Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis

Draft Report

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EPA Contract No. EP-D-04-006

June 2006

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EXHIBITS

ACRONYMS AND ABBREVIATIONS

AEO 2005	*Annual Energy Outlook 2005*
AIM	architectural and industrial maintenance
ARB	Air Resources Board
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CBP	County Business Patterns
CENRAP	Central Regional Air Planning Association
CI	compression ignition
CNG	compressed natural gas
CO	carbon monoxide
CTGs	control technique guidelines
DOE	U.S. Department of Energy
EGAS	Economic Growth Analysis System
EGUs	electricity generating units
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FCCUs	fluid catalytic cracking units
FCUs	fluid coking units
HAPs	hazardous air pollutants
HDDV	heavy-duty diesel vehicle
HDV	heavy-duty vehicle
I/M	inspection and maintenance
IPM	Integrated Planning Model
LADCO	Lake Michigan Air Directors Consortium
lbs	pounds
LDGV	light-duty gas vehicle
LDT	light-duty truck
LDV	light-duty vehicle
LEV	low-emission vehicle
LPG	liquefied petroleum gas
LTO	landing and takeoff
MACT	maximum achievable control technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MERR	mobile equipment repair and refinishing
MMBtu	million British thermal units
NAAQS	National Ambient Air Quality Standards
NAAs	nonattainment areas
NAICS	North American Industrial Classification System
NEI	National Emission Inventory
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review

ACRONYMS AND ABBREVIATIONS (continued)

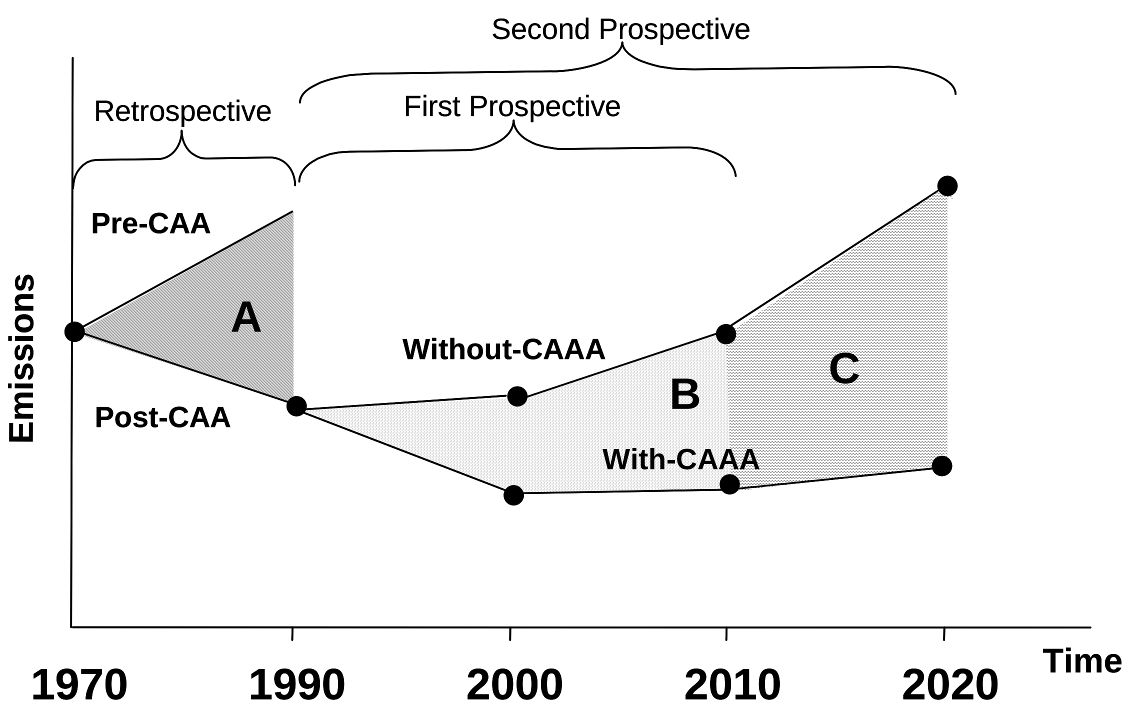
OAR	Office of Air and Radiation
OB	outboard
OTAQ	Office of Transportation and Air Quality
OTC	Ozone Transport Commission
Pechan	E.H. Pechan & Associates, Inc.
PM_{10}	particulate matter of 10 microns or less
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns or less
ppmvd	parts per million volume displacement
PWC	personal watercraft
PSD	prevention of significant deterioration
RACT	reasonably available control technology
RICE	reciprocating internal combustion engine
RPOs	regional planning organizations
RVP	Reid vapor pressure
RWC	residential wood combustion
SCC	Source Classification Code
SCR	selective catalytic reduction
S-I	spark ignition
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
TCEQ	Texas Commission on Environmental Quality
tpy	tons per year
ULNB	ultra-low NO_x burners
USDA	U.S. Department of Agriculture
VISTAS	Visibility Improvement – State and Tribal Association of the Southeast
VMT	vehicle miles traveled
VOCs	volatile organic compounds
VRS	vapor recovery system
WRAP	Western Regional Air Partnership

CHAPTER 1 - INTRODUCTION

Section 812 of the Clean Air Act Amendments of 1990 (CAAA) requires 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 required was a retrospective analysis, addressing the original CAA and covering the period 1970 to 1990. The retrospective was completed in 1997. Section 812 also requires 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.

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 outside peer review group, the Advisory Council for Clean Air Compliance Analysis (Council), and the Council provided comments, which have been incorporated into the technical analysis planning. This report describes the development of base and projection year emission estimates for the second prospective section 812 analysis. 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



The scope of this analysis is to estimate future emissions of criteria pollutants under two scenarios, depicted in schematic form in Exhibit 1-1 above:

1. A historical, "with-CAAA" scenario control case that reflects expected or likely future measures implemented since 1990 to comply with rules promulgated through September 2005[1]; 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 growth in population and economic activity and, therefore, in emissions attributable to economic and population growth.

Criteria pollutants addressed in this analysis include: volatile organic compounds (VOCs), oxides of nitrogen (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Estimates of current and future year ammonia (NH_3) emissions are also included in this study because of their importance in the atmospheric formation of secondary particles. Emissions of the remaining criteria pollutant, lead, are not addressed in this report because of the relatively modest impact of CAAA regulations on lead emissions.[2]

This report presents the results of EPA's analysis of the future effects of implementation of the CAAA's programs on air emissions from the following emission sectors: electricity generating units (EGUs), non-electricity generating unit point sources, nonroad engines/vehicles, on-road vehicles, and nonpoint sources. The study years for the analysis are 1990, 2000, 2010, and 2020.

The purpose of this report is to present the methods used to generate emissions projections under the two different control scenarios, and to provide emission summaries for each. Examples of programs modeled under this analysis include:

- Title I VOC and NO_x reasonably available control technology (RACT) requirements in ozone nonattainment areas (NAAs);
- Title II on-road vehicle and nonroad engine/vehicle provisions;
- Title III National Emission Standards for Hazardous Air Pollutants (NESHAPs);
- Title IV programs focused on emissions from electric generating units (EGUs).

The results of this analysis provide the input for the air quality modeling and benefits estimation stages of the second prospective analyses. The emission inputs to the modeling are more detailed than the summaries provided in this report. EPA plans to make those detailed files available to the public online at www.epa.gov/oar/sect812.

[1] 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 omissions (less than 10 tons per year VOCs) relative to the with-CAAA scenario. The primary MACT rule for coke oven emissions, however, involves much larger reductions and therefore is included in the with-CAAA scenario.

[2] Lead emissions were effectively controlled under regulations authorized by the original Clean Air Act. As a result, analysis of lead emissions is a major focus of the section 812 retrospective study.

Summary of Methods

The general method we apply to estimate emissions for a major source category is as follows:

1. Select a "base" inventory for a specific year. This involves selection of an historical year inventory from which projections will be based.
2. Select activity factors to use as trend indicators for projecting emissions. The activity factors should provide the best possible means for representing future air pollutant emissions levels absent controls, at the lowest feasible level of source-specific disaggregation.
3. Develop a database of scenario-specific emissions control factors, to represent emissions control efficiencies under the two scenarios of interest. The control factors are "layered on" to the projected emissions levels absent controls to estimate future emissions levels with those controls required for compliance with CAAA regulations.

This general method was applied for four of the five major source categories described in this report, and is depicted graphically in Exhibit 1-2 below. Note the term "final demand" in Exhibit 1-2 represents estimates of consumer demand for goods and services from specific sectors. Final demand is a key input to CGE modeling and to some components of the emissions modeling which have their own representations of supply (e.g., the EGU sector Integrated Planning Model, IPM), but most of the emissions modeling is driven by estimates of projected economic output, which combines demand and supply projections and modeling.

Air pollutant emissions for the fifth category, EGUs, were estimated by application of the Integrated Planning Model, a model developed by ICF Consulting that estimates generation and emissions for each EGU through an optimization procedure that considers costs of electric generation, costs of pollution control, and external projections of electric demand to forecast the fuel choice, pollution control method, and generation for each unit considered in the model. The EGU modeling is a fundamentally different method for estimating emissions than the general method we use for other source categories. Our ability to use an optimization model for EGU emissions modeling reflects the enhanced data and information available for the relatively large EGU emissions sources, as well as many years of EPA and energy industry experience in modeling the national and regional markets for electricity. The EGU modeling is described in more detail in Chapter 4.

Selection Of Base Year Inventory

Exhibit 1-3 summarizes the key databases that were used in this study to estimate emissions for historic years 1990 and 2000. These two years are the respective base years for preparing emission projections for the *without*- and *with-CAAA* scenarios for 2010 and 2020.

The *without-CAAA* scenario emission projections are made from a 1990 base year. For EGU and non-EGU point sources, 1990 emissions are estimated using the 1990 EPA National Emission Inventory (NEI) point source file. This file is consistent with the emission estimates used for the First Section 812 Prospective and is thought to be the most comprehensive and complete representation of point source emissions and associated activity in that year. Similarly, the 1990 EPA NEI nonpoint source file (known at the time as the area source file) – with a few notable exceptions – is used to estimate 1990 nonpoint source sector emissions. The exceptions are where 1990 emissions were re-computed using updated methods developed for the 2002 National Emissions Inventory (NEI) for selected source categories with the largest criteria pollutant emissions and most significant methods changes. The updated methods are described in more detail in Chapter 7.

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

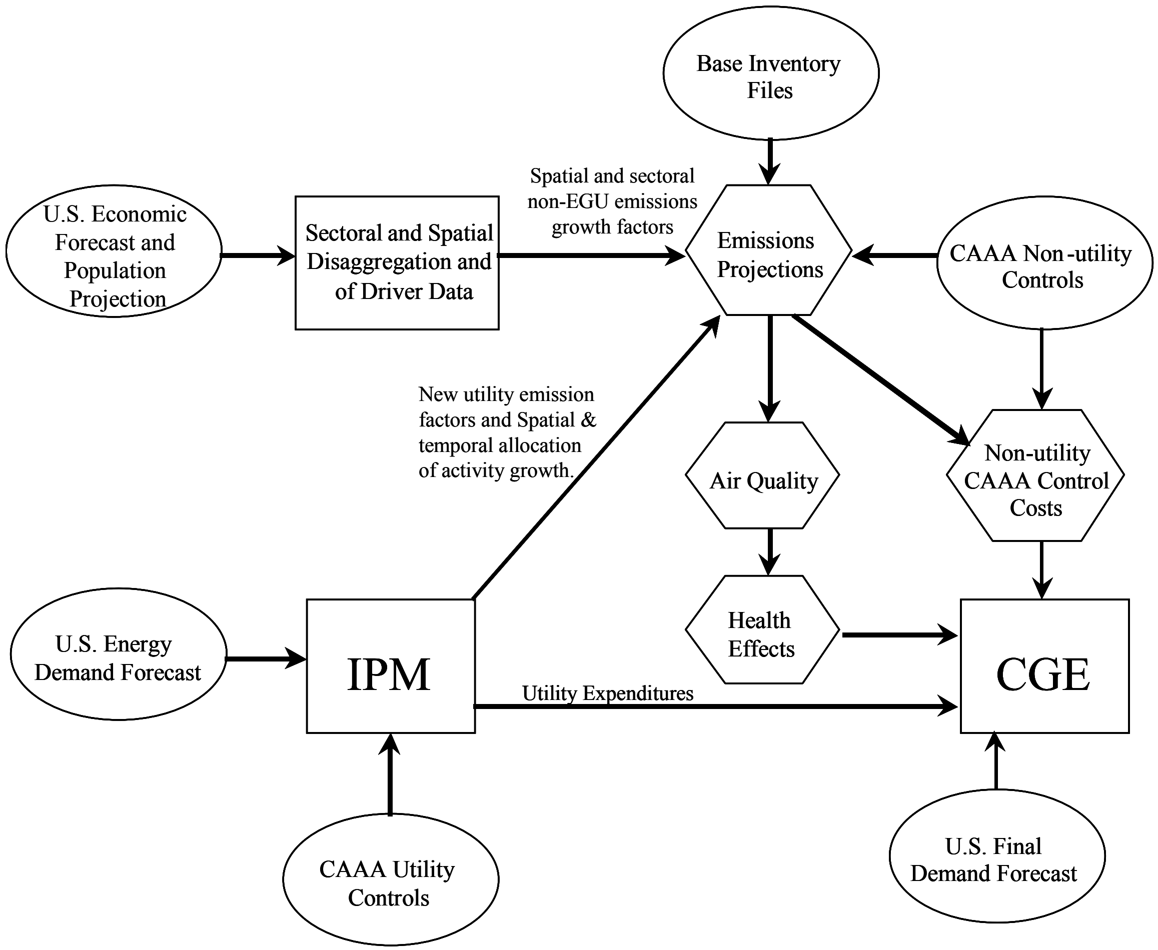


Exhibit 1-3. Base Year Emission Data Sources for the *With-* and *Without-CAAA* Scenarios

Sectors	*Without-CAAA* Scenario – 1990	*With-CAAA* Scenario – 2000
Non-EGU Point	1990 EPA Point Source NEI	2002 EPA Point Source NEI (Draft)
EGU	1990 EPA Point Source NEI	Estimated by the EPA Integrated Planning Model for 2001
Off-Road/Nonroad	NONROAD 2004 Model Simulation for Calendar Year 1990	NONROAD 2004 Model Simulation for Calendar Year 2000
On-Road	MOBILE6.2 Emission Factors and 1990 NEI VMT Database	MOBILE6.2 Emission Factors and 2000 NEI VMT Database. The California Air Resources Board (ARB) supplied estimates for California
Nonpoint	1990 EPA Nonpoint Source NEI with Adjustments for Priority Source Categories	2002 EPA Nonpoint Source NEI (Draft)

The 1990 onroad and nonroad vehicle/engine sector emissions were estimated independently for this project using consistent modeling approaches and activity estimates across the scenarios and years of interest. For example, MOBILE6.2 emission factors and 1990 and 2000 NEI vehicle miles traveled (VMT) databases were used to estimate onroad vehicle emissions for 1990 and 2000. Similarly, EPA's NONROAD 2004 model was used to estimate 1990 and 2000 emissions for nonroad vehicles/engines.

For calendar year 2000, *with-CAAA* scenario non-EGU point source emissions were estimated using the 2002 EPA NEI point source file (draft). We selected the year 2002 NEI to represent the year 2000 estimates for two reasons: 1) because the 2002 NEI incorporates a number of emissions methods refinements over the 1999 NEI, improving the accuracy of the base year estimate; and 2) because we believe that emissions for the year 2000 for this category are not significantly different from emissions for the year 2002. The draft NEI point source file was used because the final version was not available at the time this analysis was performed. For nonpoint sources, *with-CAAA* scenario emissions in calendar year 2000 also were estimated using the 2002 EPA NEI nonpoint source file (final), for the same reasons.

The logic for these base year inventory choices relates to the specific definitions of the scenarios themselves. The *with-CAAA* scenario tracks compliance with CAAA requirements over time; as a result, the best current basis for projecting the *with-CAAA* scenario incorporates decisions made since 1990 to comply with the act. The 2002 NEI provides the best current understanding of technologies applied to meet emissions reductions mandated under the CAAA. Over the next several decades, however, we would expect that the mix of economic activity across polluting sectors will change. In addition, we would expect that continued technological progress could improve the effectiveness and/or reduce the cost of applying these technologies. Pollution prevention and changes in production methods could also lead to reductions in air pollution. The change in the mix of economic activity is addressed directly by our choice of activity drivers for the projections, as discussed in the next section. Addressing the pace of technological progress is more difficult; in many cases, we have only limited ability to forecast technological advancements and their effect on air pollutant emissions. In other cases, we can use the pace of technological progress to date to project the pace of future improvements. To address this factor, the overall analytical plan includes an assessment of the effects of "learning by doing" on costs, in a sector-specific fashion. This is consistent with our assessment that, for most of the Federal measures assessed as part of the *with-CAAA* scenario, which require specific emissions reductions, technologies, or caps, emissions outcomes will not be affected by technological progress, but the costs of those reductions will be affected.[3] It is also consistent with the trend in emissions just prior to 1990, as documented in the First Prospective analysis. Just prior to passage of the CAAA, the steep downward emissions trends that had been seen in the 1970's and early 1980's for many pollutants were starting to be reversed - that is, emissions were starting to move upward as economic activity continued but the stringency of standards remained largely fixed.

The *without-CAAA* scenario involves freezing the stringency of regulation at 1990 levels. Faced with the difficult task of projecting a counterfactual scenario, the Project Team considered two options:

1. base the *without-CAAA* scenario on 1990 vintage emissions rates, and adjust the rates for economic activity over time; and
2. base the *without-CAAA* scenario on recent emissions rates, and attempt to simulate the effect of removing CAAA controls in each target year.

The Project Team chose the former approach for two reasons. First, we found that removing CAAA controls from the *with-CAAA* scenario would be a very difficult task. While the subsequent chapters show that it is feasible to simulate the marginal effect of CAAA controls in projected years, a process that mirrors the type of analysis EPA routinely performs for Regulatory Impact Analyses, for the year 2000 it is not as straightforward. Second, the Project Team concluded that projecting a *without-CAAA* scenario based on a simulated year 2000 counterfactual was more problematic than using historical year results for 1990 that reflect a control scenario consistent with our definition of the *without-CAAA* scenario.

Selection of Activity Factors for Projections

Criteria pollutant emissions were projected to 2000 (for the *without-CAAA* scenario), 2010, and 2020 to estimate future year emission levels. As noted above, emissions were projected under two scenarios:

Without-CAAA – applies expected increases in activity levels with no additional controls implemented beyond those that were in place when the CAAA were passed.

With-CAAA – applies expected increases in activity levels and incorporates the effects of controls mandated under the 1990 Amendments to the CAA.

Exhibit 1-4 summarizes the modeling approach used to project emissions for each of the major sectors.

[3] The issue of the effect of technological progress is addressed in much greater detail in the report on direct costs, which is currently in progress.

Exhibit 1-4. Modeling Approach by Major Sector

Sector	Growth Forecast	Controls Modeling Approach
Non-EGU Point	U.S. Department of Energy (DOE) *Annual Energy Outlook 2005* forecasts	Based on control factors developed by the five Regional Planning Organizations (RPOs), and California information from the ARB
EGU	DOE *Annual Energy Outlook 2005* forecasts	Integrated Planning Model (IPM)
Nonroad	EPA NONROAD Model growth forecasts are largely based on historical trends in national engine populations by category/sub-category of engine	EPA NONROAD Model
Onroad	National VMT Forecast from *Annual Energy Outlook 2005 (AEO 2005)*	MOBILE6.2 emission factors
Nonpoint	DOE *AEO 2005* forecasts	Based on control factors developed by the five RPOs, and California information from the ARB

One of the major objectives of this study was to provide the maximum feasible internal consistency in the use of projection methods. We expect that energy demand, energy prices, and diffusion rates of technologies are closely tied to the rate of growth of future air pollutant emission and are closely linked to expectations of the future growth path of the U.S. economy. Economic growth projections enter the emissions analyses of the Second Prospective in three places:

- the electricity demand forecast included in IPM (this forecast has in the recent past been based on the reference case economic growth assumptions included in the Department of Energy's AEO 2005);
- the fuel consumption forecast for non-utility sectors that serves as the activity driver for major fuel-consuming sources (this forecast is also based on the reference case economic growth assumptions included in AEO); and
- the economic growth projections that serve as activity drivers for several other sources of air pollutants (see Exhibit 1-2 above).

In addition, the AirControlNet model that we use to assess compliance options for meeting the new NAAQS (described in Chapter 8), and which also calculates associated emissions implications, has recently been re-designed to accept energy prices and labor rates as global inputs.

For this analysis, the Agency chose to use fully integrated economic growth, energy demand, and fuel price projections for "central case" economic growth scenarios. The primary advantage of this approach is that it allows the project team to conduct an internally consistent analysis of economic growth across all emitting sectors. In March 2005, the project team identified an economic/energy modeling system that could assess the impacts of alternative energy demand, fuel pricing, and technology assumptions in a fully integrated manner. The system chosen was the Department of Energy's National Energy Modeling System (NEMS). Our central case emissions estimates, described in this document, rely on the DOE Annual Energy Outlook (AEO) 2005 "reference case" scenarios. A major strength of this approach is the integrated nature of the key scenario driver data.

The Agency made this choice for two reasons: (1) the SAB Council strongly emphasized the importance of internal analytical consistency in its review of the Analytic Blueprint; (2) consistent low-growth and high-growth projections are available in DOE's Annual Energy Outlook, facilitating analysis of the impact of alternative driver data in our future uncertainty analyses for the emissions projections. Chapter 2 provides a much more detailed explanation of the application of growth factors to three of the major source categories - the methods for EGUs and nonroad engine emissions are described within the relevant souce category chapters (Chapter 4 and 5, respectively).

Applying Controls to the With-CAAA Scenario

Exhibit 1-5 provides a summary of the CAAA controls applied to estimate emissions for the *with-CAAA* scenario. For reference, we also indicate in the exhibit which controls were in place as of 1990 and are therefore implicitly incorporated in both scenarios. Chapters 3 through 7 provide detailed explanations of the controls applied in the *with-CAAA* scenario, as well as the results for each major sector.

