council recommendation of using a default rate of 5 to 10 percent for technologies for which no learning curve data are available in the empirical literature. EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.
5. Average of two estimates presented in Nicholas Baloff, "Extension of the Learning Curve--Some Empirical Results," *Operational Research Quarterly*, Vol. 22, No. 4, December 1971 and Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," *Organizational Science*, Vol. 2, No. 1, February 1991.

OVERVIEW OF MODEL SETS

AirControlNET is used in this study to estimate the costs of attaining ozone and PM National Ambient Air Quality Standards (NAAQS) compliance, and to estimate costs for Federal non-EGU point and nonpoint source controls. AirControlNET is a control strategy and costing analysis tool developed by EH Pechan for EPA's Innovative Strategies and Economics Group. AirControlNET was designed for conducting analyses of air pollution regulations and policies, specifically development and implementation of NAAQS for criteria pollutants.

AirControlNET is a relational database system that links control technologies and pollution prevention measures to EPA emission inventories. The output of this linkage is a database of control measures and cost information for reducing the emissions of criteria pollutants as well as mercury from point (EGU and non-EGU), nonpoint, nonroad, and onroad sources as provided in EPA's National Emissions Inventory (NEI).

The control measure data files in AirControlNET include the pollutant control efficiency to calculate emission reductions for specific sources within the NEI, and also direct compliance cost data (annual operating and capital) to calculate the total costs of applying each control measure to specific sources. AirControlNET contains an extensive accounting for pollution control measures available across sources and the AirControlNET database currently contains more than 500,000 emission control records. Further details on the AirControlNET database can be found in Appendix G.

Electricity generating unit (EGU) control costs are estimated using the Integrated Planning Model (IPM).[16] IPM is a dynamic, linear programming model of the electric power sector that represents several key components of energy markets (i.e., markets for fuels, emissions allowances, and electricity) and the linkages between them. The model determines the utility sector's least-cost strategy for meeting energy and peak demand requirements over a specified period of time, accounting for a number of regulatory and non-regulatory constraints (e.g., emissions caps and transmission constraints). IPM is an EPA model that provides cost estimates for CAAA-related NO_x, SO_2, and mercury controls at EGUs. Using forecasts for the electric power industry in 2010 and 2020, the IPM is designed to estimate emissions and control costs under specified control scenarios. Further information on IPM can be found at the following website: http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

COST ACCOUNTING

The costs presented in this analysis are expressed as total annualized costs (TAC) in 2000, 2010, and 2020. Annualized costs include both capital and operation and maintenance (O&M) costs. Certain CAAA provisions require affected sources to invest capital in control equipment. In order to make appropriate comparisons of costs in 2000, 2010, and 2020, it is necessary to annualize costs over the period during which costs will be incurred (i.e., their equipment life) rather than including the total capital investment in the cost accounting. To annualize capital costs over a given equipment life, a discount rate of 5 percent is used.[17] The annualization of capital costs allows for the conversion of total capital investment over a given time period to a uniform series of annual costs having the same present value as the total investment. After annualizing the capital investment for a particular control strategy, annualized capital costs are then added to the annual O&M costs to yield an estimate of the CAAA-related control costs in each of the years relevant to this analysis (2000, 2010 and 2020).

The control cost estimates from regulatory documents that used a discount rate of 7 or 10 percent were recalculated for consistency with the 5 percent discount rate assumption. For a few VOC source categories, EPA estimated that capital investment would not be necessary; and that compliance costs reflect O&M costs only. In these cases, the discount rate assumption has no effect on costs. For control measures whose costs are dominated by capital, rather than O&M costs, the annualized cost estimate is more sensitive to the discount rate assumption than controls whose costs are primarily operating cost increases.

The cost estimates presented in this report also reflect the fuel savings (losses) associated with CAAA-related rules that affect fuel economy. Where possible, we estimate the value of these (dis)benefits based on fuel price projections presented in the Energy

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[16] The Project Team used Version 2.1.9, updated with fuel and emission control technology data from AEO 2005. The version we used incorporates most of the technology data reflected in the latest EPA Base Case 2006, but retains the target years of 2007, 2010, 2015, and 2020 of Version 2.1.9. See Chapter 2 for more details.

[17] The use off a 5 percent discount rate is consistent with longstanding practice in the 812 study series and multiple reviews by the Council.

Information Administration's *Annual Energy Outlook 2005* (AEO 2005). In addition, for rules that affect the fuel economy of an engine over a period of several years, we estimate these (dis)benefits as the present value of the fuel savings (losses) realized over the entire life of the engine, subject to the availability of adequate data. For a limited number of rules affecting engine fuel economy, however, sufficient data were not available to implement this approach. We highlight each of these rules, and describe our approach for estimating their fuel economy impacts, in the chapters that follow.

SUMMARY OF RESULTS

In this section we summarize the compliance cost analysis results by source category. The control measures included in this analysis reflect any post-1990 regulations promulgated (or reasonably anticipated, such as controls to meet RFP requirements) after passage of the 1990 CAAA. Wherever possible, efforts were made in this analysis to make the cost results consistent with the emission projections analysis. In general, the emissions analysis and this cost analysis reflect all of the regulations that were promulgated before September 2005, when most of the emission projections were completed. Similar to the emissions projection analysis, regulations promulgated after September 2005 (e.g., the revised Lead NAAQS) are not reflected in this report, in an effort to make the costs and benefits analyses as consistent as possible. This chapter includes a summary of the provisions included in this analysis and a summary of costs by major emitting source category.

Exhibit 1-4 summarizes the estimated costs of the 1990 CAAAs by sector for the three analysis years: 2000, 2010 and 2020. This table shows that the direct compliance costs in 2000 are estimated to be approximately $20 billion and that these costs are dominated by the costs of motor vehicle-related provisions of the 1990 CAAAs as well as the MACT standards and electric utility controls. The major components of motor vehicle-related control costs in 2000 are for emission standards, fuel standards, and vehicle emission inspection programs in nonattainment areas. Motor vehicle emissions standard costs in 2000 are primarily for low emission vehicle programs (Cal-LEV and NLEV), Tier 1 tailpipe standards, and on-board diagnostics. Prominent motor vehicle fuel control programs in 2000 include Federal and California reformulated gasoline. These two reformulated gasoline programs are focused primarily in serious, severe and extreme 1-hour ozone NAAQS nonattainment areas.

Exhibit 1-4. Summary of 1990 CAAA Compliance Costs by Sector

SOURCE CATEGORY	ANNUAL COST (MILLION 2006$) 2000	2010	2020
Electric Utilities	**$1,370**	**$6,640**	**$10,400**
Non-EGU Industrial Point Sources	**$3,130**	**$5,190**	**$5,140**
NO_x SIP Call	$0	$134	$133
MACT	$1,500	$3,010	$2,920
National VOC Rules, RACT, and New CTGs	$439	$464	$534
Refinery Settlements	$0	$295	$324
1-Hour Ozone SIP Measures	$1,030	$1,130	$1,090
PM_{10} SIP Measures	$163	$152	$146
Onroad Vehicles and Fuels	**$14,400**	**$25,700**	**$28,300**
Motor Vehicle Emission Standards	$4,400	$7,650	$7,760
California and National LEV	$562	$2,030	$2,090
Fuels	$4,820	$9,830	$11,200
Motor Vehicle I/M programs	$4,630	$6,250	$7,260
Nonroad Vehicles and Fuels	**$298**	**$359**	**$1,150**
Nonroad Engines/Vehicle Standards	$298	$219	$320
Fuels	$0	$140	$831
Area Sources	**$663**	**$693**	**$766**
RACT and New CTGs	$446	$442	$490
Ozone Transport Commission Model Rules	$134	$181	$212
1-Hour Ozone NAAQS	$82	$70	$64
Local Controls	**$0**	**$5,260**	**$6,180**
8-Hour Ozone NAAQS	$0	$4,270	$4,390
$PM_{2.5}$ NAAQS	$0	$977	$687
Clean Air Visibility Rule	$0	$0	$1,100
Sub-Total Excluding Unidentified Measures	**$19,900**	**$43,900**	**$52,000**
Additional Estimated Costs for Unidentified Controls for 8-Hour Ozone Compliance			
Non-California areas		$8,700	$8,500
California areas		$318	$5,030
TOTAL	**$19,900**	**$53,000**	**$65,500**
Note: All values are rounded to no more than three significant digits.			

Exhibit 1-4 shows that the estimated costs of complying with 1990 CAAA provisions are estimated to more than double between 2000 and 2010 as areas develop and implement 8-hour ozone and $PM_{2.5}$ NAAQS State Implementation Plans (SIPs). One of the major components of CAAA compliance costs in 2010 is the estimated cost to achieve sufficient reductions of ozone precursor emissions to demonstrate 8-hour ozone NAAQS attainment. The Project Team estimated 8-hour ozone compliance costs in two phases. First, the Project Team estimated the cost of applying known and commercially available control technologies in nonattainment areas by the attainment date. In the second phase, the Project Team estimated the costs associated with reducing emissions in areas where there may not be enough known measures available at reasonable cost in the control strategy solution set to construct a plausible NAAQS compliance scenario. To estimate the cost of unidentified controls, the Project Team assumed that the cost of implementing these measures is $15,000 per ton. There is considerable uncertainty in this element of the cost analysis because it is unclear how individual areas will approach this issue. Because of the significant degree of uncertainty associated with the Project Team's cost estimates for unidentified controls, this component of the cost analysis is reported separately in Exhibit 1-4.

The results in Exhibit 1-4 show that the costs associated with on-road vehicles and fuels increase significantly between 2000 and 2010. This reflects the many new motor vehicle control programs initiated during this period, including the Tier 2 tailpipe standards, gasoline fuel sulfur limits, new heavy-duty emission standards, and associated diesel fuel sulfur limits. The introduction of these programs leads to a near doubling of motor vehicle control program costs during the 2000-2010 period.

As indicated in Exhibit 1-4, the estimated costs for 2020 are similar to those for 2010 for many CAAA provisions. Programs with significant cost increases between 2010 and 2020 nationally include the electric utility provisions of the Amendments (the Clean Air Interstate Rule and Clean Air Mercury Rule have compliance deadlines between 2010 and 2020), on-road and nonroad vehicle fuel rules (nonroad diesel fuel sulfur limits begin in this time period), 8-hour ozone NAAQS compliance in the areas with the most severe nonattainment problems, and the Clean Air Visibility Rule (CAVR). Motor vehicle control program costs in 2020 are nearly the same as in 2010 because we are not aware of specific new emission or fuel standards that may affect emissions and costs during this period. Overall, the costs of the Amendments increase by approximately $13 billion between 2010 and 2020.

COMPARISON WITH FIRST SECTION 812 PROSPECTIVE

To assess the reasonableness of the cost estimates presented in Exhibit 1-4, the Project Team compared these estimates to the year 2000 and 2010 cost estimates generated for the First Section 812 Prospective analysis (the First Prospective). Overall, the year 2000 cost estimate presented in Exhibit 1-4 is considerably lower than the corresponding cost estimate in the First Prospective, while the 2010 cost estimate presented in Exhibit 1-4 is higher than the corresponding First Prospective estimate. (The First Prospective estimated a 2000 annual cost of $27.6 billion and a 2010 cost of $37.8 billion.) With respect to 2000, although the motor vehicle costs presented in Exhibit 1-4 are somewhat higher than the motor vehicle costs estimated in the First Prospective, the year 2000 costs for electric utilities and nonpoint sources are significantly lower than was estimated in the First Prospective. The significant difference for utilities likely reflects differences in assumptions about the cost of obtaining low-sulfur coal from the Powder River Basin

(PRB) in Wyoming. Although the Project Team was aware of the downward trend in PRB coal costs when the First Prospective was completed, this effect was not fully addressed in the data and models available at the time of the first prospective study.

The Second Prospective cost estimates for 2010 are higher than those estimated for the First Prospective mainly because many Federal motor vehicle control programs not included in the first prospective study *with-CAAA* scenario have been promulgated since the first Prospective was completed. In addition, the current analysis includes the costs of meeting the 8 hour ozone, $PM_{2.5}$ NAAQS and Clean Air Visibility Rule requirements in 2010.

RESULTS OF LEARNING CURVE ADJUSTMENTS

As indicated above, the cost estimates presented in Exhibit 1-4 reflect the Project Team's expectations about the extent to which learning curve impacts will reduce the costs of CAAA compliance. Because of these learning curve adjustments, the aggregate cost estimates in Exhibit 1-4 are 9.0 percent lower in 2000 and 10.3 percent lower in 2020 than they would be if we were to make no adjustments for learning. Among the provisions outlined in Exhibit 1-4, the impact of the Project Team's learning curve adjustments is most significant (in proportional terms) for non-road and on-road sources. Because of our learning curve adjustments, our estimates of non-road costs are 17 percent lower in 2000 and 60 percent lower in 2010 than estimates expected without accounting for learning effects. As indicated in Chapter 4, however, much of this reduction reflects the fact that the learning curve adjustments do not affect the fuel savings component of the cost estimates for many non-road rules. Our learning curve adjustments for on-road vehicles and fuels reduce our cost estimates for this sector by approximately 13 percent in 2000 and 15 percent in 2010 and 2020. Notably, our learning curve adjustments increase the EGU, non-EGU point, and nonpoint cost estimates for 2000 because the cost functions for these sectors were developed after 2000. The original year 2000 cost estimates for these sectors were increased to ensure that the trajectory of learning was consistent throughout the study period.

CHAPTER 2 | ELECTRIC GENERATING UNIT POINT SOURCE ANALYSIS

The Clean Air Act Amendments (CAAA) of 1990 significantly expanded EPA's authority to regulate emissions from U.S. electric utilities and established a new approach to air pollution regulation in the U.S. Since the passage of the Amendments, EPA has developed several new regulations governing utility emissions of SO_2, NO_x, mercury, and other pollutants. Although several of these rules rely on command-and-control mechanisms to limit EGU emissions, Title IV of the Amendments established a market-based cap-and-trade system for reducing emissions of SO_2 from electric utilities. Similarly, under Title I of the Amendments, EPA established a cap-and-trade system for NO_x to limit inter-regional transport of ozone.

Under these cap-and-trade systems, EPA sets annual emissions caps for both SO_2 and NO_x and issues a limited number of tradable emissions allowances to affected sources authorizing them to emit one ton of SO_2 or NO_x per allowance. Emissions for electric generating units (EGUs) in aggregate must stay within the cap, but individual sources are free to trade emissions allowances among themselves, encouraging the utility sector to reduce emissions at those sources that can most cost-effectively limit their emissions. Similar to the market-based programs for SO_2 and NO_x, EPA has also established a cap-and-trade system for mercury under which utilities may trade emissions allowances to determine which facilities will most aggressively control their mercury emissions.

To supplement CAAA-related regulations, several states have also established their own emissions requirements for utilities since the passage of the Amendments in 1990. For example, the state of California is regulating NO_x and CO emissions from utility boilers located in the Bay Area Air Quality District (BAAQD) in an effort to bring the District into attainment with the National Ambient Air Quality Standards (NAAQS) for ozone.[18] Exhibit 2-1 outlines the EGU-related regulations and programs established under the Amendments.

The purpose of this chapter is to describe the approach adopted in the Second Prospective study for estimating the costs incurred by electric utilities as a result of the Clean Air Act Amendments and to present the estimates of these impacts during the 1990-2020 period. We focus on EGUs separately from other point sources because of the significance of the cap-and-trade programs outlined above and because of the magnitude of the CAAA-

[18] California's state implementation plan for the ozone NAAQS includes NO_x and CO emissions requirements for EGU steam boilers in the BAAQD with a capacity of at least 250 million Btu per hour. *Federal Register*, Volume 67, Number 97, May 20, 2002, pages 35434-35437.

related costs incurred by utilities relative to other sources. According to EPA's First Prospective Analysis of the Clean Air Act, electric utilities are expected to incur approximately 17 percent of the total costs associated with the Amendments in 2010.[19]

Exhibit 2-1. CAAA-Related Rules and Programs Reflected in Section 812 EGU Cost and Emissions Analyses

- The Clean Air Interstate Rule,
- The Clean Air Mercury Rule,
- SIP Call Post-2000,
- Reasonably Available Control Technology (RACT) and New Source Review requirements for all non-waived (NO_x waiver) non-attainment areas,
- Phase II of the Ozone Transport Commission (OTC) NO_x memorandum of understanding,[20]
- Title IV Phase I and Phase II limits for all boiler types,
- 25-ton Prevention of Significant Deterioration (PSD) regulations and New Source Performance Standards (NSPS),
- Title IV emission allowance program,
- Utility emissions caps set by individual states (CT, MA, MO, NH, NC, TX, and WI), and
- Emissions reductions achieved because of post-1990 enforcement actions (e.g., NSR cases and settlements).

The study's methodology and results are presented in four separate sections.

1. ***Analytic Tools:*** First, we provide a detailed description of the analytic tools and methods the Project Team used to estimate the costs incurred by EGUs as a result of the Amendments.
2. ***Application of the Integrated Planning Model (IPM) for the 2010 and 2020 Target Years:*** In the second section we describe the Project Team's cost analysis for the 2010 and 2020 target years.[21]

[19] U.S. EPA, The Benefits and Costs of the Clean Air Act 1990 to 2010, November 1999, EPA-410-R-99-001.

[20] Under Phase II of the OTC memorandum of understanding, eleven eastern states committed themselves to achieving regional reductions in NO_x emissions through a cap-and-trade system similar to the SO_2 trading program established under Title IV of the Amendments. As an initial step in the development of the OTC trading program, the OTC states; EPA; and representatives from industry, utilities, and environmental groups designed a model rule that identified the key elements of the program. Each OTC state then went through its own regulatory process to develop regulations consistent with the model rule.

[21] As described in greater detail below, IPM is the electric utility cost and dispatch model used to estimate EGU costs for the Second Prospective analysis of the Amendments.

3. ***Application of IPM for 2000 Target Year:*** The third section of this chapter outlines the Project Team's application of IPM for the 2000 Section 812 target year. We present this information separately from our application of IPM for 2010 and 2020 because the approach for estimating costs retrospectively is different from the approach used to project costs into the future.

4. ***Results:*** To conclude the chapter, we present the Project Team's cost estimates for 2001, 2010, and 2020. Although 2000, 2010, and 2020 represent the target years selected for the Second Prospective, the current study uses EGU costs in 2001 as a proxy for costs incurred in 2000.[22]

Because the Project Team uses the same economic model to assess both EGU cost and emissions impacts, much of the material included in the following sections is also presented in the Second Prospective emissions report previously submitted to EPA's Advisory Council on Clean Air Compliance Analysis[23] and recently revised.[24]

ANALYTIC TOOLS

To estimate the costs incurred by electric utilities as a result of the Amendments, the 812 Project Team adapted cost estimates generated by ICF Resource's Integrated Planning Model (IPM). In this section, we summarize IPM's capabilities and describe how the Project Team modified IPM's results to generate cost estimates consistent with the analytic requirements and assumptions of the Second Prospective.

IPM

IPM is a dynamic, linear programming model of the electric power sector that represents several key components of energy markets (i.e., markets for fuels, emissions allowances, and electricity) and the linkages between them. The model determines the utility sector's least-cost strategy for meeting energy and peak demand requirements over a specified period of time, accounting for a number of regulatory and non-regulatory constraints (e.g., emissions caps and transmission constraints). Below we outline the structure, features, and assumptions of IPM and the key outputs generated by the model.

IPM Structure, Features, and Assumptions[25]

As a linear programming model, IPM is structured around an objective function that represents the net present value of the costs of meeting U.S. electricity demand over

[22] Before commencing with the cost analysis for the Second Prospective, EPA conducted an analysis of EGU costs and emissions in 2001 to test the accuracy of the analytic tools that EPA typically uses for EGU cost and emission analyses. Due to resource constraints, the Project Team expanded and applied the 2001 analysis herein rather than incurring the expense of developing an entirely new EGU cost and emissions analysis for 2000.

[23] E.H. Pechan & Associates, Inc. and Industrial Economics, Inc. *Emissions Projections for the Clean Air Act Second Section 812 Prospective Analysis*, prepared for James DeMocker, U.S. EPA Office of Air and Radiation, June 2006.

[24] E.H. Pechan & Associates, Inc. and Industrial Economics, Inc. *Emissions Projections for the Clean Air Act Second Section 812 Prospective Analysis*, prepared for James DeMocker, U.S. EPA Office of Air and Radiation, March 2009.

[25] This section is based on information presented in U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V2.1.9) Using the Integrated Planning Model*, September 2005, EPA 430-R-05-011.

IPM's model time horizon. To reach a solution for a given model scenario, IPM minimizes its objective function subject to a number of regulatory and non-regulatory constraints. These constraints include emissions caps, the capacity of individual generating units, transmission constraints, reserve margins, turn down constraints (i.e., whether a unit can shut down at night), and the compatibility of individual fuels with different generating technologies. Accounting for these constraints and the characteristics of the units included in the model, IPM endogenously models utility dispatch decisions, capacity additions, and retirements to minimize the value of its objective function. In doing so, IPM takes electricity demand as exogenous rather than estimating how demand might change in response to changes in electricity prices. IPM also assumes that utilities operate in an environment of perfect competition and that they have perfect foresight of future constraints. As IPM models dispatch based on these future constraints and other information, it does not factor sunk investments into its optimization process. Therefore, the model's cost outputs do not reflect the annualized cost of CAAA-related investments made prior to the model time horizon.[26]

To simulate the behavior of the electric utility sector over the model time horizon, IPM simulates the operation of several model plants for a limited number of model run years instead of modeling each unit in the U.S. individually for every year in the model time horizon. The model plants included in IPM may represent aggregations of existing units with similar characteristics; new plants constructed over the model time horizon; or retrofit, re-powering, and retirement options available to existing units. Similarly, each model run year included in IPM (2007, 2010, 2015, and 2020) represents a multi-year period in IPM's planning horizon.[27] Although IPM reports results for a limited number of model run years, it takes investment decisions into account for each year in the model's planning horizon. For example, the model results for 2020 reflect utility investments in retrofit capital made during prior years included in the model's time horizon, such as 2009.

Similar to its representation of model plants and model run years, IPM spatially divides the U.S. electricity market into 26 model regions corresponding broadly to the North American Electric Reliability Council (NERC) regions. Based on historical demand data for each region and projections of electricity demand, IPM includes a series of seasonal load duration curves specific to each region and model run year. IPM uses this information to simulate the dispatch of each model plant and the transmission of electricity within and between each model region.

To capture the dynamics of the SO_2 and NO_x allowance markets, IPM models the banking of allowances not used by utilities for each model run year. Allowances allocated but not used during any given model run year can be used in future years. The model, however, includes no explicit assumptions regarding the initial allocation of allowances among

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[26] This model structure limits the utility of IPM for back-casting analysis, an analytical issue for the present study addressed in this chapter's section entitled "Application of IPM for 2001 Analyses."

[27] IPM also generates results for 2026, the last model run year included in the model. To avoid boundary distortions, however, EPA does not typically report the results for this year.

individual generating units. Instead, the model distributes allowances to units such that the net present value of electricity production costs incurred over the model's time horizon is minimized, taking into account the various constraints that are included in the model. The costs associated with this approach are likely to be similar to those associated with an auction-based allocation system. Although EPA issues some emission allowances through auctioning, the majority of allowances are allocated to units based on their historical heat input. Several studies have suggested that such an allocation system is less efficient than auctioning allowances.[28] Therefore, IPM may underestimate the costs of the EGU emissions requirements established under the Amendments, although the magnitude of such underestimation is uncertain.

As part of its modeling of allowance markets, IPM captures allowances banked before the model's time horizon. For the model runs supporting the 2010 and 2020 cost analyses, IPM assumes that 5 million tons of SO_2 allowances were banked before the IPM planning horizon (e.g., before 2007) and that utilities could drawn upon these allowances to meet the requirements of the Amendments. Although IPM can also account for previous banking of NO_x allowances, the model assumes that no NO_x allowances were banked prior to 2007. For the 2001 *with-CAAA* IPM model run, the configuration of the model for this study includes no explicit simulation of allowance banking or the use of allowances banked before 2001. Instead, emissions for the 2001 run were constrained to reflect actual emissions observed in 2001. We do not believe that this limitation of the model run has a significant impact on our 2001 cost estimates because actual 2001 emissions would reflect any allowance banking or use of allowances that occurred in 2001.

IPM Outputs

IPM generates several outputs relevant to the Second Prospective. These include the following:

***Costs*:** Based on the dispatch, retrofit, retirement, and plant construction decisions simulated in IPM, the model estimates annual capital costs, fixed operating and maintenance (O&M) costs, and variable O&M costs in the aggregate and at the unit level. In addition, although IPM is not designed to report costs for individual emission control retrofit technologies (e.g., flue gas desulfurization, selective catalytic reduction, selective non-catalytic reduction, etc.), such information can be extracted from the unit level results generated by the model.

NO_x, SO_2, Mercury, and Carbon Dioxide Emissions: IPM estimates emissions of NO_x, SO_2, mercury, and carbon dioxide for each model run year in the aggregate and at the unit level.

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[28] These studies include Alan J. Beamon, Tom Leckey, and Laura Martin. 2001. “Power Plant Emission Reductions Using a Generation Performance Standard,” Energy Information Administration, Draft Working Paper March 19, 2001; Karen Palmer and Dallas Burtraw, "Distribution and Efficiency Consequences of Different Approaches to Allocating Tradable Emission Allowances for Sulfur Dioxide, Nitrogen Oxides and Mercury," RFF Discussion Paper, January 2004; and Dallas Burtraw, Karen Palmer, Ranjit Bharvirkar, and Anthony Paul, "The Effect of Allowance Allocation on the Cost of Carbon Emission Trading," RFF Discussion Paper, August 2001;

Capacity and Generation: Under any given regulatory scenario, IPM estimates capacity and generation by fuel type for each model run year in IPM's planning horizon. IPM's outputs with respect to capacity and generation also include capacity by control technology (e.g., flue gas desulfurzation, etc.).

Fuel and Electricity Prices: Based on IPM's least-cost strategy for meeting electricity demand, the model endogenously estimates coal, natural gas, and electricity prices by model run year.

Allowance Prices: IPM estimates allowance prices for SO_2, NO_x, and mercury. These estimates reflect the regulatory constraints included in the model, the characteristics of affected sources, and the costs of the control technologies associated with each pollutant.

AUGMENTING AND ADJUSTING COST ESTIMATES GENERATED BY IPM

To develop EGU cost estimates consistent with the analytic requirements and assumptions of the Second Prospective, the Project Team made three modifications to the cost estimates generated by IPM. First, to augment IPM's cost estimates, the Project Team estimated the capital costs associated with investments made between 1990 (the year the Amendments were enacted) and the first year of IPM's model time horizon.[29] As indicated above, IPM's capital cost estimates do not reflect these costs. Second, because IPM uses internal private cost of capital estimates to simulate market outcomes which do not match the five percent social discount rate used for annualization of capital costs in this analysis, IPM's capital cost estimates were adjusted to be consistent with the 5 percent rate. Third, because IPM's cost projections for individual pollution control technologies do not reflect the cost-reducing effects of learning effects over time, IPM's cost projections were adjusted to account for these learning effects.[30] We describe all three of these adjustments in more detail below.

Costs Related to Investments Made Prior to the IPM Time Horizon

As described above, IPM is a forward-looking model that optimizes utilities' dispatch and investment decisions. Although IPM estimates the costs of capital investments made by utilities during the time period reflected in the model, it does not estimate the sunk costs of investments in emission controls that predate the model's time horizon because such costs have no bearing on future EGU decision-making. Therefore, the current version of the model does not capture a significant portion of the capital costs associated with CAAA controls (i.e., capital costs associated with investments made between 1990 and the beginning of IPM's planning horizon). For the IPM analysis supporting the 2010 and 2020 EGU analyses, IPM's planning horizon includes the years 2007 through 2030. As indicated above, the Project Team used the results of an IPM run for 2001 as a proxy for EGU costs in 2000. The time horizon of this analysis was limited to the year 2001.

[29] This time horizon is 2007-2030 for the IPM model runs supporting the cost estimates for 2010 and 2020. For the 2001 IPM analysis, the model time horizon is limited to 2001.

[30] These learning curve adjustments reflect firms' growing experience with existing technologies (e.g., flue gas desulfurization) but not the development and introduction of new control technologies that might reduce the costs of complying with the Amendments.

Because IPM does not estimate the capital costs associated with investments made between 1990 and the beginning of the model's time horizon, the Project Team estimated these costs based on the operating characteristics of individual generating units.[31] Ideally, these estimates would reflect the costs associated with sunk investments in abatement capital (i.e., emissions control devices and investments in capital for transitioning to low-sulfur coal) and new generating capacity. While we estimate costs related to the former, we do not estimate capital costs related to the latter due to resource and data limitations. To the extent that investment in new capacity would have been different in the absence of the Amendments than under the *with-CAAA* scenario between 1990 and the beginning of the IPM time horizon, this could bias our estimates of the incremental capital costs associated with the Amendments.[32] More specifically, if the Amendments encouraged a shift toward the construction of gas-fired or combined cycle capacity instead of coal-fired units, capital costs associated with new generating capacity could have been different under the *without-CAAA* scenario than under the *with-CAAA* scenario.[33] We believe, however, that the potential for such bias is minimal. Although investment in gas-fired and combined cycle units has been significant since the passage of the Amendments, these investments largely reflect economic forces unrelated to the Amendments, such as relatively low natural gas prices in the 1990s and the development and availability of more efficient combined-cycle generating technology.[34] Therefore, given the design of the overall study, the Project Team concluded that it was reasonable and consistent to assume that investments in new generating capacity made between 1990 and the beginning of the IPM time horizon would have been the same in the absence of the Amendments as under the *with-CAAA* scenario and focus our analysis on EGU investments in abatement capital.

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[31] Alternatively, we could have estimated these costs based on the results of IPM runs conducted in the 1990s. Unlike the version of IPM used for the current section 812 analysis, these IPM runs would have captured pollution control investments made during the 1990s and early 2000s. A major disadvantage of this approach, however, is that the results of the older IPM runs would represent past projections of the investments made by electric utilities during this time, whereas the approach developed for the current analysis reflects the actual controls installed at EGUs during the 1990s and early 2000s. Because the projections of the older IPM runs may not have been consistent with the eventual investment decisions of individual EGUs, use of these projections would contribute significant uncertainty to the current study's EGU cost estimates. Therefore, the Project Team decided not to use the results of these runs for the section 812 analysis.

[32] The IPM results, which cover the 2007-2020 period, reflect the difference between *with-CAAA* and *without-CAAA* capacity investments during this period.

[33] In addition, our results may be biased if more capacity had been added under the *without-CAAA* scenario than under the *with-CAAA* scenario. However, because we assume that electricity demand is the same under both the *with-CAAA* and *without-CAAA* scenarios, the potential significance of any potential bias is minimized.

[34] This is consistent with the characterization of investments in natural gas units presented in Curtis Carlson, Dallas Burtraw, Maureen Cropper, and Karen L. Palmer, "Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade?" *Journal of Political Economy*, 2000, Vol. 108, No. 6; and A. Denny Ellerman and Florence Dubroeucq, "The Sources of Emission Reductions: Evidence from U.S. SO_2 Emissions from 1985 through 2002," working paper, MIT Center for Energy and Environmental Policy Research, January 2004.

Investments in Emission Control Devices Prior to the IPM Time Horizon

Emission control devices represent an important part of the abatement capital installed before the IPM time horizon. These devices include flue gas desulfurization (FGD) systems, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). Because the IPM analysis supporting the Project Team's analysis for 2010 and 2020 does not estimate the costs associated with emission control devices installed between 1990 and 2006, the Project Team estimated these costs using two separate procedures: one for the *with-CAAA* scenario and another for the *without-CAAA* scenario.[35] For the *with-CAAA* scenario, the Project Team first identified all of the pollution control systems believed to be operating at EGUs in 2006.[36] We identified these systems using version 2.1.9 of EPA's NEEDS database, which underlies the version of IPM used for the Second Prospective.[37] Based on the capacity and other operating characteristics of each pollution control device identified in NEEDS, the Project Team then estimated the annualized capital costs associated with each device using the cost equations included in IPM. For the *without-CAAA* scenario, the Project Team followed a similar procedure, starting with the identification of EGU emission controls believed to be in place in 2006. However, instead of estimating the capital costs associated with all of these systems, we estimated the costs associated only with those devices necessary to meet the regulatory requirements that were in place when the Amendments were enacted in 1990.

As indicated above, a separate IPM analysis was conducted for 2001, using EGU costs in 2001 as a proxy for costs in 2000. Similar to the IPM analysis for 2010 and 2020, the 2001 analysis did not estimate the sunk costs associated with FGD, SCR, and SNCR installed before 2001, the first and only year in IPM's time horizon for the 2001 EGU analysis. Therefore, to supplement IPM's cost estimates for the 2001 analysis, we estimated the capital costs associated with emission control devices installed between 1990 and 2000 based on the estimate we developed for controls installed during the 1990-2006 period. More specifically, we used EPA's NEEDS 2000 and NEEDS 2004 databases to identify the FGD, SCR, and SNCR units installed between 2000 and 2006 that are reflected in the 1990-2006 estimate.[38,39] We then excluded the costs associated with these units from our 1990-2006 estimate to generate an estimate specific to emission control devices installed during the 1990-2000 period.

Investments in Fuel Switching Capital Prior to the IPM Time Horizon

In addition to end-of-pipe technologies to control emissions, several EGUs switched to low-sulfur coal prior to the IPM time horizon to meet the emissions requirements established under the Amendments. Although fuel switching is not a capital-intensive

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[35] As indicated above the time horizon for IPM's 2010/2020 analysis begins in 2007.

[36] Units believed to be online as of 2006 include units confirmed to be online in 2004 and additional units expected to be online by 2006.

[37] We also refer to NEEDS 2.1.9 as NEEDS 2004 throughout this chapter.

[38] The NEEDS 2000 and NEEDS 2004 databases are also known as NEEDS 2.1 and NEEDS 2.1.9, respectively.

[39] The NEEDS 2004 database includes units online in 2004 as well as capacity additions expected by 2006.

process, utilities that switch to low-sulfur coal typically invest resources in modifications to their boilers and handling equipment. To estimate the capital costs associated with such investments made prior to the IPM time horizon, we used the database underlying EPA's Clean Air Market Data and Maps system on the emissions, heat input, and capacity of EGUs included in Phase 1 and Phase 2 of the SO_2 emissions trading program established under Title IV of the Amendments.[40] The methodology that we developed based on these data is as follows:

1. ***Identify units that likely switched to low-sulfur coal prior to the IPM time horizon.*** Based on the EPA data, we estimated the annual SO_2 emissions rate for each Phase 1 and Phase 2 unit for the years 1991 through 2004. If a unit did not have a scrubber and experienced an emission rate reduction exceeding 0.5 pounds per million Btu from one year to the next, we assume that it switched to low-sulfur coal.[41] To identify fuel switching investments that predate the 2007-2030 time horizon of the IPM analysis for 2010 and 2020, we considered emission rates for the entire 1991-2004 period. Because the EPA data do not include emission rates for 2005 and 2006, we do not capture fuel switching investments made during these two years.[42] To identify units that engaged in fuel switching prior to 2001 (i.e., the single year included in the time horizon of the 2001 IPM analysis), we examined emissions rates between 1991 and 2000.

2. ***Estimate the annualized costs incurred by units that switched to low-sulfur coal prior to the IPM time horizon.*** For each unit identified in Step (1), we estimate the total cost of fuel switching based on a unit cost of $50 per kW of capacity controlled.[43,44] To annualize these costs, we used a discount rate of 5 percent and assumed a useful life of 30 years for fuel switching capital.[45]

3. ***Estimate fuel switching capital costs attributable to the Amendments.*** In Step (2) we estimated the total capital costs associated with *any* fuel switching likely to have occurred between the time the Amendments were enacted and the beginning of the IPM time horizon. Due to railroad deregulation and other factors that have reduced the cost of switching to low-sulfur coal, much of the fuel switching reflected in these costs may have occurred in the absence of the

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[40] U.S. EPA, Clean Air Markets Data and Maps, http://cfpub.epa.gov/gdm/index.cfm. Our analysis of these data was aided by prior collaboration with Dr. Denny Ellerman of the Massachusetts Institute of Technology (MIT).

[41] This 0.5 pounds per million Btu threshold represents the outer bound of normal SO_2 emission rate variability from one year to the next as estimated in A. Denny Ellerman, Paul L. Joskow, Richard Schmalensee, Juan-Pablo Montero, and Elizabeth M. Bailey, *Markets for Clean Air: The U.S. Acid Rain Program*, Cambridge University Press, 2000.

[42] Data for 2005 were not available until we had made significant progress on our analysis, and resource constraints precluded reanalysis to incorporate the 2005 data.

[43] This unit cost value represents the capital costs associated with switching to low-sulfur coal from Wyoming's Powder River Basin, as reported in Ellerman, *op cit*.

[44] For units without capacity data available, we used the average capacity of the units identified in Step (1) for which capacity data are available, using separate averages for Phase 1 and Phase 2 units.

[45] This useful life assumption is consistent with that used in IPM for emission abatement capital.

Amendments. To separate CAAA-related fuel switching costs from fuel switching costs that utilities would have incurred in the absence of the Amendments, we adapted the results of an econometric study published by Ellerman *et al.* in 2000. The results of this study suggest that approximately 52 percent of the fuel switching abatement occurring between 1995 and 1997 among units in Phase 1 of EPA's SO_2 trading program was attributable to the Amendments.[46] We applied this value to the Phase 1 fuel switching costs estimated in Step (2) to estimate the Phase 1 fuel switching costs associated with the Amendments. For units included in Phase 2 of the Title IV SO_2 program, we identified no studies estimating the extent to which abatement related to fuel switching reflected the impact of the Amendments rather than railroad deregulation and other factors that reduced the cost of fuel switching in the 1990s. In the absence of such a study, we applied the 1997 results of the Ellerman Phase 1 analysis to the Phase 2 costs estimated in Step (2). These results indicate that 49 percent of the Phase 1 fuel switching abatement in 1997 was related to the Amendments. We did not apply Ellerman's Phase 1 results for the entire 1995-1997 period to Phase 2 units because the second phase of the SO_2 trading program did not begin until 2000. We believed that the Phase 1 results for 1997 would better represent conditions in 2000 than the results for the entire 1995-1997 period.

IPM DISCOUNT RATE ADJUSTMENTS

To annualize the costs and benefits associated with the Amendments, the current study uses a social discount rate of 5 percent, consistent with the discount rate used in EPA's Retrospective and First Prospective Analyses of the Clean Air Act, following multiple reviews by the Council.[47] The interest rates included in IPM are estimates of the private cost of capital, which are needed to project the private market decisions simulated by IPM. As indicated in Exhibit 2-2, IPM uses private interest rates ranging from 5.34 percent to 6.74 percent to reflect differences in risk between different classes of investments. These rates may be appropriate for the purposes of modeling utility compliance behavior, but not for discounting in a social welfare analysis. To generate EGU capital cost estimates that are consistent with the 5 percent discount rate chosen for the Second Prospective, the Project Team de-annualized IPM's capital cost values based on the interest rates included in the model and re-annualized them using the 5 percent discount rate.

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[46] This econometric analysis is summarized in Ellerman, *op cit.* Based on the results of this analysis, Ellerman *et al.* estimate that fuel switching reduced EGU SO_2 emissions by 14.4 million tons between 1995 and 1997, 7.5 million tons of which was related to Title IV of the Amendments.

[47] The Project Team's rationale for choosing this rate is presented in Jim DeMocker, U.S. EPA. Memorandum to the 812 Prospective II Files, July 29, 2005.

Exhibit 2-2. IPM Interest Rate and Useful Life Assumptions

Investment Type	Interest Rate	Useful Life	Capital Charge Factor
Low-risk investments	5.34 percent	30 years	0.12
Medium-risk investments	6.14 percent	30 years	0.129
High-risk investments	6.74 percent	30 years	0.134
Source: U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using The Integrated Planning Model*, EPA 430-R-05-011, September 2005.			

Specifically, adjustment of IPM's annualized capital costs was implemented through the three-step procedure outlined below.

1. **De-annualize the annual capital cost estimates generated by IPM.** IPM's annual capital cost estimates were de-annualized based on the following formula:

   (1) $$T = \frac{A}{CCF}$$

   where A = Annualized capital costs as estimated by IPM

   T = Total cost of capital assets, including installation

   CCF = Capital charge factor

   Using Formula (1), the Project Team estimated the upfront (total) capital costs associated with each of the three classes of investments included in IPM (i.e., low-risk, medium-risk, and high-risk investments). As indicated in Exhibit 2-2, IPM applies different capital charge factors to different classes of investment. These capital charge factors annualize the up-front cost of EGU capital investments, but also reflect several items not reflected in a standard discount rate. More specifically, IPM's capital charge factor values reflect (1) the capital recovery factor that corresponds to the interest rate for a specific class of investment, (2) the cost impact of income taxes, (3) the income tax implications of the new pollution control investment's depreciation over time, and (4) a capital recovery factor adder of 0.03 that reflects property taxes, insurance, and working capital interest.[48,49]

2. **Estimate re-annualized capital costs excluding taxes, insurance, and working capital interest.** Based on the total capital cost estimates generated in step 1, IPM capital cost estimates were re-annualized using the following formula:

[48] The capital recovery factor for a given interest rate, i, for a capital investment with a useful life of t years is $\frac{i(1+i)^n}{(1+i)^n - 1}$. Multiplying this value by the total cost of a capital asset yields the annualized cost of the asset, excluding depreciation and tax impacts.

[49] We obtained the 0.03 estimate for the capital recovery factor adder from Chitra Kumar, U.S. EPA Office of Air and Radiation, December 23, 2005.

(2) $$A = \frac{T}{\frac{1}{r} - \frac{1}{r(1+r)^n}}$$

where A = Annualized capital costs

T = Total cost of capital assets, including installation (estimated in step 1)

r = discount rate (5 percent)[50]

n = Useful life of the asset

The results based on Formula (2) represent the annualized capital cost estimates for EGUs which are consistent with the treatment of capital costs for other sectors evaluated in the Second Prospective. Unlike the estimates included in IPM's standard outputs, these estimates only reflect the cost of capital equipment itself; they do not capture the fixed operating and maintenance costs associated with the equipment (i.e., property taxes, insurance, and working capital interest). In addition, they do not reflect income taxes or the tax implications of depreciation.

3. **Estimate annual insurance and working capital interest costs.** The annualized cost estimates generated in step 2 do not reflect costs associated with income or property taxes, insurance, or working capital interest. Similarly, they do not reflect the tax implications of depreciation. For the Second Prospective, the 812 Project Team includes insurance and working capital interest in its cost estimates but not tax impacts. Because property and income taxes represent a transfer of resources from one party to another rather than an expenditure of resources, it would not be appropriate to include them in the cost estimates for the Second Prospective. Although insurance may also represent a transfer (between insured parties), payments to insurance claimants represent the real resource expenditures necessary to repair or replace equipment damaged from fires, tornadoes, and other insured events. The value of these losses represents incremental costs associated with compliance with Clean Air Act requirements. Insurance premiums reflect the expected value of these expenditures and the administrative cost of managing individual insurance policies. Therefore, insurance costs are included herein.

   Information obtained from EPA staff indicates that one third of the 0.03 capital recovery factor adder included in IPM reflects insurance and working capital interest costs.[51] Therefore, to estimate insurance and working capital interest costs for the Second Prospective, the Project Team multiplied the total capital

[50] The Project Team also performed sensitivity analyses using alternative discount rates of 3 percent and 7 percent.

[51] Personal communication with Chitra Kumar, U.S. EPA Office of Air and Radiation, December 23, 2005.

cost estimates generated from step 1 by 0.01. These costs were added to the fixed operating and maintenance cost estimates generated by IPM.

Exhibit 2-3 presents an example of the three-step adjustment approach for a low-risk capital investment.

Exhibit 2-3. Example of IPM Capital Cost Adjustment Procedure

Step/Calculation	Value
Annualized Capital Cost for Low-risk Investments, as Reported by IPM	$10 million
Total (De-annualized) Capital Costs for Low-risk Investments	$83.3 million[1]
Annualized Capital Costs Based on 5 Percent Discount Rate and 30-year Useful Life (excluding insurance, property taxes, working capital interest, and the income tax implications of the investment)	$5.42 million
Annual Insurance and Working Capital Interest Costs (1 percent of total capital cost)	$0.83 million[2]
Notes: 1. Based on $10 million in annualized capital costs and a capital charge factor of 0.12 for low-risk investments, as presented in Exhibit 2-2. 2. Property taxes and income tax impacts excluded because they represent a transfer rather than a real resource expenditure.	

ADJUSTING EGU COST ESTIMATES TO ACCOUNT FOR LEARNING CURVE IMPACTS

A key limitation of the cost projections developed by IPM is that they do not reflect the cost-reducing effect of learning curve impacts. For example, IPM assumes that the cost of a flue gas desulfurization (FGD) unit installed in 2010 is the same as that of a comparable FGD unit installed in 2020. Several studies suggest, however, that the costs of FGD and other pollution control technologies decline as the adoption of these technologies increases. Based on the findings of these studies, the 812 Project Team adjusted IPM's 2010 and 2020 cost projections for FGD, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and activated carbon injection (ACI) retrofits to account for learning curve impacts.

Consistent with several learning curve analyses in the academic literature, we adjust IPM's retrofit cost projections for FGD, SCR, SNCR, and Activated Carbon Injection (ACI) based on the equation presented below.[52]

$$y_i = a x_i^{-b} \qquad (3)$$

where y_i= Costs of controlling the i[th] ton of NO_x (for SCR and SNCR), SO_2 (for FGD), or mercury (for ACI) emissions;

x_i= Cumulative capacity of a control technology when the i[th] ton of NO_x, SO_2, or mercury emissions is controlled;

[52] Examples of such analyses include John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, 1984, Vol. 9, No. 2, 235-247; International Energy Agency, *Experience Curves for Energy Technology Policy*, 2000; Pietro Peretto and V. Kerry Smith, "Carbon Policy and Technical Change: Market Structure, Increasing Returns, and Secondary Benefits," report prepared for the U.S. Department of Energy under grant DE-FG02-97ER62504, November 19, 2001.

b= learning curve exponent, and

a= input cost for the first ton of emissions controlled.

Based on Formula (3), each doubling in the cumulative capacity of a retrofit technology corresponds to a cost savings of ($1\text{-}2^{-b}$) percent per ton of emissions controlled, which we refer to as the learning rate. Exhibit 2-4 presents the learning rates that we use for FGD, SCR, SNCR, and ACI retrofits. For costs associated with FGD capital and O&M, SCR capital and O&M, and SNCR capital investments, we relied upon learning rate estimates available from the empirical literature. For SNCR O&M costs and ACI capital and O&M, we used a default learning rate of 10 percent.[53] We provide additional detail on the sources of these estimates below.

We apply the learning rates presented in Exhibit 2-4 to all of the FGD, SCR, SNCR, and ACI capital and O&M costs incurred by EGUs as a result of the Amendments. Because of IPM's configuration, we were not able to separate the O&M costs associated with emission controls installed prior to the IPM time horizon from the other O&M costs estimated in the model. Therefore, we do not apply any learning curve adjustments to O&M associated with FGD, SCR, SNCR, or ACI installed before the IPM planning horizon.

Flue Gas Desulfurization (Scrubber) Retrofits

Our learning curve adjustments for FGD are based on the results of a 2004 study by Rubin *et al.* examining the relationship between FGD costs and cumulative worldwide generating capacity controlled by FGD (measured in gigawatts).[54] The results of this analysis suggest that FGD capital costs per kilowatt of controlled capacity decline by 11 percent with each doubling of cumulative installed FGD capacity. This decline reflects the cost-reducing impact of firms' increased experience in the production and application of FGD technology. The data sources supporting this analysis include FGD cost studies from the Tennessee Valley Authority (TVA) for the 1970s and 1980s and a series of FGD cost assessments conducted by the Electric Power Research Institute (EPRI) between the mid-1980s and the mid-1990s. In addition, the 11 percent rate reflects worldwide FGD capacity as reported by the International Energy Agency (IEA).

The Rubin *et al.* study also presents a preliminary estimate of the learning rate for FGD O&M costs. The authors characterize this rate as preliminary because the underlying cost data represent *expected* O&M costs for a standardized FGD system at different points in time rather than the O&M data related to specific FGD systems. Nevertheless, to the extent that the trend in expected O&M costs is consistent with actual changes in O&M costs over time, this trend could serve as a useful indicator of technological change.

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[53] This rate is considered by the Project Team to be consistent with advice from the Council. See EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.

[54] Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," *International Journal of Energy Technology and Policy*, Vol. 2, Nos. 1/2, 2004.

Using the expected O&M cost estimates as surrogate data for actual O&M costs, the authors estimated a learning rate of 22 percent for FGD O&M costs.

Exhibit 2-4. Learning Rates and Cumulative Production Metrics for EGU Emission Control Technologies

Control Technology	Learning Rates	Cumulative Production Metric
Flue Gas Desulfurization[1]	*Capital Costs*: 11% *O&M Costs*: 22%	Cumulative FGD capacity.
Selective Catalytic Reduction[2]	*Capital Costs*: 14% *O&M Costs*: 21%	Cumulative SCR capacity.
Selective Non-catalytic Reduction[3]	*Capital Costs*: 15% *O&M Costs*: 10%	Cumulative number of plants with SNCR.
Activated Carbon Injection[4]	*Capital Costs: 10%* *O&M Costs: 10%*	Cumulative ACI capacity.

Notes:
1. Estimates for FGD from Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," International Journal of Energy Technology and Policy, Vol. 2, Nos. 1/2, 2004.
2. Estimates for SCR derived from Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," Journal of the Air & Waste Management Association, Vol. 55, December 2005.
3. Capital cost estimate for SNCR derived from Cynthia Manson, Matthew B. Nelson, and James E. Neumann. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," unpublished working paper, July 2002. O&M estimate for SNCR based on the Council recommendation that the Project Team use a default learning rate of 5 to 10 percent in cases where no learning rate estimates are available in the empirical literature; EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007.
4. ACI learning rates based on the Council recommendation that the Project Team use a default learning rate of 5 to 10 percent for industries and technologies not evaluated in the learning curve literature. See U.S. Environmental Protection Agency Science Advisory Board, *op cit*.

Based on the Rubin *et al.* study, we used a learning rate of 11 percent to adjust IPM's capital cost projections for FGD retrofits and a learning rate of 22 percent for FGD O&M costs. The extent to which we adjust the FGD capital cost projections for any given year reflects the vintage profile of the FGD systems in place that year. For example, FGD-related capital costs incurred by utilities in 2020 may reflect FGD units installed in 2010, others installed in 2015, and additional FGD units purchased by utilities in 2020. Therefore, in adjusting the annualized FGD capital cost estimate for 2020, we make separate learning curve adjustments for the capital costs associated with each vintage group--the first adjustment for units installed in 2010 would reflect cumulative FGD capacity in 2010, the second for units purchased in 2015 would reflect cumulative capacity in 2015, and the third adjustment for units installed in 2020 would reflect cumulative capacity in 2020.

Consistent with the Rubin *et al*. estimation of FGD learning curve impacts, we adjust IPM's FGD cost projections based on the cumulative generating capacity controlled by FGD worldwide. According to IEA data cited by Rubin *et al.* and Nolan, approximately

223.4 gigawatts (GW) of generating capacity were controlled by FGD in 2000.[55] Due to limitations in the readily available data, we only capture FGD installations made within the U.S. for the post-2000 period.[56] Based on data in EPA's NEEDS 2000 and NEEDS 2004 databases, we estimate that approximately 5.9 GW of generating capacity in the U.S. were fitted with FGD between 2000 and 2006.[57] For 2007 through 2020, we use IPM's results to estimate the additional U.S. capacity retrofitted with FGD. Because we do not capture post-2000 FGD capacity additions outside of the U.S., we may underestimate the learning impacts associated with FGD and overestimate the cost associated with this technology.

Selective Catalytic Reduction Retrofits

To adjust EGU cost impacts related to SCR retrofits, we use learning rates adapted from a recent study published by Yeh *et al.* in the *Journal of the Air & Waste Management Association.*[58] Based on SCR cost data from EPA, the Department of Energy, and EPRI, as well as coal-fired SCR capacity data from IEA, this study estimates that SCR capital costs per kilowatt of controlled capacity decline by 14 percent with every doubling in cumulative capacity controlled. Similarly, the study suggests that the learning rate for SCR O&M costs may be as high as 42 percent. This may be an overestimate, however, because the earliest cost values supporting this estimate were based on manufacturers' guarantees of a catalyst's useful life (typically a one-year catalyst life for US coal-fired plants). Later cost projections were revised because a catalyst's useful life was observed to be much longer than its guaranteed life, an apparent cost reduction that is unrelated to learning.

Based on the results of the Yeh *et al.* study, we apply a learning rate of 14 percent to IPM's estimates of SCR capital costs. Similar to our learning curve adjustments for FGD capital costs, we separate SCR capital costs by vintage and make separate learning curve adjustments for each vintage group. As described above, the Yeh *et al.* 42 percent learning rate for SCR O&M costs may over-estimate actual learning curve impacts. Nevertheless, because SCR is responsible for a significant portion of the EGU compliance costs associated with the Amendments, it is important to capture the learning

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[55] This estimate reflects 198.4 GW of EGU capacity controlled by wet FGD and 25 GW of capacity controlled by dry FGD systems. The IEA data for wet FGD capacity was provided by Sonia Yeh, co-author of Rubin *et al.*, *op. cit.* The estimate for dry FGD is from IEA Coal Power 3, as cited in Paul S. Nolan, "Flue Gas Desulfurization Technologies for Coal-Fired Power Plants," The Babcock & Wilcox Company, U.S., presented by Michael X. Jiang at the Coal-Tech 2000 International Conference, November, 2000, Jakarta, Indonesia.

[56] Although it may be possible to project FGD capacity outside of the U.S., doing so would require extensive resources beyond the scope of this analysis.

[57] As indicated above, NEEDS 2004 includes units online in 2004 as well as capacity additions expected to be online as of 2006.

[58] Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," *Journal of the Air & Waste Management Association*, Vol. 55, December 2005. Although the SCR cost data used in this study represent SCR systems at new plants rather than SCR retrofit systems, we base our learning curve adjustments for SCR retrofits on the results of this study under the assumption that the learning rate for SCR retrofits is similar to that of SCR systems at new plants.

effects associated with this technology to the extent that the data allow. To guard against potential overestimation of learning effects while still capturing at least a portion of the learning curve impacts associated SCR operations and maintenance, we apply a learning rate of 21 percent (i.e., half the learning rate estimated by Yeh *et al.*) to SCR O&M costs.

Similar to our adjustments for FGD costs, we adjust SCR capital and O&M costs based on cumulative global generating capacity controlled by SCR. The IEA data used by Rubin *et al.* indicate that approximately 77.4 GW of generating capacity were equipped with SCR systems in 2000. Because we lack sufficient data to estimate changes in global capacity controlled after 2000, we use changes in U.S. capacity controlled to generate low-end estimates of the global capacity controlled after 2000. For example, we estimate that 69 GW of U.S. capacity were fitted with SCR between 2000 and 2006 based on data presented in EPA's NEEDS 2000 and NEEDS 2004 databases. Adding this value to the 77.4 GW of global capacity controlled in 2000, we use 146 GW as our estimate of global generating capacity controlled by SCR in 2006. Similar to our approach for FGD, we use IPM's results for the Second Prospective to estimate the additional U.S. capacity retrofitted with SCR by 2010 and 2020. The primary limitation of this approach is that we may underestimate the extent to which learning reduces the costs associated with SCR because we do not capture SCR installations outside of the U.S. after 2000.

Selective Non-catalytic Reduction Retrofits

Our approach for incorporating learning curve impacts into our estimates of SNCR costs reflects information that we identified in the learning curve literature as well as advice that we received from the Council. For SNCR capital costs, we rely on the only source that we identified with information specific to the SNCR learning effect: a 2002 working paper by Manson *et al*. that estimates that the capital cost of new SNCR units declines by 14 to 16 percent with each doubling in global SNCR installations.[59] Based on this 14 to 16 percent range, we use a learning rate of 15 percent for SNCR capital costs. Similar to our learning curve adjustments for FGD and SCR capital costs, we make separate learning curve adjustments for different vintages of SNCR retrofits in use during a given year. For example, for SNCR capital costs in 2020, our learning curve adjustments for SNCR units installed in 2015 are more significant than our adjustments for units installed in 2010.

Although the cost of operating and maintaining SNCR systems may decline over time due to learning curve effects, we identified no studies quantifying the magnitude of such an effect. Therefore, consistent with the advice of the Council, we applied a learning rate of 10 percent to IPM's estimates of SNCR O&M costs.[60]

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[59] Cynthia Manson, Matthew B. Nelson, and James E. Neumann. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," unpublished working paper, July 2002. The authors developed the 14 to 16 percent estimate based on SNCR cost data from NESCAUM and EPRI and installation data from NESCAUM, *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers*, September 2000.

[60] EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.

Because the SNCR learning rate estimated by Manson *et al.* reflects the relationship between SNCR capital costs and the cumulative number of SNCR installations worldwide, we use the latter as our metric of cumulative production. Based on data cited in Manson *et al.*, approximately 300 SNCR units had been installed globally by 2000.[61] For the 2001-2020 period, we were able to estimate the number of additional installations made within the U.S. (based on EPA's NEEDS databases and the results generated by IPM) but not installations made within other countries. Therefore, we may underestimate cumulative SNCR production after 2000 and, consequently, the extent to which learning may reduce the costs associated with units installed during this period.

Activated Carbon Injection Retrofits

Similar to SNCR O&M costs, we identified no information in the empirical literature evaluating the learning effects associated with ACI. Therefore, consistent with our approach for SNCR O&M costs, we applied a 10 percent learning rate to ACI capital and O&M costs. To implement these learning curve adjustments, we used cumulative U.S. EGU capacity controlled by ACI as our metric of cumulative production.

New Electric Generating Units

For generating units projected to go online in the future, we make no adjustments to the associated costs estimated by IPM. IPM estimates these costs based on technology-specific unit cost values included in the Department of Energy's National Energy Modeling System (NEMS), which reflect DOE's assessment of the learning effects associated with individual technologies. In general, NEMS applies a ten percent learning rate to technologies during their infancy, a 5 percent learning rate to adolescent technologies, and a 1.0 percent learning rate to mature technologies.[62] The model classifies technologies as infant for their first three doublings of cumulative production, adolescent for the five subsequent doublings of cumulative production, and mature for remaining increases in cumulative production.[63] In addition, NEMS includes annual lower bound and upper bound learning limits for each generating technology. Lower bound learning rates vary by year and technology vintage (i.e., infant, adolescent, or mature), ranging from 0.65 percent for mature technologies in 2005 to 15.65 percent for infant technologies in 2020. For the upper bound, NEMS limits learning effects to the cost reduction associated with a 50 percent increase in cumulative production.

Although learning effects may reduce the costs of new generating units over time, it is unlikely that IPM's treatment of these effects has a significant effect on the estimated incremental cost associated with the Amendments. As indicated above, we assume that electricity demand is the same under both the *with-CAAA* and *without-CAAA* scenarios and therefore that the Amendments have little, if any, effect on the need for new plants.

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[61] NESCAUM, *op. cit.*

[62] Etan Gumerman and Chris Marnay. "Learning and Cost Reductions for Generating Technologies in the National Energy Modeling System (NEMS)," January 16, 2004.

[63] *Ibid.*

Learning Curve Adjustments for FGD, SCR, and SNCR Installed Before the IPM Planning Horizon

In addition to adjusting the cost projections generated by IPM to account for learning curve impacts, we made similar adjustments to the estimated capital costs associated with FGD, SCR, and SNCR installed before the IPM time horizon.[64] As described above, we developed these estimates using the cost equations included in IPM. Because these equations are based on the cost of emission controls installed in 2004, they reflect pre-2004 learning curve impacts and may underestimate the capital costs associated with FGD, SCR, and SNCR installed before 2004. For example, a scrubber installed in 1998 would likely cost more than a comparable scrubber installed in 2004 because the cost of producing a scrubber likely fell during the 1998-2004 period due to the cost-reducing effect of learning. Therefore, a cost equation that represents the cost of scrubbers installed in 2004 would underestimate the cost of scrubbers installed in 1998. To account for this effect, we apply the FGD, SCR, and SNCR learning rates presented above to the estimated capital costs associated with emission control devices installed before the IPM time horizon.

Similar to our learning curve adjustments for IPM's cost projections, we use cumulative global capacity controlled as our cumulative production metric for FGD and SCR and the number of cumulative units installed as our cumulative production measure for SNCR. For FGD and SCR, the sources cited above provide sufficient data to estimate global capacity controlled during the 1990-2006 period.[65] However, 2000 is the earliest year for which we identified information on the cumulative number of SNCR units installed.[66] To estimate cumulative SNCR installations for earlier years, we extrapolated backward in time from our estimate of 300 units in 2000, based on the average number of units installed in the U.S. each year between 2000 and 2006. For example, data in EPA's NEEDS 2000 and NEEDS 2004 databases indicate that approximately 4 units were installed in the U.S. each year between 2000 and 2006. Based on this figure, we assume that 296 SNCR units had been installed globally as of 1999.

Because FGD, SCR, and SNCR capital cost estimates for units installed before the IPM planning horizon reflect installations at different points in time, we make separate learning curve adjustments for different vintages of retrofits reflected in the capital cost estimates. For example, we make only a minor adjustment for capital costs associated with FGD installed in 2003 (i.e., one year removed from the vintage year of IPM's cost equations) but a more significant adjustment for FGD installed in 1996.

[64] We exclude ACI from this discussion because the results of the IPM runs conducted for the Second Prospective indicate that no ACI systems were installed at U.S. EGUs before IPM's planning horizon.

[65] These sources provide capacity estimates for 1990, 1995, and 2000. We interpolate between the values for these years to estimate the capacity controlled in intermediate years.

[66] As indicated in NESCAUM, *op. cit.*, 300 SNCR units had been installed globally as of 2000.

APPLICATION OF IPM FOR 2010 AND 2020 ANALYSES

The results generated by IPM depend significantly on the regulatory scenario and data inputs included in the model. In this section we describe the *with-CAAA* and *without-CAAA* scenarios for the 2010 and 2020 IPM analyses and the core data inputs included in the model. Because the IPM analysis for the 2000 target year differs significantly from the 2010 and 2020 analyses, we present the Project Team's methodology for the 2000 IPM analysis in a separate section below.

REGULATORY SCENARIOS FOR 2010 AND 2020

To assess the emissions impact of the Clean Air Act Amendments for the years 2010 and 2020, we estimate emissions under two scenarios: a baseline scenario under which the Amendments remain in place (i.e., the *with-CAAA* scenario) and a counterfactual scenario that represents a regulatory environment absent the Amendments (i.e., the *without-CAAA* scenario). The difference between IPM's *with-CAAA* and *without-CAAA* costs represents the CAAA-related costs associated with EGU investments and operations during the IPM planning horizon. EGU capital costs for investments pre-dating the IPM planning horizon are estimated based on the methods outlined above.[67]

The *with-CAAA* scenario reflects all federal, state, and local regulations affecting utilities that have been promulgated since the passage of the Amendments in 1990. These include the following:

- The Clean Air Interstate Rule,
- The Clean Air Mercury Rule,
- SIP Call Post-2000,
- Reasonably Available Control Technology (RACT) and New Source Review requirements for all non-waived (NO_x waiver) non-attainment areas,
- Phase II of the Ozone Transport Commission (OTC) NO_x memorandum of understanding,[68]
- Title IV Phase I and Phase II limits for all boiler types,
- 25-ton Prevention of Significant Deterioration (PSD) regulations and New Source Performance Standards (NSPS),
- Title IV emission allowance program,

[67] Our analysis of capital costs associated with investments that pre-date the IPM planning horizon is separate from the IPM analysis conducted for the target year 2000. Due to model constraints that are unique to the 2000 run, the IPM analysis for 2000, which is described in detail below, does not estimate any EGU capital costs. Therefore, all capital costs associated with EGU emission control investments made between 1990 and 2007 are estimated external to IPM.

[68] Under Phase II of the OTC memorandum of understanding, eleven eastern states committed themselves to achieving regional reductions in NO_x emissions through a cap-and-trade system similar to the SO_2 trading program established under Title IV of the Amendments. As an initial step in the development of the OTC trading program, the OTC states; EPA; and representatives from industry, utilities, and environmental groups designed a model rule that identified the key elements of the program. Each OTC state then went through its own regulatory process to develop regulations consistent with the model rule.

- Utility emissions caps set by individual states (CT, MA, MO, NH, NC, TX, and WI), and
- Emissions reductions achieved because of post-1990 enforcement actions (e.g., NSR cases and settlements).

Under the *without-CAAA* scenario, federal, state, and local controls of utility emissions are frozen at 1990 levels of stringency. Exhibit 2-5 presents the emissions rates and other assumptions reflected in the *without-CAAA* scenario.

Exhibit 2-5. Assumptions Reflected In The *Without-CAAA* Scenario

Element		Assumption
Existing Coal Facilities	SO_2 Rate	• Primary data source:[1] 1990 actual SO_2 emissions rate from U.S. EPA, *Clean Air Markets Data and Maps* (Based on these rates, fuels are assigned to the generating units in the model). • Secondary source: 1990 SO_2 emissions rate used for the no-CAAA scenario in the First 812 Prospective—developed by EPA as part of the NAPAP analysis. • Default: 1.2 lbs of SO_2/mmbtu of input fuel[2]
	NO_x Rate	• Primary data source:[1] 1994 NO_x RIA rates (RATE90-3.dbf) for all units outside California • Secondary source: 1990 NO_x rates used in the no-CAAA scenario for the First 812 Prospective • Default:[3] • 0.796 lbs/mmBtu of fuel input for units that came online before 1972 and burn bituminous or sub-bituminous coal • 0.7 lbs/mmbtu of fuel input for units that came online between 1972 and 1978 and burn bituminous or sub-bituminous coal • 0.6 lbs/mmbtu of fuel input for units that came online after 1978 and burn bituminous or sub-bituminous coal • 0.6 lbs/mmbtu of fuel input for units that burn lignite coal • California units will retain assumptions from EPA Base Case 2004 (v.2.1.9)
	SO_2 Controls	• Remove scrubbers from all plants that were built in response to CAAA: • Remove scrubbers from units that came online before 1978 and if the scrubber was installed after November 15, 1990. • CEMS 2001 and 2000 EIA 767 used to determine scrubber installation date. • Default: Based on the no-CAAA scenario in the First 812 Prospective
	NO_x Post-Combustion Controls	• Remove all NOx controls, except for those meeting California BACT regulations
	Hg Rate	• Mercury emission modification factors from EPA Base Case 2004 (v.2.1.9)
Existing Oil/Gas Steam Facilities	SO_2 Rate	• Primary data source:[1] 1990 actual SO_2 emissions rates from U.S. EPA, *Clean Air Markets Data and Maps*. (Fuels are assigned in the model based on these rates). • Secondary source: SO_2 emissions rate used in the no-CAAA scenario for the First 812 Prospective. • Default:[2] 0.8 lbs of SO_2/mmbtu of input fuel for oil.

Element		Assumption

	NO_x Rate	• Primary data source:[1] 1994 NO_x RIA rates for all units outside California
		• Secondary source: 1990 NO_x rates used in the no-CAAA scenario for the First 812 Prospective
		• Default:[3]
		  • 0.39 lbs/mmBtu for units that came online before 1979
		  • 0.2 lbs/mmBtu for units that came online in 1979 or later
		• For California units retain assumptions from EPA Base Case 2004 (v.2.1.9)

	SO_2 Controls	• Remove scrubbers from all plants except those built for NSPS: • Remove scrubbers from units that came online before 1978 and if the scrubbers were installed after November 15, 1990. • CEMS 2001 and 2000 EIA 767 used to determine scrubber installation date. • Default: Based on the no-CAAA scenario for the First 812 Prospective.
	NO_x Post-Combustion Controls	• Remove all NOx controls, except for those meeting California BACT regulations
	Hg Rate	• Mercury emission modification factors from EPA Base Case 2004 (v.2.1.9)
Existing Combustion Turbines		• Retain NO_x rates and controls from EPA Base Case 2004 (v.2.1.9)
Existing Combined Cycles		• Retain NO_x rates and controls from EPA Base Case 2004 (v.2.1.9)
Other Existing Units		• All assumptions based on EPA Base Case 2004 (v.2.1.9)
Potential Units (units online 2004 and later)	Coal[2,3]	• Achieves SO_2 rate of 1.2 lbs/mmbtu: plant will include scrubber and option to burn high sulfur coals--for conventional pulverized coal (CPC), integrated gasification combined cycle (IGCC), and combined cycle (CC). • Includes cost & performance of less efficient SCR/SNCR. (IGCC and CPC) • All other cost & performance assumptions based on AEO 2005. • NOx rate of 0.1 lbs/mmbtu for IGCC and 0.3 lbs/mmbtu for CPC
	Combustion Turbine and Advanced Combustion Turbine	• All cost & performance assumptions based on AEO 2005; NO_x rate of 0.1 lbs/mmbtu
	Combined Cycle and Advanced Combined Cycle	• Include cost & performance of less efficient SCR; Achieves NO_x rate of 0.1 lbs/mmbtu.
	Oil/Gas Steam Units	• Consistent with EPA Base Case 2004 (v.2.1.9) no new Oil/Gas steam option will be provided
	Renewables	• All cost and performance assumptions based on AEO 2005
Environmental Regulations		• No emission constraints representing CAAA-related environmental regulations are included. • No NSR settlements implemented in EPA Base Case 2004 (v.2.1.9) are included.

Element	Assumption
Coal supply curves and other fuel assumptions	• Retain coal supply restrictions assumed in the no-CAAA scenario for the First 812 Prospective • All other assumptions, excluding coal supply restrictions, from EPA Base Case 2004 (v.2.1.9) • Coal productivity assumptions from AEO 2005 will be incorporated.
Other Assumptions	• Unless otherwise mentioned, all other assumptions based on EPA Base Case 2004 (v.2.1.9)

Notes:

1. If a unit's emissions rate for 1990 was available from the primary data source, we assigned the unit the emissions rate from this source. If a unit's 1990 emissions rate was not available from the primary source but was available from the secondary source, we used the rate from the secondary source. Otherwise, we used the default emissions rate.
2. Default SO_2 rates for existing units and assumed emission rates new units are based on NSPS standard described in 40 CFR Ch. 1 (7-1-98) Subpart D §60.43 and 40 CFR Ch. 1 (7-1-98) Subpart Da §60.43a. The SO_2 NSPS emissions standard is differentiated between plants that commenced construction after 1971 and plants that commenced construction after 1978. In the modeling, we have assumed that the cutoff dates apply to online years rather than dates on which construction was initiated. For plants that commenced construction after 1978, the standard gives coal plants the additional option to achieve a rate of 0.6 lbs/mmbtu with control efficiency of 70%. The assumptions do not include this option.
3. NO_x rates for existing units and assumed emission rates new units are based on NSPS standard described in 40 CFR Ch. 1 (7-1-98) Subpart D §60.44 and 40 CFR Ch. 1 (7-1-98) Subpart Da §60.44a. For coal units, the standard makes several distinctions between plants using bituminous, sub-bituminous and lignite coal along with other differences between lignite coal mined in North Dakota, South Dakota and Montana and for cyclone units. For simplicity, the assumed NO_x rates for non-lignite coal in units coming online after 1978 reflects the NO_x rate for bituminous coal. Similarly, the distinction between lignite mined in the three states named above and the rest of the country has been dropped and the assumption includes the NO_x standard for lignite mined outside of the three states. As with SO_2, the proposed assumption uses the online date rather than the construction date as the criteria for the emissions standards.

INPUT DATA FOR THE 2010 AND 2020 IPM ANALYSES

The IPM analyses conducted for the Second Prospective reflect input data from several different sources. In some cases, input data already included in version 2.1.9 of IPM were retained (i.e., the version of IPM used to develop EPA's 2004 EPA Base Case), but for several key variables the inputs in version 2.1.9 were replaced with more recent data. With these updated data, the version of IPM used for the Second Prospective may reflect recent trends in the electricity market more accurately than IPM version 2.1.9.

To construct the IPM model plants representing all existing and planned electric generating units for the 2010/2020 emissions analyses, the analysis uses the National Electric Energy Data System (NEEDS) 2004 database as its primary source of data, consistent with version 2.1.9 of IPM. The NEEDS 2004 database contains the following unit-level information: location (model region, state, and county); capacity; plant type; pollution control equipment installed for SO_2, NO_x, and particulate matter; boiler configurations; mercury emission modification factors (EMF), and SO_2 and NO_x emission rates. Exhibits 2-6 and 2-7 summarize the sources of information EPA used to develop the NEEDS 2004 data for existing and planned/committed units, respectively.

Exhibit 2-6. Data Sources for Existing Units In Needs 2004

Data Source	Description
DOE's Form EIA-860a	DOE's Form EIA-860a is an annual survey of utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), status, prime mover, primary energy source, in-service year, and a plant-level cogenerator flag.
DOE's Form EIA-767	DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report", that contains data for utility nuclear and fossil fuel steam boilers such as fuel quantity and quality; boiler identification, location, status, and design information; and postcombustion NO_x control, FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided, along with generator-level generation and nameplate capacity. Note that boilers and generators are not necessarily in a one-to-one correspondence.
NERC Electricity Supply and Demand (ES&D) database	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year.
DOE's Annual Energy Outlook (AEO) 2004	The Annual Energy Outlook (AEO 2004) presents midterm forecasts of energy supply, demand and prices through 2025 prepared by the Energy Information Administration (EIA). The projects are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2004, such as heat rate, RPS inducing renewable builds, etc. is adopted in NEEDS 2004 (i.e., NEEDS 2.1.9).
Platt's NewGen Database	NewGen delivers a comprehensive, detailed assessment of the current status of proposed power plants in the United States. NewGen information is continually updated by Platts' research staff and NEEDS 2004 (i.e., NEEDS 2.1.9) used the information updated in December 2003.
EPA's Emission Tracking System (ETS)	The Emission Tracking System (ETS) database is updated quarterly. It contains boiler-level information such as primary fuel, heat input, SO_2 and NO_x controls, and SO_2, NO_x and CO_2 emissions. NEEDS 2004 (i.e., NEEDS 2.1.9) used Quarters 3 & 4 of 2002 and Quarters 1 & 2 of 2003 for developing emission rates and used Quarter 4 2003 for developing post-combustion control information.

Exhibit 2-7. Data Sources for Planned Units In Needs 2004

Type	Capacity (MW)	Years Described	Data Source
Renewables/Non-conventional			
Biomass	293	2004-2009	AEO 2004 Inventory of Planned/Committed Units
Geothermal	723	2004-2015	
Landfill Gas	137	2004-2009	
Solar	156	2004-2013	
Other	50	2007-2009	
Wind	1,280	2004-2015	
Fossil/Conventional			
Coal Steam	1,948	2004-2008	Platts RDI NewGen Database
Combined Cycle	36,622	2004-2007	
Turbine	6,065	2004-2007	
Fossil Waste	523	2004-2007	
TOTAL	47,797		

In addition to the unit data included in IPM version 2.1.9, the IPM analyses conducted for the Second Prospective also use the same natural gas supply curves from this version of the model. The natural gas supply curves from IPM 2.1.9 are based on the recommendations of a peer review panel convened in October 2003 and detailed supply and demand data obtained from the NPC's 2003 Natural Gas Study. Based on these data, EPA developed natural gas supply curves specific to each year in the IPM planning horizon.

The coal supply curves included in the 2010/2020 IPM analysis for the Second Prospective are similar to those included in version 2.1.9 of IPM. These supply functions reflect the estimated size of the coal resource base, supply costs, and coal supply productivity. For the Second Prospective, the resource base and coal supply cost estimates included in version 2.1.9 of IPM were retained but the coal supply productivity data in the model were updated with estimates from the Department of Energy's *Annual Energy Outlook 2005* (AEO 2005).

In addition to replacing the coal mine productivity data in IPM with more recent data from AEO 2005, the AEO 2005 data were also used for several other key model inputs. This application of AEO 2005 data is consistent with the cost and emissions analyses for other source categories, which also rely heavily on AEO 2005 data. The AEO 2005 data incorporated into IPM for the Second Prospective include the following:

- Electricity demand;
- Oil price projections;
- Life extension costs for fossil and nuclear power plants;
- Costs and technical specifications for new units (conventional and renewable);
- Nuclear availability and uprates,[69] and
- International energy imports.

In most cases AEO 2005 data were input directly into IPM; however, EPA adjusted the AEO 2005 projections of electricity demand to reflect EPA assumptions regarding future improvements in energy efficiency. These adjustments to AEO projections have been applied in other recent EPA analyses of the EGU sector to reflect EPA views on the future success of programs such as Energy Star. AEO 2005 projects annual electricity demand growth of 1.86 percent through 2025. Based on this estimate and the Agency's assumptions with respect to energy efficiency, EPA estimates annual growth of 1.63 percent.[70]

APPLICATION OF IPM FOR 2001 ANALYSES

As indicated in Chapter 1 of this report, the Second Prospective will estimate the impacts of the Amendments for the years 2000, 2010, and 2020. The previous section outlines the approach for estimating costs incurred by electric utilities for the 2010 and 2020 target years. For 2000, the study uses EGU costs in 2001 as a proxy for costs in 2000. Due to

[69] An uprate is the process of increasing the maximum power level at which a nuclear plant can legally operate. U.S. Nuclear Regulator Commission, "Uprates,"

http://www.nrc.gov/reactors/operating/licensing/power-uprates.html#definition, accessed June 20, 2006

[70] Personal communication with John Laitner, U.S. EPA Office of Atmospheric Programs, August 17, 2005.

resource constraints and model limitations, the Project Team adapted the 2001 validation analysis described in Appendix H instead of developing a new analysis for the year 2000.

In this section, we describe the application of IPM for the 2001 *with-CAAA* and *without-CAAA* IPM analyses. These analyses were designed differently than the 2010 and 2020 model runs because they require IPM to estimate historical counterfactual costs and emissions. As a forward-looking model, IPM was not designed for such an analysis and requires a number of adjustments to ensure that its results for a 2001 model run reasonably reflect historical conditions.

REGULATORY SCENARIOS FOR THE 2001 IPM ANALYSIS

The *with-CAAA* scenario for the 2001 IPM analysis is the same as the *with-CAAA* scenario for the 2010 and 2020 analyses except that the 2001 scenario does not incorporate regulations or NSR settlements not yet in effect in 2001. Therefore, the Clean Air Interstate Rule, Clean Air Mercury Rule, and other regulations recently promulgated are not included in the *with-CAAA* scenario for 2001. The *without-CAAA* scenario for 2001 is exactly the same as the corresponding scenarios for 2010 and 2020 in that regulatory controls on EGU emissions are frozen at 1990 levels of scope and stringency.

INPUT DATA AND CONFIGURATION OF IPM FOR THE 2001 EMISSIONS ANALYSIS

Similar to the IPM analyses conducted for 2010 and 2020, the analysis for 2001 is based on version 2.1.9 of IPM. For the 2001 analysis, the following data inputs were included in the model:

- IPM model units representing existing units were developed from the 2001 inventory of EGUs, as represented in NEEDS 2004.
- Electricity demand, peak load, and load shape were set to 2001 levels.[71] Electricity demand data from the North American Electric Reliability Council indicate that electricity demand in 2001 was approximately 1 percent lower than demand in 2000.[72]
- Coal supply curves for the year 2000, as included in the EPA 2004 Base Case.
- Natural gas supply curves for 2003, as developed after the 2003 peer review of IPM's assumptions pertaining to natural gas.
- For the *with-CAAA* scenario, emissions are constrained to the values reported in EPA's 2001 compliance reports for Title IV SO_2 and OTR NO_x cap.[73] According

[71] Electricity demand and peak load for 2001 were based on the North American Electric Reliability Council, Electricity Supply & Demand 2002 database. Load shape was based on data from the Federal Energy Regulatory Commission Form 714 for 2001.

[72] North American Electric Reliability Council, Op *cit*.

[73] Emissions of SO_2 and NO_x are constrained based on values in U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002 and U.S. EPA, "2001 OTC NO_x Budget Program Compliance Report," March 26, 2002.

to EPA data, EGU emissions of SO_2 and NO_x were approximately 5 percent and 8 percent lower, respectively, in 2001 than in 2000.[74]

- Environmental controls under the *with-CAAA* scenario are restricted to those reported in EPA's Emission Tracking System (ETS) in 2001, excluding NO_x controls added after September 2001 and all scrubbers built in 2001. NO_x controls installed after September were excluded because the Project Team assumes that controls installed at this time represent investments to limit emissions in 2002 and later years. The Project Team excluded scrubbers constructed in 2001 because no data indicating the month or season of installation were readily available.

With these inputs included in the model for the 2001 analysis, IPM was configured to make endogenous dispatch decisions but was restricted from making any investments in new control technologies or generating capacity. This ensured that the capital reflected in the model's cost and emissions estimates was consistent with the EGU capital stock in place in 2001. IPM, as a forward-looking model, does not estimate the capital costs associated with these sunk investments. Therefore, to estimate the capital costs of EGU emission control investments made between 1990 and 2001, we used the approach outlined above in the section named "Augmenting and Adjusting Cost Estimates Generated by IPM."

ASSESSING THE ROLE OF DISTRIBUTED ELECTRICITY GENERATION

At an early stage of the analysis, the Council raised the issue of assessing diesel-powered distributed generation. Specifically, in the context of commenting on air quality and emissions considerations involving uncertainty, the Council stated the following regarding scenario design:

"c) Supplemental diesel power: Many industrial facilities are exploring or adopting the use of supplemental diesel equipment for on-site electricity generation. These sources appear not to be regulated in the same way as traditional electrical generating units, but they can potentially produce substantial amounts of PM and nitrogen oxides."[75]

This comment had particular relevance at the time in light of the then recent electricity shortages and reliability issues in California.

The emissions and cost analysis results for the Second Prospective rely on the Department of Energy's Annual Energy Outlook (AEO) 2005, which itself implicitly reflects an estimate of the penetration of supplemental and distributed generation of electricity in the U.S. market through 2020. DOE's National Energy Modeling System (NEMS) includes a module that assesses cogeneration and distributed generation in the industrial sector, and also includes a separate module that assesses penetration of

[74] U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002.

[75] See EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Review of the Draft Analytical Plan for EPA's Second Prospective Analysis - Benefits and Costs of the Clean Air Act, 1990-2020: An Advisory by the Advisory Council for Clean Air Compliance Analysis", EPA-SAB-COUNCIL-ADV-01-004, September 24, 2001, Page 87.

distributed generation in the commercial and residential sectors. The industrial sector cogeneration data, along with the much larger electric utility generation forecasts, are used as driver data for runs of the Integrated Planning Model (IPM). As a result, emissions from such source categories as supplemental diesel power at industrial facilities, at the higher per-unit-of-energy-produced emissions rates noted by the Council, are reflected in the overall EGU sector emissions summaries.