This analysis is designed to reflect controls implemented by all levels of government to comply with CAAA controls. For example, Title I of the Clean Air Act requires the Agency to establish some Federal controls that apply nationwide, but this portion of the Act is focused on the establishment and compliance with National Ambient Air Quality Standards (the NAAQS). NAAQS compliance results in differing measures being implemented at the local level in response to local air quality conditions, the mix of polluting sources, and the cost of available pollution control measures. Exhibit 1-6 illustrates how the control requirements at the Federal, regional, local, and source levels are considered in order to determine the most stringent (or binding) requirement by source category for application in the core scenarios analysis. The core scenarios analysis is what is described in this report version, and it includes the measures that have been adopted by areas to meet attainment requirements for the 1-hour ozone NAAQS, and the PM_{10} NAAQS.

Exhibit 1-5. Projection Scenario Summary by Major Sector in the Second Prospective

Sector	*Without-CAAA*	*With-CAAA**	
Non-Electricity Generating Unit Point	RACT held at 1990 levels	**NO_x**:	RACT for all NAAs (except NO_x waivers), Ozone Transport Commission (OTC) small NO_x source model rule (where adopted), Cases and settlements, NO_x measures included in ozone State Implementation Plans (SIPs) and SIP Call post-2000, Additional measures to meet PM and ozone National Ambient Air Quality Standards (NAAQS).
		VOC/HAP:	RACT for all NAAs, VOC measures included in ozone SIPs, 2-, 4-, 7-, and 10-year maximum achievable control technology (MACT) standards, New control technique guidelines (CTGs).
		SO_x:	Cases and settlements, Additional measures to meet revised PM NAAQS.
		NO_x/VOC:	Rate-of-Progress (3 percent per year) requirements (further reductions in VOC), Early action compacts.
Electricity Generating Unit	RACT and New Source Review (NSR) held at 1990 levels. 250 ton Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) held at 1990 levels.	**NO_x**:	RACT and NSR for all non-waived (NO_x waiver) NAAs, SIP Call post -2000, Phase II of the OTC NO_x memorandum of understanding, Title IV Phase I and Phase II limits for all boiler types, 250 ton PSD and NSPS, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule, Cases and settlements, Additional measures to meet PM and ozone NAAQS.
		SO_x:	Title IV emission allowance program, CAIR, Clean Air Mercury Rule, Cases and settlements, Additional measures to meet revised PM NAAQS.

Exhibit 1-5 (continued)

Sector	*Without-CAAA*	*With-CAAA**	
Non-road Engines/ Vehicles**	Controls (engine standards) held at 1990 levels.	**NO_x**:	Federal Phase I and II compression ignition (CI) and spark-ignition (S-I) engine standards, Federal locomotive standards, Federal commercial marine vessel standards, Federal recreational marine vessel standards, NO_x measures included in ozone SIPs, Nonroad Diesel Rule.
		VOC/HAP:	Federal Phase I and II S-I engine standards, Federal recreational marine vessel standards, Federal large SI/recreational vehicle engine standards, Federal large SI/evaporative standards, VOC measures included in ozone SIPs.
		CO:	Federal large S-I evaporative standards, Federal Phase I and II S-I engine standards.
		PM:	Federal Phase I and II CI engine standards, Federal Phase I and II S-I engine standards, Federal locomotive standards, Federal commercial marine vessel standards, Nonroad Diesel Rule.
		SO_x:	Nonroad Diesel Rule, Gasoline fuel sulfur limits.

Exhibit 1-5 (continued)

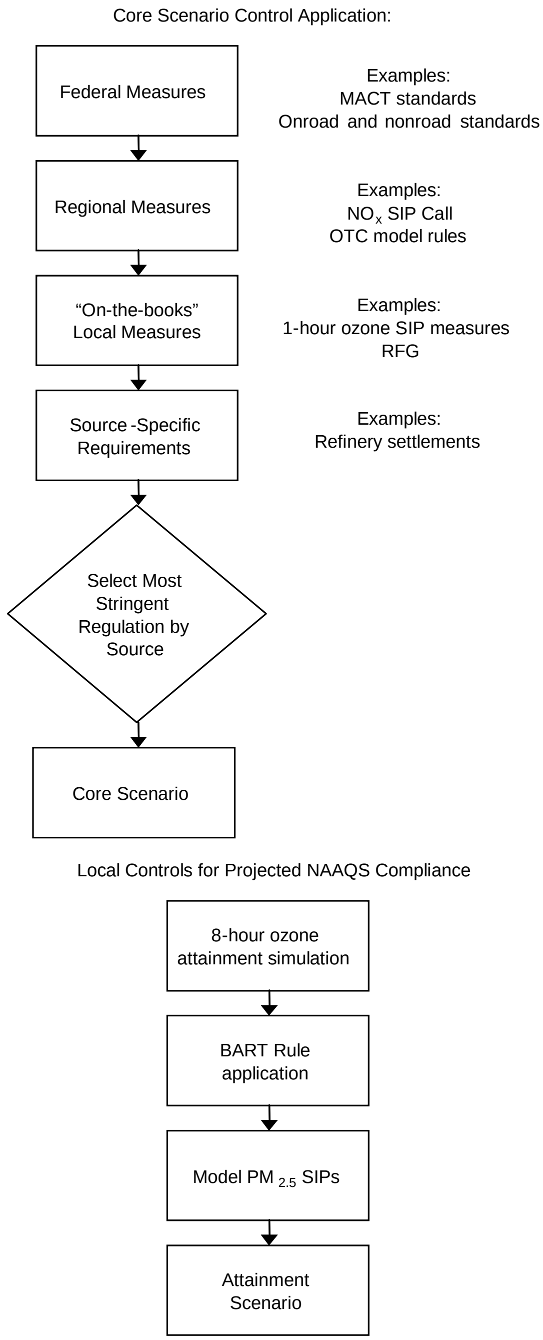
Sector	*Without-CAAA*	*With-CAAA**	
On-road Motor Vehicles***	Federal Motor Vehicle Control Program - engine standards set prior to 1990. Phase 1 Reid vapor pressure (RVP) limits. Inspection and maintenance (I/M) programs in place by 1990.	**NO_x** :	Tier 1 tailpipe standards (Title II), Tier 2 tailpipe standards, 49-State low-emission vehicle (LEV) program (Title I), I/M programs for ozone and CO NAAs (Title I), Federal reformulated gasoline for ozone NAAs (Title I), California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), NO_x measures included in ozone SIPs, heavy-duty diesel vehicle (HDDV) standards, HDDV defeat device settlements Additional measures to meet PM and ozone NAAQS.
		VOC/HAP:	Tier 1 tailpipe standards (Title II), Tier 2 tailpipe standards, 49-State LEV program (Title I), I/M programs for ozone and CO NAAs (Title I), Phase 2 RVP limits (Title II), Federal reformulated gasoline for ozone NAAs (Title I), California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), VOC measures included in ozone SIPs, HDDV standards, Enhanced evaporative test procedures, Additional measures to meet PM and ozone NAAQS.
		CO:	49-State LEV program (Title I), I/M programs for CO NAAs (Title I), Tier 2 tailpipe standards, California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), Oxygenated fuel in CO NAAs (Title I), HDDV standards.
		PM:	HDDV standards, diesel fuel sulfur content limits (Title II) (1993).
		SO_x:	Diesel fuel sulfur content limits (Title II) (1993), HDDV standards and associated diesel fuel sulfur content limits, Gasoline fuel sulfur limits, Tier 2 tailpipe standards, Additional measures to meet new PM NAAQS.

Exhibit 1-5 (continued)

Sector	*Without-CAAA*	*With-CAAA**	
Area/Nonpoint	Controls held at 1990 levels	**NO_x:**	RACT requirements, NO_x measures included in ozone SIPs, Additional measures to meet PM and ozone NAAQS.
		VOC/HAP:	RACT requirements, New CTGs, 2-, 4-, 7-, and 10-year MACT Standards, Onboard vapor recovery (vehicle refueling), Stage II vapor recovery systems (VRS), Federal VOC rules for architectural and industrial maintenance (AIM) coatings, autobody refinishing, and consumer products, Additional measures to meet PM and ozone NAAQS.
		PM:	$PM_{2.5}$ and PM_{10} NAA controls, Co-control from VOC measures included in ozone SIPs.
		NO_x/VOC:	Rate-of-Progress (3% per year) requirements (further reductions in VOC), Model rules in OTC States, Early action compacts.

NOTES: *Also includes all *Without-CAAA* measures.
**The nonroad mobile source standards included in the *With-CAAA* scenario are based on the standards found within the NONROAD2004 emissions inventory model. Three other nonroad mobile standards, not captured by the NONROAD2004 model, are also included in the *With-CAAA* scenario: the locomotive standards, commercial marine engine standards, and the large SI/evaporative standards.
***The motor vehicle mobile source standards included in the *With-CAAA* scenario are based on the standards found within the MOBILE6.2 emissions inventory model. Note that emissions associated with the Final Rule for Cleaner Highway Motorcycles (promulgated in 2004) are not accounted for in the MOBILE6.2 model, and are not included in the *With-CAAA* scenario.

Exhibit 1-6. Control Applications in the Core Scenario and Local Controls for NAAQS Compliance Analysis



Summary of Results

Exhibit 1-7 summarizes the national emission estimates by sector for each of the scenario years evaluated in this study. Exhibit 1-8 provides emission results for all sectors combined for the same set of scenario years. Exhibit 1-9 provides a graphic summary of the reductions associated with CAAA implementation for each pollutant, disaggregated by emitting sector. The ammonia emissions results, because they do not always involve reductions across the two scenarios, are not reasonably presented in this format, so are omitted from Exhibit 1-9. The results are discussed in detail in each of the subsequent chapters.

[NOTE: The analysis of local controls to meet attainment requirements for 8-hour ozone and $PM_{2.5}$ ambient standards is ongoing and will be described in Chapter 8, when completed. Key components of this analysis include estimating the incremental emission reductions expected to be associated with attaining the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the Federal BART rule. These emission reductions will be measured from the core scenarios analysis with-CAAA scenario. The bottom part of Exhibit 1-6 depicts the key parts of this local controls analysis.]

Draft - June 23, 2006

Exhibit 1-7. Summary of National (48 State) Emission Estimates by Scenario Year

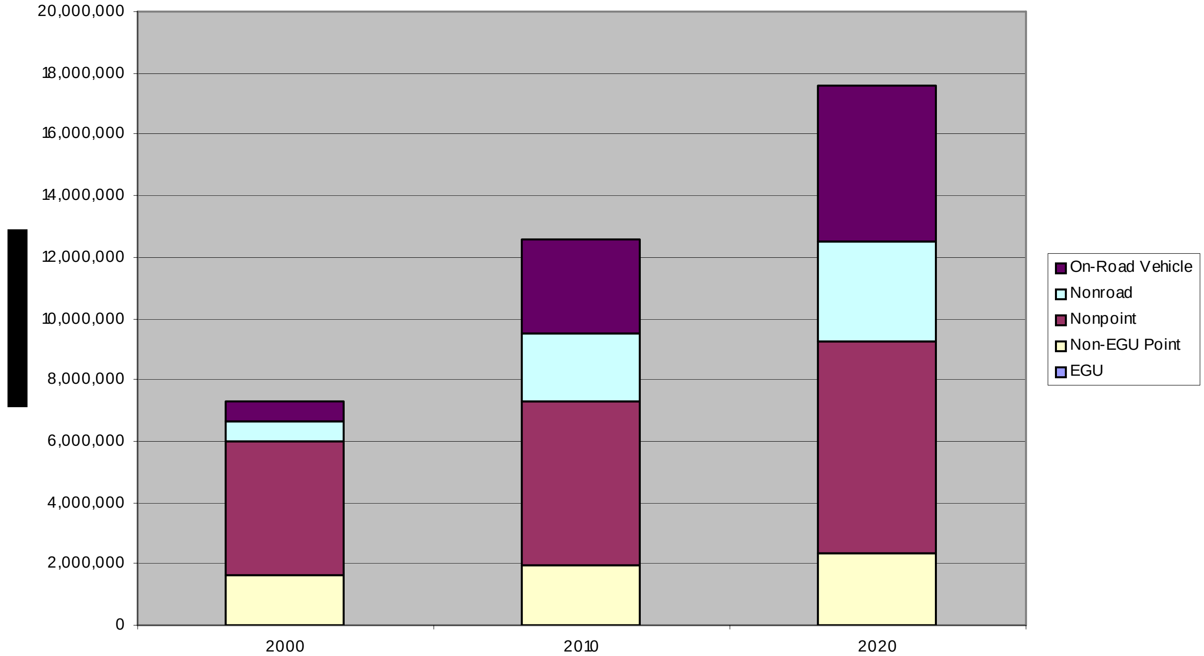
Pollutant	Sector	1990	2000 *without-CAAA*	2000 *with-CAAA*	2010 *without-CAAA*	2010 *with-CAAA*	2020 *without-CAAA*	2020 *with-CAAA*
VOC	EGU	34,558	40,237	40,882	43,333	42,661	48,001	46,991
	Non-EGU Point	2,609,368	3,083,990	1,441,342	3,480,293	1,493,995	4,029,231	1,714,402
	Nonpoint	11,678,038	12,907,437	8,544,345	14,164,412	8,872,248	16,618,917	9,715,546
	Nonroad	2,665,710	3,217,810	2,564,790	4,076,796	1,874,723	4,753,500	1,489,644
	On-Road Vehicle	9,327,660	5,872,983	5,245,756	5,734,012	2,614,007	6,784,539	1,670,617
NO_x	EGU	6,410,533	7,734,000	4,493,981	8,349,482	2,437,219	8,686,216	1,986,463
	Non-EGU Point	3,133,450	3,328,534	2,278,144	3,554,720	2,191,430	3,996,770	2,418,153
	Nonpoint	4,801,016	4,691,751	3,885,707	4,881,947	3,688,289	5,242,354	3,725,010
	Nonroad	2,067,745	2,190,711	2,091,459	2,664,838	1,643,413	3,162,409	998,918
	On-Road Vehicle	9,535,993	8,782,108	8,073,738	9,105,919	4,349,062	10,695,419	1,915,842
CO	EGU	303,713	496,430	503,306	602,048	617,860	750,538	771,654
	Non-EGU Point	5,667,404	6,466,885	3,138,265	6,808,311	3,330,740	7,381,762	3,713,336
	Nonpoint	17,514,726	16,604,526	14,613,968	15,761,435	14,605,108	16,271,263	15,451,487
	Nonroad	22,176,262	25,458,930	22,330,110	31,541,817	26,229,083	37,199,473	28,999,459
	On-Road Vehicle	109,566,997	79,037,081	67,130,866	80,491,386	42,387,967	95,549,545	36,239,508
SO_2	EGU	15,831,702	18,146,659	10,819,399	18,867,532	6,365,458	18,738,860	4,270,125
	Non-EGU Point	4,293,268	4,261,741	2,198,926	4,761,255	2,281,643	5,209,932	2,490,285
	Nonpoint	2,469,598	2,179,658	1,875,282	2,573,424	1,877,630	3,171,574	1,941,752
	Nonroad	163,254	178,247	177,095	225,300	16,930	270,252	2,750
	On-Road Vehicle	500,064	632,766	253,592	797,345	29,954	986,882	36,457
PM_{10}	EGU	530,663	751,696	728,719	834,655	658,151	896,790	637,311
	Non-EGU Point	1,277,270	1,464,183	498,632	1,668,399	498,256	1,881,910	589,650
	Nonpoint	25,155,038	25,303,549	19,329,848	24,656,631	18,844,942	25,908,596	19,015,260
	Nonroad	308,562	286,623	265,778	323,187	202,507	367,252	131,185
	On-Road Vehicle	384,733	247,056	220,854	229,246	154,216	268,733	135,559
$PM_{2.5}$	EGU	357,674	634,287	610,638	704,443	529,163	762,326	506,512
	Non-EGU Point	722,442	828,322	425,087	939,451	441,316	1,065,848	521,514
	Nonpoint	5,790,623	5,879,111	4,103,247	5,749,651	4,060,025	6,137,398	4,166,547
	Nonroad	283,960	263,798	244,620	297,466	186,440	338,036	120,854
	On-Road Vehicle	321,852	191,723	165,515	169,690	96,356	199,153	70,899
NH_3	EGU	0	3,217	3,162	1,023	822	612	559
	Non-EGU Point	243,615	236,126	931,996	237,459	1,073,038	255,636	1,274,891
	Nonpoint	3,509,844	3,973,874	3,551,567	4,196,096	3,713,161	4,507,484	3,986,783
	Nonroad	1,530	1,789	1,715	2,248	2,042	2,665	2,399
	On-Road Vehicle	154,103	272,569	272,464	336,083	334,417	397,618	395,319

 Draft - June 23, 2006

Exhibit 1-8. Emission Totals and Reductions by Pollutant - All Sectors (thousand tons per year)

		2000			2010			2020		
Pollutant	**1990**	***without-CAAA***	***with-CAAA***	**Reduction**	***without-*CAAA**	***with-CAAA***	**Reduction**	***without-CAAA***	***with-CAAA***	**Reduction**
VOC	26,315	25,122	17,837	*7,285*	27,499	14,898	*12,601*	32,234	14,637	*17,597*
NO_x	25,949	26,727	20,823	*5,904*	28,557	14,309	*14,248*	31,783	11,044	*20,739*
CO	155,229	128,064	107,717	*20,347*	135,205	87,171	*48,034*	157,153	85,175	*71,978*
SO_2	23,258	25,399	15,324	*10,075*	27,225	10,572	*16,653*	28,378	8,741	*19,637*
PM_{10}	27,400	27,541	20,558	*6,983*	27,145	19,965	*7,180*	29,323	20,509	*8,814*
$PM_{2.5}$	7,220	7,285	5,064	*2,221*	7,294	4,921	*2,373*	8,503	5,386	*3,117*
NH_3	3,909	4,488	4,761	*-273*	4,773	5,123	*-350*	5,164	5,660	*-496*

Exhibit 1-9. Reductions Associated with CAAA Compliance by Emitting Sector



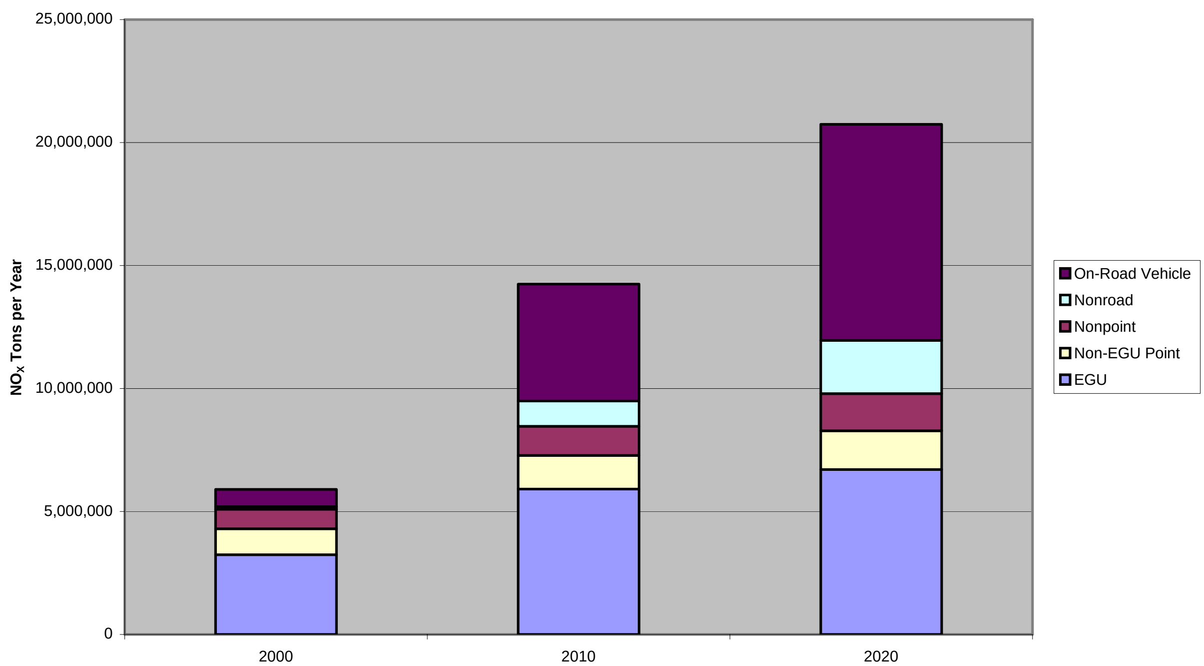
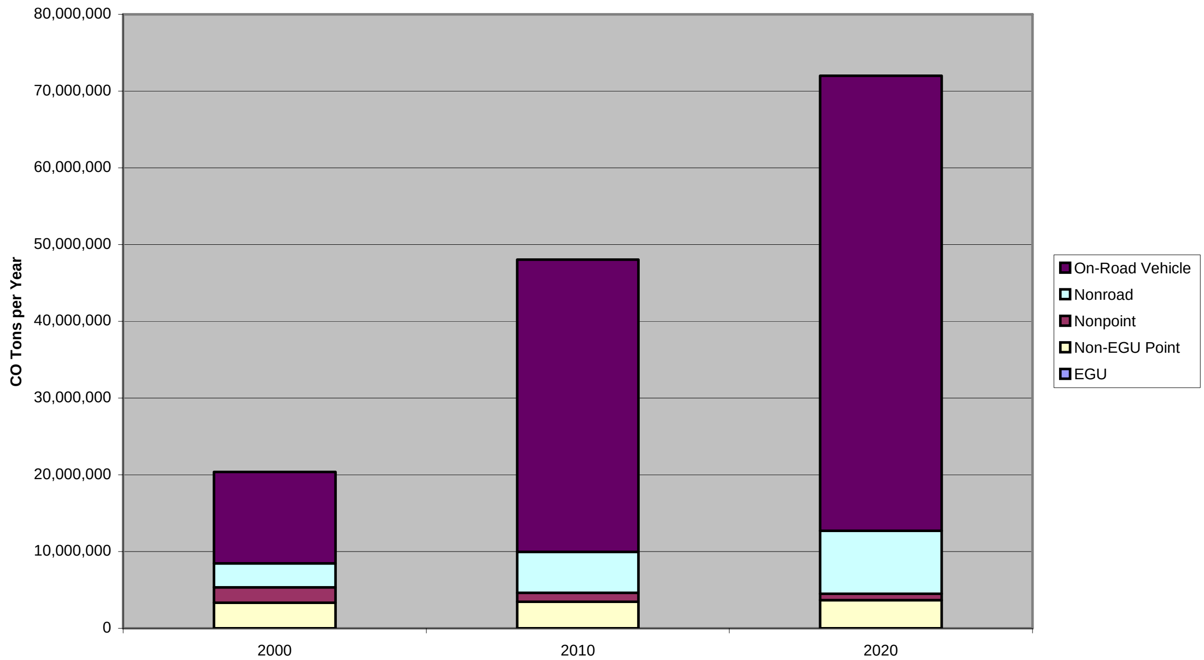


Exhibit 1-9. (continued)



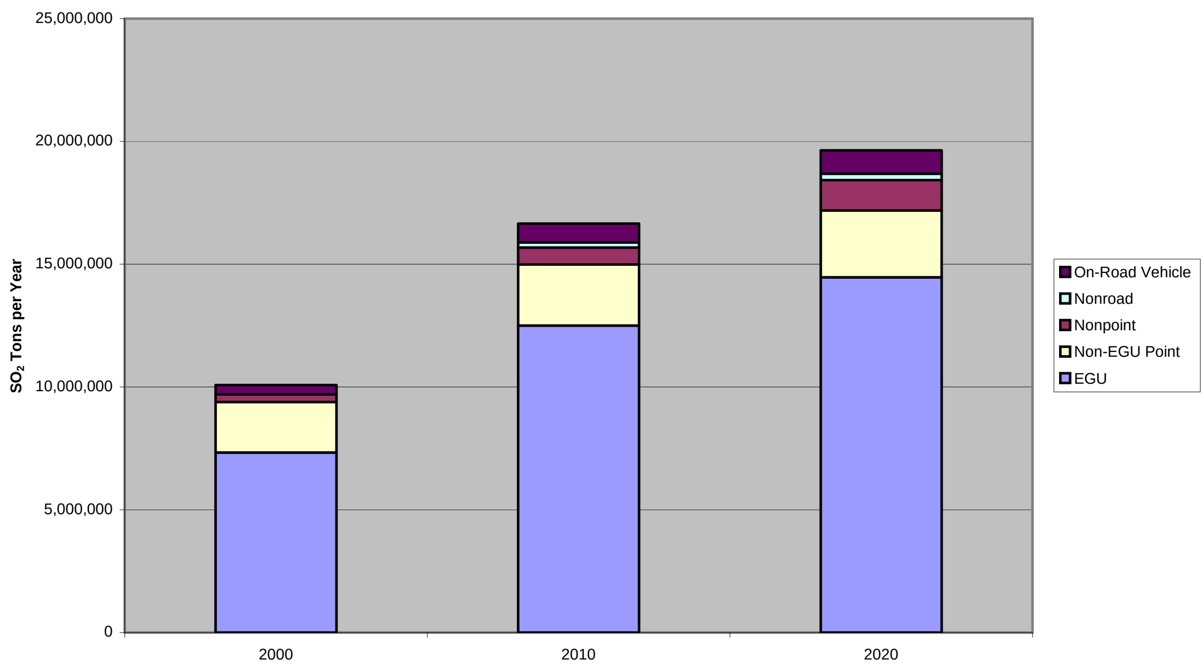
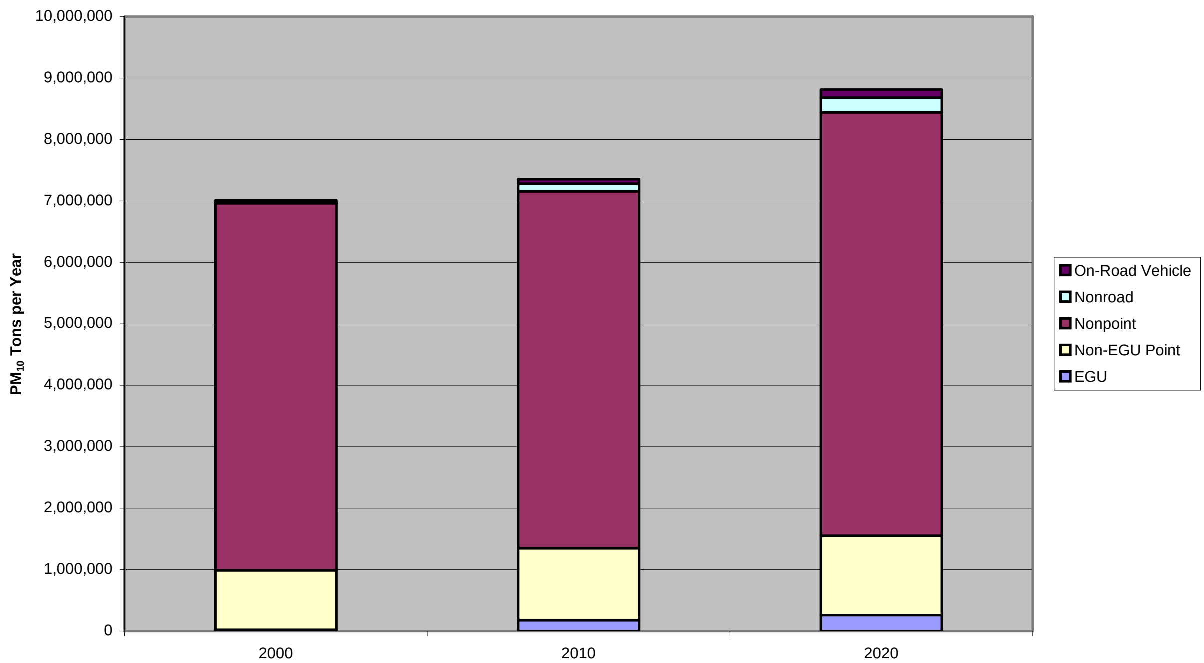
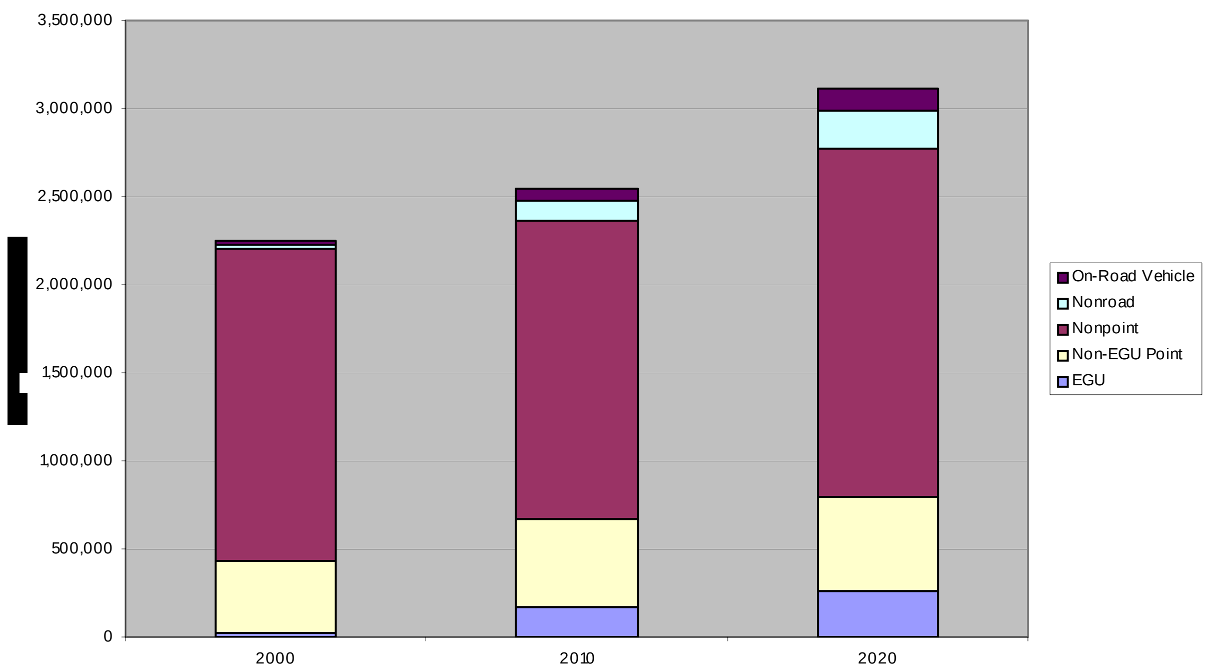


Exhibit 1-9. (continued)





CHAPTER 2 - EMISSION ACTIVITY INDICATORS

This chapter describes the development of emission activity factors that reflect the projected ratios of 2000, 2010, and 2020 emission activity to 1990 emission activity (for *without-CAAA* case emissions modeling) and ratios of 2010 and 2020 emission activity to 2002 emission activity (for *with-CAAA* case emissions modeling).[4] We develop emission activity levels for energy producing and consuming source categories from historical/forecast energy production/consumption data. It is not feasible, however, to develop estimates of actual emission activity levels for every non-energy related source category. Therefore, we derive historical and forecast changes in emission activity levels for these source categories from surrogate socioeconomic indicator data that are more readily available than emission activity data. The process of matching socioeconomic indicator data to source categories is described in this chapter.

As summarized in Chapter 1, for most source categories uncontrolled emissions are estimated by multiplying an emission factor by the level of emission-generating activity upon which the emission factor is based. For example, current guidance for estimating uncontrolled annual VOC emissions from gasoline service station underground storage tank breathing and emptying is to multiply the annual volume of service station gasoline throughput by an emission factor of 1.0 pounds of VOC per 1,000 gallons of gasoline (ERG, 2001). In this example, the volume of gasoline passing through service station underground storage tanks is the emissions activity. Ignoring potential process changes that may alter the relationship between the emission activity indicator and emissions (i.e., increase or decrease the emission factor), emission activity changes are proportional to changes in uncontrolled emissions.

The first section of this chapter describes the energy and socioeconomic data that were used as the starting point for estimating activity for three of the five major source categories addressed in this document: non-EGU point; mobile sources; and nonpoint sources. The discussion below also pertains to the use of such data for projecting nonroad source categories that are not incorporated into EPA's NONROAD emissions model (hereafter referred to as "miscellaneous" nonroad source categories).[5] The second section of this chapter is a discussion of alternative data sources and methods that were used to estimate emission activity estimates for a small number of source categories for which there are not readily available activity indicators. The final section of this chapter describes how growth indicators were assigned to emission sources in the base year inventory.

Note that this chapter includes only minimal discussion of activity indicators for mobile sources. For mobile sources, the process of projecting activity involves simply taking the *AEO 2005* VMT projections for target years of interest, disaggregating spatially and to vehicle class, and using the results as input for the MOBILE 6 model. The process of disaggregation to MOBILE 6 vehicle categories and to the county level is described in Chapter 6. In addition, the process for developing appropriate activity factors for EGU and nonroad engine sources is described in Chapters 4 and 5, respectively.

Energy And Socioeconomic Data Emission Activity Indicators

Energy Consumption Data

In keeping with past EPA practice, this study relies on energy data from the U.S. Department of Energy (DOE)'s Energy Information Administration (EIA) to backcast/forecast energy consumption and

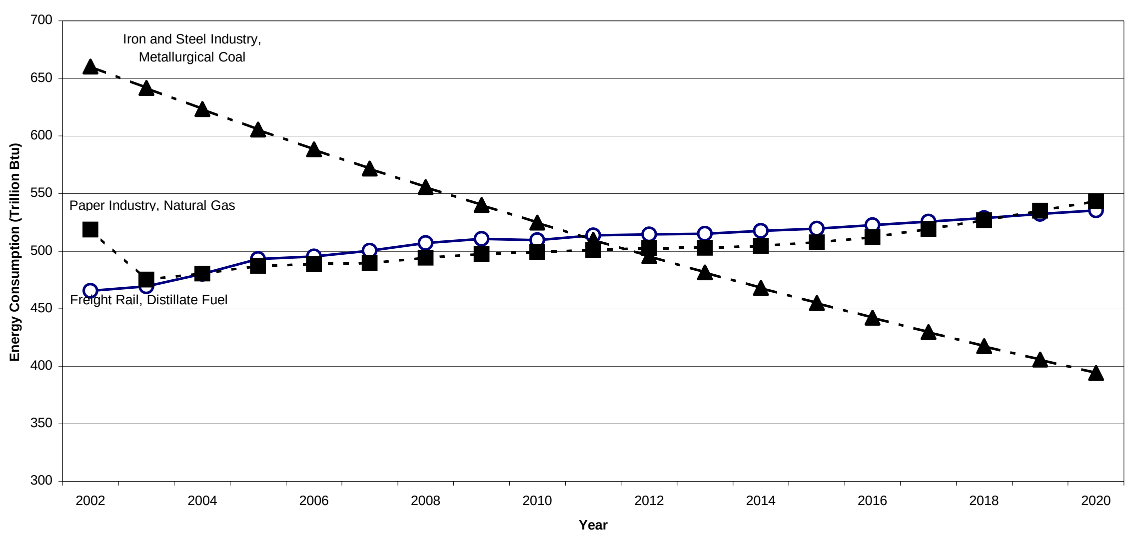
[4] As identified earlier (see Table I-1), there is no need to develop growth factors to estimate year 2000 with CAA case emissions.

[5] These "miscellaneous" nonroad categories describe aircraft, marine vessel, and railroad emission processes.

energy production emission source categories. To reflect the 1990 to 2000 trend in energy consumption for source categories, the project team generally relied on historical time-series energy data for each State from an EIA energy consumption database (EIA, 2005b). For Crude Oil and Natural Gas Production source categories, we obtained relevant 1990 and 2000 State-level activity data from an EIA source that provides the number of operating oil well days (used for Crude Oil Production) and the number of operating gas well days (used for Natural Gas Production) (EIA, 2005c). For source categories that describe railroad and marine distillate fuel consumption emission processes, we obtained State-level 1990 and 2000 consumption estimates from an EIA distillate fuel data resource (EIA, 2005d).

Each year, the EIA produces energy projections for the United States. These projections, which forecast U.S. energy supply, demand, and prices through 2025, are published in an EIA document entitled *Annual Energy Outlook 2005 (AEO 2005)* (EIA, 2005a). For most energy sectors/fuel types, *AEO 2005* reports energy forecasts by Census division. These divisions are defined by State boundaries (e.g., Texas is included in the West South Central region). When *AEO 2005* produces Census division forecasts, these regional data were used to project changes in the emissions activity for each State in the division. For example, Stage II (Gasoline Vehicle Refueling) emission activity in Texas is projected using *AEO 2005* projections of West South Central region transportation sector motor gasoline consumption. This study relies on national energy forecasts whenever *AEO 2005* only produces national projections for the energy growth indicator of interest. Exhibit 2-1 displays forecast data for 3 of the approximately 50 energy sectors for which *AEO 2005* only produces national projections.

Exhibit 2-1. Sample National AEO 2005 Energy Sector Forecasts



Socioeconomic Data

Because population growth and the performance of the U.S. economy are two of the main determinants of energy demand, the EIA also prepares socioeconomic projections. These projections feed into energy demand models incorporated into the EIA's National Energy Modeling System (NEMS). NEMS incorporates population projections and economic output forecasts for most industry sectors by Census division. For non-energy intensive economic sectors (e.g., Wholesale Trade), EIA prepares national-level output forecasts. This study relies on *AEO 2005* historical and forecast socioeconomic data as surrogates for emission activity level changes for most non-energy source categories. When *AEO 2005* reported Census division forecasts, each emission source's State identifier was used to link to the appropriate *AEO 2005* regional projections. National *AEO 2005* data were used whenever NEMS only produces national forecasts for the growth surrogate of interest. Exhibit 2-2 presents key national *AEO 2005* projections over the 2003 to 2025 forecast period.[6]

Exhibit 2-2. Key National Projection Results in AEO 2005

Variable	2003 to 2025 Annual Growth Rate (%)
Population	0.8
Real Gross Domestic Product	3.1
GDP Chain-Type Price Index	2.5
Nonfarm Business Labor Productivity	2.2
Total Industrial Output	2.3
Manufacturing Output	2.6
Energy Intensive Manufacturing Output	1.5
Nonenergy Intensive Manufacturing Output	2.9
Services Sector Output	3.3
Energy Use Per Capita	0.5
Energy Use Per $ of Real Gross Domestic Product	-1.6

County-level population data are one of the key inputs to the BenMAP model that will be used in this study to estimate the benefits of air quality changes. Population estimates at the county-level are also used as activity indicators for a small number of emissions categories. As a result, it was necessary to develop a set of population projections at the county level that is consistent with *AEO 2005* population data. The county level disaggregation step was completed using a methodology developed by Woods & Poole Economics Inc. (Woods & Poole, 2001), but updated to use *AEO 2005* regional population estimates. The first step in developing *AEO 2005* normalized county population projections was to compute factors from the population data in BenMap. These factors represent year-specific ratios of each county's BenMAP population to the BenMap population for the Census division in which the county is located. Next, the *AEO 2005* population data for each region were multiplied by the appropriate county-level factors to yield this study's county population projections.[7]

To ensure that population forecasts were available for each geographic area with stationary source/miscellaneous nonroad source category emissions in the draft 2002 NEI, we compared the NEI geographic areas to the areas in BenMAP. We identified two discrepancies between the NEI and BenMAP: BenMAP does not include Broomfield County in Colorado, and the NEI does not include Clifton Forge as an independent city in Virginia. In 2001, Clifton Forge, Virginia gave up its independent city status, and reverted back to a town. Therefore, the BenMAP Clifton Forge population estimates were added to the existing BenMAP population estimates for the county (Allegheny) in which the town is located before performing the *AEO 2005* reconciliation adjustment described above. Also in 2001, the State of Colorado created Broomfield County from areas within four counties (Adams, Boulder, Jefferson, and Weld) that contained the City of Broomfield. To develop Broomfield population estimates

[6] As noted earlier, year 2000 emission activity data were only needed in preparing the without-CAAA case emission estimates from 1990 base year emissions. For 1990 and 2000, we relied on historical energy use data.

[7] Because the AEO 2005 Pacific region population estimates include Alaska and Hawaii, while BenMAP does not include these States, it was necessary to develop adjust the AEO projections to account for this factor. The Project team first obtained July 1, 2002 county population estimates for each State from the Bureau of the Census (BOC, 2005). Next, we compiled Alaska and Hawaii population growth factors for 2010 and 2020 from the population forecasts incorporated into the Economic Growth Analysis System (EGAS) 5.0 (Houyoux, 2004a). These growth factors were multiplied by the Census 2002 population estimates to yield population forecasts for Alaska and Hawaii that were used to adjust the AEO projections for the western regions.

for each year of interest, the Project team applied factors to the *AEO 2005* adjusted BenMap population estimates for Adams, Boulder, Jefferson, and Weld counties (EPA, 2005). These factors, which reflect the proportion of the population in the City of Broomfield that was part of each of these counties in 2001, are as follows: Adams County (0.041882), Boulder County (0.073721), Jefferson County (0.002939), and Weld County (0.000055).

Alternative Emission Activity Indicators

In some instances, energy and socioeconomic forecasts are not expected to be valid surrogates of emission activity changes. As a result, for several categories we are unable to apply *AEO 2005* data as an activity indicator. In preparing recent projections to support an analysis of the Clean Air Interstate Rule (CAIR), for example, EPA chose to use alternative emission activity growth surrogates for certain source categories (Houyoux, 2004). The Project Team first reviewed the data sources/approaches that were used to support the CAIR projections for application in this study. In addition, we performed new research into the availability of alternative forecast data sources for the highest criteria pollutant-emitting source categories in 2002.

Exhibit 2-3 summarizes the non-*AEO 2005* growth indicators that we applied in this study. Because of concerns about changes in emission estimation methods between the 1990 NEI and 2002 NEI, and the high level of confidence associated with the activity data for these growth indicators, the Project team replaced the 1990 base year emission estimates for the Exhibit 2-3 source categories with estimates derived from applying the estimated 1990-2002 activity level trend to the 2002 base year emissions (i.e., we backcasted 1990 emissions for these categories).[8] The following sections describe how non-*AEO 2005* emission activity indicator data were developed for the years of interest.

Agricultural Production-Crops; Fertilizer Application; Nitrogen Solutions

The Project team obtained national 1990-2002 nitrogenous solutions and urea consumption data from the Food and Agricultural Organization of the United Nations' Statistical Database (FAOSTAT, 2005a). We relied on forecasts of planted crop acreage to project the growth rate in nitrogen solution fertilizer application. We first compiled national-level 2003-2014 forecasts of total acres planted for major crops from the U.S. Department of Agriculture (USDA) (USDA, 2005). Next, we extended the acres planted projections through 2020 using linear extrapolation. Because the base year for the USDA planted acreage forecasts was 2003, We developed 2002 estimates consistent with the forecasts by applying the ratio of national 2003 acres planted to 2002 acres planted (0.995), which was calculated from historical National Agricultural Statistics Service data (NASS, 2005a). Backcast and forecast growth factors, which represented the change in emission activity level relative to 2002, were then calculated by dividing the acres planted in each historical/forecast analysis year by the acres planted in 2002.