In addition, distributed generation through smaller "micropower" units is included in the non-EGU analyses presented in the other chapters of this report. The NONROAD model (see Chapter 4) includes emission estimates for approximately 450,000 diesel-fired generators in the nation. They are classified as light commercial engines, and include engines of 600 horsepower or less. The number of generators was estimated in part from engine manufacturer sales and equipment owner surveys (conducted for EPA by Power Systems Research), and verified by equipment owner surveys.

The Project Team also looked into projections of future growth in distributed generation and the potential impact on our emissions estimates. While industrial cogeneration and other industrial end user generation, even at a small scale, ought to be reflected in IPM, some assessments conclude that distributed end-user generation in the commercial and residential sector, which is not reflected in IPM, could be significant over the next several decades. The AEO 2005 reference case results, however, suggest relatively modest growth in this sector. EIA estimates that residential and commercial sector distributed generation is currently very small as a percentage of total electricity generation, only about 9 billion kilowatt hours (kWhrs) out of a total generation of roughly 4 trillion kWhrs. In addition, NEMS modeling forecasts that, while this category of generation will itself grow rapidly, the total generation is unlikely to grow to significant levels by 2020 (a projected 13 billion kWhrs out of a total 5.3 trillion generation, or less than one quarter of one percent). We would not necessarily expect that the Clean Air Act Amendments (or their absence) would have a major impact on the future adoption rate of either diesel or renewable distributed or supplemental generation. It is possible that the absence of the CAAA might reduce the air quality barriers to adoption of diesel technologies, but it is also possible that the future cost of these technologies per unit of generation might rise relative to the costs of centralized electricity sources in the absence of the Amendments.

Any forecast to 2020 of small-scale distributed generation, therefore, remains uncertain. There are many examples of published analyses that show much greater potential market penetration of small-scale, distributed renewable technologies than AEO 2005. Some analysts have concluded that the current version of NEMS is unusually pessimistic about market penetration rates. Others point to the small-scale diesel, natural gas, or renewable electric energy sources as showing promise, particularly for combined heat and power applications in new construction of commercial buildings.[76] Nevertheless, even if the

[76] For a review of a wide range of analyses that consider alternative futures for distributed generation and renewables penetration see, J. Aabakken and W. Short, Domestic Energy *Scenarios*, National Renewable Energy Laboratory, Document # NREL/TP-620-32742, January 2003.

penetration of these small-scale technologies were four times as great in 2020 as projected by AEO, they would make up just one percent of total generation and a much smaller portion of total emissions across all source categories. Therefore, the penetration of these technologies is unlikely to represent one of the most important sources of uncertainty in the Project Team's overall analysis of the Amendments.

RESULTS

Based on the methods and data outlined above, we estimated the CAAA-related costs incurred by EGUs as presented in Exhibit 2-8. As the exhibit indicates, we expect EGU costs to increase significantly between 2001 and 2010 and again between 2010 and 2020. This trend is consistent with the increase in EGU emission reductions that the Project Team estimates for this period, as shown in Exhibit 2-9, and largely reflects the compliance deadlines for several rules affecting EGUs during the 2001-2020 period. For example, the Clean Air Interstate Rule, NO_x SIP Call, and the Clean Air Mercury Rule all have major compliance deadlines between 2001 and 2010.[77] Similarly, both the Clean Air Interstate Rule and Clean Air Mercury Rule have additional compliance deadlines between 2010 and 2020.[78] In addition to these compliance deadlines, the upward trend in costs during the 2001-2020 period also reflects the expected increase in demand for electricity.

The results in Exhibit 2-8 indicate that NO_x controls (i.e., SCR and SNCR) make up a much larger portion of costs in 2010 and 2020 than in 2001. While we estimate that SCR and SNCR retrofits represented only 12 percent of EGU capital costs in 2001, our results suggest that they will represent between 32 and 39 percent of CAAA-related capital costs for EGUs in 2010 and 2020. The increased significance of SCR and SNCR retrofits in 2010 and 2020 most likely reflects the onset of several NO_x-related rules after 2001 such as the NO_x SIP Call and CAIR and the relatively high cost of NO_x controls.[79] Similarly, the sharp increase in costs associated with activated carbon after 2001 reflects EGU compliance with the Clean Air Mercury Rule, which sets a cap on EGU mercury emissions beginning in 2010. We also expect CAAA-related fuel costs to be significantly higher in 2020 than in 2010. This reflects a sharp increase in both natural gas prices and EGU natural gas consumption between 2010 and 2020. Although the Amendments are expected to increase natural gas prices and shift electricity production from coal to

[77] The compliance deadlines for the first phase of the Clean Air Interstate Rule are January 1, 2009 for NO_x and January 1, 2010 for SO_2. Similarly, the Clean Air Mercury Rule Phase 1 emissions cap of 38 tons per year goes into effect in 2010. The deadline for NOx SIP Call implementation was May 31, 2004 for all affected sources except those in Missouri and Georgia. The compliance deadline for sources in these two states was May 1, 2005.

[78] The compliance deadline for the second phase of the Clean Air Interstate Rule is January 1, 2015. In 2018, the mercury emissions cap established under the Clean Air Mercury Rule falls from 38 tons per year to 15 tons per year.

[79] With respect to the cost of NO_x control relative to SO_2 controls, the regulatory impact analysis for the Clean Air Interstate Rule indicates that the marginal cost of EGU NO_x abatement in 2010 under CAIR is $1,300 per ton ($1,550 per ton in year 2006$), compared to just $700 per ton of SO_2 abated ($830 per ton in year 2006$). U.S. EPA, *Regulatory Impact Analysis for the Final Clean Air Interstate Rule*, March 2005, EPA-452/R-05-002.

natural gas in 2001 and 2010, the results generated by IPM suggest that both of these effects will be much more pronounced in 2020 than in previous years.

Exhibit 2-8. Annual Costs of the Clean Air Act Amendments for Electricity Generating Units in 2001, 2010, and 2020 (millions of year 2006$)

	2001	*2010*	*2020*
Capital Costs			
Scrubber retrofits	$285	$1,160	$1,950
Selective catalytic reduction retrofits	$55	$848	$1,040
Selective non-catalytic reduction retrofits	$3	$164	$164
Activated carbon injection retrofits	$0	$1	$82
Other capital costs	$154	$435	$441
Total Capital Costs	***$497***	***$2,610***	***$3,670***
Operation and Maintenance Costs			
Scrubber retrofits	$0[a]	$1,230	$2,180
Selective catalytic reduction retrofits	$0[a]	$218	$349
Selective non-catalytic reduction	$0[a]	$7	$10
Activated carbon injection retrofits	$0[a]	$15	$244
Fuel	$500	$575	$1,920
Other O&M	$377	$1,990	$2,060
Total O&M	***$876***	***$4,030***	***$6,770***
TOTAL	***$1,370***	***$6,640***	***$10,400***

Notes:

a. Because of the configuration of IPM, we were only able to separate emission control device O&M costs from other O&M costs for those devices installed during IPM's planning horizon (i.e., 2007-2030 for the 2010/2020 analysis and 2001 for the 2001 analysis). O&M costs for controls installed prior to the IPM planning horizon are included in the Other O&M category. Therefore, because we did not allow IPM to add retrofits to individual units for the 2001 model run, we were not able to separate any O&M costs for individual emission control devices from other O&M costs for 2001.

Exhibit 2-9. Summary of EGU Emissions (values reported in thousands of tons)

	2001			**2010**			**2020**		
Pollutant	**2001 *without-CAAA***	**2001 *with-CAAA***	**2001 Reductions**	**2010 *without-CAAA***	**2010 *with-CAAA***	**2010 Reductions**	**2020 *without-CAAA***	**2020 *with-CAAA***	**2020 Reductions**
VOC	40	41	-1	43	43	1	48	47	1
NO_x	7,730	4,490	3,240	8,350	2,440	5,910	8,690	1,990	6,700
CO	496	503	-7	602	618	-16	751	772	-21
SO_2	18,100	10,800	7,330	18,900	6,370	12,500	18,700	4,270	14,500
PM_{10}	752	729	23	835	658	177	897	637	259
$PM_{2.5}$	634	611	24	704	529	175	762	507	256
NH_3	3	3	0	1	1	0	1	1	0

Note: The *with-CAAA* emissions estimates and associated reductions presented here reflect the emission control measures described in this chapter. They do not reflect the EGU local control measures reflected in Chapter 7.

To assess the extent to which the learning curve adjustments discussed above affect our estimates of EGU costs, we conducted a sensitivity analysis in which we excluded learning curve cost adjustments from the estimates presented in Exhibit 2-8. The results of this sensitivity analysis, presented in Exhibit 2-10, suggest that the learning curve adjustments had only a minimal impact on the estimated costs incurred by EGUs as a result of the Amendments. In aggregate, these adjustments do not change the cost estimates by more than 6.1 percent. As outlined above, the cost equations supporting the EGU analysis reflect the costs associated with emission controls installed in 2004. Therefore, although we reduced the cost projections generated by IPM for FGD, SCR, SNCR, and ACI investments made after 2004, we increased the cost estimates for investments made prior to 2004.[80] Because these adjustments partially offset each other, the net effect of learning curve adjustments is reduced. In addition, because our results for 2001 reflect no costs incurred after 2004 (i.e., the vintage of the cost equations in IPM), our cost estimates for 2001 are higher when we make corrections for learning curve impacts, as shown in Exhibits 2-8 and 2-10.

Exhibit 2-10. Annual Costs of the Clean Air Act Amendments for Electricity Generating Units in 2001, 2010, and 2020: No Learning Curve Cost Adjustments (millions of year 2006$)

	2001	*2010*	*2020*
Capital Costs			
Scrubber retrofits	$278	$1,180	$2,000
Selective catalytic reduction retrofits	$48	$856	$1,070
Selective non-catalytic reduction retrofits	$3	$165	$166
Activated carbon injection retrofits	$0	$1	$113
Other capital costs	$154	$435	$441
Total Capital Costs	***$483***	***$2,630***	***$3,790***
Operation and Maintenance Costs			
Scrubber retrofits	$0[a]	$1,340	$2,510
Selective catalytic reduction retrofits	$0[a]	$253	$424
Selective non-catalytic reduction retrofits	$0[a]	$7	$10
Activated carbon injection retrofits	$0[a]	$15	$373
Fuel	$500	$575	$1,920
Other O&M	$374	$1,990	$2,080
Total O&M	***$874***	***$4,180***	***$7,330***
TOTAL	***$1,360***	***$6,810***	***$11,100***

Notes:

a. Because of the configuration of IPM, we were only able to separate emission control device O&M costs from other O&M costs for those devices installed during IPM's planning horizon (i.e., 2007-2030 for the 2010/2020 analysis and 2001 for the 2001 analysis). O&M costs for controls installed prior to the IPM planning horizon are included in the Other O&M category. Therefore, because we did not allow IPM to add retrofits to individual units for the 2001 model run, we were not able to separate any O&M costs for individual emission control devices from other O&M costs for 2001.

[80] As described above, we used the capital cost equations included in IPM to estimate the capital costs associated with utilities' FGD, SCR, and SNCR investments made between 1990 and the beginning of the IPM planning horizon because capital cost data for these investments are not readily available.

COMPARISON OF COST ESTIMATES WITH THE 2005 NAPAP ASSESSMENT

To assess the reasonableness of the cost estimates presented in this chapter, we compared these estimates to the National Acid Precipitation Assessment Program's (NAPAP) 2005 assessment of the Clean Air Act Title IV requirements.[81] The 1990 Clean Air Act Amendments reauthorized NAPAP to continue the acid rain research and monitoring activities that it had conducted during the previous decade and charged NAPAP with providing Congress with periodic reports on the costs, benefits, and effectiveness of Title IV, which largely affects EGUs.

The 2005 NAPAP assessment summarizes the findings of several economic studies that estimated the cost of fully implementing the Title IV SO_2 provisions. According to NAPAP, these studies estimate annual costs ranging from $1.2 billion to $2.3 billion for full implementation in 2010.[82] Because the 2010 cost estimates for EGUs in Exhibit 2-8 reflect the cost of CAIR, CAMR, and other regulations not reflected in the NAPAP estimate, it would not be appropriate to compare the NAPAP costs with the Project Team's 2010 cost estimates. A more appropriate comparison would be between the NAPAP cost estimates and the Project Team's cost estimate for 2000, as the with-CAAA scenario for 2000 more closely matches the regulations reflected in the studies cited by NAPAP.

As indicated in Exhibit 2-8, the Project Team estimates $1.4 billion in CAAA compliance costs for EGUs in 2000. This estimate is consistent with the SO_2-related Title IV cost estimates published by NAPAP, although it is near the low end of NAPAP's estimated range. Our estimate of $1.4 billion, however, would be higher if it reflected electricity demand in 2010 instead of 2000; the cost estimates in the NAPAP assessment reflect electricity market conditions in 2010.

We note that one limitation of this comparison between the Project Team's year 2000 cost estimate for EGUs and the NAPAP estimates is that the former reflects the costs of both SO_2 and NO_x controls whereas the latter reflects the costs of SO_2 only. It was not possible to separate the Project Team's costs between NO_x and SO_2 controls, but most of the year 2000 cost estimate for EGUs is likely to reflect the cost of SO_2 controls. Both Phase 1 and Phase 2 of the Title IV SO_2 program were in effect in 2000, whereas incremental with-CAAA NO_x controls in 2000 were limited to the Ozone Transport Commission memorandum of understanding, which only applied to 12 States and the District of Columbia, and reasonably available control technology (RACT) requirements. The NO_x SIP call was not implemented until after 2000.

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[81] National Science and Technology Council. *National Acid Precipitation Assessment Panel Report to Congress: An Integrated Assessment*, Executive Office of the President. Washington, DC, 2005..

[82] The NAPAP assessment cites a range of $1 billion to $2 billion, in year 2000 dollars. Adjusting for inflation using the GDP deflator, this range increases to $1.2 billion to $2.3 billion in year 2006 dollars.

CHAPTER 3 | ON-ROAD MOTOR VEHICLES

On-road vehicles include automobiles, light trucks, motorcycles, heavy-duty trucks and other vehicles that are registered for use on roads and highways. They represent a major category of air pollutants emissions specifically addressed in both the original 1970 Clean Air Act and subsequently addressed with more stringent controls in the CAAA of 1990. Motor vehicle-related controls result from Title I ozone and CO-related nonattainment provisions, as well as Title II, which contains provisions related to mobile sources. In general, regulation of this sector is conducted at the Federal level, with some exceptions noted below (most significantly for California).

Typically, new requirements for tailpipe controls, operating refinements, evaporative emissions controls, or engine modifications apply only to new vehicles - EPA's recent pursuit of retrofit controls for diesel engines is a prominent exception - while fuels requirements take effect across the entire fleet as soon as they are fully phased-in. The impact of new engine regulations therefore depends significantly on assumptions related to the demand for new vehicles of differing types (and therefore potentially differing emissions rates), the rate of scrappage of older vehicles which tend to emit at higher rates than new vehicles, and the distribution of miles driven by vehicle class. For these reasons, the approach to estimating costs for this sector must take careful account of the timing of regulations and incorporate the latest information on demand for vehicles and demand for miles driven by vehicle class.

This chapter summarizes the costs of each of these motor vehicle measures. We first provide a general summary of methods, then present our detailed methods and results for developing direct cost estimates for each of the major on-road motor vehicle provisions of the CAAA of 1990. We conclude with a summary of the overall motor vehicle provision costs.

SUMMARY OF APPROACH

Future year motor vehicle program costs are estimated for each of the control assumptions modeled in the emission projections analysis.[83] Motor vehicle control costs are calculated based on one of the following algorithms:

Cost per new vehicle -

Cost = projected vehicle sales * change in production cost ($/new vehicle)

[83] See E.H. Pechan & Associates, Inc. and Industrial Economics, Inc. *Emissions Projections for the Clean Air Act Second Section 812 Prospective Analysis*, (Pechan and IEC, 2009).

Cost per registered vehicle -

Cost = projected vehicle registrations * change in cost per vehicle ($/vehicle)

Cost per gallon of fuel consumed -

Cost = projected fuel consumption (gallons) * change in cost per mile (¢/gallon)

Projected vehicle sales, registration, and gallons of fuel consumed are calculated from the VMT projections used in the Section 812 emissions analysis and projected motor vehicle data from the *Annual Energy Outlook 2005* (DOE, 2005). The AEO contains information on transportation sector energy use by mode and type (i.e., vehicle type), vehicle sales by technology type, vehicle stock (registration) by technology type, and fuel economy by technology type. These *Annual Energy Outlook 2005* supplemental data are used as a consistent data source to convert the Section 812 VMT projections (that were also based on AEO2005 projected VMT) to new vehicle sales, registered vehicles, and fuel consumption projections.[84]

Unit control cost inputs were developed for all the control options modeled in the Section 812 emissions analysis. The cost data file indicates the unit cost (cents/gallon, $/registered vehicle, $/new vehicle sale) for each of the motor vehicle controls, with separate unit costs calculated for each vehicle type (e.g., light-duty gasoline vehicle (LDGV), light-duty gasoline truck 1 (LDGT1), LDGT2). These unit cost estimates of individual CAAA provisions were then multiplied by the AEO-based projections of fuel consumption, registrations, and new vehicle sales to estimate the national costs of on-road vehicle compliance with Title I and Title II in each analysis year (2000, 2010, and 2020). Since some control programs, such as vehicle inspection and maintenance (I/M) programs, or reformulated gasoline, apply only in specified counties, all cost calculations were made at the county/SCC level of detail.

A key assumption in our analysis is that both total vehicle sales and the composition of the on-road motor vehicle fleet are the same under both the *with-CAAA* and *without-CAAA* scenarios. Because the Amendments have increased the price of motor vehicles, however, it is likely that total vehicle sales without the Amendments in place would exceed vehicle sales under the *with-CAAA* scenario. Similarly, to the extent that the Amendments affected the relative prices of different vehicle types, the mix of vehicles sold in the absence of the Amendments may have been different than *with-CAAA* sales patterns.

[84] To estimate VMT in 2010 and 2020, the Project Team applied the VMT growth rate implied by the AEO 2005 VMT projections to 2000 VMT estimates previously developed by EPA. The Project Team then estimated vehicle sales for 2010 and 2020 by multiplying these VMT projections by the ratio of VMT (by vehicle type) to sales (by vehicle type), as derived from AEO 2005's VMT and vehicle sales projections.

LEARNING CURVE IMPACTS

The cost of implementing the on-road vehicle emissions requirements established under the Amendments are likely to decline as vehicle and fuel producers gain experience with the technologies used to comply with these requirements. To account for this "learning curve" effect, we incorporated learning curve cost adjustments into our analyses of on-road vehicle and fuel costs. For motor vehicles, we applied a learning rate of 13 percent to the variable costs associated with fitting motor vehicles with pollution control devices required as a result of the 1990 Amendments.[85] This value is the average of two estimates we identified in the learning curve literature. Baloff (1971) suggests that the number of labor hours per unit of output for automobile assembly declines by 16 percent with each doubling of cumulative production.[86] Similarly, Epple et al. (1991) estimate that per unit labor requirements for truck manufacturing decline by 10 percent with each doubling of cumulative truck production.[87] Although these labor-hour learning rates do not necessarily correspond to the learning rates for other variable costs in automobile and truck production, they likely represent an analog of learning for variable costs because labor makes up a significant portion of these costs. In addition, to the extent that installing emission controls is similar to installing other motor vehicle components, we believe the results of the Baloff and Epple et al. studies are applicable to motor vehicle pollution controls. Absent learning rate estimates specific to these devices, the Baloff and Epple et al. results represent the best information available on the learning effects associated with motor vehicle pollution controls. To minimize the potential for overestimating the cost reductions related to learning effects, we limited our learning curve cost adjustments to the first two doublings of cumulative production, consistent with EPA practice in many regulatory impact analyses for rules affecting on-road sources.

As indicated above, our learning curve adjustments apply only to the variable costs associated with installing emission controls on motor vehicles as a result of the Amendments. We do not make learning curve adjustments for any incremental operating costs that vehicle purchasers may incur due to these controls. In addition, although vehicle manufacturers (and their suppliers) incur significant fixed costs associated with research and development, emission certification, and other activities to ensure that their vehicles are CAAA compliant, we do not believe that learning would significantly reduce the costs of these activities.

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[85] This 13 percent learning rate differs from the 20 percent learning rate used in several recent regulatory impact analyses (RIAs) for rules affecting on-road sources. In those cases where we relied on unit cost data from these RIAs to develop the cost estimates presented in this chapter, we backed the application of the 20 percent learning rate out of these unit cost estimates before applying the 13 percent learning rate.

[86] Baloff (1971) as cited in Auerswald, Philip, Stuart Kauffman, José Lobo, and Karl Shell. "The production recipes approach to modeling technological innovation: An application to learning by doing," Journal of Economic Dynamics & Control, Vol. 24, 2000, 389-450.

[87] Epple, *et al.* (1991) as cited in Auerswald, *et al.*, *op. cit*.

To estimate the cumulative production of on-road vehicles during the 1990-2020, we used sales information from two sources. For the 2000-2020 period, we used sales estimates derived from the section 812 VMT projections, as outlined above. For 1990 through 1999, we used sales data, by vehicle type, from the Oak Ridge National Laboratory's (ORNL's) *Transportation Energy Data Book*.[88] Although we would ideally use sales estimates derived from a single source rather than two sources, the combined time series derived from the Project Team's 2000-2020 sales estimates and the ORNL estimates for 1990-1999 serves as a reasonable basis for assessing learning curve impacts for on-road sources. Exhibit 3-1 presents the Project Team's vehicle sales estimates, by vehicle type, for the years 1990, 2000, 2010, and 2020.

Our learning curve cost adjustments for CAAA-related on-road fuel requirements are consistent with advice that the Project Team received from the Council. Ideally, the Project Team's learning curve adjustments for on-road fuels would reflect the learning rate for the petroleum refining industry, as estimated in the learning curve literature, but we were unable to identify any studies in the literature specific to petroleum refining. Consistent with the Council's advice for addressing learning curve impacts in those sectors for which no learning curve data are available, we applied a default learning rate of 10 percent to on-road fuels.[89,90] Because the learning curve literature estimates a learning rate of approximately 20 percent for many technologies, our assumption of a 10 percent learning rate may be conservative.[91]

Similar to our analysis of on-road vehicle rules, we estimated the cumulative production of on-road fuels over time based on data from two sources. For 2000 through 2020, we rely on the fuel sales estimates derived from the VMT projections for the Second Prospective and fuel efficiency data from AEO 2005. For 1990-1999, we use fuel sales data from the Bureau of Transportation Statistics.[92]

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[88] U.S. Department of Energy, Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 25*, 2006.

[89] EPA, Science Advisory Board, Advisory Council for Clean Air Compliance Analysis, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", EPA-SAB-COUNCIL-ADV-07-002, Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.

[90] For sectors lacking learning curve data, the Council recommended a default learning rate of 5 to 10 percent. We use the high end of this range because it is more consistent with the learning curve literature than the low-end of the Council's suggested range.

[91] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, Vol 9, No. 2, 1984.

[92] Bureau of Transportation Statistics, *National Transportation Statistics 2007*, Table 4-5, 2007.

Exhibit 3-1. Summary of Motor Vehicle Sales by Vehicle Type (thousands of vehicles)

Vehicle Type	2000[b]	2010[b]	2020[b]
LDGV	11,362	8,407	7,368
LDGT1	4,390	6,093	7,535
LDGT2	1,466	2,031	2,510
HDGV	452	745	769
LDDV	35	10	9
LDDT	39	48	61
HDDV2B	130	206	207
HDDV Other	500	498	514
a. Sales estimates derived from U.S. Department of Energy, *Annual Energy Outlook 2005*, 2005.			

Unlike our analysis of CAAA motor vehicle and on-road fuel rules, we do not incorporate learning curve cost adjustments into our analysis of inspection and maintenance programs. Because most states either run centralized inspection centers themselves or regulate the fees charged by decentralized inspection centers, it is unclear whether the learning curve impacts for I&M programs would be significant.

MAJOR PROGRAMS AND ANALYSIS METHODS

Exhibit 3-2 lists the mobile source control programs and provisions modeled in this analysis. The derivation of the unit costs for each of these programs are discussed individually in this section.

1. LIGHT-DUTY VEHICLE EMISSION STANDARDS

a. Tier 1 Certification Standards and Evaporative Controls

The 1990 CAAA specified Tier 1 emission standards for light-duty vehicles and light-duty trucks. EPA promulgated these standards in 1991, and implementation of the new standards began being phased in with the 1994 model year. The Tier 1 tailpipe standards include NO_x, VOC, and CO limits for LDGVs and LDGTs. NO_x standards are also specified for heavy-duty gasoline and diesel vehicles.

Costs for tailpipe standards and evaporative controls are calculated based on a per-vehicle production cost applied to projected sales. Costs for tailpipe standards are delineated by pollutant and vehicle type, as shown in Exhibit 3-3. Based on EPA's 1991 analysis of the Tier 1 Standards, we estimate that, for light-duty gasoline vehicles, the Tier 1 HC controls cost approximately $36.23 per vehicle and that the Tier 1 NO_x controls cost approximately $113.37 per vehicle (56FR25724, 1991).[93] The initial cost increase is multiplied by projected sales to estimate the annual cost for each projection year.

[93] These and all of the other unit cost values presented in this chapter reflect the learning curve cost adjustments we describe above. In addition, they are expressed in year 1999 dollars. Because most of the cost studies used as sources in this chapter do not express costs in year 1999 dollars and do not employ learning curve assumptions consistent with ours, the unit cost values in these studies are often different than those presented in this chapter.

Exhibit 3-2. Applicability of Mobile Source Control Programs

Control Measure	Applicability
Phase II Reid Vapor Pressure (RVP) Limits	National (standard varies by region)
Tier 1 Tailpipe Standards (LDVs and LDTs)	National
Cold Temperature CO Standard	National
Onboard Diagnostic Systems	National
Tier 2 Tailpipe Standards	National
New Evaporative Emission Test Procedure	National
Onboard Vapor Recovery System	National
Heavy-Duty NO_x Standard 4.0 grams/brake horsepower-hour (g/bhp-hr), 2.0 g equivalent	National
Heavy-Duty Diesel Vehicle 2007 Emission Standards	National
Federal Reformulated Gasoline	Nine areas required to adopt this program under the CAA plus areas which have opted in to this program
California Reformulated Gasoline	State of California
Oxygenated Fuel	All CO nonattainment areas
California Reformulated Diesel	State of California
Diesel Fuel Sulfur Limits (1993)	49 States
Diesel Fuel Sulfur Limits (15 ppm)	National
Gasoline Fuel Sulfur Limits	National
Basic Inspection and Maintenance (I/M)	All moderate ozone nonattainment areas, moderate CO nonattainment areas, and areas with I/M in 1990
Low Enhanced I/M	All areas previously required to implement high enhanced I/M who are able to meet the 1990 CAA requirements for RFP and attainment without the more stringent high enhanced I/M program
High Enhanced I/M	Serious and above ozone nonattainment areas, in metropolitan areas in the OTR with populations above 100,000, and in serious CO nonattainment areas
National LEV	Nationally, except California (49 States)
California LEV	California
Clean Fuel Fleet Program	Atlanta, Metropolitan Washington, DC, Chicago-Gary-Lake County, Milwaukee-Racine, Denver-Boulder, Baton Rouge
Heavy-Duty Diesel Defeat Device Settlements	National

Exhibit 3-3. Production Costs for Tailpipe Standards (in 1999 Dollars)

Control	Cost
VOC Tailpipe Standards	\$36.23 LDGV
	\$32.66 LDGT1
	\$10.90 LDGT2
NO_x Tailpipe Standards	\$113.37 LDGV
	\$78.02 LDGT1
	\$42.18 LDGT2
	\$14.90 heavy-duty gasoline vehicle (HDGV)
	\$72.63 heavy-duty diesel vehicle (HDDV) (4.0 g/bhp-hr)
Cold Temperature CO Standards	\$17.94 LDGV (1999 dollars)
	\$30.01 LDGT1 (1999 dollars)
	\$45.96 LDGT2 (1999 dollars)

NOTE: The cost of \$32.66 for VOC tailpipe standards for LDGT1 is based on an incremental cost for LDGT1a and LDGT1b weighted by the sales fraction of each (57 percent LDGT1a, 43 percent LDGT1b).

Evaporative VOC emissions have been reduced in gasoline-powered cars as new Federal (and California) evaporative test procedures were implemented. Based on EPA's regulatory impact analysis for these procedures, we expect the initial retail price equivalent increase of about \$8.45 per vehicle to be largely offset by fuel savings. EPA estimated these fuel savings from evaporative VOC emissions control based on fuel price projections (excluding fuel taxes) from AEO 2005. Therefore, the net cost to the consumer is estimated to range from -\$4.88 to -\$4.01 for light-duty vehicles (LDVs), \$3.23 to \$3.78 for light-duty trucks (LDTs), and -\$25.47 to -\$23.18 for heavy-duty vehicles (HDVs) (EPA, 1993e). Cost components are shown in Exhibit 3-4. Annual costs are estimated using the net vehicle cost and the estimated sales in the projection year.

Exhibit 3-4. Evaporative Emissions Control Cost Summary (in 1999 Dollars)

Year	Vehicle Type	Consumer Cost	Net Fuel Savings	Net Cost
2000	LDV	\$8.45	\$12.93	-\$4.48
	LDT	\$11.57	\$8.08	\$3.48
	HDV	\$9.54	\$33.95	-\$24.41
2010	LDV	\$8.45	\$12.46	-\$4.01
	LDT	\$11.57	\$7.79	\$3.78
	HDV	\$9.54	\$32.71	-\$23.18
2020	LDV	\$8.45	\$13.34	-\$4.88
	LDT	\$11.57	\$8.33	\$3.23
	HDV	\$9.54	\$35.00	-\$25.47

b. Cold Temperature CO Standard

Section 202 of the CAA requires EPA to set cold temperature (20^{o}F) CO emission standards for LDVs and LDTs. The 1992 final rule established emission standards at 20^{o}F, applicable for a 50,000 mile useful life of: 10.0 grams per mile (g/mi) for LDV; 10.0 g/mi for LDTs with a 3,750 pounds or less loaded vehicle weight (LVW); and 12.5 g/mi for LDTs with a LVW greater than 3,750 pounds (57FR31888, 1992). These standards were phased-in over a period of three years, with 100 percent of 1996 sales required to meet these new standards.

The cost of the cold temperature CO standard to the consumer includes the cost to the manufacturer, plus the manufacturer's and dealer's overheads and profits, plus any increase or decrease in maintenance and fuel costs. Maintenance costs should not change as a result of the proposed rule, and fuel costs are expected to decrease (EPA, 1989). Based on EPA's regulatory impact analysis for the cold temperature CO standards, we estimate that the standards increase retail prices paid by consumers by $17.94 for LDVs, $30.01 for LDT1s, and $45.96 for LDT2s. While associated fuel economy improvements are expected to offset these initial cost increases, those benefits have not been included in this analysis because the RIA for the standards lacks sufficient data to estimate these impacts.

c. Onboard Vapor Recovery

Section 202 of the CAAA required EPA to regulate vehicle refueling emissions by requiring onboard emission control systems that would provide a minimum evaporative emission capture efficiency of 95 percent. In 1994, EPA issued a final rule implementing the control of vehicle refueling emissions through the use of vehicle-based systems. It applies to LDVs and LDTs. For LDVs, the requirements began in model year 1998, and phased-in over three model years. In the 1998 model year, 40 percent of each manufacturer's LDVs were required to meet the requirements. This increased to 80 percent in the 1999 model year, and rose to 100 percent in model years 2000 and later.

This requirement also applies to LDTs. For LDTs with a gross vehicle weight (GVW) rating of 0-6,000 pounds, the requirement began in model year 2001, and phased-in over three model years at the same rate as applied to LDVs. For LDTs with a GVW rating of 6,001-8,500 pounds, the requirement began with model year 2004, and phased-in over three model years at the same rate as LDVs. The rule does not apply to HDVs.

The EPA RIA for onboard vapor recovery includes cost estimates by vehicle type expressed in two terms: (1) expected increase in vehicle price (retail price equivalent), and (2) an average lifetime operating cost (net present value) (EPA, 1993f). Per vehicle costs for onboard vapor recovery systems used in this analysis are shown in Exhibit 3-5.

Exhibit 3-5. Per Vehicle Costs for Onboard Vapor Recovery Systems (in 1999 Dollars)

	2000			2010 and 2020		
	LDV	**LDT1**	**LDT2**	**LDV**	**LDT1**	**LDT2**
Increase in Vehicle Price (RPE)	$6.29	$7.34	$7.34	$6.13	$7.15	$7.15
Average Lifetime Operating Cost (NPV)	-$2.18	-$3.40	-$3.40	-$2.18	-$3.40	-$3.40
Total Cost	$4.12	$3.94	$3.94	$3.95	$3.75	$3.75

d. Onboard Diagnostic Systems

The onboard diagnostic (OBD) regulations (section 207 of Title II) require vehicle manufacturers to install diagnostic systems on LDVs and LDTs starting with the 1994 model year. From an analysis standpoint, OBD provides emission benefits in much the same way as emission inspection programs.

RIA-presented OBD costs were estimated largely from data collected from motor vehicle manufacturers. Based on the results of the RIA, we estimate hardware costs of approximately $55 per LDV (EPA, 1993d). Given the advances in software and computing technology since the completion of the RIA, however, this value is somewhat uncertain.

e. California Low Emission Vehicle Program

In September 1990, the California Air Resources Board (CARB) approved their original low-emission vehicle (LEV) and Clean Fuels regulations. These regulations established four new classes of light and medium-duty vehicles with increasingly stringent emission levels: transitional low emission vehicle (TLEV), LEV, ultra-low emission vehicle (ULEV), and zero-emission vehicle (ZEV). The regulations also established a decreasing fleet average standard for emissions of nonmethane organic gas (NMOG). Auto manufacturers can meet the fleet average NMOG standard using any combination of TLEVs, LEVs, ULEVs, and ZEVs they choose. However, CARB also included a ZEV requirement as part of the LEV regulations. ZEVs are defined as vehicles with no direct exhaust or evaporative emissions.

Various groups have estimated the costs of producing vehicles that meet the various LEV category standards. Differences between low and high estimates are about a factor of 10. While CARB's cost estimates are the lowest, they are also the most fully documented so they are used here to develop cost per ton estimates (CARB, 1996). Adjusting the CARB estimates for learning curve impacts, we estimate per vehicle costs of $66 for TLEVs, $104 for LEVs, and $123 for ULEVs. (These costs are relative to a Federal Tier 1 vehicle).

Although the overall LEV program was widely considered successful at reducing vehicle emissions and promoting advanced emission control technologies, the ZEV experiment has fallen short of expectations (NRC, 2006). This requirement was originally premised on the availability of electric vehicles by model year 1998. The ARB has revised its original ZEV mandate four times, resulting in a much different requirement now that no longer emphasizes electric vehicles. Because of the high cost of producing ZEVs, CARB currently assumes that vehicle manufacturers will produce large numbers of partial ZEVs (PZEVs) and advanced technology PZEVs in conjunction with a limited number of ZEVs to meet the state's current ZEV requirements. We estimate that the weighted average per vehicle costs of meeting the revised ZEV requirement will be $724 in 2010 and $644 in 2020 (based on NRC, 2006 and CARB, 2007).[94] Because manufacturers may use a variety of different technologies to meet the ZEV requirements, we do not apply learning curve adjustments to these cost values.

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[94] In the February 2007 Council review draft of the 812 Direct Cost Report, we used a low-end cost estimate for ZEVs as a proxy for the per vehicle costs associated with California's current ZEV requirements. In contract, for the current analysis, we estimate the costs of the California ZEV program based on unit cost values for ZEVs, PZEVs, and advanced technology ZEVs, consistent with the current structure of the program. Additional information on the treatment of California ZEV costs in the February 2007 draft is available in E.H. Pechan & Associates and Industrial Economics, Inc., *Direct Cost Estimates for the Clean Air Act Second 812 Prospective Analysis Draft Report*, February 2007.

f. National Low Emission Vehicle Program

Based on a series of agreements between EPA, the northeastern States, and the auto manufacturers, EPA's National LEV program went into effect in 1998. As a result of these agreements, new cars and light-duty trucks sold in the northeastern states starting in model year 1999 and nationally beginning in model year 2001 met emission limits more stringent than the Tier 1 emission limits and more stringent than EPA could mandate prior to 2004. CARB estimates of LEV program costs per vehicle (see above) are used as the basis for this analysis (CARB, 1996) because the National LEV requirements are comparable to those in California.

g. Tier 2 Vehicle Emission Standards

The 1990 CAAA required EPA to consider the need, feasibility, and cost-effectiveness of tailpipe emission standards stronger than the Tier 1 standards with implementation beginning in the 2004 model year. EPA determined that tighter tailpipe standards were necessary to reach the air quality goals set out in the CAAA. However, along with tighter tailpipe controls, EPA also indicated a need for significantly lower levels of sulfur in gasoline as high sulfur levels would impede the performance of catalytic converters that would be needed to meet the new emission standards. The Tier 2 Vehicle and Gasoline Sulfur regulations were finalized in 1999. This program requires all passenger cars, light trucks, and medium-duty passenger vehicles (which includes sport-utility-vehicles and passenger vans from 8,500 to 10,000 pounds gross vehicle weight rating) to meet an average emission standard of 0.07 grams of NOx per mile, beginning in the 2004 model year. The phase-in of the final emission standards is to be completed with the 2009 model year. (The fuel portion of this regulation is costed separately, as described in the fuels section of this chapter.)

EPA’s Tier 2 RIA shows costs to consumers of the Tier 2 emission standards including potential increases in vehicle purchase price and vehicle operating costs (EPA, 1999). All Tier 2 costs are incremental to the costs of meeting the NLEV emission standards. For the initial cost, or purchase price increase, EPA anticipates that manufacturers would pass along their incremental costs for Tier 2 vehicles, including a mark-up for overhead and profit, to vehicle purchasers. To account for manufacturer overhead and profit, manufacturer incremental variable costs are multiplied by a retail price equivalent (RPE) factor. The RPE factor, 1.26, is consistent with that applied for other emission standard cost analyses. Exhibit 3-6 presents the estimated increases in Tier 2 vehicle costs. The estimated costs shown in this table include the costs of needed evaporative system improvements (incremental to onboard vapor recovery systems) as well as the improved exhaust emissions control system. Similar to the other cost estimates presented in this chapter, these estimates show the expected effects of learning curves with increased cumulative production of affected vehicles.

Exhibit 3-6. Incremental Per Vehicle Costs to Consumers for Tier 2 Vehicles (in 1999 Dollars)

Production Year	LDV	LDT1	LDT2	LDT3	LDT4/MDPV[a]
1st year	$82.43	$73.80	$129.54	$248.92	$261.57
2010 and 2020, learning curve applied and fixed R&D costs expired[b]	$45.72	$41.12	$83.47	$173.56	$181.95

NOTES:

a. MDPV = medium-duty passenger vehicle.
b. R&D costs are assumed to be phased in prior to 2010.

SOURCE: EPA, 1999.

2. HEAVY-DUTY VEHICLE EMISSION STANDARDS

a. Heavy-Duty Vehicle 2 grams/brake horsepower-hour (g/bhp-hr) Equivalent NO_x Standard

In September 1997, EPA issued a final rule for a new combined emission standard for HC and NO_x from heavy-duty engines designed for HDTs and buses. Under this new mandate, manufacturers have the option of certifying their engines to one of two standards:

2.4 g/bhp-hr nonmethane hydrocarbons (NMHC) + NO_x

or

2.5 g/bhp-hr NMHC + NO_x with a limit of 0.5 g/bhp-hr on NMHC

EPA estimates of the cost of complying with 2004 model year emission standards begin with an estimate of the baseline package of emission control technology for meeting 1998 model year standards (EPA, 1997f). The baseline control technologies projected for engines meeting 1998 emission standards include technologies that contribute directly to lower NO_x emissions and a variety of engine improvements with only secondary benefits for NO_x control. The baseline scenario includes full utilization of electronic controls and unit injectors.

EPA's analysis anticipated a combination of primary technology upgrades for the 2004 model year. Achieving very low NO_x emissions was expected to require basic research on reducing in-cylinder NO_x and HC. Modifications to basic engine design features can improve intake air characteristics and distribution during combustion. Manufacturers were also expected to use upgraded electronics and advanced fuel injection techniques and hardware to modify various fuel injection parameters, including injection pressure, further rate shaping, and some split injection.

Exhibit 3-7 shows the derivation of the unit costs for the HDV 2.0 gram equivalent NO_x emission standards that are used in this Section 812 Second Prospective Analysis to estimate 2010 costs. The EPA regulatory analysis for this standard evaluates costs for the appropriate subcategories of heavy-duty diesel and gasoline vehicles, as control technologies and costs differ somewhat among light, medium, and heavy-duty trucks.

The 1994 model year sales of different size classes of diesel trucks are used to establish sales fractions, which are expected to be representative of future year sales as well. The year 2009 per vehicle cost increases for light, medium, and HDVs are multiplied by these sales fractions to compute a sales-weighted per vehicle cost increase. The resulting incremental NPV cost increases are $175 for HDDVs. HDGVs are not affected by these new emission standards.

Exhibit 3-7. Estimated Per Vehicle Costs of 2 Gram Equivalent Heavy-Duty Vehicle Emission Standard

Vehicle Type	1995 MY Sales	Sales Fractions	2010 and 2020 Per Vehicle Cost Increase (1999$)	Weighted Per Vehicle Cost Increase (1999$)
Light Heavy-Duty Diesel	280,000	41%	$137	
Medium Heavy-Duty Diesel	140,000	21%	$171	$175
Heavy Heavy-Duty Diesel	220,000	33%	$226	
Urban Buses	35,000	5%	$179	
Total	**675,000**	**100%**		

SOURCE: EPA, 1997f.

b. Heavy-Duty Vehicle 2007 Emission Standards

In January 2001, EPA finalized its 2007 Heavy-Duty Highway Rule. This rule sets new emission standards for heavy-duty highway engines as well as requiring significant reductions to the sulfur content of diesel fuel used in highway vehicles. The regulation sets the emission standards for new heavy-duty highway vehicles to 0.01 grams per brake-horsepower-hour (g/bhp-hr) for PM, 0.20 g/bhp-hr for NOx, and 0.14 g/bhp-hr for NMHC. These emission standards were phased in starting with the 2007 model year, with phase-in to be completed with the 2010 model year. These standards apply to both diesel and gasoline highway engines. (The costing of the sulfur requirements for diesel fuel is discussed separately in the fuels section of this chapter.)

The estimated per vehicle costs for the 2007 HDDV emission standards are based on the costs estimated by EPA for the RIA. The EPA analysis divides the affected heavy-duty vehicles into four service types, and estimates per vehicle costs using this breakdown of heavy-duty vehicles into service types, as shown in Exhibit 3-8.

Exhibit 3-8. Service Classes of Heavy-Duty Vehicles

Service Class	Vehicle Class	Gross Vehicle Weight Rating (lbs)
Light	2B-5	8,500-19,500
Medium	6-7	19,501-33,000
Heavy	8	33,001+
Urban Bus	--	--

Control cost estimates are developed for three primary elements:

1. Variable costs – including incremental hardware costs, assembly costs, and associated markups.

2. Fixed costs – these include tooling, research and development, and certification. The RIA for the Standards assumes that fixed costs such as research and development are amortized over the first five years of compliance.

3. Operating costs.

These cost estimates are summarized in Exhibit 3-9.

i. Technology/Hardware Costs for Diesel Vehicles and Engines

The EPA RIA estimates of hardware costs to meet the 2007 HDDV emission standards were based on EPA's belief that a small set of technologies integrated into a single emission control system would be the primary changes manufacturers would make to meet the 2007 model year standards. This integrated system was expected to include elements that include a NO_x adsorber catalyst, a catalyzed diesel particulate filter, a diesel oxidation catalyst, and 15 ppm sulfur diesel fuel to enable the emission control technologies to meet the required emission limits. In order to comply with the requirement to eliminate crankcase emissions from all heavy-duty diesel engines, EPA projected the introduction of closed crankcase filtration systems. Lean NO_x catalysts and compact SCR systems were not considered in the EPA analysis because they were not projected to be part of 2007 model year technology changes.

ii. Operating Costs

EPA's RIA for the HDDV emission standards evaluates operating cost changes associated with new standards and technologies introduced beginning in 2007. The operating cost components that EPA identified in its RIA included the following:

1. Diesel fuel cost increases.
2. Periodic replacement of a paper filter element.
3. Reduced maintenance costs.
4. Fuel economy changes.

The EPA RIA handles diesel fuel cost increases as a net present value cost over a vehicle lifetime. This section 812 analysis accounts for the cost of reducing the sulfur content of diesel fuel to 15 ppm as if the fuel regulation was separate from the emission standard, and the estimated cost is based on the cents per gallon retail price equivalent cost increase. This fuel cost is addressed in a separate section of this chapter.

EPA estimated that there would be no fuel economy changes in the vehicles affected by the HDDV emission standard, so the estimated cost of fuel economy changes was zero. Therefore, this operating cost analysis focuses on the cost of periodic replacement of a paper filter element, and reduced maintenance costs.

Exhibit 3-9. Summary of Near and Long Term Cost Estimates of HDE 2007 Emission Standards

Light Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	***2007 (Compliance Deadline)***	***2010***	***2020***
Fixed Cost	$128	$128	$0
Variable Cost	$1,858	$1,406	$1,406
Operating Cost	$86	$86	$81
TOTAL COST PER VEHICLE	$2,072	$1,620	$1,487

Medium Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$329	$329	$0
Variable Cost	$2,235	$1,692	$1,692
Operating Cost	$115	$115	$104
TOTAL COST PER VEHICLE	$2,679	$2,136	$1,796

Heavy Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$280	$280	$0
Variable Cost	$2,946	$2,230	$2,230
Operating Cost	$375	$375	$329
TOTAL COST PER VEHICLE	$3,601	$2,885	$2,559

Urban Buses (Diesel)
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$280	$280	$0
Variable Cost	$2,608	$1,974	$1,974
Operating Cost	$205	$205	$190
TOTAL COST PER VEHICLE	$3,093	$2,459	$2,164

An integral part of the system expected to be used to meet the HDDV emission standards is a paper filter designed to capture oil mist in the blow-by gases, coalesce this oil, and return this filtered oil to the oil sump. These filters are expected to require replacement on a fixed interval of 30,000 miles. The cost of these filters in 2007 has been estimated to be $10, $12, and $15 for light, medium, and heavy heavy-duty vehicles, respectively.

There are also expected to be maintenance costs for catalyzed diesel particulate filters (CDPFs). EPA estimated that for CDPF-equipped vehicles in 2007 and beyond, the maintenance interval will be 100,000 miles for light heavy-duty vehicles and 150,000 miles for medium and heavy heavy-duty vehicles. The cost of this service is the labor cost to remove and clean the filter. This removal and reinstallation should take one hour at $65 per hour.

Eliminating the need to replace the exhaust gas recirculation (EGR) valve on heavy heavy-duty diesel engines represents a cost savings to vehicles built with EGR systems of $115 in the year of the engine rebuild. These savings only apply to vehicles built after 2004, because vehicles built prior to this will have operated primarily on high sulfur diesel fuel. Savings for light and medium heavy-duty vehicles are not estimated because engines in these vehicle classes are less likely to be rebuilt. (For heavy engines, 95 percent reaching 560,000 miles are rebuilt – 72 percent of heavy heavy-duty vehicles reach 560,000 miles (year 7 of their life).) The cost savings of $115 in the year of the engine rebuild is modeled as a $51 savings in net present value in the year of the vehicle sale (EPA, 2000).

Other maintenance savings identified by EPA in the RIA are included in this analysis as a cost savings element associated with the low sulfur diesel and are discussed in that section of this chapter.

iii. Costs for Heavy-Duty Gasoline Vehicles

The 2007 Heavy Duty Highway Rule also includes new emission standards for heavy-duty gasoline vehicles, to be implemented beginning with the 2008 model year. EPA estimated the cost of meeting these new standards as shown in Exhibit 3-10 (EPA, 2000):

Exhibit 3-10. Incremental Costs to Meet the Heavy-Duty Gasoline Emission Standards (in 1999 Dollars)

Cost Element	*2008 (Compliance Deadline)*	*2010*	*2020*
Technology/Hardware Costs	$184	$147	$139
Fixed Costs	$14	$14	$0[a]
Total Incremental Cost	$198	$161	$139

Notes:
a. The fixed costs of this rule are expected to be incurred only between 2008 and 2010. U.S. EPA, "Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements," December 2000, EPA420-R-00-026.

3. FUELS

a. Gasoline Volatility Limits

During the CAAA debate, EPA adopted regulations to restrict the Reid vapor pressure (RVP) of gasoline during the ozone season. This was accomplished in two phases. Phase I of the RVP limits was implemented before 1990. Phase II RVP limits affected motor vehicle gasoline beginning in 1991, so its emission reductions and costs are accounted for in this analysis. The Phase II volatility program establishes limits for fuel RVP in all areas of the United States (56FR64704). The RVP limit depends on the State, month, and ozone classification. From May through September, gasoline sold in northern States (both attainment and nonattainment areas) is limited to 9.0 psi under the rule. In the warmer southern States, RVP is limited to 7.8 psi in nonattainment areas and 9.0 psi in attainment areas. The estimated cost of lowering the RVP in Class C areas from 10.5 to

9.0 is 0.194 cents per gallon in the five month ozone season (adapted from Wysor, 1988). This unit cost estimate is the same as that used in the First Prospective cost analysis, adjusted for learning curve impacts.

b. Federal Reformulated Gasoline

Under the CAAA, nine cities with the worst smog pollution, classified as severe or extreme ozone nonattainment areas, were required to use reformulated gasoline (RFG). In addition, areas reclassified to severe or extreme nonattainment status are required to begin using reformulated gasoline. Moderate and marginal nonattainment areas are permitted to opt-in to the RFG program. Implementation of Phase I of the RFG program began in 1995 and implementation of Phase II began in 2000. EPA issued a final rule for Phase II RFG emission standards on February 16, 1994 (59FR7716, 1994).

Reformulated gasoline costs are based on an incremental refiner's cost increase and a monetized fuel economy disbenefit of 4.1 to 4.2 cents per gallon for Phase I and 5.2 to 5.5 cents per gallon for Phase II relative to conventional gasoline, depending on the target year (adapted from EPA, 1993g). The Phase I benefits of RFG are primarily due to the lower oxygenate (with its effect on aromatic content) requirement of RFG and the reduction of fuel benzene content and will occur year round. Thus, the costs associated with the Phase I RFG benefits are applied year-round. Phase II reformulated gasoline costs are applied for five months of the year (May through September), because fuel modifications only occur in the summer, including a lower RVP requirement and a lower sulfur content requirement. The Phase II costs are applied in addition to the Phase I costs in RFG areas.

EPA estimated that RVP control down to 6.7 psi achieves virtually all of the VOC emission reductions that are achievable at less than $5,000 per incremental ton of VOC reduced.[95] Sulfur can be reduced to a level of approximately 250 ppm at an incremental cost effectiveness of less than $5,000 per ton, gaining an additional 0.6 percent VOC reduction (on average) of 26.1 percent. RVP could also be further reduced to 6.5 psi, the lower limit for drivability purposes, to obtain an additional 1.1 percent reduction. It was also found that changes in fuel parameters other than RVP have only a small effect on VOC emissions, and can be very costly. Achieving another one percent (or less) reduction in VOC emissions would cost more than $10,000 per ton.

EPA evaluated the cost effectiveness of NO_x control using the same costs that were used in establishing the standard for VOC control. Analyses indicated that sulfur is the only fuel parameter that results in significant NO_x reductions at reasonable cost. Changes in fuel parameters other than sulfur have only a small effect on NO_x emissions, at significantly higher costs, with the possible exception of olefin control (which would increase VOC at the same time it reduced NO_x). A NO_x reduction of about 6.8 percent could be achieved with sulfur control down to about 138 ppm at a reasonable cost, whether compared on the basis of the last increment of reduction (5.8 percent to 6.8

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[95] "Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline," Federal Register, Volume 59, February 16, 1994.

percent NO_x) or the overall cost incremental to Phase I reformulated gasoline reductions.[96]

The statute set the minimum Phase II standard for toxics reduction at 25 percent, although EPA has the authority to reduce this to no lower than 20 percent based on technological feasibility considering cost. EPA proposed both levels of reductions as options. However, it was found that, for certain refiners with higher baseline levels of various parameters, compliance with the VOC and NO_x standards will not automatically lead to compliance with a 25 percent toxics standard. EPA set the toxics standard at 20 percent in both VOC control regions because the cost effectiveness of toxics control beyond a 20 percent reduction is questionable.

c. California Reformulated Gasoline

The California Phase 1 reformulated gasoline standards were implemented January 1, 1992. Phase 1 specifications mandate limits on RVP, use of deposit control additives, and the elimination of leaded gasoline. Each of these directives results in higher per-gallon costs of fuels to consumers. The CARB has estimated the costs to the consumer of each of these three proposals (CARB, 1990).

Disregarding learning curve impacts, the RVP reduction will cost 0.58 to 1.04 cents per gallon if it is assumed that costs are only incurred during the RVP season, and 0.41 to 0.70 cents per gallon if costs are spread throughout the year. Deposit control additives could range from 0.12 to 1.16 cents per gallon, with a typical cost range of 0.35 to 0.58 cents per gallon. The elimination of lead is estimated to cost 0 to 0.46 cents per gallon.

Based on the CARB documentation, the total cost of California Phase 1 reformulated gasoline is estimated to be no greater than 1.74 cents per gallon, not accounting for learning curve impacts. This is based on summing the maximum cost for RVP incurred annually (0.70 cents per gallon), the maximum cost for the typical range of deposit control additives (0.58 cents), and the maximum cost for lead elimination (0.46 cents). There is no indication that additional costs would be incurred due to a fuel economy penalty. Adjusting this estimate for learning curve impacts, we estimate that the cost of the California Phase 1 program will is approximately 1.4 cents per gallon.

California has also adopted regulations for Phase 2 reformulated gasoline (CARB, 1991); Phase 2 costs are significantly higher than those for the Phase 1 regulations that took effect in 1992. Phase 2 represents an attempt to generate maximum reductions in criteria and toxic pollutants, and in the mass and reactivity of emissions from gasoline fueled vehicles. Phase 2 gasoline must meet specified standards for sulfur content, benzene content, aromatic hydrocarbon content, olefin content, RVP, oxygen content, 90 percent distillation temperature (T90), and 50 percent distillation temperature (T50). Phase 2 standards began in California on January 1, 1996.

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[96] *Ibid.*

Adjusting CARB estimates for inflation, Phase 2 California reformulated gasoline will cost refineries an additional 5.5 to 16.6 cents per gallon to produce (CARB, 1991). This is an estimate of the increase in after-tax expenses for a refiner who makes the "average gallon" of reformulated gasoline. After adjusting for learning curve impacts, an average value of 9.4 cents per gallon was used to estimate the cost of this control option. California reformulated gasoline costs are applied throughout the year. A 2.3 to 2.5 cent per gallon fuel economy penalty that varies by target year is also applied when estimating Phase II California reformulated gasoline costs. This fuel economy penalty is based on AEO 2005 gasoline price projections for the Pacific Census Division.

d. Oxygenated Fuels

Oxygenated fuel costs are based on an incremental cost of 3.4 cents per gallon (adapted from EPA, 1993g). This was converted to a cost per mile based on the projected fuel economy. Oxygenated fuel costs are attributed to CO and are calculated based on the number of months in which oxygenated fuels are used in the area. Oxygenated fuel benefits and costs are applied in all CO nonattainment areas, during the months in which it is required.

e. California Reformulated Diesel

California's vehicular diesel fuel regulation established a 500 ppm sulfur limit and required a reduction of the aromatic content of the fuel from 30 to 10 percent. Small refineries may produce fuels with higher aromatic contents (up to 20 percent) if equivalent emissions can be demonstrated through engine testing.

Reformulated diesel costing is based on an incremental per gallon increase of 5.3 cents (adapted from Green, 1994). This cost is converted to a cost per mile for each diesel-fueled vehicle, based on the projected fuel economy.

f. Diesel Fuel Sulfur Limits

The CAAA, in Section 217, required that effective October 1, 1993, motor vehicle diesel fuel would be limited to a sulfur concentration of 0.05 percent (by weight) and a cetane index minimum of 40. The incremental cost of low sulfur diesel fuel meeting these restrictions relative to conventional diesel fuel, is estimated by Bonner & Moore to be 1.8 to 2.3 cents per gallon (EPA, 1990). Adjusting for inflation and accounting for learning curve impacts, an average value of 2.0 cents per gallon is used in this analysis. No fuel economy penalty is applied for low sulfur diesel fuel because the energy content is estimated to be less than one percent lower than that of conventional fuel.

g. Tier 2 Gasoline Sulfur Limits

The Tier 2 gasoline sulfur control program required that most refiners and importers meet a corporate average gasoline sulfur standard of 120 ppm and a cap of 300 ppm beginning in 2004. In 2006, the cap was reduced to 80 ppm and most individual refineries were required to produce gasoline averaging no more than 30 ppm sulfur.

Estimated Per Gallon Cost of Desulfuring Gasoline to 30 ppm

Year	Cost in Cents per Gallon
2010	1.70
2020	1.30

NOTE: 7 percent return on investment, before taxes, 1997 dollars. Estimates do not reflect learning curve impacts.

EPA estimated the per-gallon cost by Petroleum Administration for Defense District (PADD) based on an average refinery for each PADD using different amortization premises. In Exhibit 3-11, costs are shown for amortizing capital at a 7 percent rate of return on investment (ROI) before taxes, which is to represent the cost to society.[97] The range of costs presented in Exhibit 3-11 shows how varying the ROI before taxes from 6 to 10 percent affects the per-gallon cost estimates. This table presents costs in 2008 after program costs have stabilized. Adjusting the values in the table for inflation and accounting for learning curve impacts, we estimate costs of 1.4 cents per gallon (in 1999$) in 2010 and 1.1 cents per gallon in 2020.

Exhibit 3-11. Post Phase-in Cost (Year 2008) of Desulfurizing Gasoline to 30 ppm Based on Different Capital Amortization Rates (1997$)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	National Average
Societal Cost (7% ROI before Taxes)	2.00	1.65	1.52	2.32	2.63	1.70
Capital Payback (6% ROI, after Taxes)	2.04	1.69	1.54	2.41	2.67	1.73
Capital Payback (10% ROI, after Taxes)	2.22	1.85	1.65	2.76	2.87	1.87

h. Diesel Sulfur Standards

As discussed above, the 2007 Heavy-Duty Highway Rule limits the sulfur content of highway diesel fuel sold beginning in 2006. The diesel sulfur limit specified by this rule is 15 ppm. The total cost of 15 ppm sulfur diesel is the sum of refinery desulfurization costs, addition of a lubricity additive, and increases in distribution costs. Disregarding learning curve impacts, refinery desulfurization and distribution costs average 3.3 cents per gallon and 1.1 cents per gallon, respectively, during the initial years of the program. Lubricity additives average approximately 0.2 cents per gallon. Thus, EPA estimates the total cost of diesel fuel meeting the 15 ppm cap to be 4.5 cents per gallon during the initial years of the program. This cost will increase to 5 cents per gallon after 2010.

Low sulfur diesel fuel yields benefits in the form of reduced sulfur inhibited corrosion of vehicle components and slower acidification of engine lubricating oil, leading to longer maintenance intervals and lower maintenance costs. These benefits have applied to new

[97] This 7 percent rate is inconsistent with the 5 percent discount rate selected for the Second Prospective, but insufficient data were presented in EPA's RIA for the Tier 2 standards to adjust the fuel savings estimate to reflect a 5 percent discount rate.

vehicles and to the existing heavy-duty vehicle fleet since 2006 when the fuel was introduced. Based on information from engine manufacturers and others, EPA estimated that engine oil change intervals will be extended by 10 percent due to the use of low sulfur diesel fuel. The exhaust system components – exhaust pipes and mufflers – typically fail because of corrosion of the pipe walls. Corrosion rates are increased by sulfuric acid present in diesel exhaust, which can condense on exhaust system walls. EPA estimated that the reduction in sulfuric acid-induced corrosion may extend exhaust system component life by 5 percent.

These savings due to the use of low sulfur diesel fuel can be expressed as a savings in cents per gallon of low sulfur diesel fuel. These savings are delineated in Exhibit 3-12.

Exhibit 3-12. Cost Savings for Diesel Sulfur Standards (cents/gallon)

	Cost Savings (cents/gallon)		
	Light HDDVs	**Medium HDDVs**	**Heavy HDDVs**
Extend Oil Change Intervals	1.34	0.99	0.60
Extend Exhaust Replacement Interval	0.14	0.10	0.04

Adjusting for learning effects, we estimate that the standards will, on average, increase diesel fuel costs by 3 cents per gallon in 2010 and 3.4 cents per gallon in 2020.

4. VEHICLE EMISSIONS INSPECTION PROGRAMS

Vehicle I/M programs are designed to ensure that emission controls continue to operate properly over a vehicle's lifespan. Vehicle I/M programs were first introduced in the late 1970s, enabled by a provision in the 1977 Clean Air Amendments specifying that approval of State Implementation Plans would only be granted when "to the extent necessary and practicable" there will be "periodic inspection and testing of motor vehicles to enforce compliance with applicable emission standards."[98] The States responded by establishing programs that differed in detail but typically involved an "idle" test that was performed under no-load conditions by inserting a probe in the vehicle's tailpipe. Some programs also had visual tests to determine whether emission controls had been tampered with. Most programs also had "waiver" provisions that put an upper limit on what motorists had to spend to repair their vehicles. Once this amount had been expended, owners were excused from further expense regardless of the vehicle's emissions.

These State programs fell into two categories: "centralized" ("test-only") programs, where inspections are conducted at a relatively small number of large specialized facilities operated by the State or a State contractor; and "decentralized" ("test-and-repair") programs, where inspections occur at any of a large number of privately-owned repair shops certified to conduct emission inspections. In decentralized programs, I/M programs were often added onto existing safety inspection programs.

[98] 1977 Clean Air Act Amendments, Title 1, section 110, 2(g).

Because initial evaluations indicated that these programs were not as effective at reducing emissions as had been hoped, Congress established much more stringent requirements for State I/M programs in the CAAA. Congress directed the EPA to determine where State programs had failed and to develop program guidelines for avoiding or overcoming these failures. The EPA has developed a series of regulations, first promulgated in 1992,[99] that specify I/M program characteristics and the emission reduction credits these characteristics would receive. The MOBILE program is EPA's official tool for modeling the emission reduction effects of I/M programs.

To estimate the costs of I/M programs for the current analysis, the Project Team developed two sets of estimates: costs per tested vehicle, which differ by program design, and the number of vehicles tested. Although some I/M programs were in place before the 1990 CAAA, all of the costs associated with these programs have been attributed to the CAAA in this study because many programs were substantially changed after the 1990 CAAA and EPA's 1992 I/M program regulations.

a. Per Tested Vehicle Costs

The I/M program per vehicle cost estimates included in the First Prospective analysis were based on an EPA report from the early 1990s that focused on centralized, IM240-based programs (EPA, 1992). The actual adopted programs have been much more diverse than envisioned by the EPA report. Therefore, the Project Team conducted an analysis of I/M costs based on recent information from actual programs. This analysis determined average per tested vehicle cost estimates for eight model I/M programs.

The eight model I/M programs were developed from recent information describing program characteristics. The majority of this information was obtained from two references (ETI, 2006 and ILEPA, 2005). The Project Team also visited the websites for States' I/M programs to obtain additional information and/or confirm the accuracy of the information reported in these references. Exhibit 3-13 summarizes the eight model I/M programs.

Exhibit 3-13. Model I/M Programs Used in Estimating I/M Program Costs

Program Type	Test Type	Frequency
Centralized	Idle	Annual
Centralized	Idle	Biennial
Decentralized	Idle	Annual
Decentralized	Idle	Biennial
Centralized	Dynamometer	Annual
Centralized	Dynamometer	Biennial
Decentralized	Dynamometer	Annual
Decentralized	Dynamometer	Biennial

Note that for 2010, test type refers to the test performed on pre-1996 model year vehicles (1996+ model year vehicles are tested using OBD test), and that for 2020, all model programs are assumed to test vehicles using the OBD test exclusively.

[99] "Inspection /Maintenance Program Requirements: Final Rule," 57 Fed Reg. No. 215, November 5, 1992.

Below we describe our approach for estimating each component of I/M costs per vehicle. These include the following: inspection fees, vehicle operating expense, costs associated with vehicle owners' time, and vehicle repair costs. After describing each of these costs, we then summarize total I/M costs per vehicle.

Inspection Fees

The Project Team first analyzed the available information to identify average inspection fees charged and how these fees appeared to correlate with certain I/M program parameters.[100] Based on a review of the two aforementioned references and State websites, the Project Team identified that average fees differed for centralized versus decentralized and annual versus biennial programs. The data did not indicate fee differences between idle-based and dynamometer-based (i.e., Acceleration Simulation Mode [ASM] or IM240) programs.[101] Using information from 2005, the Project Team computed the following average inspection fees (all costs cited throughout this section are in 2005 dollars unless otherwise noted):

- Centralized annual inspections = $11;
- Centralized biennial inspections = $19;
- Decentralized annual inspections = $26; and
- Decentralized biennial inspections = $35.

As described in the following sections, the Project Team also developed estimates for (1) vehicle operating expense associated with traveling to/from inspection station; (2) opportunity cost related to owner's time spent driving to/from station and while waiting for inspection; and (3) average vehicle repair costs (net of fuel savings associated with repair). The following describes how these costs were estimated.

Vehicle Operating Expense

A review of I/M program information indicated that centralized I/M programs, which by their nature have fewer inspection stations than decentralized I/M programs, require vehicle owners to drive farther to obtain an inspection. Based on available information,[102] the Project Team assumed the following travel distances:

- Centralized programs − 10 miles (5 miles each direction); and
- Decentralized programs − 6 miles (3 miles each direction).

To estimate vehicle operating costs per mile (43.2 cents), the Internal Revenue Service's 2005 allowable mileage rate for deducting automobile operating costs (43.2 cents per

[100] Based on more detailed reviews of cost information for a sample of I/M programs, the Project Team assumed that these fees cover not only the capital and operating costs incurred by inspection stations, but also each State's program administration and enforcement costs.

[101] IM240 is a test that involves running vehicles through a 240 second test cycle on a dynamometer under load.

[102] An analysis performed of Arizona's centralized I/M program used an average one-way travel distance of 4.5 miles (Harrington and McConnell, 1999).

mile) were used.[103] By combining the mileage and the operating cost per mile estimates, the Project Team estimated the following operating costs per tested vehicle: centralized I/M programs = $4.32, and decentralized I/M programs = $2.59.

Costs Associated with Vehicle Owner's Time

Different I/M program designs result in varying amounts of required time to obtain an inspection. Total time includes the time spent traveling to/from the inspection station, the time spent waiting while the test is performed, and the time spent waiting before/after the test is performed. Based on the available information, the Project Team assumed the following average times by I/M program type:

- Decentralized idle-based I/M = 25 minutes;
- Decentralized dynamometer-based I/M = 30 minutes;[104,105]
- Centralized idle-based I/M = 55 minutes; and
- Centralized dynamometer-based I/M = 60 minutes.

These estimates were derived from the following information sources and assumptions. For *centralized dynamometer-based I/M* programs, the Project Team assumed an average 45 minutes for the travel time to/from the station and for the wait before/after test is performed based on a report citing estimates ranging from 45 to 60 minutes for centralized programs (NRC, 2001). An estimate of 15 minutes was used to reflect the time spent performing a dynamometer-based test based on a 12 to 15 minute dynamometer test estimate reported in a recent report (MADEP, 2002). For *centralized idle-based I/M* programs, the 15 minute test time to 10 minutes was reduced to reflect the fact that the idle test is simpler/quicker to perform than dynamometer tests. Further support for this estimate comes from real-time data indicating the average time spent in conducting an OBD and gas cap test was 6 minutes and 45 seconds (PADEP, 2004).[106] While idle tests take less time to perform than dynamometer tests, they should take somewhat more time than OBD tests.

In Appendix B, we describe how inspection time estimates were developed to support derivation of average per vehicle costs for decentralized OBD-only I/M programs. To estimate the average total time spent by vehicle owners in obtaining idle and dynamometer-based decentralized tests, adjustments were made to the total 20 minute

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[103] This value represents the average of the IRS mileage of 40.5 cents per mile for the first eight months of the year and 48.5 cents per mile for the final four months.

[104] Dynamometer-based I/M programs refer to ASM and IM240 test I/M programs.

[105] In some cases, owners of vehicles requiring decentralized idle-based I/M or decentralized dynamometer-based I/M may leave their vehicles at an auto repair shop for this I/M when they go in for routine maintenance (e.g., an oil change or tune-up). In such cases, there may be no incremental waiting time for the vehicle owner (e.g., if the owner is at work while the vehicle is at the repair shop). To the extent that this occurs, we may overestimate the time losses experienced by vehicle owners.

[106] This estimate excludes the time bringing the vehicle into the test bay and completing/affixing the inspection sticker, but these activities would increase this estimate only marginally.

estimate developed for a decentralized OBD-only program. For *decentralized dynamometer-based I/M* programs, an additional 10 minutes for this test was assumed based on time estimates reported in a Massachusetts report (MADEP, 2002). For *decentralized idle-based I/M* programs, the Project Team assumed an additional 5 minutes for an idle test relative to an OBD test. This time differential is consistent with the assumptions used for the centralized program in that idle tests are assumed to take 5 minutes less to perform than dynamometer tests.

To estimate the value to the vehicle owner of the time spent acquiring an inspection, the Project Team used an estimate of the opportunity cost of time derived from wage rates. Although it is not clear that time spent acquiring an inspection will in all cases represent lost time at work, we estimated the value of lost time in this case using the national average pre-tax wage rate, plus an estimate of average prorated per-hour benefits. Our estimate of this value is $26.06 per hour, reflecting wages or salaries, benefits, and taxes.[107]

The Project Team concluded that use of pre-tax wage rate plus benefits is a reasonable approximation of the social cost of lost time in the context of inspection programs for two reasons. First, using pretax wages plus benefits to value lost market work time is consistent with a recent peer-reviewed EPA guidance document on the value of lost time (EPA, 2005) and DOT guidance for lost travel time (DOT, 1997 and 2003). Second, our approach largely balances unquantifiable factors that might lead to overestimates with those that might lead to underestimates of this value. For example, the value of lost market work time may be argued to potentially overestimate the lost time from inspection programs, because in at least some cases, the lost time is more accurately characterized as lost non-market work time or leisure time, which is typically valued at a lower rate. At the same time, however, some research suggests that there is an additional disamenity factor associated with time spent waiting (e.g., DOT, 1997 and 2003), which may or may not apply in the context of vehicle inspections.

Vehicle Repair Cost (Net of Fuel Savings)

Vehicle repair costs associated with I/M programs are a function of repair incidence (inspection failure rates) and the average cost of repair. For this analysis, The Project Team estimates an average $300 spent for repairs for vehicles failing dynamometer and OBD-based tests. This $300 per repaired vehicle assumption is based on data from Wisconsin (estimated average repair cost for first retest pass of $304 in 2003 and $306 in 2004 for all tests, where IM240 and OBD-tests comprise more than 98 percent of the I/M tests performed), a 2005 Arizona study that noted average repair costs of "approximately $300" for vehicles undergoing dynamometer/OBD tests, and an EPA study that estimates

[107] This value is derived from the Department of Labor, Bureau of Labor Statistics (BLS) Employer Costs for Employee Compensation, part of the 2006 National Compensation Survey, and reflects the average of quarterly BLS estimates for 2005 (BLS, 2006). The stated value includes wages, salaries, and employee benefits for all nonfarm private and state and local government workers. The full employer costs for benefits includes: insurance benefits - life, health, and disability; legally required benefits, including Social Security, Medicare, unemployment insurance, and workers' compensation; paid leave benefits (vacations, holidays, sick leave, and other leave); and retirement and savings benefits per hour worked.

an average OBD repair cost between $210 and $481 for vehicles repaired with 100,000+ miles (WIDOT, 2006; ERG, 2005; and Gardetto, 2002).[108]

Because they use different approaches for identifying failing vehicles, different inspection protocols can be expected to yield different rates of inspection failure. Although failure rates will differ depending on detailed program parameters (e.g., model year exemptions, emission cutpoints), it was not feasible to develop model cost programs to account for all such parameters. Based on information from available I/M program studies, the Project Team assumed the following average inspection failure rates:[109]

- Annual idle tests – 7 percent;
- Biennial idle tests – 9.25 percent;
- Annual dynamometer tests – 14 percent; and
- Biennial dynamometer tests – 18.5 percent.

The estimated failure rate for an annual dynamometer-based I/M program was based on Wisconsin data indicating an approximate 14 percent failure rate in both 2003 and 2004 from the more than 700,000 vehicles tested in each year (as noted earlier, more than 98 percent of vehicles tested in Wisconsin undergo either an IM240 or OBD test).[110] Further support for the 14 percent estimate comes from a detailed study of 1995/1996 data from Arizona's annual IM240-based program, which indicated a 13.6 percent inspection failure rate (Ando, McConnell, and Harrington, 1999).[111]

The annual idle test failure rate was estimated at one-half the dynamometer test failure rate based on studies in two States (Wisconsin and New York) that provided IM240 and idle test failure rates for 2003 and 2004 (WIDOT, 2006 and NYSDEC, 2004 and 2005).

The biennial test failure rate for dynamometer-based programs was estimated at 18.5 percent based on Arizona IM240 data indicating that about 15 percent of vehicles will fail for the first time within 24 months of passing an original test and that 40 percent of previously failed/fixed vehicles will fail in their next test within 24 months – i.e., (0.15 x 0.86) + (0.4 x 0.14) = 0.185 (Wenzel and Brown, 2001). In keeping with the annual idle test failure rate assumption, the biennial idle test failure rate (9.25 percent) was estimated at one-half the biennial dynamometer test rate.

Current I/M programs are generally a mix of OBD testing for 1996+ model year vehicles and idle/dynamometer testing for older vehicles. As noted above, failure rates for idle tested vehicles are assumed to be half those of vehicles tested using dynamometer/OBD-

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108 EPA states with 95 percent statistical confidence that repair costs are within this range for OBD failures defined by illumination of the malfunctioning indicator light.

109 These failure rates represent averages across all affected vehicles. Although failure rates may vary by vehicle model year, the available data were not sufficient to estimate failure rates by model year.

110 An EPA review of Wisconsin data comparing IM240 and OBD failure rates concluded that "…the number of vehicles failing each test was roughly the same when using final cutpoints for all three pollutants" (EPA, 2002).

111 This study found that 135,734 of 995,904 tested vehicles failed in 1995/1996.

based tests. To properly estimate total repair costs in such programs, it is necessary to estimate, for each analysis year, the proportion of total vehicles that are required to obtain idle-based tests and the proportion required to obtain OBD-based tests. The OBD-based test proportion is zero in 2000 because OBD-based tests were not yet required by EPA in this year.[112] A value of zero was used for idle-based tests in 2020 because MOBILE6.2 indicates that there will be virtually no pre-1996 model year light-duty gasoline vehicles existing in 2020. Therefore, we assume that 100 percent of affected vehicles would be subject to an OBD-based test in 2020. To calculate 2010 repair costs for programs with current idle testing requirements, the Project Team assumed that 13 percent of all tested vehicles would be pre-1996 model year vintage, and, therefore, subject to an idle-based test (the other 87 percent would be subject to an OBD-based test). The 13 percent value represents the proportion of total light-duty gasoline vehicles in 2010 that are pre-1996 model year vintage in MOBILE6.2.

The EPA has developed estimates of fuel economy increases associated with repairs performed in response to I/M program inspections since at least 1992.[113] Based on findings from the most extensive in-use study identified, the Project Team assumed an average improvement of 0.75 miles per gallon for each repair (NRC, 2001). To estimate the per vehicle value of this improvement, the Project Team utilized the aforementioned inspection failure rates and proportions of total vehicles undergoing each type of test in each year, and the following assumptions: average of 12,000 miles of travel per year, baseline average fuel efficiency of 20 miles per gallon, and gasoline price projections from the U.S. Department of Energy's *Annual Energy Outlook 2005*.

Summary of I/M Cost Estimates

Exhibit 3-14 presents the estimated year 2000 costs per vehicle for each individual cost component (in year 2005 dollars). Exhibit 3-15 displays inspection (inspection fee, plus vehicle operating expense, plus vehicle owner's time cost), vehicle repair (net of fuel savings), and total cost estimates in 2005 dollars. The 2005 year total costs were adjusted to 1999 prices using 1999 and 2005 GDP implicit price deflators. Exhibit 3-16 displays the final per vehicle tested cost estimates in 1999 dollars. When the total I/M costs shown in Exhibit 3-16 were multiplied by the number of registered vehicles, all biennial program costs were first divided by 2, since vehicles in biennial inspection programs only incur these costs every other year.

[112] Note that the Project Team did not estimate repair costs for the vehicles that undergo an anti-tampering (ATP)/gas cap check in this year because of the very small assumed failure rate (data for New York indicates an 0.2 percent failure rate for an ATP/gas cap check).

[113] See EPA, 1992 as an example of one of EPA's first analyses of I/M program costs following the enactment of the Amendments.

Exhibit 3-14. Estimated Year 2000 Costs per Vehicle Tested by I/M Program Type and Detailed Cost Component (in 2005 Dollars)

	Costs of Inspection					Repair Cost/Fuel Savings			
Model Program	**Inspection Fee**	**Travel, Wait, & Inspection Time (mins)**	**Cost of Motorist Time**	**Vehicle Operating Expense**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Fuel Economy Savings**	**Total Repair Cost Net of Fuel Savings**	**Total Cost**
Centralized Annual Idle	$11.00	55	$23.89	$4.32	$39.21	$21.00	-$2.04	$18.96	$58.17
Centralized Annual Dynamometer	$11.00	60	$26.06	$4.32	$41.38	$42.00	-$4.08	$37.92	$79.30
Decentralized Annual Idle	$26.00	25	$10.86	$2.59	$39.45	$21.00	-$2.04	$18.96	$58.41
Decentralized Annual Dynamometer	$26.00	30	$13.03	$2.59	$41.62	$42.00	-$4.08	$37.92	$79.54
Centralized Biennial Idle	$19.00	55	$23.89	$4.32	$47.21	$27.75	-$3.00	$24.75	$71.95
Centralized Biennial Dynamometer	$19.00	60	$26.06	$4.32	$49.38	$55.50	-$6.01	$49.49	$98.87
Decentralized Biennial Idle	$35.00	25	$10.86	$2.59	$48.45	$27.75	-$3.00	$24.75	$73.20
Decentralized Biennial Dynamometer	$35.00	30	$13.03	$2.59	$50.62	$55.50	-$6.01	$49.49	$100.11

Exhibit 3-15. Estimated Costs per Vehicle Tested by I/M Program Type, Major Cost Component, and Year (in 2005 Dollars)

	2000			2010			2020		
Model I/M Program	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**
Centralized Annual Idle	$39.21	$18.96	$58.17	$39.21	$35.49	$74.70	$39.21	$37.92	$77.12
Centralized Annual Dynamometer	$41.38	$37.92	$79.30	$41.38	$37.96	$79.34	$41.38	$37.60	$78.98
Decentralized Annual Idle	$39.45	$18.96	$58.41	$39.45	$35.49	$74.94	$39.45	$37.92	$77.37
Decentralized Annual Dynamometer	$41.62	$37.92	$79.54	$41.62	$37.96	$79.58	$41.62	$37.60	$79.23
Centralized Biennial Idle	$47.21	$24.75	$71.95	$47.21	$46.33	$93.54	$47.21	$49.49	$96.70
Centralized Biennial Dynamometer	$49.38	$49.49	$98.87	$49.38	$49.56	$98.94	$49.38	$49.03	$98.41
Decentralized Biennial Idle	$48.45	$24.75	$73.20	$48.45	$46.33	$94.78	$48.45	$49.49	$97.94
Decentralized Biennial Dynamometer	$50.62	$49.49	$100.11	$50.62	$49.56	$100.18	$50.62	$49.03	$99.65

Exhibit 3-16. Estimated Total Costs per Vehicle Tested by I/M Program Type and Year (in 2006 Dollars)

Model I/M Program	**2000 Total Cost**	**2010 Total Cost**	**2020 Total Cost**
Centralized Annual Idle	$60.10	$77.10	$79.70
Centralized Annual Dynamometer	$81.90	$82.00	$81.60
Decentralized Annual Idle	$60.30	$77.50	$80.00
Decentralized Annual Dynamometer	$82.10	$82.20	$81.90
Centralized Biennial Idle	$74.40	$96.60	$99.80
Centralized Biennial Dynamometer	$102.10	$102.20	$101.60
Decentralized Biennial Idle	$75.60	$97.90	$101.20
Decentralized Biennial Dynamometer	$103.40	$103.50	$102.90

Notes:

Dynamometer refers to IM240 or ASM-based tests.

Total cost is rounded to nearest ten cents.

5. CLEAN FUEL FLEET PROGRAM (CFFP)

The CAAA of 1990 mandated the implementation of a fuel neutral Clean Fuel Fleet Program (CFFP) beginning in model year 1998 for those nonattainment areas designated as serious, severe, and extreme for ozone or with a design value above 16 ppm for CO. The Act, however, specifically prohibits EPA from requiring vehicle manufacturers to produce clean fuel fleet vehicles (CFFVs). The statute also provided an opt-out opportunity for those areas wishing to use other methods to meet their air quality objectives. Of the original areas covered by the CAAA, only six areas have not opted-out. They are Atlanta, Metropolitan Washington, DC, Chicago-Gary-Lake County, Milwaukee-Racine, Denver-Boulder, and Baton Rouge. Because vehicles burning Federal reformulated gasoline in these areas meet the requirements of the program, we assume that CFFP costs incremental to the other programs outlined above are zero.

6. TRANSPORTATION CONFORMITY

The primary cost impact of the transportation conformity rule involves the increased requirements for Metropolitan Planning Organizations (MPOs) to perform regional transportation and emissions modeling and document the regional air quality impacts of transportation plans and programs. A U.S. Department of Transportation (DOT) survey in September 1992 of MPOs in 98 ozone nonattainment areas indicated that during Phase I of the interim period, most MPOs spent less than $50,000 for a conformity determination on the transportation plan and Transportation Improvement Program (TIP). Of the 68 MPOs responding, 76 percent spent less than $50,000, 21 percent spent between $50,001 and $100,000, and 3 percent spent between $100,001-250,000. MPOs serving populations over one million had higher conformity costs than MPOs serving smaller populations.