[8] We also replaced the NH3 and/or CO emissions in the 1990 with estimates derived from applying *AEO 2005* indicator based growth rates to 2002 NH3/CO emissions for certain categories where 1990 emissions were anomalously lower than 2002 emissions. These categories are: Open Burning of Land Clearing Debris (SCC 2610000500); Agricultural Field Burning; Field Crop is Grasses: Burning Techniques Not Important (SCC 2801500170); Agricultural Field Burning; Field Crop is Sugar Cane: Burning Techniques Not Important (SCC 2801500250); Agricultural Field Burning; Field Crop is Wheat: Headfire Burning (SCC 2801500261); Domestic Animals Waste Emissions; Cats; Total (SCC 2806010000); Domestic Animals Waste Emissions; Dogs; Total (SCC 2806015000); Wild Animals Waste Emissions; Deer; Total (SCC 2807030000); Fertilizer Application; Anhydrous Ammonia (SCC 2801700001); Fertilizer Application; Urea (SCC 2801700004); Fertilizer Application; Diammonium Phosphate (SCC 2801700013); and Prescribed Burning of Rangeland (SCC 2810020000)

Exhibit 2-3. Emission Activity Growth Indicators Derived from Non-AEO 2005 Forecast Data

Growth Indicator	Historical and Forecast Data Sources	Geographic Resolution	Forecasted Emission Activity
Agricultural Production-Crops; Fertilizer Application; Nitrogen Solutions	Historical and forecast planted acreage (NASS, 2005a and USDA, 2005)	State up thru 2002; National thereafter	Post-2003 planted acreage for major crops
Agricultural Tilling	Planted acreage (see Nitrogen Solutions entry above); assumed 2 and 6 tilling passes per year for conservation and conventional tillage, respectively; historical percentage of tilling associated with conservation tillage practices (CTIC, 2005); and assumed 50% conservation tillage in 2010 and 2020	National	Number of annual tilling passes
Animal Husbandry	Historical and projected animal counts (FAPRI, 2005; NASS, 2004 and NASS 2005b thru f; and USDA, 2005)	State up thru 2004; National thereafter except State for all years for milk cows	Number of animals (State data up through 2004; post-2004 projection reflects national animal county/production growth rates except milk cows based on State-level projections)
Aircraft	Federal Aviation Administration forecasts of landing and take-off (LTO) operations (FAA, 2005)	State	Itinerant and local airport operations by type of aircraft (air carrier, general aviation, air taxi, and military)
Forest Wildfires	1990-2003 national average acres burned (EPA, 2005)	Not applicable	No change from national historical average activity (adjusted base year by average acres burned)
Prescribed Burning for Forest Management	1996-2003 national average acres burned (NIFC, 2005)	Not applicable	No change from national historical average activity (adjusted base year by average acres burned)
Residential Wood Fireplaces and Wood Stoves	*AEO 2005*, extrapolation of unit type wood consumption shares, and 2% annual turnover to EPA certified units	Region (Census division)	Residential renewable energy consumption and forecast distribution of wood consumption by unit type
Unpaved Roads	Projected unpaved road VMT developed from historical data (EPA, 2005)	Region (Census division)	Regional linear extrapolation equations

Agricultural Tilling

Agricultural tilling emissions are calculated from the number of planted acres for each crop tilled, the assumed number of passes per year used in tilling, the silt content of the surface soil, and the emission factor. To represent the change in emissions activity for this category, the Project team estimated the total annual number of tilling passes for 1990, 2000, 2002, 2004 (last year of available historical data), 2010, and 2020. The agricultural tilling emission activity estimation procedure utilized year-specific data for the number of acres of crops planted and the percentage of acres planted using conservation/conventional tillage practices.

The Project team compiled historic and future year acres planted data from the USDA. We first compiled the 1990, 2000, 2002, and 2004 national number of total planted acres from the USDA's National Agricultural Statistics Service (NASS, 2005a). Next, we obtained projections of the national planted acreage for major crops from the USDA (USDA, 2005).

Because these projections were available from 2004 through 2014, the Project team estimated planted acreage in 2020 via linear extrapolation of the USDA data. We projected total acres planted data in 2010 and 2020 by applying 2010/2004 and 2020/2004 growth factors from the USDA major crop acreage data to the actual 2004 national acres planted.

The Project team also compiled the national percentage of crops planted using conservation tillage for 1990, 2000, 2002, and 2004 from the Conservation Technology Information Center (CTIC, 2005). These data indicate a steady increase in conservation tillage – from 26.0 percent in 1990, to 36.6 percent in 2002, and 40.7 percent in 2004. Based on recent trends, we assumed that 50 percent of total acres tilled would use conservation tillage by 2010. The same 50 percent assumption was used for 2020. We then calculated the acreage associated with each form of tilling in each year by multiplying the tilling percentages in each year by the total acres planted in that year.

The following steps were used to estimate the total national number of tilling passes in each year. First, the Project team calculated the number of tilling passes associated with conservation tilling and the number with conventional tilling. Based on the crop-specific tilling pass assumptions used in the 2002 NEI, we developed assumptions that 6 passes per year and 2 passes per year are used in conventional tilling and conservation tilling, respectively. Next, we multiplied the aforementioned conventional and conservation tilling acreage estimates by the assumed number of passes associated with each tilling type. The product of this calculation yielded the total number of tilling passes in each year for each tilling type. These two values were then summed to compute the total number of passes associated with agricultural tilling in each forecast year. Backcast and forecast growth factors were computed by dividing each historical/forecast year number of passes by the 2002 year number of passes.

Animal Husbandry

The Project team developed inventory counts of the number of animals in 1990, 2000, 2002, 2004, 2010, and 2020 for the following animal husbandry categories: beef cows, milk cows, total non-cow cattle, total cattle, turkeys, layers, broilers, total poultry, hogs, sheep, goats, and horses. Except for horses, we developed State-level historical animal counts for each category from various USDA publications (NASS, 2004; 2005b through 2005f). Because State-level counts were not available for horses, we relied on national counts from a United Nations database (FAOSTAT, 2005b).

With the exception of milk cows, sheep, goats, and horses, the 2004 animal counts were projected to 2010 using growth rates computed from USDA national animal inventory/ production forecasts (USDA, 2005). The last year of USDA forecast data was 2014. Forecast animal counts in 2020 were developed by extrapolating the USDA's annual forecast data using linear extrapolation, and applying the resulting growth rates to the 2004 State-level animal data. For milk cows, State-level animal count projections were compiled from the Food and Agricultural Policy Research Institute (FAPRI, 2005). As with the USDA projections, it was necessary to extrapolate milk cow counts in 2020 from the annual projections data that ended in 2014. The Project team then calculated the 2010 and 2020 count of milk cows in each State by applying the State-level growth rates from the Food and Agricultural Policy Research Institute data to the 2004 count of milk cows in each State. No animal inventory or production forecasts were identified for sheep, goats, and horses. Based on a review of historical inventory data for each animal type, we applied a post-2004 no growth assumption for sheep, goats, and horses. Backcast and forecast growth factors for each animal husbandry category were computed by dividing each historical/forecast year animal count by the 2002 animal count.

Aircraft

The historical/forecast State-level number of operations (arrival and departures) by type of aircraft (commercial, air taxi, and general aviation) were obtained from the Federal Aviation Administration's Terminal Area Forecasts (FAA, 2005). The Federal Aviation Administration's itinerant and local operations data were summed to develop total operations by aircraft type. Because the number of landing and take-offs (LTOs) is the emission activity for these source categories, and because an LTO is equivalent to two total operations (i.e., one arrival and one departure), we divided the number of total operations by 2 to yield the number of LTOs. Backcast/forecast year growth factors were developed for each type of aircraft by dividing the historical/forecast year LTO projections by 2002 LTO estimates. To ensure that 1990 emission values are calculated for the same SCCs and on a consistent basis with the base year and forecast year values, we replaced the 1990 base year aircraft emission estimates with estimates computed by multiplying the 2002 emissions by the ratio of 1990 LTOs to 2002 LTOs. Similarly, we computed 2000 *without-CAAA* emission estimates by multiplying 2002 emissions by the ratio of 2000 LTOs to 2002 LTOs.

Forest Wildfires

In keeping with analyses performed in support of the CAIR, the Project team replaced the actual 2002 wildfire emission estimates from the draft NEI with estimates reflecting historical average wildfire activity. The Forest Wildfires source category is unique in that it is a high-emitting category for which the emissions producing activity is largely a function of meteorological conditions and unintentional activities. Because large year-to-year variations in emissions, which are common for this category, could unduly influence overall emission trends, we revised the 2002 NEI wildfire emissions by applying a factor (0.635) that represents the ratio of the national average acres burned in wildfires over the 1990-2003 period to the actual acres burned in 2002. The national 1990-2003 wildfire acres burned data were obtained from the National Interagency Fire Center (NIFC, 2005). We then used the adjusted 2002 wildfire emission estimates to represent emissions in each analysis year. This *no change* assumption was also used by EPA in analyzing the impacts of the CAIR (Houyoux, 2004b).

Prescribed Burning for Forest Management

Similar to wildfires, prescribed burning activity levels have fluctuated widely over time. To ensure that such changes do not unduly influence overall emission trends, we adjusted the 2002 actual prescribed burning emission estimates to reflect the historical national average acres burned in prescribed fires, which was calculated from 1996-2003 data (EPA, 2005). We applied an adjustment factor of 0.730 to the 2002 NEI prescribed burning emission estimates to reflect historical average prescribed burning activity levels. We then used the adjusted 2002 prescribed fire emission estimates to represent emissions in each analysis year. This "no change" forecast assumption was also used by EPA in analyzing the impacts of the CAIR (Houyoux, 2004b).

Residential Wood Fireplaces and Wood Stoves

The Project team estimated emission activity levels for residential wood fireplaces and wood stoves using a combination of DOE national historical residential wood consumption estimates, *AEO 2005* Census division regional energy projections, the estimated proportion of consumption by type of unit in each analysis year, and an assumed 2 percent annual turnover to lower-emitting combustion units.

a. Energy Consumption Data

Regional residential renewable energy consumption estimates were obtained from *AEO 2005* for 2002, 2010, and 2020 (wood accounts for the vast majority of residential renewable energy consumption). Because State-level residential wood consumption estimates appeared suspect, we used DOE national 1990, 2000, and 2002 residential wood consumption data to estimate the trend in residential wood consumption over this period. We then combined the two sets of estimates to develop estimates of regional residential renewable energy consumption in each year of interest.

b. Estimates of Residential Wood Consumption Proportions by Unit Type

From the U.S. Bureau of the Census' *Census of Housing*, we obtained the 1997, 1999, 2001, and 2003 national number of homes with wood stoves and number of homes with fireplaces with inserts (BOC, 2004).[9] For fireplaces without inserts, we compiled *Census of Housing* data reflecting the number of homes that use fireplaces without inserts as the main heating source and the number of homes that use fireplaces without inserts as a supplementary heating source. We then adjusted the *Census of Housing* data to reflect the estimated number of units per home − 1.1 for fireplaces with inserts; 1.17 for fireplaces without inserts, and 1.09 for stoves and the estimated percentage of fireplaces which burn wood − 74 percent (Pechan, 2006).[10] Next, we multiplied the product of these numbers by estimated annual wood consumption per unit − 1.533 cords per unit for wood stoves and fireplaces with inserts; 0.656 cords per unit for fireplaces without inserts used as the main heating source; and 0.069 cords per unit for fireplaces without inserts used for other heating (Pechan, 2006). We then summed the main heating and other heating estimates for fireplaces without inserts to yield total wood consumption for fireplace without inserts. These calculations resulted in estimated national wood consumption for 1997, 1999, 2001, and 2003 for woodstoves, fireplaces with inserts, and fireplaces without inserts.

Next, we computed the proportions of total residential wood consumption by each unit type for the available years. We then interpolated these proportions for the intervening years. Because pre-1997 *Census of Housing* values appeared anomalous, we chose to use the 1997 residential wood consumption proportions to represent the 1990 proportions.[11] Next we projected the wood consumption shares by residential wood combustion (RWC) unit type in 2010 and 2020 by extrapolating from the 1997-2003

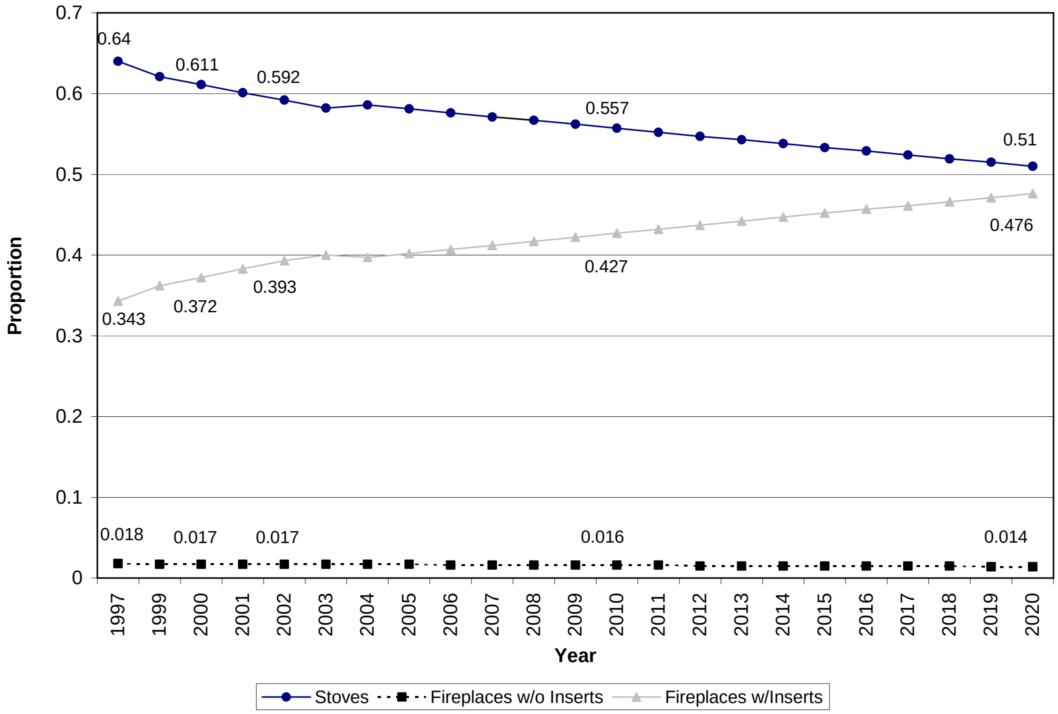
[9] Pre-1997 data were not compiled because these data reflected an anomalous disconnect in the data series trend.

[10] Note that the fact that year-specific values were not identified is not a shortcoming because such values would not affect the proportion of total wood consumption associated with each type of unit, which is the goal of these steps.

[11] For example, 21 to 22 percent of the total number of housing units with wood combustion equipment had fireplaces without inserts in post-1995 Census years; in 1989-1995, this percentage ranged from 32 to 33 percent. The 1997 *Census of Housing* acknowledges that pre-1997 comparability issues may exist because of significant data collection method changes that were first implemented in 1997.

values. Exhibit 2-4 presents the estimated proportions of total residential wood consumption by unit type over the 1997-2020 period.

Exhibit 2-4. Proportion of Total Residential Wood Consumption by Type of Unit



c. SCC-Level RWC Activity Consumption Forecasts

Two additional steps were used to develop source classification code (SCC)-level RWC activity forecasts. First, we estimated wood consumption by RWC unit type for the period 2002-2020 by multiplying *AEO 2005* regional 2002-2020 renewable energy consumption by 2002-2020 RWC unit type wood consumption proportions.[12] Next, for SCCs that disaggregate the broad RWC unit types reported in the *Census of Housing* data (i.e., woodstoves, fireplaces with inserts, and fireplaces without inserts), we allocated the consumption estimates to these more detailed SCCs. For the woodstoves and fireplaces with inserts categories, this step involved allocating consumption into three SCC-specific unit types representing non-EPA certified, EPA certified catalytic, and EPA certified non-catalytic units.

This 2002 year allocation was accomplished by multiplying the broad unit-level consumption estimates by the proportions of total RWC attributed to each SCC as reported in the 2002 NEI: 92 percent for non-EPA certified units; 5.7 percent for EPA certified non-catalytic units; and 2.3 percent for EPA certified catalytic units (Pechan, 2006). To reflect a projected increase in EPA-certified units resulting from EPA's wood heater New Source Performance Standard (NSPS), forecast year proportions were calculated by adjusting the 2002 year proportions using an annual 2 percent RWC unit turnover rate computed from 1992-2005 data (Broderick and Houck, 2005). This adjustment accounts for non-EPA

[12] Note that *AEO 2005* reflects residential natural gas price forecasts (2005/2006 average of about $9.95 per thousand cubic feet in 2003 dollars) that are lower than those recently experienced (December 2005/January 2006 average of about $14.85 per thousand cubic feet in current dollars). To the extent that future year natural gas prices may be higher than assumed, *AEO 2005* may underestimate future year residential renewable energy consumption.

certified units being replaced by NSPS compliant EPA-certified units. Therefore, by year 2020, it is assumed that 64.4 percent of residential wood consumption in woodstoves and fireplaces with inserts will occur in non-EPA certified units, 25.4 percent in EPA certified non-catalytic units, and 10.2 percent in EPA certified catalytic units.

The Project team developed 1990 and 2000 activity level estimates as follows. We first calculated ratios representing 1990 and 2000 residential wood consumption relative to 2002 consumption (1.85 and 1.38, respectively), and then multiplied these ratios by 2002 year regional residential renewable energy consumption. Next, we applied values representing the estimated 1990 and 2000 year proportions of total residential wood consumption attributable to each of the following unit types: woodstoves, fireplaces with inserts, and fireplaces without inserts (see Exhibit II-1).[13] Next, we allocated the general unit-level consumption estimates to individual SCCs. For 1990, this step assumed that zero residential wood consumption would occur in 1990 in EPA certified units because 1992 was the first year of certification (Broderick and Houck, 2005). For 2000, we utilized the aforementioned annual 2 percent turnover rate and the 2002 NEI wood consumption proportions to estimate the following proportions in 2000: 95.68 percent for non-EPA certified units; 3.08 percent for EPA certified non-catalytic units; and 1.24 percent for EPA certified catalytic units.

Finally, we calculated the backcast/forecast year growth factors for the RWC SCCs that appear in the 2002 base year inventory by dividing estimated historical/forecast year consumption by estimated 2002 year consumption.

Unpaved Roads

Unpaved road VMT is not available directly from the AEO projections. As a result, the Project team chose to compile State-level 1990-2002 unpaved road VMT data developed in support of the NEI (EPA, 2005) for application in this study.

Trends in unpaved road VMT can be upward or downward. In many areas, unpaved roads are forecast to become paved roads, reducing VMT. In other areas, unpaved roads remain unpaved and VMT grows roughly in pace with overall VMT. In a few states, however, we identified anomalous VMT growth/decline between 1990 and 1995. These anomalies (e.g., 55 percent increase in Idaho unpaved road VMT between 1993 and 1994) appear to result from large year-to-year changes in estimated unpaved road mileage by traffic volume category for certain States. Anomalies such as this were identified in the following States: California, Delaware, Idaho, Nevada, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Washington, and Wyoming. For these States, we revised the 1990 to 1995 estimates by extrapolating from the 1996-2002 VMT trends. For the state of Maryland, we identified a suspect trend over the last two years of data. Therefore, we re-estimated Maryland 2001 and 2002 unpaved road VMT via linear extrapolation of the 1990-2000 VMT data.

Because of concerns over the validity of some of the State data, it was decided that the most defensible approach would be to develop *regional* level growth factors from the adjusted historical data. Therefore, we summed the unpaved VMT estimates for each State to the Census Division level and then projected 2010 and 2020 unpaved road VMT for each region using a best fit linear equation calculated from each region's 1990 to 2002 unpaved VMT data. Exhibit 2-5 presents unpaved road VMT estimates for each Census Division for 1990, 2000, 2002, 2010, and 2020. Note that

[13] As noted earlier, we used the 1997 proportions to represent 1990 proportions.

Exhibit 2-5. VMT Estimates for Unpaved Roads by Census Division (millions of miles traveled)

Region	1990	2000	2002	2010	2020
East North Central	4,948	4,691	5,517	5,510	5,938
East South Central	2,646	2,329	2,161	1,687	1,099
Middle Atlantic	1,314	1,145	1,136	1,010	868
Mountain	8,550	7,347	7,149	5,989	4,425
New England	1,146	1,053	1,057	1,020	1,030
Pacific	6,033	4,403	4,366	3,331	1,931
South Atlantic	4,224	3,822	3,882	3,737	3,381
West North Central	8,361	8,991	8,899	9,398	9,906
West South Central	10,191	7,663	6,957	6,760	6,226
Totals	**47,415**	**41,445**	**41,124**	**38,442**	**34,804**

Assignment Of Growth Indicators To Base Year Emission Sources

The following subsections describe the methods that were used to assign growth indicators to energy and non-energy related emission source categories.

Assignments for Energy Related Source Categories

Because *AEO 2005* and historical EIA publications provide detailed energy production/ consumption data by sector and fuel type, energy-related source categories can be easily matched to an appropriate EIA growth indicator. The Project team assigned growth indicators to energy production/consumption emission source categories using recent Maximum Achievable Control Technology (MACT) and SCC growth indicator crosswalks developed in support of Version 5.0 of the Economic Growth Analysis System (EGAS) (Pechan, 2005a; 2005b).[14]

Assignments for Non-Energy Related Source Categories

For non-energy related emission source categories, we generally utilized *AEO 2005* sector output data as surrogates for changes in emission activity.[15,16] The EGAS 5.0 sector output-based crosswalks utilize Standard Industrial Classification (SIC) code-based output projections from Regional Economic Models, Inc. (REMI) as growth indicators for non-energy related MACT and SCC codes. The EGAS 5.0 output forecasts are available for approximately 165 separate economic sectors, while the *AEO 2005* output projections are available for about 50 economic sectors (see Exhibit 2-6 for list of *AEO 2005* sectors). The *AEO 2005* output based growth indicators used in this study are less sector-specific than the growth indicators used in EGAS 5.0 or in the recent CAIR projections. However, the *AEO 2005* historical/forecast economic output data are used in this study to ensure consistency with the economic projections used in forecasting *AEO 2005* energy production/consumption. The following subsections describe how the *AEO 2005* socioeconomic data were assigned as growth indicator surrogates for non-energy related source categories.

[14] These crosswalks utilize *AEO 2004* data, which are reported for essentially the same sectors/fuel types as the *AEO 2005* projections data.

[15] Note that unlike energy production/consumption data, historical sector output data were available from *AEO 2005*.

[16] In addition to sector output, population is used as the growth indicator for some non-energy source categories.