If it is assumed that the ozone areas surveyed by DOT in September 1992 are representative of all nonattainment areas, the estimated total annual conformity cost for the nation's transportation plans and TIPs is $16.6 million. This estimate is uncertain in part because it was developed during the formative stages of the transportation conformity rule. Although no definitive cost studies have been prepared since then, EPA actions subsequent to the initial promulgation of the conformity rule, in response to State and local concerns, are expected to reduce costs. These cost reducing actions include the simplified conformity process for transitional ozone areas under the new NAAQS. In addition, all other areas will be using the 1997 revised conformity rule, which streamlines conformity requirements (62FR43779, 1997).

7. HEAVY-DUTY DIESEL DEFEAT DEVICE SETTLEMENTS

On October 22, 1998, the Department of Justice and EPA announced an $83.4 million total penalty against diesel manufacturers. Under this settlement, seven major manufacturers of diesel engines will spend more than one billion dollars to resolve claims that they installed computer devices in heavy-duty diesel engines which produced illegal amounts of air pollution emissions. This settlement will prevent 75 million tons of NO_x emissions nationwide by the year 2025. The companies involved are Caterpillar, Inc., Cummins Engine Company, Detroit Diesel Corporation, Mack Trucks, Inc., Navistar

International Transportation Corporation, Renault Vehicles Industriels, s.a., and Volvo Truck Corporation.

The seven companies sold 1.3 million heavy-duty diesel engines containing illegal defeat devices, which allow an engine to pass the EPA emissions test, but then turn off emission controls during highway driving. As a result, these engines emit up to three times the current level of NO_x.

In the enforcement actions settled by the decree, EPA claimed that defendants and other engine manufacturers violated the Clean Air Act and its implementing regulations by selling engines that emitted excess pollution and by failing to disclose how the engines operated in real world conditions. A key component of the decree required defendants to meet, by October 1, 2002, engine emission standards that would not have otherwise been applicable until January 2004. This is referred to as the *pull ahead requirement*.

The decree provided that if defendants were not able to meet the October 1, 2002 deadlines, they could continue to sell non-compliant engines through three mechanisms: (1) payment of Non-Conformance Penalties (NCPs) to be calculated to correspond to the cost of compliant engines so as to maintain a level playing field between defendants and those engine manufacturers who met the deadline, (2) utilization of emissions averaging, banking, and trading, by which defendants can generate emission credits towards compliance through reducing emissions in other areas, and (3) a limited provision allowing post-deadline sales of non-compliant engines through matching pre-deadline sales of compliant engines.

For heavy-heavy duty engines, the NCPs are based on the compliance costs associated with lowering the emissions from 6.0 g/bhp-hr NMHC + NO_x to the 2004 standard of 2.5 g/bhp-hr NMHC + NO_x. (This analysis was not performed in the standard-setting rules, and therefore the cost estimates in the standard-setting rule and the NCP proposal are not comparable.) The estimated annual costs for an average model year 2004 vehicle meeting the 2.5 g/bhp-hr NMHC + NO_x emission standard were estimated to be (by component):

Amortized fixed	=	\$522
Engine manufacturer hardware	=	\$1,300
Manufacturer warranty cost	=	\$100
Vehicle manufacturer cost	=	\$100
Fuel cost	=	\$708 in year 1
Other operating (rebuild)	=	\$274 in year 5

Because the NCP cost of meeting the pull ahead standards is a short term cost that is only incurred by truck purchasers for a limited set of model years and the methods used by EPA for computing the associated costs are inconsistent with those developed for Federal emission standards, no CAAA-related cost for this action is included in this *with-CAAA* scenario cost analysis. In addition, costs to meet the applicable emission standards based on EPA's assessments of likely compliance strategies and associated costs may already account for these CAAA scenario costs.

COST SUMMARY

Exhibit 3-17 summarizes the motor vehicle unit costs used in this analysis. Individual motor vehicle provisions are listed with costs noted by vehicle type in year 2006 dollars.[114] For the fuels provisions of the CAAA, some benefits and costs only occur in certain seasons. Phase II RVP and Phase II Federal reformulated gasoline limits only result in ozone season costs, while oxygenated fuels produce CO season (winter time) costs. All other fuels programs listed in Exhibit 3-17 produce year round costs.

Exhibit 3-18 summarizes the motor vehicle costs for 2000, 2010, and 2020 given the unit cost information provided earlier in this chapter. Costs are also organized by title, with LEV program and I/M costs allocated to Title I: Nonattainment, with the remaining motor vehicle measure costs allocated to Title II: Motor Vehicles. Exhibit 3-19 presents the emissions reductions associated with these costs.

Based on the results presented in Exhibit 3-18, Title I inspection and maintenance (I&M) programs represent the most significant CAAA-related on-road program with respect to costs. During the time horizon of our analysis, we estimate that I&M makes up between 24 and 32 percent of the costs associated with CAAA-related on-road vehicle programs. Other leading on-road programs with respect to costs include the Federal and California reformulated gasoline programs, the gasoline fuel sulfur limits, the heavy-duty vehicle 2007 emission standards, and the Tier 1 NO_x standards.

As described in the introduction to this chapter, the Project Team incorporated the cost-reducing impact of learning into the cost estimates developed for this analysis. To assess the extent to which these adjustments affect the cost estimates presented in this chapter, we conducted a sensitivity analysis in which we made no adjustments for learning. Exhibit 3-20 presents the results of this analysis. Based on these results and the cost estimates presented in Exhibit 3-18, incorporating learning into our analysis reduces our cost estimates by approximately 13 to 15 percent.

[114] While most of the unit cost estimates presented throughout this chapter are expressed in year 1999 dollars, the unit and total cost estimates presented in this section are expressed in year 2006 dollars to be consistent with the other reports developed as part of the Second Prospective study.

Exhibit 3-17. Motor Vehicle Unit Costs by Provision (in 2006 Dollars)

Provision	Cost Unit	Cost Estimate by Vehicle Type in 2006 Dollars											
		LDGV	LDGT1	LDGT2	MC	HDGV	LDDV	LDDT	HDDV2B	LHDDV	MHDDV	HHDDV	BUS
Emission Standards:													
-Tier 1 Tailpipe Standards: VOC	Sales	43.1	38.9	13.0									
-Tier 1 Tailpipe Standards: NO_x	Sales	134.9	92.8	50.2		17.7			86.4	86.4	86.4	86.4	86.4
-Tier 2 Tailpipe Standards	Sales	54.4	87.7	209.7			54.4	142.8					
-Cold Temperature CO Standard	Sales	21.3	35.7	54.7									
-Evaporative Controls													
costs in 2000	Sales	-5.3	4.1	4.1		-29.0							
costs in 2010	Sales	-4.8	4.5	4.5		-27.6							
costs in 2020	Sales	-5.8	3.8	3.8		-30.3							
-On-Board Vapor Recovery System													
costs in 2000	Sales	4.9	4.7	4.7									
costs in 2010 and 2020	Sales	4.7	4.5	4.5									
-On-Board Diagnostics	Sales	65.8	65.8	65.8									
-Heavy Duty Engine Standard (2 gm equiv)	Sales								208.7	208.7	208.7	208.7	208.7
-Low Emission Vehicles (California LEVII and National Low Emission Vehicle Program)													
TLEV	Sales	78.6	78.6										
LEV	Sales	123.5	123.5										
ULEV	Sales	146.7	146.7										
ZEV (costs in 2000)	Sales	560.7	560.7										
ZEV (costs in 2010)	Sales	861.5	861.5										
ZEV (costs in 2020)	Sales	766.1	766.1										
-Heavy Duty Vehicle 2007 Emission Standards													
costs in 2010	Sales					191.7			1,927.9	1,927.9	2,541.9	3,433.3	2,926
costs in 2020	Sales					165.8			1,769.6	1,769.6	2,137.3	3,045.3	2,575

Exhibit 3-17. Motor Vehicle Unit Costs by Provision (in 2006 Dollars)

Provision	Cost Unit	Cost Estimate by Vehicle Type in 2006 Dollars											
		LDGV	LDGT1	LDGT2	MC	HDGV	LDDV	LDDT	HDDV2B	LHDDV	MHDDV	HHDDV	BUS
Fuels:													
-Phase II RVP Limits	Cents/gallon	0.2	0.2	0.2	0.2	0.2							
-Federal Reformulated Gasoline: Phase I													
costs in 2000	Cents/gallon	5.0	5.0	5.0	5.0	5.0							
costs in 2010	Cents/gallon	4.9	4.9	4.9	4.9	4.9							
costs in 2020	Cents/gallon	5.0	5.0	5.0	5.0	5.0							
-Federal Reformulated Gasoline: Phase II													
costs in 2000	Cents/gallon	1.5	1.5	1.5	1.5	1.5							
costs in 2010 and 2020	Cents/gallon	1.3	1.3	1.3	1.3	1.3							
-Oxygenated Fuels	Cents/gallon	4.0	4.0	4.0	4.0	4.0							
-Low-Sulfur Diesel Fuel (0.05% sulfur in 1993)	Cents/gallon						2.4	2.4	2.4	2.4	2.4	2.4	2.4
-California Phase I Reformulated Gasoline	Cents/gallon	1.7	1.7	1.7	1.7	1.7							
-California Phase II Reformulated Gasoline													
costs in 2000 and 2010	Cents/gallon	13.9	13.9	13.9	13.9	13.9							
costs in 2020	Cents/gallon	14.2	14.2	14.2	14.2	14.2							
-California Reformulated Diesel	Cents/gallon						6.3	6.3	6.3	6.3	6.3	6.3	6.3
-Gasoline Fuel Sulfur Limits													
costs in 2010	Cents/gallon	1.7	1.7	1.7	1.7	1.7							
costs in 2020	Cents/gallon	1.3	1.3	1.3	1.3	1.3							
-Diesel Fuel Sulfur Limits (15 ppm)													
costs in 2010	Cents/gallon						Average cost of 3.6 cents per gallon						
costs in 2020	Cents/gallon						Average cost of 4.0 cents per gallon						
Inspection/Maintenance Programs:													
See costs summarized in Exhibit 3-16													

Exhibit 3-18. Motor Vehicle Program Costs in 2000, 2010, and 2020

Program		Annual Cost (million 2006$)		
		2000 *with-CAAA*	2010 *with-CAAA*	2020 *with-CAAA*
Title I				
	National Low Emission Vehicles Program	$331	$1,580	$1,620
	California Low Emission Vehicles II Program	$231	$447	$474
	Inspection and Maintenance (I/M) Programs	$4,630	$6,250	$7,260
	Subtotal: Title I Motor Vehicle Costs	**$5,190**	**$8,280**	**$9,350**
Title II				
	Tier 1 Tailpipe Standards: VOC	$680	$626	$643
	Tier 1 Tailpipe Standards: NOx	$2,080	$1,880	$1,890
	Evaporative Controls (New Evaporative Emissions Test Procedure)	-$49	-$24	-$28
	Cold Temperature CO Standard	$480	$508	$564
	On-board Vapor Recovery System	$83	$76	$80
	On-board Diagnostics	$1,130	$1,090	$1,150
	Tier 2 Tailpipe Standards	$0	$1,260	$1,420
	Heavy-Duty Vehicle Standard (2 Gram Equivalent)	$0	$148	$150
	Heavy-Duty Vehicle 2007 Emission Standards	$0	$2,080	$1,890
	Phase II RVP Limits	$124	$148	$170
	Oxygenated Fuels	$131	$168	$206
	Federal Reformulated Gasoline: Phase I	$1,340	$1,550	$1,790
	Federal Reformulated Gasoline: Phase II	$179	$168	$189
	Gasoline Fuel Sulfur Limits	$0	$2,510	$2,210
	California Phase I Reformulated Gasoline	$232	$287	$342
	California Phase II Reformulated Gasoline	$1,940	$2,390	$2,890
	Low-sulfur Diesel Fuel (0.05% Sulfur in 1993)	$749	$959	$1,140
	California Reformulated Diesel	$118	$155	$190
	Diesel Fuel Sulfur Limits (15 ppm)	$0	$1,500	$2,030
	Subtotal: Title II Motor Vehicle Costs	**$9,220**	**$17,500**	**$18,900**
Total Motor Vehicle Control Costs		**$14,400**	**$25,700**	**$28,300**

Exhibit 3-19. Motor Vehicle Program Emissions Summary: 2000, 2010, and 2020 (values reported in thousands of tons)

	2000			2010			2020		
Pollutant	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2000 Reductions**	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2010 Reductions**	**2020 *Without-CAAA***	**2020 *With-CAAA***	**2020 Reductions**
VOC	5,870	5,250	627	5,730	2,610	3,120	6,780	1,670	5,110
NO_x	8,780	8,070	708	9,110	4,350	4,760	10,700	1,920	8,780
CO	79,000	67,100	11,900	80,500	42,400	38,100	95,500	36,200	59,300
SO_2	633	254	379	797	30	767	987	36	950
PM_{10}	247	221	26	229	154	75	269	136	133
$PM_{2.5}$	192	166	26	170	96	73	199	71	128
NH_3	273	272	0	336	334	2	398	395	2

Note: The *with-CAAA* emissions estimates and associated reductions presented here reflect the emission control measures described in this chapter. They do not reflect the on-road local control measures reflected in Chapter 7.

Exhibit 3-20. Motor Vehicle Program Costs With No Learning Curve Adjustments: 2000, 2010, and 2020

Program		Annual Cost (million 2006$)		
		2000 *with-CAAA*	2010 *with-CAAA*	2020 *with-CAAA*
Title I				
	National Low Emission Vehicles Program	$395	$1,920	$1,950
	California Low Emission Vehicles II Program	$278	$537	$575
	Inspection and Maintenance (I/M) Programs	$4,630	$6,250	$7,260
	Subtotal: Title I Motor Vehicle Costs	**$5,300**	**$8,700**	**$9,790**
Title II				
	Tier 1 Tailpipe Standards: VOC	$832	$769	$791
	Tier 1 Tailpipe Standards: NOx	$2,550	$2,310	$2,330
	Evaporative Controls (New Evaporative Emissions Test Procedure)	$5	$32	$33
	Cold Temperature CO Standard	$632	$670	$744
	On-board Vapor Recovery System	$105	$101	$106
	On-board Diagnostics	$1,460	$1,400	$1,480
	Tier 2 Tailpipe Standards	$0	$1,670	$1,870
	Heavy-Duty Vehicle Standard (2 Gram Equivalent)	$0	$194	$199
	Heavy-Duty Vehicle 2007 Emission Standards	$0	$2,620	$2,450
	Phase II RVP Limits	$154	$182	$209
	Oxygenated Fuels	$162	$207	$253
	Federal Reformulated Gasoline: Phase I	$1,520	$1,750	$2,020
	Federal Reformulated Gasoline: Phase II	$179	$207	$233
	Gasoline Fuel Sulfur Limits	$0	$3,110	$2,730
	California Phase I Reformulated Gasoline	$287	$355	$421
	California Phase II Reformulated Gasoline	$2,300	$2,840	$3,430
	Low-sulfur Diesel Fuel (0.05% Sulfur in 1993)	$925	$1,180	$1,420
	California Reformulated Diesel	$145	$190	$234
	Diesel Fuel Sulfur Limits	$0	$1,840	$2,510
	Subtotal: Title II Motor Vehicle Costs	**$11,300**	**$21,700**	**$23,400**
Total Motor Vehicle Control Costs		**$16,500**	**$30,300**	**$33,200**

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CHAPTER 4 | NONROAD ENGINES/VEHICLES

We developed nonroad engine and nonroad vehicle emission estimates using EPA's Office of Transportation and Air Quality's (OTAQ) NONROAD2004 model. The direct cost estimates presented in this chapter were developed consistent with those results. Nonroad equipment categories not included in NONROAD (e.g., refueling emissions) are discussed in Chapter 6, as nonpoint or area sources. The NONROAD2004 model was released by EPA in May 2004 (EPA, 2004a). This version of the model incorporates all Federal engine exhaust standards, and includes updates to the base year diesel engine populations.

The NONROAD model is an EPA peer-reviewed model that is used in developing both base year and forecast year emission estimates for most nonroad source categories. The model has been used in support of multiple EPA regulatory analyses, including the Clean Air Nonroad Diesel Rule and the Clean Air Interstate Rule. The NONROAD model incorporates data for numerous nonroad engine parameters to estimate both historical and forecast year emissions.

As described in detail in Chapter 5 of the accompanying emissions analysis report, the NONROAD model includes its own national equipment growth rates. These growth rates are not derived from AEO 2005 modeling, but from extrapolation of historical trends. We would have liked to have revised the NONROAD model's forecasting approach to incorporate AEO 2005 fuel consumption projections, which would have involved modifying the NONROAD national equipment growth rates. While it is feasible to alter the national growth rates, to do so might have created new inconsistencies internal to the NONROAD model, because the equipment growth rates in NONROAD were derived from the same survey source as the disaggregated equipment category scrappage/retirement and usage rates that are also part of NONROAD input data. Altering only the growth rates might make them inconsistent with the retirement rates, which might then have created inconsistencies with AEO fuel consumption projections. Therefore, the national engine growth rates used here are consistent with the national NONROAD model data/assumptions that have been used in multiple EPA regulatory analyses.[115]

[115] Our analysis of the available data from AEO 2005 suggests that the AEO data would yield higher fuel consumption estimates than NONROAD in aggregate. Unlike NONROAD, however, AEO 2005 does not contain detailed fuel consumption projections by engine type. Therefore, for the purposes of the 812 analysis, NONROAD is a more suitable tool for projecting the fuel consumption of non-road engines.

The remainder of this chapter describes the process we used to complete these three steps, presents summary results for the category, and reports on two sensitivity analyses we conducted to evaluate particular areas of concern raised during the Council and AQMS reviews of the 2003 analytical plan.

SUMMARY OF APPROACH

Future year nonroad engine program costs are estimated for the control measures reflected in the emission projections analysis.[116] Nonroad engine control costs are calculated based on one of the following algorithms:

Cost per new engine -

Cost = projected engine sales * change in production cost ($/new engine)

Cost per gallon fuel consumed -

Cost = projected fuel consumption * change in cost per gallon ($/gallon)

Cost per ton pollutant reduced -

Cost = projected emission reduction * cost per ton reduced ($/ton)

Exhibit 4-1 provides a list of the nonroad source control programs modeled in this analysis, as well as the basis for the costs. For most nonroad engine categories, the Project Team estimated the per engine costs for modifying equipment/vehicles to meet EPA standards.[117] Costs for standards affecting these categories are calculated based on a per-engine production cost applied to projected sales. To ensure consistency with the Second Prospective emissions analysis, the Project Team used sales estimates from NONROAD2004 for those standards estimated on a per vehicle or per engine basis. Costs for the nonroad diesel sulfur standards are calculated based on a per-gallon cost applied to projected fuel consumption for the affected nonroad engines. In addition, for all of these standards, EPA's cost analyses include variable costs that are marked up at a rate of 26-29 percent to account for the engine manufacturers overhead and profit. For the spark-ignition (S-I) marine engines (exhaust standards) and for locomotive and diesel commercial marine engines, we relied on cost effectiveness calculations based on the annualized cost per ton of reduction.

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[116] See "Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis" for a discussion of the emission projection methodology and the control assumptions (Pechan and IEC, 2009).

[117] Throughout most of this chapter, we present unit cost estimates in the year's dollars used in the supporting documentation (e.g., the regulatory impact analysis for a rule). After estimating the total costs associated with each rule based on these unit cost values, we convert the total annual cost of each rule to year 2006 dollars using the GDP deflator.

Exhibit 4-1. List of Nonroad Programs for Which Costs were Modeled

Standard	Cost basis
All Small Spark-Ignition Engine rules (Includes Phase 1 and 2, Class I-V, Handheld and Non-handheld categories)	costs per engine
Large Spark-Ignition (S-I) rule	costs per engine
Snowmobiles	costs per engine
ATVs	costs per engine
Off-Highway Motorcycles	costs per engine
Spark-Ignition Marine Evaporative	costs per engine
Spark-Ignition Marine Exhaust	cost per ton
Tier 2 Diesel Marine	costs per engine
Tier 1 - 4 Diesel Engines	costs per engine
Nonroad Diesel Fuel Sulfur	costs per gallon fuel
Commercial Marine	cost per ton
Locomotive	cost per ton

LEARNING CURVE IMPACTS

The costs of implementing the non-road requirements listed in Exhibit 4-1 are likely to decline as vehicle and fuel producers gain experience with the technologies used to comply with these requirements. To account for this "learning curve" effect, we incorporated learning curve cost adjustments into our analyses of non-road engine and fuel costs. No studies that we identified in the empirical literature, however, quantify the magnitude of the learning effect for non-road vehicles and engines. In the absence of such information, we assume that costs for the non-road sector decline by 10 percent with each doubling in cumulative production.[118] This learning rate is consistent with the Council's recommendation that the Project Team apply a default learning rate of 5 to 10 percent to technologies and industries for which no empirical data are available in the learning curve literature (Council, 2007). Because the learning curve literature estimates a learning rate of approximately 20 percent for many technologies, our assumption of a 10 percent learning rate may be conservative.[119] Except for rules where costs are estimated on a dollar-per-ton basis, we use cumulative engine sales as our metric of cumulative production for non-road engine rules and the cumulative sales of affected fuel for non-road fuel rules. For the few rules where we estimate costs as a function of the emissions reduction achieved, we use the (estimated) cumulative emissions reductions associated with the rule as our metric of cumulative production.

[118] The unit cost values for some of the non-road rules included our analysis already reflect a learning rate of 20 percent. Therefore, we adjusted these unit costs to reflect no learning impacts before applying the default learning rate of 10 percent.

[119] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, Vol 9, No. 2, 1984.

FUEL ECONOMY IMPACTS

As described in greater detail below, many of the non-road regulations established under the CAAA affect the fuel-economy of non-road engines. Where possible, we estimated the value of these impacts as the present value of the fuel saved (or the extra fuel consumed) over the lifetime of an affected engine (even if its lifetime extends beyond 2020), based on fuel consumption data in the corresponding RIAs and fuel price projections from AEO 2005 (see Exhibit 4-2).[120] The RIAs for some rules, however, do not include sufficient information to implement this approach. In such cases, we employed alternative methods to estimate fuel economy impacts, as outlined in the sections below.

Exhibit 4-2. Summary of AEO 2005 Fuel Price Projections (year 1999$)[a]

Year	Diesel ($/gal)	Gasoline ($/gal)	Natural Gas ($/million cubic feet)	Liquified Petroleum Gas ($/gal)
2005	$1.06	$1.27	$5.27	$0.91
2010	$0.98	$1.05	$3.65	$0.66
2015	$0.99	$1.06	$4.08	$0.67
2020	$1.01	$1.11	$4.46	$0.71
2025	$1.05	$1.16	$4.69	$0.76
2030[b]	$1.05	$1.16	$4.69	$0.76

Notes:

a. Values from U.S. Department of Energy, *Annual Energy Outlook 2005*, 2005. Values do not include excise taxes on fuel.

b. AEO 2005 projects prices through 2025. To project fuel prices beyond 2025, we held fuel prices constant at year 2025 levels.

MAJOR PROGRAMS AND ANALYSIS METHODS

The following sections provide a discussion of the general requirements for each major nonroad engine standard, and the method and source of the data for estimating costs. Note that only three standards were in effect in the year 2000, including the Small Spark-Ignition Phase 1, Spark-Ignition recreational marine, and Tier 1 nonroad diesel standards.

Small S-I Engine Standards

EPA's regulatory program for reducing NO_x, hydrocarbon (HC), and CO emissions from SI engines has been issued in phases. The initial (Phase 1) regulation was finalized in July 1995. In December 1997, EPA proposed Phase 2 standards for nonroad, small spark-ignition engines. The small gasoline engine regulations affect small handheld and non-handheld equipment used in a variety of applications, including lawn and garden, small farm and construction, and light industrial applications. All engines have been required to meet Phase 1 emission standards since 1997. For non-handheld applications, more stringent Phase 2 standards phased in between 2001 and 2007, while for handheld applications, Phase 2 standards phased in between 2002 and 2007.

[120] We exclude fuel taxes from this analysis because they represent transfers rather than real resource costs.

EPA further distinguishes handheld equipment based on engine displacement and horsepower, creating three separate classes of engines, including Class III, IV, and V, while non-handheld equipment are separated into Class I and Class II engine categories. Emission standards vary for these classes of engines. Exhibit 4-3 presents the data compiled for computing Phase 1 and Phase 2 small S-I costs for the years 2000, 2010, and 2020. Note that Phase 1 costs only apply in 2000, and the more stringent Phase 2 standards and associated costs apply in 2010 and 2020.

For Phase 1 and 2 standards, EPA estimated per engine costs to the engine manufacturer to install the necessary emission control technology, including variable hardware and production costs (EPA, 1995; EPA, 1999a; EPA, 2000). Fuel savings are expected and considered in adjusting the per engine costs. Although the RIAs for both the Phase 1 and Phase 2 standards estimate fuel economy impacts, the approach used in these documents is inconsistent with the fuel economy methodology outlined above. In addition, insufficient information is available in the RIAs to develop fuel economy estimates based on this methodology. Therefore, to estimate fuel savings for Phase 1, we scaled the per engine fuel savings reported in the RIA to reflect fuel prices as of 2000, rather than the 1993 fuel price used in the RIA. For the Phase 2 standards, we estimated fuel savings per engine as the present value of the total fuel savings realized by the fleet of affected engines in use during the time horizon used in the RIA divided by the number of affected engines sold during this time.[121]

[121] Although this approach is similar to the methodology outlined in the beginning of this chapter, it does not capture fuel savings realized after the time horizon examined in the Phase 2 RIAs. For example, the RIA for Class I and II Phase 2 engines examines fuel savings realized over the 2001-2026 period for engines sold during this period. Because engines sold near the end of this period would still be in service after 2026, post-2026 fuel savings for engines sold before 2026 are not reflected in the RIA.

Exhibit 4-3. Small S-I Engine Cost Inputs

Standard	Affected HP	Engine Sales	Cost per engine (1999 $)
Year 2000			
Phase 1 Small S-I Handheld Class III	<=1 hp	1,467,368	$6
Phase 1 Small S-I Handheld Class IV	>1 and <=3 hp	8,167,310	$6
Phase 1 Small S-I Handheld Class V	>3 and <=11hp	947,241	$6
Phase 1 Small S-I Non-handheld Class I	<=6hp	11,040,534	$3
Phase 1 Small S-I Non-handheld Class II	>6 and <=25hp	5,280,404	$3
Year 2010 Small S-I Cost Data			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1999 $)**
Phase 2 Small S-I Handheld Class III	<=1 hp	1,798,166	$21
Phase 2 Small S-I Handheld Class IV	>1 and <=3 hp	9,940,631	$16
Phase 2 Small S-I Handheld Class V	>3 and <=11hp	1,131,408	($27)
Phase 2 Small S-I Non-handheld Class I	<=6hp	13,570,063	$12
Phase 2 Small S-I Non-handheld Class II	>6 and <=25hp	6,526,636	($42)
Year 2020 Small S-I Cost Data			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1999 $)**
Phase 2 Small S-I Handheld Class III	<=1 hp	2,127,081	$21
Phase 2 Small S-I Handheld Class IV	>1 and <=3 hp	11,703,452	$15
Phase 2 Small S-I Handheld Class V	>3 and <=11hp	1,314,460	($32)
Phase 2 Small S-I Non-handheld Class I	<=6hp	16,110,766	$6
Phase 2 Small S-I Non-handheld Class II	>6 and <=25hp	7,787,368	($43)

Large S-I Engine Standards

Engines covered by these standards are large (greater than 25 horsepower) industrial S-I engines powered by gasoline, liquefied petroleum gas (LPG), or compressed natural gas (CNG). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and farm and construction applications.

In 2002, EPA adopted two tiers of emission standards to reduce exhaust emissions of HC, NO_x, and CO from large SI engines, with the first tier starting in 2004, and the Tier 2 standards starting in 2007. Manufacturers must also take steps starting in 2007 to reduce evaporative emissions, such as using pressurized fuel tanks.

Exhibit 4-4 presents the data compiled for computing Tier 1 and Tier 2 large S-I costs for the years 2010 and 2020 (EPA, 2002a). Manufacturer engine and equipment costs vary for gasoline, LPG, and CNG. Because the sales data represent all large S-I engines combined, a composite cost and savings reported for the various engine types combined was used for this analysis. This rule is predicted to result in an overall cost savings, since the fuel savings significantly outweigh the cost of compliance with the standards. Fuel savings were calculated based on the estimated fuel savings in EPA's regulatory impact analysis of the standards.

Exhibit 4-4. Large S-I Engine Cost Inputs

2010 Large S-I Cost Data			
Standard	**Engine Sales**	**Cost per Engine (1999 $)**	**Cost per engine with Fuel Savings* (1999 $)**
Large S-I	160,013	$508	($3,897)
2020 Large S-I Cost Data			
Standard	**Engine Sales**	**Cost per Engine (1999 $)**	**Cost per engine with Fuel Savings* (1999 $)**
Large S-I	194,063	$508	($4,344)
*Costs represent a savings			

Recreational Land-based Engine Standards

EPA promulgated standards for recreational gasoline engines, including snowmobiles, off-highway motorcycles, and all-terrain vehicles (ATVs) in a 2002 rulemaking. These standards affect engines manufactured in 2006 and are phased in up to the year 2012. Exhibit 4-5 presents the cost inputs as compiled from EPA's RIA for these standards (EPA, 2002b). These costs include annual per engine fixed and variable costs, as well as fuel savings, resulting in an overall savings for some equipment (e.g., snowmobiles). Note that fuel savings were reported as discounted in EPA's RIA and were annualized to match the fixed and variable costs. Fuel savings per year were estimated for each equipment type accounting for a 25 percent fuel savings by converting a portion of recreational land-based engines from a 2-stroke to 4-stroke configuration, as well as a fuel savings from control of permeation emissions.

Exhibit 4-5. Recreational Land-Based Engine Cost Inputs

Standard	**2010 Engine Sales**	**Cost per Engine (1999 $)**
Snowmobiles	135,285	($42)
ATVs	1,068,453	$47
Off-Highway Motorcycles	173,838	$94

Standard	**2020 Engine Sales**	**Cost per Engine (1999 $)**
Snowmobiles	186,970	($71)
ATVs	1,280,626	$21
Off-Highway Motorcycles	209,417	$63

Recreational Marine Standards

EPA efforts at regulating emissions from recreational marine engines are divided into three groups: exhaust emissions from S-I engines, evaporative emissions from SI engines, and diesel engines. These three categories are discussed below.

S-I Exhaust Standards

In October 1996, EPA promulgated emission standards for new S-I gasoline marine engines used in outboards, inboards, and personal watercraft. Options for compliance with this regulation include: conversion to 4-stroke, direct-injection two-stroke, and installing catalytic converters.

EPA's RIA for the final rule contains annualized program costs in each year of program implementation (EPA, 1996). Per unit costs corresponding to fixed and variable costs to the manufacturers were not reported in this RIA. As such, a cost effectiveness value was calculated based on the total annual costs (TACs) reported in the RIA and the reductions for each year of interest. The RIA estimated that the nationwide annual cost of the regulation would be approximately $46.3 million in 2000 and $340 million in 2020. According to the RIA, the VOC emission reduction is expected to reach 538,400 tpy by 2020. The cost per ton values were calculated from these data.

Exhibit 4-6 also shows the emission reductions calculated from the Section 812 emission estimates. These reductions were estimated by summing emissions from affected recreational marine source classification codes (SCCs) for the *without-CAAA* and *with-CAAA* scenario for each year, and calculating the difference. In 2010 and 2020, because evaporative emission standards for these same SCCs phase in, it was necessary to estimate the fraction of the total VOC emissions due to exhaust. A rule penetration value was calculated from national level default runs of the NONROAD model for 2010 and 2020, since the inventory only reported VOC emissions in the aggregate (evaporative and exhaust combined). Cost-per ton was applied to these reductions to estimate total costs for each year.

Exhibit 4-6. Yearly Cost per Ton Values for S-I Marine Exhaust Standards

Year	Total Annualized Costs	VOC Reductions (RIA)	Cost per ton (1993$, excl. learning effects)	Cost per ton (1999$, with learning effects)	Reductions Calculated from Section 812 Inventory
2000	46,295,786	24,430	$1,895	$1,776	47,448
2010	357,969,394	359,453	$996	$893	298,504
2020	340,138,753	538,443	$632	$567	368,952

S-I Evaporative Standards

EPA has finalized evaporative HC emission standards for all gasoline-fueled boats (e.g., yachts, sport boats, fishing boats, jet boats, and other types of pleasure craft, including personal watercraft and boats with outboard engines). The evaporative emission standard requires all boats built in 2008 and later to reduce evaporative HC emissions by 80 percent. Manufacturers are expected to meet this standard with a variety of emission-control technologies, including non-permeable fuel tanks and hoses, pressurized fuel tanks with pressure relief valves, insulated tanks, bladder fuel tanks, and volume compensating air bladders.

Increased costs for marine vessels are estimated to be approximately $36 per boat on average. Actual costs may be higher or lower, depending on the size of the engine and the approach the manufacturer uses to meet the standards. Increased costs are partially offset by a discounted lifetime fuel savings ranging from $31 to $34 due to reducing gasoline losses (EPA, 2002b). As shown in Exhibit 4-7, adjusted per unit costs are estimated by subtracting these fuel savings from the per engine costs. Projected sales in 2010 and 2020 were then multiplied by these per engine costs.

Exhibit 4-7. S-I Marine Evaporative Cost Inputs

Year	Per Unit Cost (1999 $)	Per Unit Fuel Savings, (1999$)	Net Per Unit Cost, (1999$)	Sales
2010	$29.25	$31.74	($2.50)	749,384
2020	$28.03	$33.45	($5.43)	804,091

Compression Ignition (C-I) Recreational Marine Exhaust Standards

In 2002, EPA promulgated regulations to limit VOC, NO_x, CO, and PM from C-I recreational marine engines. These are marine diesel engines over 37 kilowatts (kW) that are used in yachts, cruisers, and other types of pleasure craft. The standards are phased in, beginning in 2006, depending on the size of the engine. Exhibit 4-8 presents the projected sales and cost data compiled for computing C-I marine costs for the years 2010, and 2020, derived from EPA's RIA (EPA, 2002a).

Exhibit 4-8. C-I Recreational Marine Engine Cost Inputs

Year 2010		
Affected HP	**Engine Sales**	**Cost per Engine (1999 $)**
50-300	13,103	$215
300-750	5,675	$362
>750	630	$968
Year 2020		
Affected HP	**Engine Sales**	**Cost per Engine (1999 $)**
50-300	16,128	$208
300-750	6,985	$267
>750	775	$555

NONROAD DIESEL STANDARDS

EPA is regulating NO_x, smoke, VOC, CO, and PM emissions from C-I engines in several phases. EPA finalized the Tier 1 regulation in 1994, Tier 2 and Tier 3 standards in 1998, and more stringent Tier 4 standards in 2004. The C-I Tier engine standards are phased in at various schedules and stringency levels depending on the horsepower of subject C-I engines. The latest Tier 4 diesel engine standards as well as the nonroad diesel sulfur limits described in the next section are referred to as the Clean Air Nonroad Diesel Rule.

Exhibit 4-9 presents the sales and cost per engine data compiled from the relevant regulatory support materials (derived from EPA, 1994; EPA, 1998; EPA, 2004). In the year 2000, only Tier 1 standards were in effect. In 2010, a small number of Tier 2, many Tier 3, and even more Tier 4 engines (for the smallest horsepower ranges) will be manufactured. By 2020, all new engines manufactured will need to meet the Tier 4 engine standards. As such, sales and cost data for only these Tier-level engines were compiled for the relevant years. For all three target years, engine and equipment costs of control include variable costs (for incremental hardware costs, assembly costs, and associated markups) and fixed costs (for tooling, R&D, and certification). Operating costs associated with engine use are also included. The costs presented for the Tier 3 and Tier 4 standards represent near-term costs.

NONROAD DIESEL SULFUR STANDARDS

In addition to Tier 4 engine standards, EPA's Clean Air Nonroad Diesel Rule includes a two-step fuel sulfur control program consisting of a sulfur cap of 500 parts per million (ppm) beginning in 2007 to be followed by a nonroad sulfur cap of 15 ppm beginning in 2010 and a locomotive and marine (L&M) sulfur cap of 15 ppm beginning in 2012. In addition to fuel desulfurization costs, the RIA presents estimates of other operating costs – catalyzed diesel particulate filter (CDPF) and closed crankcase ventilation (CCV) maintenance costs, as well as savings due to decreased intervals for oil change maintenance – associated with the final rule (EPA, 2004). The new emission-control technologies are expected to introduce additional operating costs in the form of increased fuel consumption and increased maintenance demands.[122] Operating costs are expressed in terms of cents/gallon of fuel consumed. The cent-per-gallon costs and savings are then combined with projected fuel volumes to generate the aggregate costs of the fuel program in this final rule. A summary of these costs and savings is provided in Exhibit 4-10, which shows the final net costs. The per-gallon costs are expressed as total annualized costs for the year in question (i.e., not discounted), and were used directly for this analysis. The fuel consumption estimates for nonroad engines (i.e., excluding locomotive and marine) presented in Exhibit 4-10 are from the NONROAD model. NONROAD does not include fuel consumption data for locomotive or marine engines; therefore, the Project Team used fuel consumption estimates from the final RIA for these engines.

[122] Although fuel economy impacts are reflected in the unit cost values we use from the RIA, insufficient information is available in the RIA to adjust the estimated fuel economy impacts to be consistent with the fuel economy methodology presented in the beginning of this chapter.

Exhibit 4-9. C-I Nonroad Engine Cost Inputs

Year 2000			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1999 $)**
Tier 1 C-I	<=50	158,702	$46
Tier 1 C-I	>50	262,145	$176

Year 2010			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1999 $)**
Tier 2 C-I	>750	1,903	$66
Tier 3 C-I	50-100	82,416	$232
Tier 3 C-I	100-175	86,150	$541
Tier 3 C-I	175-600	80,549	$717
Tier 3 C-I	600-750	2,456	$1,887
Tier 4 C-I	0-25	118,066	$143
Tier 4 C-I	25-50	144,572	$816
Tier 4 C-I	50-75	85,175	$776

Year 2020			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1999 $)**
Tier 4 C-I	0-25	150,066	$137
Tier 4 C-I	25-50	178,901	$784
Tier 4 C-I	50-75	105,276	$746
Tier 4 C-I	75-100	101,599	$1,263
Tier 4 C-I	100-175	104,906	$1,537
Tier 4 C-I	175-300	74,623	$2,328
Tier 4 C-I	300-600	22,984	$3,363
Tier 4 C-I	600-750	2,986	$6,582
Tier 4 C-I	>750	2,314	$8,583

Exhibit 4-10. C-I Nonroad Diesel Fuel and Operating Cost Inputs

Fuel Costs of Low Sulfur Diesel Fuel

Year	Affected Nonroad (NR) 500 ppm (10^6 gallons)	Affected Nonroad (NR) 15 ppm (10^6 gallons)	Affected Locomotive & Marine (L&M) 500 ppm (10^6 gallons)	Affected Locomotive & Marine (L&M) 15 ppm (10^6 gallons)	Fuel Costs 500 ppm ($ gallons)	Fuel Costs 15 ppm ($ gallons)	NR Fuel Costs 500 ppm (10^6 dollars)	NR Fuel Costs 15 ppm (10^6 dollars)	L&M Fuel Costs 500 ppm (10^6 dollars)	L&M Fuel Costs 15 ppm (10^6 dollars)	NRLM Annual Fuel Costs (10^6 dollars)
2010	5,092	7,851	3,185	0	$0.028	$0.058	$143	$455	$89	-	$687
2020	-	15,538	-	3,024		$0.070	-	$1,088	-	$212	$1,299

Oil Change Maintenance Savings

Year	Affected NR 500 ppm (10^6 gallons)	Affected NR 15 ppm (10^6 gallons)	Affected L&M 500 ppm (10^6 gallons)	Affected L&M 15 ppm (10^6 gallons)	NR Fuel Savings savings $0.029/gal ($10^6$ dollars)	NR Fuel Savings savings $0.032/gal ($10^6$ dollars)	L&M Fuel Savings savings $0.010/gal ($10^6$ dollars)	L&M Fuel Savings savings $0.011/gal ($10^6$ dollars)	Annual Savings (10^6 dollars)
2010	5,092	7,851	3,185	0	$148	$251	$32	-	$431
2020	-	15,538	-	3,024	-	$497	-	$33	$530

Catalyzed Diesel Particulate Filter (CDPF) Maintenance and Regeneration/Closed-Crankcase Ventilation (CCV) Maintenance Costs

Year	Fuel Consumed in New CDPF Engines (10^6 gallons)	Annual Costs	Fuel Consumed in CCV Engines (10^6 gallons)	Annual Costs	Total Annual Maintenance Costs
2010	-	$0	306	$0	$0
2020	13,952	$198	15,459	$23	$221

Net Operating Costs

Year	Annual Costs (10^6 dollars, not reflecting learning curve impacts)	Annual Costs (10^6 year 2002 dollars, with learning curve impacts)	Annual Costs (10^6 year 1999 dollars, with learning curve impacts)
2010	$256	$126	$118
2020	$990	$743	$698

Notes: All costs expressed as 2002 $ to maintain direct cross-reference to the RIA source data, except where otherwise noted.
NR = nonroad
L&M = locomotive and marine
NRLM – nonroad, locomotive, marine

Commercial Marine

EPA has promulgated two sets of commercial marine vessel (CMV) regulations: a regulation setting Category 1 and 2 marine diesel engine standards and a regulation setting Category 3 marine diesel engine standards. Category 1 marine diesel engines are defined as engines of greater than 37 kW but with a per-cylinder displacement of 5 liters/cylinder or less. Category 2 marine diesel engines cover engines of 5 to 30 liters/cylinder, and Category 3 marine diesel engines include the remaining, very large, engines. In addition to the EPA standards, beginning in 2000, marine diesel engines greater than or equal to 130 kW will be subject to an international NO_x emissions treaty (MARPOL) developed by the International Maritime Organization. Cost information was not available for the international NO_x standards. However, cost and emission reduction information developed in support of the Category 1 and 2 marine diesel engine rulemaking (EPA, 1999b) and the Category 3 marine diesel engine rulemaking (EPA, 2003) is modeled incremental to the MARPOL standards.

EPA expects the costs of compliance with the Category 3 marine standards to be negligible. Because engine manufacturers have been manufacturing engines in compliance with MARPOL Annex VI NO_x standards for the last few years, EPA did not attribute any emission reductions or costs to the EPA rule. While there will be certification and compliance costs, these costs will be negligible, because manufacturers will be able to use the same test data for both programs. Accordingly, EPA did not calculate values to quantify the cost-effectiveness of the final rule. EPA prepared per engine cost estimates for application of the two advanced control technologies: direct water injection and SCR, but these technologies were not part of EPA's rulemaking (EPA, 2003).[123]

Exhibit 4-11 presents total annualized costs in 2010 and 2020 associated with technologies to meet standards specified for Category 1 and 2 vessels (EPA, 1999b). $HC+NO_x$ and PM emission reductions were also reported by EPA, so that the cost per ton of reduced emissions could be computed for 2010 and 2020. These cost per ton values were then applied to reductions calculated from the emissions projections by year. These reductions were estimated by extracting emissions from the affected commercial marine diesel SCCs for the *without-CAAA* and *with-CAAA* scenario for each year, and calculating the difference between the scenarios.

[123] Although no cost estimates exist for MARPOL compliance, we can estimate that this omission from our cost estimates is likely to be negligible. EPA (1999) estimates that MARPOL regulations account for roughly 4,000, 43,000, and 77,000 tons of NOx emissions reductions counted in our emissions inventories for 2000, 2010, and 2020, respectively. The incremental cost per ton for additional engine modifications to meet EPA's Tier 2 requirements, however, is modest - between $50 and $172 per ton - mainly because these engines tend to be very efficient to control because they have high hours of operation and long useful lives. With a typical increasing marginal cost curve, we would therefore expect cost per ton for meeting the prior MARPOL requirements would be even more cost effective. Even at $172 per ton, the 77,000 ton reduction in 2020 would yield a total cost of an additional $13.2 million.

Exhibit 4-11. Commercial Marine Diesel Cost Inputs

Year 2010

	HC + NO_x						**PM**					
Standard	**Costs in RIA, reflecting RIA learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton (1997 $)**	**$/Ton (1999$, w/ 812 learning)**	**Section 812 Inventory Reductions**	**Costs in RIA, reflecting RIA learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton (1997 $)**	**$/Ton (1999$, w/ 812 learning)**	**Section 812 Inventory Reductions**
Cat 1 CMV	9,200,000	14,375,000	60,500	238			4,600,000	7,187,500	2,500	2,875		
Cat 2 CMV	3,000,000	3,000,000[1]	11,100	270			NA[2]	NA[2]	NA[2]	NA[2]		
Combined Cat 1/Cat 2	12,200,000	17,375,000	71,600	243	202	42,493	4,600,000	7,187,500	2,500	2,875	2,389	2,440

Year 2020

	HC + NO_x						**PM**					
Standard	**Costs in RIA, reflecting RIA learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton (1997 $)**	**$/Ton (1999$, w/ 812 learning)**	**Section 812 Inventory Reductions**	**Costs in RIA, reflecting RIA learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton (1997 $)**	**$/Ton (1999$, w/ 812 learning)**	**Section 812 Inventory Reductions**
Cat 1 CMV	4,300,000	6,718,750	141,000	$48			2,200,000	3,437,500	5,800	593		
Cat 2 CMV	600,000	937,500	41,700	$22			NA[2]	NA[2]	NA[2]	NA[2]		
Combined Cat 1/Cat 2	4,900,000	7,656,250	182,700	$42	35	121,796	2,200,000	3,437,500	5,800	593	492	3,152

Notes:

1. Insufficient data are presented in the regulatory impact analysis for the standards to remove learning curve impacts from the costs for Category 2 vessels in 2010. However, because Category 2 vessels make up a fairly small portion of costs in 2010, this is unlikely to have a significant impact on our results.
2. NA = Not applicable

Note that EPA regulations affecting emissions from these categories use a completely different categorization scheme than SCCs used in inventory reporting. The two diesel commercial marine SCCs reported in the Section 812 emission inventories include:

- 2280002100 – Marine Vessels, Commercial, Diesel, Port emissions; and
- 2280002200 – Marine Vessels, Commercial, Diesel, Underway emissions.

Consistent with the emission projections analysis, diesel port emissions are assumed to be Category 1 and 2 engines, while diesel underway emissions are assumed to be those from larger Category 3 engines. Therefore, because the costs for category 3 engines are expected to be negligible, costs were only calculated using reductions from diesel port emissions.

Locomotives

In January 1997, EPA proposed draft Locomotive Emission Standards to control emissions of NO_x, VOC, CO, PM, and smoke from newly manufactured and remanufactured diesel-powered locomotive and locomotive engines. In December 1997, EPA finalized the locomotive emission standards (EPA, 1997a). The locomotive standards are to be implemented in three phases, depending on the manufacture date. When fully phased-in by 2040, EPA estimates that the rule will achieve a 60 percent reduction in NO_x emissions, and a 46 percent reduction in PM emissions.

Options for compliance with this regulation include: retarded injection timing, enhanced air cooling, electronic controls, fuel management and combustion chamber configuration. These standards are not expected to require exhaust gas recirculation, catalytic after treatment, or the use of alternative fuels.

EPA completed a cost analysis for the final locomotive standards which incorporates initial equipment costs; remanufacturing costs; fuel economy costs; and certification, production line and in-use testing costs (EPA, 1997b). EPA estimated the per locomotive cost of the draft rule to range from $70,000 for Tier 0 to $252,000 for Tier 2. Initial equipment costs are assumed to accrue in the first year of service, with remanufacture occurring every six years thereafter. EPA estimated total costs as the sum of all yearly costs from 2000 to 2040. EPA estimated that the total annual program cost is $80 million per year for an overall program cost effectiveness of $163/ton (in year 2002 dollars) of NO_x abated over the 2005-2040 period (EPA, 1997a).[124] Adjusting for inflation and using AEO 2005 fuel price projections, the Project Team estimates costs of approximately $180 per ton (in year 1999 dollars).[125] The regulatory support document for the standards does not present TAC estimates for each implementation year; therefore, we used the average annualized cost per ton of NO_x abated across the entire

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[124] In generating this estimate, EPA assumed that the useful life of a locomotive, expressed in MW-hr, is 7.5 times the rated horsepower of the engine. For example, EPA assumed that a 3,500-hp locomotive would have a useful life of 26,250 MW-hr.

[125] EPA's RIA for the locomotive standards does not contain sufficient information to estimate the net present value of the fuel economy disbenefits per affected engine. Therefore, based on information in the RIA, we estimate additional fuel costs per ton of NO_x emissions reduced based on the AEO 2005 projection of diesel prices in 2015.

implementation period (i.e., a net present value (NPV) cost effectiveness). Exhibit 4-12 shows the cost per ton values and the NO_x reductions computed for all locomotives from the Section 812 2010 and 2020 inventories.

Exhibit 4-12. Locomotive Cost Inputs

Year 2010

Standard	$/Ton NO_x Reduced (1999 $)	Section 812 Inventory Reductions
Locomotive	$180	448,223

Year 2020

Standard	$/Ton NO_x Reduced (1999 $)	Section 812 Inventory Reductions
Locomotive	$180	571,583

COST SUMMARY

Exhibit 4-13 summarizes the nonroad engine program costs for 2000, 2010, and 2020 given the unit cost information provided earlier in this chapter. Exhibit 4-14 presents the emissions reductions associated with these costs. Note that costs for Phase 1 Small S-I and Tier 1 Diesel standards are not reported in 2010 and 2020 because more stringent levels of standards replace these lower tier standards, and no new Phase 1 or Tier 1 engines are sold as of 2010. Similarly, Tier 2 and Tier 3 Diesel engines are not sold as of 2020, so no costs are reported for these tiers in 2020.

As indicated in Exhibit 4-13, the S-I Marine Exhaust and Tier 1 Diesel Engine standards were responsible for a significant portion of the nonroad costs resulting from the Amendments in 2000 (approximately 55 percent combined). Although the S-I Marine Exhaust standards are expected to represent the largest share of nonroad costs in 2010, the Nonroad Diesel Engine and Sulfur standards and the Locomotive Emission standards are also expected to make up a significant portion of 2010 nonroad costs. By 2020, the Nonroad Diesel Engine standards are expected to represent most of the nonroad vehicle and fuel costs associated with the Amendments.

The cost estimates presented in Exhibit 4-13 reflect the learning curve adjustments outlined in the introduction to this chapter. To assess the extent to which these adjustments affect our cost estimates, we developed alternative estimates that reflect no learning curve impacts, as summarized in Exhibit 4-15. As suggested by the results in Exhibits 4-13 and 4-15, the Project Team's learning curve adjustments have a significant effect on the Project Team's cost estimates for the non-road sector. For 2000, these adjustments lead to a 17 percent reduction in estimated costs; this effect increases to 60 percent and 41 percent in 2010 and 2020 respectively. The significant magnitude of this effect partially reflects the fuel economy savings reflected in several of the cost estimates. For example, disregarding learning curve impacts, we estimate per unit costs of approximately $129 per engine for off-road motorcycles sold in 2010, which reflects $181 in control costs and $53 in fuel savings.[126] When we adjust for learning, the $181

[126] Consistent with the unit costs presented earlier in this chapter, these values are in year 1999 dollars.

control cost estimate declines to $147 per engine, a reduction of 19 percent. However, the estimated net cost per motorcycle falls to $94 ($147 - $53=$94), which is 27 percent less than the $129 net cost without learning curve impacts. As this example illustrates, the percent reduction in total costs resulting from the introduction of learning curve impacts into an analysis could be more significant than the actual learning effect (e.g., 19 percent in the example above) when the original cost values reflect fuel economy impacts.

Exhibit 4-13. Nonroad Engine Program Costs in 2000, 2010, and 2020

Standard	Annual Cost (million 2006 $)		
	2000	2010	2020
Small SI Engines	**$134**	**$61**	**-$65**
Phase 1 Small S-I Handheld Class III	$10	N/A	N/A
Phase 1 Small S-I Handheld Class IV	$57	N/A	N/A
Phase 1 Small S-I Handheld Class V	$7	N/A	N/A
Phase 1 Small S-I Non-handheld Class I	$44	N/A	N/A
Phase 1 Small S-I Non-handheld Class II	$16	N/A	N/A
Phase 2 Small S-I Handheld Class III	N/A	$45	$52
Phase 2 Small S-I Handheld Class IV	N/A	$187	$208
Phase 2 Small S-I Handheld Class V	N/A	-$36	-$50
Phase 2 Small S-I Non-handheld Class I	N/A	$191	$123
Phase 2 Small S-I Non-handheld Class II	N/A	-$325	-$397
Large S-I Engines	N/A	**-$742**	**-$1,003**
Recreational Land-based Engines	N/A	**$73**	**$33**
Snowmobiles	N/A	-$7	-$16
ATVs	N/A	$60	$33
Off-Highway Motorcycles	N/A	$19	$16
Recreational Marine	**$100**	**$322**	**$250**
S-I Marine Evaporative	N/A	-$2	-$5
S-I Marine Exhaust	$100	$317	$249
C-I Recreational Marine	N/A	$7	$7
Nonroad Diesel Engine Standards	**$64**	**$391**	**$975**
Tier 1 Diesel	$64	N/A	N/A
Tier 2 Diesel	N/A	$0	N/A
Tier 3 Diesel	N/A	$152	N/A
Tier 4 Diesel	N/A	$239	$975
Nonroad Diesel Sulfur	N/A	**$141**	**$831**
Commercial Marine	N/A	**$17**	**$7**
Locomotive	N/A	**$96**	**$123**
Total Control Costs	**$298**	**$359**	**$1,150**
Notes: N/A = Not applicable			

Exhibit 4-14. Nonroad Engine Program Emissions Reductions in 2000, 2010, and 2020 (values reported in thousands of tons)

Pollutant	2000			2010			2020		
	2000 *Without-CAAA*	**2000 *With-CAAA***	**2000 *Reductions***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2010 *Reductions***	**2020 *Without-CAAA***	**2020 *With-CAAA***	**2020 *Reductions***
VOCs	3,220	2,560	653	4,080	1,870	2,200	4,750	1,490	3,260
NOx	2,190	2,090	99	2,660	1,640	1,020	3,160	999	2,160
CO	25,500	22,300	3,130	31,500	26,200	5,310	37,200	29,000	8,200
SO_2	178	177	1	225	17	208	270	3	268
PM_{10}	287	266	21	323	203	121	367	131	236
$PM_{2.5}$	264	245	19	297	186	111	338	121	217
NH_3	2	2	0	2	2	0	3	2	0

Note: The *with-CAAA* emissions estimates and associated reductions presented here reflect the emission control measures described in this chapter. They do not reflect the nonroad local control measures reflected in Chapter 7.

Exhibit 4-15. Nonroad Engine Program Costs in 2000, 2010, and 2020 with No Learning Curve Cost Adjustments

Standard	Annual Cost (million 2006 $)		
	2000	2010	2020
Small SI Engines	**$164**	**$219**	**$90**
Phase 1 Small S-I Handheld Class III	$12	N/A	N/A
Phase 1 Small S-I Handheld Class IV	$70	N/A	N/A
Phase 1 Small S-I Handheld Class V	$9	N/A	N/A
Phase 1 Small S-I Non-handheld Class I	$53	N/A	N/A
Phase 1 Small S-I Non-handheld Class II	$19	N/A	N/A
Phase 2 Small S-I Handheld Class III	N/A	$56	$65
Phase 2 Small S-I Handheld Class IV	N/A	$240	$267
Phase 2 Small S-I Handheld Class V	N/A	-$27	-$41
Phase 2 Small S-I Non-handheld Class I	N/A	$259	$179
Phase 2 Small S-I Non-handheld Class II	N/A	-$308	-$379
Large S-I Engines	N/A	**-$719**	**-$976**
Recreational Land-based Engines	N/A	**$107**	**$63**
Snowmobiles	N/A	-$3	-$12
ATVs	N/A	$84	$52
Off-Highway Motorcycles	N/A	$27	$23
Recreational Marine	**$118**	**$402**	**$317**
S-I Marine Evaporative	N/A	$3	$1
S-I Marine Exhaust	$118	$392	$307
C-I Recreational Marine	N/A	$8	$8
Nonroad Diesel Engine Standards	**$79**	**$472**	**$1,204**
Tier 1 Diesel	$79	N/A	N/A
Tier 2 Diesel	N/A	$0	N/A
Tier 3 Diesel	N/A	$188	N/A
Tier 4 Diesel	N/A	$284	$1,204
Nonroad Diesel Sulfur	N/A	**$287**	**$1,107**
Commercial Marine	N/A	**$21**	**$9**
Locomotive	N/A	**$104**	**$132**
Total Control Costs	**$361**	**$892**	**$1,945**

Notes:
N/A = Not applicable

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CHAPTER 5 | NON-ELECTRIC GENERATING UNIT POINT SOURCE ANALYSIS

This chapter describes the compliance cost analysis performed for point sources other than electric generating units. The non-EGU point source emissions category includes a diverse set of emitting sources, from multiple industries, of varying sizes. The key CAAA requirements that are covered in this chapter for this sector include VOC RACT, OTC State Model VOC and NO_x rules, the NO_x SIP Call, Title III MACT emission standards, new CTGs, refinery cases and settlements, and measures adopted by areas beyond the above to attain or maintain the 1-hour ozone and PM_{10} NAAQS. Measures implemented to meet the 8-hour ozone and $PM_{2.5}$ NAAQS requirements are described separately in Chapter 7.

Almost all of the rules applicable to this category are regional (e.g., the NOx SIP call) or local (i.e., in a particular city that is not attaining the National Ambient Air Quality Standard for a criteria pollutant) in their implementation. Even the Federal requirements for measures such as Reasonable Available Control Technology tend to be applicable only in non-attainment areas, that is, they have a local "trigger" for implementation. As a result, much of this chapter reflects costing of rules consistent with our research into measures that have been applied in particular parts of the U.S. The main exception is Federal MACT standards implemented under Title III of the CAAA.

MAJOR PROGRAMS AND ANALYSIS METHODS

This section describes the most prominent elements of the 1990 CAAA that have affected non-EGU point source emissions and direct compliance costs since the Amendments were passed.

REASONABLY AVAILABLE CONTROL TECHNOLOGY

Point source control measures for VOC include Title I reasonable available control technology (RACT) and control technique guideline (CTG) requirements. Point source Title I RACT and CTG controls are applied in areas depending on ozone nonattainment classification. These controls are required in moderate and above 1-hour ozone nonattainment areas, and throughout the Northeast Ozone Transport Region (OTR).

OTC STATE MODEL RULES

The Ozone Transport Commission (OTC) was formed by Congress through the CAAA of 1990 to help coordinate control plans for reducing ground-level ozone in the Northeast and Mid-Atlantic States. Twelve States and the District of Columbia are represented in the OTC. During 2001, the OTC States evaluated available control measures that might be necessary to attain and maintain the 1-hour ozone NAAQS, as well as start reducing remaining 8-hour average ozone levels. As a result of its evaluation, the OTC States adopted several model rules to further reduce VOC and NO_x emissions in the region. The VOC model rules were developed to reduce emissions from consumer products, portable fuel containers, architectural and industrial maintenance (AIM) coatings, mobile equipment refinishing and repair operations, and solvent cleaning operations. The NO_x model rule has the potential to reduce emissions from stationary internal combustion engines, gas turbines, industrial boilers, and cement kilns. This NO_x model rule will yield additional reductions for smaller NO_x sources that are not covered under current regional NO_x programs.

The cost of complying with each of the individual model rules, which have each been adopted by each of the states within the OTC region in some form, are estimated based on information in the OTC-sponsored analysis (Pechan, 2001). The estimates in the OTC-sponsored analyses are all on a cost per ton basis, and their development is described in detail in the referenced report. For the cost estimates presented here, the relevant cost per ton values, by model rule, are applied to the relevant emissions reductions estimated in that state and for that model rule, relative to the *without-CAAA* case emissions. Note that the emissions reductions take into account detailed information, collected from Regional Planning Organizations (RPOs) about the implementation and specific market penetration of model rules in individual states within the OTC region. The product of the emissions reduction and cost per ton values yield the estimate of incremental compliance costs.

NO_X SIP CALL

For non-EGUs, the NO_x SIP Call affects emissions from industrial, commercial and institutional boilers, gas turbines, cement kilns, and reciprocating internal combustion engines.[127] The affected states have discretion about how to implement regulations to achieve the required emission reductions, so there are state-by-state differences in how each source category is regulated. The cost analysis uses the expected emission reductions by source (from 2002 to 2010 and 2002 to 2020) to determine the control technique that is likely to be used in each case to meet the emission reduction requirements. The cost estimates for the non-EGU source SIP Call sources were developed using the AirControlNET model. The estimated NO_x emission reductions (or control factors) were matched with the most cost effective control measures that had a control efficiency near the needed emission reduction. Then AirControlNET cost equations, or a default cost per ton for the control technology, were multiplied by the expected emission change to estimate the annual cost of compliance. Generally, the available AirControlNET control measures had NO_x control efficiencies within 10 percent of the needed emission reduction.

[127] These cost estimates and all of the other program-specific cost estimates presented in this chapter do not reflect the cost-reducing impact of learning curve impacts. We incorporate adjustments for learning into the results summary presented at the end of this chapter.

The estimated NO_x SIP Call compliance costs are shown in Exhibit 5-1 for 2010 and 2020. The estimated costs are \$116 million in 2010 and \$118 million in 2020. These cost estimates are considerably below the costs estimated in the First Prospective analysis, which applied a more extensive set of NO_x controls to the entire 38 state Ozone Transport Assessment Group (OTAG) region, but they are comparable to the costs estimated by EPA in the NO_x SIP Call Regulatory Impact Analysis (RIA). The September 1998 version of the NO_x SIP Call RIA had non-EGU cost estimates totaling \$277 million (in 1990 dollars) for industrial boilers/turbines, IC engines, and cement manufacturing (EPA, 1998). A major difference is that the scenario analyzed in the First Prospective, which was developed prior to the rule being finalized and based on information available at the time, applied to a larger geographic area than was covered in the final rule. In addition, since the First Prospective estimate was developed, some of the cost equations have changed that have resulted in lower cost estimates for certain NO_x control technologies (for IC engine low emission combustion controls, for example).

Exhibit 5-1. NO_x SIP Call Cost Summary by State

State	Annual Cost in 2010 (million 1999$)	Annual Cost in 2020 (million 1999$)	Avg. $/ton
Alabama	13.0	13.3	678
Connecticut	1.2	1.3	1,406
Delaware	3.0	3.1	1,267
DC	0.2	0.2	1,564
Georgia	0.7	0.8	858
Illinois	3.3	3.2	971
Indiana	3.1	3.3	545
Kentucky	1.1	1.2	669
Maryland	5.3	5.5	1,084
Massachusetts	5.8	6.2	1,404
Michigan	2.3	2.3	644
New Jersey	1.8	2.0	1,073
New York	12.5	12.4	1,179
North Carolina	7.7	7.9	980
Ohio	5.4	5.1	845
Pennsylvania	16.7	16.4	1,123
Rhode Island	0.7	0.8	1,636
South Carolina	1.7	1.9	734
Tennessee	11.8	11.6	1,087
Virginia	9.8	10.5	921
West Virginia	9.1	9.3	824
TOTAL	**116.4**	**118.2**	

MACT STANDARDS

Exhibits 5-2 and 5-3 display EPA cost estimates for promulgated MACT standards by MACT bin (e.g., 2-year, 4-year, etc.) (Schaefer, 2006). Total capital, total annual (annualized capital plus operating and maintenance costs), and monitoring, recordkeeping, and reporting (MRR) are presented based on the sum of the existing and new source cost estimates provided by EPA. These tables also identify compliance dates and the cost year. In cases where the cost year was not provided by EPA, the Project

Team estimated the year based on the average relationship between the cost year and compliance year for the MACT standards within each bin. For 4-year and 7-year MACT standards, the team assumed the cost year was 5 years before the year of compliance; for 10-year MACT standards, the team assumed the cost year was 8 years before the year of compliance.

Because this study employs a 5 percent discount rate for annualizing capital investments, it was necessary to determine the discount rates used by EPA in developing total annual costs. A review of the five MACT standards with the largest capital costs indicated that EPA used both 7 and 10 percent discount rates in annualizing capital costs. The version of OMB Circular A-94 published in 1992 suggests that OMB reduced its recommended discount rate at that time from 10 percent to 7 percent (OMB, 1992). Therefore, the Project Team assumed that a 10 percent discount rate was used by EPA in annualizing capital costs for MACT rules promulgated in 1992 or earlier and that a 7 percent rate was used for MACT rules finalized after 1992.

It was also necessary to identify the number of years for which capital costs are annualized. The review of sample MACT standards indicated that various years were used, with the time-frame dependent on the estimated life of the capital equipment (e.g., 15 years for flares). For the five MACT standards with the highest capital costs, the Project Team used the equipment life estimates presented in the regulatory support documents. For all other MACT standards, the Project Team assumed a 15-year equipment life. Based on the review of the sample MACT standards, the useful life of most equipment installed for MACT compliance is between 10 and 20 years.

The Project Team then subtracted estimated annualized capital costs from the total annual costs assuming a 15 year equipment life and either a 7 or 10 percent discount rate. [128] Next, capital costs were re-annualized using a 5 percent discount rate and a 15 year equipment life, and added to the remaining annual costs to yield the 5 percent discount rate-based total annual costs.

Exhibits 5-2 and 5-3 report two sets of total annual cost estimates – the original estimates reported in EPA's regulatory database, and estimates that adjust the annual costs to reflect use of a 5 percent discount rate. The final four columns in each table present the cost estimates in 1999 prices. These estimates were calculated by multiplying the EPA's original cost estimates by the appropriate GDP price index as discussed in Chapter 1.

Exhibit 5-4 reports the MACT standard cost estimates in 1999 prices for each analysis year. Because 2002 emissions data are used to reflect year 2000 CAAA-scenario emissions, the year 2000 estimates in this table include costs for all MACT standards with compliance dates of 2002 or earlier. Throughout the Second Prospective study, we have used the 2002 NEI as the basis for estimating the year 2000 target analysis year results. The choice of rules to include in the 2000 target year cost analysis is therefore designed to keep the costs and emissions/benefits analyses consistent in scope.

[128] For the five MACT standards with the largest total capital cost, the Project Team used the equipment life and discount rate information reported in the regulatory background documents for this calculation.

Exhibit 5-2. Original and Adjusted Cost Estimates for MACT Standards Included in 2000 Year Baseline

			Costs in millions of $					Costs in millions of 1999$				
Source Category	Compliance Date	Cost Year	Capital	Orig Total Annual	5% Total Annual	MRR	Total Annual w/ MRR	Capital	Orig Total Annual	5% Total Annual	MRR	Total Annual w/ MRR
2-Year												
Dry Cleaning-Perchloroethylene	09/23/96	1996	35.0	3.9	3.4	1.3	4.7	36.5	4.1	3.6	1.3	4.9
Hazardous Organic NESHAP (SOCMI)	05/14/01	1989	450.0	230.0	214.2	70.0	284.2	560.6	286.5	266.8	87.2	354.0
4-Year												
Aerospace Industry (surface coating)	09/01/98	1990	30.0	21.0	19.9	0.0	19.9	36.0	25.2	23.9	0.0	23.9
Chromium Electroplating	01/25/97	1988	45.0	22.0	20.4	11.6	32.0	58.2	28.4	26.4	15.0	41.4
Coke Ovens	01/01/98	1998	444.0	84.0	78.0	0.0	78.0	450.4	85.2	79.2	0.0	79.2
Commercial Sterilizers	12/06/98	1987	49.0	6.6	4.9	0.0	4.9	65.5	8.8	6.5	0.0	6.5
Gasoline Distribution-Stage I	12/15/97	1990	116.7	15.5	11.4	2.4	13.8	140.0	18.6	13.7	2.8	16.5
Halogenated Solvent Degreasing	12/02/97	1991	0.0	-19.0	-19.0	11.6	-7.4	0.0	-22.0	-22.0	13.4	-8.6
Industrial Cooling Towers	03/08/95	1998	2.4	15.2	15.2	0.0	15.2	2.4	15.4	15.4	0.0	15.4
Magnetic Tape (surface coating)	12/15/97	1992	5.7	1.2	1.0	0.2	1.2	6.5	1.3	1.1	0.2	1.3
Marine Vessel Loading Operations	09/19/99	1994	440.0	100.0	93.8	0.0	93.8	477.1	108.4	101.7	0.0	101.7
Off-Site Waste and Recovery Operations	02/01/00	1995	42.0	18.0	17.4	0.0	17.4	44.6	19.1	18.5	0.0	18.5
Petroleum Refineries-Other Sources Not Distinctly Listed	08/18/98	1998	163.0	47.3	45.1	10.1	55.2	165.4	48.0	45.8	10.2	56.0
Printing/Publishing (Surface Coating)	05/30/99	1994	0.0	40.0	40.0	0.0	40.0	0.0	43.4	43.4	0.0	43.4
Polymers & Resins Group I	07/31/97	1989	26.0	18.4	17.5	0.0	17.5	32.4	22.9	21.8	0.0	21.8
Polymers & Resins Group II	03/03/98	1993	0.9	0.7	0.6	0.0	0.6	1.0	0.7	0.7	0.0	0.7
Polymers & Resins Group IV	07/31/97	1989	17.2	-1.9	-2.5	0.0	-2.5	21.4	-2.4	-3.1	0.0	-3.1
Secondary Lead Smelters	06/23/97	1992	4.0	2.8	2.7	0.9	3.6	4.5	3.2	3.0	1.1	4.1
Shipbuilding and Ship Repair	12/16/96	1991	0.0	2.0	2.0	0.9	2.9	0.0	2.3	2.3	1.1	3.4
Wood Furniture (surface coating)	11/21/97	1992	7.0	15.3	15.1	0.0	15.1	7.9	17.3	17.1	0.0	17.1
7-Year												
Acetal Resins	06/29/02	1997	0.0	0.4	0.4	0.0	0.4	0.0	0.4	0.4	0.0	0.4
Acrylic/Modacrylic Fibers	06/29/02	1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ferroalloys Production	05/20/01	1996	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Polyurethane Foam Production	10/08/01	1994	74.0	8.1	7.1	0.0	7.1	80.2	8.8	7.7	0.0	7.7
Hydrogen Fluoride	06/29/02	1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mineral Wool Production	06/01/02	1997	2.6	1.4	1.4	0.0	1.4	2.7	1.4	1.4	0.0	1.4
Oil & Nat Gas Production	06/17/02	1997	7.2	4.4	4.3	0.0	4.3	7.4	4.5	4.4	0.0	4.4
Pharmaceuticals Production	09/21/01	1998	139.3	75.0	73.1	0.0	73.1	141.3	76.1	74.2	0.0	74.2

Source Category	Compliance Date	Cost Year	Costs in millions of $ Capital	Orig Total Annual	5% Total Annual	MRR	Total Annual w/ MRR	Costs in millions of 1999$ Capital	Orig Total Annual	5% Total Annual	MRR	Total Annual w/ MRR
Phosphoric Acid and Phosphate Fertilizers	06/10/02	1997	1.4	0.9	0.8	0.0	0.8	1.4	0.9	0.9	0.0	0.9
Polycarbonates Production (Generic MACT)	06/29/02	1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Polyether Polyols Production	06/01/02	1996	10.2	7.7	7.6	0.0	7.6	10.6	8.0	7.9	0.0	7.9
Portland Cement Manufacturing	06/10/02	1997	200.0	70.0	67.3	0.0	67.3	205.1	71.8	69.0	0.0	69.0
Primary Aluminum	10/07/99	1994	160.0	40.0	37.8	4.0	41.8	173.5	43.4	41.0	4.3	45.3
Primary Lead Smelting	05/04/01	1996	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pulp & Paper (non-combust) MACT I and (non-chem) MACT III	04/15/98	1995	755.0	172.0	162.1	0.0	162.1	802.2	182.8	172.3	0.0	172.3
Steel Pickling-HCL Process	06/22/01	1996	20.0	4.9	4.6	1.9	6.5	20.9	5.1	4.8	2.0	6.8
Wool Fiberglass Manufacturing	06/14/02	1997	19.5	6.3	6.0	0.0	6.1	20.0	6.5	6.2	0.0	6.2
10-Year												
Nat Gas Transmission & Storage	06/17/02	1994	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.3	0.0	0.3
Total			3,267.4	1,014.3	954.0	115.0	1,069.0	3,576.0	1,124.4	1,056.3	138.6	1,194.9

NOTES:

MRR - Monitoring, Recordkeeping, and Reporting

MACT standards without cost estimates:

Hazardous Waste Combustion -- 4-yr MACT with cost information reported as blank 09/30/03
Publicly Owned Treatment Works (POTW) -- 7-yr MACT w/ existing source costs listed as "not quantifiable" 10/26/02
Tetrahydrobenzaldehyde Manufacture -- 7-yr MACT w/ costs included in Hazardous Organic NESHAP above 05/12/01

Exhibit 5-3. Original and Adjusted Cost Estimates for MACT Standards Not Included in 2000 Year Baseline

			Costs in millions of $					Costs in millions of 1999$				
Source Category	**Compliance Date**	**Cost Year**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Total Annual w/ MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Total Annual w/ MRR**
7-Year												
Pesticide Active Ingredient Production	12/23/03	1998	81.9	44.9	43.8	0.3	44.1	83.1	45.5	44.4	0.3	44.7
Polymers & Resins III	01/20/03	1998	2.3	3.3	3.3	1.4	4.7	2.3	3.3	3.3	1.4	4.7
Secondary Aluminum	03/24/03	1994	105.4	76.7	75.3	9.2	84.5	114.3	83.2	81.6	10.0	91.6
Site Remediation	10/08/06	2001	18.0	9.0	8.8	0.0	8.8	17.2	8.6	8.4	0.0	8.4
Solvent Extraction for Vegetable Oil Production	04/12/04	1999	29.7	12.3	11.9	4.2	16.1	29.7	12.3	11.9	4.2	16.1
Wet Formed Fiberglass Mat Production	04/11/05	2000	5.3	1.6	1.5	0.0	1.5	5.2	1.6	1.5	0.0	1.5
10-Year												
Asphalt Processing and Asphalt Roofing Manufacturing	05/01/06	1999	3.7	2.1	2.1	0.5	2.6	3.7	2.1	2.1	0.5	2.6
Auto & Light Duty Truck	04/26/07	1999	670.0	154.0	145.0	1.0	146.0	670.0	154.0	145.0	1.0	146.0
Coke Ovens: Pushing, Quenching, & Battery Stacks	04/14/06	2001	89.5	20.2	19.0	1.4	20.4	85.5	19.3	18.2	1.3	19.5
Fabric Printing, Coating, & Dyeing	05/29/06	2000	18.8	14.5	14.2	1.4	15.7	18.4	14.2	13.9	1.4	15.3
Friction Products Manufacturing	10/18/05	2000	1.0	0.1	0.0	0.1	0.1	0.9	0.1	0.0	0.1	0.1
Integrated Iron & Steel	05/20/06	2001	93.0	16.0	14.7	1.0	15.7	88.9	15.3	14.1	1.0	15.1
Large Appliances (surface coating)	07/23/05	1997	0.0	1.6	1.6	1.5	3.1	0.0	1.7	1.7	1.5	3.2
Leather Finishing Operations	02/27/05	1997	5.6	0.4	0.4	0.0	0.4	5.7	0.5	0.4	0.0	0.4
Lime Manufacturing	01/05/07	1997	28.2	18.0	17.6	0.6	18.2	28.9	18.5	18.1	0.6	18.7
Manufacturing Nutritional Yeast	05/21/04	1998	0.3	0.7	0.7	0.2	0.8	0.3	0.7	0.7	0.2	0.9
Metal Can (surface coating)	11/13/06	1997	0.0	58.7	58.7	8.4	67.1	0.0	60.2	60.2	8.6	68.8
Metal Coil (surface coating)	06/10/05	1997	18.1	7.6	7.4	0.8	8.1	18.6	7.8	7.5	0.8	8.3
Metal Furniture (surface coating)	05/23/06	1998	0.0	14.8	14.8	10.1	24.9	0.0	15.0	15.0	10.2	25.2
Misc. Metal Parts and Products	01/02/07	1999	0.0	57.3	57.3	44.8	102.1	0.0	57.3	57.3	44.8	102.1
MON	11/10/06	1998	127.0	75.1	73.4	0.8	74.2	128.8	76.2	74.5	0.8	75.3
Paper and Other Web (surface coating)	12/04/05	1998	222.0	69.0	66.0	3.1	69.1	225.2	70.0	67.0	3.2	70.2
Petroleum Refineries	04/11/05	1998	213.0	79.0	76.1	20.0	96.1	216.1	80.1	77.2	20.3	97.5
Plastic Parts (surface coating)	04/19/07	1997	0.8	10.9	10.9	5.4	16.3	0.8	11.2	11.2	5.5	16.7
Plywood & Composite Wood Products	07/30/07	1999	471.0	140.0	133.1	5.6	138.7	471.0	140.0	133.1	5.6	138.7
Reciprocating Internal Combustion Engines (RICE) (NESHAP/NSPS)	06/15/07	1998	439.0	248.0	242.1	11.4	253.5	445.4	251.6	245.6	11.6	257.2
Rubber Tire Manufacturing	07/11/05	1997	0.0	25.9	25.9	0.0	25.9	0.0	26.6	26.6	0.0	26.6

			Costs in millions of $					Costs in millions of 1999$				
Source Category	**Compliance Date**	**Cost Year**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Total Annual w/ MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Total Annual w/ MRR**
Semiconductor Manufacturing	05/22/06	1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stationary Combustion Turbines	03/05/07	1998	0.0	86.0	86.0	0.3	86.3	0.0	87.2	87.2	0.3	87.5
Taconite Iron Ore Processing	10/30/06	2000	57.0	9.0	8.2	0.9	9.1	55.8	8.8	8.1	0.9	9.0
Wood Building Products (surface coating) (formerly Flat Wood Paneling Products)	05/28/06	1998	0.0	22.5	22.5	0.0	22.5	0.0	22.8	22.8	0.0	22.8
Total			2,700.5	1,279.3	1,242.4	134.3	$1,376.6	2,715.8	1,295.7	1,258.6	136.1	1,394.7

Exhibit 5-4. Cost Estimates for MACT Standards by Analysis Year

	2000 (in millions of 1999$)					2010 (in millions of 1999$)					2020 (in millions of 1999$)				
Source Category	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**
2-Year															
Dry Cleaning-Perchloroethylene	36.5	4.1	3.6	1.3	4.9	36.5	4.1	3.6	1.3	4.9	36.5	4.1	3.6	1.3	4.9
Hazardous Organic NESHAP (SOCMI)	560.6	286.5	266.8	87.2	354.0	560.6	286.5	266.8	87.2	354.0	560.6	286.5	266.8	87.2	354.0
4-Year															
Aerospace Industry (surface coating)	36.0	25.2	23.9	0.0	23.9	36.0	25.2	23.9	0.0	23.9	36.0	25.2	23.9	0.0	23.9
Chromium Electroplating	58.2	28.4	26.4	15.0	41.4	58.2	28.4	26.4	15.0	41.4	58.2	28.4	26.4	15.0	41.4
Coke Ovens	450.4	85.2	79.2	0.0	79.2	450.4	85.2	79.2	0.0	79.2	450.4	85.2	79.2	0.0	79.2
Commercial Sterilizers	65.5	8.8	6.5	0.0	6.5	65.5	8.8	6.5	0.0	6.5	65.5	8.8	6.5	0.0	6.5
Gasoline Distribution-Stage I	140.0	18.6	13.7	2.8	16.5	140.0	18.6	13.7	2.8	16.5	140.0	18.6	13.7	2.8	16.5
Halogenated Solvent Degreasing	0.0	-22.0	-22.0	13.4	-8.6	0.0	-22.0	-22.0	13.4	-8.6	0.0	-22.0	-22.0	13.4	-8.6
Industrial Cooling Towers	2.4	15.4	15.4	0.0	15.4	2.4	15.4	15.4	0.0	15.4	2.4	15.4	15.4	0.0	15.4
Magnetic Tape (surface coating)	6.5	1.3	1.1	0.2	1.3	6.5	1.3	1.1	0.2	1.3	6.5	1.3	1.1	0.2	1.3
Marine Vessel Loading Operations	477.1	108.4	101.7	0.0	101.7	477.1	108.4	101.7	0.0	101.7	477.1	108.4	101.7	0.0	101.7
Off-Site Waste and Recovery Operations	44.6	19.1	18.5	0.0	18.5	44.6	19.1	18.5	0.0	18.5	44.6	19.1	18.5	0.0	18.5
Petroleum Refineries-Other Sources Not Distinctly Listed	165.4	48.0	45.8	10.2	56.0	165.4	48.0	45.8	10.2	56.0	165.4	48.0	45.8	10.2	56.0
Printing/Publishing (Surface Coating)	0.0	43.4	43.4	0.0	43.4	0.0	43.4	43.4	0.0	43.4	0.0	43.4	43.4	0.0	43.4
Polymers & Resins Group I	32.4	22.9	21.8	0.0	21.8	32.4	22.9	21.8	0.0	21.8	32.4	22.9	21.8	0.0	21.8
Polymers & Resins Group II	1.0	0.7	0.7	0.0	0.7	1.0	0.7	0.7	0.0	0.7	1.0	0.7	0.7	0.0	0.7
Polymers & Resins Group IV	21.4	-2.4	-3.1	0.0	-3.1	21.4	-2.4	-3.1	0.0	-3.1	21.4	-2.4	-3.1	0.0	-3.1
Secondary Lead Smelters	4.5	3.2	3.0	1.1	4.1	4.5	3.2	3.0	1.1	4.1	4.5	3.2	3.0	1.1	4.1
Shipbuilding and Ship Repair	0.0	2.3	2.3	1.1	3.4	0.0	2.3	2.3	1.1	3.4	0.0	2.3	2.3	1.1	3.4

Source Category	2000 (in millions of 1999$) Capital	Orig Total Annual	5% Total Annual	MRR	5% Total Annual + MRR	2010 (in millions of 1999$) Capital	Orig Total Annual	5% Total Annual	MRR	5% Total Annual + MRR	2020 (in millions of 1999$) Capital	Orig Total Annual	5% Total Annual	MRR	5% Total Annual + MRR
Wood Furniture (surface coating)	7.9	17.3	17.1	0.0	17.1	7.9	17.3	17.1	0.0	17.1	7.9	17.3	17.1	0.0	17.1
7-Year in 2000 Baseline															
Acetal Resins	0.0	0.4	0.4	0.0	0.4	0.0	0.4	0.4	0.0	0.4	0.0	0.4	0.4	0.0	0.4
Acrylic/Modacrylic Fibers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ferroalloys Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Polyurethane Foam Production	80.2	8.8	7.7	0.0	7.7	80.2	8.8	7.7	0.0	7.7	80.2	8.8	7.7	0.0	7.7
Hydrogen Fluoride	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mineral Wool Production	2.7	1.4	1.4	0.0	1.4	2.7	1.4	1.4	0.0	1.4	2.7	1.4	1.4	0.0	1.4
Oil & Nat Gas Production	7.4	4.5	4.4	0.0	4.4	7.4	4.5	4.4	0.0	4.4	7.4	4.5	4.4	0.0	4.4
Pharmaceuticals Production	141.3	76.1	74.2	0.0	74.2	141.3	76.1	74.2	0.0	74.2	141.3	76.1	74.2	0.0	74.2
Phosphoric Acid and Phosphate Fertilizers	1.4	0.9	0.9	0.0	0.9	1.4	0.9	0.9	0.0	0.9	1.4	0.9	0.9	0.0	0.9
Polycarbonates Production (Generic MACT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Polyether Polyols Production	10.6	8.0	7.9	0.0	7.9	10.6	8.0	7.9	0.0	7.9	10.6	8.0	7.9	0.0	7.9
Portland Cement Manufacturing	205.1	71.8	69.0	0.0	69.0	205.1	71.8	69.0	0.0	69.0	205.1	71.8	69.0	0.0	69.0
Primary Aluminum	173.5	43.4	41.0	4.3	45.3	173.5	43.4	41.0	4.3	45.3	173.5	43.4	41.0	4.3	45.3
Primary Lead Smelting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pulp & Paper (non-combust) MACT I and (non-chem) MACT III	802.2	182.8	172.3	0.0	172.3	802.2	182.8	172.3	0.0	172.3	802.2	182.8	172.3	0.0	172.3
Steel Pickling-HCL Process	20.9	5.1	4.8	2.0	6.8	20.9	5.1	4.8	2.0	6.8	20.9	5.1	4.8	2.0	6.8
Wool Fiberglass Manufacturing	20.0	6.5	6.2	0.0	6.2	20.0	6.5	6.2	0.0	6.2	20.0	6.5	6.2	0.0	6.2
7-Year Not in 2000 Baseline															
Pesticide Active Ingredient Production						83.1	45.5	44.4	0.3	44.7	83.1	45.5	44.4	0.3	44.7
Polymers & Resins III						2.3	3.3	3.3	1.4	4.7	2.3	3.3	3.3	1.4	4.7
Secondary Aluminum						114.3	83.2	81.6	10.0	91.6	114.3	83.2	81.6	10.0	91.6
Site Remediation						17.2	8.6	8.4	0.0	8.4	17.2	8.6	8.4	0.0	8.4
Solvent Extraction for Vegetable Oil Production						29.7	12.3	11.9	4.2	16.1	29.7	12.3	11.9	4.2	16.1

	2000 (in millions of 1999$)					2010 (in millions of 1999$)					2020 (in millions of 1999$)				
Source Category	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**
Wet Formed Fiberglass Mat Production						5.2	1.6	1.5	0.0	1.5	5.2	1.6	1.5	0.0	1.5
10-Year in 2000 Baseline															
Nat Gas Transmission & Storage	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.3	0.0	0.3
10-Year Not in 2000 Baseline															
Asphalt Processing and Asphalt Roofing Manufacturing						3.7	2.1	2.1	0.5	2.6	3.7	2.1	2.1	0.5	2.6
Auto & Light Duty Truck						670	154	145	1	146.0	670	154	145	1	146.0
Coke Ovens: Pushing, Quenching, & Battery Stacks						85.5	19.3	18.2	1.3	19.5	85.5	19.3	18.2	1.3	19.5
Fabric Printing, Coating, & Dyeing						18.4	14.2	13.9	1.4	15.3	18.4	14.2	13.9	1.4	15.3
Friction Products Manufacturing						0.9	0.1	0	0.1	0.1	0.9	0.1	0	0.1	0.1
Integrated Iron & Steel						88.9	15.3	14.1	1	15.1	88.9	15.3	14.1	1	15.1
Large Appliances (surface coating)						0	1.7	1.7	1.5	3.2	0	1.7	1.7	1.5	3.2
Leather Finishing Operations						5.7	0.5	0.4	0	0.4	5.7	0.5	0.4	0	0.4
Lime Manufacturing						28.9	18.5	18.1	0.6	18.7	28.9	18.5	18.1	0.6	18.7
Manufacturing Nutritional Yeast						0.3	0.7	0.7	0.2	0.9	0.3	0.7	0.7	0.2	0.9
Metal Can (surface coating)						0	60.2	60.2	8.6	68.8	0	60.2	60.2	8.6	68.8
Metal Coil (surface coating)						18.6	7.8	7.5	0.8	8.3	18.6	7.8	7.5	0.8	8.3
Metal Furniture (surface coating)						0	15	15	10.2	25.2	0	15	15	10.2	25.2
Misc. Metal Parts and Products						0	57.3	57.3	44.8	102.1	0	57.3	57.3	44.8	102.1
MON						128.8	76.2	74.5	0.8	75.3	128.8	76.2	74.5	0.8	75.3
Paper and Other Web (surface coating)						225.2	70	67	3.2	70.2	225.2	70	67	3.2	70.2
Petroleum Refineries						216.1	80.1	77.2	20.3	97.5	216.1	80.1	77.2	20.3	97.5
Plastic Parts (surface						0.8	11.2	11.2	5.5	16.7	0.8	11.2	11.2	5.5	16.7

	2000 (in millions of 1999$)					2010 (in millions of 1999$)					2020 (in millions of 1999$)				
Source Category	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**5% Total Annual + MRR**
coating)															
Plywood & Composite Wood Products						471	140	133.1	5.6	138.7	471	140	133.1	5.6	138.7
Reciprocating Internal Combustion Engines (RICE) (NESHAP/NSPS)						445.4	251.6	245.6	11.6	257.2	445.4	251.6	245.6	11.6	257.2
Rubber Tire Manufacturing						0	26.6	26.6	0	26.6	0	26.6	26.6	0	26.6
Semiconductor Manufacturing						0	0	0	0	0.0	0	0	0	0	0.0
Stationary Combustion Turbines						0	87.2	87.2	0.3	87.5	0	87.2	87.2	0.3	87.5
Taconite Iron Ore Processing						55.8	8.8	8.1	0.9	9.0	55.8	8.8	8.1	0.9	9.0
Wood Building Products (surface coating) (formerly Flat Wood Paneling Products)						0	22.8	22.8	0	22.8	0	22.8	22.8	0	22.8
Total	3,576.0	1,124.4	1,056.3	138.6	1,194.9	6,291.8	2,420.1	2,314.9	274.7	2,589.6	6,291.8	2,420.1	2,314.9	274.7	2,589.6

NOTES:

MRR - Monitoring, Recordkeeping, and Reporting

MACT Standards without cost information:
Hazardous Waste Combustion -- 4-yr MACT with cost information reported as blank
Publicly Owned Treatment Works (POTW) -- 7-yr MACT w/ existing source costs listed as "not quantifiable"
Tetrahydrobenzaldehyde Manufacture -- 7-yr MACT w/ costs included in Hazardous Organic NESHAP

NEW CONTROL TECHNIQUE GUIDELINES

In section 183 of the CAAA of 1990, EPA was required to issue control techniques guidelines for 11 categories of stationary sources of VOC emissions for which such guidelines had not been issued previously. These new CTGs were required to be issued within 3 years of enactment. Although EPA issues no Federal regulations to implement CTGs, they yield emissions reductions through a process that involves state adoption of the guidelines in state regulations to achieve the same or similar emissions reductions. States have flexibility to implement regulations that follow the CTGs exactly, or they may choose to adapt the CTGs using their own analyses. CTGs are typically adopted in states with 1-hour ozone moderate or worse non-attainment areas.