Exhibit 2-6. AEO 2005 Economic Sectors

Geography	Sector	NAICS Code(s)
Regional	MFGO1 Food Products	311
	MFGO2 Beverage and Tobacco Products	312
	MFGO3 Textile Mills & Textile Products	313,314
	MFGO4 Apparel	315
	MFGO5 Wood Products	321
	MFGO6 Furniture and Related Products	337
	MFGO7 Paper Products	322
	MFGO8 Printing	323
	MFGO9 Basic Inorganic Chemicals	32511,32519
	MFGO10 Basic Organic Chemicals	32512 – 32518
	MFGO11 Plastic and Synthetic Rubber Materials	3252
	MFGO12 Agricultural Chemicals	3253
	MFGO13 Other Chemical Products	3254 – 3259
	MFGO14 Petroleum Refineries	32411
	MFGO15 Other Petroleum and Coal Products	32412,32419
	MFGO16 Plastics and Rubber Products	326
	MFGO17 Leather and Allied Products	316
	MFGO18 Glass & Glass Products	3272
	MFGO19 Cement Manufacturing	32731
	MFGO20 Other Nonmetallic Mineral Products	327 less 3272 & 32731
	MFGO21 Iron & Steel Mills, Ferroalloy & Steel Products	3311,3312
	MFGO22 Alumina & Aluminum Products	3313
	MFGO23 Other Primary Metals	3314,3315
	MFGO24 Fabricated Metal Products	332
	MFGO25 Machinery	333
	MFGO26 Other Electronic & Electric Products	334 less 3345 & 335
	MFGO27 Transportation Equipment	336
	MFGO28 Measuring & Control Instruments	3345
	MFGO29 Miscellaneous Manufacturing	339
	MFGO30 Crop Production	111
	MFGO31 Other Agriculture, Forestry, Fishing & Hunting	112 – 115
	MFGO32 Coal Mining	2121
	MFGO33 Oil & Gas Extraction & Support Activities	211,213
	MFGO34 Other Mining & Quarrying	2122,2123
	MFGO35 Construction	23
	Sum of All Chemicals	325
	Sum of All Petroleum	324
	Sum of All Stone, Clay, Glass and Cement	327
	Sum of All Primary Metals	331
	Total Manufacturing Output	31 – 33
	Total Industrial Output	11,21,23,31 – 33

Exhibit 2-6 (continued)

Geography	Sector	NAICS Code(s)
National	NMFGO1 Transportation & Warehousing	48,49
	NMFGO2 Broadcasting & Telecommunications	513
	NMFGO3 Electric Power Generation & Distribution	2211
	NMFGO4 Natural Gas Distribution	2212
	NMFGO5 Water, Sewage & Related System	2213
	NMFGO6 Wholesale Trade	42
	NMFGO7 Retail Trade	44,45
	NMFGO8 Finance & Insurance, Real Estate	52,53
	NMFGO9 Other Services	51,54 – 81
	NMFGO10 Public Administration	921,922,923
	Total NonManufacturing/Service Gross Output	22,42,44,45,48,49,51–81, 92
	Total Gross Output	All

a. MACT Code Assignments

As part of the regulatory development process, EPA has identified the economic sectors affected by MACT standards. EPA regulatory documents generally list the North American Industrial Classification (NAICS) codes potentially affected by MACT standards. Because this information can be used to specifically relate MACT codes to NAICS codes, we used MACT codes to link to the appropriate *AEO 2005* output sector whenever a valid MACT code was reported in the base year inventory.[17] Before the transition from SIC codes to NAICS codes, EPA regulatory documents listed the SIC codes affected by MACT standards. For these regulations, we used a U.S. Bureau of the Census crosswalk that links SIC codes to NAICS codes to assign the appropriate *AEO 2005* NAICS-based growth indicator(s) to MACT codes (BOC, 2005).

b. SCC Assignments

When a valid MACT code was not available for an emission record in the inventory, we assigned the growth indicator based on the SCC. We used a combination of the EGAS 5.0 SCC-based crosswalk and the U.S. Bureau of the Census' SIC code to NAICS code crosswalk to assign *AEO 2005* NAICS-based growth indicators to SCCs. Because the EGAS 5.0 crosswalk links REMI SIC code-based economic sectors to SCCs, we used the Census' SIC code to NAICS code crosswalk to identify the *AEO 2005* sector indicator(s) to apply for a given non-energy related SCC (note that, in keeping with EGAS 5.0, population is used as the growth indicator for many such SCCs).

In some cases, the Project team did not include one or more NAICS codes that were attributable to a particular SIC code included in the EGAS 5.0 crosswalk. These exceptions result from cases where EGAS assigns a MACT code or SCC to multiple SIC codes, and where one or more of these SIC codes is associated with a NAICS sector that is expected to be much less directly related to the emission activity than the NAICS codes associated with the other SIC codes. For example, the EGAS 5.0 crosswalk

[17] Because of anomalously high output-based growth rates associated with the *AEO 2005* industry sectors linked to MACT code 1614 (Halogenated Solvent Cleaning), we chose to assign growth indicators for emission records with MACT code 1614 by linking to the SCCs reported in the base year inventory (see following section for discussion of this approach).

assigns the All Processes/All Industries Degreasing SCC (241500000) to economic output data for SIC codes 25 (Furniture and Fixtures), 33 (Primary Metal Industries), 39 (Miscellaneous Manufacturing Industries), and 75 (Automobile Repair, Services, and Parking). The AEO sectors (and NAICS codes) that match most closely to these SIC codes are: MFGO6 Furniture and Related Products (NAICS 337); MFGO23 Other Primary Metals (NAICS 3314 and 3315); MFGO29 Miscellaneous Manufacturing (NAICS 339); and NMFGO9 Other Services (NAICS 51, 54-81). Because NAICS codes 51, 54-81 are roughly equivalent to SIC codes 58, 70, 73, 75, 76, 78-80, 82-84, 86, 89, the NMFGO9 includes many more economic sectors than are included in the EGAS 5.0 crosswalk growth indicator for SCC 2415000000. Therefore, output for the NMFGO9 sector was not incorporated into the growth indicator for SCC 2415000000.

CHAPTER 3 - NON-ELECTRICITY GENERATING UNIT POINT SOURCES

Overview of Approach

This chapter addresses emissions from 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, and in many cases with some variation geographically. The applicable CAAA rules for this source category are listed in Exhibit 1-5 in Chapter 1. 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 pollution) 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 reports on the results of 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. For MACT standards, the focus in this chapter is not on the air toxics emissions reductions that are the main focus of those standards, but on the ancillary criteria pollution emissions reductions in the form of VOCs.

Chapter 2 describes the activity indicator portion of the emissions projection effort for non-EGU point sources; as a result, in this chapter the methods discussion focuses on how the effect of current and future control programs was incorporated in the emission projections for the *with-CAAA* scenario. The methods can be summarized as follows: the non-EGU point source emission projection approach for the *with-CAAA* scenario uses the 2002 draft NEI point source emissions file as the base year, applies the growth factors described in Chapter 2 to estimate activity changes between the base year and the 2010 and 2020 projection years, and applies control factors or emission caps to simulate the effect of air pollution control programs in each forecast year. The first section of this chapter focuses on documenting the specific control measures that are applied in the *with-CAAA* scenario, and the second section provides a summary of the emissions estimation results.

Control Scenario Methods

The May 2003 analytical plan proposed use of the 1999 NEI as the basis for estimating non-EGU point and nonpoint source emissions for 2010 and 2020. The draft 2002 NEI has been available since February of 2005, so it replaced the 1999 NEI as the base year emission inventory for these new projections. The 2002 NEI is the first emissions database prepared by EPA since the Consolidated Emissions Reporting Rule took effect, so the 2002 NEI represents a more complete reporting of criteria pollutant emissions and sectors by the States than the 1999 NEI. Another important attribute of the 2002 calendar year emission database is that it is the yardstick for measuring progress by the States toward reaching 8-hour ozone and $PM_{2.5}$ attainment targets. The main concern with using the 2002 draft NEI in this study was that there might be significant changes in the database made in response to quality control reviews. However, waiting for the final 2002 NEI to be completed would have severely affected the schedule for this second section 812 prospective. Therefore, the EPA Project Team decided to use the draft 2002 NEI as the basis for making 2010 and 2020 emission projections. This use is consistent with the practice of many multi-state Regional Planning Organizations (RPOs) that are currently using the 2002 draft NEI for regional haze modeling.

One of the important components of the emission projections is identifying and quantifying the effect of Federal, State, and local air pollution control strategies on post-2002 emission rates. Because of the recent and ongoing activity of the five RPOs in developing emission projections for their own modeling domains, each of the RPOs was queried, and any available control factor files were obtained.

The common projection year by the RPOs is 2018. All RPOs have either developed, or are working towards developing, 2018 emission forecasts. Some are also developing emission forecasts for 2009 or 2010 because these are expected 8-hour ozone attainment years. For the purposes of this section 812 analysis, control factors for the different projection years were reviewed, and adjusted, where necessary, to account for the timing of regulation implementation and ensure a match with this study's target years of 2010 and 2020. Exhibit 3-1 lists the RPOs, the geographic areas that they include, their projection years, and the information that was received from each to support this section 812 project.

Exhibit 3-1. Regional Planning Organization Criteria Pollutant Control Factors for Regions/States – Base Case 2010 and 2020

Regional Planning Organization	Geographic Area Covered	Analysis Year(s)	Notes
1. Mid-Atlantic/ Northeast Visibility Union (MANE-VU)	Northeast and Mid-Atlantic	2018	MANE-VU provided a matrix that summarized their on-the-books rules by State and sub-state area. Their control factors were not available during this study period.
2. Visibility Improvement - State and Tribal Association of the Southeast (VISTAS)	Southeast	2009 2018	Source: MACTEC, 2005.
3. Lake Michigan Air Directors Consortium (LADCO)	Great Lakes area	2007 2009 2012 2018	Source: Pechan, 2004a.
4. Central Regional Air Planning Association (CENRAP)	Midwest	2018	Source: Pechan, 2005.
5. Western Regional Air Partnership (WRAP)	Western	2018	Control factors were not available during this study period.
5a. California		2010 2020	California projection year control factors were provided by the California Air Resources Board.

The following sections describe the primary Federal, regional, State, and local air pollution control programs that are reflected in the 2010 and 2020 emission projections.

With-CAAA Scenario

Federal Programs

MACT Standards

Numerous MACT standards have been promulgated pursuant to Section 112 of Title I of the CAA, and control emissions of hazardous air pollutants (HAPs) from stationary sources of air pollution. Many HAPs are also VOCs. Many of the MACT standards are expected to produce associated VOC reductions, so the emission projections capture the expected effects of post-2002 MACT standards.

The Project Team performed the following steps to determine the MACT standards expected to have the greatest impact of VOC, NO_x, and PM emissions for the forecast year:

1. Identified the source categories and associated SCCs for each MACT standard having a post-2002 compliance date for existing sources.
2. Eliminated MACT categories that do not achieve significant VOC emission reductions.
3. VOC emission reduction estimates for the reciprocating internal combustion engine MACT category are based on information found in a CAIR technical support document (Alpine, 2004).
4. VOC emission reduction estimates for all other MACT categories are based on information found in the preamble to the final rule of each MACT Subpart as published in the *Federal Register*. Exhibit 3-2 lists those MACT categories for which VOC, NO_x, and/or PM emission reduction percentages could be estimated based on emission reduction information found in the preamble to each respective final rule.

Cases and Settlements

EPA has judicial settlements with a number of companies that own U.S. petroleum refineries. For this analysis, Pechan incorporated the expected emission reductions and costs of these consent decrees in its *with-CAAA* scenario analyses for 2010 and 2020. The focus of the 812 emission projections is on criteria air pollutants, and because the refinery settlements most affect SO_2 and NO_x, this analysis focuses on the parts of the settlements that affect SO_2 and NO_x emissions. Because of resource constraints, not all of the refineries affected by consent decrees are included in this analysis. Prioritization was established based on a ranking of the EPA-estimated criteria pollutant emission reductions by company. The companies with the largest expected emission reductions were included in this study. Exhibit 3-3 lists the companies and individual refineries that were evaluated in this study. This table also provides information about the fluid catalytic cracking units (FCCUs) and heater/boiler emission control requirements for each refinery.

Because of the large number of refineries whose post-2000 emissions are affected by these settlements, we examined a sample of the settlements to determine where there might be common elements that could be combined into one or more model rules to most efficiently simulate the effect of the settlements. Knowing where there are differences among the settlement requirements as well as the parameters that determine the differences helped in designing an approach that would be used along with the 2002 EPA NEI and future year activity indicators to estimate 2010 and 2020 refining emissions.

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

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

Exhibit 3-2. Post-2002 MACT Standards and Expected VOC, NO_x, and PM Reductions

MACT Standard - Source Category	Code of Federal Regulations Subpart	Compliance Date (existing sources)	VOC (% Reduction)	NO_x (% Reduction)	Total PM (% Reduction)
Asphalt		5/1/2006	85		
Auto and Light Duty Trucks	IIII	4/26/2007	40		
Coke Ovens: Pushing, Quenching and Battery Stacks	CCCCC	4/14/2006	43		
Fabric Printing, Coating & Dyeing	OOOO	5/29/2006	60		
Friction Products Manufacturing	QQQQQ	10/18/2005	44		
Integrated Iron and Steel	FFFFF	5/20/2006	20		20
Large Appliances	NNNN	7/23/2005	45		
Leather Finishing Operations	TTTT	2/27/2005	51		
Lime Manufacturing	AAAAA	1/5/2007			23
Manufacturing Nutritional Yeast	CCCC	5/21/2004	10		
Metal Can	KKKK	6/10/2005	70		
Metal Coil	SSSS	6/10/2005	53		
Metal Furniture	RRRR	5/23/2006	73		
Misc. Coating Manufacturing	HHHHH	12/11/2006	64		
Misc. Metal Parts and Products	MMMM	1/2/2007	48		
Misc. Organic Chemical Production and Processes	FFFF	11/10/2006	66		
Paper and Other Web	JJJJ	12/4/2005	80		
Pesticide Active Ingredient Production	MMM	12//23/2003	65		
Petroleum Refineries	UUU	4/11/2005	55		
Plastic Parts	PPPP	4/19/2007	80		
Plywood and Composite Wood Products	DDDD	9/28/2007	54		
Polymers and Resins III	OOO	1/20/2003	51		
Reciprocating Internal Combustion Engines (RICE)	ZZZZ	6/15/2007	13	17	
Rubber Tire Manufacturing	XXXX	7/11/2005	52		
Secondary Aluminum Production	RRR	3/24/2003			61
Site Remediation	GGGGG	10/8/2006	50		
Solvent Extraction for Vegetable Oil Production	GGGG	4/12/2004	25		
Stationary Combustion Turbines	YYYY	3/5/2007	90		
Taconite Iron Ore Processing	RRRRR	10/30/2006			62
Wet Formed Fiberglass Mat Production	HHHH	4/11/2005	74		
Wood Building Products	QQQQ	5/28/2006	63		

Exhibit 3-3. Refinery-Specific Summary of Consent Decree Requirements

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
BP Amoco	Carson	CA	SO_2 catalyst additive	Low NO_x combustion promoter and NO_x adsorbing catalyst additive designed to achieve 20 parts per million volume displacement (ppmvd)	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Whiting	IN	FCU 500: Install wet gas scrubber; FCU 600: Use SO_2 adsorbing catalyst additive and/or hydrotreatment.	FCU 600: Install SCR; FCU 500: Low NO_x combustion promoter and NO_x adsorbing catalyst additive	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Mandan	ND	Install wet gas scrubber		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Toledo	OH	SO_2 catalyst additive	Install SNCR system	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Texas City	TX	FCCU3: Install wet gas scrubber; FCCU2: SO_2 catalyst additive; FCCU1: Continue hydrotreatment	FCCU 2: Install SCR to achieve 20 ppmvd or lower; FCCU 1 and FCCU 3: Low NO_x combustion promoter and NO_x adsorbing catalyst additive	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Salt Lake City	UT	Meet an SO_2 limit of 9.8 kg/1000 kg coke burnoff		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Yorktown	VA	Use SO_2 adsorbing catalyst additive		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Cherry Point	WA				
CITGO	Corpus Christi	TX	SO_2 reducing additives	FCCU1: Low NO_x combustion promoter (20 ppmvd limit); FCCU2: 23 ppmvd NO_x limit	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
CITGO Asphalt Refining Co.	Savannah	GA	No FCCU	No FCCU	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from one heater or boiler
CITGO Asphalt Refining Co.	Paulsboro	NJ	No FCCU	No FCCU	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from one heater or boiler

Exhibit 3-3 (continued)

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
CITGO Global Refinery	Lemont	IL	New wet gas scrubber	Low NO_x combustion promoter (20 ppmvd limit)	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
CITGO Petroleum Company	Lake Charles	LA	Unit A - SO_2 reducing additives; Unit B - New wet gas scrubber; Unit C - New wet gas scrubber	Low NO_x combustion promoter (20 ppmvd limit)	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
Conoco Philips Global Refinery	Borger	TX	Install 2 new wet gas scrubbers (to achieve 25 ppmvd)	FCCUs 29 and 40: Enhanced SCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Belle Chasse (Alliance)	LA	Install new wet gas scrubber (to achieve 25 ppmvd)	Scrubber-based NO_x emission reduction technology to achieve 20 ppmvd	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Linden (Bayway)	NJ	Existing wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy, plus install SCR on crude pipe still heater
Conoco Philips Global Refinery	Sweeny	TX	Hydrotreating the feed. SO_2 catalyst additives at FCCUs 3 and 27.	FCCU 27: Install an SCR system. By 2010, meet 20 ppmvd limit; FCCU 3: Catalyst additives and low NO_x combustion promoters	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Carson	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Wilmington	CA	SO_2 catalyst additives	NO_x catalyst additives and low NO_x combustion promoters	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Ferndale	WA	Existing wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Rodeo	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Santa Maria	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Trainer	PA	Install new wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Roxanna (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 1: Scrubber-based NO_x emission reduction technology to achieve 20 ppmvd	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Hartford (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 2: Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy

Exhibit 3-3 (continued)

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Deer Park Refinery (Shell Oil Company)	Deer Park	TX	Install new wet gas scrubber (25 ppmvd or lower)	Install SCR designed to achieve 20 ppmvd	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Use qualifying controls to reduce NO_x emissions from combustion units
Equilon	Anacortes	WA	Install a wet gas scrubber (to achieve 25 ppmvd or lower on a 365-day rolling average basis)	Apply NO_x adsorbing catalyst additive and low NO_x CO combustion promoter	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Bakersfield	CA	No FCCU	No FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Martinez	CA	Optimize existing use of SO_2 Adsorbing Catalyst Additive. Incorporate lower SO_2 emission limits into operating permits.	Optimize existing SNCR system	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Wilmington	CA	Optimize existing use of SO_2 Adsorbing Catalyst Additive. Incorporate lower SO_2 emission limits into operating permits.	Apply NO_x adsorbing catalyst additive and low NO_x CO combustion promoter	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Marathon Ashland Refinery	Robinson	IL	Existing wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Catlettsburg	KY	New wet gas scrubber on unit 1; catalyst additive on other unit	Apply NO_x adsorbing catalyst additive plus SNCR	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per

Exhibit 3-3 (continued)

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
						MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Garyville	LA	Existing wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Detroit	MI	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	St Paul Park	MN	New wet gas scrubber on unit 1; catalyst additive on other unit	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Canton	OH	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.

Exhibit 3-3 (continued)

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Marathon Ashland Refinery	Texas City	TX	New wet gas scrubber	Catalyst additive plus SNCR	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Montana Refining Co.	Great Falls	MT	SO_2 catalyst additive	Use NO_x reducing catalyst additive and low NO_x combustion promoters	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	No large heaters/boilers here
Motiva	Convent	LA	New wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Delaware City	DE	New wet gas scrubber	SNCR at FCU; Catalyst additives at FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Norco	LA	Existing wet gas scrubber plus lower SO_2 emission limit (25 ppmvd)	SNCR at FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Port Arthur	TX	Existing wet gas scrubber plus lower SO_2 emission limit (25 ppmvd)	Catalyst additive or meet 20 ppmvd on a 365 day rolling average basis	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Navajo Refining	Artesia	NM	New wet gas scrubber (meet 25 ppmvd)	Use NO_x reducing catalyst additive and low NO_x combustion promoters (NO_x rate $\leq$ 34.916/hr)	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Achieve 0.06 lbs/MMBtu at Boiler B-7 and B-8
Premcor Refining (formerly Clark Refining)	Hartford	IL	Install new wet gas scrubber to meet 25 ppmvd SO_2		Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Install a combination of current and next generation ULNBs on identified units
Premcor Refining Group	Blue Island	IL	2001 closure	2001 closure	2001 closure	2001 closure
Sunoco Petroleum Refinery	Toledo	OH	Install new wet gas scrubber to meet 25 ppmvd SO_2	Install SCR systems or alternate technology to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	
Sunoco Petroleum Refinery	Tulsa	OK			Refining fuel gas to meet the H_2S limits in 40 CFR 60.604(a) and (b)	
Sunoco Petroleum Refinery	Philadelphia	PA	Install new wet gas scrubber to meet 25 ppmvd SO_2	1232 FCCU: Install SCR system to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	Use qualifying controls to reduce NO_x emissions greater than 40 MMBtu/hr by at least 2,189 tpy
Sunoco Petroleum	Marcus Hook	PA	Install new wet gas scrubber to	Install SCR systems or alternate	Accept NSPS Subpart J applicability	Use qualifying controls to reduce

Exhibit 3-3 (continued)

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Refinery			meet 25 ppmvd SO_2	technology to meet 20 ppmvd	and reduce or eliminate fuel oil burning	NO_x emissions greater than 40 MMBtu/hr by at least 2,189 tpy
Valero Eagle Refinery	Texas City	TX	Use existing wet gas scrubber (achieve 25 ppmvd)	Install LoTOx system or alternative technology from each FCCU (to achieve 20 ppmvd)	Discontinue fuel oil burning. Subject to NSPS Subparts A and J for fuel gas combustion devices.	