The cost effectiveness values for these CTGs are listed in Exhibit 5-5. The later section in this chapter headed "1-hour ozone SIP measures" explains how these cost effectiveness values were used in this analysis to estimate projection year *with-CAAA* scenario costs by projection year.

REFINERY CASES AND SETTLEMENTS

EPA's internal petroleum refinery initiative is an integrated enforcement and compliance strategy to address air emissions from the nation's petroleum refineries. Since March 2000, EPA has entered into 17 settlements with U.S. companies that represent nearly 77 percent of the nation's petroleum refinery capacity. These settlements cover 85 refineries in 25 states, and on full implementation will result in annual emission reductions of about 80 thousand NO_x tons per year (tpy) and 235 thousand annual SO_2 tons (EPA, 2006). Settling companies have agreed to invest more than $4.4 billion in control technologies and pay civil penalties of $55 million. They will also perform supplemental environmental projects valued at approximately $63 million.

The effects of these emission reductions have been included in the 2010 and 2020 emission projections - for consistency, we therefore estimate the costs. These emissions reductions typically apply at refineries that would not otherwise be affected by CAAA regulations; the settlements typically apply because a facility has violated New Source Review (NSR) requirements that were in place prior to the CAAA. In addition, they apply to emissions of criteria pollutants not typically addressed through MACT requirements that apply at petroleum refineries. As a result, these emissions should be, but are not, reflected in the *with-CAAA* scenario (based on the 2002 NEI, which reflects actual emissions in 2002). They are implemented in this analysis as adjustment to the NEI which implies additional costs beyond those for CAAA regulations estimated elsewhere.

The five major refinery sources that are affected by the judicial settlements are:

1. Fluid Catalytic Cracking Units (FCCUs)/Fluid Coking Units (FCUs)
2. Process Heaters and Boilers
3. Flare Gas Recovery
4. Leak Detection and Repair
5. Benzene/Wastewater

The control requirements and variation on this theme by these source types can be summarized as follows:

1. FCCU/FCU:
   a. SO_2 Option 1 – Install wet gas scrubbers
      Option 2 – Use catalyst additives
      Option 3 – Use existing wet gas scrubbers
   b. NO_x Option 1 – Install selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR)
      Option 2 – Use catalyst additives
2. Heaters/Boilers

Control requirements apply to heaters and boilers that are 40 million British thermal units (mmBtu) per hour capacity or larger. Some emission source summaries list process heaters/boilers greater than 100 mmBtu/hour separately, but the requirements do not appear to be different from what is required for 40-100 mmBtu. In many cases, the consent decrees establish NO_x emission reduction objectives across a number of refineries that are owned by the same firm. Therefore, the companies have discretion in disclosing which individual heaters/boilers to control, as well as the control techniques to apply.

Although information on specific settlements is not always available, particularly on an annual cost basis, we estimated direct compliance costs on an annualized per refinery basis using the following steps:

1. The refineries and associated FCCUs that are affected by the settlements were identified in the 2010 and 2020 core scenario point source emission databases.

2. Control costs were estimated for the subset of refineries that had FCCU SO_2 emissions of at least 100 tons per year and existing SO_2 control efficiencies below the level required by the settlement agreements.

3. Control costs were estimated using the AirControlNET control cost equations for applying a wet gas scrubber to achieve 90 percent SO_2 control. This is one of the controls that EPA has required that some refineries install at FCCUs as part of their settlements. Some settlements require that FCCUs reduce emissions via catalyst additives. However, control cost information was not available for catalyst additives. Because cost information was available for wet gas scrubbers, and control levels are similar to those expected for catalyst additives, wet gas scrubbers were estimated to be representative of the compliance costs for controlling all FCCU SO_2 emissions (Eagleson et el., 2004).

4. The average cost effectiveness of applying wet gas scrubbing to FCCUs was estimated based on the costs of applying this control technique to a 25,000 barrel per stream day FCC unit and a 90 percent control efficiency.

Exhibit 5-5 provides estimates of the annualized costs of the refinery settlements in 2010 and 2020 for the states with affected refineries.

Exhibit 5-5. Refinery Settlements - State-Level Cost Summary

	2010			2020		
State	**Annual Cost (million 1999$)**	**Annualized Capital Cost (million 1999$)**	**O&M Cost (million 1999$)**	**Annual Cost (million 1999$)**	**Annualized Capital Cost (million 1999$)**	**O&M Cost (million 1999$)**
California	4.6	3.3	1.3	6.1	4.4	1.7
Illinois	27.0	19.5	7.4	30.9	22.4	8.5
Indiana	20.1	14.6	5.5	23.0	16.7	6.3
Louisiana*	11.6	8.4	3.2	13.3	9.6	3.7
Minnesota	1.8	1.3	0.5	2.0	1.5	0.6
New Mexico	1.4	1.0	0.4	1.6	1.2	0.5
Ohio	69.3	50.2	19.1	79.4	57.5	21.9
Pennsylvania	45.9	33.3	12.7	52.6	38.1	14.5
Texas	69.0	50.0	19.0	75.4	54.6	20.8
Utah	1.7	1.2	0.5	2.0	1.4	0.5
Washington	2.3	1.6	0.6	2.6	1.9	0.7
U.S.	254.7	184.5	70.2	288.9	209.3	79.6

* One refinery in Louisiana (Conoco Phillips Belle Chasse) was shut down for approximately six months after Hurricane Katrina, but as of March 2006 DOE reports it is once again operating at full capacity. There is no information the Project Team is aware of to suggest that the terms of specific settlements have been altered for this or other Louisiana refineries in response to Katrina-induced damage.

1-HOUR OZONE SIP MEASURES-VOC AND NO_X

Title I of the Clean Air Act contains the nonattainment provisions, and it includes a mix of federal measures and state implementation plan (SIP) requirements which are designed to bring each nonattainment area into compliance with the relevant national ambient air quality standards. This section addresses the requirements for bringing areas into attainment of the 1-hour ozone NAAQS. This cost analysis estimates 1-hour ozone NAAQS compliance costs by first estimating the cost of meeting RACT, control technique guideline, and regional VOC control measures. As indicated in Exhibit 5-6 below, two of these measures apply nationally (marine vessel loading and waste management facilities rules), but most of these measures are applied in marginal, moderate, or worse ozone non-attainment areas. Then, the cost of measures that go beyond the above to achieve additional VOC and NO_x emission reductions by nonattainment area are estimated using area-specific information about requirements and the AirControlNET model to estimate the associated control costs. We describe the main elements of this two-step estimation process below.

Federal Rule Analysis

Exhibit 5-6 summarizes the non-EGU point source VOC control cost information that was used in the analysis to estimate the cost of national VOC rules, new CTGs, and VOC RACT for non-EGU point source categories. (We present similar control cost inputs for area/nonpoint sources in Chapter 6.) Exhibit 5-6 cost per ton values were developed in the first prospective analysis (EPA, 1999) and are applied here after adjusting from 1990$ to 1999$ using the GDP implicit price deflator.

Results of the analysis of the costs for national VOC rules, new CTGs, and VOC RACT requirements are shown in Exhibit 5-7 (for 2000), Exhibit 5-8 (for 2010), and Exhibit 5-9 (for 2020). These tables include the costs for meeting these Title I requirements for both point and nonpoint sources. Total cost estimates were developed by multiplying the expected emission reductions (the difference between *with-* and *without-CAAA* scenario emissions, derived from the Section 812 emissions inventory - see USEPA 2006) by the cost efficiency ($/ton) values in Exhibit 5-6. The analysis was conducted for each of the affected source categories for each projection year, then aggregated to generate total cost estimates. Most of the emission reductions begin in the years between 1990 and 2000, and continue to be in place throughout the study period.

Exhibit 5-6. Non-EGU Point Source VOC Cost Inputs by Provision

Non-EGU Point Source Provision	$ per ton VOC (1999$)
National Rules	
Marine vessel loading: petroleum liquids	1,600
TSDFs	141
New CTGs (moderate and above)	
Printing – lithographic	-100
SOCMI distillation	454
SOCMI reactor	454
Non-CTG and Group III CTG RACT (moderate and above)	
Automobile surface coating	3,356
Bakeries	1,003
Beverage can surface coating	899
Carbon black manufacture	938
Charcoal manufacturing	1,688
Cold cleaning	1,018
Fabric printing	2,000
Flatwood surface coating	2,969
Leather products	1,250
Metal surface coating	2,969
Organic acids manufacture	1,250
Paint and varnish manufacture	790
Paper surface coating	-153
Plastic parts surface coating	552
Rubber tire manufacture	133
SOCMI reactor: pharmaceutical	1,928
Whiskey fermentation – aging	32
CTG RACT (marginal and above)	
Cellulose acetate manufacture	805
Dry cleaning-stoddard	65
In-line degreasing	-364
Open-top degreasing	-354
Printing-letterpress	113
Terephthalic acid manufacture	830
Vegetable oil manufacture	-64

Note: Negative values in this table result in situations where application of the control technique yields net savings. Net savings can result where the VOC emissions are associated with fugitive feedstock or product emissions - the savings are from conservation of the feedstock or product. In some cases, product substitution may also result in cost savings (e.g., water-based substitute degreasers may be less expensive than VOC-based degreasers).

Exhibit 5-7. 1-Hour Ozone NAAQS Implementation Cost by Provision - 2000

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	23.8
Area	Automobile refinishing	10.6
Area	Bulk Terminals	2.3
Area	Consumer solvents	36.2
Area	Dry cleaning – petroleum	12.6
Area	Municipal solid waste landfills	69.4
Area	OTC Mobile MER Rule	20.4
Area	OTC Solvent Cleaning Rule	81.5
Area	Oil and natural gas production fields	27.8
Area	Paper surface coating	0.2
Area	Pharmaceutical manufacture	1.3
Area	Service stations - stage I-truck unloading	33.4
Area	Treatment, storage and disposal facilities	121.4
Non-EGU	Automobile Surface Coating	108.3
Non-EGU	Bakeries	6.8
Non-EGU	Beverage Can Surface Coating	19.0
Non-EGU	Carbon Black Manufacture	2.6
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.1
Non-EGU	Fabric Printing	10.8
Non-EGU	Flatwood Surface Coating	11.9
Non-EGU	In-line Degreasing	-0.3
Non-EGU	Leather Products	1.5
Non-EGU	Marine Vessel Loading: Petroleum Liquids	57.6
Non-EGU	Metal Surface Coating	120.8
Non-EGU	Municipal Landfills	6.7
Non-EGU	Open Top Degreasing	-1.8
Non-EGU	Organic Acids Manufacture	0.8
Non-EGU	Paint & Varnish Manufacture	4.2
Non-EGU	Paper Surface Coating	-3.3
Non-EGU	Plastic Parts Surface Coating	4.1
Non-EGU	Printing – Letterpress	-0.1
Non-EGU	Printing – Lithographic	-0.3
Non-EGU	Rubber Tire Manufacture	0.3
Non-EGU	TSDFs	0.5
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	-0.0
Non-EGU	Whiskey Fermentation - Aging	0.2
	TOTAL	**791.2**

Exhibit 5-8. 1-Hour Ozone NAAQS Implementation Cost By Provision - 2010

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	26.1
Area	Automobile refinishing	14.9
Area	Bulk Terminals	2.7
Area	Consumer solvents	39.5
Area	Dry cleaning – petroleum	17.7
Area	Municipal solid waste landfills	81.9
Area	OTC Consumer Products Rule	17.5
Area	OTC Mobile MER Rule	23.6
Area	OTC Solvent Cleaning Rule	117.8
Area	Oil and natural gas production fields	20.8
Area	Paper surface coating	0.2
Area	Pharmaceutical manufacture	1.5
Area	Service stations – stage I-truck unloading	40.1
Area	Treatment, storage and disposal facilities	143.3
Non-EGU	Automobile Surface Coating	131.9
Non-EGU	Bakeries	7.9
Non-EGU	Beverage Can Surface Coating	21.1
Non-EGU	Carbon Black Manufacture	2.6
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.1
Non-EGU	Fabric Printing	9.4
Non-EGU	Flatwood Surface Coating	13.3
Non-EGU	In-line Degreasing	-0.4
Non-EGU	Leather Products	1.2
Non-EGU	Marine Vessel Loading: Petroleum Liquids	66.7
Non-EGU	Metal Surface Coating	128.9
Non-EGU	Municipal Landfills	9.6
Non-EGU	Open Top Degreasing	-2.5
Non-EGU	Organic Acids Manufacture	0.8
Non-EGU	Paint & Varnish Manufacture	5.7
Non-EGU	Paper Surface Coating	-3.6
Non-EGU	Plastic Parts Surface Coating	4.4
Non-EGU	Printing – Letterpress	-0.1
Non-EGU	Printing – Lithographic	-0.3
Non-EGU	Rubber Tire Manufacture	0.3
Non-EGU	TSDFs	0.6
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	-0.0
Non-EGU	Whiskey Fermentation - Aging	0.1
	TOTAL	**945.7**

Exhibit 5-9. 1-Hour Ozone NAAQS Implementation Cost by Provision - 2020

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	28.3
Area	Automobile refinishing	20.7
Area	Bulk Terminals	3.2
Area	Consumer solvents	42.8
Area	Dry cleaning – petroleum	24.6
Area	Municipal solid waste landfills	104.9
Area	OTC Consumer Products Rule	18.5
Area	OTC Mobile MER Rule	28.3
Area	OTC Solvent Cleaning Rule	157.6
Area	Oil and natural gas production fields	15.6
Area	Paper surface coating	0.3
Area	Pharmaceutical manufacture	1.9
Area	Service stations - stage I-truck unloading	47.0
Area	Treatment, storage and disposal facilities	183.6
Non-EGU	Automobile Surface Coating	165.0
Non-EGU	Bakeries	9.3
Non-EGU	Beverage Can Surface Coating	25.3
Non-EGU	Carbon Black Manufacture	2.9
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.2
Non-EGU	Fabric Printing	8.6
Non-EGU	Flatwood Surface Coating	16.2
Non-EGU	In-line Degreasing	-0.5
Non-EGU	Leather Products	1.0
Non-EGU	Marine Vessel Loading: Petroleum Liquids	76.5
Non-EGU	Metal Surface Coating	151.7
Non-EGU	Municipal Landfills	13.3
Non-EGU	Open Top Degreasing	-3.5
Non-EGU	Organic Acids Manufacture	0.9
Non-EGU	Paint & Varnish Manufacture	7.9
Non-EGU	Paper Surface Coating	-4.1
Non-EGU	Plastic Parts Surface Coating	4.8
Non-EGU	Printing – Letterpress	-0.1
Non-EGU	Printing – Lithographic	-0.3
Non-EGU	Rubber Tire Manufacture	0.4
Non-EGU	TSDFs	0.7
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	-0.0
Non-EGU	Whiskey Fermentation – Aging	0.1
	TOTAL	**1,153.8**

Exhibits 5-7 through 5-9 show that the estimated cost of these VOC regulations is close to $800 million in 2000, increasing to almost $1 billion by 2010, and to $1.15 billion in 2020. Source categories with more than $100 million in estimated compliance costs in 2000 include hazardous waste treatment, storage and disposal facilities (TSDFs), automobile surface coating (at auto assembly plants), and metal surface coating. While the magnitude of the estimated compliance costs increases somewhat from 2000 to 2010, the distribution remains nearly the same, with the exception that the OTC model rules are added, with the OTC solvent cleaning rule being among the most costly in 2010. The OTC solvent cleaning rule has an estimated $110 million compliance cost in that year. Results for 2020 are similar to those in 2010. By 2020, municipal solid waste landfills have a compliance cost above $100 million.

Air ControlNET-Based Analyses

AirControlNET's Least Cost Module was used to estimate additional non-EGU and area source control costs for the 1-hr ozone standard that are not captured elsewhere. In this analysis, the Least Cost Module inputs were 2002 annual NO_x and VOC reduction targets by nonattainment area and the nonattainment area county specifications. The targets were derived from our research of adopted rules implemented in SIPs for non-attainment areas not among the eastern states affected by the NOx SIP call or Ozone Transport Region model rules. Our research for these areas is reported in detail in Chapter 3 of the accompanying Second Prospective emissions report. The results of the cost analysis for these additional measures are summarized by area in Exhibit 5-10. Analysis for two of the areas including in Exhibit 5-10 - the Bay Area Air Quality Management District (BAAQMD) in northern California, and the South Coast Air Quality Management District in southern California - is described in greater detail in the next section and in Appendix D.

The 1-hour ozone NAAQS cost analysis for the nonattainment areas in Texas and Louisiana with NO_x emissions caps takes the total point source NO_x emission reductions that are needed from 2002 NO_x emission levels and applies an emissions cap, or an emission reduction target in order to meet the emission cap. In the Houston-Galveston-Brazoria (HGB) area, the NO_x cap attempts to achieve an 80 percent reduction in certain point source NO_x emitters from a 1999 baseline. This reduction is modeled in the section 812 study as a 55 percent reduction from 2002 emissions from non-EGU point sources.

In total, AirControlNET applies non-EGU point source control measures to the HGB area to reduce 43,000 tons per year of NO_x emissions. These reductions are achieved at an average cost of $6,000 per ton. However, the marginal cost of the last ton reduced is about $12,500 per ton. The most expensive controls simulated are applying low NO_x burners plus selective catalytic reduction (SCR) to the process heaters at the petrochemical facilities in the HGB area.

Similar analyses are performed to estimate the NO_x program control costs associated with the 1-hour ozone SIPs for the Beaumont-Port Arthur and Dallas-Ft. Worth areas in Texas, and the Baton Rouge, LA area. The control regions are the same as the 1-hour ozone nonattainment area definition in the two Texas areas. The Baton Rouge emissions cap applies to a nine parish control region in and around the nonattainment area.

The 1-hour ozone cost estimation for the California nonattainment areas focuses on the source categories with expected VOC and NO_x emission changes resulting from regulations that influence emissions in the period between 1999 and 2010. As is noted in the companion emissions analysis report, the ARB provided a control factor file by source category and air pollution control district that was applied to estimate emission changes via regulation during this period. The source classification codes for these affected source categories were matched with control measures in AirControlNET to estimate the costs associated with meeting the regulations by nonattainment area.

Exhibit 5-10. 1-Hour Ozone Non-EGU Point Source Control Cost

Nonattainment Area	Emission Reduction Target (tons)		Available AirControlNET Reductions (tons)		Annual Cost (million 1999$)	
	NO_x	VOC	NO_x	VOC	NO_x	VOC
Baton Rouge	25,448	-	27,948	-	$17	$-
Beaumont-Port Arthur	7,187	-	8,688	-	6	-
Dallas-Fort Worth	199	-	239	-	0	-
Houston Galveston Area	62,210	-	43,095	-	266	-
Los Angeles-South Coast	1,194	5,563	1,565	418	1	5
Monterey Bay	-	-	-	-	-	0
Sacramento Metro	6	84	17	25	0	0
San Diego	-	31	-	68	-	1
San Francisco-Bay Area	8,524	372	9,796	388	13	5
San Joaquin Valley	3,859	71	3,975	83	1	1
San Joaquin Valley-Merced	10	-	45	-	0	-
Santa Barbara-Santa Maria	758	659	999	-	0	-
Southeast Desert Modified	459	809	536	100	0	1
Ventura Co CA	9	6	17	-	0	-
TOTALS					$304	$13

The ability of AirControlNET to correctly simulate the compliance strategy and cost of meeting the emission requirements for a source category is related to whether the model has control measures for each source category that are representative of how the source will actually comply. For example, for VOC emitting point sources in the South Coast Air Basin (SCAB), AirControlNET estimates that coating operations will need to build total permanent enclosures around each major VOC emission source. This control technique can cost upwards of $10,000 per ton in some situations.

California Nonattainment Area SIP-Based Analyses

As a supplement to the 1-hour ozone cost analysis described previously in this chapter, historical information from the 1-hour ozone SIPs from two of the prominent ozone nonattainment areas in California - the Bay Area and the South Coast Air Basin were evaluated. This information allowed us to develop an independent estimate of the costs to meet the 1-hour ozone NAAQS for these areas and to improve upon the estimates made using AirControlNET. This analysis is described in Appendix D and summarized below.

For the Bay Area, the 2005 Ozone Strategy describes how the Bay Area will fulfill California Clean Air Act planning requirements through the proposed control strategy. The control strategy includes stationary source control measures to be implemented through Air District regulations; mobile source control measures to be implemented through incentive programs and other activities; and transportation control measures to be implemented through incentive programs in cooperation with the Metropolitan Transportation Commission, local governments, transit agencies, and others.

The estimated annual cost of the Bay Area stationary and area source control measures to meet the 1-hour ozone NAAQS is $286 million in 1999 dollars. This cost estimate is based on control measures that have estimated dollar per ton estimates in the BAAQMD clean air plans. This cost estimate could be somewhat higher if the cost of measures which had no dollar per ton estimates provided in BAAQMD reports were included, assuming that most of these measures are unlikely to be cost-saving in nature.

The 1997 South Coast Air Quality Management District (SCAQMD) plan for attaining the 1-hour ozone NAAQS for the South Coast Air Basin was used to estimate the cost of stationary and area source control measures adopted in the SCAB since the 1990 CAAA (SCAQMD, 1996). The annual cost of the ozone precursor control measures adopted in this time period is estimated to be $219 million (1999 dollars). This represents the cost of the point and area source control measures with cost per ton values provided in the SCAQMD plan documents. This expenditure is expected to provide combined reactive organic gas (ROG) plus NO_x emission reductions of 123.1 tons per day, or 44,931 tons per year. Therefore, the combined ROG plus NO_x cost effectiveness is $4,870 per ton.

Exhibit 5-10 shows the estimated cost for the ozone NAAQS compliance measures implemented by the ozone nonattainment areas in Texas and California (those outside of the NO_x SIP Call area). The columns labeled "Emission Reduction Target" provide the estimated emission amounts that need to be reduced to either meet the NO_x emissions cap (in Louisiana and Texas areas) or the emissions that are estimated to be reduced via regulation (in total) in the air districts in California.

Houston-Galveston-Brazoria Area Highly Reactive VOC Rules Analyses

A significant feature of the Houston-Galveston-Brazoria area 1-hour ozone SIP is the initiation of control programs to reduce highly reactive VOC (HRVOC) emissions at petroleum refineries and chemical plants in the nonattainment area. This cost analysis estimates the costs of applying controls to three HRVOC source types in this area: flares, fugitive VOC emissions, and cooling towers. In addition to the AirControlNET-based analysis of the costs of meeting the NO_x emissions cap in the HGB area, a separate assessment was performed of the costs of meeting the recent fugitive VOC emission limits that have been included in the 1-hour ozone SIP, and is described below.

Vent gas streams at petroleum refineries, natural gas processing and petrochemical processes that have the potential to emit highly reactive VOCs in the Houston-Galveston area are subject to certain VOC emission monitoring and control requirements. This rule establishes a fixed pounds per hour emission rate for all highly reactive VOCs emitted from each flare at a facility. In order to estimate the costs of this flare control requirement at HGB area facilities, the 2002 emission inventory for this nonattainment area was used to establish the cost of controlling a single flare based on cost estimates developed by the Texas Commission on Environmental Quality (TCEQ) and information from the EPA OAQPS Control Cost Manual for flares (which provided a breakdown between capital and operating costs). Based on data from the EPA cases and settlements that indicated that each refinery has on average three flares per facility, the per flare control costs were applied to the affected facilities in the HGB ozone nonattainment area to estimate the total annualized costs of this regulation in 2010 and 2020. The resulting cost estimate was $6.3 million.

Recent amendments to the HGB area SIP to reduce highly reactive VOCs from chemical and petroleum industry plants seek to reduce fugitive VOC emissions. The proposed leak detection and repair requirements will add quarterly monitoring for a variety of components that have been found to leak, yet in most cases are not currently required to be monitored. This rule would eliminate the leak skip option for valves, and would require an additional round of monitoring during the third quarter (July-September) of each year. The annual costs for this requirement were estimated using estimates made by the TCEQ which include the annual costs of increased monitoring frequency, adding new monitoring, repair costs and equipment upgrades. This estimated annual compliance cost for the HGB area is estimated to be $133.5 million.

For cooling tower controls, the HGB SIP measure establishes a one part per million by weight VOC concentration rise as a leak definition for cooling tower systems. The measure further requires monthly inspection of the cooling water to detect VOC leaks and allows a maximum of 45 days for any leak to be repaired after it is detected. Based on cost estimates from various vendors and TCEQ staff regarding purchase and installation of continuous flow monitors and sampling expenses, the initial capital cost and any associated first year operating expenses are estimated to be $70,000 for each cooling tower and heat exchange system in the HGB area. Annual operating and maintenance costs are estimated to be $52,000 for each cooling tower heat exchange system. For the estimated 115 affected units in the HGB area, regional compliance costs are estimated to be $2.1 million in capital and $6 million in annual operating and maintenance cost. The resulting annualized cost estimate for this measure in the HGB area is $6.2 million.

The total annualized cost of these HRVOC emission reduction measures is $146 million.

PM_{10} SIP MEASURES

In this section we describe the estimates of costs that have been incurred to meet the PM_{10} ambient air quality standards since 1990. These estimates were developed by reviewing PM_{10} SIPs and associated control cost estimates for selected serious PM_{10} nonattainment areas. The serious PM_{10} nonattainment area SIPs that were reviewed included those for Coachella Valley, CA, South Coast, CA, Clark County, NV, and Maricopa County, AZ. The estimated compliance cost for these four PM_{10} nonattainment areas was $24 to $29 million. In these areas, most of the compliance cost was in controlling fugitive dust emissions from paved and unpaved roads and construction activities. More information about this serious PM_{10} nonattainment area analysis is provided in Appendix C.

To estimate the compliance costs for the remaining serious PM_{10} nonattainment areas and the moderate PM_{10} nonattainment areas, a model PM_{10} SIP was developed that applied control measures in AirControlNET to the three major fugitive dust source categories listed above to estimate control costs. Controls on each of these source categories are judged to be representative of the control measures applied in PM_{10} nonattainment areas in the western United States, where most of the PM_{10} nonattainment areas were found. The total estimated cost to attain the PM_{10} NAAQS is estimated to be \$125 to \$130 million per year. Exhibit 5-11 summarizes the estimated costs of attaining the PM_{10} NAAQS at the state-level. This table includes the costs for serious and moderate PM_{10} nonattainment areas. A list of all non-attainment areas addressed in our PM_{10} analysis is included in Table C-8 in Appendix C

Exhibit 5-11. Cost Summaries by State for PM_{10} NAAQS

State	Annual Cost (million 1999$)
Arizona	18.1
California	24.5
Colorado	9.0
Connecticut	0.4
Idaho	11.1
Illinois	4.0
Indiana	2.1
Minnesota	0.2
Montana	7.6
Nevada	17.3
New Mexico	11.8
New York	0.1
Ohio	1.0
Oregon	6.9
Pennsylvania	0.8
Texas	1.5
Utah	2.3
Washington	7.7
West Virginia	0.4
Wyoming	2.7
TOTAL	**129.6**

SUMMARY OF RESULTS FOR THIS SECTOR

The program-specific cost estimates presented in the previous sections reflect the cost of manufacturing, installing, and operating individual emissions controls based on the prevailing state of technology. However, as regulated facilities gain experience with these technologies, costs are likely to decline. To account for this "learning curve" effect, we incorporated learning curve cost adjustments into our estimates of non-EGU point source compliance costs. As described in greater detail in Chapter 1, we applied a 10 percent learning rate as a learning curve adjustment for this sector, consistent with the Council's recommendation to use a default learning rate for technologies for which no empirical estimates of learning curve impacts are available in the literature (Council, 2007). That is, we assume a 10 percent reduction in costs with every doubling in cumulative production or cumulative experience. Because the learning curve literature estimates a learning rate of approximately 20 percent for many technologies, our assumption of a 10 percent learning rate may be conservative.[129] To measure cumulative experience with pollution control technologies used by non-EGU point sources, we used cumulative aggregate emissions reductions by non-EGU point sources in NO_x, SO_2, VOC, and PM since the enactment of the original Clean Air Act of 1970 as our metric of cumulative experience.

We estimated the emissions reductions for these pollutants over time based on the Second Prospective emissions estimates and the estimates developed for EPA's retrospective analysis of the Clean Air Act (U.S. EPA, 1997).[130]

Exhibit 5-12 summarizes the non-EGU point source costs for the major cost elements discussed in the preceeding sections, and Exhibit 5-13 presents the emission reductions associated with these costs.[131] As indicated in Exhibit 5-12, the annual costs expected to be incurred by non-EGU point sources under the Amendments range from $2.6 billion in 2000 to $4.4 billion in 2010 and $4.3 billion in 2020. In addition, the results in Exhibit 5-12 indicate that the MACT standards make up the most significant portion of costs among all of the non-EGU point source air pollution control programs.

To estimate the effect of the learning curve adjustments on total costs, Exhibit 5-14 presents cost estimates for the non-EGU point source sector with no learning curve adjustments. As suggested by these results, learning only has a small effect on the Project Team's cost estimates. For 2000, incorporating learning into the analysis increases the Project Team's cost estimates by 5.3 percent, while the learning curve adjustments for 2020 reduce the cost estimates by 5.4 percent. The learning curve adjustments increase the cost estimate for 2000 because the Project Team assumed that the unit cost values used for the analysis reflect the state of technology as of 2006; the learning that occurred between 2000 and 2006 should not be reflected in the Project Team's cost estimates for 2000.

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[129] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, Vol 9, No. 2, 1984.

[130] EPA's retrospective analysis of the Clean Air Act (CAA) of 1970 estimates without-CAA emissions for the 1970 to 1990 period. To estimate without-CAA emissions for 1990 through 2020, we assume that the growth rate for without-CAA emissions during this period would be the same as that estimated for the without-CAAA scenario, as estimated for the Second Prospective Emissions Analysis.

[131] Although the unit cost values presented earlier in this chapter are expressed in year 1999 dollars, the cost summary presented in this section expresses costs in year 2006 dollars to be consistent with the presentation of monetized estimates in other reports developed as part of the Second Prospective study.

Exhibit 5-12. Non-EGU Point Source Cost Summary (millions of year 2006$)

	Annual Cost		
	2000	**2010**	**2020**
NOx SIP Call	$0	$134	$133
MACT	$1,500	$3,010	$2,920
National VOC Rules, RACT, and New CTGs	$439	$464	$534
Refinery Settlements	$0	$295	$324
1-Hour Ozone SIP Measures			
AirControlNET-Based Analyses	$397	$370	$357
CA Area SIP Costs	$633	$590	$569
H-G HRVOC Measures	$0	$169	$164
PM_{10} SIP Measures	$163	$152	$146
Total	**$3,130**	**$5,190**	**$5,140**

Exhibit 5-13. Non-EGU Point Source Emissions Summary (values reported in thousands of tons)

Pollutant	2000 *Without-CAAA*	2000 *With-CAAA*	2000 *Reductions*	2010 *Without-CAAA*	2010 *With-CAAA*	2010 *Reductions*	2020 *Without-CAAA*	2020 *With-CAAA*	2020 *Reductions*
VOCs	3,080	1,400	1,680	3,460	1,440	2,030	4,000	1,650	2,350
NO_x	3,330	2,290	1,040	3,560	2,250	1,310	4,000	2,510	1,490
CO	6,470	3,110	3,350	6,810	3,290	3,520	7,380	3,680	3,700
SO_2	4,100	2,190	1,910	4,490	2,180	2,310	4,870	2,390	2,480
PM_{10}	2,010	598	1,420	2,200	583	1,620	2,490	682	1,810
$PM_{2.5}$	365	365	0	394	394	0	451	451	0
NH_3	236	154	82	237	174	64	256	202	54

Notes: The *with-CAAA* emissions estimates and associated reductions presented here reflect the emission control measures described in this chapter. They do not reflect the non-EGU point source local control measures reflected in Chapter 7.

Exhibit 5-14. Non-EGU Point Source Cost Summary, No Learning Curve Adjustments (millions of year 2006$)

	Annual Cost		
	2000	**2010**	**2020**
NOx SIP Call	$0	$138	$140
MACT	$1,420	$3,080	$3,080
National VOC Rules, RACT and New CTGs	$417	$474	$568
Refinery Settlements	$0	$303	$344
1-Hour Ozone SIP Measures			
AirControlNET-Based Analyses	$377	$377	$377
CA Area SIP Costs	$601	$601	$601
H-G HRVOC Measures	$0	$174	$174
PM_{10} SIP Measures	$155	$155	$155
Total	**$2,970**	**$5,300**	**$5,440**

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CHAPTER 6 | NONPOINT SOURCE ANALYSIS

Many of the Title I requirements of the CAAA of 1990 provisions affect VOC emissions from nonpoint sources. These requirements include Title I RACT, new control technique guidelines (CTGs), and national rules. Title I RACT controls were applied in moderate and above 1-hour ozone nonattainment areas and throughout the Ozone Transport Region. Title I national rules included those that reduce VOC emissions from consumer products, architectural and industrial maintenance (AIM) coatings, autobody refinishing, hazardous waste transportation, storage, and disposal facilities (TSDFs), municipal landfills, and marine vessel loading. Cost per ton estimates were available for each of the national rules and these values were applied in this analysis to estimate the cost of complying with the Amendments.

Title I RACT requirements were identified in the First Prospective analysis. Rather than duplicate the effort for this historical program, we rely on the incremental emissions estimates from that analysis here, but update the cost estimates to reflect unit cost values in the current version of AirControlNET. Pages 33-42 of the First Prospective emissions report (Pechan, 1998) identify the source categories, control levels and cost per ton values that were used to estimate Title I RACT costs for the First Prospective. Table VII-13 in the First Prospective emissions report summarizes the Title I RACT area source unit costs that were applied in this analysis. The information from Table VII-13 was used to identify the control technique in AirControlNET that could achieve the expected emission reduction. These RACT-level control techniques were then applied to the 1990 NEI projected to 2000, 2010 and 2020 (the *without-CAAA* scenario) to estimate the tonnage reductions achieved by each RACT requirement for each source category. Exhibit 6-1 summarizes the estimated emission reductions (control efficiencies), rule effectiveness values, and average cost per ton applied in this analysis to estimate the area (nonpoint) source costs of national, regional and local regulations to reduce VOC emissions from this sector post-1990.

Exhibit 6-2 shows the estimated cost for the 1-hour ozone NAAQS compliance measures applied to area (nonpoint) sources for the ozone nonattainment areas in California. The columns labeled “Emission Reduction Target” provide the estimated emission reductions via regulation (in total) in the air districts in California. The column labeled “Available Reductions in AirControlNET” indicates measures identified in AirControlNET applied to achieve the needed reductions. The unit costs for the measures selected from AirControlNET are presented in the right-hand column of Exhibit 6-2. Note that there is one area (Monterey Bay) where there were no measures available to meet the 491 ton VOC emission reduction target. Costs to adopt those unidentified measures are not reflected in this report.

Exhibit 6-1. Area Source VOC Cost Inputs by Source Category

Source Category	VOC Control-Effectiveness (%)	VOC Rule-Effectiveness (%)	Cost Per Ton (1999$)
Architectural & industrial maintenance coating	20	100	223
Automobile refinishing	37	100	148
Bulk Terminals	78	100	243
Consumer solvents	20	49	306
Dry cleaning – petroleum	44	100	590
Municipal solid waste landfills	82	100	1,317
Oil and natural gas production fields	95	80	419
Paper surface coating	37	80	419
Pharmaceutical manufacture	37	80	3,424
SOCMI batch reactor processes	78	80	4,283
Service stations - stage I-truck unloading	95	80	984
Treatment, storage and disposal facilities	94	100	186
Web Offset Lithography	80	80	-132
OTC AIM Coating Rule	45	100	6,628
OTC Solvent Cleaning Rule	66	100	1,400
OTC Consumer Products Rule	34	49	1,032
OTC Mobile MER Rule	61	100	2,534
OTC Portable Gas Container Rule	33	100	581

Note: VOC control- and rule-effectiveness are derived from EPA guidance to states on the extent to which these measures may be credited toward forecast emissions reductions in state implementation plans.

The program-specific cost data presented in Exhibits 6-1 and 6-2 reflect the cost of manufacturing, installing, and operating individual emissions controls based on the prevailing state of technology. However, as regulated facilities gain experience with these technologies, costs are likely to decline. To account for this "learning curve" effect, we incorporated learning curve adjustments into our aggregate cost estimates for the nonpoint sector. Similar to the cost estimates for non-EGU point sources presented in Chapter 5, the cost estimates in Exhibit 6-3 reflect the Project Team's adjustments for learning curve impacts. Consistent with the Council's advice that the Project Team use a default learning rate for technologies and industries for which no empirical information is available in the learning curve literature, we used a default learning rate of 10 percent for nonpoint sources. Because the learning curve literature estimates a learning rate of approximately 20 percent for many technologies, our use of a 10 percent default learning rate may be conservative.[132] To measure cumulative experience with pollution control technologies used by nonpoint sources, we used cumulative aggregate emissions reductions by nonpoint sources of NO_x, SO_2, VOC, and PM since the enactment of the original Clean Air Act of 1970 as our metric of cumulative experience. We estimated the emissions reductions for these pollutants over time based on the Second Prospective emissions estimates and the estimates developed for EPA's retrospective analysis of the Clean Air Act (U.S. EPA, 1997).

[132] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, Vol 9, No. 2, 1984.

Exhibit 6-2. 1-Hour Ozone NAAQS Area Source Control Cost Estimates

Nonattainment Area	Emission Reduction Target (tons)		Available Reductions in AirControlNET (tons)		Annual Cost (million 1999$)	
	NO_x	VOC	NO_x	VOC	NO_x	VOC
Baton Rouge	-	-	-	-	-	-
Beaumont-Port Arthur	-	-	-	-	-	-
Dallas-Fort Worth	-	-	-	-	-	-
Houston Galveston Area	-	-	-	-	-	-
Los Angeles-South Coast	15	18,458	39	19,103	-	52
Monterey Bay	-	491	-		-	(0)
Sacramento Metro	-	200	-	250	-	0
San Diego	-	-	-	-	-	-
San Francisco-Bay Area	241	3,992	313	4,087	0	5
San Joaquin Valley	1,227	5,865	2,109	6,287	0	4
San Joaquin Valley-Merced		294	-	321	-	1
Santa Barbara-Santa Maria-Lomp	-	-	-	-	-	-
Southeast Desert Modified	-	-	-	-	-	-
Ventura Co CA	-	-	-	-	-	-
TOTALS					$0	$62

Note: Costs for Monterey Bay NAA are slightly negative because the VOC measures employed are net cost saving.

Exhibit 6-3 summarizes the cost results for the three major components of the nonpoint sector.[133] The cost estimates for the first two elements in the exhibit (CTGs plus RACT and OTC Model Rules) are based on the values listed as area source measures in Exhibits 5-7 through 5-9 in Chapter 5. The table shows that the annual estimated costs for this sector range from $557 million in 2000 to $644 million in 2020. Exhibit 6-4 summarizes the emissions reductions associated with these costs.

To assess the extent to which the learning curve adjustments described above affected the cost estimates presented in Exhibit 6-3, we developed alternative cost estimates that reflect no learning curve impacts. Exhibit 6-5 summarizes the results of this analysis. These results indicate that the learning curve adjustments discussed above have a moderate effect on the Project Team's cost estimates, ranging from a 10.7 percent increase in costs for 2000 to a 12.8 percent reduction in costs for 2020. As with non-EGU point sources, our learning curve adjustment increased estimated costs for 2000 while decreasing estimated costs for 2010 and 2020. This reflects the Project Team's assumption that the unit cost values used for the analysis reflect the state of technology as of 2006; the learning that occurred between 2000 and 2006 should not be reflected in the Project Team's cost estimates for 2000.

[133] Although the unit cost values presented earlier in this chapter are expressed in year 1999 dollars, the cost summary presented in this section expresses costs in year 2006 dollars to be consistent with the presentation of monetized estimates in other reports developed as part of the Second Prospective study.

Exhibit 6-3. Nonpoint Source Cost Analysis Summary (millions of year 2006$)

	Annual Costs		
	2000	**2010**	**2020**
CTGs Plus RACT	$446	$442	$490
OTC Model Rules	$134	$181	$212
1-Hour Ozone NAAQS	$82	$70	$64
TOTALS	**$663**	**$693**	**$766**

Exhibit 6-4. Nonpoint Source Emissions Summary for 2000, 2010, and 2020 (values reported in thousands of tons)

Pollutant	2000			2010			2020		
	2000 *Without-CAAA*	2000 *With-CAAA*	2000 *Reductions*	2010 *Without-CAAA*	2010 *With-CAAA*	2010 *Reductions*	2020 *Without-CAAA*	2020 *With-CAAA*	2020 *Reductions*
VOCs	12,300	8,540	3,720	13,400	8,870	4,550	15,700	9,720	5,990
NOx	4,650	3,890	765	4,840	3,690	1,150	5,200	3,730	1,470
CO	15,600	14,600	1,020	14,700	14,600	103	15,100	15,500	-363
SO_2	2,070	1,880	196	2,450	1,880	576	3,040	1,940	1,100
PM_{10}	23,100	19,300	3,790	22,800	18,800	3,970	24,300	19,000	5,240
$PM_{2.5}$	4,370	4,100	264	4,360	4,060	298	4,620	4,170	451
NH_3	3,620	3,550	70	3,830	3,710	115	4,130	3,990	144

Note: The *with-CAAA* emissions estimates and associated reductions presented here reflect the emission control measures described in this chapter. They do not reflect the nonpoint local control measures reflected in Chapter 7.

Exhibit 6-5. Nonpoint Source Cost Analysis Summary, No Learning Curve Adjustments (millions of year 2006$)

	Annual Costs		
	2000	**2010**	**2020**
CTGs Plus RACT	$403	$463	$563
OTC Model Rules	$121	$189	$243
1-Hour Ozone NAAQS	$74	$74	$74
TOTALS	**$599**	**$726**	**$879**

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CHAPTER 7 | LOCAL CONTROL MEASURES ANALYSIS

The cost analysis described in the previous chapters of this report reflect Federal measures and state and local control programs that were on-the-books as of September 2005, but do not include the additional local measures expected to be adopted to achieve further progress toward 8-hour ozone and $PM_{2.5}$ NAAQS attainment. This chapter describes the analysis that was performed to estimate the control costs resulting from implementation of the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the Clean Air Visibility Rule, or CAVR (sometimes referred to as the best available retrofit technology, or BART, rule). These are all proposed or final rules that have been issued recently by EPA. The baseline for performing this local control measures evaluation is the core scenario from the *with-CAAA* 2010 and 2020 cases.

The local control measure analysis was performed in three sequential steps: 8-hour ozone NAAQS implementation; CAVR rule implementation; and PM NAAQS implementation.[134] Note that our analysis assumes that efforts toward compliance with the 1-hour ozone NAAQS and the current PM_{10} NAAQS for historical years are captured in the core scenarios as they currently exist, which include local controls identified by RPOs and which are described in the previous chapters of this report.

The main cost and control measure database used for these analyses was developed from version 4.1 of AirControlNET released in September 2005, with some updates to incorporate 1-hour ozone NAAQS local control measure information and additional on-road mobile source control measures. The analysis year for the ozone and PM NAAQS analyses is 2010. The Project Team applied local controls identified for 2010 to generate results for 2020. The analysis year for the CAVR is 2020, since it is expected that the majority of controls implemented to satisfy this rule's requirements will occur after 2010. The methods used for each analysis are described below, in the order in which they were implemented as further incremental reductions from the core scenario emissions inventories.

8-HOUR OZONE ANALYSIS

This analysis focused on the implementation costs in nonattainment areas in the United States. These nonattainment areas are divided into two overlapping groups. The first

[134] The sequence of controls modeled in this analysis was designed to mimic how SIP planners would approach control strategies for their districts—they must first take account of national and regional requirements and then determine what local controls may be needed to make progress toward attainment. The array of local control options available after the implementation of national and regional requirements influences the costs of local controls in a given location. Within the local controls analysis itself, we use the same control measure database to estimate the cost of all local controls. The modeled sequencing of these local controls does not affect the total cost of local controls but may affect the attribution of local control costs between the 8-hour Ozone NAAQS, CAVR, and the $PM_{2.5}$ NAAQS.

group includes areas where additional local controls are anticipated to be needed to meet the NAAQS by 2010. Reduction target levels for this group of areas were derived directly from the area-specific target emissions reduction levels derived to support the ozone implementation economic analysis (Pechan 2005a). Because percentage reduction (both VOC and NO_x) emission targets were used, and because the Federal rule inventories and target years used in the present analysis differ from those used in the economic analysis (the present analysis starts from a 2002 baseline, while the previous EPA analyses use a 2001 platform–developed from a 1999 NEI baseline), the actual absolute reductions for each nonattainment area differ slightly from those modeled in the economic analysis.

The second group consists of 8-hour ozone nonattainment areas for which certain mandatory CAA control obligations for moderate and above areas are required pursuant to Subpart 2 of the Act. Mandatory controls include adoption of an inspection and maintenance program for light-duty vehicles and a 15 percent VOC emission reduction requirement. For purposes of this analysis, we assume that both Group 1 and Group 2 areas require adoption of reasonably available control technology (RACT) on large stationary sources (those emitting more than 100 tons of VOC or NO_x per year) in areas that have not already adopted RACT. It should be noted that, under the CAA, states determine RACT levels and applicability on a case-by-case or source category basis considering EPA guidance and other information. Therefore, RACT levels eventually set by individual states may differ from the RACT levels adopted for this analysis.

An important caveat for the 8-hour ozone NAAQS attainment analysis is that VOC and NO_x emission reduction targets for California nonattainment areas were not estimated by EPA. This decision was motivated primarily by poor model performance at the time simulations were conducted by EPA for ozone concentrations in various ozone nonattainment areas within California. As a result, the Project Team developed alternative methods to estimate VOC and NO_x emission reductions targets to meet the 8-hour ozone NAAQS for California nonattainment areas. These methods are described in more detail in Appendix E of this document.

For California, the 8-hour ozone NAAQS attainment costs were estimated for serious and above nonattainment areas. California areas that are classified as either serious or severe ozone nonattainment are: Sacramento Metro (subpart 2 serious), San Joaquin Valley (subpart 2 serious), Riverside Co. (Coachella Valley) (subpart 2 serious), and Los Angeles-South Coast Air Basin (subpart 2 severe 17).

For each area, publicly available 8-hour ozone modeling results and/or draft 8-hour ozone SIPs were consulted and inquiries were made to State employee contacts when emissions reduction target information was not available. Since these nonattainment areas are classified as serious or above, we assumed that RACT requirements had previously been met and no further RACT control measures were needed to satisfy the RACT requirement. Similarly since the VOC reasonable further progress (RFP) requirements for these nonattainment areas were included in the 2010 VOC emission reduction targets (see Appendix E) no additional control measures were needed. One consequence of this approach is that the 2010 costs for California presented here include the cost of satisfying RFP requirements in addition to reductions needed to meet 8-hour ozone NAAQS in 2010 even though the attainment date in two areas is not until 2013.

RACT AND I/M

RACT controls on EGU and non-EGU point sources were applied in the areas where RACT requirements had not yet been met. As a general rule, 8-hour ozone nonattainment area counties were assumed to have already met their RACT requirements if they were previously designated as nonattainment of the 1-hour ozone NAAQS.

For this study, RACT applicability was determined on a control measure basis using the following criteria initially developed for the 8-hour ozone NAAQS implementation economic analysis. Note that all of the criteria have to be met:

- Current NO_x control efficiency is zero, i.e., it is an uncontrolled source in 2002;
- Total annual NO_x emissions of the source is greater than 100 tons (i.e., large source);
- Control efficiency of the control is less than 81 percent for NO_x;
- Control cost is less than $1,580 per ton NO_x reduced (i.e., cost effective control is available); and
- If multiple controls meeting the above criteria are available, then the control measure with the lowest NO_x control efficiency from all that are available for that source is applied (i.e., RACT represents the minimum available control that nonetheless meets the above criteria).

I/M controls are then applied to counties where required. Once I/M and RACT controls were applied, the costs of meeting the additional emission reduction requirements (RFP and Target levels) were determined for each area by using control techniques, efficiencies, and cost databases in concert with the incremental emission reduction and progress requirements mentioned above. For additional local controls, a least-cost algorithm was used to identify and apply the control measures to meet the progress requirements, where applicable. First, the potential sources of emission and reductions and their costs were identified. Next, the lowest cost, second lowest, third lowest, and so forth, control measures were selected until the progress requirement was met. Because of the discrete nature of control measures and their efficiencies, sometimes the emission reduction or progress target is exceeded. Any excess might be used as an offset against new source growth emissions, if the excesses were significant.

REASONABLE FURTHER PROGRESS (RFP) REQUIREMENTS

The reasonable further progress requirement (RFP) is an attainment program element requiring incremental reductions in the emissions of the applicable air pollutant pursuant to Part D of the CAA and its Amendments. The RFP requirements are intended to ensure that each ozone nonattainment area makes progress toward achieving sufficient precursor emission reductions to attain the national ambient air quality standards for ozone. More specifically, the Act requires certain ozone nonattainment areas classified as moderate or above to achieve actual VOC emission reductions of at least 15 percent over an initial 6-year period, and subsequently to achieve further emission reduction progress of three percent per year averaged over each consecutive three-year period until attainment.

The first step needed to determine if additional RFP emission reductions are required in certain 8-hour ozone nonattainment areas is to compare VOC emission estimates of 2002 with 2008. This is because the VOC emission reduction requirements obtained from 2002 to 2008 as a result of on-the-books Federal and local air pollution control programs count toward the 15 percent reduction requirement. For the 8-Hour Ozone Implementation rule, 2002 is the base year. Exhibit 7-1 shows the VOC progress requirements to meet a 15 percent reduction from 2002 emission levels by 2008. The 15 percent reduction calculation allows 100 percent credit for VOC reductions achieved from 2002 to 2008 through implementation of other emission reduction programs, such as implementation of OTC model rules to reduce VOC solvent emissions. The 2008 emissions were estimated by interpolating 2002 and 2010 emission estimates.

The one exception to the 100 percent credit allowance is that mobile source reductions are discounted by 13 percent (i.e., only 87 percent of mobile source reductions are creditable toward the RFP progress requirements). The reason this discount is applied is because there are certain reductions in motor vehicle emissions that will occur in the future, but are the result of actions taken prior to the enactment of the 1990 CAAA. (The methods to account for non-creditable reductions when calculating RFP Targets for the 2008 and Later RFP Milestone Years is provided in Appendix A to the Preamble for the Final Rule to Implement the 8-Hour Ozone NAAQS, at 70 FR 71612.)

The reductions required to meet RFP targets are allowed from sources within a 100 km radius of the nonattainment area boundary for VOC reductions and within a 200 km radius of the nonattainment area boundary for NO_x reductions. However, each time a source/control measure from outside the nonattainment area boundary was selected to meet an RFP target requirement, the RFP target for that area was recalculated. RFP target recalculation was performed by adding the selected source emissions to the base inventory of the area. The RFP target recalculation followed the RFP target calculation methods described below.

Exhibit 7-1. Reasonable Further Progress Requirements for VOC in Designated 8-Hour Ozone Nonattainment Areas

Area Name	Base Case 2008 VOC Emissions (tons)	Estimated Additional VOC Reductions to Meet 15% RFP Requirements (tons)	Estimated Additional VOC Reductions Observed in 2008 as a % of 2008 Base Case Emissions
Allegan Co, MI	11,446	1,876	16.40%
Atlanta, GA	228,148	3,637	1.60%
Baltimore, MD	95,268	13,256	13.90%
Beaumont-Port Arthur, TX	40,683	8,607	21.20%
Buffalo-Niagara Falls, NY	65,367	2,325	3.60%
Chicago-Gary-Lake County, IL-IN	92,000	-	0.00%
Cleveland-Akron-Lorain, OH	126,044	13,319	10.60%
Columbus, OH	58,772	5,245	8.90%
Dallas-Fort Worth, TX	162,128	33,197	20.50%
Detroit-Ann Arbor, MI	170,290	11,253	6.60%
Door Co, WI	4,412	1,184	26.80%
Houston-Galveston-Brazoria, TX	210,185	49,043	23.30%
Indianapolis, IN	58,050	-	0.00%
Kent and Queen Anne's Cos, MD	3,918	90	2.30%
Kern Co (Eastern Kern), CA	33,816	1,115	3.30%
Knoxville, TN	48,788	2,372	4.90%
Los Angeles South Coast Air Basin, CA	297,667	6,790	2.30%
Milwaukee-Racine, WI	99,269	12,621	12.70%
Nevada Co. (Western Part), CA	4,461	-	0.00%
New York-N. New Jersey-Long Island, NY-NJ	571,745	-	0.00%
Philadelphia-Wilmin-Atlantic Ci, PA-NJ-MD	256,489	9,401	3.70%
Providence (All RI), RI	26,859	-	0.00%
Raleigh-Durham-Chapel Hill, NC	64,458	9,134	14.20%
Sacramento Metro, CA	61,301	5,173	8.40%
San Diego, CA	73,409	9,265	12.60%
San Joaquin Valley, CA	106,002	11,941	11.30%
Sheboygan, WI	8,771	1,538	17.50%
South Bend-Elkhart, IN	24,937	266	1.10%
Ventura Co, CA	24,718	6,802	27.50%
Washington, DC-MD-VA	135,314	10,785	8.00%
Youngstown-Warren-Sharon, OH-PA	29,605	1,104	3.70%

Note: Estimates for most California 8-hour ozone NAAs were developed separately - see text and Appendix E for details.

RFP CALCULATION METHODOLOGY

The first step in determining if additional RFP emission reductions are required is to compare VOC emission estimates for calendar year 2002 with those estimated for 2008. This computation is necessary because the VOC emission reductions obtained from 2002 to 2008 as a result of on-the-books Federal and local air pollution control programs count toward the 15 percent reduction requirement.

The RFP requirement for each nonattainment area is calculated by subtracting 85 percent of 2002 emissions (i.e., reduction by 15 percent) from the 2008 emissions, assuming that mobile source emission changes are discounted by 13 percent. If this value is greater than zero, this is the RFP reduction requirement for that nonattainment area. If that value is less than or equal to zero, no further RFP reduction is required.

Below is a sample calculation for Baltimore, MD nonattainment area:

2002 emissions totals = 99,796 tons VOC

2010 *with-CAAA* scenario emissions totals = 93,758 tons

Interpolation of 2002 and 2010 yields 2008 emissions = 95,267 tons

After discounting of mobile emissions by 13 percent, 2002 emission = 96,484 tons.

Additional VOC tons required = (2008 Emissions) - (85 percent of discounted 2002 Emissions)

= (95,267) - (0.85 x 96,484)

= 13,256 tons

ADDITIONAL EMISSION REDUCTIONS TO MEET TARGETS

Similarly, and after applying I/M, RACT, and RFP, if an area required additional reductions to meet their emission reduction target for NO_x and/or VOC (e.g., Group 1 areas), source/controls within 100 km radius of the nonattainment area boundary for VOC reductions and within 200 km radius of the nonattainment area boundary for NO_x reductions are selected on a least cost basis, as described above for RFP. No measures are applied, however, if their cost exceeds $15,000 per ton. The rationale for incorporating this threshold into the analysis is that controls more costly than $15,000 per ton may not be cost effective. Thus, local air quality agencies would seek reductions from other (unidentified) controls measures. This is consistent with the practice of the South Coast Air Quality Management District (SCAQMD) in California, which attempts to identify viable alternatives for any control requirements with an estimated cost exceeding $16,500 per ton.[135] When costs are above this threshold, the SCAQMD also conducts more detailed cost-effectiveness and economic impact analyses of the controls.

MARGINAL COST ANALYSIS

Exhibit 7-2 presents the marginal and average cost per ton, by metropolitan area, of the NO_x and VOC emissions reductions associated with the RACT, I/M, and RFP measures described above.[136] As the table indicates, marginal and average costs per ton of NO_x and VOC abated vary significantly by area. These differences largely reflect the distribution of NO_x and VOC reductions across different source categories and the stringency of the Federal, state, and local programs that were on the books in each area as of September 2005 (the RACT, I/M, RFP, and additional measures reflected in Exhibit 7-2 are incremental to programs in place in September 2005). For example, the average costs per ton of NO_x reduced are highest in Allegan County, Michigan and the Detroit-Ann Arbor area, both of which we expect to rely exclusively on reductions from onroad sources, which tend to be more expensive to control on a per ton basis than large industrial and

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135 South Coast Air Quality Management District (2006). 2007 Air Quality Management Plan. http://www.aqmd.gov/aqmp/07aqmp/07AQMP.html.

136 As indicated above, our analysis of RACT, I/M, and RFP reflects only identified measures included in version 4.1 of AirControlNet.

utility point sources. Similarly, the average and marginal cost per ton of NO_x abated is lowest in the Atlanta area. This reflects the area's ability to achieve most its NO_x reductions through additional controls at electric utilities. Based on the local controls analysis presented in the Second Prospective emissions report, we estimate that Atlanta will reduce NO_x emissions by an additional 7,223 tons in 2010 to demonstrate further progress toward compliance with the 8-hour ozone NAAQS and that 98 percent of this reduction can be achieved through additional controls at electric utilities. Although we expect other areas to also rely heavily on reductions at utilities, the cost of reducing EGU NO_x emissions in the Atlanta area is lower than in other areas because utilities are not regulated as stringently in Georgia as in other regions. For example, although we expect the Raleigh area to achieve most of its NO_x reductions through electric utility controls, the marginal and average cost per ton of NO_x abated is high in Raleigh relative to Atlanta because North Carolina emissions requirements for electric utilities are more stringent than Georgia's requirements. In other words, utilities in North Carolina have already implemented the controls at the lower end of their marginal cost function.

Exhibit 7-2. 2010 Marginal Cost Per Ton for Identified Local Controls to Meet the 8-Hour Ozone NAAQS (1999$)

	Marginal Cost per ton		Average Cost per ton	
Nonattainment Area	**NOx**	**VOC**	**NOx**	**VOC**
Allegan Co, MI	$26,145	$13,284	$20,860	$7,774
Atlanta, GA	$50	$1,032	$10	$788
Baltimore, MD	$8,608	$13,285	$2,437	$4,791
Beaumont-Port Arthur, TX	$27,588	$24,990	$7,045	$6,653
Buffalo-Niagara Falls, NY	$2,087	$1,433	$1,198	$1,253
Chicago-Gary-Lake County, IL-IN	$3,381	$14,005	$1,629	$6,543
Chicago-Gary-Lake County, IL-IN (Cook, IL & Lake, IN)	$12,644	$13,284	$3,456	$7,586
Cleveland-Akron-Lorain, OH	$26,091	$1,433	$770	$1,179
Columbus, OH	$27,045	$1,433	$7,425	$1,177
Dallas-Fort Worth, TX	$27,453	$18,511	$4,086	$5,808
Detroit-Ann Arbor, MI	$26,444	$2,908	$20,556	$1,962
Door Co, WI	$26,423	$2,677	$3,018	$1,411
Houston-Galveston-Brazoria, TX	$27,495	$17,941	$6,853	$5,763
Indianapolis, IN	$2,710	-	$1,418	-
Kent and Queen Anne's Cos, MD	$28,564	$13,285	$12,638	$7,349
Knoxville, TN	$28,118	$17,967	$16,931	$1,689
Los Angeles South Coast Air Basin, CA	$3,956	$6,603	$2,182	$1,789
Milwaukee-Racine, WI	$12,644	$2,908	$3,012	$1,882
Nevada Co. (Western Part), CA	$1,783	$6,388	$1,703	$3,091
New York-N. New Jersey-Long Island, NY-NJ	$12,644	$13,286	$2,810	$6,323
Philadelphia-Wilmin-Atlantic Ci, PA-NJ-MD	$12,644	$13,286	$3,888	$6,303
Providence (All RI), RI	$8,608	-	$2,895	-
Raleigh-Durham-Chapel Hill, NC	$27,687	$18,465	$9,760	$2,548
Sacramento Metro, CA	$8,608	$11,802	$2,368	$3,703
San Diego, CA	-	$13,284	-	$7,414
San Joaquin Valley, CA	$12,644	$13,287	$2,240	$5,848
Sheboygan, WI	$12,644	$2,908	$2,789	$1,834
South Bend-Elkhart, IN	$2,174	$13,284	$1,603	$5,424
Ventura Co, CA	$3,472	$13,284	$1,577	$5,613
Washington DC	$12,644	$13,286	$1,379	$2,736
Youngstown-Warren-Sharon, PA-OH	$26,899	$17,099	$5,204	$2,036

Note also that the targets for 8-hour ozone compliance were determined by air quality modeling and do not necessarily present the optimal, least cost solution to ozone compliance. In other words, the targets represent a feasible emissions reduction path to 8-hour ozone compliance, but other, less costly paths may exist that involve a different mix of NO_x and VOC reductions.

CLEAN AIR VISIBILITY RULE ANALYSIS

The EPA rule aimed at addressing regional haze is commonly known as the Best Available Retrofit Technology rule, or BART rule, but will be referred to hereafter by its official EPA name: the Clean Air Visibility Rule, or CAVR (except that the widely used term "BART-eligible" will still be used herein).

The Project Team estimated the non-EGU NO_x and SO_2 emissions reductions and control costs using methods developed previously for the EPA analysis of the implementation of the CAVR. EGU costs associated with CAVR are included in the core scenarios.

For the EPA analysis of the CAVR, EPA evaluated three possible scenarios of actions the states may take to comply with this rule. Of the three scenarios, this section 812 study uses the medium stringency option. The CAVR requirements of the regional haze rule apply to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility impairing pollution. Those facilities fall into 26 categories, including utility and industrial boilers, and large industrial plants such as pulp mills, refineries and smelters. Many of these facilities have not previously been subject to federal pollution control requirements for these pollutants.

The two main data inputs used in this analysis are the 2020 control measure database developed using AirControlNET version 4.1 and a list of potentially affected non-EGU BART-eligible sources previously developed by EPA. The control measure database contains a listing of control strategies and the resulting emission reductions, control costs, and annualized capital and O&M costs at the facility-level for each control strategy.

For this analysis, the Project Team determined the NO_x and SO_2 control measure applicability, emissions reductions, and control costs for non-EGU BART-eligible sources for a scenario that limited the control set to a maximum average annualized cost of $4,000/ton (See Pechan, 2005b). The $4,000/ton limit is the definition of the medium stringency option that was evaluated in the CAVR RIA. Note that the definition of what constitutes BART, which is determined on a case-by-case basis, could be a considerably different control level from what might be an appropriate cost per ton threshold in any nonattainment area plan.

In practice, the states must consider a number of factors when determining what facilities will be covered by CAVR including: the cost of controls, the effect of controls on energy usage or any non-air quality environmental impacts, the remaining useful life of the equipment to be controlled, any existing controls in place, and the expected visibility improvement from controlling the emissions.

$PM_{2.5}$ NAAQS ATTAINMENT ANALYSIS

On September 8, 2005, EPA proposed requirements that State and local governments have to meet as they implement the NAAQS for $PM_{2.5}$. The implementation rule stated that nonattainment area State Implementation Plans (SIPs) should include reasonably available control measure (RACM) and RACT control programs as well as show RFP. SIPs are due in April 2008 for $PM_{2.5}$ NAAQS attainment – three years after designation. There are 39 $PM_{2.5}$ nonattainment areas. The proposed rule requires States to meet the $PM_{2.5}$ standard by 2010.

EPA's proposed implementation of the $PM_{2.5}$ NAAQS presents different options that EPA might select for identifying which $PM_{2.5}$ precursors an area might need to control, proposed options for $PM_{2.5}$ classification, as well as options for RACT, RACM, and RFP (70 FR 71612). This analysis focuses on estimating the potential costs of controlling PM precursors following EPA's preferred approach at proposal, with a few exceptions noted below. Our approach can be summarized as follows:

1. $PM_{2.5}$ precursors are SO_2 and NO_x. States are not required to address ammonia as a $PM_{2.5}$ nonattainment plan precursor unless the State or EPA makes a technical demonstration that ammonia emissions from sources in the State significantly contribute to the $PM_{2.5}$ problem. EPA proposes that States are not required to address VOCs as $PM_{2.5}$ nonattainment precursors. (No ammonia or VOC controls were included in this $PM_{2.5}$ analysis.)
2. There is no separate RACT requirement if an area can demonstrate that it will be in attainment by 2010. Extension areas (i.e., those areas that cannot demonstrate attainment by 2010) apply RACT to affected sources in return for receiving the extension. The extension could be from one to five years past 2010. EPA's own evaluation of State SIPs for compliance with the RACT and RACM requirements will include comparisons of measures considered or adopted by other States. $PM_{2.5}$ controls will focus on upgrades to existing control technologies and compliance monitoring methods. RACT determinations are needed for PM precursors (SO_2 and NO_x).
3. No cost per ton threshold is specified. (EPA's proposed implementation rule says that their preferred approach is to not specify a cost per ton threshold, which leaves areas discretion in how they might apply their own cost per ton thresholds.[137] As a practical matter, a $15,000 per ton upper limit is applied in this analysis, for the same reasons outlined above for the 8-hour Ozone NAAQS analysis. In practice, the upper limit cost per ton threshold will differ by pollutant and geographic area according to the need to reduce certain pollutants per local source mixes and atmospheric conditions.)
4. RACT controls must be in place by 2009.

[137] Note that the rule has since been finalized, in two Phases, with Phase 2 completed in November 2005.

5. For RACM, States are required to provide a demonstration that they have adopted all reasonably available measures needed to attain as expeditiously as practicable. (This analysis includes as many RACM measures as matched with measures in AirControlNET. These assignments were made based on the judgment of the Project Team.)

EPA and States are currently working to develop a list of likely control measures anticipated for inclusion in $PM_{2.5}$ SIPs. While area-specific SIP control measures are not available for this analysis, the Project Team developed a representative model SIP control program based on available control measures in AirControlNET for primary $PM_{2.5}$, SO_2, and NO_x. Note that point source and EGU control measures in AirControlNET were applied only to sources with annual emissions greater than 100 tons, as suggested in the EPA proposed rule.

For this analysis, the Project Team estimated attainment costs and emissions reductions using the AirControlNET control measure dataset and applied the model control measures to sources in the nonattainment areas. The model SIP measure list was applied to all $PM_{2.5}$ nonattainment area counties, up to a maximum cost per ton of $15,000 for SO_2, and NO_x sources, based on the rationale described above. This maximum cost per ton is applied on a source category-control measure combination basis. The cost and emissions analysis also includes estimates of the costs associated with the implementation of the mandatory control requirements in the nonattainment areas, such as NO_x RACT.

Exhibit 7-3 summarizes estimated state-level and national 8-hour ozone NAAQS and $PM_{2.5}$ NAAQS attainment costs for 2010. CAVR costs are not shown in this table because they are not expected to be incurred in 2010. The estimated national cost of 8-hour ozone and $PM_{2.5}$ NAAQS compliance in 2010 are $3.7 billion and $0.8 billion, respectively - with a total annual cost of $4.6 billion. The expected costs of 8-hour NAAQS compliance are dominated by the costs from a relatively small number of 8-hour ozone nonattainment areas. A significant portion of the non-California estimated compliance costs are expected to be incurred in six nonattainment areas:

1. Chicago- Gary-Lake County, IL
2. Dallas- Ft. Worth, TX
3. Detroit-Ann Arbor, MI
4. Houston-Galveston-Brazoria, TX
5. New York- North New Jersey- Long Island, NY
6. Philadelphia- Wilmington- Atlantic City, DE-NJ-PA

Note that the cost of reducing any residual ozone nonattainment tons is not included in the cost estimates presented here. Costs of controlling these remaining tons are estimated in Appendix E and summarized in the Key Uncertainties section of this chapter.

$PM_{2.5}$ NAAQS cost estimates largely reflect the cost of applying RACT and RACM in the nonattainment areas, so these 2010 costs are more evenly distributed across the nonattainment areas than for ozone. At the state level, the highest 2010 $PM_{2.5}$ nonattainment costs are predicted for California, and the mid-east region that includes Ohio, Pennsylvania, and West Virginia.

Exhibit 7-3. 2010 Local Control Cost Summary

	Annual Cost (million 1999$)		
State	**Ozone NAAQS**	**PM NAAQS**	**Total**
Alabama	-	60	60
California	424	137	561
Connecticut	184	4	188
Delaware	32	20	52
DC	0.3	0.3	1
Georgia	4	27	31
Illinois	384	14	398
Indiana	135	68	202
Kentucky	-	14	14
Maryland	192	8	200
Michigan	143	49	192
Missouri	-	30	30
Montana	-	0.2	0.2
New Jersey	352	17	369
New York	482	21	503
North Carolina	28	8	36
Ohio	83	123	206
Pennsylvania	411	92	503
Rhode Island	4	-	4
Tennessee	24	35	59
Texas	746	-	746
Virginia	12	6	18
West Virginia	-	102	102
Wisconsin	89	-	89
TOTAL	**3,730**	**835**	**4,560**

Note: Entries where no numerical values are provided indicate that no areas in the state are projected to be in non-attainment with the corresponding NAAQS requirement in 2010.

Exhibits 7-4 and 7-5 show the breakdown of 8-hour ozone NAAQS and $PM_{2.5}$ NAAQS costs by sector. Exhibit 7-4 shows that 64 percent of the 8-hour ozone NAAQS compliance cost is expected to be borne by the area source or nonpoint source sector. Key affected area source categories include consumer solvents, architectural and commercial coatings, automobile refinishing, and other miscellaneous coatings. Further on-road motor vehicle emission control costs are estimated to be $473 million in 2010, or 13 percent of the 8-hour ozone control national total. Non-EGU point sources and EGUs are estimated to be 18 percent and 5 percent of the national 2010 control cost, respectively, for 8-hour ozone NAAQS compliance.

Exhibit 7-5 shows the by sector breakdown for $PM_{2.5}$ NAAQS costs in 2010. These costs are dominated by control costs estimated to be incurred by the non-EGU point source sector (about 47 percent) and on-road sources (about 37 percent). The remaining 16 percent of the 2010 $PM_{2.5}$ NAAQS costs are split among EGUs, the non-road sector, and area sources.

Exhibit 7-4. 2010 8-Hour Ozone NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	2,380
On-road	473
Non-EGU Point	674
EGU	201
TOTAL	**3,730**

Exhibit 7-5. 2010 $PM_{2.5}$ NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	32
On-road	306
Non-road	41
Non-EGU Point	391
EGU	66
TOTAL	**835**

Exhibit 7-6 provides the local control measure cost summary for the 2020 projection year. This table summarizes state-level and national costs for the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the CAVR. Total national local control measure costs in 2020 are estimated to be $5.8 billion in 2020, up from $4.6 billion in 2010. Most of this increase is explained by the incidence of CAVR costs in the period between 2010 and 2020 that are not expected to be incurred in 2010. The 8-hour ozone NAAQS compliance costs increase slightly between 2010 and 2020 as areas control the emissions that would be higher in 2020 than in 2010 with source sector growth. CAVR costs are more evenly distributed across the states than NAAQS compliance costs, as NAAQS compliance costs are focused in and surrounding the nonattainment areas. CAVR costs are related to the presence or absence of the industries (source categories) that are BART-eligible.

$PM_{2.5}$ NAAQS cost estimates are lower in 2020 than in 2010 because some source categories like on-road vehicles and non-road engines have much lower direct $PM_{2.5}$ (and other PM precursor emissions) in 2020 because of cleaner fuels and/or more stringent emission standards. Hence, there is less opportunity for cost effective emission reductions from some source sectors in 2020 than in 2010.

Exhibit 7-6. 2020 Local Control Cost Summary

State	Annual Cost (million 1999$)			
	Ozone NAAQS	PM NAAQS	CAVR	Total
Alabama	-	60	56	115
Arizona	-	-	3	3
Arkansas	-	-	2	2
California	570	80	32	681
Colorado	-	-	21	21
Connecticut	199	3	1	203
Delaware	31	21	1	53
DC	0.4	-	-	0.4
Florida	-	-	51	51
Georgia	5	22	43	70
Idaho	-	-	9	9
Illinois	450	11	21	482
Indiana	153	50	36	239
Iowa	-	-	31	31
Kansas	-	-	11	11
Kentucky	-	8	23	31
Louisiana	-	-	164	164
Maine	-	-	31	31
Maryland	173	4	2	178
Massachusetts	-	-	3	3
Michigan	167	29	68	264
Minnesota	-	-	21	21
Mississippi	-	-	33	33
Missouri	-	20	5	25
Montana	-	-	1	1
Nebraska	-	-	5	5
Nevada	-	-	0.3	0.3
New Hampshire	-	-	3	3
New Jersey	363	12	2	376
New Mexico	-	-	11	11
New York	545	16	10	571
North Carolina	29	2	22	53
Ohio	95	82	46	223
Oklahoma	-	-	18	18
Oregon	-	-	7	7
Pennsylvania	391	73	11	474
Rhode Island	1	-	0	1
South Carolina	-	-	51	51
Tennessee	31	28	49	108
Texas	842	-	7	849
Virginia	12	1	-	13
Washington	-	-	28	28
West Virginia	-	97	14	111
Wisconsin	75	-	43	118
Wyoming	-	-	15	15
TOTAL	**4,130**	**619**	**1,010**	**5,760**

Note: Entries where no numerical values are provided indicate that no areas in the state are projected to be in non-attainment with the corresponding NAAQS requirement in 2020, or that no BART-eligible sources exist in the indicated state in 2020.

Exhibit 7-7 summarizes expected 8-hour ozone NAAQS compliance costs in 2020 by sector. The distribution of costs by sector changes somewhat in 2020 (from 2010). On-road vehicle emission control costs (from local measures) are 17 percent lower in 2020 than in 2010 as Tier 2 and HDDV emission standards penetrate the fleet (making further on-road vehicle emission controls less necessary or cost effective). Costs for EGUs are nearly the same in 2020 as in 2010, while non-EGU point source and nonpoint source costs are slightly higher in 2020 compared with 2010.

Exhibit 7-8 displays the 2020 estimated cost for meeting CAVR requirements by industry (i.e., SIC code) among non-EGU point sources. This table shows that 86 percent of the CAVR costs for non-EGUs are expected to be borne by four industries: paper and allied products; chemicals; petroleum; and stone, clay and glass. All other industries are expected to incur costs around 14 percent of the $1 billion total for CAVR.