The control requirements and variations 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 scrubber

   b. NO_x Option 1 – Install selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR)
      Option 2 – Use catalyst additives

2. Heaters/Boilers

Control requirements apply to boilers and heaters 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 per hour separately, but the requirements do not appear to be different from what is required for 40-100 MMBtus. 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 some discretion in deciding which individual boilers/heaters to control as well as the control techniques to apply.

   a. SO_2 Eliminate burning of solid and liquid fuels
   b. NO_x Install ultra-low NO_x burners (ULNB) or other technologies to reduce overall NO_x emissions from heaters and boilers greater than 40 MMBtu per hour

3. Flare Gas Recovery

Meet new source standards at all sulfur recovery plants and most hydrocarbon flares. Install flare gas recovery systems and take other actions to reduce emissions from process upsets. Reroute and eliminate sulfur pit emissions. Implement protocol to diagnose and prevent upsets that result in significant releases of SO_2 and other gases.

4. Leak Detection and Repair

Implement an enhanced program for identifying and repairing leaking valves and pumps, through more frequent monitoring, the use of more stringent definitions of what constitutes a leak, and regular auditing of each facility's leak detection and repair program.

5. Benzene/Wastewater

Develop an enhanced program for ensuring compliance with benzene waste management practices through comprehensive auditing, regular monitoring, and improved emission controls (e.g., secondary carbon canisters and water scrubbers).

Issues related to modeling the refinery settlement associated emission reductions are as follows:

1. Finding the FCCU/FCU records in the 2002 EPA NEI was straightforward in most situations because most refineries have one or two of these units and there are a limited number of associated SCCs. We did find one refinery where the FCCU emissions were

zero, but the CO boilers had large estimated NO_x and SO_2 emissions. We applied the FCCU control requirements to the CO boiler emissions.

2. FCCU SO_2 control requirements were modeled as follows:

a. New wet gas scrubber – a 90 percent SO_2 control efficiency was applied or the specific control efficiency listed in the consent decree, which may be slightly different from 90 percent.

b. Catalyst additives – where required to reduce FCCU SO_2 emissions, a 70 percent control efficiency was applied. The 70 percent control efficiency was estimated from information in the literature about the expected SO_2 emission reductions of this control technique (EPA, 1989).

c. If there was no requirement, or an existing wet gas scrubber, no additional control efficiency was applied. This may underestimate the reductions at refineries with existing wet gas scrubbers that will have to make some upgrades to their scrubbers.

3. Heater/boiler SO_2 control requirements were not applied in this analysis because it was found that there were very few fuel oil burning heaters and boilers at refineries in the NEI.

4. Heater/boiler NO_x controls for the units to which they are applied will be simulated using a 0.04 lbs per million Btu NO_x emission rate. Meeting this emission reduction requirement is expected to provide an average NO_x emission reduction of 50 percent from 2002 levels.

5. Some refineries in the 2002 NEI have provided estimates of their boiler and process heater capacities. When these estimates are provided, they are used to determine which units are subject to the boiler/heater SO_2 and NO_x control requirements (all units > 40 million Btu/hour with non-zero emissions are assumed to be subject to the control requirements). For refineries that do not provide the capacity values, we applied controls to all heaters and boilers with 2002 NO_x emissions above 10 tpy.

6. While the other requirements of the settlements are expected to produce additional emission reductions beyond those applied to FCCUs/FCUs and boilers and heaters, we did not incorporate these emission reductions in our emission projections. The flare gas recovery, leak detection and repair, and benzene/wastewater requirements are expected to produce less significant changes in criteria air pollutant emissions, plus these are source types for which the 2002 NEI emissions estimates are expected to be much more uncertain than they are for the combustion categories.

Regional/Local Programs – MANE-VU

MANE-VU was formed by the mid-Atlantic and Northeastern States, tribes, and Federal agencies to coordinate regional haze planning activities for the region. Because MANE-VU's emission projections for non-EGUs were not completed by the time this study was performed, the following methods were used to estimate control program effects on 2010 and 2020 emissions:

In October 1998, EPA issued the NO_x SIP Call, a final rule under section 110(k) of the CAA, requiring 22 States and the District of Columbia to revise their SIPs to impose additional controls on NO_x

emissions. NO_x emissions for the MANE-VU States affected by the NO_x SIP Call were reduced to reflect the NO_x SIP Call requirements. MANE-VU States with NO_x SIP Call requirements include Connecticut, Delaware, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, and Virginia.

These steps were applied to the four major source categories that are affected by the NO_x SIP Call as follows:

1. For boilers, all sources in the SIP Call-affected States with a boiler design capacity in the 2002 NEI greater than or equal to 250 MMBtu were deemed to be large sources.
2. For turbines, all sources in the SIP Call-affected States with a boiler design capacity in the 2002 NEI greater than or equal to 250 MMBtu were tagged as large sources.
3. For internal combustion engines, all sources with 2002 NO_x emissions greater than 1 ton per day (tpy) were tagged as large sources.
4. For cement manufacturing, all sources with 2002 NO_x emissions greater than 1 ton per day were tagged as large sources.

Once the large sources were determined, the following NO_x control percentages were applied according to the source category affected:

Industrial Boilers	60%
Gas Turbines	60%
Internal Combustion Engines	82%
Cement Manufacturing	25%

<u>Regional/Local Programs – VISTAS</u>

For the Southeast region, VISTAS provided control factor files for the requirements affecting non-EGU sources in 2009 and 2018 (MACTEC, 2005). The relevant files and a short description of the information contained in each file, and its application in this study, is provided below:

1. Atlanta SIP – NO_x control efficiencies are provided for the sources in the Atlanta, GA 1-hour ozone nonattainment area that have post-2002 emission reduction requirements.

2. NO_x SIP Phase I – For large industrial boilers and turbines, the VISTAS analysis includes States in the VISTAS region affected by the NO_x SIP Call that have developed rules. These controls are to be in effect by 2007, so the VISTAS analysis includes capped emissions for SIP Call sources at 2007 levels, which are applied to estimate 2010 and 2020 NO_x emissions at these affected facilities.

3. NO_x SIP Call Cement Kilns – This applies a 25 percent future year control efficiency to all NO_x SIP Call affected units in the VISTAS States.

4. NO_x SIP Call – Phase II – RICE Engines – This applies an 82 percent future year control efficiency to all large RICE engines in the region.

5. Refinery Cases and Settlements – Three refineries in the VISTAS region are affected by consent decrees. The refineries are (1) the Chevron refinery in Pascagoula, MS, (2) the Ergon refinery in Vicksburg, MS, and (3) the Ergon refinery in Newell, WV. Because these refineries were not included in the refinery cases and settlements analysis performed by Pechan for this project, the VISTAS analysis was used to quantify the emission reductions for these three refineries.

Regional/Local Programs – Midwest RPO

The Midwest RPO analysis included control factor development for the following projection years: 2007, 2008, 2009, 2012, and 2018 (Pechan, 2004a). The 5-State Midwest RPO region includes Indiana, Illinois, Michigan, Ohio, and Wisconsin. The control programs affecting non-EGU point source emissions in the study region included:

- Current State/local regulations to meet 1-hour ozone requirements (e.g., regulations implementing Phase I/II NO_x SIP Call).
- MACT standards, including combustion turbine MACT and industrial boiler/process heater/RICE MACT.

In the State and sub-State areas that are affected by the NO_x SIP Call, the regulatory approaches and timing are relatively consistent across the Midwest RPO region. For example, Illinois, Indiana, Ohio, and the fine grid portion of Michigan all have industrial, commercial, and institutional boilers and gas turbines included in the trading program. Because five month ozone season NO_x allowances have been established for the large non-EGU sources in the trading program by Illinois, Indiana, Ohio, and Michigan, those allowances were used to develop plant and unit-specific NO_x control factors to simulate the effect of this portion of the NO_x SIP Call on industrial, commercial, and institutional boilers and gas turbines.

For stationary RICE within the Midwest RPO States, the effect of the NO_x SIP Call requirements on the source category was estimated by using the EPA list of large engines by State, matching these with appropriate point IDs in the 2002 point source emissions file, and applying an 82 percent emission reduction to these specific engines. The effect of the NO_x SIP Call requirements on affected cement kilns was simulated via a 25 percent control efficiency applied to the two point source SCCs for cement kilns (30500606 and 30500706).

Regional/Local Programs – CENRAP

The CENRAP control factor analysis focused on Federal, State, and local rules and regulations that are expected to reduce emissions or emission rates for criteria pollutants in the CENRAP States post-2002 (Pechan, 2005c). The primary focus of the CENRAP non-EGU point source control factor analysis was on estimating the effect of 1-hour ozone nonattainment SIP rules in the areas where they apply. In addition, there are non-EGU point source NO_x control requirements in the fine grid portion of Missouri for the NO_x SIP Call.

For the 1-hour ozone nonattainment areas in Texas, non-EGU control factor development was consistent with Texas Commission on Environmental Quality (TCEQ) ozone episode modeling files. These control factors account for non-EGU control requirements in the following geographic areas: Beaumont/Port Arthur, Houston/Galveston, Dallas/Ft. Worth, and East Texas.

Beaumont/Port Arthur

The Beaumont/Port Arthur ozone nonattainment area includes Hardin, Jefferson, and Orange counties. TCEQ expects that Tier 1 reductions in NO_x emissions from these three counties will be enough for the Beaumont/Port Arthur area to attain the 1-hour ozone standard. Control factors were developed by facility and unit by the TCEQ by comparing survey results that established base year NO_x emission factors with Chapter 117 NO_x emission limits (which are by source category). The survey included all

Beaumont/Port Arthur NO_x sources with 25 tpy or more of NO_x. Source-specific NO_x control factors range from 0.16 to 1.00 for affected sources.

Houston/Galveston

The Houston/Galveston ozone nonattainment area includes Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller counties. On December 6, 2000, the TCEQ adopted a program for the trading of NO_x allowances in the Houston/Galveston nonattainment area. The trading of these allowances takes place under an area-wide cap. The program requires incremental reductions beginning in 2003 and continuing through 2007, when the full reductions of the program are to be achieved. The trading program is expected to provide as much flexibility in meeting these limits as possible.

The most recent Houston/Galveston area SIP revision is based on analysis to date showing that limiting emissions of ethylene, propylene, 1,3-butadiene, and butanes in conjunction with an 80 percent reduction in NO_x is equivalent in terms of air quality benefit to that resulting from a 90 percent point source NO_x reduction requirement.

The TCEQ files for 2007 and 2010, when applied to estimate control factors for 2010 and 2020, yield a control factor of 0.45 (a 55 percent reduction). The control factor affects all non-EGU point source NO_x emissions in their nonattainment area.

There are also requirements for additional fugitive VOC emission reductions in Houston-Galveston. These include new rules to reduce emissions of highly reactive VOCs from four key industrial sources: fugitives, flares, process vents, and cooling towers. The highly reactive VOC rules are performance-based, emphasizing monitoring, record keeping, reporting, and enforcement, rather than establishing individual unit emission rates. This was decided based on a review of how such controls were applied in the Houston SIP analysis, which involved adding highly reactive VOCs to the 2000 emission inventory and removing those highly reactive VOC emissions in the future case. Ultimately, it was decided to not apply any VOC control factors to the 2002 VOC emissions in the 2010 and 2020 emission projections to account for these fugitive VOC controls. The result of this decision is that VOC emissions from this source category are probably underestimated in the section 812 analysis when compared with similar analyses performed in the Texas Air Quality Study, but that future year VOC emission estimates should be comparable.

Dallas/Fort Worth

Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies NO_x control factors proposed for specific industrial boilers and engines and EGUs in that area. These unit specific reductions were applied to estimate 2010 and 2020 NO_x emissions.

30 TAC 117, Subchapter 13 limits NO_x emissions from cement kilns in the Dallas/Fort Worth area. This rule establishes emission limits on the basis of lbs of NO_x per ton of clinker produced. These limits are based on the NO_x emissions averaged over each 30 consecutive day period (later changed to a 365 day period), and vary depending on the type of cement kiln. These NO_x emission limits by kiln type are as follows:

1. For each long wet kiln:
    a. In Bexar, Comal, Hays, and McLennan Counties, 6.0 lbs/ton of clinker produced
    b. In Ellis County, 4.0 lbs/ton

2. For each long dry kiln, 5.1 lbs/ton
3. For each preheater kiln, 3.8 lbs/ton
4. For each preheater-precalciner or precalciner kiln, 2.8 lbs/ton

These emission limits are expected to achieve a 30 percent reduction in cement kiln NO_x emissions.

Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies eleven cement kilns modeled as part of the proposed Dallas/Fort Worth NO_x emission reduction strategy. The level of NO_x controls required by the Texas Natural Resource Conservation Commission ranged by unit from 6 percent to 66 percent. These controls were applied on a unit-by-unit basis.

Control factors were developed by facility and unit by the TCEQ using the same emission factor survey and comparison with NO_x emission limit technique that was described above for Beaumont-Port Arthur. The survey included all Dallas/Fort Worth NO_x sources that reported 2 tons per year or more of NO_x. Source-specific control factors range from 0.13 to 1.00 for affected sources.

Agreed order control factors from the TCEQ were applied to simulate the effects of such orders on two facilities. A control factor of zero is applied to the Eastman plant (482030019), simulating the shutdown of this facility. NO_x control factors are applied to three boilers at the Alcoa (483310001) aluminum production facility. The Alcoa emission changes are in response to a consent decree.

Another TCEQ control factor file contains information about the future year criteria pollutant emissions for the cement kilns in Ellis County. These emission estimates were used to estimate appropriate growth and control factors for the 2010 and 2020 emission forecasts for this area/source category.

Missouri

The fine grid counties in eastern Missouri are affected by EPA NO_x SIP Call requirements. The State of Missouri supplied information about unit-specific NO_x emission reductions for affected facilities. For non-EGUs, this included an 8 ton per ozone season NO_x emission limit applied to Anheuser Busch-Unit 6, a 9 ton per ozone season limit applied to Trigen-Unit 5, and a 36 ton per ozone season limit applied to Trigen-Unit 6.

Kansas

Rule 28-19-717 requires control of VOC emissions from commercial bakery ovens in Johnson and Wyandotte counties. This rule applies to bakery ovens with a potential to emit VOCs equal to or greater than 100 tpy. Each commercial bakery oven (at the unit-level) subject to this regulation shall install and operate VOC emissions control devices for each bakery oven to achieve at least an 80 percent total removal efficiency on the combined VOC emissions of all baking ovens, calculated as the capture efficiency times the control device efficiency. Each bakery oven unit in these two counties with more than 100 tpy of VOC emissions in 2002 had an 80 percent VOC control efficiency applied in the 2010 and 2020 projections.

Louisiana

Point sources in the Baton Rouge nonattainment area and the nearby region of influence are affected by Chapter 22 NO_x control provisions. The provisions of this chapter apply to any affected facility in the Baton Rouge nonattainment area (the entire parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge) and the Region of Influence (affected facilities in the attainment parishes of East Feliciana, Pointe Coupee, St. Helena, and West Feliciana). The provisions of this chapter apply during the ozone season (May 1 to September 30) of each year. Based on the stated compliance deadline of May 1, 2005, we modeled this rule as fully in effect by 2005.

The effects of this NO_x regulation were included in the analysis by applying a 34 percent NO_x emission reduction to the 2002 non-EGU point source emissions in the greater Baton Rouge area. This control factor application is consistent with what was included in the most recent Houston-Galveston area modeling domain assessments by the TCEQ.

Regional/Local Programs – WRAP

The WRAP Stationary Sources Forum is currently revising its 2018 emission projections from a 2002 base year. The summary information provided by the WRAP for its ongoing project indicated that there are very few post-2002 stationary source control requirements in the region outside the State of California. The information that the WRAP study had included on refinery cases and settlements was limited, so the information on refinery cases and settlements that was gathered for this section 812 project was used to characterize the emission changes from those initiatives.

In order to estimate the 2010 and 2020 emission benefits of air pollution emission regulations in California, a request was made to the California ARB to provide control factors that the ARB uses in its own emission projections. ARB staff provided a control factor file that was used in the Central California Ozone Study modeling effort. The Central California Ozone Study projections were based on the 1999 inventory, so the control factors are normalized to 1999. Because 2002 control factors were provided, the 2010 and 2020 control factors were normalized to a 2002 base year by Pechan. This normalization divides the 2010 and 2020 control factors by the associated 2002 control factors for each pollutant and source category. The California file includes control factors by district, air basin, and county, with source categories designated by California's Emission Inventory Codes. The California file has both rule-specific and composite (with all rules applied) control factors. The composite control factors were used in this analysis.

Without-CAAA Scenario

The base year for the evaluation of the *without-CAAA* scenario is the 1990 EPA NEI. For point sources, this database was used along with the activity growth indicators described in Chapter II to estimate *without-CAAA* emissions in 2000, 2010, and 2020.

Emission Summary By Scenario

Exhibit 3-4 summarizes the national (48 State) results of the non-EGU point source analysis for 2002, 2010, and 2020. The *with-CAAA* VOC emission projections for this sector show an overall 3 percent increase in VOC emissions from 2002 to 2010 and a 14 percent increase from 2010 to 2020. For VOC emissions, there is no dominant source category. This is a sector where many of the sources added controls in the 1990 to 2000 period in response to EPA NESHAPs. Between 2000 and 2010, there are additional NESHAP requirements for certain source categories like petroleum refineries that produce lower emissions in 2010 than in 2000. However, for most source categories, VOC emissions are estimated to increase from 2000 to 2010. Then, because no additional emission control requirements are imposed after 2010, *with-CAAA* VOC emissions in the 2010 to 2020 period increase in proportion to expected activity growth in this period, consistent with our projection approach assuming that, absent new controls, emissions grow with economic or throughput activity.

Exhibit 3-4. National Non-EGU Emissions by Major Source Category (tpy)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
Fuel Comb. Industrial	165,662	176,845	144,360	207,636	147,378	241,680	163,578
Fuel Comb. Other	8,495	9,442	13,256	15,500	12,682	16,918	14,070
Chemical & Allied Product	460,077	508,150	129,084	559,123	135,723	634,624	159,431
Metals Processing	121,909	146,967	46,828	149,819	49,588	159,799	55,297
Petroleum & Related Industrial	254,433	286,604	127,690	333,979	141,567	368,163	154,474
Other Industrial Processes	339,726	419,370	395,447	491,336	416,661	587,710	477,948
Solvent Utilization	886,454	1,112,333	366,635	1,229,615	338,830	1,447,906	398,179
Storage & Transport	336,269	376,959	189,262	434,340	221,016	496,120	253,623
Waste Disposal & Recycling	35,759	46,449	25,911	57,723	27,678	74,609	34,594
Miscellaneous	584	871	2,869	1,223	2,872	1,702	3,210
Total	**2,609,368**	**3,083,990**	**1,441,342**	**3,480,293**	**1,493,995**	**4,029,231**	**1,714,402**
NO_x							
Fuel Comb. Industrial	2,177,807	2,217,609	1,497,166	2,292,740	1,341,038	2,565,916	1,445,426
Fuel Comb. Other	145,311	161,238	114,252	170,931	104,751	188,912	116,177
Chemical & Allied Product	164,330	168,118	63,060	182,803	68,117	209,829	84,408
Metals Processing	97,996	120,151	65,382	127,814	72,532	138,584	77,717
Petroleum & Related Industrial	133,024	167,122	59,324	194,297	58,387	208,452	62,695
Other Industrial Processes	374,790	444,006	414,755	525,278	479,775	608,168	550,616
Solvent Utilization	1,246	1,544	6,526	1,695	2,200	2,053	2,564
Storage & Transport	1,682	2,435	11,498	2,658	13,757	3,298	15,863
Waste Disposal & Recycling	37,265	46,312	44,774	56,504	49,373	71,557	61,014
Miscellaneous	0	0	1,404	0	1,500	0	1,675
Total	**3,133,450**	**3,328,534**	**2,278,144**	**3,554,720**	**2,191,430**	**3,996,770**	**2,418,153**
CO							
Fuel Comb. Industrial	693,720	752,541	1,004,485	928,377	1,084,747	1,095,384	1,189,235
Fuel Comb. Other	169,993	181,770	94,191	204,735	105,226	212,363	116,886
Chemical & Allied Product	1,183,331	1,303,012	291,667	1,308,657	358,732	1,435,083	447,888
Metals Processing	2,639,651	3,056,498	983,665	3,010,235	926,835	3,087,741	987,350
Petroleum & Related Industrial	328,301	443,318	106,912	518,757	115,356	583,194	125,620
Other Industrial Processes	535,747	587,736	451,219	686,670	530,634	787,115	607,486
Solvent Utilization	4,523	4,480	1,552	4,877	1,797	5,116	2,139
Storage & Transport	75,464	90,497	117,507	89,058	113,544	102,000	124,771
Waste Disposal & Recycling	36,674	47,032	85,576	56,945	92,481	73,765	110,381
Miscellaneous	0	0	1,490	0	1,389	1	1,581
Total	**5,667,404**	**6,466,885**	**3,138,265**	**6,808,311**	**3,330,740**	**7,381,762**	**3,713,336**