Exhibit 7-7. 2020 8-Hour Ozone NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	2,800
On-road	392
Non-EGU Point	735
EGU	200
TOTAL	**4,130**

Exhibit 7-8. 2020 CAVR Implementation Cost by 2 digit SIC for Non-EGU Point Sources

SIC (2-digit)	SIC Name	Annual Cost (million 1999$)
12	Coal Mining	1
13	Oil and Gas Extraction	19
14	Nonmetallic Minerals, Except Fuels	5
20	Food and Kindred Products	39
22	Textile Mill Products	1
24	Lumber and Wood Products	1
26	Paper and Allied Products	274
28	Chemicals and Allied Products	230
29	Petroleum and Coal Products	208
30	Rubber and Misc. Plastics Products	1
32	Stone, Clay, and Glass Products	158
33	Primary Metal Industries	51
35	Industrial Machinery and Equipment	0.1
37	Transportation Equipment	1
49	Electric, Gas, and Sanitary Services	6
65	Real Estate	0
82	Educational Services	8
91	Executive, Legislative, and General	0
97	National Security and Intl. Affairs	0
	Unknown	5
	TOTAL	**1,010**

Exhibit 7-9 presents 2020 estimated $PM_{2.5}$ NAAQS compliance costs. This \$619 million total is 26 percent below the 2010 estimate. The lower 2020 value is largely attributable to reduced on-road and non-road source costs, as federal programs implemented during the 2010 to 2020 period achieve high fleet penetration rates, obviating the need for retrofits.

Exhibit 7-9. 2020 $PM_{2.5}$ NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	37
On-road	139
Non-road	13
Non-EGU Point	376
EGU	53
TOTAL	**619**

LEARNING CURVE COST ADJUSTMENTS

The costs of the local controls described above reflect the cost of manufacturing, installing, and operating various emissions controls based on the current state of technology. However, as regulated facilities gain experience with these measures, costs are likely to decline. To account for this "learning curve" effect, we incorporated learning curve adjustments into our cost estimates for local controls. More specifically, we applied a 10 percent learning rate to local controls for EGU, non-EGU point, and nonpoint sources. We made no learning curve cost adjustments for on-road and non-road local controls because it is unclear whether some of the measures implemented for on-road and non-road local control programs would exhibit learning-related cost savings (e.g., inspection and maintenance programs regulated by States). The 10 percent learning rate that we apply to EGU, non-EGU point, and nonpoint local controls is consistent with the Council's recommendation to use a default learning rate for technologies for which no empirical estimates of learning curve impacts are available in the literature (Council, 2007). By using a learning rate of 10 percent, we assume a 10 percent reduction in costs with every doubling in cumulative production or cumulative experience. Because the learning curve literature estimates a learning rate of approximately 20 percent for many technologies, our assumption of a 10 percent learning rate may be conservative.[138]

Similar to the primary analyses of non-EGU point source and nonpoint source costs presented in Chapters 5 and 6, we measure cumulative experience with EGU, non-EGU point, and nonpoint source control technologies based on the cumulative emissions reductions achieved by each of these source categories since the enactment of the original Clean Act Act of 1970. For non-EGU point sources and nonpoint sources, we use cumulative reductions of NO_x, SO_2, PM, and VOCs combined. For EGUs, we

[138] For an analysis of the learning rates estimated in the empirical literature, see John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, Vol 9, No. 2, 1984.

use cumulative reductions of NO_x, SO_2, and PM. Because EGUs are not major sources of VOCs, we exclude VOCs from our cumulative experience metric for these sources.[139]

Exhibit 7-10 summarizes the estimated costs of local controls (identified measures only) after accounting for the cost-reducing impact of learning.[140] For comparison, Exhibit 7-11 presents the costs of local controls without learning curve impacts. As indicated in Exhibit 7-10, we estimate that the cost of local controls is approximately $4.4 billion in 2010 and $5.2 billion in 2020 (or $5.2 billion and $6.2 billion in 2010 and 2020 respectively in year 2006 dollars), after adjusting for learning. As suggested by the results in Exhibits 7-10 and 7-11, the learning curve adjustments described above reduce the Project Team's cost estimates for local controls by 3.1 percent for 2010 and 9.9 percent for 2020.

Exhibit 7-10. Summary of Local Control Costs With Learning Curve Adjustments (Identified Measures)

Program and Sector	2010 (million 1999$)	2010 (million 2006$)	2020 (million 1999$)	2020 (million 2006$)
Ozone NAAQS	**3,590**	**4,270**	**3,690**	**4,390**
Area	2,270	2,700	2,440	2,900
On-road	473	563	392	466
Non-EGU Point	655	779	674	802
EGU	195	232	182	217
PM NAAQS	**821**	**977**	**577**	**687**
Area	30	35.7	33	39
On-road	306	364	139	165
Non-road	41	48.8	13	16
Non-EGU Point	380	452	344	409
EGU	64	76.2	48	57
CAVR	**-**	**-**	**925**	**1,100**
Area	-	-	1	1
Non-EGU	-	-	924	1,100
TOTAL	**4,420**	**5,260**	**5,190**	**6,180**

[139] As an alternative to the cumulative experience metrics described here, the Project Team could have measured cumulative experience separately for the 8-Hour Ozone NAAQS, the PM NAAQS, and CAVR. This approach would reflect differences in the pollutants targeted by each of these programs. For example, because NO_x and VOCs are ozone precursors, the cumulative reductions in these two pollutants combined (estimated separately for non-EGU point, nonpoint, and EGU sources) could serve as the cumulative experience metric for the 8-hour Ozone NAAQS. Similarly, for the PM NAAQS, the Project Team could have used reductions of NO_x, SO_2, and PM combined (for each sector individually) as its metric of cumulative experience. Employing this approach, however, would yield results similar to those presented in Exhibit 7-10. Under this alternative methodology, the Project Team would estimate costs of $4.45 billion in 2010 rather than $4.42 billion and $5.28 billion for 2020 rather than the estimate of $5.19 billion presented in Exhibit 7-10.

[140] In addition to reporting costs in year 1999 dollars, this section expresses costs in year 2006 dollars to be consistent with the presentation of monetized estimates in other reports developed as part of the Second Prospective study.

Exhibit 7-11. Summary of Local Control Costs Without Learning Curve Adjustments (Identified Measures)

Program and Sector	2010 (million 1999$)	2010 (million 2006$)	2020 (million 1999$)	2020 (million 2006$)
Ozone NAAQS	**3,730**	**4,440**	**4,130**	**4,910**
Area	2,380	2,830	2,800	3,330
On-road	473	563	392	466
Non-EGU	674	802	735	875
EGU	201	239	200	238
PM NAAQS	**835**	**994**	**619**	**737**
Area	32	38.1	37	44
On-road	306	364	139	165
Non-road	41	48.8	13	15.5
Non-EGU Point	391	465	376	447
EGU	66	78.5	53	63.1
CAVR	-	-	**1,010**	**1200**
Area	-	-	1	**1.19**
Non-EGU	-	-	1,010	**1200**
TOTAL	**4,560**	**5,430**	**5,760**	**6,850**

EVALUATION OF UNIDENTIFIED MEASURES

The modeled VOC and NO_x emission reductions for some 8-hour ozone NAAQS nonattainment areas in the local control measures analysis are not sufficient to bring them into attainment with the 8-hour standard (based on the emission reduction targets that were used). We assume the implementation of unidentified controls to make up for the emission reduction shortfalls for areas where identified controls are insufficient for attainment. To estimate the cost of these unidentified controls, we assume that the cost of implementing these measures is $15,000 per ton of pollutant reduced, consistent with the cost threshold for identified controls.

In 2010, identifiable control measures are projected to be insufficient to achieve the VOC emission reductions necessary for attainment in five areas: Chicago, the Central San Joaquin Valley, Houston-Galveston, New York, and Philadelphia. In total, the VOC emissions shortfall in these 8-hour ozone nonattainment areas is approximately 255,800 tons per year in 2010, as shown in Exhibit 7-12. Similarly, the NO_x reductions from identified local controls in eight non-attainment areas are insufficient for attainment with the 8-hour standard in 2010. The estimated NO_x shortfall projected for these areas in 2010 is approximately 249,600 tons. At a cost of $15,000 per ton, the cost of achieving these VOC and NO_x reductions to attain the 8-hour ozone NAAQS would be approximately $7.6 billion ($9.0 billion in year 2006 dollars).

Similar to 2010, we predict that the identified local controls implemented in 2020 will not result in the VOC and NO_x reductions necessary for attainment with the 8-hour ozone NAAQS. Based on the reduction targets for individual nonattainment areas and the emissions reductions achieved with identified controls, we estimate a 346,600-ton shortfall in VOC emissions reductions and a 411,300-ton shortfall in NO_x reductions, as summarized in Exhibit 7-13. Assuming a cost of $15,000 per ton for unidentified controls, we estimate that nonattainment areas will incur costs of approximately $11.4 billion to achieve these reductions ($13.6 billion in year 2006 dollars).

Exhibit 7-12. Summary of Unidentified Measures: 2010

Area Name	VOC Reductions from Unidentified Measures (tons)	NO_x Reductions from Unidentified Measures (tons)	Cost (million 1999$)	Cost (million 2006$)
Baltimore	-	14,900	$224	$267
Central San Joaquin Valley, CA	9,960	7,830	$267	$318
Chicago – Cook/Lake Cos.	13,700	-	$206	$245
Chicago – Rest	3,650	2,700	$95	$113
Houston – Galveston	85,000	59,700	$2,170	$2,580
Milwaukee	0	5,820	$87	$104
New York	135,000	139,000	$4,120	$4,900
Philadelphia	8,220	17,500	$387	$461
Providence	-	1,910	$29	$35
TOTAL	**256,000**	**250,000**	**$7,580**	**$9,020**

Exhibit 7-13. Summary of Unidentified Measures: 2020

Area Name	VOC Reductions from Unidentified Measures (tons)	NO_x Reductions from Unidentified Measures (tons)	Cost (million 1999$)	Cost (million 2006$)
Baltimore	-	17,600	$265	$315
Central San Joaquin Valley, CA	11,000	-	$165	$196
Chicago – Cook/Lake Cos.	9,300	-	$140	$167
Chicago – Rest	127	1,540	$25	$30
Houston – Galveston	79,500	57,100	$2,050	$2,440
Los Angeles, CA	129,000	142,000	$4,070	$4,840
Milwaukee	-	6,620	$99	$118
New York	118,000	150,000	$4,010	$4,770
Philadelphia	-	34,400	$516	$614
Providence	-	2,240	$34	$41
TOTAL	**347,000**	**411,000**	**$11,400**	**$13,600**

As indicated above, we assume a cost of $15,000 per ton for unidentified NO_x and VOC controls. While a marginal cost of $15,000 per ton to reduce remaining VOC and NO_x tons seems to be a reasonable value to use given the costs being incurred via strategies to achieve emission reductions via identified measures, this marginal cost is likely to vary by area. Variables that affect the amounts spent on air pollution control include the source mix in each area, the quantity of emission reduction needed relative to uncontrolled emission rates, and the willingness of the decision-makers in an area to impose control costs on the sources in their area.

Various assumptions have been made about the cost of controlling these residual tons under the CAAA of 1990 dating back to 1988 when analyses were being performed of the Congressional bill alternatives that ultimately produced the 1990 Amendments. A 1988 EPA-sponsored study found that "one of the important findings of this study (and other similar studies) was that there are not enough identifiable control measures to calculate how much it might cost for all metropolitan areas to attain the ozone NAAQS. Therefore, the cost of controlling residual tons after all identifiable controls are applied was estimated using a range of $2,000 to $10,000 per ton" (Pechan, 1988)

California's requirement for sources to report the costs of emission offsets provides some evidence about the potential costs to control residual ozone nonattainment VOC and NO_x tons (ARB, 2006). Since 1993, California has required local air quality management districts to collect information about the cost of offset transactions from stationary source owners who purchase offsets as required by district New Source Review (NSR) programs. State law also requires districts to adopt emission reduction credit banking programs. Districts are required to collect specific information about offset transactions, including the price paid in dollars per ton, the pollutant traded, the amount traded and the year of the transaction. Districts that are not required to submit a plan for attainment of state ambient air quality standards and that also meet federal air quality standards are exempt from these requirements.

A total of 340 transactions occurred during 2005 in California. Excluding 70 subsidiary transactions, where there were no associated costs, leaves 270 transactions. Of these, 46 were for NO_x and 163 were for hydrocarbons. These transactions generally represent trades of offsets that are valid for the lifetime of the permitted source using the offsets. This is in contrast to other types of credits that are valid for much shorter time periods (like one year). During 2005, the median price per ton for NO_x offsets was $25,000. The NO_x average was $43,982 per ton. (California's NO_x offset costs would be expected to be higher than in most other areas of the country because of the need for high levels of emission reductions and because the fuel mix is dominated by natural gas, whose NO_x emissions are more costly to control than those in areas where coal dominates.) Reviewing the average NO_x offset cost in California dating back to 1993 shows that the cost stayed below $20,000 per ton until the year 2000, and has increased significantly since then, with the average for the 2003-2005 period being $40,000 per ton or more throughout this period.

For VOC, the median offset price was $6,849 during 2005 in California, with an average of $6,328 per ton. The highest VOC price per ton was $26,950 and the lowest was $200. The 12-year trend in the average cost of VOC offsets has shown that this average stays between $6,000 and $12,000 per ton in most years with no perceptible upward or downward long-term trend.

Other evidence that can be used to estimate the marginal cost of reducing NO_x tons is provided by the NO_x Budget Trading Program in the eastern United States (EPA, 2006). The 2005 program compliance report by EPA shows that the NO_x allowance price is within the range of $2,000 to $4,000 per ton. Results also show that most of the add-on controls being applied to sources in the control region are being installed at large coal-fired EGUs, which are the most cost effective to control. Only about 3 percent of the industrial coal-fired units use add-on NO_x controls. This suggests that in areas that will require add-on NO_x controls to meet emission reduction targets, the cost to reduce industrial source NO_x tons will be higher than the allowance prices observed so far in the NO_x Budget Trading Program market.

SENSITIVITY ANALYSIS: ALTERNATIVE COST CAP FOR IDENTIFIED CONTROLS AND ALTERNATIVE UNIT COST FOR UNIDENTIFIED CONTROLS

As indicated above, the Project Team used a cost cap of $15,000 per ton to estimate the costs of identified local controls and also applied a cost of $15,000 per ton to unidentified controls. To assess the sensitivity of the local controls analysis to changes in these values, the Project Team estimated the costs of local controls based on a $10,000 per ton cost cap for identified controls and a $10,000 per ton cost for unidentified controls. As indicated in Exhibits 7-14 and 7-15, this alternative approach would yield lower cost estimates for both identified local controls and unidentified measures. The estimated costs of identified controls decline when the $10,000 cap is applied because controls that cost between $10,000 and $15,000 per ton are not implemented. In addition, although the application of the $10,000 cost cap increases the emissions reductions to be achieved through unidentified controls (relative to when the $15,000 cost cap is used), reducing the cost of unidentified controls to $10,000 per ton more than offsets the costs associated with these additional emissions reductions.

Exhibit 7-14. 2010 Local Controls Sensitivity Analysis, Without Learning Curve Adjustments

Program and Sector	2010: $15,000/ton cap and $15,000/ton for unidentified controls		2010: $10,000/ton cap and $10,000/ton for unidentified controls	
	Million1999$	**Million 2006$**	**Million1999$**	**Million 2006$**
Identified Controls	**4,560**	**5,430**	**3,380**	**4,020**
Ozone NAAQS	3,730	4,440	2,630	3,130
PM NAAQS	835	994	751	894
Unidentified Controls	**7,580**	**9,020**	**6,960**	**8,280**
TOTAL	**12,100**	**14,400**	**10,300**	**12,300**

Exhibit 7-15. 2020 Local Controls Sensitivity Analysis, Without Learning Curve Adjustments

Program and Sector	2020: $15,000/ton cap and $15,000/ton for unidentified controls		2020: $10,000/ton cap and $10,000/ton for unidentified controls	
	Million1999$	**Million 2006$**	**Million1999$**	**Million 2006$**
Identified Controls	**5,760**	**6,850**	**4,390**	**5,220**
Ozone NAAQS	4,130	4,910	2,850	3,390
PM NAAQS	619	737	542	645
CAVR	1,010	1,200	996	1,190
Unidentified Controls	**11,400**	**13,600**	**9,730**	**11,600**
TOTAL	**17,100**	**20,300**	**14,100**	**16,800**

REFERENCES

ARB, 2006: "Emission Reduction Offsets Transition Cost Summary Report for 2005," Air Resources Board, State of California Environmental Protection Agency, March 2006.

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APPENDIX A

ESTIMATED COSTS OF THE CLEAN AIR ACT AMENDMENTS BY STATE

APPENDIX A | ESTIMATED COSTS OF THE CLEAN AIR ACT AMENDMENTS BY STATE

INTRODUCTION

This appendix presents the project team's disaggregation of the costs associated with the Clean Air Act Amendments (CAAA) to the state level. The methodology employed by the project team to conduct this analysis varies by source category due to differences in the data available for each sector. Below we describe the methodology employed to develop the state-level cost allocations for each source category and summarize CAAA-related costs by state.

SUMMARY OF METHODOLOGY

In this section, we describe our approach for disaggregating the estimated costs of the Amendments to the state level by source category.

ELECTRIC GENERATING UNITS

Our disaggregation of EGU CAAA-related costs to the state level relies on unit-level cost estimates generated for the EGU analysis presented in Chapter 2 of this document. Although the project team did not estimate all EGU costs at the unit level, three major cost components were estimated for individual units:

1. Capital and O&M costs for air pollution control devices (e.g., flue gas desulfurization systems) that IPM projects that individual EGUs will install in response to the Amendments,
2. Capital costs associated with air pollution control devices installed prior to IPM's analytic time horizon, and[1]
3. Capital costs associated with investments in fuel switching for EGUs that switched to low-sulfur coal before IPM's planning horizon.

The project team estimated all other EGU costs (e.g., fuel costs) at the national level.

To develop a disaggregation of EGU costs at the state level, we assumed that the geographic distribution of those cost components estimated at the unit level, as summarized above, would serve as a reasonable indicator of the geographic distribution

[1] As explained in Chapter 2 of this document, because IPM is a forward looking model, the results generated by IPM do not include the capital costs associated with investments that pre-date the model's analytic time horizon.

of all CAAA-related EGU costs. For 2010 and 2020, costs estimated at the unit level represent approximately 60 percent of the estimated costs associated with the Amendments.

NON-EGU POINT AND NONPOINT SOURCES

The project team's state-level disaggregation of costs for non-EGU point and nonpoint sources varied by emission control program as summarized below.

AirControlNET-Based Analyses. The project team's AirControlNET-based analyses for the 1-Hour Ozone NAAQS estimated compliance costs by source. To develop state-level estimates, the project team aggregated these source-level cost values by state.

NO_x SIP Call, Refinery Cases and Settlements, California 1-hour Ozone SIP Costs, PM_{10} NAAQS, and Houston-Galveston Area Highly Reactive VOC Rules. For each of these regulatory programs, the results presented in the main body of this report are presented by state. These state-level cost estimates are reflected in this appendix.

MACT Standards. The project team employed a two-step approach for disaggregating the costs of MACT standards to the state level. First, the project team identified the industries affected by each standard and allocated MACT-related costs to individual industries. Second, after estimating MACT-related costs by industry, the project team disaggregated the estimated costs for each industry to the state level in proportion to the projected geographic distribution of each industry's output for each target year.

To determine the distribution of each industry's output in 2000, the project team relied upon BEA data for gross domestic product by state and by industry.[2] To project the distribution of each industry's output in 2010 and 2020, the project team applied region-specific, industry-level growth factors derived from the Department of Energy's *Annual Energy Outlook 2005* to BEA's 2004 estimates of gross domestic product by state and by industry.[3,4]

National VOC Rules, RACT, New CTGs, and OTC Model Rules. To generate the cost estimates presented in Chapters 5 and 6 for these measures, the project team estimated the emissions reductions associated with these measures at the county level and applied fixed dollar-per-ton values to the tonnage of emissions controlled by these measures. To generate state-level cost estimates, the project team summed the county-level values by state.

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[2] U.S. Department of Commerce, Bureau of Economic Analysis (BEA), Gross Domestic Product by State, http://www.bea.gov/regional/gsp/default.cfm?series=NAICS, accessed August 22, 2008.

[3] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2005*, February 2005.

[4] Although more recent data for gross domestic product by state were available, the project team used 2004 BEA data as the basis for the projections to 2010 and 2020 to be consistent with AEO 2005, which includes historical economic data for 2004 but projects economic growth for 2005 and later years.

ON-ROAD VEHICLES AND FUELS

The project team disaggregated CAAA-related costs for the on-road sector to the state level based on the on-road activity data (e.g., sales projections) used for the cost analysis presented in Chapter 3. The project team disaggregated costs separately for on-road engine rules, fuel rules, and inspection and maintenance (I&M) programs due to differences in the activity data available for each of these on-road sub-sectors. Our disaggregation approach for each of these subsectors is as follows:

On-road Engine Rules: For on-road engine rules, we distributed costs across individual states based on state-level projections of vehicle sales by vehicle type (e.g., light-duty gasoline vehicles, light-duty gasoline trucks, etc.) derived from the Department of Energy's *Annual Energy Outlook 2005*. This approach assumes that vehicle consumers ultimately bear the full costs associated with CAAA on-road engine rules. In addition, because each engine rule affects a different combination of vehicle types, the proportional distribution of on-road engine rule costs by state varies by rule. For example, EPA's onboard diagnostics requirements apply to light-duty gasoline vehicles (LDGVs) and light-duty gasoline trucks (LDGTs); therefore, the project team distributed the costs for these requirements according to the geographic distribution of LDGV and LDGT sales. By comparison, the evaporative controls requirements established under the Amendments apply to LDGVs, LDGTs, and heavy-duty gasoline vehicles (HDGVs), so the costs for these requirements were distributed based on state-level sales estimates for LDGVs, LDGTs, and HDGVs.

On-road Fuel Rules: To disaggregate the costs of on-road fuel rules to the state level, we assumed that the geographic distribution of these costs is consistent with the geographic distribution of projected fuel consumption in those states where the various on-road fuel requirements are in effect. For example, we distributed the costs of oxygenated fuels by state based on fuel consumption in those states where CO nonattainment areas are located. This approach assumes that fuel consumers ultimately bear the full costs associated with CAAA-related fuel requirements.

Inspection and Maintenance Programs: The national I&M costs presented in Chapter 3 of this document represent an aggregation of state-level cost estimates that the project team developed based on the number and type of inspections conducted in each state. We use these state-level I&M cost estimates to generate the state-level on-road cost values presented in this appendix.

NON-ROAD ENGINES AND FUELS

To disaggregate costs to the state level for the non-road sector, the project team employed three separate approaches as described below.

Non-road engine rules, excluding the commercial marine and locomotive standards. For non-road engines rules, excluding the commercial marine and locomotive standards, the project team disaggregated the estimated costs of the Amendments in proportion to the NONROAD model's state-level projections of non-road engine populations, by engine type. For example, NONROAD estimates that approximately 12.6 percent of the 2020 population of large spark-ignition (SI) engines will be located in California. Based on this value, we assume that engine users in California will incur 12.6 percent of the CAAA-related costs associated with large SI engines.

Ideally, we would disaggregate non-road engine costs based on sales rather than engine populations, but state-level non-road engine sales estimates were not readily available for this analysis. Therefore, we use the geographic distribution of non-road engine populations as an indicator of the corresponding distribution for non-road engine sales.

Commercial marine and locomotive standards. Because the project team estimated CAAA-related costs for commercial marine and locomotive engines based on the emissions reductions achieved from these sources (i.e., on a dollar-per-ton basis), sales and population estimates for these engines were not developed for the cost analysis presented in Chapter 4. In the absence of this information, the project team disaggregated commercial marine and locomotive engine costs to the state level based on the projected output of the water transportation and railroad transportation industries, respectively, by state. The project team developed these projections based on BEA and AEO 2005 data, as summarized above for MACT standards.

Non-road fuel costs. The project team disaggregated the costs of non-road fuel rules to the state level based on the NONROAD model's state-level projections of non-road engine fuel consumption.

LOCAL CONTROLS: IDENTIFIED MEASURES

The project team used the AirControlNET database to estimate the costs of identified local controls by source. To develop state-level cost estimates for these controls, the project team summed the source-specific cost estimates by state.

LOCAL CONTROLS: UNIDENTIFIED MEASURES

As indicated in Chapter 7 of this document, the project team estimated the costs of unidentified measures by 8-hour ozone nonattainment area. The project team summed these area-specific cost values to the state level to estimate the costs unidentified measures by state.

RESULTS

Exhibits A-1 through A-3 summarize the estimated costs of the Amendments by state and source category for 2000, 2010, and 2020, respectively. Exhibit A-4 presents total annual costs by state for each target year.

Exhibit A-1. CAAA-Related Costs by State in 2000 (Millions of 2006$)

State	EGUs	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Alabama	$19.8	$103.2	$5.4	$32.9	$0.0	$0.0	$161.3
Arizona	$91.5	$308.9	$4.5	$54.4	$0.0	$0.0	$459.3
Arkansas	$0.0	$73.4	$3.7	$14.4	$0.0	$0.0	$91.5
California	$0.5	$4,171.6	$27.2	$1,022.3	$0.0	$0.0	$5,221.6
Colorado	$49.3	$198.5	$3.9	$26.5	$0.0	$0.0	$278.2
Connecticut	$1.2	$235.1	$3.6	$40.8	$0.0	$0.0	$280.8
Delaware	$2.4	$46.1	$1.3	$15.8	$0.0	$0.0	$65.5
District of Columbia	$0.0	$35.7	$0.3	$1.8	$0.0	$0.0	$37.8
Florida	$71.0	$296.5	$22.3	$63.7	$0.0	$0.0	$453.4
Georgia	$41.5	$333.6	$7.6	$86.1	$0.0	$0.0	$468.9
Idaho	$0.0	$43.7	$1.8	$19.8	$0.0	$0.0	$65.3
Illinois	$38.9	$414.6	$11.6	$93.1	$0.0	$0.0	$558.2
Indiana	$108.9	$320.1	$6.1	$79.4	$0.0	$0.0	$514.5
Iowa	$7.1	$170.1	$5.0	$18.9	$0.0	$0.0	$201.1
Kansas	$2.0	$54.3	$4.0	$12.0	$0.0	$0.0	$72.3
Kentucky	$82.8	$200.4	$4.2	$38.7	$0.0	$0.0	$326.1
Louisiana	$3.1	$78.8	$6.4	$82.7	$0.0	$0.0	$171.0
Maine	$0.0	$120.1	$1.8	$16.9	$0.0	$0.0	$138.8
Maryland	$28.4	$368.5	$5.0	$56.6	$0.0	$0.0	$458.5
Massachusetts	$5.0	$330.7	$6.7	$56.2	$0.0	$0.0	$398.7
Michigan	$23.0	$189.7	$12.5	$140.6	$0.0	$0.0	$365.8
Minnesota	$36.0	$112.0	$8.4	$23.5	$0.0	$0.0	$179.9
Mississippi	$4.4	$173.7	$3.7	$15.0	$0.0	$0.0	$196.8
Missouri	$52.5	$199.7	$7.3	$54.8	$0.0	$0.0	$314.2
Montana	$0.0	$20.9	$1.6	$14.5	$0.0	$0.0	$37.0
Nebraska	$1.6	$75.8	$2.9	$6.0	$0.0	$0.0	$86.3
Nevada	$0.0	$89.1	$1.8	$35.2	$0.0	$0.0	$126.0
New Hampshire	$8.7	$32.4	$1.7	$9.6	$0.0	$0.0	$52.4
New Jersey	$13.5	$435.2	$8.8	$153.7	$0.0	$0.0	$611.1
New Mexico	$31.8	$162.8	$1.5	$20.7	$0.0	$0.0	$216.8
New York	$37.2	$676.6	$15.4	$142.4	$0.0	$0.0	$871.7
North Carolina	$2.8	$295.3	$8.7	$109.9	$0.0	$0.0	$416.6
North Dakota	$1.7	$230.1	$2.3	$2.3	$0.0	$0.0	$236.5
Ohio	$195.3	$381.1	$11.9	$138.5	$0.0	$0.0	$726.8
Oklahoma	$0.0	$84.9	$4.4	$13.8	$0.0	$0.0	$103.2
Oregon	$0.0	$124.7	$4.0	$21.3	$0.0	$0.0	$150.0

Exhibit A-1. CAAA-Related Costs by State in 2000 (Millions of 2006$)

State	EGUs	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Pennsylvania	$125.4	$650.9	$10.6	$168.1	$0.0	$0.0	$955.0
Rhode Island	$0.0	$64.5	$0.9	$10.7	$0.0	$0.0	$76.1
South Carolina	$6.2	$87.6	$4.8	$29.2	$0.0	$0.0	$127.8
South Dakota	$2.4	$16.2	$1.9	$1.8	$0.0	$0.0	$22.3
Tennessee	$92.6	$225.2	$6.1	$62.2	$0.0	$0.0	$386.1
Texas	$6.2	$1,136.6	$19.2	$545.6	$0.0	$0.0	$1,707.7
Utah	$0.0	$121.9	$2.4	$15.5	$0.0	$0.0	$139.8
Vermont	$0.0	$137.9	$0.7	$5.0	$0.0	$0.0	$143.6
Virginia	$3.8	$208.2	$6.2	$69.8	$0.0	$0.0	$288.0
Washington	$0.0	$244.3	$6.6	$41.7	$0.0	$0.0	$292.5
West Virginia	$157.7	$143.2	$1.6	$33.9	$0.0	$0.0	$336.4
Wisconsin	$17.6	$168.0	$7.0	$58.3	$0.0	$0.0	$250.9
Wyoming	$0.0	$15.5	$0.7	$15.9	$0.0	$0.0	$32.1
Total	**$1,373.6**	**$14,408.1**	**$297.9**	**$3,792.4**	**$0.0**	**$0.0**	**$19,872.1**

Exhibit A-2 CAAA-Related Costs by State in 2010 (Millions of 2006$)

State	EGU	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Alabama	$270.1	$273.6	$6.6	$81.7	$69.9	$0.0	$702.0
Arizona	$58.1	$547.8	$5.0	$72.7	$0.0	$0.0	$683.7
Arkansas	$0.0	$234.7	$8.2	$30.9	$0.0	$0.0	$273.9
California	$2.0	$5,737.3	$1.8	$1,157.3	$646.0	$317.5	$7,861.7
Colorado	$41.0	$363.7	$4.9	$39.2	$0.0	$0.0	$448.8
Connecticut	$30.7	$332.1	$0.5	$66.8	$214.8	$737.9	$1,382.7
Delaware	$1.7	$71.1	$2.2	$36.6	$60.1	$55.1	$227.0
District of Columbia	$0.0	$55.0	$1.3	$4.3	$0.7	$0.0	$61.2
Florida	$293.2	$882.7	$42.1	$131.3	$0.0	$0.0	$1,349.4
Georgia	$259.1	$970.4	$5.5	$156.3	$35.7	$0.0	$1,427.0
Idaho	$0.0	$115.7	$4.8	$22.1	$0.0	$0.0	$142.6
Illinois	$435.2	$638.8	$9.1	$180.9	$453.9	$331.1	$2,049.0
Indiana	$730.6	$615.6	$3.6	$135.7	$232.6	$27.5	$1,745.5
Iowa	$12.2	$342.9	$12.3	$40.8	$0.0	$0.0	$408.2
Kansas	$1.1	$148.3	$11.4	$26.3	$0.0	$0.0	$187.1
Kentucky	$283.8	$354.0	$6.8	$77.3	$16.7	$0.0	$738.6
Louisiana	$1.8	$255.3	$16.4	$119.5	$0.0	$0.0	$393.1
Maine	$0.1	$225.1	$2.0	$21.7	$0.0	$0.0	$248.9
Maryland	$324.8	$558.5	$6.1	$104.4	$229.9	$276.6	$1,500.2
Massachusetts	$104.1	$428.7	$6.0	$86.4	$0.0	$0.0	$625.1
Michigan	$48.3	$509.3	$8.5	$210.8	$225.5	$0.0	$1,002.4
Minnesota	$37.4	$295.7	$15.0	$57.1	$0.0	$0.0	$405.3
Mississippi	$7.4	$347.7	$7.1	$29.6	$0.0	$0.0	$391.8
Missouri	$97.5	$384.2	$12.4	$87.5	$35.0	$0.0	$616.6
Montana	$0.3	$58.7	$7.5	$19.4	$0.2	$0.0	$86.1
Nebraska	$0.9	$265.6	$15.9	$17.7	$0.0	$0.0	$300.0
Nevada	$28.2	$189.8	$4.4	$43.2	$0.0	$0.0	$265.6
New Hampshire	$34.9	$78.2	$1.2	$16.1	$0.0	$0.0	$130.4
New Jersey	$64.4	$567.1	$4.0	$152.3	$421.5	$1,615.7	$2,825.0
New Mexico	$18.7	$321.0	$3.6	$26.5	$0.0	$0.0	$369.8
New York	$47.1	$883.8	$8.4	$208.1	$575.3	$2,714.6	$4,437.3
North Carolina	$801.6	$750.7	$1.3	$241.5	$41.2	$0.0	$1,836.4
North Dakota	$25.3	$444.3	$10.1	$7.1	$0.0	$0.0	$486.8
Ohio	$1,030.0	$740.2	$5.5	$282.5	$241.6	$0.0	$2,299.6
Oklahoma	$0.0	$240.5	$8.8	$30.5	$0.0	$0.0	$279.8
Oregon	$0.0	$289.2	$5.3	$38.9	$0.0	$0.0	$333.4
Pennsylvania	$567.5	$1,066.0	$4.3	$278.9	$577.9	$224.3	$2,718.8

Exhibit A-2 CAAA-Related Costs by State in 2010 (Millions of 2006$)

State	EGU	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Rhode Island	$0.0	$90.9	-$0.4	$16.2	$4.5	$34.2	$145.4
South Carolina	$73.1	$264.8	$4.0	$67.5	$0.0	$0.0	$409.3
South Dakota	$1.4	$45.8	$6.8	$7.4	$0.0	$0.0	$61.4
Tennessee	$175.3	$498.4	$6.4	$105.4	$69.0	$0.0	$854.5
Texas	$38.3	$2,266.9	$22.1	$916.7	$859.7	$2,583.8	$6,687.4
Utah	$0.0	$241.4	$6.7	$26.1	$0.0	$0.0	$274.2
Vermont	$0.0	$303.4	$0.4	$8.2	$0.0	$0.0	$312.0
Virginia	$80.1	$364.1	$9.0	$130.7	$21.1	$0.0	$605.1
Washington	$27.6	$479.6	$9.5	$70.8	$0.0	$0.0	$587.5
West Virginia	$516.1	$270.9	$5.2	$75.4	$118.4	$0.0	$986.0
Wisconsin	$71.7	$310.2	$5.4	$86.3	$103.3	$103.9	$680.8
Wyoming	$1.4	$44.2	$4.5	$26.0	$0.0	$0.0	$76.1
Total	**$6,644.3**	**$25,764.0**	**$359.3**	**$5,876.6**	**$5,254.4**	**$9,022.2**	**$52,920.7**

Exhibit A-3. CAAA-Related Costs by State in 2020 (Millions of 2006$)

State	EGU	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Alabama	$426.6	$270.6	$12.1	$73.5	$129.1	$0.0	$911.9
Arizona	$53.1	$645.3	$19.4	$80.5	$2.8	$0.0	$801.1
Arkansas	$175.8	$262.6	$19.0	$29.4	$1.6	$0.0	$488.5
California	$1.8	$6,678.9	$58.1	$1,111.0	$720.0	$5,036.3	$13,606.1
Colorado	$128.7	$402.1	$27.2	$42.5	$23.1	$0.0	$623.6
Connecticut	$28.0	$347.5	$3.7	$66.9	$211.2	$658.1	$1,315.5
Delaware	$23.7	$77.0	$3.9	$28.7	$57.0	$106.4	$296.7
District of Columbia	$0.0	$58.7	$2.7	$4.1	$0.4	$0.0	$65.9
Florida	$285.7	$973.4	$63.9	$120.3	$55.6	$0.0	$1,498.9
Georgia	$689.8	$1,090.4	$22.8	$144.6	$75.5	$0.0	$2,023.1
Idaho	$0.0	$119.6	$14.6	$23.1	$10.0	$0.0	$167.4
Illinois	$507.4	$644.2	$63.1	$207.5	$505.8	$182.2	$2,110.1
Indiana	$825.8	$631.6	$34.6	$163.9	$256.4	$13.7	$1,925.8
Iowa	$80.6	$358.8	$43.8	$37.0	$34.1	$0.0	$554.3
Kansas	$106.3	$146.8	$39.1	$24.1	$12.1	$0.0	$328.4
Kentucky	$510.8	$358.5	$15.7	$61.6	$34.1	$0.0	$980.7
Louisiana	$65.4	$274.0	$24.4	$117.8	$179.3	$0.0	$660.9
Maine	$2.2	$240.4	$2.9	$23.7	$34.1	$0.0	$303.2
Maryland	$349.7	$615.2	$13.3	$99.6	$188.0	$324.4	$1,590.2
Massachusetts	$102.8	$448.1	$29.3	$90.0	$3.8	$0.0	$674.0
Michigan	$200.7	$506.6	$23.4	$236.6	$300.1	$0.0	$1,267.5
Minnesota	$34.2	$301.9	$40.1	$51.7	$22.6	$0.0	$450.5
Mississippi	$141.9	$355.3	$14.5	$27.1	$36.1	$0.0	$574.8
Missouri	$235.2	$383.9	$31.6	$85.7	$27.4	$0.0	$763.8
Montana	$0.3	$61.3	$25.6	$21.0	$1.2	$0.0	$109.3
Nebraska	$103.5	$290.5	$37.9	$15.7	$5.1	$0.0	$452.7
Nevada	$36.7	$233.0	$16.4	$46.2	$0.3	$0.0	$332.5
New Hampshire	$31.9	$80.7	$1.7	$17.4	$2.9	$0.0	$134.7
New Jersey	$77.5	$606.1	$10.8	$189.6	$392.7	$1,517.5	$2,794.3
New Mexico	$49.1	$347.5	$10.2	$28.1	$12.4	$0.0	$447.3
New York	$159.2	$907.3	$30.5	$240.2	$600.2	$2,787.1	$4,724.5
North Carolina	$1,049.6	$901.2	$18.1	$180.3	$56.7	$0.0	$2,205.9
North Dakota	$128.0	$471.6	$34.0	$6.3	$0.0	$0.0	$640.0
Ohio	$1,106.3	$741.4	$39.3	$314.9	$250.6	$0.0	$2,452.5
Oklahoma	$191.3	$248.3	$21.3	$29.9	$19.1	$0.0	$509.9
Oregon	$0.0	$334.5	$19.0	$37.8	$7.2	$0.0	$398.5
Pennsylvania	$731.0	$1,136.9	$19.3	$311.7	$504.8	$307.7	$3,011.3

Exhibit A-3. CAAA-Related Costs by State in 2020 (Millions of 2006$)

State	EGU	On-road Sources	Non-road Sources	Non-EGU Point and Nonpoint Sources	Identified Local Controls	Unidentified Local Controls	Total
Rhode Island	$0.0	$95.7	$0.0	$17.3	$0.9	$40.0	$153.9
South Carolina	$119.5	$281.7	$10.8	$57.3	$55.7	$0.0	$525.0
South Dakota	$29.2	$45.3	$23.6	$6.4	$0.0	$0.0	$104.5
Tennessee	$344.9	$525.1	$17.0	$102.2	$121.6	$0.0	$1,110.8
Texas	$164.2	$2,573.1	$67.9	$903.4	$918.5	$2,437.6	$7,064.6
Utah	$23.0	$279.8	$27.2	$29.2	$0.0	$0.0	$359.2
Vermont	$0.0	$342.3	$1.2	$9.0	$0.0	$0.0	$352.5
Virginia	$196.8	$387.4	$22.2	$126.8	$13.8	$0.0	$747.1
Washington	$45.5	$544.2	$28.3	$70.1	$30.6	$0.0	$718.5
West Virginia	$671.5	$287.1	$8.6	$73.1	$122.5	$0.0	$1,162.9
Wisconsin	$183.0	$313.2	$25.0	$97.7	$127.2	$118.2	$864.4
Wyoming	$20.7	$44.5	$11.2	$29.1	$16.7	$0.0	$122.2
Total	**$10,439.0**	**$28,271.1**	**$1,150.5**	**$5,911.4**	**$6,180.9**	**$13,529.2**	**$65,482.0**

Exhibit A-4. Summary of CAAA-Related Costs by Target Year
(Millions of 2006$)

State	2000	2010	2020
Alabama	$161.3	$702.0	$911.9
Arizona	$459.3	$683.7	$801.1
Arkansas	$91.5	$273.9	$488.5
California	$5,221.6	$7,861.7	$13,606.1
Colorado	$278.2	$448.8	$623.6
Connecticut	$280.8	$1,382.7	$1,315.5
Delaware	$65.5	$227.0	$296.7
District of Columbia	$37.8	$61.2	$65.9
Florida	$453.4	$1,349.4	$1,498.9
Georgia	$468.9	$1,427.0	$2,023.1
Idaho	$65.3	$142.6	$167.4
Illinois	$558.2	$2,049.0	$2,110.1
Indiana	$514.5	$1,745.5	$1,925.8
Iowa	$201.1	$408.2	$554.3
Kansas	$72.3	$187.1	$328.4
Kentucky	$326.1	$738.6	$980.7
Louisiana	$171.0	$393.1	$660.9
Maine	$138.8	$248.9	$303.2
Maryland	$458.5	$1,500.2	$1,590.2
Massachusetts	$398.7	$625.1	$674.0
Michigan	$365.8	$1,002.4	$1,267.5
Minnesota	$179.9	$405.3	$450.5
Mississippi	$196.8	$391.8	$574.8
Missouri	$314.2	$616.6	$763.8
Montana	$37.0	$86.1	$109.3
Nebraska	$86.3	$300.0	$452.7
Nevada	$126.0	$265.6	$332.5
New Hampshire	$52.4	$130.4	$134.7
New Jersey	$611.1	$2,825.0	$2,794.3
New Mexico	$216.8	$369.8	$447.3
New York	$871.7	$4,437.3	$4,724.5
North Carolina	$416.6	$1,836.4	$2,205.9
North Dakota	$236.5	$486.8	$640.0
Ohio	$726.8	$2,299.6	$2,452.5
Oklahoma	$103.2	$279.8	$509.9
Oregon	$150.0	$333.4	$398.5
Pennsylvania	$955.0	$2,718.8	$3,011.3
Rhode Island	$76.1	$145.4	$153.9
South Carolina	$127.8	$409.3	$525.0
South Dakota	$22.3	$61.4	$104.5
Tennessee	$386.1	$854.5	$1,110.8
Texas	$1,707.7	$6,687.4	$7,064.6
Utah	$139.8	$274.2	$359.2
Vermont	$143.6	$312.0	$352.5
Virginia	$288.0	$605.1	$747.1
Washington	$292.5	$587.5	$718.5
West Virginia	$336.4	$986.0	$1,162.9
Wisconsin	$250.9	$680.8	$864.4
Wyoming	$32.1	$76.1	$122.2
Total	**$19,872.1**	**$52,920.7**	**$65,482.0**

APPENDIX B

LOCAL CONTROL MEASURE COST DOCUMENTATION

APPENDIX B | LOCAL CONTROL MEASURE COST DOCUMENTATION

ONBOARD DIAGNOSTIC (OBD)-BASED VEHICLE EMISSIONS INSPECTION

To support 8-hour ozone and $PM_{2.5}$ NAAQS control strategy analyses in areas that do not have existing vehicle emissions inspection and maintenance (I/M) programs, Pechan developed the model I/M program summarized in Table B-1. This model program was designed to reflect the most common parameters of current OBD-based I/M programs in Louisiana and a few other States. It is important to note that the model program is limited to 1996+ model year vehicles because 1996 was the first year that such vehicles were required to be OBD-compliant. In addition, the program exempts vehicles from the four most recent model years (MYs).

Starting with 1996 model year light-duty gasoline powered vehicles, EPA regulations required that they be equipped with onboard diagnostic systems (OBD). These systems use sensors to identify failures of engine components or systems that are known to increase exhaust emissions. When a component fails, the OBD system lights an indicator on the vehicle dash to show that the engine requires service. Using software provided by the engine manufacturer, a trained mechanic can retrieve detailed information about the failure that can help to diagnose and repair the problem.

These OBD systems can be used in an I/M program to identify vehicles with emissions-related problems that are potential high emitters, without the need for a tailpipe test. Currently, 16 states use an OBD scan to identify high emitters in their I/M programs for 1996 and newer model year LDGVs and LDGTs. These vehicles do not undergo a tailpipe test.

An ODB-I/M check consists of two types of examination: A visual check of the dashboard display function and status (also known as the MIL and/or bulb check) and an electronic examination of the OBD computer itself. The real world experience of states already using OBD in their inspection programs, coupled with EPA studies, are highlighting the benefits of OBD testing and providing data that supports inclusion of OBD into operating programs. OBD offers significant air quality benefits, short inspection time for the consumer, and an accurate diagnosis of needed repairs. Repair costs of OBD-failed vehicles are comparable to that of traditional tailpipe tests.

Real world data has shown that the use of OBD for inspecting vehicle emission control systems offers many benefits to the consumer, the technician, and the environment, including: accurate diagnosis that leads to effective, durable repairs, short inspection times, early vehicle maintenance opportunity, which leads to greater fuel efficiency and reliability, incentive to car manufacturers to produce more durable engines and emission controls, simple and affordable testing method, early detection of potential emission exceedance, state-of-the-art evaporative emission detection.

Table B-1. Model OBD-Based I/M Program Used in Local Control Measure Analysis

I/M Program:	
Start year:	2006
Pre-1981 MYR stringency rate:	20%
Model years covered:	1996-2050 (w/exemption for 4 most recent MYs)
Waiver rate (pre-1981):	3%
Waiver rate (1981 and newer):	3%
Compliance rate:	96%
Inspection type:	Test Only[1]
Inspection frequency:	Annual
Vehicle types covered:	LDGV, LDGT 1 & 2
Test Type/Cutpoints:	OBD I/M
Anti-tampering Program:	
Start year:	2006
Model years covered:	1975-1995
Vehicle types covered:	LDGV, LDGT 1 & 2
Inspection type:	Test Only
Inspection frequency:	Annual
Compliance rate:	100%
Tampering inspections performed:	Air Pump, Catalyst, Fuel inlet restrictor, EGR, Evaporative system, PCV system, Gas cap
Evaporative System Pressure Test:	
Start year:	2006
Model years covered:	1975-2050
Vehicle types covered:	LDGV, LDGT 1 & 2
Inspection type:	Test Only
Inspection frequency:	Annual
Compliance rate:	96%

To estimate the cost of this I/M program, Pechan developed two sets of estimates: costs per vehicle, and the number of affected vehicles.[2]

PER VEHICLE COSTS

To assist in developing representative cost estimates, Pechan obtained information on OBD-based I/M programs in Louisiana, Maine, New Hampshire, North Carolina, and Vermont, as well as detailed related I/M information from numerous I/M studies. The following describes how total per vehicle costs were developed by summing estimates for the following major cost components: inspection fees, vehicle operating expense, vehicle owner's time, and repair (net of fuel economy savings). Note that unless otherwise noted, all costs are reported in 2005 prices.

[1] Although there is no difference in emission reductions in MOBILE6.2 between centralized (i.e., test only) and decentralized (i.e., test and repair) programs, there are differences in costs per tested vehicle. Because all existing OBD-based I/M programs are decentralized, for the purposes of estimating costs, Pechan has assumed that the model program would be decentralized.

[2] Note that this number excludes vehicles from the most recent 4 model years that are exempt from model I/M program.

Inspection Fees

Inspection fee information was obtained from two references (ETI, 2006 and ILEPA, 2005) and visits to the State I/M program websites. Pechan derived an average per vehicle inspection cost of $10 based on an assumption that one-half of the average cost of actual OBD/gas cap check/vehicle safety inspection programs (costs of $18, $18.50, and $22 were observed) is for emissions-related program activities. This assumption seems reasonable given the following inspection fee information for the OBD-only programs:

- The average cost of the OBD test/gas cap check portion of the inspection fee is approximately $6;
- The average cost of a vehicle safety inspection is approximately $12; and
- Emissions-related safety inspection activities account for about one-third of the total cost of a safety inspection.[3]

Vehicle Operating Expense

Based on available average travel distance information for a *centralized* I/M program,[4] Pechan assumed an average total of 6 miles of vehicle travel to obtain a *decentralized* OBD-based test (3 miles each direction). To estimate vehicle operating costs per mile (43.2 cents), Pechan used the Internal Revenue Service's 2005 allowable mileage rate for deducting automobile operating costs (43.2 cents per mile).[5] By combining the mileage and the operating cost per mile estimates, Pechan estimated a vehicle operating cost per tested vehicle of $2.59.

Costs Associated with Vehicle Owner's Time

The time required for a vehicle owner to obtain an inspection includes the time spent traveling to/from the inspection station, the time spent waiting while the test is performed, and the time spent waiting before/after the test is performed. For the model OBD-based I/M program Pechan assumed a total time of 20 minutes. Real-time data for Pennsylvania's program indicates that an OBD test and gas cap check takes an average of about 6 minutes and 45 seconds (PADEP, 2004). For the purposes of this study, Pechan assumed approximately double the test time (an additional 13 minutes and 15 seconds) for travel time to/from the station and for time while the vehicle owner waits before/after the inspection is performed.

To estimate the value to the vehicle owner of the time spent acquiring an inspection, the Project Team used an estimate of the opportunity cost of time derived from wage rates.

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[3] Also note that Pechan assumed that the inspection fee covers not only the capital and operating costs incurred by inspection stations, but also program administration and enforcement costs. This assumption was based on available information for North Carolina's program.

[4] An analysis performed of Arizona's centralized I/M program used an average one-way travel distance of 4.5 miles (Harrington and McConnell, 1999).

[5] This value represents the average of the IRS mileage of 40.5 cents per mile for the first eight months of the year and 48.5 cents per mile for the final four months.

Although it is not clear that time spent acquiring an inspection will in all cases represent lost time at work, we estimated the value of lost time in this case using the national average pre-tax wage rate, plus an estimate of average prorated per-hour benefits. Our estimate of this value is $26.06 per hour, reflecting wages or salaries, benefits, and taxes.[6] The Project Team concluded that use of pre-tax wage rate plus benefits is a reasonable approximation of the social cost of lost time in the context of inspection programs for two reasons. First, using pretax wages plus benefits to value lost market work time is consistent with a recent peer-reviewed EPA guidance document on the value of lost time (EPA, 2005) and DOT guidance for lost travel time (DOT, 1997 and 2003). Second, our approach largely balances unquantifiable factors that might lead to overestimates with those that might lead to underestimates of this value. For example, the value of lost market work time may be argued to potentially overestimate the lost time from inspection programs, because in at least some cases, the lost time is more accurately characterized as lost non-market work time or leisure time, which is typically valued at a lower rate. At the same time, however, some research suggests that there is an additional disamenity factor associated with time spent waiting (e.g., DOT, 1997 and 2003), which may or may not apply to the context of vehicle inspections.

By multiplying the national average after-tax wage by the 20 minute time estimate, Pechan estimates the time required to obtain an OBD-based inspection is worth an average of $8.69 (2005 dollars) to the vehicle owner.

Vehicle Repair Cost (Net of Fuel Savings)

Vehicle repair costs associated with I/M programs are a function of repair incidence (inspection failure rates) and the average cost of repair. For this analysis, Pechan estimates an average $300 spent for repairs for vehicles failing OBD-based tests. This $300 per repaired vehicle assumption is based on data from Wisconsin (estimated average repair cost for first retest pass of $304 in 2003 and $306 in 2004 for all tests, where IM240 and OBD-tests comprise more than 98 percent of the I/M tests performed), a 2005 Arizona study that noted average repair costs of “approximately $300” for vehicles undergoing dynamometer/OBD tests, and an EPA study that estimates an average OBD repair cost between $210 and $481 for vehicles repaired with 100,000+ miles (WIDOT, 2006; ERG, 2005; and Gardetto, 2002).[7]

Based on information from available I/M program studies, Pechan assumed an average failure rate of 14 percent for an OBD-based I/M program with annual inspections. This estimated failure rate was based on Wisconsin data indicating an approximate 14 percent

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[6] This value is derived from the Department of Labor, Bureau of Labor Statistics (BLS) Employer Costs for Employee Compensation, part of the 2006 National Compensation Survey, and reflects the average of quarterly BLS estimates for 2005 (BLS, 2006). The stated value includes wages, salaries, and employee benefits for all nonfarm private and state and local government workers. The full employer costs for benefits includes: insurance benefits - life, health, and disability; legally required benefits, including Social Security, Medicare, unemployment insurance, and workers' compensation; paid leave benefits (vacations, holidays, sick leave, and other leave); and retirement and savings benefits per hour worked.

[7] EPA states with 95 percent statistical confidence that repair costs are within this range for OBD failures defined by illumination of the malfunctioning indicator light.

failure rate in both 2003 and 2004 from the more than 700,000 vehicles tested in each year (more than 98 percent of vehicles tested in Wisconsin undergo either an IM240 or OBD test – an EPA review of Wisconsin data comparing IM240 and OBD failure rates concluded that "…the number of vehicles failing each test was roughly the same when using final cutpoints for all three pollutants" (EPA, 2002).

As noted above, the OBD test portion of the model I/M program is limited to 1996+ model year vehicles. To properly estimate total repair costs for this program, it is therefore necessary to estimate the proportion of total I/M program vehicles that are subject to the OBD test. All vehicles subject to the model I/M program will receive an OBD test by 2020 because MOBILE6.2 indicates that there will be no pre-1996 model year light-duty gasoline vehicles in this year. Based on MOBILE6.2 data, Pechan assumed that 82 percent of all vehicles subject to the I/M program in 2010 are required to obtain an OBD test.

The EPA has developed estimates of fuel economy increases associated with repairs performed in response to I/M program inspections since at least 1992 (EPA, 1992). Based on findings from the most extensive in-use study identified, Pechan assumed an average improvement of 0.75 miles per gallon for each repair (NRC, 2001). To estimate the per vehicle value of this improvement, Pechan utilized the aforementioned inspection failure rates and proportions of total vehicles subject to the OBD test (for 2010), and the following assumptions: average of 12,000 miles of travel per year, baseline average fuel efficiency of 20 miles per gallon, and a gasoline price of $2.34 per gallon (DEO, 2006).

SUMMARY OF COST ESTIMATES

Table B-2 presents the estimated year 2010 and 2020 costs per vehicle by individual cost component (in year 2005 prices). Table B-3 displays inspection (inspection fee, plus vehicle operating expense, plus vehicle owner's time cost), vehicle repair (net of fuel savings), and total cost estimates in 2005 prices. The 2005 year total costs were adjusted to 1999 prices using 1999 and 2005 GDP implicit price deflators. Table B-4 displays the final per vehicle cost estimates in 1999 price terms (rounded to the nearest half dollar).

COUNT OF VEHICLES

To determine the fraction of registered vehicles subject to this I/M program (i.e., those more than four model years old), Pechan used by-model-year MOBILE6 output data for 2010 and 2020. From the 2010 output, Pechan summed the registration distribution fractions of vehicles from the 1986 through 2006 model years separately for the LDGV, LDGT1, and LDGT2 vehicle types. From the 2020 output, Pechan summed the registration distribution fractions of these vehicles from the 1996 through 2016 model years. Table B-5 shows the resulting fractions of vehicles that were not exempted from the I/M program. These fractions were then multiplied by the count of total vehicles registered in an area to be modeled with I/M and the I/M program per-vehicle cost to obtain the total cost of this I/M program in a given area.

Table B-2. Estimated Costs per Vehicle Tested by Year and Detailed Cost Component (2005$)

	Costs of Inspection					Repair Cost/Fuel Savings			
Program Year	Inspection Fee	Travel, Wait, & Inspection Time (mins)	Cost of Motorist Time	Vehicle Operating Expense	Total Inspection Cost	Vehicle Repair Cost	Fuel Economy Savings	Total Repair Cost Net of Fuel Savings	Total Cost
2010	$10.00	20	$8.69	$2.59	$21.28	$34.44	-$5.83	$28.61	$50.00
2020	$10.00	20	$8.69	$2.59	$21.28	$42.00	-$7.10	$34.90	$56.00

Table B-3. Estimated Costs per Vehicle Tested by Major Cost Component and Year (2005$)

Year	Total Inspection Cost	Vehicle Repair Cost	Total Cost
2010	$21.28	$28.61	$50.00
2020	$21.28	$34.90	$56.00

Table B-4. Estimated Costs per Vehicle Tested by Major Cost Component and Year (1999$)

Year	Total Inspection Cost	Vehicle Repair Cost	Total Cost
2010	$18.47	$24.84	$43.50
2020	$18.47	$30.29	$49.00

Note: Total costs are rounded to nearest half-dollar.

Table B-5. Fractions of Vehicles Not Exempted from the I/M Program

Vehicle Type	Fraction of Vehicles Affected by I/M Program in 2010	Fraction of Vehicles Affected by I/M Program in 2020
LDGV	0.7354	0.7354
LDGT1	0.7116	0.7117
LDGT2	0.7342	0.7339

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APPENDIX C

PM-10 NAAQS ANALYSIS

APPENDIX C | PM-10 NAAQS ANALYSIS

For the second prospective analysis, Pechan examined the control measures adopted by the PM-10 nonattainment areas classified as serious under the CAAA of 1990. There are six serious PM-10 nonattainment areas, and they likely bear the highest percentage of the PM-10 attainment costs, and provide a reasonable indicator of the types of control measures that were adopted to bring areas into attainment of the PM-10 ambient standard. The serious PM-10 nonattainment areas as of May 8, 1997 were as follows: Clark Co., NV, Coachella Valley, CA, Los Angeles South Coast Air Basin, CA, Owens Valley, CA, Phoenix, AZ, and San Joaquin Valley, CA. Information available about the costs of control measures adopted in these areas where available is described below.

The Coachella Valley is the desert portion of Riverside County in the Salton Sea Air Basin. The South Coast Air Quality Management District (SCAQMD) is the local agency responsible for air quality assessment and improvement in the Coachella Valley. This area's original plan for meeting the PM-10 NAAQS was submitted to EPA during 1996 (SCAQMD, 1996). When it became apparent that the Coachella Valley would not be able to continue to demonstrate attainment of the PM-10 NAAQS through the 2001 attainment year, AQMD staff in conjunction with local jurisdictions, agencies and stakeholders prepared the 2002 CVSIP, which includes control measure enhancements that meet the Most Stringent Measure requirements (SCAQMD, 2002).

Table C-1 summarizes the Coachella Valley 2002 SIP PM-10 control measures and costs by source category/control measure. PM-10 exceedances in the Coachella Valley are primarily due to locally generated sources of fugitive dust, which include natural windblown sources, agricultural activities, construction activities, and travel on paved and unpaved roads. So, the SIP focuses on controlling PM-10 emissions from fugitive dust emitting source categories. The SIP demonstrates attainment by 2006. The Coachella Valley SIP estimates emission reductions on a tons per day basis. Annual costs of PM-10 control are estimated by multiplying these daily tons by 365 days times the estimated per ton costs. Where the PM-10 SIP provides a cost range, the lower and upper limits of this range are used to estimate the associated range of annual direct compliance costs. The estimated annual cost of the PM-10 SIP in the Coachella Valley is estimated to be about $631 thousand in 2002 dollars.

Table C-1. Coachella Valley PM-10 Control Measure Costs

Control Measure		Emission Reductions tpd	Cost/ton Lower	Cost/ton Upper	Annual $ Lower	Annual $ Upper
CV BCM 1	Construction	2.0	197	197	143,810	143,810
CV BCM 2	Disturbed Lands	0.0	281	810	0	0
CV BCM 3	Unpaved roads and lots	0.7	978	978	253,449	253,449
CV BCM 4	Paved roads	0.6	1,119	1,119	232,808	232,808
CV BCM 5	Agriculture	0.0	134	134	978	978
CV CTY 1	Overseeding				0	0
	Total	**3.3**			**631,045**	**631,045**

The PM-10 SIP in Clark County, NV focuses on applying controls to five PM-10 emitting source categories: disturbed vacant land, unpaved parking lots, construction activities, paved road dust and unpaved road dust (Clark County, 2001). Table C-2 summarizes the annual costs of applying PM-10 controls to reduce PM-10 emissions in Clark County. The cost estimates for Clark County are dominated by the cost incurred by the construction industry to reduce PM emissions at active construction sites in the nonattainment area. Costs to reduce paved road dust in Clark County (and other similar PM-10 nonattainment areas) are modest because paved road controls involve purchasing PM-10 efficient street sweepers. Because Clark County already has street sweepers for paved roads in operation, the incremental cost of replacing a retired street sweeper is small. In addition, these purchases are made at standard replacement rates. The total annual cost of the PM-10 plan in Clark County, NV is estimated to be in the range of $6.6 million to $12.1 million.

Table C-2. Clark County PM-10 SIP Control Measure Costs

Source Category	Annual Control Costs, per year
1. Disturbed Vacant Land Control Costs	$780,000
2. Unpaved Parking Lots	$39,000 to $167,700
3. Construction Activities	$5,788,964 to $11,272,219
4. Paved Road Dust	--
5. Unpaved Road Dust (paving unpaved roads over 150 vehicle trips per day will be in place and enforced during 2001)	--

Source: Clark County, 2001.

The Maricopa County (Phoenix, AZ) PM-10 nonattainment area is located on the eastern portion of Maricopa County and encompasses the cities of Phoenix, Mesa, Scottsdale, Tempe, Chandler, Glendale as well as 17 other jurisdictions. The Phoenix plan shows that the principal sources contributing to PM-10 exceedances in the Phoenix area are fugitive dust sources, such as construction sites, vacant lots, paved and unpaved roads, and various other dust sources (MAG, 1999). The principal controls relied on for attainment are controls on these fugitive dust sources. Table C-3 summarizes the control measures, emissions reductions, and control costs estimated by the Maricopa Association of Governments for their PM-10 SIP. Where costs were not estimated in the Phoenix, AZ PM-10 SIP, the cost per ton estimates for similar measures applied in Las Vegas and

Coachella Valley were used to estimate annual costs. The total annual cost of the PM-10 compliance plan in the Phoenix nonattainment area is estimated to be about $8 million.

Table C-4 summarizes the emission reductions and control costs estimated for the South Coast Air Basin's PM-10 SIP (SCAQMD, 1996). The South Coast plan relies on controlling many of the same fugitive dust emission source categories that are controlled in the other serious area plans. The South Coast compliance strategy is more reliant on paved and unpaved road controls than in the other areas. In addition, the South Coast PM-10 plan has control requirements for some source categories that are not significant contributors to PM-10 ambient concentrations in other serious nonattainment areas. For the source categories with cost estimates available, the annual cost of the South Coast PM-10 SIP is about $8.5 million.

Table C-3. Phoenix Control Measures Relied on in the Attainment Demonstration

Measure	Emission Reduction (tpd)	Cost per PM-10 ton	Annual Control Cost
Strengthening and Better Enforcement of Fugitive Dust Control Rules (Construction Sites)	60.6	$203	$4,490,157
Unpaved Roads and Alleys	12.2	$537	2,391,261
Unpaved Parking Lots	3.7	537	725,219
Vacant Disturbed Lots	1.8	537	156,804
PM-10 Efficient Street Sweepers	1.1	485	194,727
Curbing, Paving, or Stabilizing Shoulders on Paved Roads	1.0	212	77,380
Curbing, Paving, or Stabilizing Unpaved Access Points	0.4		
PM-10 Episode Thresholds	0.07		
Restaurant Charbroiler Controls	0.07		
Cleaner Burning Gasoline	0.03		
Pre-1988 HDDV Standards	0.02		
Coordinate Traffic Signals	0.01		
Total	**81**		**8,035,548**

Table C-4. South Coast, CA PM-10 Control Measure Costs

Control Measure Number	Control Measure Name	Daily Tons Reduced		Cost per PM-10 ton	Annual Control Cost
		2006	2010		
CMB-09	Petroleum Refinery FCCUs	0.03	0.03	tbd	
BCM-01	Paved Roads (Rule 403)	53.6	54.8	50	978,200
BCM-03	Unpaved Roads, Unpaved Parking Lots and Staging Areas (Rule 403)	15.2	15.2	563	3,123,524
BCM-04	Agricultural Activities (Rule 403)	9	9	154	505,890
BCM-06	Fugitive Dust Sources meet BACM Requirements	5.9	6.1	212	456,542
PRC-01	Woodworking Operations	8.6	9.1	tbd	
PRC-03	Restaurant Operations	2	2	4,690	3,423,700
WST-01	Livestock Waste	6	5.9	tbd	
WST-02	Composting	tbd	0	tbd	
	Total	**100.3**	**102.1**		**8,487,856**

Because not all of the serious PM-10 nonattainment area SIPs report control cost estimates, there is a need to compare the control measures adopted by Coachella Valley and Clark County, where we do have cost estimates with the measures adopted by the other serious PM-10 nonattainment areas in order to use the cost information available to estimate direct compliance costs in the other areas. Table C-5 shows the primary source categories and measures that are controlled in each of these areas, and whether the SIP in each area includes measures that reduce PM-10 emissions for that source type. This table shows that there is a consistent set of source categories and control measures included in these PM-10 SIPs. The only variation from area-to-area is in whether agricultural activities are an important enough source category in an area to warrant having a control program.

In addition to what is shown in Table C-5, many of the PM-10 SIPs for the serious PM-10 nonattainment areas include an assessment of whether the measures that they are adopting meet the EPA's Most Stringent Measure requirements. This assessment requires evaluating the stringency of measures applied in other PM-10 nonattainment areas by source category. What these evaluations show is that the measures adopted in the PM-10 nonattainment areas shown in Table C-5 for the source categories shown in that same table are consistent in stringency. Therefore, the per ton costs of those measures should be consistent across these areas and if the planned PM-10 emissions reductions are known, reasonable cost estimates should be able to be made for the other serious PM-10 nonattainment areas.

Table C-5. Serious PM-10 Nonattainment Area Fugitive Dust Regulations

Category/Measure	Coachella Valley	Clark County	Maricopa County	San Joaquin Valley	South Coast AQMD
Construction Activities	x	x	x	x	x
Disturbed Vacant Lands	x	x	x	x	x
Unpaved Roads	x	x	x	x	x
Unpaved Parking Lots	x	x	x	x	x
Paved Road Dust	x	x	x	x	x
Agricultural Activities	x		x	x	x

The PM-10 NAAQS direct compliance cost estimates for the serious PM-10 nonattainment areas whose annualized control program costs have been estimated from their SIP documents can be summarized in Table C-6.

Table C-6. Selected Serious PM-10 Nonattainment Area NAAQS Compliance Costs

Serious PM-10 Area	Annual Cost-Lower Thousand $	Annual Cost-Upper Thousand $
Coachella Valley, CA	631	631
Clark Co., NV	6,608	12,226
Phoenix, AZ	8,035	8,035
South Coast, CA	8,487	8,487
Total	**23,761**	**29,379**

To estimate the PM-10 NAAQS compliance costs for the remaining serious PM-10 nonattainment areas, as well as the moderate PM-10 nonattainment areas, the following method was used. A model PM-10 SIP was developed that applied control measures in AirControlNET for the three main fugitive dust source categories in the serious PM-10 nonattainment area SIPs to the PM-10 emissions in each individual nonattainment area to estimate the cost of such a model SIP. The three affected source categories are paved road fugitive dust, unpaved road fugitive dust and fugitive dust from construction activity. Controls on each of these three source categories are judged to be representative of the control measures applied in PM-10 nonattainment areas in the western United States, where most of the PM-10 nonattainment areas are found. The AirControlNET control measures applied to these source categories were: paved roads - PM-10 efficient street sweepers, unpaved roads - asphalt paving of a portion of the unpaved road mileage each year, and construction activity - track out controls and watering during grading operations. These measures are representative of the control requirements in the PM-10 SIPs that were reviewed. For estimating the cost of the street sweeping measure, 10 percent of the paved road miles in a county were assumed to be controlled in each year. This assumption accounts for the fraction of any county that is within the nonattainment area proper as well as the fraction of the road miles that are likely to be treated.

The estimated PM-10 NAAQS attainment costs for the states with PM-10 nonattainment areas are shown in Table C-7. The Table C-7 cost estimates exclude the costs for the serious PM-10 nonattainment areas for the four surveyed areas whose costs are shown above. Therefore, the total estimated cost to attain the PM-10 NAAQS is estimated to be $124 to $130 million per year.

Table C-7. PM-10 NAAQS Cost Estimates by State

State	Annual Cost (millions 1999$)
Arizona	10.1
California	15.4
Colorado	9.0
Connecticut	0.4
Idaho	11.1
Illinois	4.0
Indiana	2.1
Minnesota	0.2
Montana	7.6
Nevada	5.1
New Mexico	11.8
New York	0.1
Ohio	1.0
Oregon	6.9
Pennsylvania	0.8
Texas	1.5
Utah	2.3
Washington	7.7
West Virginia	0.4
Wyoming	2.7
Total	**100.3**

Note: This table excludes the costs for the four serious PM-10 nonattainment areas evaluated separately, which were Coachella Valley, Clark County, Maricopa County, and South Coast.

Table C-8. Classifications of PM-10 Nonattainment Areas as of May 1997

Serious	
Clark Co, NV	Owens Valley, CA
Coachella Valley, CA	Phoenix, AZ
Los Angeles South Coast Air Basin, CA	San Joaquin Valley, CA
Moderate	
Ajo (Pima County), AZ	Mohave Co, AZ
Anthony, NM	Mono Basin, CA
Aspen, CO	Mun. of Guaynabo, PR
Boise-Northern Ada County, ID	New Haven Co, CT
Bonner Co (Sandpoint), ID	New York Co, NY
Butte, MT	Nogales, AZ
Canon City, CO	Ogden, UT
Clairton & 4 Boroughs, PA	Olympia, Tumwater, Lacey, WA
Columbia Falls, MT	Pagosa Springs, CO
Cuyahoga Co, OH	Paul Spur, AZ
Denver Metro, CO	Payson, AZ
Douglas (Cochise County), AZ	Pierce Co, WA
Eagle River, AK	Pinehurst, ID
East Chicago, IN	Pocatello, ID
El Paso Co, TX	Poison, MT
Eugene-Springfield, OR	Ramsey Co, MN
Flathead County; Whitefish and vicinity	Rillito, AZ

Follansbee, WV	Ronan, MT
Granite City, Nameoki Twsp, IL	Routt Co, CO
Grants Pass, OR	Sacramento Co, CA
Hayden/Miami, AZ	Salt Lake Co, UT
Imperial Valley, CA	San Bernardino Co, CA
Jefferson Co, OH	Sanders County (part); Thompson Falls and vicinity
Juneau, AK	Searles Valley, CA
Kahspell, MT	Sheridan, WY
Kent, WA	Shoshone Co, ID
King Co, WA	Southeast Chicago, IL
Klamath Falls, OR	Spokane Co, WA
LaGrande, OR	Telluride, CO
Lake Co, OR	Utah Co, UT
Lamar, CO	Vermillion Co, IN
Lame Deer, MT	Wallula, WA
Lane Co, OR	Washoe Co, NV
Libby, MT	Weirton, WV
Lyons Twsp., IL	Yakima Co, WA
Medford-Ashland, OR	Yuma, AZ
Missoula, MT	
Source: Green Book, 1997 - Ozone/Carbon Monoxide/Particulate Matter/Sulfur Dioxide/Lead Areas Designated Nonattainment, EPA, OAQPS, Air Quality Strategies & Standards Division, May 9, 1997	

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APPENDIX D

1-HOUR OZONE NAAQS COSTS

APPENDIX D | 1-HOUR OZONE NAAQS COSTS

This analysis uses some of the published information about state implementation plans adopted in order to meet the 1-hour ozone National Ambient Air Quality Standards (NAAQS) to establish where costs may be missing from the estimates made using Control Technique Guidelines (CTG)/Reasonably Available Control Technology (RACT) and other similar measures applied to point and area sources in the analyses that are summarized in Chapters III and VII of this report. Part of this analysis reviews the ozone State Implementation Plan (SIP) measures adopted in the Atlanta, Georgia ozone nonattainment area and compares those measures with the cost estimates performed using AirControlNET and other tools in this report. The second part of the analysis evaluates the measures adopted in one hour ozone nonattainment areas in the State of California to improve upon the cost estimates developed in the preliminary analysis.

Table D-1 summarizes the control measures adopted by the State of Georgia to reduce ozone precursor emissions to the levels needed to attain the 1-hour ozone NAAQS in the Atlanta nonattainment area (Georgia DNR, 2005). This table compares the primary ozone precursor control measures included in the Atlanta 1-hour ozone SIP with the measures that were included in the cost analysis in this 812 study. The bottom line is that 812 cost analysis accounts for the costs of all of the measures included in the 1-hour ozone SIP with the exception of (1) lowering auto windshield washer fluid VOC content (13 counties), and (2) limiting industrial source permitted emissions. While our cost estimates may differ from the ones made by the Georgia Department of Environmental Protection (DEP), or others, they capture the vast majority of the measures included in the most recent ozone SIP.

Table D-1. Atlanta 1-Hour Ozone Nonattainment Area Control Measure Comparison

Georgia Control Measures	Section 812 Study Cost Analysis
1. Requiring Stage I at gasoline facilities - 13 counties	Area - service stations - Stage I
2. Expanding VOC and NO_x RACT requirements to 6 additional counties	Non-EGU point source and area source costs
3. Requiring Stage II VRS at facilities - 13 counties	Area source costs
4. Lowering auto windshield washer fluid VOC content	Not modeled in 812
5. Lowering gasoline RVP	Onroad vehicle costs
6. Lowering gasoline S content	Onroad vehicle costs
7. NO_x power plant limits	NO_x SIP Call costs
8. Implementing enhanced I/M - 13 counties	Onroad vehicle costs
9. Limiting industrial source permitted emissions	Not modeled in 812

The Bay Area Air Quality Management District (BAAQMD) 1-hour ozone plan for the San Francisco, California ozone nonattainment area lists all of the 55 rules and rule amendments that have been adopted since the first Bay Area Clean Air Plan was adopted in 1991 (BAAQMD, 2006). This information allows us to develop an independent estimate of the costs to meet the 1-hour ozone NAAQS for this area and to improve upon the estimates already made in the 812 analysis. The 2005 Ozone Strategy describes how the Bay Area will fulfill California Clean Air Act (CCAA) planning requirements through the proposed control strategy. The control strategy includes stationary source control measures to be implemented through Air District regulations; mobile source control measures to be implemented through incentive programs and other activities; and transportation control measures to be implemented through incentive programs in cooperation with MTC, local governments, transit agencies and others.

One of the differences between areas in the state of California versus elsewhere in the United States is that the State of California has established ambient air quality standards for ground-level ozone. State standards are set by the California Air Resources Board (ARB). The California 1-hour ozone standard is set at 0.09 parts per million (ppm). In April 2005, ARB established a new 8-hour average ozone standard of 0.070 ppm. ARB plans to retain the 1-hour State ozone standard and is currently working on designations and implementation guidance for the new 8-hour standard.

Table D-2 lists each of the individual control measures that have been included in the 1-hour ozone SIP for the Bay Area since 1991 and use the available information in the plans about emission reductions and cost effectiveness to estimate the total annualized cost of the measures adopted to date (BAAQMD, 1994 and BAAQMD, 2006). The reactive organic gas (ROG) and NO_x emission reduction estimates listed in Table D-2 are daily tons, so these values are multiplied by 365 to get annual equivalents. This table excludes the costs of meeting onroad and nonroad emission standards because those costs are already accounted for in the 812 cost analysis.

Table D-2 shows that the estimated annualized cost of the Bay Area stationary and area source control measures to meet the 1-hour ozone NAAQS is $258 million in 1993 dollars, which is $341 million in 2006 dollars. This cost estimate is based on the Table D-2 control measures that have estimated dollar per ton cost estimates in the BAAQMD clean air plans. This cost estimate would be somewhat higher with the cost of measures which had no dollar per ton estimates provided in BAAQMD reports.

BAAQMD efforts to reduce emissions from mobile sources during the years 2001-2003 have focused on incentive and education programs (BAAQMD, 2006). The District's Transportation Fund for Clean Air program provides incentives for clean fuel buses, other clean air vehicle projects, ride sharing bicycle facilities, smart growth, transit information and arterial management projects. This program also funds the District's vehicle buy back program, the smoking vehicle program and the spare the air program. In coordination with the ARB, the BAAQMD also administers the Carl Moyer Program and the Lower Emission School Bus program. Table D-3 provides information about the cost of BAAQMD mobile source programs during fiscal years 2000/1-2002/3. This table shows that the Bay Area is sending between $32 and $37 million per year funding incentive programs to reduce mobile source emissions via incentive programs.

Table D-2. BAAQMD Area Stationary and Area Source Control Measures to Meet the 1-Hour Ozone NAAQS

Reg #	Rule		Adoption Date	Emission ROG	Reductions NO_x	Cost/ton ROG	Cost/ton NO_x	Annual Cost
SURFACE COATING AND SOLVENT USE								
Reg 8-35	Coatings and Ink Manufacturing	A14	3/18/1992	0.4	0	6,000		876,000
Reg 8-51	Adhesives	A11	11/18/1992	13	0			
Reg 8-29	Aerospace Coatings	A3	2/3/1993	0.025	0	2,000		18,250
Reg 8-19	Surface Coating of Misc Metal	A5	2/3/1993	0.095	0	2,000		69,350
Reg 8-31	Surface Coating of Plastic Parts & Products	A6	2/3/1993	negligible	0	2,000		
Reg 8-20	Graphic Arts Printing Operations	A13	10/6/1993	1.3	0			0
Reg 8-4	General Solvent & Surface Coating	A10	6/1/1994	unknown	0			
Reg 8-12, 8-13, 8-14, 8-19, 8-23, 8-29, 8-30, 8-31, 8-32, & 8-38	Eliminations of Coatings Rules Alternate Emission Control Plans		6/15/1994	unknown	0			
Reg 8-3	Solvent and Surface Coating	A1, SS-11	5/15/1996	unknown	0	2,000		
Reg 8-51	Adhesives	A11	6/5/1996	6	0			
Reg 8-32	Wood Furniture & Cabinet Coatings		6/19/1996	6.15	0			90
Reg 8-45, 8-50	Motor Vehicle & Mobile Equip Coating & Polyester Resin		11/6/1996	unknown	0			
Reg 8-51	Adhesive and Sealant Products	A11	11/6/1996	unknown	0			
Reg 8-11	Can and Coil Coating		11/19/1997	0.35	0			
Reg 8-51	Adhesive and Sealant Products	A11	1/7/1998	unknown	0			
Reg 8-30	Semiconductor Manufacturing		10/7/1998	unknown	0			
Reg 8-3	Architectural Coatings	A1, SS-11	11/4/1998	unknown	0	2,000		

Reg #	Rule		Adoption Date	Emission ROG	Reductions NO_x	Cost/ton ROG	Cost/ton NO_x	Annual Cost
Reg 8-16, 8-20, & 8-45	Substitute Solvents Used for Surface Preparation/Clean-up of Coatings		Reg 8-16 adopted 9/16/1998 Reg 8-20 adopted 3/3/1999 Reg 8-45 adopted 1/9/1999	2.9	0			
Reg 8-52	Polystyrene, Polyethylene & Polypropylene Mfg		7/9/1999	0.3	0			
Reg 8-51	Adhesive and Sealant Products	A11	5/2/2001	unknown	0			
Reg 8-43	Surface Coating of Marine Vessels		4/18/2001	unknown	0			
Reg 8-16	Aqueous Solvents		10/16/2001	2.2	0			
Reg 8-3	Architectural Coatings	A1, SS-11	11/21/2001	3.8	0	2,000		2,774,000
Reg 8-51	Adhesive and Sealant Products		7/17/2002	unknown	0			
Reg 8-4, 8-14, 8-19, 8-31, & 8-43	Surface Preparation and Clean-up Solvents	A5, SS-13	10/16/2002	2.1	0	2,000		1,533,000
FUELS/ORGANIC LIQUIDS STORAGE AND DISTRIBUTION								
Reg 8-5	Storage of Organic Liquids	B2, SS-12	1/20/1993	2.5	0	2,000		1,825,000
Reg 8-6	Organic Chemical Terminals & Bulk Plants	B3	2/2/1994	0.01	0			
Reg 8-7	Gasoline Dispensing Facilities		11/17/1999	3.8	0			
Reg 8-5	Organic Liquid Storage	B2, SS-12	12/15/1999	0.9	0	2,000		657,000
Reg 8-7	Gasoline Dispensing Facilities		11/6/2002	unknown	0			
Reg 8-5	Organic Liquid Storage	B2, SS-12	11/27/2002	0.13	0	2,000		94,900
REFINERY AND CHEMICAL PLANT PROCESSES								
Reg 8-18	Pump & Compressor Seals at Refineries & Chemical Plants	C2	3/4/1992	6.5	0			
Reg 8-22 & 8-25	Valves & Flanges at Refineries & Chemical Plants	C3	3/4/1992	Emissions reduction included in above rule amendment	0			

Reg #	Rule		Adoption Date	Emission ROG	Reductions NO_x	Cost/ton ROG	Cost/ton NO_x	Annual Cost
Reg 8-28	Pressure Relief Devices at Refineries & Chemical Plants	C1	12/17/1997 & 3/18/1998	0.13	0			
Reg 8-18	Equipment Leaks at Refineries & Chemical Plants	SS-16	1/7/1998	1.2	0			
Reg 8-18	Equipment Leaks at Refineries & Chemical Plants	SS-16	11/27/2002	unknown	0			
Reg 12-11	Petroleum Refinery Flare Monitoring		6/4/2003	none	0			
Reg 8-18	Low Emission Refinery Valves	SS-16	1/21/2004	0.2	0			
Reg 8-10	Process Vessel Depressurization	C4, SS-17	1/21/2004	unknown	0	1,000		
Reg 8-8	Refinery Wastewater (Oil-Water) Separators	FS-9	9/15/2004	2.1	0			
Reg 12-12	Petroleum Refinery Flare Control		7/20/2005	TBD	0			
COMBUSTION OF FUELS								
Reg 9-6	Residential Water Heating	D7	4/1/1992	0	3.3		3,400-11,400	8,913,300
Reg 9-7	Boilers, Steam Generators, & Process Heaters	D4	9/16/1992	0	14.9		6,800	36,981,800
Reg 9-8	Non-Utility Reciprocating Engines	D1	1/20/1993	0	8.3		1,000-9,000	15,147,500
Reg 9-9	Control of Emissions from Stationary Gas Turbines	D2	5/5/1993	0	7		2,000-4,000	7,665,000
Reg 9-10	Boilers, Steam Generators, & Process Heaters	D4	1/5/1994	0	21		6,800	52,122,000
Reg 9-12	Glass Manufacturing Plant Melting Furnaces	D6	1/19/1994	0	1.2		4,000	1,752,000
Reg 9-11	Electric Power Generating Boilers	D3	2/16/1994	0	17.5		18,000	1.15E+08
Reg 9-10	Boilers, Steam Generators, & Process Heaters		7/17/2002	0	unknown			

Reg #	Rule		Adoption Date	Emission ROG	Reductions NO_x	Cost/ton ROG	Cost/ton NO_x	Annual Cost
OTHER STATIONARY SOURCE CONTROL MEASURES								
Reg 1	Enhanced Compliance Through Parametric Monitoring		10/7/1998	unknown	unknown			
Reg 8-34	Solid Waste Disposal		10/6/1999	unknown	0			
Reg 8-40	Prohibit Aeration of Petroleum Contaminated Soil		12/15/1999	2.7	0			
				58.79	73.2			
AIR DISTRICT RULES ADOPTED SINCE 2000								
Reg 8-3	Architectural Coatings	A1	11/21/2001	3.8	0	2,000		2,774,000
Reg 8-5	Organic Liquid Storage	B2	11/27/2002	0.1	0	6,350-11,900		333,063
Reg 8-4	Surface Prep and Cleanup Solvents	A5	10/16/2002	2.1	0	1,100		843,150
Reg 8-16	Aqueous Solvents	SS-14	10/16/2001	2.2	0			
Reg 12-11	Petroleum Refinery Flare Monitoring	SS-15	6/4/2003	0	0			
Reg 8-18	Low Emission Refinery Valves	SS-16	1/21/2004	0.2	0			
Reg 8-10	Process Vessel Depressurization	C4	1/21/2004	unknown	0	1,000		
Reg 8-8	Refinery Wastewater	FS-9	9/15/2004	2.1				
Reg 2-2	10 tpy no net increase requirement		12/21/2004	unknown				
Reg 12-12	Petroleum Refinery Flare Control		7/20/2005	unknown				
				10.5	0			
2005 Strategy								
Reg 8-45	Auto refinishing	SS-1		0.7	0	1,000		255,500
Reg 8-20	Graphic Arts	SS-2		0.15	0	800		43,800
	High emitting spray booths	SS-3		0.5	0	5,500		1,003,750
Reg 8-50	Polyester Resins	SS-4		0.3	0	800		87,600
Reg 8-32	Wood Coating Operations	SS-5		0.68	0	2,000-3,700		707,370
Reg 12-12	Refinery flares	SS-6		tbd	tbd	800-1,600		
Reg 8-33, 39	Gasoline Bulk Terminals and Plants	SS-7		0.14		700		35,770
Reg 8-44	Marine Loading Operations	SS-8		0.44		2,800		449,680

Reg #	Rule		Adoption Date	Emission ROG	Reductions NO_x	Cost/ton ROG	Cost/ton NO_x	Annual Cost
Reg 8-5	Organic Liquid Storage	SS-9		tbd		tbd		
Reg 8-28	Pressure Relief Devices	SS-10		0.001		7,000-22,000		5,293
Reg 8-8	Wastewater Systems	SS-11		2.1		1,900-2,400		1,647,975
Reg 9-7	ICI boilers	SS-12			0.75		5,000	1,368,750
Reg 9-6, 7	Large water heaters and smal boilers	SS-13			0.39		0-3,000	213,525
Reg 9-9	Stationary Gas Turbines	SS-14			1.2		5,000-10,000	3,285,000
	Energy conservation	SS-15		unknown	unknown	na		

Table D-3. Funding and Emission Reductions from Incentive Programs

Fiscal Year	FY00/01		FY01/02		FY02/03	
Measure	**Funding ($)**	**Emission Reductions***	**Funding ($)**	**Emission Reductions***	**Funding ($)**	**Emission Reductions***
Smoking Vehicle	508,490	36	545,664	60	522,008	61
Vehicle Buy Back	2,326,588	643	2,264,977	372	3,753,850	582
Vehicle Incentive Program	1,360,000	37	1,311,000	42	1,000,000	5
Spare the Air	622,329	25	649,426	20	667,690	23
Lawnmower Buy Back	125,000	5.3	129,200	5.5	158,800	6.7
Trip Reduction/ Ridesharing	3,028,770	268	4,273,748	161	5,932,746	239
Telecommuting	41,496	2				
Smart Growth	938,375	36	550,000	13	995,186	34
Arterial Management	724,715	46	1,899,000	62	2,980,000	167
Bicycle Facilities	2,368,051	78	1,162,047	49	3,470,763	123
Shuttle and Feeder Buses	3,524,306	136	3,369,273	111	3,082,874	88
Transit Buses	1,534,535	123	3,921,396	248	1,463,370	58
School Buses	1,072,500	31	3,920,000	80	1,330,000	39
Natural Gas Vehicles	4,734,000	267	1,359,812	95	2,846,153	129
Infrastructure for CNG	695,544	N/A	1,373,739	N/A	375,615	N/A
Infrastructure for EV	93,000	N/A	9,000	N/A	57,000	N/A
Lower Emission School Bus Program	8,673,611	182	4,238,607	89	3,172,852	127
Carl Moyer Program	4,340,000	2,859	1,570,344	906	1,573,102	906
TOTAL	**36,786,310**	**4,769**	**32,458,233**	**2,328**	**33,223,209**	**2,581**

* Emission reductions are total tons of ROG, NO_x, and PM combined over the life of the project.

The 1997 South Coast Air Quality Management District 1997 plan for attaining the 1-hour ozone NAAQS for the South Coast Air Basin was used to estimate the cost of stationary and area source control measures adopted in the SCAB since the 1990 CAAA (SCAQMD, 1996). Table D-4 lists the measures and associated costs based on the analysis at the time that these measures were included in the SCAB Plan. The measures in this table are those that are expected to be incorporated in the control factors used to estimate VOC and NO_x emission reduction requirements in this area post-1999. The 1997 plan costs are in 1993 dollars and are based on the SCAQMD's discounted cash flow analysis. This discounted cash flow analysis provided cost estimates in dollars per ton of the pollutant reduced.

The estimated annual cost of the ozone precursor control measures shown in Table D-4 is $198 million. This represents the cost of the point and area source control measures with cost per ton values listed in Table D-4. This expenditure is expected to provide combined ROG plus NO_x emission reductions of 123.1 tons per day, or 44,931 tons per year. Therefore, the combined ROG plus NO_x cost effectiveness is $4,406 per ton (in 1993 dollars). The equivalent annual cost expressed in 2006 dollars is $261 million.

Table D-4. SCAQMD Area Stationary and Area Source Control Measures to Meet the 1-Hour Ozone NAAQS

Control Measure #	Rule	Rule #	Implementing Agency	Adoption Date	Implementation Period	2010 Annual Average Emission Reductions		Cost/ton		Annual Cost
						ROG	NOx	ROG	NOx	
SURFACE COATING AND SOLVENT USE										
CTS-02E	Emission Reductions from Adhesives	1168	SCAQMD/ ARB	2000	2007-2010	0.9		6,850		2,250,225
CTS-02H	Emission Reductions from Metal Parts and Products	1107	SCAQMD	1997	1998-2000	4.9		4,560		8,155,560
CTS-02M	Emission Reductions from Plastic, Rubber, Glass Coatings	1145	SCAQMD	1997	1998-2000	1.3		4,850		2,301,325
CTS-02N	Emission Reductions from Solvent Degreasers	1122	SCAQMD/ ARB	1997	2000-2005	35.2		100		1,284,800
CTS-02O	Emissions Reductions from Solvent Usage	442	SCAQMD	2000	2000-2005	2.4		2,470		2,163,720
CTS-03	Consumer Product Education Labeling Program		SCAQMD	1998	2000-2005					
CTS-04	Public Awareness/Education Programs - Area Sources		SCAQMD	1998	2000-2005					
CTS-07	Further Emission Reductions from Architectural Coatings	1113	SCAQMD	1996	1998	33.3		12,270		149,135,715
CP-02	Emission Reductions from Consumer Products		ARB	1997	2005-2008	33.9		2,100		25,984,350
DPR-01	Emission Reductions From Pesticide Applications		DPR	1997	2005	1.4				
PETROLEUM OPERATIONS AND FUGITIVE EMISSIONS										
FUG-03	Further Emission Reductions from Floating Roof Tanks	463	SCAQMD	1999	2000					
FUG-04	Further Emission Reduction from Fugitive Sources	1173	SCAQMD	1997	1997	0.5				
COMBUSTION SOURCES										
CMB-02B	Emission Reduction from Small Boilers and Process Heaters		SCAQMD	1997	1999		2.4		4,650	4,073,400
CMB-03	Area Source Credit Programs		SCAQMD	1997	1997-2000					
CMB-04	Area Source Credits for Energy Conservation/ Efficiency		SCAQMD	1997	1997-2000					
CMB-06	Emission Standards for New Commercial and Residential Water Heaters		SCAQMD	1999	2003-2013		7.6		660	1,830,840
CMB-07	Emission Reductions from Petroleum Refinery Flares		SCAQMD	1999	2000					
MISCELLANEOUS SOURCES										

Control Measure #	Rule	Rule #	Implementing Agency	Adoption Date	Implementation Period	2010 Annual Average Emission Reductions ROG	NOx	Cost/ton ROG	NOx	Annual Cost
MSC-01	Promotion of Lighter Color Roofing and Road Materials and Tree Planting Programs		SCAQMD, Local Gov't	1999	2000					
MSC-02	In-Use Compliance Program for Air Pollution Control Equipment		SCAQMD	1997	1998					
MSC-03	Promotion of Catalyst-Surface Coating Technology Programs		SCAQMD	1998	2000-2004					
PRC-03	Emission Reductions from Restaurant Operations		SCAQMD	1997	2000-2004	1.2		3,700		1,620,600
WST-01	Emission Reductions from Livestock Waste		SCAQMD	1998	2004-2006	3.3				
WST-02	Emission Reductions from Composting		SCAQMD	1998	2004-2006					
WST-03	Waste Burning	444	SCAQMD	1997	1997-2010					
WST-04	Disposal of Materials Containing VOC		SCAQMD	1997	1998-2001	0.7				
FSS-04	Emission Charges of $5,000 per Ton of VOC for Stationary Sources Emitting Over 10 Tons per Year		SCAQMD	TBD	TBD			5,000		
COMPLIANCE FLEXIBILITY PROGRAMS										
FLX-01	Intercredit Trading Program		SCAQMD	1997	1997-1998					
FLX-02	Air Quality Investment Fund		SCAQMD	1997	1997-1998					
TRANSPORTATION CONTROL AND INDIRECT SOURCE MEASURES										
TCM-01	Transportation Improvements		SCAG	1997	2000-2010					
ADVANCED TRANSPORTATION TECHNOLOGY INCENTIVE MEASURES										
ATT-01	Telecommunications		The Partnership SCAQMD, SCAG, Local Gov't	TBD	TBD					
ATT-02	Advanced Shuttle Transit		The Partnership SCAQMD, SCAG, Local Gov't	TBD	TBD					
ATT-03	Zero-Emission Vehicles/Infrastructure		The Partnership SCAQMD, SCAG, Local Gov't	TBD	1997-2010					
ATT-04	Alternative Fuel Vehicles/Infrastructure		The Partnership SCAQMD, SCAG, Local Gov't	TBD	1997-2010					

Control Measure #	Rule	Rule #	Implementing Agency	Adoption Date	Implementation Period	2010 Annual Average Emission Reductions		Cost/ton		Annual Cost
						ROG	NOx	ROG	NOx	
ATT-05	Intelligent Vehicle Highway Systems (IVHS)		The Partnership SCAQMD, SCAG, Local Gov't	TBD	TBD					
FURTHER STUDY STRATEGY										
FSS-02	Market-Based Transportation Pricing		State or Local Agencies	TBD	TBD					
ON-ROAD MOBILE SOURCES										
M1	Accelerated Retirement of Light-Duty Vehicles		ARB/ SCAQMD	1997	1997-2010	16	9			
M4	Heavy-Duty Diesel Vehicles; Early Introduction of Low-NOx Engines		ARB	TBD	1997-2002	0	1			
M5	Heavy-Duty Diesel Vehicles; Additional NOx Reductions in CA		ARB	1997	2002	1	6			
M7	Accelerated Retirement of Heavy-Duty Vehicles		ARB	1997	1997-2010	1	9			
MON-09	In-Use Vehicle Emission Mitigation		SCAQMD	1997	1998-2010					
MON-10	Emissions Reduction Credit for Truck Stop Electrification		SCAQMD	1997	1998-2010					
OFF-ROAD MOBILE SOURCES										
M11	Industrial Equipment; Gas & LPG - CA		ARB	1997	2000-2004	15	8			
MOF-07	Credits for the Replacement of Existing Pleasure Craft Engines with New Lower Polluting Engines		SCAQMD	1997	1998-2010					
Costs are in 1993 dollars	Based on a discounted cash flow analysis performed by the SCAQMD					152	43			198,800,535

Source: SCAQMD, 1996.

Note that the costs of the mobile source strategies listed in Table D-4 are not included in the cost estimate provided above because these measures were not included in the 2010 and 2020 emission projections performed for this area.

REFERENCES

BAAQMD, 2006: "Bay Area 2005 Ozone Strategy, Volume I, FINAL - ADOPTED," Bay Area Air Quality Management District, San Francisco, CA. January 4, 2006.

BAAQMD, 2006: "Bay Area 2005 Ozone Strategy, Volume II, FINAL - ADOPTED," Bay Area Air Quality Management District, San Francisco, CA. January 4, 2006.

BAAQMD, 1994: "BAY AREA '94 CLEAN AIR PLAN, *Volume III*, APPENDIX G, Stationary and Mobile Source Control Measure Descriptions, Adopted," Bay Area Air Quality Management District, San Francisco, CA. December 21, 1994.

Georgia DNR, 2005: "Georgia's Redesignation Request and Maintenance Plan for the Atlanta 1-Hour Ozone Nonattainment Area," Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Atlanta, GA. February 1, 2005.

SCAQMD, 1996: "1997 Air Quality Management Plan - Final," South Coast Air Quality Management District, Diamond Bar, CA. November 1996.

APPENDIX E

8-HOUR OZONE NAAQS ANALYSIS FOR CALIFORNIA AREAS

APPENDIX E | 8-HOUR OZONE NAAQS ANALYSIS FOR CALIFORNIA AREAS

Because no modeling results were available from EPA for estimating the VOC and NO_x emission reduction targets for California areas not attaining the 8-hour ozone NAAQS, alternate methods were needed for estimating the needed ozone precursor emission reductions and associated costs to meet the 8-hour ozone NAAQS in California nonattainment areas. A large fraction of the State is classified as being nonattainment for 8-hour ozone. Pechan's cost analysis approach was to identify expected needed ozone precursor emission reductions by area for the areas that are classified as serious or severe, with the likelihood that these areas will have the highest expected compliance costs. California areas that are classified as either serious or severe ozone nonattainment are: Sacramento Metro (subpart 2 serious), San Joaquin Valley (subpart 2 serious), Riverside Co. (Coachella Valley) (subpart 2 serious), and Los Angeles-South Coast Air Basin (subpart 2 severe 17).

Publicly available information about each of these areas 8-hour ozone modeling and/or draft implementation plans was consulted and inquiries were made in cases where no information was posted. The information available for each area is described below.

The draft 2007 plan for the South Coast Air Basin (SCAQMD, 2006) estimates the expected emission reductions that are needed from a 2002 baseline to meet both reasonable further progress (RFP) and to attain the 8-hour ozone NAAQS. For reasonable progress, the SCAQMD is only required to provide for VOC and/or NO_x reductions of 3 percent per year from the 2002 baseline averaged over each consecutive 3 year period beginning in 2008 until the Basin's attainment date (i.e., June 2017).

Table E-1 shows the SCAQMD percentage reductions for both VOC and NO_x emissions necessary to meet the 3 percent requirement. Up until the year 2017, projected VOC baseline emissions are sufficient to meet the CAA requirements. For the milestone years 2017 and 2020, the baseline VOC emission levels are below the target levels. In 2017, VOC planned reductions from control measures in the draft SCAQMD plan are needed to show compliance with the targeted VOC thresholds. In 2020, the ozone carrying capacities require reduction target levels beyond the 3 percent per year goal, and are estimated to be 70.4 and 78.2 percent for VOC and NO_x, respectively. These values are used to estimate the emission reductions needed in the South Coast Air Basin in 2020 to meet the 8-hour ozone NAAQS.

Table E-1. South Coast Air Basin Percent of VOC and NO_x Emission Reductions from the 2002 Baseline to Meet RFP Requirements

Year	VOC	NO_x	CAA*
2008	18.0	0.0	18.0
2011	27.0	0.0	27.0
2014	36.0	0.0	36.0
2017	45.0	0.0	45.0
2020	70.4	78.2	Attainment

* The percent VOC and NO_x reductions must equal the CAA percent reduction requirements listed here.

The San Joaquin Valley Unified Air Pollution Control District has also performed modeling to estimate the additional VOC and NO_x emission reductions that will be needed in order to attain the 8-hour ozone NAAQS within this nonattainment area (SJVUAPCD, 2006). This modeling included various combinations of NO_x and VOC emission reductions. The combinations generate a data set of predicted ozone levels as a function of VOC and NO_x percentage reductions. The data is used as a carrying capacity diagram, which shows the level of emissions that the atmosphere can carry and still demonstrate attainment.

The SJVUAPCD carrying capacity diagrams show that approximately a 60 percent reduction in VOC and NO_x emissions from the 2012 baseline throughout the Central California modeling domain is needed to achieve the 8-hour average ozone NAAQS in the San Joaquin Valley. This amount of control is driven by the reductions needed to achieve the NAAQS near Arvin. Other sites are expected to reach attainment earlier, with fewer reductions needed. For instance, a 40 percent domain-wide reduction of 2012 VOC and NO_x emissions is needed to demonstrate attainment of the 8-hour ozone NAAQS at Parlier, the site downwind of Fresno in the central portion of the Valley with the worst air quality. Sites farther north, such as Merced, are expected to come into attainment with an approximate 20 percent NO_x and VOC reduction across the domain. This information was used by Pechan to establish appropriate needed emission reductions by county for the different sub-areas within the San Joaquin Valley.

The Sacramento Metro region has used air quality modeling results for 2012, 2018, and 2023 to see if existing controls would result in 8-hour ozone NAAQS attainment, and if not, to estimate what combinations of VOC and NO_x control might be used to reach attainment (SMAQMD, 2006). The 2012 air quality modeling analysis for the peak monitoring site in the Sacramento region indicates that the federal 8-hour ozone standard could be attained by reducing 2012 emissions of VOC and NO_x by approximately 27 percent each. Therefore, the 2012 attainment targets for the Sacramento nonattainment area are about 95 tons per day (tpd) of VOC and 86 tpd of NO_x. This shortfall represents additional reductions of 35 tpd VOC and 32 tpd NO_x from baseline 2012 forecasts. Table E-2 summarizes the attainment targets and emission reductions needed in the Sacramento area to attain the 8-hour ozone NAAQS in 2012. The ozone modeling analysis indicates that other combinations of VOC and NO_x reductions may be possible to bring the area into attainment as well.

Table E-2. Summary of Attainment Targets and Emission Reductions Needed in the Sacramento Nonattainment Area for 2012

Sacramento Nonattainment Area	VOC (tpd)	NO_x (tpd)
2002 Baseline Emissions	168	176
2012 Emissions Forecast	130	118
% Shortfall from 2012 Emissions Forecast	27%	27%
2012 Attainment Targets	95	86
2012 Emission Reductions Needed (Shortfall)	35	32

The 2018 modeling analysis for the Sacramento region indicates that the 8-hour ozone NAAQS could be attained by reducing 2018 emissions of VOC and NO_x by 10 percent each. Therefore, the 2018 attainment targets for the Sacramento nonattainment area are about 107 tpd of VOC and 78 tpd of NO_x. This shortfall represents additional reductions of 12 tpd of VOC and 9 tpd of NO_x. Table E-3 summarizes the attainment targets and emission reductions needed in the Sacramento area to attain the 8-hour ozone NAAQS in 2018. In addition to the attainment control strategy of equal percentage reductions from both VOC and NO_x emissions, the ozone modeling analysis indicates that other combinations of VOC and NO_x emission reductions may be possible for attainment as well.

Table E-3. Summary of Attainment Targets and Emission Reductions Needed in the Sacramento Nonattainment Area for 2018

Sacramento Nonattainment Area	VOC (tpd)	NO_x (tpd)
2002 Baseline Emissions	168	176
2018 Emissions Forecast	119	87
% Shortfall from 2018 Emissions Forecast	10%	10%
2018 Attainment Targets	107	78
2018 Emission Reductions Needed (Shortfall)	12	9

The Coachella Valley 8-hour ozone nonattainment area is a sub region of Riverside County that is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. This is a desert area that is impacted by pollutant transport from the South Coast Air Basin. Within the state of California, the Coachella Valley Planning Area is under the purview of the South Coast Air Quality Management District. Plans for meeting the 8-hour ozone standard for the Coachella Valley Planning Area are not addressed in the Draft 2007 AQMP (SCAQMD, 2006). Therefore, no specific attainment targets are available now for this nonattainment area. Given the likelihood that the air quality plan for Coachella Valley will rely on reducing South Coast Air Basin emissions, and resulting transport, this portion of Riverside County was not modeled separately from the rest of the South Coast. Because the area and mobile source emissions within the Coachella Valley area will be difficult to identify separately (they are computed and stored as county-level estimates in the emission inventory), they were included in the analysis as if Riverside County was all within the South Coast Air Basin.

As confirmation of the reasonableness of excluding marginal 8-hour ozone nonattainment areas from the California compliance cost analysis, the Bay Area AQMD was contacted and they said that they are not required to conduct modeling for 8-hour NAAQS attainment, they just need to show continued progress towards reaching attainment (Vintze, 2006). Therefore, they currently have no plans to adopt control measures beyond those committed to in their 1 hour ozone plan.

Table E-4 summarizes the needed ozone precursor emission reductions for each California area included in this analysis in terms of the compliance year closest to the 2010 and 2020 analysis years used in this section 812 analysis. For each area, the needed emission reduction percentages are expressed in relation to either 2002 or a projection year's emissions. The emission reduction targets for the San Joaquin Valley are presented separated for each of the three sub-areas within the larger ozone nonattainment area. The text and tables below describe how the emission reduction percentages in Table E-4 were translated into effective emission reduction targets in 2010 and 2020 by area.

Table E-4. Percentage Target Reductions for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2010 NO_x Target (%)	2010 VOC Target (%)	2020 NO_x Target (%)	2020 VOC Target (%)
Central San Joaquin Valley, CA	40 (from 2012 baseline)	40 (from 2012 baseline)	40 (from 2012 baseline)	40 (from 2012 baseline)
Los Angeles, CA	-	24 (RFP requirement)	78.2 (from 2002 baseline)	70.4 (from 2002 baseline)
Northern San Joaquin Valley, CA	20 (from 2012 baseline)	20 (from 2012 baseline)	20 (from 2012 baseline)	20 (from 2012 baseline)
Sacramento, CA	27 (from 2012 baseline)	27 (from 2012 baseline)	10 (from 2018 baseline)	10 (from 2018 baseline)
Southern San Joaquin Valley, CA	60 (from 2012 baseline)	60 (from 2012 baseline)	60 (from 2012 baseline)	60 (from 2012 baseline)

The AirControlNET model that is used to estimate direct compliance costs uses absolute target tons in the least cost analysis for selecting local control measures to attain the 8-hour ozone NAAQS. In order to calculate absolute reduction target tons for some of these areas, 2012 and 2018 emissions were needed. The estimated 2012 and 2018 emissions were calculated by interpolating from the 2010 and 2020 core scenario emissions inventories for each geographic area of interest. Tables E-5 and E-6 show these steps.

Table E-5 provides NO_x and VOC emissions for the with CAAA scenario for each of these nonattainment areas for the years - 2002, 2010 and 2020.

Table E-5. 2002, 2010, and 2020 Core Scenario Emissions Estimates for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2002 NO_x Annual Emissions	2002 VOC Annual Emissions	2010 NO_x Annual Emissions	2010 VOC Annual Emissions	2020 NO_x Annual Emissions	2020 VOC Annual Emissions
Central San Joaquin Valley, CA	75,074	64,913	54,700	60,925	39,598	63,773
Los Angeles, CA	508,635	359,867	398,441	276,934	293,043	272,870
Northern San Joaquin Valley, CA	64,398	49,787	40,685	42,177	29,490	43,970
Sacramento, CA	84,143	69,275	67,580	58,642	48,096	57,351
Southern San Joaquin Valley, CA	62,127	39,523	52,320	31,913	50,891	31,447

Linear interpolation was performed using following formula.

$$x_1 - x_0$$

$$y = y_0 + \alpha(y_1 - y_0)$$

Where:

X	=	Year that we want to interpolate
X_0	=	Year 2010
X_1	=	Year 2020
Y	=	Emissions for the interpolated year X
Y_0	=	2010 Emissions
Y_1	=	2020 Emissions

So 2012 NO_x and VOC emissions was calculated using following formula -

α = (2012 - 2010) / (2020 - 2010) = 0.2

2012 Emissions = 2010 Emissions + (0.2) x (2020 Emissions - 2010 Emissions)

Similarly 2018 emissions was calculated using -

α = (2018 - 2010) / (2020 - 2010) = 0.8

2018 Emissions = 2010 Emissions + (0.8) x (2020 Emissions - 2010 Emissions)

Table E-6 provides interpolated 2012 and 2018 NO_x and VOC emissions for each nonattainment areas.

Table E-6. Estimated 2012 and 2018 Emissions for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2012 NO_x Annual Emissions	2012 VOC Annual Emissions	2018 NO_x Annual Emissions	2018 VOC Annual Emissions
Central San Joaquin Valley, CA	51,680	61,495	42,619	63,204
Los Angeles, CA	377,361	276,121	314,123	273,683
Northern San Joaquin Valley, CA	38,446	42,536	31,729	43,611
Sacramento, CA	63,684	58,384	51,993	57,609
Southern San Joaquin Valley, CA	52,034	31,820	51,177	31,541

Absolute target reduction tons required to attain 8-hour ozone NAAQS were calculated by subtracting required attainment emissions, calculated using percentage reduction targets, from total emissions.

So for 2010,

2010 Target Reduction = 2010 Total Emissions - (Baseline Year Emissions x (1 - % Target Reduction))

Similarly for 2020,

2020 Target Reduction = 2020 Total Emissions - (Baseline Year Emissions x (1 - % Target Reduction))

These are the absolute target tons that AirControlNET will use to select local control measures on least cost basis. These calculated absolute target tons are provided in Table E-7.

Table E-7. Absolute Target Tons Required to Attain the 8-Hour Ozone NAAQS in California Nonattainment Areas

Nonattainment Area	2010 NO_x Target Reductions	2010 VOC Target Reductions	2020 NO_x Target Reductions	2020 VOC Target Reductions
Central San Joaquin Valley, CA	23,692	24,028	8,591	26,877
Los Angeles, CA	-	3,436	182,161	166,349
Northern San Joaquin Valley, CA	9,928	8,149	(1,267)	9,941
Sacramento, CA	21,091	16,022	1,303	5,503
Southern San Joaquin Valley, CA	31,506	19,185	30,077	18,719

For these serious or severe California nonattainment areas, it was assumed that RACT was already applied in the base inventory. So no further RACT controls were simulated as mandatory measures for these nonattainment areas.

I/M controls were then applied to counties where required. Once I/M and RACT controls were applied, the costs of meeting the additional emission reduction requirements were determined for each area by using control techniques, efficiencies, and cost databases in concert with the incremental emission reduction and progress requirements listed in Table E-7. For additional local controls, a least-cost algorithm was used to identify and apply the control measures to meet the progress requirements, where applicable. First, the potential sources of emission and reductions and their costs were identified. Next, the lowest cost, second lowest, third lowest, and so forth, control measures were selected until the progress requirement or attainment target was met. Because of the discrete nature of control measures and their efficiencies, sometimes the emission reduction or progress target was exceeded. Any excess might be used as an offset against new source growth emissions, if the excess were significant.

Similarly, if an area required additional reductions to meet their emission reduction target for NO_x and/or VOC, source/controls within 100 km radius for VOC reductions and within 200 km radius for NO_x reductions were selected on a least cost basis, as described above.

RESULTS

Table E-8 summarizes estimated nonattainment area-level and state-level 8-hour ozone NAAQS attainment costs for 2010. The estimated cost of 8-hour ozone NAAQS compliance in California in 2010 is $424 million for identified measures applied in the California serious and severe nonattainment areas(1999$). Note that the modeled VOC and NO_x emission reductions for Central San Joaquin Valley were not sufficient to meet attainment. The residual tons column in Table E-8 provides the shortfall reductions. Costs are also estimated for residual VOC and NO_x shortfall assuming a control cost of $15,000/ton. Including the cost of the unidentified measures (of $267 million) brings the total annual cost of meeting the 8-hour ozone NAAQS requirements in 2010 to $691 million.

As is the case for the Local Control Measures Analysis provided in Chapter VIII for non-California areas, control measures for each nonattainment area in California were selected from sources located within the nonattainment area and within a 100 km buffer for VOC control measures and within a 200 km buffer for NO_x control measures. Control measures were selected on a least-cost basis to meet their emission reduction target for NO_x and VOC. Because of the close proximity of these nonattainment areas, the 100 and/or 200 km buffer areas sometimes overlap. In these cases, and because nonattainment areas were analyzed independently, the possibility exists that a source/control measure combination could be selected more than once to satisfy reduction requirements of more than one area. Any double counting of cost and reductions is expected to be small in most of these areas.

Note that this cost estimate probably overstates the 2010 costs for the areas other than the South Coast because the attainment dates for the San Joaquin Valley and Sacramento are 2012. This analysis for 2010 examines the expected costs of achieving the 2012 attainment level emission quantities in these two areas earlier than the CAA requires. Costs estimated for the South Coast for 2010 are those to meet estimated rate-or-progress requirements in that year.

Tables E-9 shows the projected 2010 VOC and NO_x emission reductions by sector for each 8-hour ozone nonattainment area. For VOC, this table shows that the majority of the expected emission reductions will come from the non-point source sector. Tables E-9 also shows that NO_x control measure selection is more evenly spread among the sectors than the VOC selection. NO_x control measure choices in any individual area are a function of the source mix and the availability of cost effective controls by sector.

Table E-10 summarizes the results of the California area 8-hour ozone NAAQS cost analysis for 2020. Total direct control costs in 2020 based on applying known, available control measures are estimated to be $570 million, up from $424 million in 2010. Most of this cost increase is explained by change in targets between 2010 and 2020. However, year 2020 shows a significant increase in the amount of residual tons because sufficient control measures are not available to meet the very large emission reductions required in the South Coast Air Basin (Los Angeles) to attain the 8-hour ozone NAAQS in 2020. Costs are also estimated for residual VOC and NO_x shortfalls in LA to be almost $4.1 billion, assuming a control cost of $15,000/ton. The total estimated cost to meet the 8-hour ozone NAAQS in California, including the cost of unidentified measures is $4.8 billion.

Comparing the 2020 and 2010 cost analysis summaries for the individual nonattainment areas shows that the attainment costs for the SJV and Sacramento areas are considerably lower in 2020 than in 2010. This occurs because the core scenarios are expected to produce continuing emission reductions between 2010 and 2020, so the needed emission reductions to reach attainment emission levels in 2020 are lower than in 2010. A significant part of these 2010 to 2020 emission reductions for VOC and NO_x are achieved by emission and fuel standards applied to onroad vehicles and nonroad engines/vehicles.

Table E-11 shows the modeled VOC and NO_x emission reductions in 2020 by sector. The distribution of costs by sector changes somewhat in 2020 (from 2010). This is mainly due to change in target requirements for nonattainment areas in 2020. What these two analysis years have in common is that VOC control measures selections are dominated by area source controls and NO_x emission reductions are achieved mainly via point source control measures.

Table E-8. 8-Hour Ozone NAAQS Cost Analysis Summary for California Areas (2010)

Nonattainment Area	VOC Tons Reduced from Core Scenario	NO_x Tons Reduced from Core Scenario	Residual VOC tons	Residual NO_x tons	Cost of unidentified measures (millions 1999$)
Central San Joaquin Valley, CA	14,073	15,860	9,955	7,832	267
Los Angeles, CA	3,611	-	-	-	-
Northern San Joaquin Valley, CA	8,165	11,107	-	-	-
Sacramento, CA	16,252	21,152	-	-	-
Southern San Joaquin Valley, CA	19,456	31,608	-	-	-
Totals	**61,557**	**79,727**	**9,955**	**7,832**	**267**

Table E-9. California 2010 Local Control Measure Emission Reductions by Sector and Nonattainment Area

	VOC					NO_x				
Nonattainment Area	**EGU**	**POINT**	**AREA**	**ONROAD**	**NONROAD**	**EGU**	**POINT**	**AREA**	**ONROAD**	**NONROAD**
Central San Joaquin Valley, CA	-	5	13,845	223	-	1,825	10,724	1,193	2,119	-
Los Angeles, CA	-	-	3,611	-	-	-	-	-	-	-
Northern San Joaquin Valley, CA	-	-	8,165	-	-	1,885	8,774	447	-	-
Sacramento, CA	-	-	16,098	153	-	1,707	16,455	1,056	1,934	-
Southern San Joaquin Valley, CA	-	-	19,456	-	-	3,860	26,130	1,617	-	-
Totals	**-**	**5**	**61,175**	**376**	**-**	**9,278**	**62,083**	**4,314**	**4,052**	**-**

Table E-10. 8-Hour Ozone NAAQS Cost Analysis Summary for California Areas (2020)

Nonattainment Area	VOC Tons Reduced from Core Scenario	NO_x Tons Reduced from Core Scenario	Residual VOC tons	Residual NO_x tons	Cost of unidentified measures (millions 1999$)
Central San Joaquin Valley, CA	15,879	9,889	10,998	-	165
Los Angeles, CA	37,529	39,842	128,820	142,319	4,067
Northern San Joaquin Valley, CA	9,948	-	-	-	-
Sacramento, CA	5,517	1,634	-	-	-
Southern San Joaquin Valley, CA	18,740	30,319	-	-	-
Totals	**87,613**	**81,683**	**139,818**	**142,319**	**4,232**

Table E-11. California 2020 Local Control Measure Emission Reductions by Sector and Nonattainment Area

	VOC					NO_x				
Nonattainment Area	EGU	POINT	AREA	ONROAD	NONROAD	EGU	POINT	AREA	ONROAD	NONROAD
Central San Joaquin Valley, CA	-	23	15,856	-	-	1,387	8,306	196	-	-
Los Angeles, CA	-	183	37,087	259	-	3,491	32,767	1,893	1,691	-
Northern San Joaquin Valley, CA	-	-	9,948	-	-	-	-	-	-	-
Sacramento, CA	-	-	5,517	-	-	-	1,524	110	-	-
Southern San Joaquin Valley, CA	-	-	18,740	-	-	3,789	24,929	1,601	-	-
Totals	**-**	**206**	**87,148**	**259**	**-**	**8,667**	**67,526**	**3,799**	**1,691**	**-**

REFERENCES

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APPENDIX F

MOBILE SOURCE CONTROL MEASURE COST DOCUMENTATION

APPENDIX F | MOBILE SOURCE CONTROL MEASURE COST DOCUMENTATION

This appendix describes the development of cost and emission reduction estimates for some mobile source control measures that were prepared as part of this section 812 analysis. These are control measures that were included in the AirControlNET model in order to simulate attainment strategies for the 8-hour ozone NAAQS and the PM2.5 NAAQS. The control measure analyses described in this section are for onroad and nonroad diesel retrofit technologies targeting PM control, onroad vehicle retrofit control technologies targeting NOx control, and eliminating long duration diesel truck idling.

ONROAD AND NONROAD DIESEL RETROFITS AND VEHICLE REPLACEMENT

The Section 812 local PM control measures analysis of onroad and nonroad diesel retrofits and vehicle replacement was based on EPA's analysis of this control measure as performed for the PM NAAQS RIA (EPA, 2006a). This section summarizes EPA's analysis, along with the emission control efficiencies assumed and the derivation of the control measure cost effectiveness values used in the Section 812 local PM measures analysis.

Retrofitting heavy-duty diesel vehicles and equipment manufactured before stricter standards are in place – in 2007 for highway engines and in 2008 for most nonroad equipment – can provide PM, NOx, HC, and CO benefits. EPA's PM NAAQS RIA included the following retrofit strategies:

- Installation of emissions after-treatment devices:
    - diesel oxidation catalysts (DOCs)
    - diesel particulate filters (DPFs)
- Rebuilding nonroad engines
- Early replacement and retirement of onroad vehicles

EPA focused on these strategies due to their high emissions reduction potential and widespread application. Emissions reductions through retrofits vary significantly by strategy and by the type and age of the engine and its application. EPA applied a mix of the above four retrofit strategies (DOCs, DPFs, rebuild, replacement) to highway heavy-duty diesel trucks class 5 and above (over 16,000 pounds GVWR) and buses, from model years 1990 through 2006, and to nonroad engines, from model years 1988 through 2007, excluding locomotive, marine, pleasure craft, and aircraft engines.

Using the retrofit module in EPA's National Mobile Inventory Model (NMIM), EPA calculated the total percentage reduction in emissions (PM, NOx, HC, and CO) from the retrofit measure for each relevant engine category (source category code, or SCC). This analysis was based on NMIM 2005 (version NMIM20060310), NONROAD2005 (February 2006), and MOBILE6.2.03 which included the updated diesel PM file PMDZML.csv dated March 17, 2006. The resulting estimated emission reductions, which were modeled in the Section 812 local measures analysis, from the onroad retrofit/retirement control strategies are shown by SCC in Table F-1. The estimated emission reductions from the nonroad retrofit/rebuild control program are shown by SCC in Table F-2. For this Section 812 analysis, the 2015 reductions derived by EPA for the PM NAAQS RIA were applied in 2010.

The Section 812 costing of the onroad and nonroad diesel retrofit/replacement/rebuild measure was based on the PM cost effectiveness values that EPA developed for the PM NAAQS analysis (EPA, 2006a). The retrofit measures were divided into two categories: the first 50 percent of retrofit potential (low end) and the second 50 percent of retrofit potential (high end). The low end is categorized as the most cost-effective retrofits since, ideally, states and local governments would first retrofit the most cost-effective fleets in terms of expected emissions reduction (based on vehicle miles traveled or VMT, expected life, model year, engine type, etc.) and cost of retrofit (based on technology and installation costs).

EPA developed illustrative cost-effectiveness ($/ton of PM) estimates for retrofits based on EPA's recent study of diesel retrofits (EPA, 2006b). Although the diesel retrofit study contains the most current data available, it was intentionally narrow in scope. Thus, several limitations affecting the PM NAAQS analysis and this Section 812 analysis should be noted:

- The diesel retrofit study does not address several categories of engines included in this local measures analysis such as class 5 highway trucks and most nonroad engines.
- The diesel retrofit study does not estimate cost-effectiveness for engine repowering or replacement.
- The diesel retrofit study is based on 2007 costs for technologies and emissions data for fleets. VMT, technology costs, and other variables will be different in 2010 and 2020.
- For highway engines, the diesel retrofit study is based on emission factors from recent testing which are roughly 2.3 times higher than emissions factors found in MOBILE 6.2.

Table F-1. Onroad Retrofit/Retirement Control Efficiencies by SCC

	2010 Control Efficiency (%)					2020 Control Efficiency (%)				
SCC	NO_x	VOC	PM-10	PM-2.5	CO	NO_x	VOC	PM-10	PM-2.5	CO
2230072110	0.5	6.0	5.7	5.7	9.0	0.5	3.4	5.4	5.4	7.7
2230072130	0.5	5.6	5.5	5.5	8.5	0.4	3.1	5.2	5.2	7.3
2230072150	0.5	5.8	5.6	5.6	8.7	0.4	3.2	5.3	5.3	7.4
2230072170	0.5	5.9	5.7	5.7	8.9	0.5	3.3	5.4	5.4	7.6
2230072190	0.5	5.9	5.7	5.7	8.9	0.5	3.3	5.4	5.4	7.6
2230072210	0.5	5.9	5.7	5.7	8.9	0.5	3.3	5.3	5.3	7.5
2230072230	0.5	5.8	5.7	5.7	8.8	0.4	3.2	5.3	5.3	7.4
2230072250	0.5	6.0	5.8	5.8	9.1	0.5	3.4	5.5	5.5	7.8
2230072270	0.5	5.9	5.7	5.7	9.0	0.5	3.3	5.4	5.4	7.6
2230072290	0.5	5.9	5.8	5.8	9.0	0.5	3.3	5.4	5.4	7.6
2230072310	0.5	5.9	5.7	5.7	8.9	0.5	3.3	5.3	5.3	7.6
2230072330	0.5	5.9	5.7	5.7	8.9	0.4	3.2	5.3	5.3	7.5
2230073110	2.1	24.2	27.5	27.5	37.7	1.7	12.0	23.4	23.4	28.6
2230073130	2.1	23.9	27.4	27.5	37.5	1.7	11.8	23.2	23.2	28.4
2230073150	2.1	24.0	27.4	27.4	37.6	1.7	11.9	23.3	23.3	28.5
2230073170	2.1	24.2	27.5	27.5	37.7	1.7	12.0	23.4	23.4	28.6
2230073190	2.1	24.1	27.5	27.5	37.7	1.7	11.9	23.3	23.3	28.6
2230073210	2.1	24.1	27.5	27.5	37.7	1.7	11.9	23.3	23.3	28.5
2230073230	2.1	23.9	27.4	27.4	37.6	1.7	11.6	23.1	23.1	28.1
2230073250	2.1	24.2	27.5	27.5	37.7	1.7	11.9	23.4	23.4	28.5
2230073270	2.1	24.0	27.4	27.4	37.6	1.7	11.7	23.1	23.1	28.3
2230073290	2.1	24.0	27.5	27.5	37.6	1.7	11.7	23.2	23.2	28.3
2230073310	2.1	23.9	27.4	27.4	37.6	1.7	11.6	23.1	23.1	28.2
2230073330	2.0	23.9	27.5	27.5	37.6	1.6	11.5	23.0	23.0	28.0
2230074110	2.2	23.3	27.2	27.2	37.8	1.9	11.9	21.9	21.9	28.6
2230074130	2.2	23.3	27.2	27.2	37.8	1.7	11.8	21.8	21.8	28.6
2230074150	2.2	23.3	27.2	27.2	37.8	1.7	11.8	21.8	21.8	28.6
2230074170	2.2	23.3	27.2	27.2	37.8	1.7	11.9	21.9	21.9	28.7
2230074190	2.2	23.3	27.2	27.2	37.8	1.7	11.8	21.8	21.8	28.6
2230074210	2.1	23.3	27.2	27.2	37.8	1.7	11.8	21.8	21.8	28.5
2230074230	2.2	23.2	27.2	27.2	37.7	1.8	11.6	21.6	21.6	28.3
2230074250	2.2	23.3	27.2	27.2	37.8	1.9	11.8	21.8	21.8	28.6
2230074270	2.1	23.1	27.2	27.2	37.7	1.7	11.6	21.6	21.6	28.3
2230074290	2.1	23.2	27.2	27.2	37.7	1.7	11.6	21.6	21.6	28.3
2230074310	2.1	23.1	27.2	27.2	37.7	1.7	11.5	21.5	21.5	28.2
2230074330	2.0	23.0	27.2	27.2	37.7	1.6	11.3	21.4	21.4	28.0
2230075110	2.4	35.5	24.6	24.6	41.9	2.1	23.0	23.9	23.9	36.3
2230075130	2.4	34.0	24.5	24.5	41.3	2.0	21.3	23.0	23.0	35.2
2230075150	2.4	34.6	24.6	24.6	41.6	2.0	22.0	23.2	23.2	35.7
2230075170	2.4	35.2	24.6	24.6	41.8	2.0	22.7	23.7	23.7	36.2
2230075190	2.4	35.1	24.6	24.6	41.7	2.0	22.6	23.6	23.6	36.1
2230075210	2.4	35.0	24.6	24.6	41.7	2.0	22.4	23.6	23.6	36.0
2230075230	2.4	34.4	24.7	24.7	41.6	2.0	21.2	23.0	23.0	35.3
2230075250	2.4	36.6	24.3	24.3	41.6	2.1	23.5	24.5	24.5	37.1
2230075270	2.4	35.2	24.5	24.5	41.6	2.0	21.7	23.4	23.4	36.0
2230075290	2.4	35.3	24.5	24.5	41.7	2.0	21.9	23.5	23.5	36.1
2230075310	2.4	34.7	24.6	24.6	41.7	2.0	21.1	23.0	23.0	35.6
2230075330	2.4	34.5	24.7	24.7	41.7	2.0	21.3	23.1	23.1	35.4

Table F-2. Nonroad Retrofit Control Efficiencies by SCC

	2010 Control Efficiency (%)					2020 Control Efficiency (%)				
SCC	NO_x	VOC	PM-10	PM-2.5	CO	NO_x	VOC	PM-10	PM-2.5	CO
2270001060	8.6	41.1	18.7	18.7	22.9	7.5	38.6	18.2	18.2	21.7
2270002003	4.8	20.4	11.0	11.0	12.7	1.8	4.9	5.8	5.8	5.9
2270002006	4.8	23.3	13.4	13.4	11.1	1.2	6.0	3.7	3.7	2.7
2270002009	4.7	23.3	13.2	13.2	11.3	1.1	5.7	3.5	3.5	2.6
2270002015	5.0	22.1	11.1	11.1	13.0	2.0	6.2	5.6	5.6	5.9
2270002018	6.5	20.7	14.6	14.6	17.5	3.4	5.4	8.4	8.4	9.2
2270002021	6.0	26.9	13.6	13.6	15.1	2.6	9.0	6.6	6.6	6.6
2270002024	7.1	29.3	15.2	15.2	18.6	5.3	17.9	12.1	12.1	14.6
2270002027	4.4	23.0	11.7	11.7	11.9	1.4	6.8	3.7	3.7	3.6
2270002030	5.8	30.2	15.6	15.6	17.3	2.7	13.9	10.1	10.1	10.4
2270002033	8.6	36.3	17.1	17.1	20.8	7.8	29.5	16.5	16.5	19.5
2270002036	2.9	9.5	6.0	6.0	7.6	0.9	1.1	3.0	3.0	2.7
2270002039	4.4	25.4	13.2	13.2	14.8	1.7	10.2	7.3	7.3	7.7
2270002042	8.4	38.7	18.3	18.3	20.2	7.3	31.7	16.6	16.6	16.7
2270002045	7.4	27.0	15.8	15.8	18.8	4.9	10.8	10.9	10.9	12.8
2270002048	3.8	12.9	8.5	8.5	10.2	1.3	1.8	4.3	4.3	4.1
2270002051	1.7	4.8	4.5	4.5	6.0	0.1	0.3	0.6	0.6	0.9
2270002054	7.1	28.0	15.3	15.3	16.8	4.1	11.8	10.4	10.4	11.0
2270002057	6.5	30.2	13.6	13.6	16.0	0.0	0.0	0.0	0.0	0.0
2270002060	7.0	26.1	14.9	14.9	18.4	0.0	0.0	0.0	0.0	0.0
2270002066	8.7	42.7	19.1	19.1	21.9	7.5	37.1	17.0	17.0	18.8
2270002069	5.5	18.5	11.5	11.5	14.5	2.4	4.4	6.6	6.6	7.5
2270002072	8.0	41.7	19.8	19.8	22.8	6.5	38.6	18.9	18.9	20.8
2270002075	7.2	26.5	17.2	17.2	20.4	3.4	10.0	10.2	10.2	12.4
2270002078	7.9	44.1	19.5	19.5	24.0	6.3	38.8	17.8	17.8	20.7
2270002081	8.6	32.3	17.6	17.6	21.8	7.1	20.2	15.4	15.4	18.7
2270003010	8.0	43.8	19.9	19.9	24.2	6.8	41.9	19.7	19.7	22.8
2270003020	0.5	2.2	1.4	1.4	1.6	0.0	0.0	0.1	0.1	0.0
2270003030	3.9	16.7	8.7	8.7	9.2	1.2	3.3	3.9	3.9	3.7
2270003040	7.3	31.2	15.8	15.8	17.2	3.8	11.5	8.2	8.2	8.4
2270003050	8.4	39.9	17.2	17.2	23.0	8.0	37.6	17.2	17.2	21.7
2270003060	2.0	12.4	6.0	6.0	5.7	0.2	1.6	1.3	1.3	1.4
2270003070	1.7	6.1	4.0	4.0	4.7	0.1	0.1	0.4	0.4	0.3
2270004031	7.8	40.1	19.7	19.7	20.3	6.0	33.1	17.3	17.3	15.7
2270004036	9.4	35.4	16.9	16.9	21.9	8.8	28.3	16.5	16.5	20.6
2270004046	5.6	30.2	15.3	15.3	15.8	2.4	13.7	7.8	7.8	7.6
2270004056	4.0	20.7	9.9	9.9	10.8	1.0	4.9	2.3	2.3	2.6
2270004066	9.1	38.6	18.4	18.4	21.7	8.4	31.8	17.6	17.6	19.9
2270004071	2.8	13.8	7.2	7.2	7.5	0.7	2.9	2.4	2.4	2.3
2270004076	7.6	37.5	17.8	17.8	19.1	5.4	27.6	14.3	14.3	14.5
2270005010	1.5	8.3	6.7	6.7	5.5	0.1	0.8	0.8	0.8	0.6
2270005015	8.2	34.0	16.6	16.6	20.8	6.7	24.4	14.7	14.7	18.0
2270005020	8.7	37.7	13.5	13.5	23.4	8.4	32.6	14.0	14.0	21.9
2270005025	8.6	35.2	16.3	16.3	22.2	7.5	33.0	16.5	16.5	21.0
2270005030	8.6	40.4	18.2	18.2	21.8	8.1	35.5	17.3	17.3	19.7
2270005035	9.1	31.1	14.0	14.0	21.6	8.6	28.3	14.4	14.4	20.5
2270005040	9.1	33.9	15.6	15.6	20.7	8.6	28.2	15.4	15.4	19.7
2270005045	8.4	41.6	16.2	16.2	23.0	8.0	37.4	16.2	16.2	21.4
2270005055	8.8	33.9	15.5	15.5	21.5	8.1	28.5	15.5	15.5	20.1
2270005060	8.0	36.3	17.7	17.7	19.3	5.4	20.3	12.4	12.4	12.8
2270006005	8.3	38.7	18.3	18.3	20.6	6.8	31.2	16.4	16.4	17.3
2270006010	8.4	38.3	18.1	18.1	20.1	7.1	31.3	16.5	16.5	16.8
2270006015	7.1	34.2	16.6	16.6	17.3	3.8	16.4	10.3	10.3	10.0
2270006020	0.0	0.0	0.0	0.0	0.0	-	-	0.0	0.0	-
2270006025	7.9	44.6	20.7	20.7	24.0	6.0	40.3	19.5	19.5	21.7
2270006030	8.6	38.7	17.9	17.9	21.1	7.4	33.0	16.7	16.7	18.6
2270006035	6.4	31.6	15.5	15.5	15.9	3.2	15.0	9.3	9.3	8.9
2270007015	2.5	7.8	5.5	5.5	7.2	0.6	0.5	2.0	2.0	2.1

	2010 Control Efficiency (%)					2020 Control Efficiency (%)				
SCC	NO_x	VOC	PM-10	PM-2.5	CO	NO_x	VOC	PM-10	PM-2.5	CO
2270008005	7.2	27.4	14.7	14.7	18.2	4.8	11.5	10.2	10.2	12.2
2270009010	6.5	32.2	16.3	16.3	18.1	3.1	15.7	8.1	8.1	8.7
2270010010	7.4	27.5	16.6	16.6	19.8	3.8	10.3	9.9	9.9	12.4
2282020005	7.3	34.8	18.7	18.7	17.4	4.9	23.9	13.9	13.9	11.2
2282020010	6.9	40.1	17.4	17.4	21.0	4.4	29.3	11.9	11.9	14.3
2285002015	8.8	40.4	17.7	17.7	22.1	8.1	36.6	17.3	17.3	20.4

Table F-3 presents the cost effectiveness values from the diesel retrofit study by measure and vehicle group. To estimate the cost-effectiveness of the low end potential of highway vehicle retrofits, EPA averaged the low end of the cost effectiveness range of both measures (DOC and CDPF) for all three groups of highway vehicles in the diesel retrofit study (school buses, class 6 and 7 trucks, and class 8b trucks). To estimate the cost-effectiveness of the high end potential of highway retrofits, EPA first calculated the average of the minimum and maximum cost per ton of both measures for all three groups of vehicles. EPA then averaged these six values to determine the high-end cost effectiveness value. EPA used the average, rather than the high end of the cost-effectiveness range, because EPA expects that technology and installation costs are likely to decrease in the future.

Table F-3. Cost-Effectiveness Values for Various Diesel PM Retrofit Measures ($/ton PM)

Vehicle/Engine Type	Measure	Minimum Cost Effectiveness	Maximum Cost Effectiveness	Average Cost Effectiveness
School Bus	DOC	$12,000	$49,100	$30,550
	CDPF	$12,400	$50,500	$31,450
Class 6&7 Truck	DOC	$27,600	$67,900	$47,750
	CDPF	$28,400	$69,900	$49,150
Class 8b Truck	DOC	$11,100	$40,600	$25,850
	CDPF	$12,100	$44,100	$28,100
250 hp Bulldozer	DOC	$18,100	$49,700	$33,900

Source: EPA, 2006b

To estimate of the cost-effectiveness of the low end potential of nonroad engine retrofits, EPA used the low end of the cost-effectiveness range for DOC retrofits of 250 hp bulldozers. To estimate the cost-effectiveness of the high end potential of nonroad engine retrofits, EPA used the average of the range of cost-effectiveness for DOC retrofits of 250 hp bulldozers. Again, the average, rather than the high end of the cost-effectiveness range, was used because EPA believes that technology and installation costs are likely to decrease in the future.

The resulting onroad and nonroad cost effectiveness values, as modeled in the Section 812 local measures cost analysis, are presented in Table F-4. Note that these Table F-4 $/ton PM estimates are applied across the board for all types of retrofit measures (DOCs, CDPFs, repower, replacement) and highway vehicle and nonroad engine types. For this Section 812 analysis, the average of the high and low end of the package of retrofit measures was used to calculate the cost of this measure. This resulted in a cost effectiveness value of $26,371 per ton of PM for the highway retrofit package and $26,000 per ton of PM for the nonroad retrofit package.

Table F-4. Modeled Cost-Effectiveness Values for Diesel PM Retrofit Measures (DOC, DPF, Repower, Replace)

Engine Category	Low End Cost Effectiveness ($/ton PM)	High End Cost Effectiveness ($/ton PM)	Average Cost Effectiveness ($/ton PM)
Highway	$17,267	$35,475	$26,371
Nonroad	$18,100	$33,900	$26,000

ONROAD DIESEL RETROFITS FOR NO_X CONTROL

The on-highway diesel retrofit control measures selected for the PM NAAQS analysis focused on technologies whose primary benefit is reducing NOx emissions. NOx reductions were only achieved for the small portion of vehicles projected to undergo replacement. However, a number of ozone nonattainment areas need control measures focused on NOx reductions to help them in attaining the 8-hour ozone standard. To achieve this, another diesel retrofit control option was developed, with control measures selected to achieve significant NOx emission reductions.

An assessment of the Texas Emission Reduction Plan (TERP) in the Dallas-Fort Worth area evaluated the emission reductions and costs that could be achieved with a variety of emission control strategies aimed at reducing NOx emissions (ENVIRON, 2004). This report included an evaluation of available NOx retrofit technologies for onroad diesel engines. Based on the costs and emission reductions from the analyzed retrofit control measures, two technologies were selected for inclusion in this local control measures analysis—Exhaust Gas Recirculation (EGR)+Diesel Particulate Filter (DPF) and Cleaire Lean NOx.

The Table F-5 summarizes the per-vehicle costs, NOx emission reductions, and cost per ton of NOx expected to be achieved with each of these two technologies. The annualized capital cost is based on a 10 year equipment life and a discount rate of 5 percent. Based on the relative penetration rates of these two technologies assumed in the Dallas-Ft. Worth analysis, it was estimated that the lower-cost technology (Cleaire Lean NOx) would be used in 60 percent of the diesel retrofits and that the higher-cost technology (EGR+DPF) would be used in 40 percent of the diesel retrofits. The resulting cost per ton of NOx reduced of $8,600 (in 1999 dollars) was used in the local measures analysis.

This measure was modeled with a 45 percent NOx reduction, based on a 55 percent NOx reduction for the Cleaire Lean NOx technology at a 60 percent penetration rate and 30 percent reduction for the EGR+DPF technology at a 40 percent penetration rate. Reductions of VOC, CO, and PM were also modeled for this control measure at 75 percent, 75 percent, and 80 percent reduction, respectively, based on evaluating the emission reduction range of EPA's verified DPF technologies.

Table F-5. Onroad Diesel Retrofit NOx Control Technology Cost Estimates

	Cleaire Lean NO_x	**EGR+DPF**
Capital Cost	$20,000	$23,000
Annualized Capital Cost	$2,590	$2,979
Incremental Annual Fuel Cost	$271	$455
Total Annual Cost (2004$)	$2,861	$3,434
Annual NO_x Emission Reduction (tons)	0.43	0.24
Cost per ton NO_x (2004$)	$6,654	$14,307
Assumed Technology Mix	60%	40%
Weighted Cost per ton NO_x (2004$)		$9,700
Weighted Cost per ton NO_x (1999$)		$8,600

These emission reductions and costs were applied to heavy heavy-duty diesel vehicles (HHDDVs) (those greater than 33,000 pounds Gross Vehicle Weight Rating) from model years 1988 through 1997. This was done by first estimating the fraction of the HHDDV class within each of these model year ranges in 2010 and 2020, using the MOBILE6 default registration data by vehicle age. In 2010, 24.54 percent of the HHDDVs were determined to be in this model year range. By 2020, only 9.64 percent of the HHDDV fleet was estimated to be from the 1988 through 1997 model year range. NOx, VOC, CO, and PM emission totals for this vehicle type were multiplied by the appropriate fraction of vehicles affected by this control measure (i.e., 0.2454 in 2010 and 0.0964 in 2020) as well as by the emission reduction percentage for that pollutant to calculate the tons of emissions reduced. The NOx emission reduction in tons was then multiplied by the cost effectiveness of $8,600/ton to estimate the cost of this control measure in each area.

ELIMINATING LONG DURATION TRUCK IDLING

Virtually all long duration truck idling – idling that lasts for longer than 15 minutes – from heavy-duty diesel class 8a and 8b trucks (i.e., those over 33,000 pounds GVWR) can be eliminated with two strategies:

- truck stop and terminal electrification (TSE); and
- mobile idle reduction technologies (MIRTs) such as auxiliary power units, generator sets, and direct-fired heaters.

TSE can eliminate idling when trucks are resting at truck stops or public rest areas and while trucks are waiting to perform a task at private distribution terminals. When truck spaces are electrified, truck drivers can shut down their engines and use electricity to power equipment which supplies air conditioning, heat, and electrical power for on-board appliances. MIRTs can eliminate long duration idling from trucks that are stopped away from these central sites.

EPA estimates that the elimination of long duration truck idling could reduce emissions of all pollutants by 3.4 percent from Class 8a and 8b heavy-duty diesel trucks, consistent with the current MOBILE6.2 inventory assumptions (EPA, 2004). In the PM NAAQS RIA (EPA, 2006a), EPA identified this measure as a no cost strategy (i.e., $0/ton PM). Both TSEs and MIRTs have upfront capital costs, but these costs can be fully recovered by the fuel savings from eliminating long duration idling. Thus, this measure was also modeled in the Section 812 local measures analysis at $0/ton PM.

REFERENCES

ENVIRON, 2004: ENVIRON International Corporation, "Texas Emission Reduction Plan Assessment in the Dallas-Fort Worth Area, Final Report," prepared for Houston Advanced Research Center, November 12, 2004.

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EPA, 2006a: U.S. Environmental Protection Agency, "2006 National Ambient Air Quality Standards for Particle Pollution, Regulatory Impact Analysis," October 6, 2006 available at http://www.epa.gov/ttn/ecas/ria.html.

EPA, 2006b: U.S. Environmental Protection Agency, "Diesel Retrofit Technology: An Analysis of the Cost-Effectiveness of Reducing Particulate Matter from Heavy-Duty Diesel Engines Through Retrofits," EPA420-S-06-002, Office of Transportation and Air Quality, March 2006 available at http://www.epa.gov/cleandiesel/documents/420s06002.pdf.

APPENDIX G

AIRCONTROLNET TECHNICAL DOCUMENTATION

APPENDIX G | AIRCONTROLNET TECHNICAL DOCUMENTATION

INTRODUCTION

As indicated in the main body of this report, the Project Team uses AirControlNET to estimate the costs of attaining the National Ambient Air Quality Standards (NAAQS) for ozone and PM, and to estimate the costs of Federal non-EGU point and non-point source controls.

AirControlNET is a control technology analysis tool developed by E.H. Pechan & Associates, Inc. (Pechan) to support the U.S. Environmental Protection Agency (EPA) in its analysis of air pollution policies and regulations. The tool provides data on emission sources, potential pollution control measures and emissions reductions, and the costs of implementing those controls.

The core of AirControlNET is a relational database system in which control technologies are linked to sources within EPA emissions inventories. The system contains a database of control measure applicability, efficiency, and cost information for reducing the emissions contributing to ambient concentrations of ozone, PM10, PM2.5, SO2, NO2, as well as visibility impairment (regional haze) from point, area, and mobile sources. PM10 and PM2.5 as included in AirControlNET represent primary emissions of PM. The control measure data file in AirControlNET includes not only the technology's control efficiency, and calculated emission reductions for that source, but also estimates the costs for application of the control measure.

AirControlNET relies on the control efficiency, throughput, fuel use, and emission factor data provided in the NEI to perform cost related analyses. AirControlNET also requires information on the technical characteristics of individual control measures, which Pechan obtained by examining the technical and economic data available for each measure. AirControlNET currently contains information on several hundred different control measure/source combinations.

DESCRIPTION OF THE MODEL

The purpose of this appendix is to briefly outline the contents of the AirControlNET model. To that end, we first summarize the various types of data included in the model. Second and finally, we provide a table that details the controls included in AirControlNET by pollutant.

In determining the costs for each control measure, AirControlNET links basic cost information from EPA and other studies to input parameters contained in the associated emission inventory. Currently, AirControlNET contains several hundred source category and pollutant-specific control measures. Exhibit G-1, lists the number of controls included in AirControlNET for each pollutant-source category combination.

Exhibit G-1. Summary Of The Number Of Control Measures

Major Pollutant	Utility	Non-Utility Point	Area	Onroad	Nonroad	Total
NH3	0	0	3	0	0	3
NOx	26	417	15	15	8	481
PM	24	165	12	13	0	214
SO2	6	37	0	0	0	43
VOC	0	7	65	5	12	89
Hg	5	0	0	0	0	5

Source: E.H. Pechan & Associates, Inc. "AirControlNET Version 4.1 Documentation Report.

Pechan compiled the control measure data included in AirControlNET from studies prepared in support of various rulemakings and research efforts. The data elements in AirControlNET for each control measure are as follows:

Pollutants: Presently AirControlNET includes controls for NOx, SO2, VOC, PM10, PM2.5, Hg, and NH3. PM10 and PM2.5 as included in AirControlNET represent primary emissions of PM.

Sector: AirControlNET contains an assortment of control measures for each emission sector included in the model (i.e. utility, point, area, onroad, and non-road sources). These measures are applied to emissions sources in EPA’s National Emission Inventory (NEI) to create overall emission reduction scenarios for which the associated costs can be estimated.

Control Efficiencies: The control measure data file in AirControlNET includes each technology's control efficiency.

Cost Information: The cost information is AirControlNET varies by control technology. For some controls it contains annual capital and operation & maintenance costs, while for others it contains data on the costs per ton of emissions abated. Other cost components include capital recovery factor (where applicable) and dollar year of each cost estimate (e.g., $1997). AirControlNET converts each cost estimate to consistent year dollars.

Base Year of Cost: The cost information for the control measures in AirControlNET have been compiled through a series of analyses performed by EPA and others over several years. In every case, the costs for control measures are estimated in the base year provided by the original study.

POD: The cost POD is an internal field which groups similar source types together such that a specific control measure can be applied to all SCCs in a given group.

Affected SCC: The Source Classification Code, or the SCC, in combination with the POD are what link AirControlNet's control measure information to individual sources included in the NEI. This linkage is essential for AirControlNET functions allowing the user to create various cost related scenarios based on the selected control measures applied to specific sources of emissions.

Rule Effectiveness: Rule effectiveness is the assumption of how effective a rule containing a control measure would be. Rule effectiveness is generally 80 to 100 percent for point source rules and potentially less for area source or mobile source rules.

Rule Penetration: Rule penetration is the assumed fraction of the targeted SCC which is affected by the control measure. It is generally assumed to be 100 percent for point sources, but can be less for area or mobile sources.

Measure Code: AirControlNet's control measure codes are unique codes that represent a unique control measure-source type combination. Each measure is identified by an alphanumeric measure code or a "meas code." The first character of the code is a letter that corresponds to the major pollutant controlled.

Typical Value: A "Typical Value" as specified in AirControlNet reflects the value for a given measure of interest (e.g., control efficiency) that has been determined to be the "best" value for that measure. The typical value can be, but is not necessarily, a statistical measure of central tendency.

SUMMARY OF TECHNOLOGIES INCLUDED IN THE MODEL

Cost equations in AirControlNET use either plant capacity or stack flow to determine annual capital, and/or O&M costs (in those cases where capital and O&M are measured separately). Capital costs are converted to annualized costs using the capital recovery factor, which is based on the interest rate and the useful life (in years) of the control equipment. Costs estimated on per ton of emissions abated also represent annual costs.

This section reports the various control measures included in the AirControlNET modeling system. The first table summarizes the various types of cost equations included in AirControlNET for those controls not estimated on a cost-per-ton basis, and the subsequent tables detail the full suite of control measures included in AirControlNET.

Exhibit G-2. Types Of Cost Equations Included In AirControlNET, For Controls Where Costs Not Estimated On A Per Ton Basis

Cost Equation Type	Cost Equation Details	Comments
Type 1	Scaling Factor (SF) = (Model Plant boiler capacity / MW)^(Scaling Factor Exponential)	Cost equations are based on capacity in the range of > 0 to < 2000 mmBTU/hr.
	Capital Cost = TCC x NETDC x SF x 1000	If capacity is not within range, a cost per ton value is applied. Capital cost equations
	Fixed O&M Cost = OMF x NETDC x 1000	are in the form of $ = capital multiplier (capacity) ^ capital exponent. Annual
	Variable O&M Cost = OMV x NETDC x 1000 x CAPFAC x 8760 /1000	costs are in the form of $ = annual multiplier (capacity) ^ annual exponent. Multipliers
	CRF = I x (1+ I)^Eq. Life / [(1+ I)^Eq. Life - 1]	and exponents are available for a no control baseline and a RACT baseline.
	Annualized Capital Cost = Capital Cost x CRF	Control measure is not applied if boiler capacity is missing
	Total Cost = Capital Cost x CRF + O&M Cost	
Type 2	Annual Cost = Annual Cost Multiplier x (boiler Capacity)^Exponent	
	Capital Coat = Capital Cost Multiplier x (boiler Capacity)^Exponent	
Type 3	Capital Cost = Capital Cost factor x Gas Flow Rate factor x Retrofit fator x Min. Stack flow rate	Min Stack Flow Rate >= 1028000 acfm
	Capital Cost = ((1028000/Min. stack flow rate)^0.6)x Capital Cost factor x Gas Flow Rate factor x Retrofit fator x Min. Stack Flow rate	Min Stack Flow Rate < 1028000 acfm
	O&M Cost = (3.35 + (0.00729 x 8736)) x Min. stack flow rate x 0.9383	Capital Cost factor = $192 / kw
	Total Cost = (Capital cost x CRF) + O&M Cost	Gas flow rate factor = 0.486 KW/acfm
Type 4	Capital Cost = 990000 + 9.836 x Min. Stack flow rate	Min Stack flow Rate >= 1028000 acfm
	O&M Cost = 75800 + 12.82 x Min. Stack Flow Rate	Min Stack flow Rate < 1028000 acfm
	Total Cost = Capital Cost x CRF + O&M Cost	
Type 5	Capital Cost = 2882540 + 244.74 x Min. Stack Flow Rate	
	O&M Cost = 749170 + 148.40 x Min. Stack Flow Rate	
	Total Cost = Capital Cost x CRF + O&M Cost	
Type 6	Capital cost = 3449803 + (135.86 x Min. Stack Flow rate)	
	O&M Cost = 797667 + (58.84 x Min. Stack Flow Rate)	
	Total Cost = Capital Cost x CRF + O&M Cost	

Cost Equation Type	Cost Equation Details	Comments
Type 7	Capital cost = 2882540 + (244.74 x Min. Stack Flow Rate) + 93.3 x 1.1 x Min. Stack Flow Rate x 0.9383	
	Capital cost = 2882540 + (244.74 x Min. Stack Flow Rate) + (((1028000 / Min. Stack Flow Rate) ^ 0.6)) x 93.3 x 1.1 x Min. Stack Flow Rate x 0.9383	
	O&M Cost = 749170 + (148.40 x Min. Stack Flow Rate) + (3.35 + (0.000729 x 8736) x Min. Stack Flow Rate ^ 0.9383)	
Type 8	Capital Cost= Typical Capital Cost x Min. Stack Flow Rate	
	O&M Cost= Typical O&M Cost x Min. Stack Flow Rate	For Min. Stack flow rate less than 5 cfm, default cost per ton cost effective was used
	Total Cost = Capital Cost x CRF + 0.04 x capital cost + O&M Cost	Min. Stack Flow Rate > 5

Exhibit G-3. AirControlNET NO_x Controls

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Utility Source NOx Control Strategies							
Utility Boiler - Coal/Wall	SNCR	35.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Wall	NGR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Wall	SCR	80.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Wall	LNB	41.0	Equation	Type 1	15	None	-
Utility Boiler - Coal/Wall	LNBO	55.9	Equation	Type 1	15	None	-
Utility Boiler - Coal/Wall	LNB	40.3	Equation	Type 1	15	None	-
Utility Boiler - Coal/Wall	LNBO	55.9	Equation	Type 1	16	None	-
Utility Boiler - Coal/Tangential	SNCR	35.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Tangential	NGR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Tangential	SCR	80.0	Equation	Type 1	20	None	-
Utility Boiler - Coal/Tangential	LNC1	33.1	Equation	Type 1	15	None	-
Utility Boiler - Coal/Tangential	LNC2	12.7	Equation	Type 1	15	None	-
Utility Boiler - Coal/Tangential	LNC3	53.1	Equation	Type 1	15	None	-
Utility Boiler - Coal/Tangential	LNC1	43.3	Equation	Type 1	15	None	-
Utility Boiler - Coal/Tangential	LNC2	48.3	Equation	Type 1	15	None	-
Utility Boiler - Coal/Tangential	LNC3	58.3	Equation	Type 1	15	None	-
Utility Boiler - Oil-Gas/Wall	SNCR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Oil-Gas/Wall	NGR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Oil-Gas/Wall	SCR	80.0	Equation	Type 1	20	None	-
Utility Boiler - Oil-Gas/Tangential	SNCR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Oil-Gas/Tangential	NGR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Oil-Gas/Tangential	SCR	80.0	Equation	Type 1	20	None	-
Utility Boiler - Cyclone	SNCR	35.0	Equation	Type 1	20	None	-
Utility Boiler - Cyclone	NGR	50.0	Equation	Type 1	20	None	-
Utility Boiler - Cyclone	SCR	80.0	Equation	Type 1	20	None	-
Point Source NOx Control Strategies							
ICI Boilers - Coal/Wall	SNCR	40.0	Equation/cost per ton	Type 2	20	cost per ton	950
ICI Boilers - Coal/Wall	LNB	50.0	Equation/cost per ton	Type 2	10	cost per ton	1,280
ICI Boilers - Coal/Wall	SCR	70.0	Equation/cost per ton	Type 2	20	cost per ton	1,170
ICI Boilers - Coal/FBC	SNCR - Urea	75.0	Equation/cost per ton	Type 2	20	cost per ton	790
ICI Boilers - Coal/Stoker	SNCR	40.0	Equation/cost per ton	Type 2	20	cost per ton	920
ICI Boilers - Coal/Cyclone	SNCR	35.0	cost per ton		20	None	770
ICI Boilers - Coal/Cyclone	Coal Reburn	50.0	cost per ton		20	None	420
ICI Boilers - Coal/Cyclone	SCR	80.0	cost per ton		20	None	760

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
ICI Boilers - Coal/Cyclone	NGR	55.0	cost per ton		20	None	480
ICI Boilers - Residual Oil	LNB	50.0	cost per ton		10	None	410
ICI Boilers - Residual Oil	LNB + FGR	60.0	cost per ton		10	None	760
ICI Boilers - Residual Oil	SCR	80.0	Equation/cost per ton	Type 2	20	cost per ton	1,140
ICI Boilers - Residual Oil	SNCR	50.0	Equation/cost per ton	Type 2	20	cost per ton	1,810
ICI Boilers - Distillate Oil	LNB	50.0	cost per ton		10	None	1,630
ICI Boilers - Distillate Oil	LNB + FGR	60.0	cost per ton		10	None	1,630
ICI Boilers - Distillate Oil	SCR	80.0	Equation/cost per ton	Type 2	20	cost per ton	2,150
ICI Boilers - Distillate Oil	SNCR	50.0	Equation/cost per ton	Type 2	20	cost per ton	3,270
ICI Boilers - Natural Gas	LNB	50.0	cost per ton		10	None	740
ICI Boilers - Natural Gas	LNB + FGR	60.0	cost per ton		10	None	1,580
ICI Boilers - Natural Gas	OT + WI	65.0	cost per ton		10	None	500
ICI Boilers - Natural Gas	SCR	80.0	Equation/cost per ton	Type 2	20	cost per ton	1,720
ICI Boilers - Natural Gas	SNCR	50.0	Equation/cost per ton	Type 2	20	cost per ton	2,730
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	55.0	Equation/cost per ton	Type 2	20	cost per ton	1,190
ICI Boilers - Wood/Bark/FBC	SNCR - Ammonia	55.0	Equation/cost per ton	Type 2	20	cost per ton	1,140
ICI Boilers - MSW/Stoker	SNCR - Urea	55.0	cost per ton		20	None	1,470
Internal Combustion Engines - Oil	IR	25.0	cost per ton		15	None	640
Internal Combustion Engines - Oil	SCR	80.0	cost per ton		15	None	1,630
Internal Combustion Engines - Gas	IR	20.0	cost per ton		15	None	790
Internal Combustion Engines - Gas	L-E (Medium Speed)	87.0	cost per ton		15	None	380
Internal Combustion Engines - Gas	L-E (Low Speed)	87.0	cost per ton		15	None	176
Internal Combustion Engines - Gas	SCR	90.0	cost per ton		15	None	305
Internal Combustion Engines - Gas	AF RATIO	20.0	cost per ton		15	None	970
Internal Combustion Engines - Gas	AF + IR	30.0	cost per ton		15	None	950
Gas Turbines - Oil	Water Injection	68.0	Equation/cost per ton	Type 2	15	cost per ton	970
Gas Turbines - Oil	SCR + Water Injection	90.0	Equation/cost per ton	Type 2	15	cost per ton	1,660
Gas Turbines - Natural Gas	Water Injection	76.0	Equation/cost per ton	Type 2	15	cost per ton	1,120
Gas Turbines - Natural Gas	Steam Injection	80.0	Equation/cost per ton	Type 2	15	cost per ton	770
Gas Turbines - Natural Gas	LNB	84.0	Equation/cost per ton	Type 2	15	cost per ton	300

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Gas Turbines - Natural Gas	SCR + LNB	94.0	Equation/cost per ton	Type 2	15	cost per ton	1,590
Gas Turbines - Natural Gas	SCR + Steam Injection	95.0	Equation/cost per ton	Type 2	15	cost per ton	1,430
Gas Turbines - Natural Gas	SCR + Water Injection	95.0	Equation/cost per ton	Type 2	15	cost per ton	1,930
Process Heaters - Distillate Oil	LNB	45.0	cost per ton		15	None	2,230
Process Heaters - Distillate Oil	LNB + FGR	48.0	cost per ton		15	None	2,970
Process Heaters - Distillate Oil	SNCR	60.0	cost per ton		15	None	2,450
Process Heaters - Distillate Oil	ULNB	74.0	cost per ton		15	None	1,380
Process Heaters - Distillate Oil	SCR	75.0	cost per ton		15	None	7,630
Process Heaters - Distillate Oil	LNB + SNCR	78.0	cost per ton		15	None	2,750
Process Heaters - Distillate Oil	LNB + SCR	92.0	cost per ton		15	None	7,190
Process Heaters - Residual Oil	LNB + FGR	34.0	cost per ton		15	None	2,430
Process Heaters - Residual Oil	LNB	37.0	cost per ton		15	None	1,620
Process Heaters - Residual Oil	SNCR	60.0	cost per ton		15	None	1,510
Process Heaters - Residual Oil	ULNB	73.0	cost per ton		15	None	830
Process Heaters - Residual Oil	LNB + SNCR	75.0	cost per ton		15	None	1,770
Process Heaters - Residual Oil	SCR	75.0	cost per ton		15	None	4,470
Process Heaters - Residual Oil	LNB + SCR	91.0	cost per ton		15	None	4,290
Process Heaters - Natural Gas	LNB	50.0	cost per ton		15	None	2,000
Process Heaters - Natural Gas	LNB + FGR	55.0	cost per ton		15	None	2,830
Process Heaters - Natural Gas	SNCR	60.0	cost per ton		15	None	2,400
Process Heaters - Natural Gas	ULNB	75.0	cost per ton		15	None	1,350
Process Heaters - Natural Gas	SCR	75.0	cost per ton		15	None	10,110
Process Heaters - Natural Gas	LNB + SNCR	80.0	cost per ton		15	None	3,050
Process Heaters - Natural Gas	LNB + SCR	88.0	cost per ton		15	None	9,800
Adipic Acid Manufacturing	Thermal Reduction	81.0	cost per ton		10	None	420
Adipic Acid Manufacturing	Extended Absorption	86.0	cost per ton		10	None	90

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Nitric Acid Manufacturing	Extended Absorption	95.0	cost per ton		10	None	480
Nitric Acid Manufacturing	SCR	97.0	cost per ton		10	None	590
Nitric Acid Manufacturing	SNCR	98.0	cost per ton		10	None	550
Glass Manufacturing - Container	Electric Boost	10.0	cost per ton		10	None	7,150
Glass Manufacturing - Container	Cullet Preheat	25.0	cost per ton		10	None	940
Glass Manufacturing - Container	LNB	40.0	cost per ton		10	None	1,690
Glass Manufacturing - Container	SNCR	40.0	cost per ton		10	None	1,770
Glass Manufacturing - Container	SCR	75.0	cost per ton		10	None	2,200
Glass Manufacturing - Container	OXY-Firing	85.0	cost per ton		10	None	4,590
Glass Manufacturing - Flat	Electric Boost	10.0	cost per ton		10	None	2,320
Glass Manufacturing - Flat	LNB	40.0	cost per ton		3	None	700
Glass Manufacturing - Flat	SNCR	40.0	cost per ton		10	None	740
Glass Manufacturing - Flat	SCR	75.0	cost per ton		10	None	710
Glass Manufacturing - Flat	OXY-Firing	85.0	cost per ton		10	None	1,900
Glass Manufacturing - Pressed	Electric Boost	10.0	cost per ton		10	None	8,760
Glass Manufacturing - Pressed	Cullet Preheat	25.0	cost per ton		10	None	810
Glass Manufacturing - Pressed	LNB	40.0	cost per ton		10	None	1,500
Glass Manufacturing - Pressed	SNCR	40.0	cost per ton		10	None	1,640
Glass Manufacturing - Pressed	SCR	75.0	cost per ton		10	None	2,530
Glass Manufacturing - Pressed	OXY-Firing	85.0	cost per ton		10	None	3,900
Cement Manufacturing - Dry	Mid-Kiln Firing	30.0	cost per ton		15	None	460
Cement Manufacturing - Dry	LNB	25.0	cost per ton		15	None	560
Cement Manufacturing - Dry	SNCR - Urea Based	50.0	cost per ton		15	None	770
Cement Manufacturing - Dry	SNCR - NH3 Based	50.0	cost per ton		15	None	850
Cement Manufacturing - Dry	SCR	80.0	cost per ton		15	None	3,370
Cement Manufacturing - Wet	Mid-Kiln Firing	30.0	cost per ton		15	None	420
Cement Manufacturing - Wet	LNB	25.0	cost per ton		15	None	530
Cement Manufacturing - Wet	SCR	80.0	cost per ton		15	None	2,880
Iron & Steel Mills - Reheating	LEA	13.0	cost per ton		10	None	1,320
Iron & Steel Mills - Reheating	LNB	66.0	cost per ton		5	None	300
Iron & Steel Mills - Reheating	LNB + FGR	77.0	cost per ton		5	None	380