Exhibit 3-4 (continued)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
SO_2							
Fuel Comb. Industrial	2,218,863	1,883,769	1,065,558	2,117,958	1,031,903	2,202,448	1,038,931
Fuel Comb. Other	204,683	137,583	90,081	147,545	90,144	150,582	88,864
Chemical & Allied Product	296,686	353,586	254,296	368,170	303,920	424,809	370,404
Metals Processing	725,409	882,607	208,123	939,660	233,370	1,107,051	267,213
Petroleum & Related Industrial	428,029	516,727	222,423	606,255	218,246	664,625	236,526
Other Industrial Processes	395,788	457,195	334,382	544,753	399,660	613,460	461,289
Solvent Utilization	317	369	181	400	173	453	189
Storage & Transport	1,748	2,321	5,983	2,654	5,165	3,100	5,818
Waste Disposal & Recycling	21,747	27,584	15,344	33,861	16,252	43,404	20,158
Miscellaneous	0	0	2,557	0	809	0	893
Total	**4,293,268**	**4,261,741**	**2,198,926**	**4,761,255**	**2,281,643**	**5,209,932**	**2,490,285**
PM_{10}							
Fuel Comb. Industrial	224,201	221,090	128,495	265,650	125,242	303,449	140,016
Fuel Comb. Other	16,662	13,442	9,526	14,007	8,918	14,769	9,824
Chemical & Allied Product	76,408	88,497	19,918	90,050	22,294	102,143	25,581
Metals Processing	216,779	267,501	67,913	278,468	57,528	301,790	63,556
Petroleum & Related Industrial	53,278	55,400	17,538	64,994	18,807	74,852	21,795
Other Industrial Processes	568,646	674,223	191,206	790,671	204,758	895,127	255,737
Solvent Utilization	4,214	5,394	6,208	6,062	6,592	7,149	7,663
Storage & Transport	102,006	118,919	40,561	133,753	36,439	150,544	42,722
Waste Disposal & Recycling	15,077	19,716	16,676	24,743	17,080	32,086	22,058
Miscellaneous	0	0	592	0	598	0	696
Total	**1,277,270**	**1,464,183**	**498,633**	**1,668,399**	**498,257**	**1,881,910**	**589,650**
$PM_{2.5}$							
Fuel Comb. Industrial	159,353	163,081	89,180	200,168	81,798	231,990	88,530
Fuel Comb. Other	9,574	8,981	5,870	9,420	5,244	10,142	5,560
Chemical & Allied Product	46,370	53,218	13,848	54,986	14,228	62,931	15,717
Metals Processing	157,472	193,353	49,387	201,930	41,725	217,728	44,336
Petroleum & Related Industrial	25,884	27,014	16,865	31,770	16,659	36,564	18,408
Other Industrial Processes	266,411	314,004	205,177	361,906	237,191	414,016	299,761
Solvent Utilization	3,717	4,738	4,391	5,311	4,436	6,246	4,972
Storage & Transport	41,881	48,675	28,574	55,002	28,331	61,749	30,422
Waste Disposal & Recycling	11,781	15,256	11,450	18,958	11,379	24,481	13,446
Miscellaneous	0	0	345	0	325	0	363
Total	**722,442**	**828,322**	**425,087**	**939,451**	**441,315**	**1,065,848**	**521,515**

Exhibit 3-4 (continued)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
NH_3							
Fuel Comb. Industrial	9,952	10,935	444,158	11,770	515,064	13,384	603,531
Fuel Comb. Other	256	167	1,171	139	1,282	152	1,427
Chemical & Allied Product	182,577	168,067	77,506	163,208	83,297	171,819	81,992
Metals Processing	5,901	7,522	3,110	7,477	3,078	7,619	2,977
Petroleum & Related Industrial	42,845	47,741	2,494	53,309	2,906	61,033	3,328
Other Industrial Processes	2,084	1,693	133,059	1,555	153,789	1,630	181,333
Solvent Utilization	0	0	1,984	0	2,505	0	3,362
Storage & Transport	0	0	712	0	766	0	799
Waste Disposal & Recycling	0	0	257,554	0	298,648	0	383,178
Miscellaneous	0	0	10,247	0	11,703	0	12,963
Total	**243,615**	**236,126**	**931,995**	**237,459**	**1,073,038**	**255,636**	**1,274,891**

In interpreting our NO_x emissions results, it is important to remember that non-EGU point source NO_x emissions are a product of fuel combustion. In the eastern United States, many of the large fuel combustion sources are subject to the requirements of the NO_x SIP Call, and these requirements affect industrial boiler, gas turbine, RICE engine, and cement kiln emissions starting after 2002. Outside the NO_x SIP Call area, there are stringent NO_x rules affecting NO_x sources in eastern Texas, the Baton Rouge area in Louisiana, and in many Air Districts in California. Sources and geographic areas affected by these requirements contribute to the expected emission reductions between 2000 and 2010. After 2010, some NO_x emission increases are anticipated as fuel consumption by the industrial sector continues to grow. Uncertainties in the NO_x emission projections include whether NO_x SIP Call States include their affected non-EGU boilers and gas turbines as trading program sources, whose NO_x emissions are effectively capped, and whether sources affected by a 5 month ozone season control program install controls that also reduce NO_x emissions during the 7 month winter season.

Non-EGU SO_2 emissions are expected to stay relatively stable over the forecast period. Industrial fuel combustion SO_2 emissions from boilers decline slightly from 2000 to 2010, and then increase to near 2000 levels by 2020. The slight upward trend in non-EGU SO_2 emissions over the forecast period is a result of strong expected activity growth in the chemical industry and other industrial processes. Some industries, such as copper smelting, that have historically been major SO_2 emission contributors, are now modest contributors to non-EGU SO_2 emissions, and have little influence on future national SO_2 emissions in this sector. Refinery settlements produce SO_2 emission reductions in the forecast period for the petroleum industry.[18]

Comparisons of *with-* versus *without-CAAA* criteria pollutant emissions are generally according to expectations – as *with-CAAA* emissions in 2000, 2010, and 2020 are normally less than *without-CAAA* emissions. Several exceptions can be noted in some of the smaller emitting categories for all pollutants, and in the overall results shown in Table 3-4 for ammonia. For example, the total non-EGU point source ammonia emissions in 2000 are 236 thousand tons in the *without-CAAA* scenario, and 932 thousand tons in the 2000 *with-CAAA* scenario. While adoption of NO_x control techniques at point sources that involve ammonia injection could account for some of the difference between the two estimates, it is more likely that there was more emphasis during the 2002 NEI point source emission inventory development process in identifying and assigning NH_3 emission estimates to the significant NH_3 emitters – like cement kilns – than occurred during 1990 emission inventory preparation. Therefore, the differences between *with-* and *without-CAAA* NH_3 emissions in Table 3-4 are probably an artifact of the methods differences in developing point source emission estimates between 1990 and 2002. The effects of this factor for the total emissions results for other pollutants are far less pronounced, reflecting the fact that emissions estimation methods for ammonia have progressed from a relatively primitive state in the early 1990's to a better informed state currently.

The magnitude of ammonia emissions from this source category make this an important issue to resolve before air quality modeling commences, and the Project Team is working to address this issue. Options for resolving the inconsistency include:

1. Using 2002 NH_3 emissions rates for both the *with-* and *without-CAAA* scenarios for this pollutant, which would effectively make the two scenarios identical (in terms of the spatial distribution and magnitude of emissions) for this pollutant/source category combination. This option would leave us without a clear strategy for estimating 1990 emissions on a consistent basis. We have not yet investigated whether backcasting 1990

[18] Note that the non-EGU SO2 emission projections do not include any influence of best available retrofit technology (BART) controls. BART controls are addressed as part of the local controls analysis, described in Chapter 8.

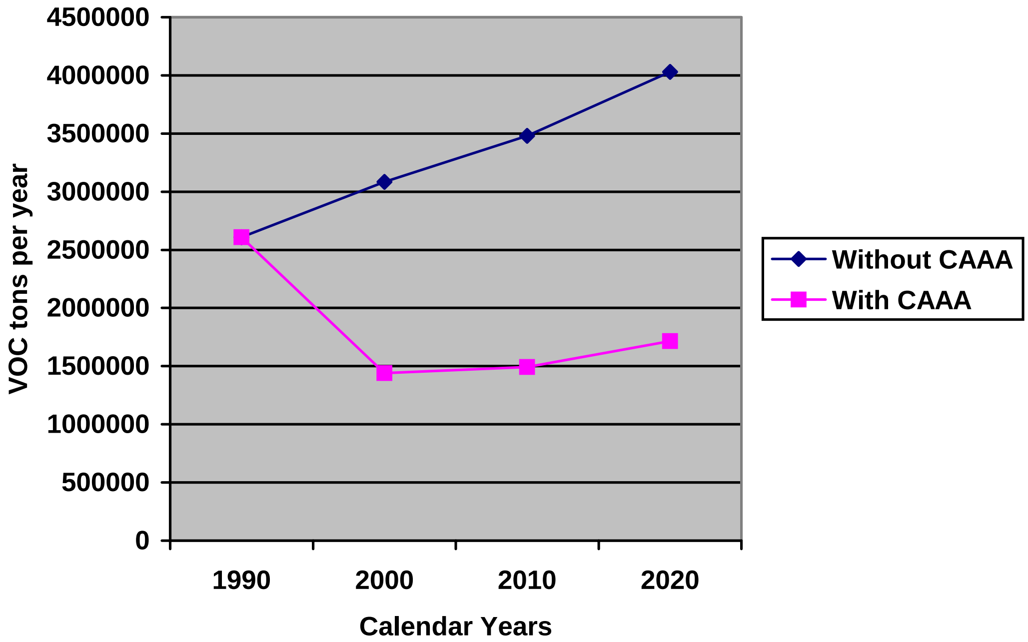
emissions from 2002 based on ratios of activity factors is feasible, but pursuing that approach would be inconsistent with the approach used for other pollutants in this source category.

2. Using the 1990 NEI emissions as the base inventory for both scenarios. This option achieves full consistency for each target year/scenario combination, but would likely generate serious inaccuracies in the *with-CAAA* scenario. This option seems inferior to the first option.

3. Some combination or hybrid approach that makes use of a broader range of data or perhaps a complete different data source.

Exhibit 3-5 displays the non-EGU point source sector *with-* and *without-CAAA* emission summaries by pollutant in a graphic format.

Exhibit 3-5. *With-* and *Without-CAAA* Scenario Non-EGU Point Source Emission Summaries by Pollutant



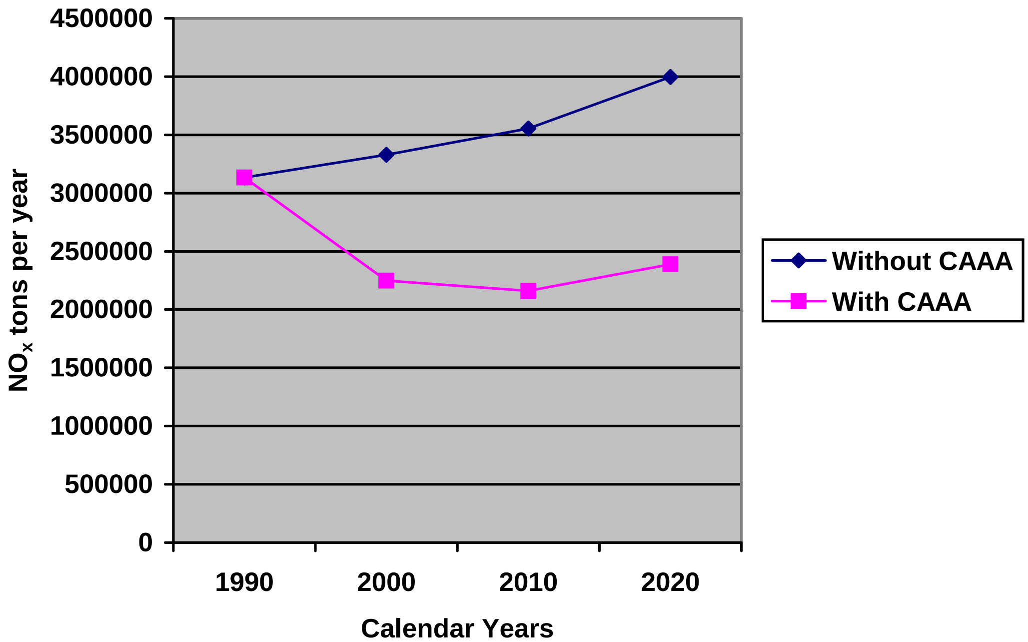
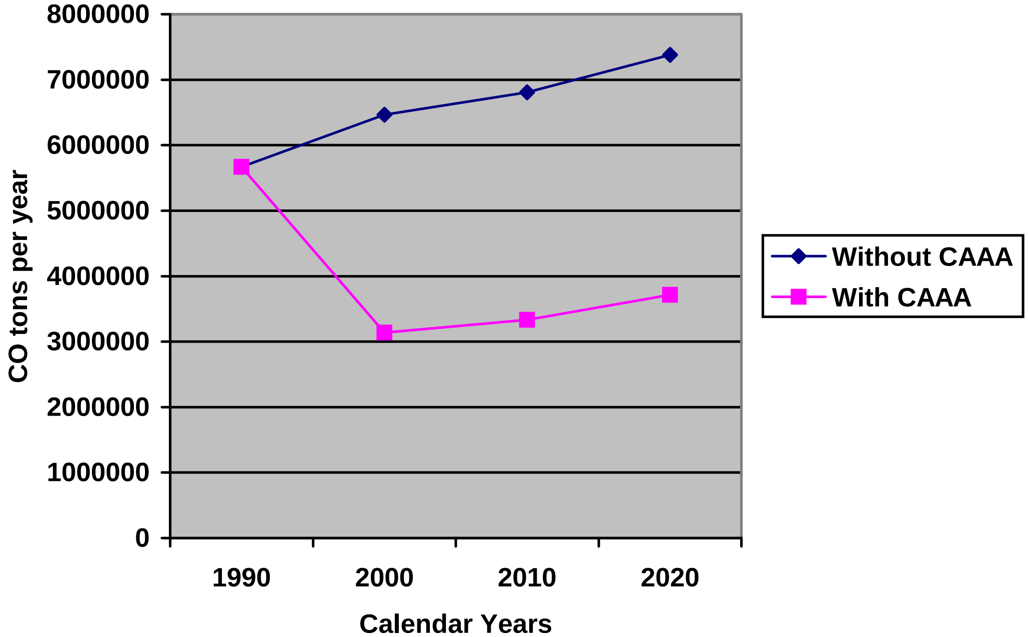


Exhibit 3-5 (continued)



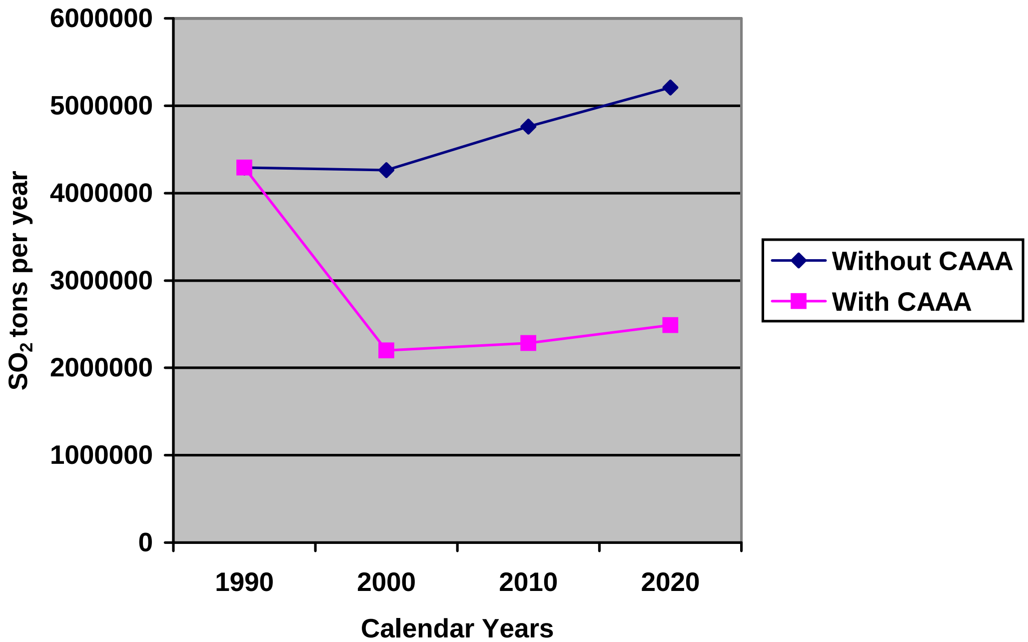
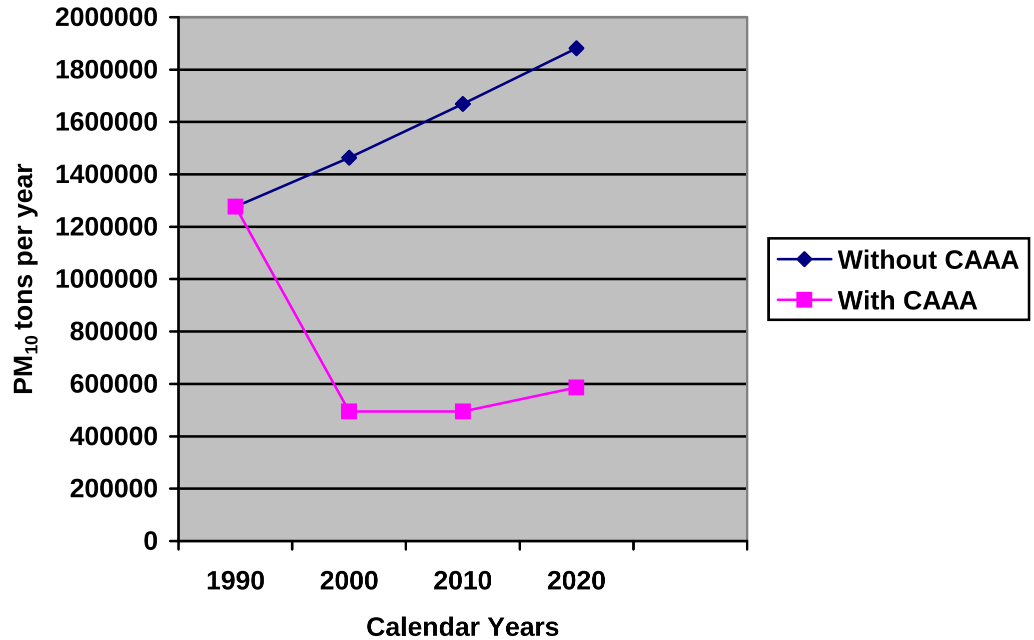


Figure 3-5 (continued)



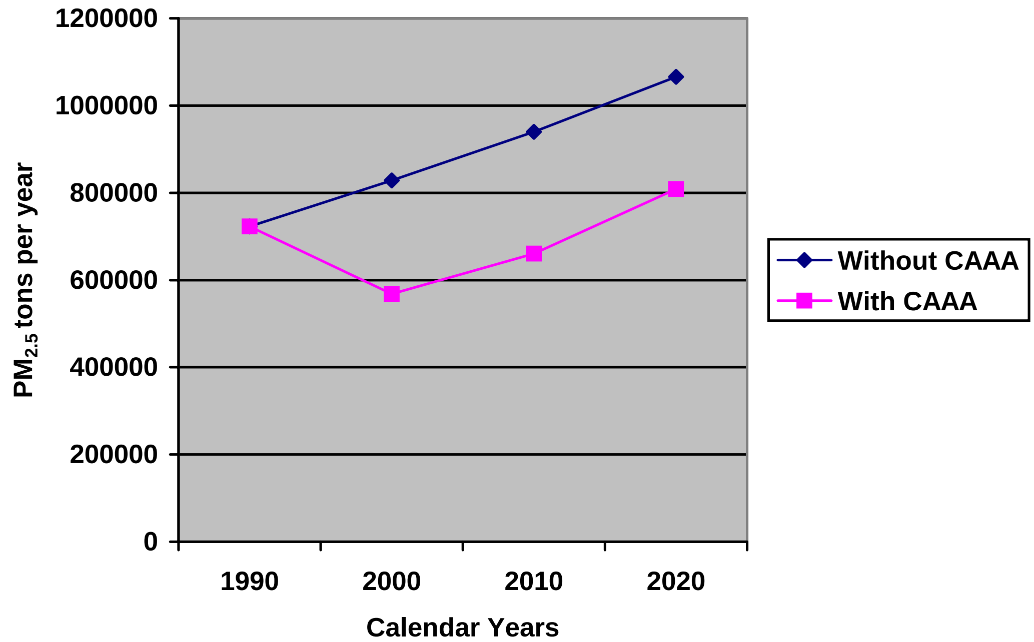
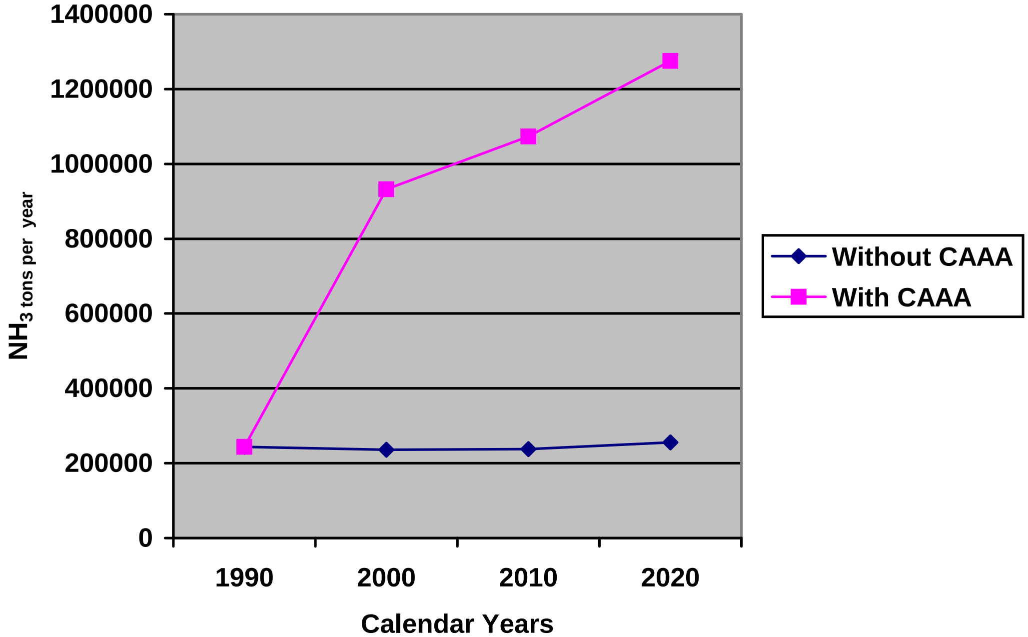


Exhibit 3-5 (continued)



CHAPTER 4 - ELECTRICITY GENERATING UNIT POINT SOURCES

Introduction

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 the EGU sector 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.[19]

The purpose of this chapter is to describe the 812 project team's approach for estimating the impact of the Clean Air Act Amendments on EGU emissions between 1990 and 2020 and to present the project team's estimates of these impacts. 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 EGU emissions relative to emissions from other sources. According to EPA's 2002 National Emissions Inventory, EGUs were responsible for 67 percent of total SO_2 emissions in 2002 and 22 percent of NO_x emissions.[20]

We present the project team's methodology and results in four separate sections. First, we provide a detailed description of the analytic tools the project team used to estimate EGU emissions. In the second and third sections, we describe the project team's application of these tools. We present this information in two separate sections because the project team's approach for estimating emissions retrospectively is different than its approach for projecting emissions into the future. To conclude the chapter, we present the project team's emissions estimates for the four target years selected for the Second Prospective: 1990, 2000, 2010, and 2020.[21]

[19] 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.