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Iron & Steel Mills - Annealing	LNB	50.0	cost per ton		10	None	570
Iron & Steel Mills - Annealing	LNB + FGR	60.0	cost per ton		10	None	750
Iron & Steel Mills - Annealing	SNCR	60.0	cost per ton		10	None	1,640
Iron & Steel Mills - Annealing	LNB + SNCR	80.0	cost per ton		10	None	1,720
Iron & Steel Mills - Annealing	SCR	85.0	cost per ton		10	None	3,830
Iron & Steel Mills - Annealing	LNB + SCR	90.0	cost per ton		10	None	4,080
Iron & Steel Mills - Galvanizing	LNB	50.0	cost per ton		9	None	490
Iron & Steel Mills - Galvanizing	LNB + FGR	60.0	cost per ton		9	None	580
Municipal Waste Combustors	SNCR	45.0	cost per ton		20	None	1,130
Medical Waste Incinerators	SNCR	45.0	cost per ton		20	None	4,510
ICI Boilers - Process Gas	LNB	50.0	cost per ton		10	None	740
ICI Boilers - Process Gas	LNB + FGR	60.0	cost per ton		10	None	1,580
ICI Boilers - Process Gas	OT + WI	65.0	cost per ton		10	None	500
ICI Boilers - Process Gas	SCR	80.0	cost per ton		20	None	1,720
ICI Boilers - Coke	SNCR	40.0	cost per ton		20	None	950
ICI Boilers - Coke	LNB	50.0	cost per ton		10	None	1,280
ICI Boilers - Coke	SCR	70.0	cost per ton		20	None	1,170
ICI Boilers - LPG	LNB	50.0	cost per ton		10	None	1,630
ICI Boilers - LPG	LNB + FGR	60.0	cost per ton		10	None	1,630
ICI Boilers - LPG	SCR	80.0	cost per ton		20	None	2,150
ICI Boilers - LPG	SNCR	50.0	cost per ton		20	None	3,270
ICI Boilers - Bagasse	SNCR - Urea	55.0	cost per ton		20	None	1,190
ICI Boilers - Liquid Waste	LNB	50.0	cost per ton		10	None	410
ICI Boilers - Liquid Waste	LNB + FGR	60.0	cost per ton		10	None	760
ICI Boilers - Liquid Waste	SCR	80.0	cost per ton		20	None	1,140
ICI Boilers - Liquid Waste	SNCR	50.0	cost per ton		20	None	1,810
IC Engines - Gas, Diesel, LPG	IR	25.0	cost per ton		15	None	640
IC Engines - Gas, Diesel, LPG	SCR	80.0	cost per ton		15	None	1,630
Process Heaters - Process Gas	LNB	50.0	cost per ton		15	None	2,000
Process Heaters - Process Gas	LNB + FGR	55.0	cost per ton		15	None	2,830
Process Heaters - Process Gas	SNCR	60.0	cost per ton		15	None	2,400
Process Heaters - Process Gas	ULNB	75.0	cost per ton		15	None	1,350
Process Heaters - Process Gas	SCR	75.0	cost per ton		15	None	10,110
Process Heaters - Process Gas	LNB + SNCR	80.0	cost per ton		15	None	3,050
Process Heaters - Process Gas	LNB + SCR	88.0	cost per ton		15	None	9,800

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Process Heaters - LPG	LNB	45.0	cost per ton		15	None	2,230
Process Heaters - LPG	LNB + FGR	48.0	cost per ton		15	None	2,970
Process Heaters - LPG	SNCR	60.0	cost per ton		15	None	2,450
Process Heaters - LPG	ULNB	74.0	cost per ton		15	None	1,380
Process Heaters - LPG	SCR	75.0	cost per ton		15	None	7,630
Process Heaters - LPG	LNB + SNCR	78.0	cost per ton		15	None	2,750
Process Heaters - LPG	LNB + SCR	92.0	cost per ton		15	None	7,190
Process Heaters - Other Fuel	LNB + FGR	34.0	cost per ton		15	None	2,430
Process Heaters - Other Fuel	LNB	37.0	cost per ton		15	None	1,620
Process Heaters - Other Fuel	SNCR	60.0	cost per ton		15	None	1,510
Process Heaters - Other Fuel	ULNB	73.0	cost per ton		15	None	830
Process Heaters - Other Fuel	LNB + SNCR	75.0	cost per ton		15	None	1,770
Process Heaters - Other Fuel	SCR	75.0	cost per ton		15	None	4,470
Process Heaters - Other Fuel	LNB + SCR	91.0	cost per ton		15	None	4,290
Gas Turbines - Jet Fuel	Water Injection	68.0	cost per ton		15	None	970
Gas Turbines - Jet Fuel	SCR + Water Injection	90.0	cost per ton		15	None	1,660
Space Heaters - Distillate Oil	LNB	50.0	cost per ton		10	None	1,630
Space Heaters - Distillate Oil	LNB + FGR	60.0	cost per ton		10	None	1,630
Space Heaters - Distillate Oil	SCR	80.0	cost per ton		20	None	2,150
Space Heaters - Distillate Oil	SNCR	50.0	cost per ton		20	None	3,270
Space Heaters - Natural Gas	LNB	50.0	cost per ton		10	None	740
Space Heaters - Natural Gas	LNB + FGR	60.0	cost per ton		10	None	1,580
Space Heaters - Natural Gas	OT + WI	65.0	cost per ton		10	None	500
Space Heaters - Natural Gas	SCR	80.0	cost per ton		20	None	1,720
Space Heaters - Natural Gas	SNCR	50.0	cost per ton		20	None	2,730
Ammonia - NG-Fired Reformers	LNB	50.0	cost per ton		10	None	740
Ammonia - NG-Fired Reformers	LNB + FGR	60.0	cost per ton		10	None	1,580
Ammonia - NG-Fired Reformers	OT + WI	65.0	cost per ton		10	None	500
Ammonia - NG-Fired Reformers	SCR	80.0	cost per ton		20	None	1,720
Ammonia - NG-Fired Reformers	SNCR	50.0	cost per ton		20	None	2,730
Ammonia - Oil-Fired Reformers	LNB	50.0	cost per ton		10	None	410
Ammonia - Oil-Fired Reformers	LNB + FGR	60.0	cost per ton		10	None	760
Ammonia - Oil-Fired Reformers	SCR	80.0	cost per ton		20	None	1,140
Ammonia - Oil-Fired Reformers	SNCR	50.0	cost per ton		20	None	1,810
Lime Kilns	Mid-Kiln Firing	30.0	cost per ton		15	None	460
Lime Kilns	LNB	30.0	cost per ton		15	None	560
Comm./Inst. Incinerators	SNCR	45.0	cost per ton		20	None	1,130
Indust. Incinerators	SNCR	45.0	cost per ton		20	None	1,130
Sulfate Pulping - Recovery	LNB	50.0	cost per ton		10	None	740

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Furnaces							
Sulfate Pulping - Recovery Furnaces	LNB + FGR	60.0	cost per ton		10	None	1,580
Sulfate Pulping - Recovery Furnaces	OT + WI	65.0	cost per ton		10	None	500
Sulfate Pulping - Recovery Furnaces	SCR	80.0	cost per ton		20	None	1,720
Sulfate Pulping - Recovery Furnaces	SNCR	50.0	cost per ton		20	None	2,730
Ammonia Prod; Feedstock Desulfurization	LNB + FGR	60.0	cost per ton		10	None	1,580
Plastics Prod-Specific; (ABS) Resin	LNB + FGR	55.0	cost per ton		15	None	2,830
Starch Mfg; Combined Operations	LNB + FGR	55.0	cost per ton		15	None	2,830
By-Product Coke Mfg; Oven Underfiring	SNCR	60.0	cost per ton		10	None	1,640
Pri Cop Smel; Reverb Smelt Furn	LNB + FGR	60.0	cost per ton		10	None	750
Iron Prod; Blast Furn; Blast Htg Stoves	LNB + FGR	77.0	cost per ton		5	None	380
Steel Prod; Soaking Pits	LNB + FGR	60.0	cost per ton		10	None	750
Fuel Fired Equip; Process Htrs; Pro Gas	LNB + FGR	55.0	cost per ton		15	None	2,830
Sec Alum Prod; Smelting Furn/Reverb	LNB	50.0	cost per ton		10	None	570
Steel Foundries; Heat Treating Furn	LNB	50.0	cost per ton		10	None	570
Fuel Fired Equip; Furnaces; Natural Gas	LNB	50.0	cost per ton		10	None	570
Asphaltic Conc; Rotary Dryer; Conv Plant	LNB	50.0	cost per ton		15	None	2,000
Ceramic Clay Mfg; Drying	LNB	50.0	cost per ton		15	None	2,000
Coal Cleaning-Thrml Dryer; Fluidized Bed	LNB	50.0	cost per ton		10	None	1,280
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	LNB	40.0	cost per ton		3	None	1,690
Sand/Gravel; Dryer	LNB + FGR	55.0	cost per ton		15	None	2,830
Fluid Cat Cracking Units; Cracking Unit	LNB + FGR	55.0	cost per ton		15	None	2,830
Conv Coating of Prod; Acid Cleaning Bath	LNB	50.0	cost per ton		15	None	2,000
Natural Gas Prod; Compressors	SCR	20.0	cost per ton		15	None	1,651
In-Process; Bituminous Coal; Cement Kiln	SNCR - urea based	50.0	cost per ton		15	None	770
In-Process; Bituminous Coal; Lime Kiln	SNCR - urea based	50.0	cost per ton		15	None	770
In-Process Fuel Use;Bituminous Coal; Gen	SNCR	40.0	cost per ton		20	None	1,100
In-Process Fuel Use; Residual Oil; Gen	LNB	37.0	cost per ton		15	None	1,620
In-Process Fuel Use; Natural Gas; Gen	LNB	50.0	cost per ton		15	None	2,000

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
In-Proc;Process Gas;Coke Oven/Blast Furn	LNB + FGR	55.0	cost per ton		15	None	2,830
In-Process; Process Gas; Coke Oven Gas	LNB	50.0	cost per ton		15	None	2,000
Surf Coat Oper;Coating Oven Htr;Nat Gas	LNB	50.0	cost per ton		15	None	2,000
Solid Waste Disp;Gov;Other Incin;Sludge	SNCR	45.0	cost per ton		20	None	1,130
Area Source NOx Control Strategies							
Industrial Coal Combustion	RACT to 50 tpy (LNB)	21.0	cost per ton			None	1,350
Industrial Coal Combustion	RACT to 25 tpy (LNB)	21.0	cost per ton			None	1,350
Industrial Oil Combustion	RACT to 50 tpy (LNB)	36.0	cost per ton			None	1,180
Industrial Oil Combustion	RACT to 25 tpy (LNB)	36.0	cost per ton			None	1,180
Industrial NG Combustion	RACT to 50 tpy (LNB)	31.0	cost per ton			None	770
Industrial NG Combustion	RACT to 25 tpy (LNB)	31.0	cost per ton			None	770
Commercial/Institutional - NG **	Water heater replacement	0.0	cost per ton			None	0
Commercial/Institutional - NG **	LNB (1997 AQMD)	0.0	cost per ton			None	0
Commercial/Institutional - NG **	Water heater + LNB Space heaters	0.0	cost per ton			None	0
Residential NG **	Water heater replacement	0.0	cost per ton			None	0
Residential NG **	LNB (1997 AQMD)	0.0	cost per ton			None	0
Residential NG **	Water heater + LNB Space heaters	0.0	cost per ton			None	0
Open Burning	Episodic Ban	100.0	cost per ton			None	0
Agricultural Burning	Seasonal Ban	100.0	cost per ton			cost per ton	0

Exhibit G-4. AirControlNET VOC Controls

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost/ Ton ($/Ton)
area Source VOC Control Strategies				
Dry Cleaning - Perchloroethyl	MACT (condensers/adsorbers)	44	cost per ton	528
Architectural Coatings	AIM Coating Federal Rule	20	cost per ton	228
Architectural Coatings	South Coast Phase I	34	cost per ton	1,443
Architectural Coatings	South Coast Phase II	47	cost per ton	4,017
Architectural Coatings	OTC AIM Coating Rule	55	cost per ton	6,628
Architectural Coatings	South Coast Phase III	73	cost per ton	10,059
Traffic Markings	AIM Coating Federal Rule	20	cost per ton	228
Traffic Markings	South Coast Phase I	34	cost per ton	1,443
Traffic Markings	South Coast Phase II	47	cost per ton	4,017
Traffic Markings	South Coast Phase III	73	cost per ton	10,059
Industrial Maintenance Coating	AIM Coating Federal Rule	20	cost per ton	228
Industrial Maintenance Coating	South Coast Phase I	34	cost per ton	1,443
Industrial Maintenance Coating	South Coast Phase II	47	cost per ton	4,017
Industrial Maintenance Coating	South Coast Phase III	73	cost per ton	10,059
Metal Coil & Can Coating	MACT	36	cost per ton	1,000
Metal Coil & Can Coating	BAAQMD Rule 11 Amended	42	cost per ton	2,007
Metal Coil & Can Coating	Incineration	90	cost per ton	8,937
Wood Product Surface Coating	MACT	30	cost per ton	446
Wood Product Surface Coating	SCAQMD Rule 1104	53	cost per ton	881
Wood Product Surface Coating	Incineration	86	cost per ton	4,202
Wood Furniture Surface Coating	MACT	30	cost per ton	446
Wood Furniture Surface Coating	New CTG	47	cost per ton	967
Wood Furniture Surface Coating	Add-On Controls	75	cost per ton	20,000
Adhesives - Industrial	SCAQMD Rule 1168	73	cost per ton	2,202
Open Top Degreasing	MACT	31	cost per ton	-69
Open Top Degreasing	SCAQMD 1122 (VOC content limit	76	cost per ton	1,248
Open Top Degreasing	Airtight degreasing system	98	cost per ton	9,789
Paper Surface Coating	Incineration	78	cost per ton	4,776
Cold Cleaning	NESHAP/MACT	63	cost per ton	-69
Cold Cleaning	OTC Solvent Cleaning Rule	66	cost per ton	1,400
Cold Cleaning	SCAQMD 1122 (VOC content limit	76	cost per ton	1,249
Cold Cleaning	Airtight degreasing system	98	cost per ton	9,784
Rubber/Plastics Mfg	SCAQMD - low VOC	60	cost per ton	1,020
Metal Furn, Appliances, Parts	MACT	36	cost per ton	1,000
Metal Furn, Appliances, Parts	SCAQMD Limits	55.2	cost per ton	2,027
Automobile Refinishing	Federal Rule	37	cost per ton	118
Automobile Refinishing	CARB BARCT limits	47	cost per ton	750
Automobile Refinishing	OTC MER Rule	61	cost per ton	2,534
Automobile Refinishing	FIP Rule (VOC content & TE)	89	cost per ton	7,200
Machn, Electric, Railroad Ctng	MACT level of control	36	cost per ton	1,000
Machn, Electric, Railroad Ctng	SCAQMD Limits	55.2	cost per ton	2,027
Machn, Electric, Railroad Ctng	OTC MER Rule	61	cost per ton	2,534
Aerosol Paints	CARB Tier 2 standards - reform	42	cost per ton	2,732
Consumer Solvents	Federal Consumer Solvents Rule	25	cost per ton	232
Consumer Solvents	OTC Consumer Products Rule	39.2	cost per ton	1,032
Consumer Solvents	CARB mid-term limits	55	cost per ton	2,192
Consumer Solvents	CARB long-term limits	85	cost per ton	2,880
Aircraft Surface Coating	MACT/CTG	60	cost per ton	165
Aircraft Surface Coating	OTC MER Rule	61	cost per ton	2,534
Marine Surface Coating	MACT	24	cost per ton	2,090
Marine Surface Coating	OTC MER Rule	61	cost per ton	2,534

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost/ Ton ($/Ton)
Marine Surface Coating	Add-on control levels	90	cost per ton	8,937
Electrical/Electronic Coating	MACT	36	cost per ton	5,000
Electrical/Electronic Coating	SCAQMD Rule	70	cost per ton	5,976
Motor Vehicle Coating	MACT	36	cost per ton	1,000
Motor Vehicle Coating	Incineration	90	cost per ton	8,937
Consumer Adhesives	Federal Consumer Solvents Rule	25	cost per ton	232
Consumer Adhesives	OTC Consumer Products Rule	39.2	cost per ton	1,032
Consumer Adhesives	CARB mid-term limits	55	cost per ton	2,192
Consumer Adhesives	CARB long-term limits	85	cost per ton	2,880
Bakery Products	Incineration >100,000 lbs brea	39.9	cost per ton	1,470
Cutback Asphalt	Switch to emulsified asphalts	100	cost per ton	0
SOCMI Fugitives	Equipment and maintenance	60	cost per ton	-303
Petroleum Refinery Fugitives	Equipment and maintenance	78	cost per ton	804
Oil and Natural Gas Production	Equipment and maintenance	37	cost per ton	317
Municipal Solid Waste Landfill	Gas Collection (SCAQMD/BAAQMD)	70	cost per ton	700
Pesticide Application	Reformulation - FIP rule	20	cost per ton	9,300
Stage II Service Stations	Low Pressure/Vacuum Relief Valves	91.6	cost per ton	1,080
Stage II Service Stations - Underground Tanks	Low Pressure/Vacuum Relief Valves	73	cost per ton	1,080
Graphic Arts	Use of Low or No VOC materials	65	cost per ton	4,150
Portable Gasoline Containers	OTC Portable Gas Container Rule	33	cost per ton	581

Exhibit G-5. AirControlNET SO_2 Controls

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Utility Source So2 Control Strategies							
Utility Boilers - High Sulfur Content	FGD Wet Scrubber	90	Equation	Type 1	15	None	-
Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	90	Equation	Type 1	15	None	-
Utility Boilers - Very High Sulfur Content	FGD Wet Scrubber	90	Equation	Type 1	15	None	-
Point Source So2 Control Strategies							
Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)	FGD	90	Equation	Type 7	15	None	-
Sulfuric Acid Plants - Contact Absorber (99% Conversion)	Increase % Conversion ro Meet NSPS (99.7)	90	Equation	Type 4	15	None	-
Sulfuric Acid Plants - Contact Absorber (99% Conversion)	Dual absorption + FGD	99	Equation	Type 7	15	None	-
Sulfuric Acid Plants - Contact Absorber (98% Conversion)	Increase % Conversion ro Meet NSPS (99.7)	95	Equation	Type 4	15	None	-
Sulfuric Acid Plants - Contact Absorber (98% Conversion)	Dual absorption + FGD	99.5	Equation	Type 7	15	None	-
Sulfuric Acid Plants - Contact Absorber (97% Conversion)	Increase % Conversion ro Meet NSPS (99.7)	96.7	Equation	Type 4	15	None	-
Sulfuric Acid Plants - Contact Absorber (97% Conversion)	Dual absorption + FGD	99.67	Equation	Type 7	15	None	-
Sulfuric Acid Plants - Contact Absorber (93% Conversion)	Increase % Conversion ro Meet NSPS (99.7)	98.6	Equation	Type 4	15	None	-
Sulfuric Acid Plants - Contact Absorber (93% Conversion)	Dual absorption + FGD	99.86	Equation	Type 7	15	None	-
Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))	Amine Scrubbing	98.4	Equation	Type 5	15	None	-
Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))	Amine Scrubbing	97.8	Equation	Type 5	15	None	-
Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (96-97% removal))	Amine Scrubbing	97.1	Equation	Type 5	15	None	-
Inorganic Chemical Manufacture	FGD	90	Equation	Type 3	15	None	-
By-Product Coke Manufacturing (Coke Oven Plants)	Coke Oven Gas Desulfurization	90	Equation	Type 6	15	None	-
Process Heaters (Oil and	FGD	90	Equation	Type 3	15	None	-

Source	Measure Name	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Gas Production Industry)							
Primary Metals Industry	FGD	90	Equation	Type 3	15	None	-
Secondary Metal Production	FGD	90	Equation	Type 3	15	None	-
Mineral Products Industry	FGD	90	Equation	Type 3	15	None	-
Pulp and Paper Industry (Sulfate Pulping)	FGD	90	Equation	Type 3	15	None	-
Petroleum Industry	FGD	90	Equation	Type 3	15	None	-
Bituminous/Subbituminous Coal (Industrial Boilers)	FGD	90	Equation	Type 3	15	None	-
Residual Oil (Industrial Boilers)	FGD	90	Equation	Type 3	15	None	-
Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)	FGD	90	Equation	Type 3	15	None	-
In-process Fuel Use - Bituminous/Subbituminous Coal	FGD	90	Equation	Type 3	15	None	-
Lignite (Industrial Boilers)	FGD	90	Equation	Type 3	15	None	-
Residual Oil (Commercial/Institutional Boilers)	FGD	90	Equation	Type 3	15	None	-
Municipal Waste Combustors	FGD	90	Equation	Type 3	15	None	-
Steam Generating Unit-Coal/Oil	FGD	90	Equation	Type 3	15	None	-
Primary Copper Smelters (copper converter, smelting furnace, and roaster)	Dual absorption	99	Equation	Type 4	15	None	-
Primary Lead Smelters - Sintering	Dual absorption	99	Equation	Type 4	15	None	-
Primary Zinc Smelters - Sintering	Dual absorption	99	Equation	Type 4	15	None	-
Bituminous/Subbituminous Coal (Industrial Boilers)	IDIS	40	cost per ton		30	cost per ton	2,107
Lignite (Industrial Boilers)	IDIS	40	cost per ton		30	cost per ton	2,107
Bituminous/Subbituminous Coal (Industrial Boilers)	SDA	90.0	cost per ton		30	cost per ton	1,973
Lignite (Industrial Boilers)	SDA	90.0	cost per ton		30	cost per ton	1,973
Bituminous/Subbituminous Coal (Industrial Boilers)	Wet FGD	90.0	cost per ton		30	cost per ton	1,980
Lignite (Industrial Boilers)	Wet FGD	90.0	cost per ton		30	cost per ton	1,980
Residual Oil (Industrial Boilers)	Wet FGD	90.0	cost per ton		30	cost per ton	4,524
Area Source So2 Control Strategies							
Residential Home Heating	Switch to Low Sulfur Fuel	75.0	cost per ton			cost per ton	2,350

Exhibit G-6. AirControlNET PM Controls

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Utility Source PM Control Strategies								
Utility Boilers - Coal	Fabric Filter - Mechanical Shaker	PM_{10} / $PM_{2.5}$	95	Equation	Type 1	15	None	-
Utility Boilers - Gas/Oil	Fabric Filter - Mechanical Shaker	PM_{10} / $PM_{2.5}$	95	Equation	Type 1	15	None	-
Point Source PM Control Strategies								
Industrial Boilers - Coal	Fabric Filter (Pulse Jet Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	117
Industrial Boilers - Coal	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Industrial Boilers - Coal	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Industrial Boilers - Coal	Venturi Scrubber	PM_{10}	82	Equation/cost per ton	Type 8	10	cost per ton	751
Industrial Boilers - Wood	Fabric Filter (Pulse Jet Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	117
Industrial Boilers - Wood	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Industrial Boilers - Wood	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Industrial Boilers - Wood	Venturi Scrubber	PM_{10}	93	Equation/cost per ton	Type 8	10	cost per ton	751
Industrial Boilers - Oil	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Industrial Boilers - Oil	Venturi Scrubber	PM_{10}	92	Equation/cost per ton	Type 8	10	cost per ton	751
Industrial Boilers - Liquid Waste	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Commercial Institutional Boilers - Coal	Fabric Filter (Pulse Jet Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	117
Commercial Institutional Boilers - Coal	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Commercial Institutional Boilers - Coal	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Commercial Institutional Boilers - Wood	Fabric Filter (Pulse Jet Type)	PM_{10}	80	Equation/cost per ton	Type 8	20	cost per ton	117
Commercial Institutional Boilers - Wood	Dry ESP-Wire Plate Type	PM_{10}	90	Equation/cost per ton	Type 8	20	cost per ton	110
Commercial Institutional Boilers - Wood	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	80	Equation/cost per ton	Type 8	20	cost per ton	148
Commercial	Dry ESP-Wire	PM_{10}	98	Equation/cost	Type 8	20	cost per ton	110

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Institutional Boilers - Oil	Plate Type			per ton				
Non-Ferrous Metals Processing - Copper	Fabric Filter (Mech. Shaker Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	126
Non-Ferrous Metals Processing - Copper	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Non-Ferrous Metals Processing - Copper	Wet ESP - Wire Plate Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	220
Non-Ferrous Metals Processing - Copper	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Non-Ferrous Metals Processing - Lead	Fabric Filter (Mech. Shaker Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	126
Non-Ferrous Metals Processing - Lead	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Non-Ferrous Metals Processing - Lead	Wet ESP - Wire Plate Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	220
Non-Ferrous Metals Processing - Lead	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Non-Ferrous Metals Processing - Zinc	Fabric Filter (Mech. Shaker Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	126
Non-Ferrous Metals Processing - Zinc	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Non-Ferrous Metals Processing - Zinc	Wet ESP - Wire Plate Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	220
Non-Ferrous Metals Processing - Zinc	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Non-Ferrous Metals Processing - Aluminum	Fabric Filter (Mech. Shaker Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	126
Non-Ferrous Metals Processing - Aluminum	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110
Non-Ferrous Metals Processing - Aluminum	Wet ESP - Wire Plate Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	220
Non-Ferrous Metals Processing - Aluminum	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Non-Ferrous Metals Processing - Other	Fabric Filter (Mech. Shaker Type)	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	126
Non-Ferrous Metals Processing	Dry ESP-Wire Plate Type	PM_{10}	98	Equation/cost per ton	Type 8	20	cost per ton	110

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
- Other								
Non-Ferrous Metals Processing - Other	Wet ESP - Wire Plate Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	220
Non-Ferrous Metals Processing - Other	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Coke	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Ferrous Metals Processing - Coke	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Coke	Venturi Scrubber	PM_{10}	93.0	Equation/cost per ton	Type 8	10	cost per ton	751
Ferrous Metals Processing - Ferroalloy Production	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Ferrous Metals Processing - Ferroalloy Production	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Ferrous Metals Processing - Ferroalloy Production	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Iron & Steel Production	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Ferrous Metals Processing - Iron & Steel Production	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Ferrous Metals Processing - Iron & Steel Production	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Ferrous Metals Processing - Iron & Steel Production	Wet ESP - Wire Plate Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	220
Ferrous Metals Processing - Iron & Steel Production	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Iron & Steel Production	Venturi Scrubber	PM_{10}	73.0	Equation/cost per ton	Type 8	10	cost per ton	751
Ferrous Metals Processing - Gray Iron Foundaries	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Ferrous Metals Processing - Gray Iron Foundaries	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Gray Iron Foundaries	Impingement-plate scrubber	PM_{10}	64.0	Equation/cost per ton	Type 8	10	cost per ton	431
Ferrous Metals	Venturi	PM_{10}	94.0	Equation/cost	Type 8	10	cost per ton	751

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Processing - Gray Iron Foundaries	Scrubber			per ton				
Ferrous Metals Processing - Steel Foundaries	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Ferrous Metals Processing - Steel Foundaries	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Ferrous Metals Processing - Steel Foundaries	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Ferrous Metals Processing - Steel Foundaries	Venturi Scrubber	PM_{10}	73.0	Equation/cost per ton	Type 8	10	cost per ton	751
Mineral Products - Cement Manufacture	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Mineral Products - Cement Manufacture	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Mineral Products - Cement Manufacture	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Mineral Products - Cement Manufacture	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Mineral Products - Cement Manufacture	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Mineral Products - Coal Cleaning	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Mineral Products - Coal Cleaning	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Mineral Products - Coal Cleaning	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Mineral Products - Coal Cleaning	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Mineral Products - Coal Cleaning	Venturi Scrubber	PM_{10}	99.0	Equation/cost per ton	Type 8	10	cost per ton	751
Mineral Products - Stone Quarrying & Processing	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Mineral Products - Stone Quarrying & Processing	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Mineral Products - Stone Quarrying & Processing	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Mineral Products -	Wet ESP -	PM_{10}	99.0	Equation/cost	Type 8	20	cost per ton	220

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Stone Quarrying & Processing	Wire Plate Type			per ton				
Mineral Products - Stone Quarrying & Processing	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Mineral Products - Stone Quarrying & Processing	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Mineral Products - Stone Quarrying & Processing	Venturi Scrubber	PM_{10}	95.0	Equation/cost per ton	Type 8	10	cost per ton	751
Mineral Products - Other	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Mineral Products - Other	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Mineral Products - Other	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Mineral Products - Other	Wet ESP - Wire Plate Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	220
Mineral Products - Other	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Mineral Products - Other	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Asphalt Manufacture	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Asphalt Manufacture	Fabric Filter (Mech. Shaker Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	126
Asphalt Manufacture	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Asphalt Manufacture	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Grain Milling	Fabric Filter (Pulse Jet Type)	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	117
Grain Milling	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Grain Milling	Fabric Filter - Reverse-Air Cleaned Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	148
Wood Pulp & Paper	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Wood Pulp & Paper	Wet ESP - Wire Plate Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	220
Chemical Manufacture	Wet ESP - Wire Plate Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	220
Municipal Waste Incineration	Dry ESP-Wire Plate Type	PM_{10}	98.0	Equation/cost per ton	Type 8	20	cost per ton	110
Fabricated Metal Products - Abrasive Blasting	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Fabricated Metal Products - Machining	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Fabricated Metal Products - Welding	Paper/Nonwoven Filters - Cartridge Collector Type	PM_{10}	99.0	Equation/cost per ton	Type 8	20	cost per ton	142
Industrial Boilers - Coal	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Industrial Boilers - Wood	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Industrial Boilers - Oil	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Commercial Institutional Boilers - Coal	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Commercial Institutional Boilers - Wood	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Commercial Institutional Boilers - Oil	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Non-Ferrous Metals Processing - Copper	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Non-Ferrous Metals Processing - Lead	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Non-Ferrous Metals Processing - Zinc	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Non-Ferrous Metals Processing - Aluminum	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Non-Ferrous Metals Processing - Other	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Coke	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Ferroalloy Production	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Iron & Steel Production	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Gray Iron Foundaries	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Steel Foundaries	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Mineral Products - Cement Manufacture	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Mineral Products - Coal Cleaning	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Mineral Products - Stone Quarrying & Processing	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Mineral Products - Other	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Asphalt Manufacture	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Chemical Manufacture	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Coal	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Commercial Institutional Boilers - Solid Waste	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Coke	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Bagasse	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - LPG	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Liquid Waste	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Natural Gas	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Electric Generation - Oil	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Electric Generation - Wood	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Ferrous Metals Processing - Other	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Industrial Boilers - Coke	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Industrial Boilers - Solid Waste	Increased Monitoring Frequency (IMF) of PM Controls	$PM_{2.5}$	6.5	cost per ton			None	620
Industrial Boilers - Coal	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Industrial Boilers - Wood	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Industrial Boilers - Oil	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Commercial Institutional Boilers - Coal	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Commercial Institutional Boilers - Wood	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Commercial Institutional Boilers - Oil	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Non-Ferrous Metals Processing - Copper	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Non-Ferrous Metals Processing - Lead	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Non-Ferrous Metals Processing - Zinc	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Non-Ferrous Metals Processing - Aluminum	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Non-Ferrous Metals Processing - Other	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Coke	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Ferroalloy Production	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Iron & Steel Production	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Gray Iron Foundaries	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Steel Foundaries	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Mineral Products - Cement Manufacture	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Mineral Products - Coal Cleaning	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Mineral Products - Stone Quarrying & Processing	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Mineral Products - Other	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Asphalt Manufacture	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Chemical Manufacture	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Coal	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Commercial Institutional Boilers - Solid Waste	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Coke	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Bagasse	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - LPG	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Liquid Waste	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Electric Generation - Natural Gas	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Oil	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Solid Waste	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Electric Generation - Wood	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Ferrous Metals Processing - Other	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Industrial Boilers - Coke	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Industrial Boilers - Solid Waste	CEM Upgrade and Increased Monitoring Frequency of PM Controls	$PM_{2.5}$	7.7	cost per ton			None	5,200
Area Source PM Control Strategies								
Paved Road	Vacuum Sweeping	PM_{10}	varies by State	-			varies by State	
Unpaved Road	Chemical Stabilization	PM_{10}	varies by State	-			varies by State	
Unpaved Road	Hot Asphalt Paving	PM_{10}	varies by State	-			varies by State	
Agricultural Burning	Bale Stack/Propane Burning	PM_{10}	varies by State	-			varies by State	
Agricultural Tilling	Soil Conservation Plans	PM_{10}	varies by State	-			varies by State	
Beef Cattle Feedlots	Watering	PM_{10}	50	cost per ton			None	307
Construction Activities	Dust Control Plan	PM_{10}	62.5	cost per ton			None	3,600
Prescribed Burning	Increase Fuel Moisture	PM_{10}	50	cost per ton			None	2,617
Residential Wood	Education and	PM_{10}	50	cost per ton			None	1,320

Source	Measure Name	Major Pollutant	Control Efficiency (%)	Cost Type	Cost Equation (Where Applicable)	Equipment Life (Years)	Default Cost Calculation	Cost/ Ton ($/Ton)
Combustion	Advisory Program							
Residential Wood Combustion	NSPS Compliant Wood Stove	PM_{10}	82	cost per ton			None	1,453
Conveyorized Charbroilers	Catalytic Oxidizer	PM_{10}	83	cost per ton			None	2,150
Conveyorized Charbroilers	ESP for Commercial Cooking	PM_{10}	18.5	cost per ton			None	7,000

Exhibit G-7. AirControlNET NH_3 Controls

Source	Measure Name	Control Efficiency (%)	Cost Type	Default Cost Calculation	Cost/ Ton ($/Ton)
Utility Source PM Control Strategies					
Cattle Feedlots	Chemical Additive to Waste	50	cost per ton	None	228
Poultry Operations	Chemical Additive to Waste	75	cost per ton	None	1,014
Hog Operations	Chemical Additive to Waste	50	cost per ton	None	73

APPENDIX H

SUPPLEMENTAL DOCUMENTATION FOR THE INTEGRATED PLANNING MODEL (IPM)

APPENDIX H | SUPPLEMENTAL DOCUMENTATION FOR THE INTEGRATED PLANNING MODEL (IPM)

As outlined in Chapter 2 of this document, the Project Team used the Integrated Planning Model (IPM) to estimate a portion of the costs incurred by electric generating units (EGUs) as a result of the Amendments. This appendix supplements the description of IPM presented in Chapter 3 with information on the Project Team's treatment of distributed generation and a summary of EPA's model validation and peer review efforts related to IPM.

IPM'S TREATMENT OF DISTRIBUTED GENERATION

The SAB Council raised the issue of assessing diesel-powered distributed generation in its 2001 advisory letter on a prior version of the Second Prospective Analytical Plan. In Appendix G of the letter, in the context of commenting on air quality and emissions considerations involving uncertainty, the Council listed the following concern about scenario design:

"c) Supplemental diesel power: Many industrial facilities are exploring or adopting the use of supplemental diesel equipment for on-site electricity generation. These sources appear not to be regulated in the same way as traditional electrical generating units, but they can potentially produce substantial amounts of PM and nitrogen oxides."[1]

This comment had particular relevance at the time in light of the then recent electricity shortages and reliability issues in California.

The emissions and cost analysis results for the Second Prospective rely on the Department of Energy's Annual Energy Outlook (AEO) 2005, which itself implicitly reflects an estimate of the penetration of supplemental and distributed generation of electricity in the U.S. market through 2020. DOE's National Energy Modeling System (NEMS) includes a module that assesses cogeneration and distributed generation in the industrial sector, and also includes a separate module that assesses penetration of distributed generation in the commercial and residential sectors. The industrial sector cogeneration data, along with the much larger electric utility generation forecasts, are used as driver data for the IPM runs supporting the Second Prospective. As a result, emissions from such source categories as supplemental diesel power at industrial

[1] See EPA-SAB-COUNCIL-ADV-01-004, "Review of the Draft Analytical Plan for EPA's Second Prospective Analysis - Benefits and Costs of the Clean Air Act, 1990-2020: An Advisory by the Advisory Council for Clean Air Compliance Analysis", September 24, 2001, Page 87.

facilities, at the higher per-unit-of-energy-produced emissions rates noted by the SAB, ought to be reflected in the overall EGU sector emissions summaries.

In addition, distributed generation through smaller "micropower" units is included in the non-EGU analyses. The NONROAD model includes emission estimates for about 450,000 diesel-fired generators in the nation. They are classified as light commercial engines, and include engines of 600 horsepower or less. The number of generators was estimated in part from engine manufacturer sales and equipment owner surveys (conducted for EPA by Power Systems Research), and verified by equipment owner surveys.

The Project Team also looked into projections of future growth in distributed generation and the potential impact on our emissions estimates. While industrial cogeneration and other industrial end user generation, even at a small scale, ought to be reflected in IPM, some assessments conclude that distributed end-user generation in the commercial and residential sector, which his not reflected in IPM, could be significant over the next several decades. The AEO 2005 reference case results, however, suggest relatively modest growth in this sector. EIA estimates that residential and commercial sector distributed generation is currently very small as a percentage of total electricity generation, only about 9 billion kWhrs out of a total generation of roughly 4 trillion kWhrs. In addition, NEMS modeling forecasts that, while this category of generation will itself grow rapidly, the total generation is unlikely to grow to significant levels by 2020 (a projected 13 billion kWhrs out of a total 5.3 trillion generation, or less than one quarter of one percent). We would not necessarily expect that the Clean Air Act Amendments (or their absence) would have a major impact on the future adoption rate of either diesel or renewable distributed or supplemental generation. It is possible that the absence of the CAAA might reduce the air quality barriers to adoption of diesel technologies, but it is also possible that the future cost of these technologies per unit of generation might rise relative to the costs of centralized electricity sources in the absence of the Amendments.

Any forecast to 2020 of small-scale distributed generation, therefore, remains uncertain. There are many examples of published analyses that show much greater potential market penetration of small-scale, distributed renewable technologies than AEO 2005. Some analysts have concluded that the current version of NEMS is unusually pessimistic about market penetration rates. Others point to the small-scale diesel, natural gas, or renewable electric energy sources as showing promise, particularly for combined heat and power applications in new construction of commercial buildings.[2] Nevertheless, even if the penetration of these small-scale technologies were four times as great in 2020 as projected by AEO, they would make up just one percent of total generation and a much smaller portion of total emissions across all source categories. Therefore, the penetration

[2] For a review of a wide range of analyses that consider alternative futures for distributed generation and renewables penetration see, J. Aabakken and W. Short, *Domestic Energy Scenarios,* National Renewable Energy Laboratory, Document # NREL/TP-620-32742, January 2003.

of these technologies is unlikely to represent one of the most important sources of uncertainty in the project team's overall analysis of the Amendments.

IPM PEER REVIEW AND MODEL VALIDATION

Because IPM is a proprietary model, it has not undergone a comprehensive peer review. In 2003, however, EPA organized an independent review of the natural gas supply curves included in the model. In addition, EPA periodically conducts validation analyses to test the credibility of IPM's results.

PEER REVIEW OF IPM'S NATURAL GAS SUPPLY CURVES[3]

On October 23-24, 2003 EPA convened a panel of eight independent experts for a peer review of the natural gas assumptions used in EPA's applications of IPM. Based on the recommendations of the peer review panel and detailed supply and demand data obtained from the National Petroleum Council's 2003 Natural Gas Study, EPA subsequently updated the assumptions underlying the natural gas supply curves that were developed for EPA Base Case 2004. These changes include the following:

Resource Data and Reservoir Description: A complete update to the undiscovered natural gas resource base for the Western Canada Sedimentary Basin (WCSB) and key regional updates within the U.S. were completed as new data became available in 2002 and 2003. For the U.S., the primary data sources were the United States Geological Survey (USGS) and the Minerals Management Service (MMS). ICF investigated the conventional resource assessment of the Canadian Gas Potential Committee (CGPC), unconventional resource assessments published by the Alberta Energy Utilities Board (AEUB), publicly available reports, and information available from the provincial energy departments for Saskatchewan and British Columbia. Key updates included:

- Reviewing assumptions regarding conventional resource plays and, where warranted, modifying the internal field size distribution procedure so that the maximum undiscovered field size did not exceed the maximum undiscovered field size class estimates of the USGS for corresponding assessment units.[4]
- Reducing well spacing assumptions to reflect current production practices.
- Where new data were available, updating reservoir parameters such as average depth and gas composition.
- Comparing and calibrating modeled production trends in the Rocky Mountain and Gulf Coast regions with recent established history, using regional natural gas production reports from Lippman Consulting, Inc.
- Substantially re-categorizing and updating undiscovered Canadian resources based on recent estimates published by CGPC, including a complete update of

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[3] The discussion of EPA's natural gas supply curves presented in this section is based on the summary presented in chapter 8 of U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V2.1.9) Using the Integrated Planning Model*, September 2005, EPA 430-R-05-011.

[4] A resource play is an accumulation of hydrocarbons known to exist over a large area.

undiscovered resources for established plays in the Western Canadian Sedimentary Basin.

Treatment of Frontier Resources: Using a variety of recent publicly available data sources, ICF updated the representation of Alaska North Slope, Mackenzie Delta, Sable Island, and existing and potential liquified natural gas (LNG) terminals in the North American Natural Gas Analysis System (NANGAS), which was the model used to generate the natural gas supply curves for EPA Base Case 2004.

Exploration and Production (E&P) Characterization: Among the key revisions in E&P characterization that resulted from the peer review process were:

- Increasing the required rate of return (hurdle rate) from 10 percent to 15 percent for exploration projects and 12 percent for development projects.
- Setting success rate improvement assumptions of 0.5 percent per year for onshore projects and 0.8 percent per year for offshore projects.
- Establishing operating cost decline rates of 0.54 percent per year and drilling cost decline rates of 1.9 percent per year for onshore and 1.2 percent per year for offshore.
- Making use of the research and development (R&D) program evaluation undertaken by the U.S. Department of Energy's Strategic Center for Natural Gas to identify key technology levers and advancement rates.

Natural Gas Demand: The supply of natural gas available to utilities in IPM is calculated as the total amount of gas supplied at a given Henry Hub price minus the total volume consumed by non-EGU consumers at that price. The relationships between the Henry Hub price and total supply and between the Henry Hub price and non-EGU demand are estimated outside of IPM in NANGAS, but IPM uses these relationships to estimate the amount of natural gas available to utilities. Based on the peer review recommendations, the following improvements were made to the NANGAS representation of end use demand used to estimate the amount of natural gas available for utilities in IPM:

- Capturing demand destruction in the industrial feedstock sector by incorporating into NANGAS the natural gas demand forecasts for the feedstock and process heat sectors developed for the NPC natural gas study.
- Revising the macroeconomic equations used to generate the estimates of residential and commercial sector demand for natural gas and capturing income elasticity in the estimates of residential demand.

Validation Analyses

To supplement the peer review of the natural gas supply curves included in IPM, EPA periodically conducts its own analyses to test the validity of the model's results. EPA recently performed such an analysis to examine the accuracy of IPM's dispatching of EGU generating capacity. To conduct this analysis, EPA populated IPM with 2001 data for several key variables: generating capacity by fuel type, Henry Hub natural gas prices, load duration curves for each IPM model region, and electricity demand. EPA included 2001 capacity and retrofit investments in the model for the purposes of the analysis, but restricted IPM from making any investment decisions. This ensured that the capital reflected in the model's simulation of plant dispatch was consistent with the EGU capital stock in place in 2001. After running IPM under these conditions, EPA compared the model's generation and emissions results to actual generation and emissions data for 2001.[5] Overall, IPM's generation and emissions estimates for each plant type were within ten percent of the actual values. This result suggests that IPM's methodology for minimizing generating costs subject to operational and regulatory constraints represents a reasonable approximation of actual dispatch decisions.

In addition to the validation analysis conducted for 2001, EPA evaluates the accuracy of IPM's results during the development of each new EPA Base Case (i.e., for each model update). More specifically, EPA examines whether IPM's Base Case results for the earliest model run year reasonably reflect the historical operation of the electric power system. Model outputs checked against recent historical data include the following:

- Regional capacity and generation by major generator type (coal, oil/gas steam, etc.);
- Regional capacity factors for each major generator type. In addition to comparing IPM's estimates to historical data, EPA determines whether they are consistent with planned retirements and capacity additions and with expectations of future capacity availability;
- Fuel consumption by type (e.g., coal and gas) and by coal rank (e.g., bituminous);
- Inter-regional transmission, and
- Wholesale electricity prices for each IPM region.

If IPM's near-term projections for any of these variables differ significantly from recent historical values, EPA re-evaluates and, as necessary, modifies the model's inputs, assumptions, and structure.

[5] EPA compared IPM's generation estimates to EIA estimates for this analysis. IPM's emissions estimates for SO_2 and NO_x were compared to values presented in U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002.

APPENDIX I

TRAJECTORY OF CAAA-RELATED COSTS FOR THE 1990-2020 PERIOD

APPENDIX I | TRAJECTORY OF CAAA-RELATED COSTS FOR THE 1990-2020 PERIOD

INTRODUCTION

This appendix presents the project team's assessment of the temporal trajectory of costs associated with the Clean Air Act Amendments (CAAA) for the 1990-2020 period. As indicated in the main body of this document, the project team estimated CAAA-related costs for three target years: 2000, 2010, and 2020. Expanding upon these estimates, this appendix presents cost estimates for each year between 1990 and 2020. The purpose of generating this trajectory is twofold. First, the trajectory will inform the potential development of net present value estimates of the net benefits of the Amendments. Second, the cost trajectory will provide useful insights with respect to the intra-decadal incidence of CAAA-related costs. In the sections that follow, we summarize our approach for generating the cost trajectory and present cost estimates for each year during the 1990-2020 period.

SUMMARY OF METHODOLOGY

In this section, we describe our approach for developing the cost trajectory for each major source category. As described in greater detail below, the cost trajectory for several source categories is based on the trajectory of CAAA-related emissions reductions. We estimate these reductions on an annual basis based on the trajectory of without-CAAA emissions (by pollutant and source category) and the corresponding trajectory of with-CAAA emissions. To develop the emissions trajectories for the without-CAAA scenario, we interpolated between the without-CAAA emissions estimates for 1990, 2000, 2010, and 2020 presented in the Section 812 emissions report.[1] For the with-CAAA scenario, we used two distinct methodologies for developing emissions trajectories: one approach for the 1990-2006 period and a second for emissions between 2007 and 2020, as described below.

> **With-CAAA Emissions – 1990 to 2006:** To estimate annual with-CAAA emissions for the 1990 to 2006 period, we applied annual emissions growth rates implied by EPA's emissions trends data to the emissions estimates developed by the 812 project team.[2] For example, EPA's emissions trends data suggest that NOx emissions from on-road vehicles were 1.5 percent lower in 1991 than in

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[1] E.H. Pechan & Associated, Inc. and Industrial Economics, Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis Revised Draft Report, September 2008.

[2] EPA's emissions trends data are available at http://www.epa.gov/ttn/chief/trends/.

1990. Therefore, to estimate on-road vehicle NOx emissions for 1991, we reduced the 1990 estimate presented in the Section 812 emissions report by 1.5 percent. To estimate 1992 NOx emissions for the on-road sector, we multiplied the estimate generated for 1991 by the growth rate implied by EPA's emissions trends data for 1992. We followed this approach to estimate emissions through 1999, but for 2000, we used the emissions estimates presented in the Section 812 emissions report.3 We then applied the growth rates implied by EPA's emissions trends data to the year 2000 emissions estimates to develop the emissions trajectory for 2001 through 2006.

The emissions trajectories that we developed for 1990 to 2006 largely reflect the methodology described in the previous paragraph. In a limited number of cases, however, this approach suggests sharp, temporary shifts in emissions that are inconsistent with the overall trend in emissions between target years (i.e., 1990, 2000, and 2010). Where this occurred, we smoothed the emissions trajectory by interpolating between the emissions estimates for prior and later years.

With-CAAA Emissions – 2007 to 2020: To generate with-CAAA emissions trajectories for 2007 through 2020, we relied on linear interpolation. To estimate emissions for 2007 through 2009, we interpolated between the year 2006 estimates derived from the methodology described in the previous two paragraphs and the year 2010 estimates presented in the Section 812 emissions report.4 For 2011 through 2019, we interpolated between the emissions estimates for 2010 and 2020.

ELECTRIC GENERATING UNITS

To develop the cost trajectory for electric generating units (EGUs), we employed three separate approaches, as summarized below:

EGU Costs - 1990 to 2000: To estimate EGU costs for each year during the 1990-2000 period, we scaled the year 2000 cost estimate presented in the main body of this report based on the CAAA-related SO2 and (for 1999) NOx reductions achieved each year during this period. For example, we estimate that the SO2 reductions achieved in 1995 were 68 percent of those achieved in 2000. Therefore, we assume that CAAA-related costs for EGUs in 1995 are 68 percent of the estimated costs for 2000. Because the Ozone Transport Commission Model Rule for NOx went into effect in 1999, we incorporated both SO2 and NOx emissions reductions into our calculations for 1999. In addition, we assume that EGUs achieve no CAAA-related emission reductions until 1995, the year in which Phase 1 of the Title IV SO2 allowance program went into effect.

EGU Costs – 2001 to 2006: As indicated in the main body of this report, we used IPM to estimate EGU costs for 2000, 2010, and 2020. IPM, however, also

[3] Ibid

[4] Ibid

estimates EGU costs for each year between 2007 and 2030 based on the results for each IPM model run year. Therefore, we estimate EGU costs for 2001 through 2006 by interpolating between the IPM-based cost estimates generated for 2000 and 2007.

EGU Costs – 2007 to 2020: To generate the EGU cost trajectory for 2007 through 2020, we relied on the annual cost estimates generated by IPM for each of these years.[5]

ON-ROAD VEHICLES AND FUELS

To generate the cost trajectory for the on-road sector, we first identified the compliance date of each on-road vehicle and fuel rule summarized in the main body of this document. Second, we estimated the number of vehicles or gallons of fuel affected by each rule on an annual basis. For on-road engine and fuel rules, we estimated the sales of affected vehicles and fuel based on the methodology described in Chapter 3 of this report. For inspection and maintenance (I&M) programs, we estimated the number of inspections by inspection type through interpolation and (for I&M programs in effect prior to 2000) extrapolation of the inspection counts supporting the cost estimates for 2000, 2010, and 2020. Based on the number of vehicles or gallons of fuel associated with each rule and the unit cost values presented in Chapter 3, we estimated on-road sector costs for each year between 1990 and 2020.

NON-ROAD ENGINES AND FUELS

We developed the cost trajectory for the non-road sector largely through linear interpolation of the non-road cost estimates presented in the main body of this report. For non-road rules with pre-2000 compliance dates, however, we assumed a flat cost trajectory between their compliance date and 2000. Also, for rules taking effect between 2000 and 2010, we scaled the estimated costs for 2010 based on the estimated percentage change in costs between 2010 and 2011. For the Non-road Diesel Engine Standards and the Non-road Diesel Fuel Standards, the two most significant non-road rules with respect to costs, we assumed that the changes in costs between 2010 and 2020 would follow the same pattern as the changes in costs presented in the regulatory impact analysis (RIA) for these standards.[6] For example, the RIA suggests that the change in costs between 2010 and 2013 for the Non-road Diesel Engine Standards represents 95 percent of the change in costs between 2010 and 2020. Therefore, we estimate the costs of the standards in 2013 based on the following equation:

$$\text{(I-1)} \qquad NRC_{2013} = NRC_{2010} + 0.95\left(NRC_{2020} - NRC_{2010}\right)$$

where NRC_{2013}= Costs of the Non-road Engine Standards in 2013
NRC_{2010}= Costs of the Non-road Engine Standards in 2010

[5] Although IPM models EGU costs for a limited number of target years, it also generated cost estimates for intervening years based on model year results.

[6] U.S. EPA, *Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines*, May 2004.

NRC_{2020}= Costs of the Non-road Engine Standards in 2020
$0.95=(NRC_{2013} - NRC_{2010})/ (NRC_{2020} - NRC_{2010})$

NON-EGU POINT AND NONPOINT SOURCES

For non-EGU point sources and nonpoint sources, we developed cost trajectories based on the respective emissions reduction trajectories for each of these source categories. For both of these sectors, we assume that the change in costs for any given year relative to the previous target year (i.e., 1990, 2000, 2010, or 2020) is based on the proportional relationship between (1) the difference between the combined NO_x, VOC, SO_2, and PM_{10} reductions achieved that year and those achieved during the previous target year and (2) the difference between the combined reductions for the following target year and the reductions of the previous target year. For example, for nonpoint sources, we estimate that the change in the combined reductions of NO_x, VOC, SO_2, and PM_{10} between 2003 and 2000 is approximately 59 percent of the change in reductions between 2000 and 2010. Therefore, we estimate nonpoint costs for 2003 based on the following equation.

(I-2) $$NPC_{2003} = NPC_{2000} + 0.59(NPC_{2010} - NPC_{2000})$$

where NPC_{2003}= Nonpoint sector costs in 2003
NPC_{2000}= Nonpoint sector costs in 2000
NPC_{2010}= Nonpoint sector costs in 2010
0.59= (Nonpoint emissions reductions in 2003 – Nonpoint emissions reductions in 2000)/
(Nonpoint emissions reductions in 2010 – Nonpoint emissions reductions in 2000)

LOCAL CONTROLS

To develop the cost trajectory for local controls, we followed separate approaches for the 8-Hour Ozone NAAQS, the $PM_{2.5}$ NAAQS, and the Clean Air Visibility Rule (CAVR), as described below.

8-Hour Ozone NAAQS

For most non-attainment areas, the compliance date for the 8-Hour Ozone NAAQS is expected to be during or near 2010.[7] The attainment date for the Los Angeles area, however, is 2017. Due to the difference in these compliance dates and the magnitude of the estimated costs for the Los Angeles area, we employed two methodologies for generating the cost trajectory for the 8-Hour Ozone NAAQS: one approach for California and a second approach for non-California areas. Both methodologies apply to both identified and unidentified controls.

[7] This is based on compliance occurring five years after the effective date of a non-attainment designation. EPA's designation of non-attainment areas was effective June 15, 2004; therefore, the effective date for most areas is June 15, 2009 and 2010 represents the first full year of attainment. 69 FR 23858, April 30, 2004 and 69 FR 23950, April 30, 2004.

Cost Trajectory for California Areas

As described in Appendix E of this report, our analysis of 8-Hour Ozone local controls for California focuses on four serious or severe ozone non-attainment areas: Sacramento Metro (subpart 2 serious), San Joaquin Valley (subpart 2 serious), Riverside Co. (Coachella Valley) (subpart 2 serious), and Los Angeles-South Coast Air Basin (subpart 2 severe 17). The combined cost of identified and unidentified measures to address ozone nonattainment in these areas is $804 million in 2010 and $5.6 billion in 2020 (both in year 2006 dollars). Most of this increase in costs between 2010 and 2020 reflects measures implemented in the Los Angeles-South Coast Air Basin, which has a compliance deadline of 2017. The compliance dates for other California areas are between 2010 and 2012, but the increase in costs for these areas is small relative to the increase for the Los Angeles area. Given the flat cost trajectory for these areas and the 2017 compliance date for the Los Angeles-South Coast Basin, we assume that the cost of local controls for the 8-Hour Ozone NAAQS remains flat in California between 2011 and 2016 at 2010 levels. For 2017 through 2019, we assume that costs will increase to the level estimated for 2020, or $5.6 billion.

Cost Trajectory for Non-attainment Areas Outside of California

As indicated above, we expect that the 8-Hour Ozone attainment date for most non-attainment areas will be during or near 2010. To develop a cost trajectory for these areas, we interpolate between the cost estimates for 2010 and 2020.

$PM_{2.5}$ NAAQS

Similar to the 8-Hour Ozone NAAQS (outside of California), the attainment date for $PM_{2.5}$ nonattainment areas is 2010. Therefore, we generated the cost trajectory for $PM_{2.5}$ NAAQS local controls by interpolating between the 2010 and 2020 cost estimates.

Clean Air Visibility Rule

The local controls analysis presented in Chapter 7 of this report estimated the cost of local controls implemented by non-EGU sources to comply with CAVR in 2020. As indicated in the regulatory impact analysis for CAVR, however, EPA expects that sources will install controls to comply with the rule by 2014.[8] Based on this implementation date, we developed a cost trajectory for CAVR for the 2014 to 2020 period, based on the following approach:

1. ***Estimate costs for 2015:*** For the Section 812 cost trajectory, we used the 2015 non-EGU cost estimate presented in Chapter 8 of the CAVR RIA, adjusted for learning based on the methodology described in Chapter 7 of this document.

2. ***Interpolate between 2015 and 2020 estimates:*** We interpolated between the 2015 estimate generated in Step 1 and the year 2020 estimate presented in Chapter 7 of this report to develop a cost trajectory spanning the years 2015 through 2020.

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[8] U.S. EPA, Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, June 2005.

3. ***Extrapolate to estimate costs for 2014:*** To incorporate 2014 into the cost trajectory, we extrapolated back one year from the 2015 estimate based on the trend in CAVR costs between 2015 and 2020.

RESULTS

Exhibit I-1 presents the estimated cost trajectory for 1990 through 2020 based on the methods described in the previous section.

Exhibit I-1. Trajectory of CAAA-Related Costs: 1990 through 2020 (Millions of 2006$)

Year	EGUs	On-road Sources	Non-road Sources	Non-EGU Point Sources	Nonpoint Sources	Local Controls (Identified and Unidentified)	Total
1990	$0	$0	$0	$0	$0	$0	**$0**
1991	$0	$337	$0	$282	$55	$0	**$675**
1992	$0	$570	$0	$228	$70	$0	**$867**
1993	$0	$806	$0	$301	$53	$0	**$1,160**
1994	$0	$3,418	$0	$359	$107	$0	**$3,883**
1995	$931	$6,510	$0	$308	$160	$0	**$7,910**
1996	$847	$9,309	$64	$1,257	$377	$0	**$11,853**
1997	$810	$9,417	$198	$1,474	$518	$0	**$12,417**
1998	$812	$10,979	$198	$1,725	$602	$0	**$14,316**
1999	$1,058	$13,340	$198	$2,378	$670	$0	**$17,644**
2000	$1,374	$14,408	$298	$3,130	$663	$0	**$19,872**
2001	$1,969	$15,848	$320	$3,083	$669	$0	**$21,890**
2002	$2,565	$15,873	$342	$3,688	$678	$0	**$23,146**
2003	$3,161	$16,072	$364	$3,834	$680	$0	**$24,112**
2004	$3,757	$17,096	-$217	$3,979	$683	$0	**$25,298**
2005	$4,353	$17,679	-$132	$4,122	$685	$0	**$26,708**
2006	$4,949	$22,751	-$40	$4,266	$687	$0	**$32,613**
2007	$5,545	$23,830	$33	$4,493	$689	$0	**$34,590**
2008	$5,914	$23,985	$81	$4,721	$690	$0	**$35,391**
2009	$6,281	$23,924	$180	$4,948	$691	$0	**$36,025**
2010	$6,644	$25,764	$359	$5,184	$693	$14,277	**$52,921**
2011	$7,027	$25,948	$633	$5,180	$700	$14,226	**$53,714**
2012	$7,407	$26,052	$942	$5,176	$707	$14,176	**$54,461**
2013	$7,786	$26,264	$1,129	$5,172	$715	$14,125	**$55,190**
2014	$8,163	$26,501	$1,233	$5,168	$722	$15,435	**$57,223**
2015	$8,538	$26,696	$1,255	$5,164	$730	$15,341	**$57,725**
2016	$8,922	$27,017	$1,225	$5,160	$737	$15,247	**$58,309**
2017	$9,304	$27,358	$1,207	$5,156	$745	$19,992	**$63,761**
2018	$9,685	$27,686	$1,184	$5,152	$752	$19,898	**$64,357**
2019	$10,063	$27,962	$1,163	$5,148	$759	$19,804	**$64,899**
2020	$10,439	$28,271	$1,150	$5,144	$767	$19,710	**$65,482**

APPENDIX J

PRIVATE EXPENDITURES ASSOCIATED WITH THE CLEAN AIR ACT AMENDMENTS IN 2010 AND 2020, BY STATE AND INDUSTRY

APPENDIX J | PRIVATE EXPENDITURES ASSOCIATED WITH THE CLEAN AIR ACT AMENDMENTS IN 2010 AND 2020, BY STATE AND INDUSTRY

To support the computable general equilibrium (CGE) analysis for EPA's Second Prospective analysis of the Clean Air Act Amendments of 1990 (the Amendments), this appendix presents the project team's estimates of the private expenditures associated with the Amendments. As noted by the Advisory Council on Clean Air Compliance Analysis (the Council), the private cost inputs required for a CGE analysis and the direct cost metrics presented in the main body of this report differ in their treatment of transfer payments (e.g., excise taxes on fuel).[1] Because transfers do not represent a cost to society, the direct cost estimates presented in the main body of this report do not include transfer payments. However, because transfers may affect the decision-making of regulated industries, these payments are reflected in the private expenditure estimates presented in this appendix.

In addition to including transfer payments, the private cost estimates presented in this appendix differ from the project team's direct cost estimates in two important ways:

1. ***Use of private discount rates:*** Unlike the direct cost estimates presented in the main body of this document, the private cost estimates presented in this appendix reflect the private discount rates of affected industries. For each industry, we estimated the private discount rate based on the industry-specific weighted average cost of capital (WACC) as reported in Ibbotson Associates' *Cost of Capital Yearbook*.[2] For each industry, we use the average of the annual 1997 through 2006 WACC values reported by Ibbotson.

2. ***Exclusion of motorist waiting time from cost estimates for inspection and maintenance programs:*** As indicated in Chapter 3 of this report, the project team's cost estimates for motor vehicle inspection and maintenance programs reflect the value of motorist waiting time. Although waiting time represents a welfare loss to society, this cost is not incurred as an expenditure. Because CGEs are expenditure-based models, we therefore exclude motorist waiting time from the private expenditure estimates presented in this appendix.

1 U.S. Environmental Protection Agency Science Advisory Board, Advisory Council on Clean Air Compliance Analysis, EPA-SAB-COUNCIL-ADV-07-002, "Benefits and Costs of Clean Air Act – Direct Costs and Uncertainty Analysis", Advisory Letter, June 8, 2007. Available at http://www.epa.gov/sab/pdf/council-07-002.pdf.

2 Ibbotson Associates, Cost of Capital Yearbook, 1997 through 2006 editions.

As indicated above, we present the private expenditures associated with the Amendments by state and by industry. To allocate these expenditures to the state level, we followed the methodology presented in Appendix A. We allocated costs to individual industry sectors based on publicly available information on the industry designations of the emissions sources regulated under the Amendments. To allocate expenditures for unidentified controls to individual industries, we assumed that the distribution of these expenditures across industries is the same as the corresponding distribution for the costs of all identified controls.

Exhibits J-1 and J-2 present the project team's private expenditure estimates by state and by industry for the 2010 and 2020 target years. Because CGE models are generally used for forward-looking analyses, we did not generate private expenditure estimates for 2000.

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
Energy Sectors														
Coal	1	2121	-$0.67	-$0.26	-$0.02	-$3.99	$0.11	-$1.39	-$0.13	$0.02	-$0.88	-$1.11	$0.20	-$0.66
Crude Oil	2	211111, 4861	$1.04	$1.07	$0.76	$9.40	$1.10	$1.81	$0.47	$0.37	$4.65	$2.51	$0.51	$4.83
Electricity Generation	3	2211	$354.74	$59.68	$1.49	$286.50	$43.33	$109.03	$21.68	$0.73	$390.14	$338.29	$0.59	$696.15
Natural Gas	4	211112, 2212, 4862	$1.89	$1.09	$0.76	$55.56	$1.10	$11.09	$13.87	$0.52	$4.66	$4.79	$0.52	$28.62
Refined Petroleum	5	324, 48691	$20.79	$2.62	$1.54	$45.51	$1.95	$6.30	$1.45	$0.69	$10.85	$7.11	$0.61	$43.64
Agriculture	6	11	-$0.67	-$0.26	-$0.02	$27.34	$0.11	-$1.39	-$0.13	$0.02	-$0.88	-$1.11	$0.20	$0.45
Construction	7	23	-$0.52	$10.12	-$0.02	$168.02	$3.42	$70.89	$12.00	$0.34	-$0.88	$0.46	$1.79	$147.74
Metal Mining	8	21 less 2121, 211111, 211112	-$0.08	$0.38	$0.08	$0.03	$0.50	-$1.24	-$0.13	$0.02	-$0.56	-$0.54	$0.26	-$0.10
****--- Manufactured Goods ---****														
FOO Food Products	9	311	$0.22	$0.75	$0.56	$7.00	$0.26	$2.43	$0.08	$0.00	$0.63	$2.41	$0.11	$12.62
BEV Beverages and Tobacco	10	312	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
TEX Textile Mills	11	313	$1.28	$0.24	$0.09	$2.45	$0.15	$1.96	$0.12	$0.00	$0.68	$6.17	$0.01	$0.24
TPM Textile Product Mills	12	314	$0.35	$0.03	$0.02	$0.37	$0.04	$0.04	$0.02	$0.00	$0.07	$1.57	$0.01	$0.06
WAP Wearing Apparel	13	315	$0.25	$0.00	$0.06	$1.61	$0.04	$0.14	$0.00	$0.00	$0.13	$0.12	$0.01	$0.14
LEA Leather	14	316	$0.02	$0.00	$0.01	$1.17	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.00
* Lumber and Wood														
SAW Sawmills	15	3211	$1.30	$0.96	$1.72	$14.26	$0.88	$0.29	$0.26	$0.00	$3.18	$1.91	$1.06	$2.33

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
PLY Plywood and Venner	16	3212	$1.30	$0.96	$1.72	$15.30	$0.87	$0.29	$0.26	$0.00	$3.17	$1.91	$1.06	$2.32
LUM Other Lumber	17	3219	$1.69	$0.96	$1.72	$20.04	$0.87	$0.86	$0.32	$0.00	$3.17	$2.10	$1.06	$7.28
PAP Pulp and Paper Mills	18	3221	$14.88	$0.87	$5.21	$17.09	$0.73	$6.02	$2.78	$0.00	$5.42	$18.18	$0.50	$8.72
CPP Converted Paper Products	19	3222	$5.10	$0.40	$2.40	$6.07	$0.34	$2.73	$1.06	$0.00	$2.48	$7.93	$0.23	$3.76
PRN Printing	20	323	$0.08	$0.05	$0.05	$1.89	$0.13	$0.55	$0.01	$0.00	$0.31	$0.25	$0.02	$5.75
* Chemicals														
CHM Chemicals and gases	21	3251	$6.47	$0.99	$1.14	$70.47	$2.25	$24.51	$15.76	$0.32	$14.61	$22.59	$0.63	$12.04
RSN Resins	22	3252	$0.75	$0.11	$0.13	$8.37	$0.27	$2.87	$1.86	$0.04	$1.71	$2.64	$0.08	$1.42
FRT Fertilizer	23	3253	$0.16	$0.02	$0.04	$38.75	$0.06	$9.13	$0.17	$0.00	$0.15	$0.23	$0.02	$30.78
MED Drugs and medicine	24	3254	$1.40	$0.21	$0.25	$15.29	$0.49	$5.32	$3.43	$0.07	$3.17	$4.91	$0.14	$2.61
PAI Paints and adhesives	25	3255	$0.66	$0.62	$0.34	$258.48	$0.57	$11.86	$0.55	$0.07	$2.22	$1.98	$0.18	$44.78
SOP Soap	26	3256	$0.17	$0.02	$0.03	$1.85	$0.06	$0.65	$0.43	$0.01	$0.38	$0.60	$0.02	$0.32
OCM Other chemicals	27	3259	$4.39	$0.94	$0.55	$23.06	$0.94	$111.47	$2.64	$0.17	$3.94	$5.56	$0.29	$4.92
* Plastic and Rubber														
PLS Plastic	28	3261	$0.57	$0.19	$0.79	$3.07	$0.26	$0.71	$0.16	$0.00	$0.59	$1.39	$0.06	$3.79
RUB Rubber	29	3262	$0.42	$0.14	$0.58	$7.71	$0.19	$1.09	$0.12	$0.00	$0.43	$1.02	$0.05	$3.50
* Nonmetallic Minerals														
CLY Clay	30	3271	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
GLS Glass	31	3272	$0.02	$0.00	$0.02	$2.81	$0.02	$0.02	$0.01	$0.00	$0.02	$0.07	$0.01	$0.11
CEM Cement	32	3273	$1.47	$0.33	$1.06	$9.21	$0.65	$2.16	$0.59	$0.02	$1.60	$3.86	$0.19	$5.36
LIM Lime and Gypsum	33	3274	$0.39	$0.11	$0.27	$2.33	$0.23	$0.56	$0.16	$0.01	$0.43	$1.04	$0.07	$1.36
ONM Other Non-Metallic Minerals	34	3279	$16.54	$0.06	$0.11	$135.12	$0.10	$4.67	$31.76	$0.00	$0.17	$11.56	$0.03	$38.99

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
* Primary Metals														
I_S Iron and Steel	35	3311, 3312, 33151	$4.68	$9.30	$1.13	$8.86	$5.64	$1.12	$0.07	$0.00	$3.81	$6.82	$0.86	$9.37
ALU Aluminum	36	3313, 331521, 331524	$7.28	$7.56	$1.72	$3.80	$4.59	$1.36	$0.07	$0.00	$3.52	$7.13	$0.70	$9.44
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.38	$0.33	$0.03	$0.76	$0.20	$0.22	$1.55	$0.00	$0.09	$0.17	$0.03	$16.13
FMP Fabricated Metal Products	38	332	$4.22	$4.01	$3.86	$62.49	$2.21	$18.41	$0.64	$0.03	$5.67	$9.62	$0.46	$28.34
* Machinery and Equipment														
CEQ Construction and Ag Equipment	39	3331	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
IEQ Industrial Equipment	40	3332	-$0.01	$0.00	$0.00	-$0.08	$0.00	$1.58	$0.08	$0.00	-$0.02	-$0.02	$0.00	-$0.01
SEQ Service Industry Equipment	41	3333	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
HVC HVAC Equipment	42	3334	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
MEQ Metalworking Equipment	43	3335	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
EEQ Engines	44	3336	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.02	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
CEQ General Equipment	45	3339	-$0.01	$0.56	$0.00	$5.19	$0.00	-$0.33	-$0.03	$0.00	$0.18	$0.27	$0.00	$1.07
* Electronic Equipment														
CPU Computers	46	3341	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
CMQ Communication Equipment	47	3342	-$0.01	$0.26	$0.00	$0.52	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
TVQ TV Equipment	48	3343	-$0.02	-$0.09	$0.00	-$0.55	-$0.03	-$0.04	-$0.01	$0.00	-$0.06	-$0.03	-	-$0.06

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
													$0.03	
SMI Semiconductor Equipment	49	3344	-$0.01	$0.00	$0.00	-$0.08	$0.00	$0.93	$0.02	$0.00	-$0.02	-$0.02	$0.00	-$0.01
INS Instruments	50	3345	$0.02	$0.00	$0.06	$0.10	$0.01	$0.45	$0.05	$0.00	$0.01	$0.08	$0.00	$0.15
MGT Magnetic Recording Equipment	51	3346	$0.02	$0.00	$0.06	$0.09	$0.01	$0.07	$0.12	$0.00	$0.01	$0.07	$0.00	$0.14
ELQ Elec Equipment and Appliances	52	335	$0.04	$0.01	$0.11	$0.24	$0.02	$0.16	$0.01	$0.00	$0.03	$0.16	$0.01	$0.28
* Transport Equipment														
M_V Motor Vehicles	53	3361	$1.70	$0.33	$0.37	$7.08	$0.05	$1.34	$5.29	$0.00	$0.35	$24.67	$0.05	$2.49
TKB Truck Bodies	54	3362	$1.25	$2.77	$0.35	$9.92	$0.46	$9.06	$0.03	$0.01	$2.68	$2.55	$0.06	$1.00
MVP Motov Vehicle Parts	55	3363	$1.70	$0.16	$0.37	$1.60	$0.05	$0.48	$0.07	$0.00	$0.35	$1.08	$0.05	$2.49
ARC Aircraft	56	3364	$0.51	$1.15	$0.15	$4.07	$0.19	$3.74	$3.13	$0.01	$1.10	$11.76	$0.03	$4.44
R_R Rail Cars	57	3365	-$0.01	$0.00	$0.00	-$0.08	$0.00	-$0.03	$0.00	$0.00	-$0.02	-$0.02	$0.00	-$0.01
SHP Ships	58	3366	$0.02	$0.07	$0.01	$7.48	$0.01	$33.40	$0.02	$0.02	$0.06	$0.05	$0.01	$0.02
OTQ Other Transport Equipment	59	3369	-$0.01	$0.00	$0.00	$4.36	$0.00	$0.92	$0.03	$0.00	-$0.02	$0.17	$0.00	$0.52
FUR Furniture	60	337	$2.01	$0.59	$0.59	$13.76	$0.58	$1.18	$1.18	$0.02	$1.76	$2.92	$0.13	$7.09
MSC Miscellaneous Manufacturing	61	339	$0.11	$0.09	$0.08	$259.25	$0.07	$117.24	$5.55	$0.18	$0.15	$0.22	$0.03	$163.69
****--- Services ---****														
* Wholesale and Retail Trade														
WHL Wholesale Trade	62	42	$0.00	$0.88	$0.00	$0.21	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00
RTL Retail Trade	63	44-45	$0.00	$5.47	$0.00	$0.00	$0.00	$11.49	$1.60	$0.24	$0.00	$0.00	$0.00	$7.06
* Transportation Services														
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
RTP Railroad transportation	65	482	$2.11	$1.86	$2.04	$4.28	$1.79	$0.10	$0.49	$1.03	$3.71	$4.50	$0.83	$7.86
WTP Water transportation	66	483	$1.20	$0.13	$0.22	$18.86	$0.01	$6.76	$0.10	$0.28	$42.15	$0.56	$0.01	$4.07
TTP Freight truck transportation	67	484	$96.73	$85.63	$84.26	$677.38	$73.77	$140.58	$13.44	$9.79	$278.84	$201.68	$40.00	$110.54
PIP Pipeline transport	68	486	$5.92	$0.07	$0.20	$1.42	$0.27	$0.15	$0.01	$0.01	$0.07	$0.08	$0.02	$0.30
OTP Other transportation services	69	485, 487, 488	$0.08	$0.02	$0.01	$27.57	$0.02	$4.23	$4.03	$0.14	$0.13	$0.15	$0.00	$7.45
* Other Services														
INF Information	70	51	$0.08	$0.10	$0.05	$2.06	$0.28	$0.25	$0.03	$0.10	$0.52	$0.42	$0.02	$0.36
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.03	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$0.00	$0.00	$22.53	$0.00	$17.35	$3.26	$0.00	$0.00	$0.00	$0.00	$15.55
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$2.94	$3.35	$1.20	$50.33	$0.65	$15.36	$0.16	$0.16	$4.78	$2.15	$0.11	$11.87
EDU Education	76	61	$0.12	$0.00	$0.00	$0.23	$0.00	$0.45	$0.13	$0.02	$0.00	$0.00	$0.00	$0.92
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$2.47	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.38	$1.87	$0.15	$36.03	$0.34	$18.36	$3.52	$0.56	$1.81	$3.82	$0.07	$21.18
PUB Public Services	81	92	$0.48	$10.94	$0.00	$45.29	$7.19	$2.56	$0.90	$0.00	$0.00	$0.00	$11.42	$10.76
Households	82		$228.62	$393.37	$160.62	$5,452.13	$267.41	$595.03	$74.80	$43.61	$663.32	$721.79	$78.76	$579.76

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
Energy Sectors														
Coal	1	2121	-$0.46	$1.01	$0.88	-$0.28	-$0.05	-$0.13	-$0.39	-$0.29	-$1.68	$0.26	-$0.14	-$0.19
Crude Oil	2	211111, 4861	$1.55	$2.21	$1.93	$0.65	$2.04	$0.24	$3.41	$1.37	$1.36	$1.80	$0.79	$1.51
Electricity Generation	3	2211	$985.53	$17.77	$4.08	$334.60	$7.28	$0.80	$558.90	$145.31	$69.99	$41.07	$11.20	$145.48
Natural Gas	4	211112, 2212, 4862	$31.70	$2.21	$1.93	$0.72	$2.64	$0.24	$4.61	$4.00	$3.51	$1.80	$0.80	$1.53
Refined Petroleum	5	324, 48691	$27.59	$2.36	$2.06	$2.20	$16.93	$0.72	$7.71	$3.27	$5.98	$4.86	$1.84	$3.34
Agriculture	6	11	$0.25	$1.01	$0.88	-$0.28	-$0.05	-$0.13	-$0.26	-$0.29	-$1.41	$0.26	-$0.14	-$0.06
Construction	7	23	$20.33	$1.01	$0.88	$0.06	-$0.05	$0.01	$28.13	-$0.29	$8.14	$0.37	-$0.14	$0.42
Metal Mining	8	21 less 2121, 211111, 211112	-$0.14	$1.10	$0.94	$0.82	$0.09	-$0.13	$2.08	-$0.22	-$1.48	$0.66	-$0.08	$0.05
****--- Manufactured Goods ---****														
FOO Food Products	9	311	$0.56	$0.77	$0.31	$1.06	$0.53	$0.05	$1.74	$0.74	$0.53	$0.45	$0.15	$0.90
BEV Beverages and Tobacco	10	312	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
TEX Textile Mills	11	313	$0.14	$0.07	$0.06	$0.11	$0.05	$0.13	$0.28	$3.15	$1.38	$0.16	$0.13	$0.23
TPM Textile Product Mills	12	314	$0.03	$0.03	$0.03	$0.03	$0.01	$0.03	$0.07	$0.16	$0.01	$0.05	$0.03	$0.03
WAP Wearing Apparel	13	315	$0.02	$0.06	$0.04	$0.17	$0.01	$0.04	$0.03	$0.08	$0.00	$0.04	$0.07	$0.10
LEA Leather	14	316	$0.15	$0.02	$0.02	$0.02	$0.00	$0.89	$0.15	$0.01	-$0.03	$0.01	$0.01	$0.01
* Lumber and Wood														
SAW Sawmills	15	3211	$1.23	$3.17	$1.51	$1.13	$0.69	$0.27	$0.56	$0.33	$0.92	$1.93	$1.12	$1.69

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
PLY Plywood and Venner	16	3212	$1.22	$3.16	$1.51	$1.12	$0.69	$0.26	$0.56	$0.33	$0.91	$1.93	$1.11	$1.68
LUM Other Lumber	17	3219	$5.08	$3.16	$1.51	$1.12	$0.69	$0.26	$1.26	$0.33	$1.16	$1.93	$1.11	$1.68
PAP Pulp and Paper Mills	18	3221	$12.09	$2.95	$0.79	$5.23	$6.36	$4.32	$10.46	$4.24	$5.66	$7.94	$3.21	$5.33
CPP Converted Paper Products	19	3222	$1.52	$1.37	$0.37	$2.36	$4.11	$1.99	$0.78	$1.84	$2.58	$3.65	$1.47	$2.45
PRN Printing	20	323	$0.23	$0.14	$0.20	$0.15	$0.04	$0.01	$0.20	$0.13	-$0.17	$0.57	$0.04	$0.24
* Chemicals														
CHM Chemicals and gases	21	3251	$15.23	$6.67	$2.62	$5.05	$17.74	$0.32	$20.04	$7.67	$5.23	$3.39	$3.30	$11.66
RSN Resins	22	3252	$1.79	$0.80	$0.32	$0.67	$2.09	$0.04	$2.36	$0.90	$1.35	$0.40	$0.39	$1.38
FRT Fertilizer	23	3253	$7.12	$0.25	$0.11	$0.13	$0.56	$0.00	$6.17	$0.17	$0.33	$0.12	$0.09	$0.41
MED Drugs and medicine	24	3254	$3.31	$1.47	$0.58	$1.10	$3.87	$0.07	$4.36	$1.67	$1.11	$0.74	$0.72	$3.26
PAI Paints and adhesives	25	3255	$3.71	$0.52	$0.38	$0.93	$1.02	$0.15	$6.48	$0.98	$6.40	$0.64	$0.40	$1.03
SOP Soap	26	3256	$0.41	$0.20	$0.09	$0.13	$0.49	$0.01	$0.54	$0.20	$0.11	$0.10	$0.09	$0.32
OCM Other chemicals	27	3259	$8.10	$1.08	$0.67	$1.10	$15.70	$0.23	$50.72	$2.10	$2.19	$1.08	$0.75	$1.93
* Plastic and Rubber														
PLS Plastic	28	3261	$2.05	$0.64	$0.60	$0.88	$0.24	$0.14	$0.58	$0.85	$1.99	$1.02	$0.43	$0.91
RUB Rubber	29	3262	$1.93	$0.48	$0.45	$0.64	$0.18	$0.10	$0.75	$0.62	$1.73	$0.75	$0.32	$0.67
* Nonmetallic Minerals														
CLY Clay	30	3271	-$0.01	$0.02	$0.02	$0.00	$0.00	$0.00	-$0.01	$0.00	-$0.03	$0.01	$0.00	$0.00
GLS Glass	31	3272	$0.08	$0.05	$0.03	$0.03	$0.07	$0.00	$0.02	$0.02	$0.02	$0.04	$0.01	$0.04
CEM Cement	32	3273	$3.58	$1.35	$0.69	$1.36	$3.14	$0.30	$1.23	$1.19	$2.19	$1.54	$0.63	$1.91
LIM Lime and Gypsum	33	3274	$0.91	$0.41	$0.21	$0.36	$0.80	$0.08	$0.33	$0.31	$0.53	$0.45	$0.17	$0.56
ONM Other Non-Metallic Minerals	34	3279	$112.87	$0.18	$0.10	$2.21	$0.34	$0.07	$33.58	$0.58	$26.65	$0.19	$0.07	$2.07

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
* Primary Metals														
I_S Iron and Steel	35	3311, 3312, 33151	$6.27	$1.10	$0.70	$13.90	$1.55	$0.04	$1.40	$1.00	$2.96	$4.57	$0.79	$2.67
ALU Aluminum	36	3313, 331521, 331524	$6.28	$1.12	$0.72	$21.60	$2.36	$0.03	$2.62	$0.89	$6.74	$4.67	$1.22	$2.88
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$13.73	$0.05	$0.04	$0.37	$0.04	$0.01	$0.26	$0.16	$0.03	$0.14	$0.02	$0.07
FMP Fabricated Metal Products	38	332	$13.65	$3.14	$1.59	$3.31	$2.22	$0.89	$4.77	$9.16	$28.24	$6.92	$1.73	$6.63
* Machinery and Equipment														
CEQ Construction and Ag Equipment	39	3331	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
IEQ Industrial Equipment	40	3332	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.12	$0.65	$1.16	-$0.03	$0.00	$0.00	$0.00
SEQ Service Industry Equipment	41	3333	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
HVC HVAC Equipment	42	3334	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
MEQ Metalworking Equipment	43	3335	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
EEQ Engines	44	3336	-$0.01	$0.02	$0.02	$0.00	$0.00	$0.00	-$0.01	$0.00	-$0.03	$0.01	$0.00	$0.00
CEQ General Equipment	45	3339	-$0.01	$0.02	$0.02	$1.53	$0.00	$0.00	$0.62	$0.11	$0.23	$0.00	$0.00	$0.28
* Electronic Equipment														
CPU Computers	46	3341	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
CMQ Communication Equipment	47	3342	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	$0.29	-$0.01	$0.14	$0.00	$0.00	$0.00
TVQ TV Equipment	48	3343	-$0.02	$0.01	$0.01	-$0.01	$0.00	-$0.01	-$0.03	-$0.10	-$0.04	-$0.04	$0.00	-$0.01

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
SMI Semiconductor Equipment	49	3344	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.25	$0.33	$1.16	-$0.03	$0.00	$0.00	$0.00
INS Instruments	50	3345	$0.04	$0.07	$0.03	$0.04	$0.00	$0.01	$0.25	$0.46	$0.03	$0.04	$0.02	$0.06
MGT Magnetic Recording Equipment	51	3346	$0.03	$0.07	$0.03	$0.04	$0.00	$0.00	$0.00	$0.04	$0.03	$0.04	$0.02	$0.05
ELQ Elec Equipment and Appliances	52	335	$0.07	$0.11	$0.05	$0.07	$0.01	$0.00	$0.01	$0.09	$0.08	$0.08	$0.03	$0.10
* Transport Equipment														
M_V Motor Vehicles	53	3361	$8.32	$0.65	$0.25	$3.25	$0.63	$0.11	$10.76	$0.21	$64.99	$0.51	$0.49	$20.20
TKB Truck Bodies	54	3362	$1.82	$0.22	$3.36	$0.27	$1.47	$0.75	$0.69	$2.66	$0.88	$1.12	$0.76	$2.86
MVP Motov Vehicle Parts	55	3363	$8.30	$0.65	$0.25	$3.24	$0.63	$0.02	$0.29	$0.10	$20.40	$0.51	$0.48	$2.13
ARC Aircraft	56	3364	$2.68	$0.10	$1.40	$0.11	$0.61	$0.31	$0.28	$1.10	$2.86	$0.47	$0.32	$18.51
R_R Rail Cars	57	3365	-$0.01	$0.02	$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.03	$0.00	$0.00	$0.00
SHP Ships	58	3366	$0.08	$0.02	$0.11	$0.00	$0.04	$1.91	$1.70	$0.63	$0.14	$0.04	$0.02	$0.08
OTQ Other Transport Equipment	59	3369	$0.04	$0.02	$0.02	-$0.01	$0.00	$0.09	$0.09	$0.47	$6.00	$0.00	$0.00	$0.01
FUR Furniture	60	337	$3.08	$1.40	$0.42	$3.43	$0.14	$0.13	$3.91	$1.22	$22.45	$1.32	$2.11	$5.50
MSC Miscellaneous Manufacturing	61	339	$9.73	$0.13	$0.08	$0.12	$0.14	$0.53	$58.38	$4.94	$14.36	$0.16	$0.05	$0.27
****--- Services ---****														
* Wholesale and Retail Trade														
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.62
RTL Retail Trade	63	44-45	$0.00	$0.00	$0.00	$0.71	$0.00	$3.10	$22.12	$6.37	$0.00	$0.00	$0.00	$1.08
* Transportation Services														
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$3.12	$3.30	$4.85	$2.33	$1.74	$0.24	$1.20	$1.03	$1.80	$3.17	$1.39	$4.91

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
WTP Water transportation	66	483	$4.12	$0.40	$0.02	$2.02	$12.88	$0.18	$2.13	$1.83	$0.86	$1.17	$1.39	$1.56
TTP Freight truck transportation	67	484	$153.63	$90.99	$50.19	$92.89	$76.77	$53.88	$147.91	$50.79	$192.16	$95.18	$100.67	$101.89
PIP Pipeline transport	68	486	$2.15	$0.08	$0.31	$0.67	$5.85	$0.02	$0.58	$0.03	$0.59	$0.11	$0.18	$0.07
OTP Other transportation services	69	485, 487, 488	$2.32	$0.01	$0.02	$0.37	$5.98	$0.00	$6.78	$0.09	$10.04	$0.03	$0.01	$0.13
* Other Services														
INF Information	70	51	$0.08	$0.06	$0.13	$0.06	$0.07	$0.02	$0.20	$0.24	$0.16	$0.16	$0.03	$0.19
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.31	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.21	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$2.82	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.00	$0.27	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$10.96	$0.20	$0.63	$2.72	$7.36	$1.25	$6.17	$7.03	$17.58	$0.51	$1.51	$1.01
EDU Education	76	61	$1.00	$0.00	$0.00	$0.00	$0.06	$0.00	$0.10	$0.98	$0.69	$0.00	$0.00	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$23.60	$0.26	$0.24	$0.47	$0.30	$0.85	$14.73	$4.10	$5.97	$0.42	$0.16	$0.95
PUB Public Services	81	92	$5.04	$0.00	$0.00	$0.00	$0.00	$0.00	$2.48	$0.08	$0.55	$0.14	$0.00	$0.00
Households	82		$491.49	$273.27	$103.09	$282.15	$191.74	$184.14	$531.20	$359.86	$501.16	$218.03	$270.30	$285.17

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
Energy Sectors													
Coal	1	2121	$0.69	$0.84	$0.26	-$0.24	-$2.84	$0.06	-$4.16	-$1.70	$1.28	-$1.49	$0.15
Crude Oil	2	211111, 4861	$1.08	$1.50	$0.97	$0.53	$6.96	$0.60	$18.70	$1.31	$1.58	$1.83	$1.46
Electricity Generation	3	2211	$1.05	$2.96	$29.03	$46.64	$224.37	$19.41	$275.26	$1,180.12	$35.44	$1,341.92	$2.50
Natural Gas	4	211112, 2212, 4862	$1.08	$1.50	$0.97	$0.53	$9.03	$0.60	$26.24	$1.32	$1.58	$24.19	$1.47
Refined Petroleum	5	324, 48691	$0.77	$1.29	$1.40	$1.51	$20.19	$2.50	$45.15	$5.92	$0.59	$78.60	$2.57
Agriculture	6	11	$0.69	$0.84	$0.26	-$0.24	-$2.84	$0.06	-$4.16	-$1.14	$1.28	-$0.80	$0.15
Construction	7	23	$1.35	$0.84	$14.56	-$0.24	$202.82	$0.50	$331.25	-$1.40	$1.28	$6.26	$0.15
Metal Mining	8	21 less 2121, 211111, 211112	$0.93	$0.89	$0.83	-$0.23	-$2.19	$0.25	-$0.14	-$1.46	$1.38	-$1.13	$0.25
****--- Manufactured Goods ---****													
FOO Food Products	9	311	$0.03	$0.29	$0.06	$0.04	$5.72	$0.05	$9.39	$3.34	$0.09	$5.80	$0.17
BEV Beverages and Tobacco	10	312	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
TEX Textile Mills	11	313	$0.02	$0.04	$0.04	$0.08	$1.64	$0.02	$4.02	$3.99	$0.03	$0.50	$0.03
TPM Textile Product Mills	12	314	$0.01	$0.02	$0.01	$0.02	$0.29	$0.01	$0.54	$1.00	$0.03	$0.07	$0.01
WAP Wearing Apparel	13	315	$0.01	$0.02	$0.01	$0.00	$0.57	$0.00	$2.62	$0.59	$0.03	$0.04	$0.08
LEA Leather	14	316	$0.01	$0.02	$0.01	$0.00	$1.31	$0.00	$1.37	$0.21	$0.02	$0.04	$0.01
* Lumber and Wood													
SAW Sawmills	15	3211	$0.58	$2.26	$0.11	$0.09	$0.79	$0.54	$3.04	$2.17	$0.77	$0.96	$1.08
PLY Plywood and Venner	16	3212	$0.57	$2.26	$0.11	$0.09	$0.79	$0.54	$3.03	$2.16	$0.76	$0.96	$1.08
LUM Other Lumber	17	3219	$0.57	$2.26	$0.11	$0.09	$7.20	$0.54	$4.64	$2.40	$0.76	$1.32	$1.08

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
PAP Pulp and Paper Mills	18	3221	$0.30	$0.61	$0.29	$0.79	$15.70	$0.11	$28.96	$7.52	$0.08	$14.58	$2.26
CPP Converted Paper Products	19	3222	$0.15	$0.29	$0.14	$0.36	$6.82	$0.05	$9.39	$3.21	$0.05	$3.69	$1.04
PRN Printing	20	323	$0.02	$0.08	$0.05	$0.04	$0.05	$0.01	$4.83	$0.18	$0.03	-$0.34	$0.06
* Chemicals													
CHM Chemicals and gases	21	3251	$0.17	$1.40	$0.34	$0.39	$21.69	$0.25	$25.67	$86.52	$0.09	$9.32	$1.07
RSN Resins	22	3252	$0.03	$0.18	$0.04	$0.04	$2.51	$0.03	$2.96	$10.17	$0.03	$1.07	$0.13
FRT Fertilizer	23	3253	$0.02	$0.06	$0.01	$0.00	$13.12	$0.01	$2.90	$0.93	$0.03	$0.62	$0.04
MED Drugs and medicine	24	3254	$0.05	$0.32	$0.08	$0.08	$4.68	$0.05	$5.53	$18.83	$0.04	$3.04	$0.24
PAI Paints and adhesives	25	3255	$0.12	$0.25	$0.24	$0.14	$34.45	$0.22	$32.96	$7.86	$0.10	$1.70	$0.44
SOP Soap	26	3256	$0.02	$0.05	$0.01	$0.01	$0.54	$0.01	$0.63	$2.34	$0.03	$0.23	$0.03
OCM Other chemicals	27	3259	$0.18	$0.42	$0.36	$0.22	$248.20	$0.33	$29.00	$32.13	$0.13	$12.40	$0.69
* Plastic and Rubber													
PLS Plastic	28	3261	$0.02	$0.26	$0.21	$0.22	$2.16	$0.04	$3.17	$1.88	$0.07	$3.57	$0.78
RUB Rubber	29	3262	$0.02	$0.20	$0.16	$0.16	$1.58	$0.03	$3.71	$1.66	$0.06	$3.09	$0.58
* Nonmetallic Minerals													
CLY Clay	30	3271	$0.01	$0.02	$0.01	$0.00	-$0.05	$0.00	-$0.07	-$0.03	$0.02	-$0.03	$0.00
GLS Glass	31	3272	$0.01	$0.03	$0.01	$0.00	$0.17	$0.00	$0.22	$0.11	$0.03	$0.07	$0.02
CEM Cement	32	3273	$0.09	$0.44	$0.18	$0.20	$9.28	$0.14	$12.49	$6.01	$0.11	$4.05	$0.63
LIM Lime and Gypsum	33	3274	$0.04	$0.14	$0.07	$0.05	$2.22	$0.05	$2.98	$1.62	$0.05	$1.01	$0.16
ONM Other Non-Metallic Minerals	34	3279	$0.02	$0.07	$0.03	$0.02	$72.23	$0.02	$88.18	$0.93	$0.03	$12.93	$0.07
* Primary Metals													

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
I_S Iron and Steel	35	3311, 3312, 33151	$3.50	$0.52	$8.21	$0.12	$3.34	$2.77	$6.81	$2.90	$1.16	$6.15	$1.10
ALU Aluminum	36	3313, 331521, 331524	$2.85	$0.53	$6.68	$0.11	$3.23	$2.26	$5.52	$3.02	$1.18	$9.26	$1.68
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.14	$0.03	$0.30	$0.04	$0.37	$0.10	$0.90	$0.05	$0.06	$16.29	$0.04
FMP Fabricated Metal Products	38	332	$0.14	$1.26	$0.67	$1.99	$32.99	$0.31	$26.84	$16.82	$0.21	$42.47	$3.64
* Machinery and Equipment													
CEQ Construction and Ag Equipment	39	3331	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
IEQ Industrial Equipment	40	3332	$0.01	$0.02	$0.00	$0.27	$1.50	$0.00	$3.84	-$0.03	$0.02	-$0.03	$0.00
SEQ Service Industry Equipment	41	3333	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
HVC HVAC Equipment	42	3334	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
MEQ Metalworking Equipment	43	3335	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
EEQ Engines	44	3336	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.07	-$0.03	$0.02	-$0.03	$0.00
CEQ General Equipment	45	3339	$0.01	$0.02	$0.00	$0.04	$19.98	$0.00	$1.45	$0.53	$0.02	$1.29	$0.00
* Electronic Equipment													
CPU Computers	46	3341	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
CMQ Communication Equipment	47	3342	$0.01	$0.02	$0.00	$0.00	$9.04	$0.00	-$0.08	$2.57	$0.02	$1.68	$0.00
TVQ TV Equipment	48	3343	$0.01	$0.01	$0.00	-$0.02	-$0.10	-$0.06	-$0.22	-$0.07	$0.02	-$0.05	$0.00
SMI Semiconductor Equipment	49	3344	$0.01	$0.02	$0.00	$0.20	$1.21	$0.00	$3.35	-$0.03	$0.02	-$0.03	$0.00

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
INS Instruments	50	3345	$0.01	$0.03	$0.01	$0.10	$0.54	$0.00	$1.67	$0.11	$0.02	$0.17	$0.01
MGT Magnetic Recording Equipment	51	3346	$0.01	$0.03	$0.01	$0.02	$0.03	$0.00	$0.09	$0.10	$0.02	$0.16	$0.01
ELQ Elec Equipment and Appliances	52	335	$0.01	$0.03	$0.01	$0.04	$0.10	$0.00	$0.25	$0.22	$0.02	$0.32	$0.02
* Transport Equipment													
M_V Motor Vehicles	53	3361	$0.02	$0.23	$0.04	$0.06	$1.21	$0.03	$9.92	$9.30	$0.08	$32.32	$0.66
TKB Truck Bodies	54	3362	$0.02	$0.15	$0.07	$0.11	$0.52	$0.10	$3.77	$0.67	$0.09	$4.73	$0.35
MVP Motov Vehicle Parts	55	3363	$0.02	$0.23	$0.04	$0.05	$0.45	$0.03	$2.59	$1.17	$0.08	$10.69	$0.66
ARC Aircraft	56	3364	$0.02	$0.07	$0.03	$0.04	$0.19	$0.04	$4.40	$0.82	$0.05	$24.60	$0.15
R_R Rail Cars	57	3365	$0.01	$0.02	$0.00	$0.00	-$0.05	$0.00	-$0.08	-$0.03	$0.02	-$0.03	$0.00
SHP Ships	58	3366	$0.01	$0.02	$0.01	$0.03	$3.26	$0.00	$9.78	$0.00	$0.03	$0.10	$0.01
OTQ Other Transport Equipment	59	3369	$0.01	$0.02	$0.00	$0.16	$5.63	$0.00	$0.53	$0.33	$0.02	$0.85	$0.00
FUR Furniture	60	337	$0.06	$0.45	$0.32	$0.10	$8.51	$0.05	$17.62	$7.79	$0.09	$21.75	$0.21
MSC Miscellaneous Manufacturing	61	339	$0.02	$0.05	$0.03	$0.81	$182.15	$0.04	$395.72	$1.67	$0.03	$7.33	$0.06
****--- Services ---****													
* Wholesale and Retail Trade													
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.00	$0.33	$0.00	$0.00	$0.00	$0.00	$0.42	$0.00
RTL Retail Trade	63	44-45	$0.00	$0.00	$0.00	$2.65	$23.32	$0.00	$59.10	$7.00	$0.00	$0.77	$0.00
* Transportation Services													
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$1.75	$10.98	$0.57	$0.04	$1.53	$1.48	$1.28	$1.56	$1.30	$4.47	$1.54
WTP Water transportation	66	483	$0.01	$0.02	$0.04	$0.05	$19.02	$0.01	$34.66	$0.84	$0.02	$2.01	$0.02

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
TTP Freight truck transportation	67	484	$20.41	$103.74	$23.67	$28.27	$234.98	$82.51	$426.62	$112.06	$116.48	$219.89	$80.95
PIP Pipeline transport	68	486	$0.06	$0.33	$0.03	$0.02	$0.31	$0.19	$0.57	$7.89	$0.07	$0.66	$0.78
OTP Other transportation services	69	485, 487, 488	$0.00	$0.01	$0.01	$0.00	$66.46	$0.01	$24.57	$2.46	$0.00	$1.98	$0.01
* Other Services													
INF Information	70	51	$0.01	$0.05	$0.03	$0.03	$0.96	$0.03	$3.49	$0.21	$0.02	$0.18	$0.07
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.34	$0.00	$0.26	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.00	$0.08	$0.00	$1.17	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$0.00	$0.00	$0.00	$0.25	$0.00	$89.19	$0.09	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$0.05	$0.19	$2.37	$1.03	$42.28	$0.16	$43.18	$3.63	$0.35	$16.67	$4.09
EDU Education	76	61	$0.00	$0.00	$0.00	$0.00	$0.24	$0.00	$3.79	$0.00	$0.00	$0.07	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.07	$0.19	$1.23	$0.55	$89.88	$0.11	$329.40	$4.22	$0.06	$3.34	$0.21
PUB Public Services	81	92	$8.27	$0.00	$4.81	$0.00	$14.05	$13.35	$3.56	$0.07	$0.00	$0.87	$0.00
Households	82		$41.18	$165.39	$153.47	$54.71	$1,141.44	$254.05	$1,925.00	$599.15	$354.09	$610.82	$170.03

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	*NAICS*	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
Energy Sectors																
Coal	1	2121	-$0.16	-$1.77	-$0.28	-$0.72	$0.83	-$0.79	-$1.86	$0.36	-$0.07	-$0.48	-$0.33	-$0.06	-$0.72	$0.16
Crude Oil	2	211111, 4861	$0.90	$5.51	$0.14	$1.05	$1.06	-$0.42	$20.00	$0.79	$0.15	$2.40	$0.96	$1.12	$0.89	$0.61
Electricity Generation	3	2211	$2.02	$851.58	$1.19	$88.87	$3.05	$197.74	$228.80	$0.82	$0.43	$117.57	$29.58	$615.70	$133.62	$2.23
Natural Gas	4	211112, 2212, 4862	$0.90	$16.12	$0.35	$1.09	$1.06	$2.60	$129.63	$0.89	$0.15	$3.44	$0.96	$4.57	$6.88	$0.61
Refined Petroleum	5	324, 48691	$2.09	$68.10	$0.83	$3.47	$0.46	$0.74	$448.01	$2.58	$0.44	$5.65	$4.90	$2.36	$3.16	$0.89
Agriculture	6	11	-$0.16	-$1.32	-$0.28	-$0.72	$0.83	-$0.79	-$1.83	$0.36	-$0.07	-$0.48	-$0.33	-$0.06	-$0.72	$0.16
Construction	7	23	$0.09	$45.75	-$0.28	-$0.72	$0.83	-$0.77	$356.65	$3.82	-$0.07	$0.17	$1.43	$1.27	-$0.24	$0.23
Metal Mining	8	21 less 2121, 211111, 211112	-$0.07	-$0.12	-$0.27	-$0.59	$0.87	-$0.60	$9.52	$0.61	-$0.03	-$0.02	-$0.20	$1.38	-$0.57	$0.94
****--- Manufactured Goods ---****																
FOO Food Products	9	311	$0.23	$2.40	$0.02	$0.11	$0.07	$2.32	$8.75	$0.36	$0.03	$1.83	$0.32	$0.04	$1.49	$0.01
BEV Beverages and Tobacco	10	312	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
TEX Textile Mills	11	313	$0.06	$2.22	$0.98	$2.32	$0.03	$0.99	$0.60	$0.04	$0.01	$0.73	$0.11	$0.01	$0.67	$0.01
TPM Textile Product Mills	12	314	$0.02	$0.17	$0.07	$0.64	$0.02	$0.15	$0.14	$0.02	$0.00	$0.20	$0.03	$0.00	$0.05	$0.00
WAP Wearing Apparel	13	315	$0.02	$0.28	$0.00	$0.07	$0.02	$0.13	$0.37	$0.01	$0.01	$0.11	$0.04	$0.00	$0.03	$0.00
LEA Leather	14	316	$0.00	$0.28	$0.06	$0.00	$0.02	$0.01	$0.10	$0.01	$0.00	$0.18	$0.00	$0.00	$1.20	$0.00
* Lumber and Wood																
SAW Sawmills	15	3211	$2.18	$1.78	$0.05	$0.73	$1.29	$0.66	$7.39	$0.28	$0.15	$0.84	$3.16	$0.15	$1.67	$0.20

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
PLY Plywood and Venner	16	3212	$2.17	$1.78	$0.05	$0.73	$1.29	$0.66	$7.37	$0.28	$0.15	$0.83	$3.16	$0.15	$1.67	$0.20
LUM Other Lumber	17	3219	$2.17	$3.26	$0.05	$0.73	$1.29	$0.69	$17.33	$0.28	$0.15	$1.08	$3.16	$0.15	$2.51	$0.20
PAP Pulp and Paper Mills	18	3221	$4.96	$24.52	$0.36	$10.76	$0.28	$15.60	$39.74	$1.49	$0.39	$8.35	$7.94	$0.23	$28.12	$0.04
CPP Converted Paper Products	19	3222	$2.28	$8.04	$0.16	$4.89	$0.14	$3.74	$7.94	$0.69	$0.18	$2.84	$3.65	$0.11	$9.48	$0.02
PRN Printing	20	323	$0.11	$0.00	-$0.08	$0.09	$0.04	$0.24	$1.93	$0.10	$0.02	$0.23	$0.14	$0.02	$0.29	$0.01
* Chemicals																
CHM Chemicals and gases	21	3251	$2.08	$9.49	$1.46	$12.90	$0.18	$10.60	$96.59	$1.65	$0.22	$16.22	$2.13	$11.58	$4.14	$0.78
RSN Resins	22	3252	$0.24	$1.12	$0.17	$1.51	$0.03	$1.24	$11.35	$0.20	$0.03	$1.90	$0.25	$1.36	$0.48	$0.09
FRT Fertilizer	23	3253	$0.04	$6.38	$0.03	$0.13	$0.02	$0.27	$3.07	$0.05	$0.00	$0.17	$0.04	$0.13	$0.28	$0.02
MED Drugs and medicine	24	3254	$0.45	$2.04	$0.31	$2.80	$0.05	$2.30	$21.02	$0.36	$0.05	$3.53	$0.46	$2.52	$0.89	$0.17
PAI Paints and adhesives	25	3255	$0.46	$18.23	$0.18	$0.81	$0.10	$0.95	$30.62	$0.33	$0.07	$1.28	$0.73	$0.54	$10.80	$0.08
SOP Soap	26	3256	$0.05	$0.23	$0.03	$0.34	$0.02	$0.28	$2.61	$0.05	$0.00	$0.44	$0.05	$0.32	$0.10	$0.02
OCM Other chemicals	27	3259	$0.77	$90.95	$0.67	$1.83	$0.15	$10.32	$645.91	$0.55	$0.12	$2.75	$1.16	$2.33	$3.77	$0.16
* Plastic and Rubber																
PLS Plastic	28	3261	$0.25	$2.06	$0.16	$1.91	$0.07	$1.28	$4.06	$0.15	$0.03	$1.34	$0.41	$0.17	$1.90	$0.02
RUB Rubber	29	3262	$0.18	$1.97	$0.12	$1.41	$0.06	$1.27	$5.19	$0.11	$0.02	$1.00	$0.30	$0.12	$1.62	$0.02
* Nonmetallic Minerals																
CLY Clay	30	3271	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.03	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
GLS Glass	31	3272	$0.01	$0.10	$0.00	$0.02	$0.02	$0.03	$0.30	$0.02	$0.00	$0.05	$0.02	$0.01	$0.06	$0.00
CEM Cement	32	3273	$0.61	$5.61	$0.20	$1.61	$0.10	$2.06	$14.33	$0.40	$0.09	$2.42	$0.99	$0.37	$3.02	$0.08
LIM Lime and Gypsum	33	3274	$0.16	$1.34	$0.05	$0.43	$0.04	$0.54	$3.64	$0.14	$0.02	$0.65	$0.25	$0.10	$0.76	$0.03
ONM Other Non-Metallic Minerals	34	3279	$0.06	$143.48	$0.30	$1.29	$0.03	$0.67	$260.78	$0.08	$0.01	$1.05	$0.10	$63.34	$10.19	$0.01

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
* Primary Metals																
I_S Iron and Steel	35	3311, 3312, 33151	$0.94	$12.15	$0.14	$1.44	$0.55	$2.49	$8.32	$3.68	$0.55	$5.47	$1.42	$17.33	$2.94	$11.39
ALU Aluminum	36	3313, 331521, 331524	$0.39	$9.87	$0.12	$1.33	$0.56	$3.88	$14.30	$2.99	$0.49	$5.06	$0.59	$16.01	$3.11	$9.27
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.02	$29.41	$0.07	$0.03	$0.03	$7.64	$0.56	$0.14	$0.03	$0.31	$0.03	$0.48	$2.24	$0.41
FMP Fabricated Metal Products	38	332	$2.46	$17.88	$3.79	$5.30	$0.39	$9.80	$45.29	$1.45	$0.57	$5.85	$2.84	$1.00	$28.39	$0.21
* Machinery and Equipment																
CEQ Construction and Ag Equipment	39	3331	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
IEQ Industrial Equipment	40	3332	$0.00	$1.26	$0.12	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.13	$1.03	-$0.01	$0.00	-$0.01	$0.00
SEQ Service Industry Equipment	41	3333	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
HVC HVAC Equipment	42	3334	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
MEQ Metalworking Equipment	43	3335	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
EEQ Engines	44	3336	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.03	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
CEQ General Equipment	45	3339	$0.00	$1.55	-$0.05	-$0.01	$0.02	-$0.03	$0.16	$0.17	$0.00	-$0.03	-$0.01	$0.16	-$0.03	$0.00
* Electronic Equipment																
CPU Computers	46	3341	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
CMQ Communication Equipment	47	3342	$0.00	$0.04	-$0.01	-$0.01	$0.02	-$0.01	$2.22	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
TVQ TV Equipment	48	3343	-$0.19	-$0.06	-$0.01	-$0.02	$0.01	-$0.05	-$0.36	$0.00	-$0.01	-$0.03	-$0.03	$0.00	-$0.04	$0.00

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
SMI Semiconductor Equipment	49	3344	$0.00	$0.68	$0.12	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.21	$0.62	-$0.01	$0.00	-$0.01	$0.00
INS Instruments	50	3345	$0.01	$0.29	$0.09	$0.04	$0.02	$0.09	$0.11	$0.01	$0.02	$0.19	$0.02	$0.00	$0.14	$0.00
MGT Magnetic Recording Equipment	51	3346	$0.01	$0.08	$0.03	$0.04	$0.02	$0.08	$0.12	$0.01	$0.00	$0.02	$0.02	$0.00	$0.13	$0.00
ELQ Elec Equipment and Appliances	52	335	$0.02	$0.18	$0.05	$0.08	$0.02	$0.16	$0.22	$0.02	$0.01	$0.05	$0.03	$0.01	$0.26	$0.00
* Transport Equipment																
M_V Motor Vehicles	53	3361	$0.31	$1.05	$0.03	$1.41	$0.07	$18.27	$5.54	$0.37	$0.04	$1.20	$0.29	$0.22	$1.85	$0.01
TKB Truck Bodies	54	3362	$0.43	$2.27	$0.24	$0.49	$0.03	$0.79	$6.95	$0.63	$0.11	$2.00	$7.69	$0.20	$2.47	$0.01
MVP Motov Vehicle Parts	55	3363	$0.31	$0.68	$0.00	$1.41	$0.07	$2.59	$3.05	$0.36	$0.03	$0.84	$0.29	$0.22	$1.85	$0.01
ARC Aircraft	56	3364	$0.18	$25.21	$0.10	$0.43	$0.02	$0.47	$2.86	$0.26	$0.04	$8.18	$3.19	$51.75	$2.32	$0.01
R_R Rail Cars	57	3365	$0.00	-$0.03	-$0.01	-$0.01	$0.02	-$0.01	-$0.04	$0.01	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00
SHP Ships	58	3366	$0.01	$2.30	$0.70	$0.00	$0.02	$0.01	$20.36	$0.02	$0.02	$7.12	$0.21	$0.00	$0.12	$0.00
OTQ Other Transport Equipment	59	3369	$0.00	$0.24	$0.10	-$0.01	$0.02	$0.01	$24.73	$0.01	$0.08	$0.11	-$0.01	$0.00	$0.65	$0.00
FUR Furniture	60	337	$0.79	$16.09	$0.16	$0.27	$0.18	$14.48	$11.43	$0.65	$0.22	$3.75	$0.82	$11.10	$5.08	$0.02
MSC Miscellaneous Manufacturing	61	339	$0.15	$93.81	$2.34	$0.12	$0.03	$0.57	$111.95	$0.05	$0.46	$3.11	$0.13	$0.03	$20.96	$0.01
****--- Services ---****																
* Wholesale and Retail Trade																
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.16	$0.00	$0.29	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTL Retail Trade	63	44-45	$0.00	$13.86	$1.36	$0.00	$0.00	$1.71	$0.00	$0.46	$1.36	$11.31	$0.00	$0.00	$0.00	$0.00
* Transportation Services																
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$1.58	$5.91	$0.02	$1.23	$0.61	$2.91	$15.90	$1.01	$0.09	$3.88	$2.63	$2.20	$2.26	$3.02

Exhibit J-1. Summary of CAAA-Related Private Costs: 2010 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
WTP Water transportation	66	483	$1.76	$2.08	$0.30	$0.32	$0.02	$3.17	$18.03	$0.04	$0.17	$5.28	$11.61	$1.21	$0.15	$0.03
TTP Freight truck transportation	67	484	$70.35	$253.51	$22.19	$92.15	$16.41	$125.97	$721.59	$43.50	$71.68	$57.29	$98.67	$71.09	$108.16	$15.73
PIP Pipeline transport	68	486	$0.02	$1.94	$0.01	$0.56	$0.02	$0.87	$8.45	$0.08	$0.00	$3.14	$0.06	$1.31	$0.07	$0.13
OTP Other transportation services	69	485, 487, 488	$0.03	$18.47	$0.30	$0.02	$0.00	$0.41	$62.96	$0.01	$0.00	$2.67	$0.06	$2.08	$2.69	$0.00
* Other Services																
INF Information	70	51	$0.09	$0.39	$0.04	$0.07	$0.01	$0.12	$1.14	$0.05	$0.01	$0.36	$0.44	$0.03	$0.11	$0.01
OFI Finance and Insurance	71	52	$0.00	$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$10.36	$0.08	$0.00	$0.00	$0.00	$4.57	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$0.56	$31.10	$1.99	$1.51	$0.04	$8.78	$76.10	$0.68	$0.49	$4.80	$1.57	$4.54	$2.33	$0.06
EDU Education	76	61	$0.00	$1.52	$0.26	$0.00	$0.00	$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.23	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.31	$40.57	$0.94	$0.29	$0.07	$2.48	$30.16	$0.40	$0.31	$5.09	$0.54	$0.23	$6.94	$0.03
PUB Public Services	81	92	$7.78	$9.65	$0.11	$0.00	$0.00	$0.00	$36.23	$0.14	$0.00	$0.02	$7.27	$0.56	$0.11	$3.11
Households	82		$209.14	$956.54	$100.87	$185.38	$31.18	$383.98	$3,150.39	$186.31	$242.50	$316.44	$351.72	$237.88	$276.73	$30.16

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
Energy Sectors														
Coal	1	2121	$0.85	$2.36	$2.00	$13.44	$3.79	$0.63	$0.45	$0.23	$5.29	$2.39	$1.86	$8.95
Crude Oil	2	211111, 4861	$2.45	$4.08	$2.72	$33.03	$5.06	$3.85	$1.13	$0.57	$10.65	$5.90	$2.26	$15.16
Electricity Generation	3	2211	$547.28	$53.48	$213.29	$406.98	$157.81	$91.57	$67.65	$0.71	$368.39	$864.04	$0.76	$713.39
Natural Gas	4	211112, 2212, 4862	$11.40	$4.10	$2.88	$89.74	$6.86	$13.78	$19.51	$0.73	$46.62	$14.52	$4.01	$37.55
Refined Petroleum	5	324, 48691	$19.75	$3.37	$1.41	$71.67	$2.50	$6.34	$1.68	$0.67	$10.53	$6.90	$0.79	$55.19
Agriculture	6	11	$0.85	$2.36	$2.00	$64.58	$3.79	$0.63	$0.45	$0.23	$5.29	$2.39	$1.86	$9.34
Construction	7	23	$0.85	$12.94	$2.00	$331.76	$6.98	$63.34	$11.31	$0.23	$5.29	$2.82	$3.39	$136.80
Metal Mining	8	21 less 2121, 211111, 211112	$1.62	$3.14	$2.08	$16.33	$4.25	$0.78	$0.46	$0.23	$6.24	$2.91	$1.93	$9.55
****--- Manufactured Goods ---****														
FOO Food Products	9	311	$0.24	$0.97	$0.59	$12.01	$0.89	$2.33	$0.10	$0.01	$0.73	$2.57	$0.71	$9.97
BEV Beverages and Tobacco	10	312	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
TEX Textile Mills	11	313	$1.29	$0.29	$0.12	$4.22	$0.21	$1.70	$0.13	$0.01	$0.72	$5.91	$0.04	$0.41
TPM Textile Product Mills	12	314	$0.37	$0.08	$0.06	$0.89	$0.11	$0.07	$0.03	$0.01	$0.18	$1.57	$0.04	$0.24
WAP Wearing Apparel	13	315	$0.27	$0.06	$0.10	$2.83	$0.13	$0.19	$0.01	$0.00	$0.25	$0.19	$0.04	$0.36
LEA Leather	14	316	$1.26	$3.63	$0.05	$1.81	$5.16	$0.09	$0.04	$0.00	$0.16	$0.06	$5.57	$2.89
* Lumber and Wood														
SAW Sawmills	15	3211	$1.24	$1.28	$1.60	$21.10	$1.19	$0.33	$0.30	$0.00	$3.18	$1.91	$1.38	$2.80

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
PLY Plywood and Venner	16	3212	$1.24	$1.27	$1.60	$22.62	$1.18	$0.33	$0.30	$0.00	$3.17	$1.90	$1.38	$2.80
LUM Other Lumber	17	3219	$7.71	$1.27	$1.60	$27.60	$1.18	$0.78	$0.38	$0.01	$4.89	$3.29	$1.38	$7.53
PAP Pulp and Paper Mills	18	3221	$54.90	$1.15	$4.74	$23.73	$1.00	$6.02	$3.11	$0.00	$16.92	$35.52	$2.45	$9.86
CPP Converted Paper Products	19	3222	$4.74	$0.55	$2.20	$9.14	$0.50	$2.75	$1.19	$0.00	$2.49	$7.65	$0.32	$4.39
PRN Printing	20	323	$0.10	$0.11	$0.08	$4.85	$0.23	$0.56	$0.02	$0.01	$0.41	$0.29	$0.06	$5.69
* Chemicals														
CHM Chemicals and gases	21	3251	$5.41	$0.84	$1.10	$70.25	$1.87	$17.94	$8.02	$0.14	$6.47	$9.89	$0.54	$23.96
RSN Resins	22	3252	$0.65	$0.14	$0.16	$8.70	$0.28	$2.13	$0.95	$0.02	$0.85	$1.21	$0.09	$2.98
FRT Fertilizer	23	3253	$0.18	$0.07	$0.07	$78.45	$0.13	$7.77	$0.21	$0.01	$0.26	$0.29	$0.05	$32.24
MED Drugs and medicine	24	3254	$1.19	$0.22	$0.27	$15.50	$0.46	$3.92	$1.75	$0.03	$1.49	$2.19	$0.14	$5.35
PAI Paints and adhesives	25	3255	$0.63	$0.71	$0.38	$374.42	$0.64	$12.06	$0.36	$0.06	$2.20	$1.95	$0.21	$44.89
SOP Soap	26	3256	$0.16	$0.07	$0.07	$2.16	$0.12	$0.50	$0.23	$0.01	$0.27	$0.32	$0.05	$0.82
OCM Other chemicals	27	3259	$5.51	$1.04	$2.88	$35.58	$0.98	$98.70	$2.22	$0.15	$4.99	$4.87	$0.31	$6.41
* Plastic and Rubber														
PLS Plastic	28	3261	$0.58	$0.23	$0.82	$4.98	$0.33	$0.68	$0.19	$0.00	$0.70	$1.42	$0.09	$3.50
RUB Rubber	29	3262	$0.44	$0.18	$0.62	$11.79	$0.26	$1.07	$0.14	$0.01	$0.54	$1.06	$0.08	$3.36
* Nonmetallic Minerals														
CLY Clay	30	3271	$0.02	$0.04	$0.04	$0.25	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
GLS Glass	31	3272	$0.05	$0.05	$0.06	$4.46	$0.09	$0.06	$0.03	$0.00	$0.14	$0.14	$0.04	$0.28
CEM Cement	32	3273	$1.44	$0.36	$1.06	$13.47	$0.69	$1.96	$0.73	$0.02	$1.80	$4.12	$0.21	$4.91
LIM Lime and Gypsum	33	3274	$0.40	$0.16	$0.30	$3.82	$0.30	$0.54	$0.19	$0.01	$0.53	$1.08	$0.10	$1.38
ONM Other Non-Metallic Minerals	34	3279	$20.93	$0.12	$0.15	$248.10	$21.40	$4.26	$35.09	$0.01	$15.32	$37.23	$2.63	$69.96

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
* Primary Metals														
I_S Iron and Steel	35	3311, 3312, 33151	$4.61	$8.96	$1.34	$13.77	$5.48	$1.03	$0.09	$0.00	$3.86	$6.77	$0.86	$8.06
ALU Aluminum	36	3313, 331521, 331524	$2.09	$10.12	$1.48	$21.00	$6.18	$1.63	$0.12	$0.00	$5.14	$10.09	$0.96	$3.56
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.42	$0.37	$0.07	$1.50	$0.27	$0.25	$1.89	$0.00	$0.26	$0.23	$0.07	$15.70
FMP Fabricated Metal Products	38	332	$4.16	$4.43	$3.98	$97.38	$2.29	$17.18	$0.80	$0.03	$5.78	$10.63	$0.49	$25.09
* Machinery and Equipment														
CEQ Construction and Ag Equip.	39	3331	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
IEQ Industrial Equipment	40	3332	$0.02	$0.04	$0.04	$0.24	$0.07	$1.53	$0.10	$0.01	$0.10	$0.05	$0.04	$0.17
SEQ Service Industry Equipment	41	3333	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
HVC HVAC Equipment	42	3334	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
MEQ Metalworking Equipment	43	3335	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
EEQ Engines	44	3336	$0.02	$0.04	$0.04	$0.25	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
CEQ General Equipment	45	3339	$0.02	$1.04	$0.04	$12.62	$0.07	-$0.39	-$0.03	$0.00	$0.33	$0.48	$0.04	$1.41
* Electronic Equipment														
CPU Computers	46	3341	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
CMQ Communication Equipment	47	3342	$0.02	$0.42	$0.04	$1.42	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
TVQ TV Equipment	48	3343	$0.00	-$0.04	$0.03	-$0.44	$0.04	$0.00	$0.00	$0.00	$0.06	$0.04	$0.00	$0.13

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
SMI Semiconductor Equipment	49	3344	$0.02	$0.04	$0.04	$0.24	$0.07	$1.09	$0.04	$0.01	$0.10	$0.05	$0.04	$0.17
INS Instruments	50	3345	$0.05	$0.05	$0.10	$0.51	$0.08	$0.48	$0.07	$0.01	$0.13	$0.14	$0.04	$0.32
MGT Magnetic Recording Equip.	51	3346	$0.04	$0.05	$0.10	$0.49	$0.08	$0.10	$0.27	$0.00	$0.13	$0.14	$0.04	$0.31
ELQ Elec Equip. and Appliances	52	335	$0.07	$0.06	$0.15	$0.72	$0.09	$0.18	$0.02	$0.00	$0.15	$0.22	$0.04	$0.43
* Transport Equipment														
M_V Motor Vehicles	53	3361	$1.67	$0.48	$0.41	$14.63	$0.12	$1.36	$7.31	$0.00	$0.46	$29.11	$0.08	$2.40
TKB Truck Bodies	54	3362	$1.22	$2.73	$0.38	$15.37	$0.51	$8.18	$0.04	$0.02	$2.68	$2.50	$0.09	$1.06
MVP Motov Vehicle Parts	55	3363	$1.67	$0.20	$0.41	$2.81	$0.12	$0.47	$0.09	$0.00	$0.46	$1.11	$0.08	$2.39
ARC Aircraft	56	3364	$0.52	$1.16	$0.18	$6.52	$0.26	$3.40	$3.45	$0.01	$5.55	$11.33	$0.69	$15.98
R_R Rail Cars	57	3365	$0.02	$0.04	$0.04	$0.24	$0.07	$0.01	$0.01	$0.00	$0.10	$0.05	$0.04	$0.17
SHP Ships	58	3366	$0.05	$0.12	$0.05	$15.77	$0.08	$34.46	$0.03	$0.02	$0.17	$0.11	$0.04	$0.19
OTQ Other Transport Equipment	59	3369	$0.02	$0.04	$0.04	$18.23	$0.07	$1.01	$0.04	$0.00	$0.10	$0.23	$0.04	$0.67
FUR Furniture	60	337	$19.93	$0.78	$0.56	$22.05	$0.78	$1.31	$1.40	$0.02	$1.76	$8.69	$0.19	$7.38
MSC Miscellaneous Mfg.	61	339	$0.13	$0.13	$0.12	$482.41	$0.14	$135.88	$4.96	$0.25	$0.26	$0.27	$0.06	$166.16
****--- Services ---****														
* Wholesale and Retail Trade														
WHL Wholesale Trade	62	42	$0.00	$1.00	$0.00	$0.33	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00
RTL Retail Trade	63	44-45	$0.00	$6.17	$0.00	$0.00	$0.00	$12.96	$2.34	$0.30	$0.00	$0.00	$0.00	$6.54
* Transportation Services														
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$2.54	$3.07	$2.40	$8.06	$2.96	$0.13	$0.71	$1.29	$4.63	$5.61	$1.37	$11.44

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Alabama	Arizona	Arkansas	California	Colorado	Conn.	Delaware	DC	Florida	Georgia	Idaho	Illinois
WTP Water transportation	66	483	$1.07	$0.16	$0.19	$26.48	$0.02	$6.52	$0.11	$0.26	$39.13	$0.52	$0.02	$4.41
TTP Freight truck transportation	67	484	$95.34	$93.84	$104.75	$1,054.69	$85.16	$108.63	$15.62	$11.88	$329.37	$230.63	$44.57	$94.73
PIP Pipeline transport	68	486	$5.86	$0.09	$0.19	$2.10	$0.35	$0.15	$0.01	$0.01	$0.07	$0.08	$0.03	$0.34
OTP Other transportation svcs.	69	485, 487, 488	$0.03	$0.03	$0.01	$42.13	$0.03	$3.63	$4.95	$0.15	$0.13	$0.09	$0.01	$5.87
* Other Services														
INF Information	70	51	$0.07	$0.12	$0.05	$3.06	$0.36	$0.25	$0.03	$0.10	$0.51	$0.41	$0.02	$0.42
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.04	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$0.00	$0.00	$30.82	$0.00	$15.99	$3.72	$0.00	$0.00	$0.00	$0.00	$14.66
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$3.39	$3.97	$1.38	$87.18	$0.80	$16.42	$0.19	$0.16	$5.10	$2.32	$0.14	$12.86
EDU Education	76	61	$0.11	$0.00	$0.00	$0.07	$0.00	$0.43	$0.17	$0.03	$0.00	$0.23	$0.00	$0.76
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$3.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.41	$2.06	$0.18	$98.16	$0.44	$21.48	$5.31	$0.67	$2.21	$4.52	$0.09	$23.94
PUB Public Services	81	92	$0.51	$10.55	$0.00	$78.38	$6.93	$2.29	$1.36	$0.00	$1.06	$0.00	$11.00	$9.65
Households	82		$222.16	$460.51	$165.44	$9,523.19	$286.97	$572.92	$93.22	$45.06	$688.72	$794.34	$76.55	$533.86

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
Energy Sectors														
Coal	1	2121	$4.62	$5.95	$5.15	$1.53	$1.97	$0.32	$1.70	$3.81	$2.28	$5.01	$1.41	$3.42
Crude Oil	2	211111, 4861	$7.06	$6.97	$6.04	$2.40	$3.88	$0.71	$5.48	$5.60	$6.02	$6.32	$2.29	$4.86
Electricity Generation	3	2211	$1,064.47	$95.68	$130.09	$621.55	$87.25	$4.40	$591.22	$137.23	$253.64	$36.00	$191.50	$294.54
Natural Gas	4	211112, 2212, 4862	$17.80	$9.14	$8.08	$3.71	$57.78	$26.19	$6.81	$11.35	$12.03	$7.78	$6.79	$5.01
Refined Petroleum	5	324, 48691	$36.82	$2.00	$1.75	$3.26	$21.58	$0.78	$7.71	$3.52	$8.55	$5.10	$1.72	$2.83
Agriculture	6	11	$4.82	$5.95	$5.15	$1.53	$1.97	$0.32	$1.70	$3.81	$2.38	$5.01	$1.41	$3.44
Construction	7	23	$23.68	$5.95	$5.15	$1.53	$1.97	$0.46	$18.40	$3.81	$11.67	$5.11	$1.41	$3.60
Metal Mining	8	21 less 2121, 211111, 211112	$4.99	$6.02	$7.87	$2.49	$2.09	$0.32	$4.54	$3.88	$3.45	$5.33	$1.47	$3.60
****--- Manufactured Goods ---****														
FOO Food Products	9	311	$0.62	$28.97	$0.38	$1.12	$0.56	$0.06	$1.99	$0.84	$0.57	$3.94	$0.17	$0.95
BEV Beverages and Tobacco	10	312	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
TEX Textile Mills	11	313	$0.24	$0.16	$0.14	$0.15	$0.09	$0.14	$0.31	$2.94	$1.12	$0.24	$0.15	$0.30
TPM Textile Product Mills	12	314	$0.13	$0.13	$0.11	$0.06	$0.05	$0.04	$0.11	$0.23	$0.09	$0.14	$0.06	$0.10
WAP Wearing Apparel	13	315	$0.13	$0.15	$0.12	$0.20	$0.04	$0.06	$0.08	$0.17	$0.09	$0.13	$0.10	$0.16
LEA Leather	14	316	$0.24	$0.12	$0.13	$0.12	$0.04	$0.72	$0.20	$0.09	$0.21	$1.03	$0.04	$0.08
* Lumber and Wood														
SAW Sawmills	15	3211	$1.59	$2.76	$1.35	$1.08	$0.67	$0.29	$0.59	$0.43	$1.20	$1.72	$1.07	$1.49
PLY Plywood and Venner	16	3212	$1.58	$2.76	$1.35	$1.08	$0.66	$0.29	$0.59	$0.43	$1.20	$1.71	$1.06	$1.48
LUM Other Lumber	17	3219	$5.60	$2.76	$1.35	$1.08	$3.69	$1.09	$1.29	$0.43	$1.46	$2.36	$3.21	$1.48

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
PAP Pulp and Paper Mills	18	3221	$12.19	$7.41	$0.74	$5.77	$10.94	$17.19	$10.58	$4.59	$10.63	$11.02	$6.68	$4.53
CPP Converted Paper Products	19	3222	$1.93	$1.24	$0.39	$2.21	$3.82	$2.12	$0.81	$2.03	$3.22	$3.15	$1.39	$2.12
PRN Printing	20	323	$0.37	$0.22	$0.25	$0.17	$0.07	$0.02	$0.23	$0.22	-$0.06	$0.57	$0.06	$0.27
* Chemicals														
CHM Chemicals and gases	21	3251	$32.49	$6.69	$2.67	$4.24	$16.62	$0.26	$8.99	$6.07	$11.32	$3.44	$2.78	$11.59
RSN Resins	22	3252	$3.91	$0.89	$0.40	$0.63	$1.99	$0.04	$1.09	$0.78	$2.29	$0.49	$0.35	$1.44
FRT Fertilizer	23	3253	$6.93	$0.34	$0.19	$0.16	$0.60	$0.01	$6.35	$0.24	$0.39	$0.21	$0.11	$0.46
MED Drugs and medicine	24	3254	$7.15	$1.54	$0.66	$0.95	$3.65	$0.06	$1.98	$1.38	$2.50	$0.82	$0.63	$3.41
PAI Paints and adhesives	25	3255	$4.46	$0.59	$0.44	$1.05	$1.02	$0.15	$7.35	$1.03	$2.37	$0.71	$0.40	$1.09
SOP Soap	26	3256	$0.98	$0.29	$0.17	$0.14	$0.49	$0.01	$0.28	$0.24	$0.35	$0.19	$0.10	$0.38
OCM Other chemicals	27	3259	$9.21	$1.13	$0.73	$1.24	$22.36	$0.23	$38.98	$2.02	$4.10	$1.14	$1.12	$1.94
* Plastic and Rubber														
PLS Plastic	28	3261	$2.03	$0.72	$0.66	$0.89	$0.28	$0.14	$0.62	$0.90	$1.97	$1.08	$0.45	$0.95
RUB Rubber	29	3262	$2.00	$0.56	$0.51	$0.66	$0.22	$0.10	$0.87	$0.68	$1.78	$0.82	$0.34	$0.72
* Nonmetallic Minerals														
CLY Clay	30	3271	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.10	$0.03	$0.07
GLS Glass	31	3272	$0.17	$0.14	$0.11	$0.06	$0.11	$0.01	$0.06	$0.10	$0.09	$0.13	$0.04	$0.11
CEM Cement	32	3273	$3.50	$1.41	$0.76	$1.34	$3.08	$0.30	$1.36	$1.22	$2.17	$1.59	$0.63	$1.93
LIM Lime and Gypsum	33	3274	$0.96	$0.48	$0.29	$0.39	$0.82	$0.09	$0.37	$0.38	$0.59	$0.52	$0.19	$0.60
ONM Other Non-Metallic Minerals	34	3279	$133.8 9	$1.25	$10.57	$13.05	$143.26	$5.34	$35.28	$0.67	$96.18	$17.80	$30.46	$8.40
* Primary Metals														

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
I_S Iron and Steel	35	3311, 3312, 33151	$5.77	$1.15	$0.76	$13.64	$1.83	$0.05	$1.46	$1.03	$2.77	$4.47	$0.80	$2.63
ALU Aluminum	36	3313, 331521, 331524	$2.49	$1.02	$0.68	$6.18	$2.02	$0.04	$3.68	$1.01	$5.29	$3.94	$0.38	$2.49
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$31.95	$0.14	$0.12	$15.16	$0.08	$0.02	$0.34	$0.24	$11.90	$0.22	$0.05	$0.14
FMP Fabricated Metal Products	38	332	$12.99	$3.15	$1.63	$3.32	$2.30	$0.86	$5.31	$8.96	$28.68	$6.82	$1.73	$6.72
* Machinery and Equipment														
CEQ Construction and Ag Equip.	39	3331	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
IEQ Industrial Equipment	40	3332	$0.09	$0.11	$0.10	$0.03	$0.04	$0.13	$0.75	$1.25	$0.04	$0.09	$0.03	$0.06
SEQ Service Industry Equipment	41	3333	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
HVC HVAC Equipment	42	3334	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
MEQ Metalworking Equipment	43	3335	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
EEQ Engines	44	3336	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.05	$0.10	$0.03	$0.07
CEQ General Equipment	45	3339	$0.09	$0.11	$0.10	$1.78	$0.04	$0.01	$0.89	$0.16	$0.29	$0.09	$0.03	$0.39
* Electronic Equipment														
CPU Computers	46	3341	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
CMQ Communication Equipment	47	3342	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.39	$0.07	$0.23	$0.09	$0.03	$0.06
TVQ TV Equipment	48	3343	$0.08	$0.10	$0.09	$0.02	$0.04	$0.00	$0.01	-$0.02	$0.03	$0.05	$0.03	$0.06
SMI Semiconductor Equipment	49	3344	$0.09	$0.11	$0.10	$0.03	$0.04	$0.31	$0.54	$1.48	$0.04	$0.09	$0.03	$0.06

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
INS Instruments	50	3345	$0.13	$0.16	$0.11	$0.07	$0.04	$0.02	$0.31	$0.57	$0.10	$0.13	$0.05	$0.12
MGT Magnetic Recording Equip.	51	3346	$0.13	$0.16	$0.11	$0.07	$0.04	$0.01	$0.04	$0.12	$0.10	$0.13	$0.05	$0.12
ELQ Elec Equip. and Appliances	52	335	$0.16	$0.20	$0.13	$0.10	$0.05	$0.01	$0.04	$0.16	$0.15	$0.16	$0.06	$0.17
* Transport Equipment														
M_V Motor Vehicles	53	3361	$8.07	$0.72	$0.32	$3.17	$0.66	$0.13	$13.25	$0.30	$73.97	$0.58	$0.50	$23.46
TKB Truck Bodies	54	3362	$1.82	$0.31	$3.29	$0.29	$1.47	$0.73	$0.71	$2.63	$0.91	$1.16	$0.76	$2.80
MVP Motov Vehicle Parts	55	3363	$8.05	$0.72	$0.32	$3.17	$0.66	$0.03	$0.33	$0.17	$19.77	$0.58	$0.50	$2.13
ARC Aircraft	56	3364	$8.91	$0.19	$1.42	$3.44	$0.63	$0.68	$0.31	$1.14	$7.43	$0.54	$1.79	$13.27
R_R Rail Cars	57	3365	$0.09	$0.11	$0.10	$0.03	$0.04	$0.01	$0.03	$0.07	$0.04	$0.09	$0.03	$0.06
SHP Ships	58	3366	$0.17	$0.12	$0.19	$0.04	$0.08	$2.11	$2.01	$0.76	$0.24	$0.12	$0.05	$0.14
OTQ Other Transport Equipment	59	3369	$0.14	$0.11	$0.10	$0.13	$0.04	$0.11	$0.17	$0.58	$7.05	$0.09	$0.03	$0.08
FUR Furniture	60	337	$6.27	$2.55	$0.43	$3.15	$3.13	$0.14	$3.95	$2.52	$26.98	$1.93	$1.93	$4.62
MSC Miscellaneous Mfg.	61	339	$10.63	$0.22	$0.16	$0.15	$0.17	$0.57	$68.47	$5.36	$15.60	$0.24	$0.08	$0.35
****--- Services ---****														
* Wholesale and Retail Trade														
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.64
RTL Retail Trade	63	44-45	$0.00	$0.00	$0.00	$0.74	$0.00	$3.90	$26.42	$8.00	$0.00	$0.00	$0.00	$1.11
* Transportation Services														
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$4.89	$3.60	$5.28	$2.80	$2.04	$0.34	$1.54	$1.43	$2.84	$3.45	$1.67	$5.35
WTP Water transportation	66	483	$4.81	$0.33	$0.01	$1.81	$11.27	$0.19	$2.03	$1.88	$1.01	$0.95	$1.25	$1.27

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Indiana	Iowa	Kansas	Kentucky	Louisiana	Maine	Maryland	Mass.	Mich.	Minn.	Miss.	Missouri
TTP Freight truck transportation	67	484	$163.74	$102.92	$52.61	$91.43	$84.23	$64.04	$130.02	$48.90	$180.92	$102.65	$109.99	$89.95
PIP Pipeline transport	68	486	$2.34	$0.07	$0.27	$0.66	$5.62	$0.03	$0.65	$0.03	$0.70	$0.09	$0.17	$0.06
OTP Other transportation svcs.	69	485, 487, 488	$1.91	$0.01	$0.01	$0.35	$6.60	$0.01	$6.10	$0.09	$5.85	$0.02	$0.01	$0.03
* Other Services														
INF Information	70	51	$0.10	$0.06	$0.11	$0.06	$0.07	$0.02	$0.21	$0.26	$0.19	$0.13	$0.03	$0.16
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.33	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.21	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$2.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.00	$0.29	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$12.76	$0.18	$0.68	$3.14	$8.56	$1.46	$7.28	$9.07	$20.31	$0.46	$1.74	$1.05
EDU Education	76	61	$0.81	$5.89	$0.00	$0.08	$0.06	$0.03	$0.11	$1.01	$0.64	$0.00	$0.00	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$30.13	$0.30	$0.28	$0.59	$0.35	$1.08	$19.12	$5.21	$7.60	$0.47	$0.18	$0.99
PUB Public Services	81	92	$4.85	$0.00	$0.00	$0.00	$16.46	$0.00	$1.65	$0.12	$0.58	$0.14	$0.00	$0.00
Households	82		$487.19	$274.82	$97.42	$279.42	$197.53	$187.24	$588.78	$373.99	$504.30	$210.09	$265.62	$279.75

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
Energy Sectors													
Coal	1	2121	$3.34	$4.12	$2.16	$0.10	$2.16	$1.10	$9.18	$1.94	$4.80	$4.65	$2.43
Crude Oil	2	211111, 4861	$3.84	$4.68	$3.07	$0.93	$9.23	$1.80	$25.65	$4.86	$5.05	$8.73	$3.63
Electricity Generation	3	2211	$1.23	$129.25	$40.22	$41.27	$237.17	$52.67	$623.13	$1,447.03	$162.66	$1,399.71	$244.88
Natural Gas	4	211112, 2212, 4862	$3.84	$5.63	$3.07	$4.89	$11.22	$1.80	$35.50	$14.21	$5.05	$30.41	$9.64
Refined Petroleum	5	324, 48691	$0.99	$1.10	$1.79	$1.62	$14.80	$3.41	$32.59	$5.74	$0.50	$110.13	$2.35
Agriculture	6	11	$3.34	$4.12	$2.16	$0.10	$2.16	$1.10	$9.18	$2.54	$4.80	$4.80	$2.43
Construction	7	23	$3.97	$4.12	$15.94	$0.10	$212.04	$1.53	$295.75	$1.94	$4.80	$11.01	$2.43
Metal Mining	8	21 less 2121, 211111, 211112	$3.63	$4.16	$2.84	$0.11	$2.72	$1.47	$12.83	$2.16	$4.88	$5.07	$2.74
****--- Manufactured Goods ---****													
FOO Food Products	9	311	$0.08	$0.35	$0.09	$0.05	$5.18	$0.07	$8.72	$3.44	$0.15	$5.11	$0.21
BEV Beverages and Tobacco	10	312	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
TEX Textile Mills	11	313	$0.07	$0.10	$0.07	$0.09	$1.58	$0.04	$3.68	$3.85	$0.10	$0.57	$0.07
TPM Textile Product Mills	12	314	$0.06	$0.08	$0.05	$0.03	$0.37	$0.03	$0.75	$1.03	$0.09	$0.18	$0.05
WAP Wearing Apparel	13	315	$0.06	$0.08	$0.04	$0.01	$0.51	$0.03	$2.20	$0.67	$0.09	$0.18	$0.12
LEA Leather	14	316	$0.06	$0.08	$0.04	$0.00	$1.09	$0.02	$1.62	$1.03	$0.09	$0.16	$0.06
* Lumber and Wood													
SAW Sawmills	15	3211	$0.78	$1.97	$0.18	$0.11	$0.65	$0.71	$2.40	$2.15	$0.72	$1.30	$1.02
PLY Plywood and Venner	16	3212	$0.78	$1.97	$0.18	$0.11	$0.65	$0.70	$2.40	$2.15	$0.71	$1.29	$1.02

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
LUM Other Lumber	17	3219	$0.78	$1.97	$0.18	$0.11	$6.82	$0.70	$3.95	$2.38	$0.71	$1.63	$1.30
PAP Pulp and Paper Mills	18	3221	$0.43	$0.57	$0.40	$0.87	$11.44	$0.16	$24.41	$17.29	$0.13	$14.56	$3.47
CPP Converted Paper Products	19	3222	$0.23	$0.30	$0.21	$0.39	$4.94	$0.08	$6.91	$3.14	$0.11	$4.60	$0.98
PRN Printing	20	323	$0.07	$0.13	$0.10	$0.05	-$0.12	$0.03	$4.58	$0.24	$0.10	-$0.16	$0.10
* Chemicals													
CHM Chemicals and gases	21	3251	$0.19	$1.44	$0.31	$0.31	$82.31	$0.22	$97.45	$37.72	$0.16	$20.13	$1.04
RSN Resins	22	3252	$0.08	$0.24	$0.07	$0.04	$9.74	$0.04	$11.64	$4.48	$0.10	$2.45	$0.16
FRT Fertilizer	23	3253	$0.07	$0.12	$0.05	$0.01	$12.11	$0.03	$2.82	$0.97	$0.09	$0.70	$0.08
MED Drugs and medicine	24	3254	$0.09	$0.38	$0.10	$0.07	$17.97	$0.06	$21.37	$8.25	$0.10	$5.63	$0.26
PAI Paints and adhesives	25	3255	$0.17	$0.30	$0.30	$0.15	$35.59	$0.24	$34.17	$7.79	$0.16	$2.07	$0.48
SOP Soap	26	3256	$0.07	$0.12	$0.05	$0.01	$2.30	$0.03	$2.84	$1.07	$0.09	$0.64	$0.07
OCM Other chemicals	27	3259	$0.22	$0.46	$0.43	$0.22	$231.44	$0.35	$31.96	$25.69	$0.19	$13.39	$0.84
* Plastic and Rubber													
PLS Plastic	28	3261	$0.07	$0.31	$0.24	$0.22	$2.01	$0.06	$3.07	$1.90	$0.13	$3.51	$0.82
RUB Rubber	29	3262	$0.07	$0.25	$0.19	$0.16	$1.50	$0.05	$3.78	$1.76	$0.12	$2.61	$0.62
* Nonmetallic Minerals													
CLY Clay	30	3271	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.18	$0.04	$0.09	$0.09	$0.05
GLS Glass	31	3272	$0.06	$0.09	$0.04	$0.01	$0.23	$0.02	$0.42	$0.19	$0.09	$0.18	$0.06
CEM Cement	32	3273	$0.14	$0.49	$0.21	$0.20	$8.01	$0.16	$10.90	$6.38	$0.17	$3.99	$0.66
LIM Lime and Gypsum	33	3274	$0.09	$0.20	$0.10	$0.05	$2.10	$0.07	$2.94	$1.64	$0.11	$1.08	$0.20
ONM Other Non-Metallic Minerals	34	3279	$1.29	$5.97	$0.44	$0.02	$63.99	$13.32	$100.54	$2.93	$0.10	$70.97	$14.63
* Primary Metals													

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
I_S Iron and Steel	35	3311, 3312, 33151	$3.40	$0.56	$7.90	$0.12	$2.98	$2.68	$6.14	$2.92	$1.18	$5.73	$1.32
ALU Aluminum	36	3313, 331521, 331524	$3.84	$0.50	$8.93	$0.12	$3.00	$3.03	$5.10	$4.37	$1.05	$5.83	$1.45
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.19	$0.09	$0.33	$0.04	$0.44	$0.12	$12.20	$0.11	$0.12	$15.77	$0.08
FMP Fabricated Metal Products	38	332	$0.19	$1.29	$0.71	$1.92	$26.77	$0.33	$23.65	$17.91	$0.27	$42.65	$3.76
* Machinery and Equipment													
CEQ Construction and Ag Equip.	39	3331	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
IEQ Industrial Equipment	40	3332	$0.06	$0.08	$0.04	$0.28	$1.60	$0.02	$4.12	$0.04	$0.09	$0.09	$0.05
SEQ Service Industry Equipment	41	3333	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
HVC HVAC Equipment	42	3334	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
MEQ Metalworking Equipment	43	3335	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
EEQ Engines	44	3336	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.18	$0.04	$0.09	$0.09	$0.05
CEQ General Equipment	45	3339	$0.06	$0.08	$0.04	$0.05	$20.78	$0.02	$1.90	$0.90	$0.09	$1.65	$0.05
* Electronic Equipment													
CPU Computers	46	3341	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
CMQ Communication Equipment	47	3342	$0.06	$0.08	$0.04	$0.00	$7.50	$0.02	$0.17	$3.23	$0.09	$1.90	$0.05
TVQ TV Equipment	48	3343	$0.06	$0.07	$0.04	-$0.01	$0.00	-$0.03	$0.05	$0.00	$0.09	$0.07	$0.04
SMI Semiconductor Equipment	49	3344	$0.06	$0.08	$0.04	$0.25	$1.40	$0.02	$3.86	$0.04	$0.09	$0.09	$0.05

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	Sector Number	*NAICS*	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
INS Instruments	50	3345	$0.06	$0.09	$0.04	$0.11	$0.70	$0.02	$2.12	$0.17	$0.09	$0.28	$0.05
MGT Magnetic Recording Equip.	51	3346	$0.06	$0.09	$0.04	$0.02	$0.11	$0.02	$0.33	$0.17	$0.09	$0.27	$0.05
ELQ Elec Equip. and Appliances	52	335	$0.06	$0.10	$0.05	$0.04	$0.18	$0.02	$0.47	$0.28	$0.09	$0.43	$0.06
* Transport Equipment													
M_V Motor Vehicles	53	3361	$0.07	$0.29	$0.08	$0.07	$1.37	$0.05	$11.47	$10.84	$0.14	$35.65	$0.69
TKB Truck Bodies	54	3362	$0.07	$0.20	$0.10	$0.11	$0.56	$0.11	$3.66	$0.70	$0.15	$4.62	$0.38
MVP Motov Vehicle Parts	55	3363	$0.07	$0.29	$0.08	$0.05	$0.50	$0.05	$2.62	$1.20	$0.14	$10.44	$0.69
ARC Aircraft	56	3364	$0.07	$0.13	$0.07	$0.05	$0.26	$0.06	$8.25	$2.90	$0.12	$20.86	$3.18
R_R Rail Cars	57	3365	$0.06	$0.08	$0.04	$0.00	$0.04	$0.02	$0.17	$0.04	$0.09	$0.09	$0.05
SHP Ships	58	3366	$0.06	$0.08	$0.04	$0.04	$3.70	$0.02	$11.02	$0.07	$0.09	$0.21	$0.06
OTQ Other Transport Equipment	59	3369	$0.06	$0.08	$0.04	$0.16	$6.06	$0.02	$1.07	$0.44	$0.09	$0.41	$0.05
FUR Furniture	60	337	$0.12	$0.44	$0.44	$0.11	$7.44	$0.08	$17.66	$13.17	$0.14	$19.40	$0.23
MSC Miscellaneous Mfg.	61	339	$0.07	$0.11	$0.06	$0.86	$158.26	$0.05	$398.59	$2.03	$0.10	$6.02	$0.10
****--- Services ---****													
* Wholesale and Retail Trade													
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.00	$0.32	$0.00	$0.00	$0.00	$0.00	$0.42	$0.00
RTL Retail Trade	63	44-45	$0.00	$0.00	$0.00	$3.10	$27.09	$0.00	$64.93	$7.75	$0.00	$0.77	$0.00
* Transportation Services													
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$2.89	$11.96	$0.94	$0.06	$1.42	$2.45	$1.19	$1.95	$1.41	$7.06	$1.81
WTP Water transportation	66	483	$0.02	$0.01	$0.05	$0.05	$13.14	$0.02	$23.90	$0.78	$0.01	$2.36	$0.01

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Montana	Nebraska	Nevada	New Hamp.	New Jer.	New Mex.	New York	N. Carolina	N. Dakota	Ohio	Okla.
TTP Freight truck transportation	67	484	$22.09	$130.85	$25.32	$31.18	$144.20	$96.83	$301.65	$110.38	$140.64	$192.55	$88.74
PIP Pipeline transport	68	486	$0.08	$0.29	$0.04	$0.03	$0.25	$0.25	$0.48	$7.89	$0.06	$0.71	$0.72
OTP Other transportation svcs.	69	485, 487, 488	$0.00	$0.01	$0.02	$0.01	$64.83	$0.01	$17.31	$1.50	$0.00	$1.15	$0.01
* Other Services													
INF Information	70	51	$0.02	$0.04	$0.04	$0.03	$0.70	$0.03	$2.55	$0.20	$0.01	$0.23	$0.07
OFI Finance and Insurance	71	52	$0.00	$0.00	$0.00	$0.00	$0.32	$0.00	$0.25	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.00	$0.00	$0.00	$0.08	$0.00	$1.13	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$0.00	$0.00	$0.00	$0.24	$0.00	$89.64	$0.00	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$0.06	$0.18	$2.80	$1.20	$45.42	$0.20	$45.46	$4.11	$0.40	$19.57	$4.72
EDU Education	76	61	$0.00	$0.00	$0.00	$0.11	$0.24	$0.00	$3.54	$0.05	$0.00	$0.00	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.08	$0.22	$1.22	$0.69	$106.04	$0.15	$389.60	$5.38	$0.07	$3.96	$0.24
PUB Public Services	81	92	$7.97	$0.00	$4.64	$0.00	$13.80	$13.18	$14.57	$0.08	$0.00	$0.85	$0.00
Households	82		$41.03	$161.94	$188.63	$52.85	$1,133.17	$265.53	$1,833.52	$727.58	$356.29	$605.58	$167.50

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
Energy Sectors																
Coal	1	2121	$2.39	$2.24	-$0.05	$0.88	$3.35	$1.54	$11.90	$3.58	$0.16	$2.19	$3.35	$0.66	$3.60	$1.00
Crude Oil	2	211111, 4861	$3.42	$7.97	$0.42	$2.60	$3.55	$1.89	$30.60	$4.14	$0.40	$4.98	$4.60	$1.81	$5.53	$1.58
Electricity Generation	3	2211	$2.40	$1,070.06	$1.30	$147.37	$39.52	$416.51	$428.76	$30.95	$0.46	$264.99	$49.32	$800.30	$300.46	$27.60
Natural Gas	4	211112, 2212, 4862	$8.20	$18.84	$0.64	$11.14	$3.55	$12.57	$108.46	$4.25	$0.40	$6.18	$9.41	$8.72	$12.33	$2.46
Refined Petroleum	5	324, 48691	$2.01	$95.84	$0.92	$3.36	$0.39	$0.70	$446.96	$3.62	$0.47	$5.48	$5.76	$2.84	$3.79	$1.14
Agriculture	6	11	$2.39	$2.35	-$0.05	$0.88	$3.35	$1.54	$11.92	$3.58	$0.16	$2.19	$3.35	$0.66	$3.60	$1.00
Construction	7	23	$2.64	$38.04	-$0.05	$0.88	$3.35	$1.54	$360.91	$7.31	$0.16	$2.39	$5.04	$2.20	$4.10	$1.08
Metal Mining	8	21 less 2121, 211111, 211112	$2.47	$3.69	-$0.04	$0.99	$3.39	$1.71	$22.94	$3.89	$0.20	$2.60	$3.47	$2.43	$3.77	$1.95
****--- Manufactured Goods ---****																
FOO Food Products	9	311	$0.54	$2.49	$0.03	$0.14	$0.11	$2.26	$8.63	$0.49	$0.04	$1.92	$0.38	$0.06	$4.06	$0.03
BEV Beverages and Tobacco	10	312	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
TEX Textile Mills	11	313	$0.11	$2.15	$0.94	$2.24	$0.08	$0.98	$0.80	$0.10	$0.01	$0.75	$0.18	$0.02	$0.62	$0.02
TPM Textile Product Mills	12	314	$0.06	$0.25	$0.08	$0.64	$0.07	$0.19	$0.39	$0.08	$0.01	$0.24	$0.10	$0.02	$0.14	$0.02
WAP Wearing Apparel	13	315	$0.07	$0.30	$0.00	$0.10	$0.07	$0.17	$0.59	$0.08	$0.01	$0.17	$0.11	$0.02	$0.13	$0.02
LEA Leather	14	316	$0.10	$0.30	$0.07	$0.34	$0.06	$0.05	$0.36	$0.07	$0.00	$0.24	$0.07	$0.01	$1.08	$0.02
* Lumber and Wood																

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
SAW Sawmills	15	3211	$2.14	$1.46	$0.06	$0.73	$1.14	$0.65	$6.54	$0.42	$0.17	$0.86	$3.10	$0.16	$2.08	$0.27
PLY Plywood and Venner	16	3212	$2.13	$1.46	$0.06	$0.73	$1.14	$0.65	$6.52	$0.41	$0.17	$0.85	$3.09	$0.16	$2.07	$0.27
LUM Other Lumber	17	3219	$2.13	$3.03	$0.06	$1.34	$1.14	$1.25	$16.73	$0.41	$0.17	$1.09	$6.77	$0.16	$3.01	$0.27
PAP Pulp and Paper Mills	18	3221	$8.76	$20.11	$0.40	$20.49	$0.29	$19.95	$36.55	$1.95	$0.42	$8.21	$12.60	$0.24	$68.87	$5.81
CPP Converted Paper Products	19	3222	$2.22	$6.31	$0.18	$4.72	$0.17	$3.50	$6.97	$0.93	$0.20	$2.77	$3.54	$0.12	$11.30	$0.04
PRN Printing	20	323	$0.15	-$0.10	-$0.07	$0.11	$0.08	$0.26	$2.43	$0.19	$0.03	$0.27	$0.20	$0.04	$0.50	$0.02
* Chemicals																
CHM Chemicals and gases	21	3251	$1.41	$39.33	$1.18	$5.64	$0.22	$8.87	$84.77	$1.38	$0.18	$7.11	$1.46	$5.06	$8.75	$0.64
RSN Resins	22	3252	$0.21	$4.71	$0.14	$0.68	$0.08	$1.07	$10.19	$0.22	$0.02	$0.87	$0.23	$0.61	$1.09	$0.09
FRT Fertilizer	23	3253	$0.09	$6.56	$0.03	$0.16	$0.07	$0.30	$3.11	$0.11	$0.01	$0.22	$0.11	$0.14	$0.34	$0.04
MED Drugs and medicine	24	3254	$0.34	$8.60	$0.26	$1.24	$0.10	$1.96	$18.65	$0.35	$0.04	$1.58	$0.37	$1.11	$1.96	$0.15
PAI Paints and adhesives	25	3255	$0.51	$20.70	$0.18	$0.65	$0.15	$0.94	$34.20	$0.40	$0.07	$1.11	$0.81	$0.36	$1.14	$0.09
SOP Soap	26	3256	$0.08	$1.12	$0.03	$0.17	$0.07	$0.27	$2.54	$0.10	$0.01	$0.24	$0.10	$0.15	$0.31	$0.04
OCM Other chemicals	27	3259	$0.78	$92.06	$0.67	$1.27	$0.19	$10.15	$603.59	$0.61	$0.11	$1.99	$1.32	$1.86	$4.38	$0.57
* Plastic and Rubber																
PLS Plastic	28	3261	$0.29	$2.08	$0.17	$1.90	$0.12	$1.29	$4.04	$0.20	$0.04	$1.35	$0.47	$0.18	$1.84	$0.04
RUB Rubber	29	3262	$0.23	$2.07	$0.12	$1.40	$0.10	$1.21	$5.62	$0.17	$0.03	$1.03	$0.37	$0.13	$1.63	$0.03
* Nonmetallic Minerals																
CLY Clay	30	3271	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.23	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
GLS Glass	31	3272	$0.06	$0.17	$0.00	$0.06	$0.07	$0.08	$0.53	$0.08	$0.00	$0.10	$0.08	$0.02	$0.13	$0.02
CEM Cement	32	3273	$0.62	$5.30	$0.21	$1.73	$0.15	$2.01	$13.28	$0.44	$0.09	$2.59	$0.99	$0.41	$2.90	$0.09
LIM Lime and Gypsum	33	3274	$0.20	$1.40	$0.06	$0.45	$0.09	$0.57	$3.57	$0.20	$0.03	$0.69	$0.31	$0.11	$0.79	$0.05

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
ONM Other Non-Metallic Minerals	34	3279	$0.35	$144.69	$0.31	$27.72	$0.07	$4.75	$261.84	$0.15	$0.01	$1.14	$25.93	$72.86	$15.36	$6.83
* Primary Metals																
I_S Iron and Steel	35	3311, 3312, 33151	$0.98	$11.56	$0.14	$1.44	$0.57	$2.48	$9.30	$3.59	$0.53	$5.43	$1.49	$17.05	$2.70	$10.93
ALU Aluminum	36	3313, 331521, 331524	$1.47	$9.55	$0.14	$1.93	$0.51	$1.14	$12.24	$4.05	$0.52	$7.26	$2.22	$22.84	$1.35	$12.36
OPM Other Primary Metals	37	3314, 331522, 331525, 331528	$0.18	$27.92	$0.08	$1.61	$0.08	$7.50	$0.87	$0.20	$0.03	$0.38	$0.10	$2.45	$2.35	$0.42
FMP Fabricated Metal Products	38	332	$2.47	$16.81	$3.85	$5.28	$0.42	$9.94	$47.70	$1.52	$0.55	$5.95	$2.87	$1.00	$27.89	$0.23
* Machinery and Equipment																
CEQ Construction and Ag Equip.	39	3331	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
IEQ Industrial Equipment	40	3332	$0.05	$1.46	$0.13	$0.02	$0.06	$0.03	$0.22	$0.07	$0.13	$1.14	$0.06	$0.01	$0.07	$0.02
SEQ Service Industry Equipment	41	3333	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
HVC HVAC Equipment	42	3334	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
MEQ Metalworking Equipment	43	3335	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
EEQ Engines	44	3336	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.23	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
CEQ General Equipment	45	3339	$0.05	$1.80	-$0.06	$0.02	$0.06	$0.01	$0.46	$0.40	$0.00	$0.01	$0.06	$0.20	$0.03	$0.02
* Electronic Equipment																
CPU Computers	46	3341	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
CMQ Communication Equipment	47	3342	$0.05	$0.11	$0.00	$0.02	$0.06	$0.03	$2.98	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
TVQ TV Equipment	48	3343	-$0.13	$0.01	$0.00	$0.01	$0.06	$0.00	-$0.07	$0.06	-$0.01	$0.02	$0.04	$0.01	$0.05	$0.02
SMI Semiconductor Equipment	49	3344	$0.05	$0.88	$0.15	$0.02	$0.06	$0.03	$0.22	$0.07	$0.26	$0.96	$0.06	$0.01	$0.07	$0.02
INS Instruments	50	3345	$0.06	$0.42	$0.10	$0.07	$0.07	$0.13	$0.35	$0.07	$0.03	$0.25	$0.09	$0.02	$0.21	$0.02
MGT Magnetic Recording Equip.	51	3346	$0.06	$0.16	$0.03	$0.06	$0.07	$0.12	$0.37	$0.07	$0.01	$0.07	$0.08	$0.02	$0.20	$0.02
ELQ Elec Equip. and Appliances	52	335	$0.06	$0.26	$0.06	$0.11	$0.07	$0.20	$0.45	$0.08	$0.01	$0.10	$0.10	$0.02	$0.32	$0.02
* Transport Equipment																
M_V Motor Vehicles	53	3361	$0.36	$1.39	$0.04	$1.39	$0.12	$20.42	$6.25	$0.42	$0.05	$1.27	$0.36	$0.23	$1.82	$0.03
TKB Truck Bodies	54	3362	$0.48	$2.32	$0.25	$0.49	$0.07	$0.80	$6.60	$0.67	$0.11	$1.96	$7.73	$0.20	$2.37	$0.02
MVP Motov Vehicle Parts	55	3363	$0.36	$0.75	$0.01	$1.39	$0.12	$2.55	$3.07	$0.42	$0.03	$0.86	$0.36	$0.23	$1.82	$0.03
ARC Aircraft	56	3364	$0.23	$21.42	$0.11	$16.58	$0.07	$42.07	$2.87	$0.32	$0.05	$8.37	$3.25	$40.44	$10.53	$7.13
R_R Rail Cars	57	3365	$0.05	$0.04	$0.00	$0.02	$0.06	$0.03	$0.22	$0.07	$0.00	$0.04	$0.06	$0.01	$0.07	$0.02
SHP Ships	58	3366	$0.06	$2.84	$0.80	$0.03	$0.06	$0.05	$25.20	$0.08	$0.03	$8.09	$0.28	$0.02	$0.21	$0.02
OTQ Other Transport Equipment	59	3369	$0.05	$0.31	$0.10	$0.02	$0.06	$0.05	$30.56	$0.07	$0.09	$0.18	$0.06	$0.01	$0.78	$0.06
FUR Furniture	60	337	$0.78	$15.18	$0.18	$8.41	$0.20	$27.18	$9.91	$0.87	$0.23	$4.13	$0.83	$7.44	$20.44	$0.04
MSC Miscellaneous Mfg.	61	339	$0.19	$85.27	$2.94	$0.14	$0.08	$0.21	$130.2 3	$0.11	$0.49	$3.77	$0.19	$0.04	$18.68	$0.02
****--- Services ---****																
* Wholesale and Retail Trade																
WHL Wholesale Trade	62	42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.17	$0.00	$0.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTL Retail Trade	63	44-45	$0.00	$17.77	$1.77	$0.00	$0.00	$1.78	$0.00	$0.52	$1.71	$14.22	$0.00	$0.00	$0.00	$0.00
* Transportation Services																

Exhibit J-2. Summary of CAAA-Related Private Costs: 2020 (Millions of 2006$)

Sector	**Sector Number**	***NAICS***	Oreg.	Penn.	R. Island	S. Car.	S. Dak.	Tenn.	Texas	Utah	Verm.	Virg.	Wash.	W. Virg.	Wisc.	Wyom.
ATP Air transportation	64	481	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTP Railroad transportation	65	482	$1.96	$5.98	$0.03	$1.53	$0.66	$3.51	$17.49	$1.67	$0.13	$4.84	$3.27	$2.74	$3.48	$4.99
WTP Water transportation	66	483	$1.63	$1.57	$0.32	$0.29	$0.01	$2.84	$14.77	$0.05	$0.17	$4.90	$10.72	$1.12	$0.18	$0.04
TTP Freight truck transportation	67	484	$83.01	$219.03	$19.54	$103.55	$17.08	$128.67	$723.24	$51.90	$89.82	$50.47	$115.64	$78.85	$78.13	$16.70
PIP Pipeline transport	68	486	$0.02	$1.88	$0.02	$0.58	$0.02	$0.89	$7.31	$0.11	$0.00	$3.93	$0.06	$1.42	$0.08	$0.17
OTP Other transportation svcs.	69	485, 487, 488	$0.03	$18.23	$0.34	$0.02	$0.00	$0.08	$62.32	$0.01	$0.00	$1.25	$0.06	$2.30	$2.07	$0.00
* Other Services																
INF Information	70	51	$0.09	$0.32	$0.04	$0.07	$0.01	$0.11	$0.99	$0.06	$0.02	$0.36	$0.43	$0.03	$0.13	$0.01
OFI Finance and Insurance	71	52	$0.00	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Business Services	72	53	$0.00	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Real Estate	73	54	$0.00	$11.44	$0.09	$0.00	$0.00	$0.00	$4.74	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Professional Services	74	55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administrative Services	75	56	$0.59	$36.87	$2.41	$1.70	$0.03	$10.14	$82.80	$0.81	$0.58	$5.48	$1.72	$5.31	$2.67	$0.08
EDU Education	76	61	$0.00	$1.44	$0.27	$0.00	$0.00	$0.17	$0.00	$0.00	$0.00	$0.16	$0.00	$0.00	$0.18	$0.00
DOC Health Care	77	62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Entertainment Services	78	71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Accomodations	79	72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Services	80	81	$0.37	$52.53	$1.24	$0.35	$0.09	$4.02	$36.48	$0.51	$0.40	$6.27	$0.63	$0.29	$8.42	$0.04
PUB Public Services	81	92	$7.50	$5.71	$0.12	$0.00	$0.00	$0.00	$35.11	$0.13	$0.00	$0.02	$7.00	$0.56	$0.12	$3.00
Households	82		$234.08	$1,024.19	$107.98	$187.64	$29.32	$397.76	$3,338.27	$210.96	$262.32	$334.94	$386.03	$240.33	$268.71	$28.91