[20] 2002 NEI as cited in U.S. EPA, "Acid Rain Program 2003 Progress Report," September 2004, EPA 430-R-04-009.

[21] Although the Second Prospective will estimate the impacts of the Amendments for the years 2000, 2010, and 2020, the project team uses EGU emissions in 2001 as a proxy for emissions in 2000. Before commencing with the emissions analysis for the Second Prospective, EPA conducted an analysis of EGU emissions in 2001 to test the accuracy of the analytic tools that EPA typically uses for EGU emission analyses. Due to resource constraints, the project team expanded upon this analysis for the Second Prospective rather than developing an entirely new EGU emissions analysis for 2000.

Analytic Tools

To assess CAAA-related emissions impacts for NO_x, SO_2, and mercury, the 812 project team used the Integrated Planning Model (IPM) developed by ICF Resources, Inc. 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). In this section, we summarize the structure, features, and assumptions of IPM; the key outputs generated by the model; and recent EPA efforts to assess the validity of IPM's results.

IPM Structure, Features, and Assumptions[22]

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 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 each unit, 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.[23]

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.[24] 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 in 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

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[22] 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.

[23] Because IPM's results do not reflect costs associated with pre-2007 investments, the project team will conduct an analysis offline to estimate these costs. The project team addresses this issue in more detail in the cost report for the Second Prospective.

[24] IPM also includes 2026 as a model run year, but EPA does not typically report the results for this year. Because 2026 is the last model run year in IPM's planning horizon, the results for 2026 may be skewed.

Council (NERC) regions. Based on historical demand data for each region and EPA 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.

IPM Outputs

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

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 aggregate and at the unit level.

***Costs*:** Based on the simulated 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 aggregate and at the unit level.

***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.

***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.

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[25]

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

[25] 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.

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.[26]
- 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 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), 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.

[26] A resource play is an accumulation of hydrocarbons known to exist over a large area.

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. Recently EPA 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.[27] Overall, IPM's 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;

[27] 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.

- 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.

Estimation of Emissions for Pollutants Not Included in IPM

To estimate emissions of pollutants not included in IPM, the 812 project team followed the procedures approved by EPA for post-processing the output data generated by IPM version 2.1.9. Using this methodology, the project team estimated EGU emissions of CO, VOC, PM_{10}, $PM_{2.5}$, and NH_3 as a function of the estimated fuel consumption for each unit, the content of the fuel consumed by each unit, the emissions factor for each pollutant, and the estimated control efficiency for each pollutant (PM_{10} and $PM_{2.5}$ only). Equations 1 and 2 summarize how the project team used this information.

$$(1) \quad E_{CO,VOC,NH3} = FC \times EF_{CO,VOC,NH3}$$

$$(2) \quad E_{PM10,PM2.5} = FC \times EF_{PM10,PM2.5} \times A \times (1 - CE)$$

Where $E_{CO,VOC,NH3}$= Emissions of CO, VOC, or NH_3,
FC= Fuel consumption,
$EF_{CO,VOC,NH3}$= Emissions factor for CO, VOC, or NH_3,
$E_{PM10,PM2.5}$=Emissions of PM_{10} or $PM_{2.5}$,
$EF_{PM10,PM2.5}$=Emissions factor for PM_{10} or $PM_{2.5}$,
A= Ash content, and
CE=Control efficiency.

To apply the methodology summarized in Equations 1 and 2, the project team used the fuel consumption estimates generated by IPM and modified estimates of EPA's AP-42 emission factors approved by the Agency's Office of Air Quality Planning & Standards as of August 2003. These modified emission factors are used for both the with-CAAA and without-CAAA scenarios. The project team estimates the ash content for each unit as the weighted average of the monthly values reported on each unit's 2001 EIA-767 form. For PM_{10} and $PM_{2.5}$ control efficiencies, the project team used the values selected by EPA for the development of the 2002 National Emissions Inventory. For each control technology, these values are the same for both the with-CAAA and without-CAAA scenarios.

Under the methodology outlined in Equations 1 and 2, the difference between with-CAAA and without-CAAA EGU emissions of CO, VOC, and NH_3 depends only on the difference in the fuel mix between scenarios. Utilities do not control emissions of these pollutants under either scenario, and controls for SO_2, NO_x, and mercury do not limit CO, VOC, or NH_3 emissions. In contrast, the difference between with-CAAA and without-CAAA emissions of particulate matter (PM_{10} and $PM_{2.5}$) depends on both the fuel mix and the control technologies installed for SO_2 and NO_x under each scenario. The technologies that utilities use to control SO_2 and NO_x emissions reduce emissions of both PM_{10} and $PM_{2.5}$.

IPM Analyses For 2010 And 2020

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 developed by the 812 project team for the 2010 and 2020 IPM analyses and the core data inputs the project team included in the model. Because the project team's 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 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 with-CAAA and without-CAAA emissions represents the emissions impact of the Amendments.

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,[28]
- 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).

Under the without-CAAA scenario, federal, state, and local controls of utility emissions are frozen at 1990 levels of stringency. Exhibit 4-1 presents the emissions rates and other assumptions reflected in the without-CAAA scenario.

[28] 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.

Exhibit 4-1

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— provided 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.

Exhibit 4-1

ASSUMPTIONS REFLECTED IN THE WITHOUT-CAAA SCENARIO

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.

Exhibit 4-1

ASSUMPTIONS REFLECTED IN THE WITHOUT-CAAA SCENARIO

Element		Assumption
	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.
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 emissions analyses conducted for the Second Prospective reflect input data from several different sources. In some cases, the project team used input data already included in version 2.1.9 of IPM (i.e., the version of IPM used to develop EPA's 2004 EPA Base Case), but for several key variables the project team replaced the inputs in version 2.1.9 of the model 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 that 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 project team used the National Electric Energy 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 4-2 and 4-3 summarize the sources of information EPA used to develop the NEEDS 2004 data for existing and planned/committed units, respectively.

EXHIBIT 4-2

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 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 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 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 4-3

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. As indicated above, the natural gas supply curves from IPM v2.1.9 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. Although more up-to-date supply curves may better reflect recent increases in natural gas prices, a recent sensitivity analysis conducted by EPA suggests that IPM's results are not highly sensitive to natural gas prices.[29] Therefore, updating the model with more recent supply curves is unlikely to have a significant impact on the EGU emissions results for the Second Prospective.

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 812 project team retained the resource base and coal supply cost estimates included in version 2.1.9 of IPM but updated the coal supply productivity data in the model 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 812 project team also used AEO 2005 data for several other key model inputs. This application of AEO 2005 data is consistent with the project team's 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,[30] and

[29] U.S. EPA, "Multi-pollutant Analysis: Natural Gas Price Sensitivity, " April 2006, http://www.epa.gov/airmarkets/mp/.

[30] 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,"

- 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.[31]

IPM Analyses For 2001

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 project team's approach for estimating emissions impacts at electric utilities for the 2010 and 2020 target years. For 2000, the project team uses EGU emissions impacts in 2001 as a proxy for impacts in 2000. Due to resource constraints and model limitations, the project team adapted the 2001 validation analysis examined above instead of developing a new analysis for the year 2000.

In this section, we describe the project team's 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 emissions retrospectively. 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 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 reflect any 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 812 project team included the following data inputs in the model:

- IPM model units representing existing units were developed from the 2001 inventory of EGUs, as represented in NEEDS 2004.

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

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

- Electricity demand, peak load, and load shape were set to 2001 levels.[32] 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.[33]

- 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.[34] According 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.[35]

- 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 emissions estimates was consistent with the EGU capital stock in place in 2001.

Results

In this section we present the results of the EGU emissions analyses conducted for the Second Prospective. These results include emissions under the with-CAAA and without-CAAA scenarios; the projected generation and capacity mix (by fuel type) under each scenario; estimated allowance prices for SO_2, NO_x, and mercury; and fuel and electricity prices under each scenario. We also compare the results for the 2001 with-CAAA scenario with ETS-CEM data collected for 2001.

Emissions

Exhibits 4-4 and 4-5 summarize our EGU emissions estimates for VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, Hg, and NH_3 for 1990, 2001, 2010, and 2020. Under the without-CAAA scenario, NO_x and SO_2 emissions grow significantly between 1990 and 2010, but emissions of both pollutants remain relatively flat during the 2010-2020 period. Without-CAAA emissions of NO_x from electric utilities increase by

32 The project team used electricity demand and peak load for 2001 as estimated in the North American Electric Reliability Council, Electricity Supply & Demand 2002 database. For load shape, the project team used data from the Federal Energy Regulatory Commission Form 714 for 2001.

33 North American Electric Reliability Council, O*p cit.*

34 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.

35 U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002.

approximately 4 percent during this period while SO_2 emissions fall by approximately 1 percent. This reflects the confluence of a number of factors during the 2010-2020 period, including increased reliance on coal-fired plants in compliance with the NSPS and a change in the relative prices of different types of coal. Based on AEO 2005 projections of coal mine productivity, IPM estimates that the price of low-sulfur sub-bituminous coal will decline relative to other types of coal during this period.

Under the with-CAAA scenario, EGU emissions of both NO_x and SO_2 decline significantly between 1990 and 2020. As indicated in Exhibit 4-4, emissions of NO_x from utilities fell from 6.4 million tons in 1990 to 4.5 million tons in 2001. We estimate that emissions will continue falling to 2.4 million tons in 2010 and 2.0 million tons in 2020. Relative to the without-CAAA scenario, this represents a 71 percent reduction in EGU NO_x emissions for 2010 and a 77 percent reduction for 2020. Similarly, SO_2 emissions from utilities fell from 15.8 million tons in 1990 to 10.8 million tons in 2001 under the with-CAAA scenario and are expected to decline further to 6.4 million tons in 2010 and 4.3 million tons in 2020. For 2001 this represents a 40 percent reduction in SO_2 emissions relative to the without-CAAA scenario and a 77 percent reduction for 2020.

In addition to NO_x and SO_2, the Amendments also lead to reduced emissions of PM_{10} and $PM_{2.5}$ from electric utilities, although these reductions are not as significant as those for NO_x and SO_2. For 2010, we estimate that direct $PM_{2.5}$ and PM_{10} emissions will be 25 percent and 21 percent less, respectively, under the with-CAAA scenario than under the without-CAAA scenario. By 2020 these differences will change to 34 percent and 29 percent for $PM_{2.5}$ and PM_{10} respectively.

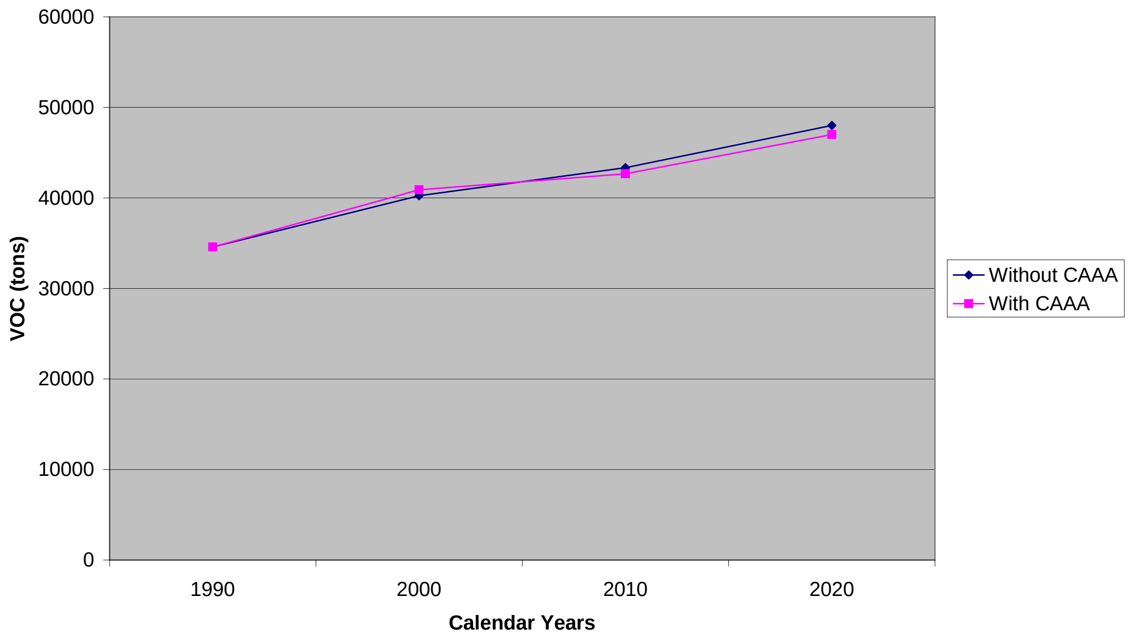
For most of the other pollutants included in Exhibit 4-4, emissions from utilities increase under both the with-CAAA and without-CAAA scenarios. In contrast, estimated EGU emissions of ammonia appear to fall significantly between 2001 and 2020 under both scenarios. These results are artificially low because EPA's post-processing methodology for version 2.1.9 of IPM does not include ammonia emission factors for combined cycle units or turbines, which were not available at the time this methodology was developed. Between 2001 and 2020, utilities are expected to replace several boiler units with combined cycle or turbine systems. Because the post-processing methodology does not capture ammonia emissions from these sources, total ammonia emissions appear to decline under both the with-CAAA and without-CAAA scenarios. Although these estimates do not accurately reflect EGU ammonia emissions, the results in Exhibit 4-4 suggest that EGU ammonia emissions are relatively insignificant relative to emissions from other sources. For example, we estimate that non-EGU point sources will emit approximately 1.1 million tons of ammonia in 2010 under the with-CAAA scenario, compared to just 822 tons for electric utilities. Nevertheless, the project team is currently exploring different options for addressing this limitation of the EGU emissions analysis, including updating the IPM post-processing methodology to include recently developed NH_3 emission factors for combined cycle units and turbine systems.

The results in Exhibit 4-4 also suggest that with-CAAA emissions of carbon monoxide (CO) exceed CO emissions under the with-CAAA scenario. This reflects the shift in generation from coal-fueled units to natural gas systems under the with-CAAA scenario. Because natural gas units emit more CO per unit of heat input than coal units, CO emissions are higher under the with-CAAA scenario. Similarly, with-CAAA emissions of volatile organic compounds (VOCs) exceed without-CAAA emissions in 2001 because natural gas units emit more VOCs per unit of heat input than coal-fueled systems.

EXHIBIT 4-4 EGU EMISSIONS TOTALS BY POLLUTANT (tons)								
Pollutant	**Fuel Type**	**1990**	**2001 without-CAAA**	**2001 with-CAAA**	**2010 without-CAAA**	**2010 with-CAAA**	**2020 without-CAAA**	**2020 with-CAAA**
VOC	Coal	27,127	32,120	32,683	35,631	34,950	37,354	35,911
	Gas	2,166	7,845	8,064	7,547	7,623	10,556	10,989
	Other	5,266	273	135	155	91	91	91
	Total	34,558	40,238	40,882	43,333	42,664	48,001	46,992
NO_x	Coal	5,639,083	7,381,429	4,231,399	8,037,163	2,270,314	8,245,052	1,805,780
	Gas	565,385	345,587	253,973	296,971	151,989	426,196	165,714
	Other	206,065	6,984	8,609	15,348	14,916	14,969	14,969
	Total	6,410,533	7,734,001	4,493,981	8,349,482	2,437,219	8,686,216	1,986,463
CO	Coal	234,285	297,781	300,499	332,292	340,308	349,125	351,638
	Gas	50,623	196,788	201,852	268,556	276,772	400,632	419,235
	Other	18,805	1,861	955	1,200	779	782	782
	Total	303,713	496,430	503,306	602,048	617,860	750,539	771,654
SO_2	Coal	15,218,684	18,095,299	10,797,563	18,853,888	6,365,458	18,738,860	4,270,125
	Gas	757	0	0	0	0	0	0
	Other	612,261	51,360	21,836	13,644	0	0	0
	Total	15,831,702	18,146,659	10,819,399	18,867,532	6,365,458	18,738,860	4,270,125
Primary PM_{10}	Coal	506,247	734,401	711,370	812,049	635,036	863,743	602,775
	Gas	4,758	16,455	16,854	21,845	22,490	32,418	33,907
	Other	19,657	840	495	761	625	630	630
	Total	530,663	751,696	728,719	834,655	658,151	896,790	637,311
Primary $PM_{2.5}$	Coal	337,857	617,037	593,325	681,929	506,137	729,368	472,065
	Gas	3,924	16,455	16,854	21,845	22,490	32,418	33,907
	Other	15,893	795	459	670	536	540	540
	Total	357,674	634,287	610,638	704,443	529,163	762,326	506,512
NH_3	Coal	Not estimated	285	289	316	310	329	317
	Gas	Not estimated	2,680	2,766	640	511	282	241
	Other	Not estimated	252	107	67	0	0	0
	Total	Not estimated	3,217	3,162	1,023	822	612	559

Exhibit 4-5

EGU Emissions Summaries under the With-CAAA and Without-CAAA Scenarios, by Pollutant



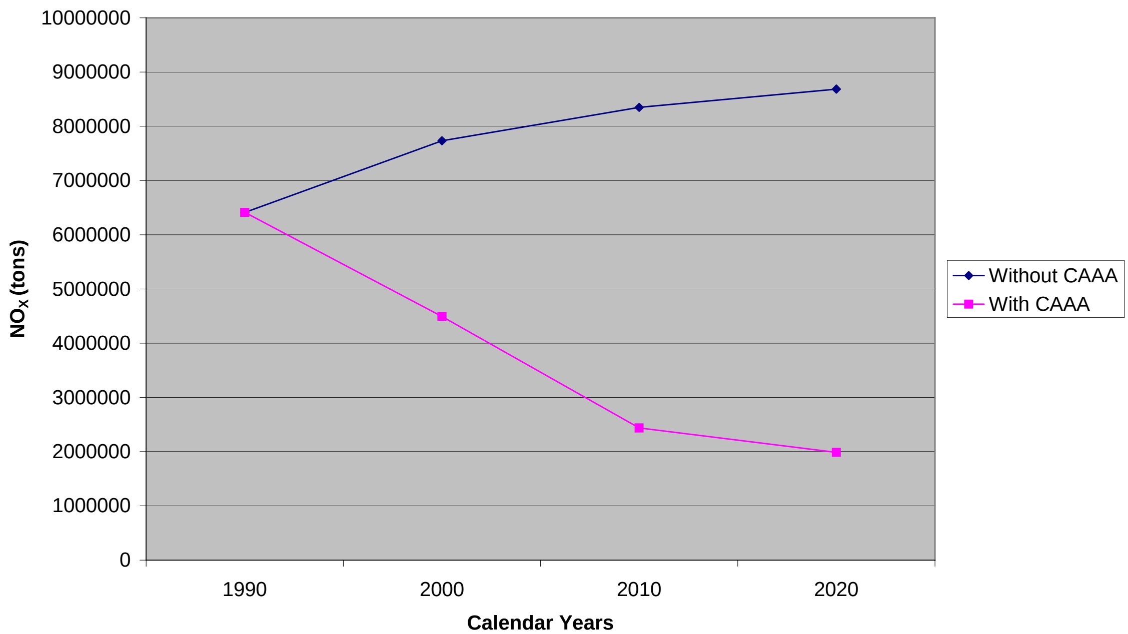
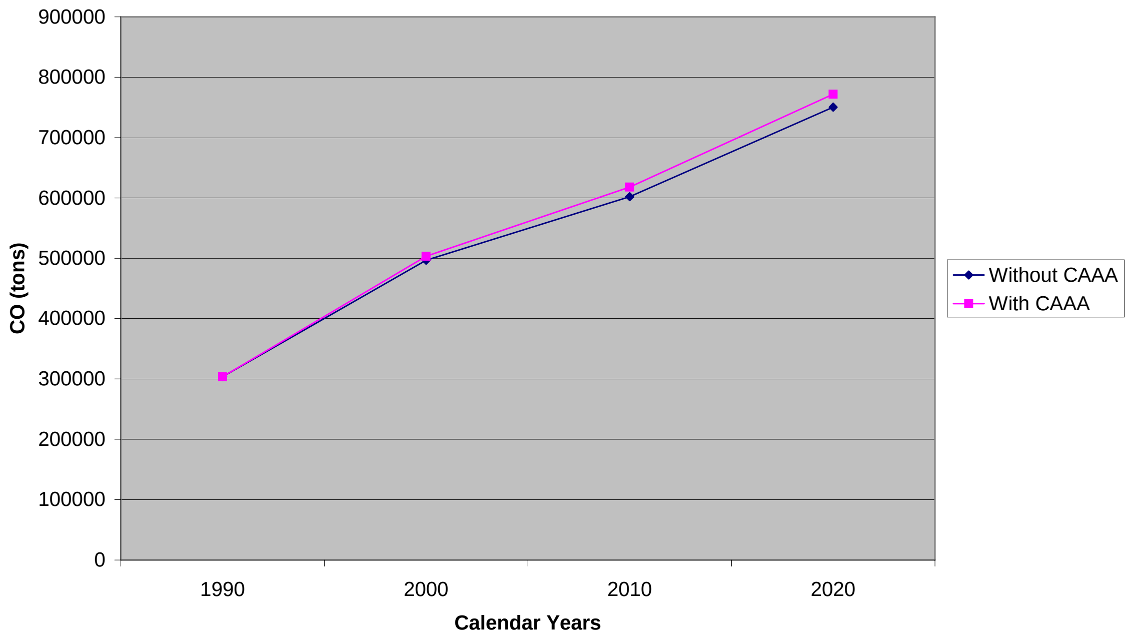


Exhibit 4-5 (continued)



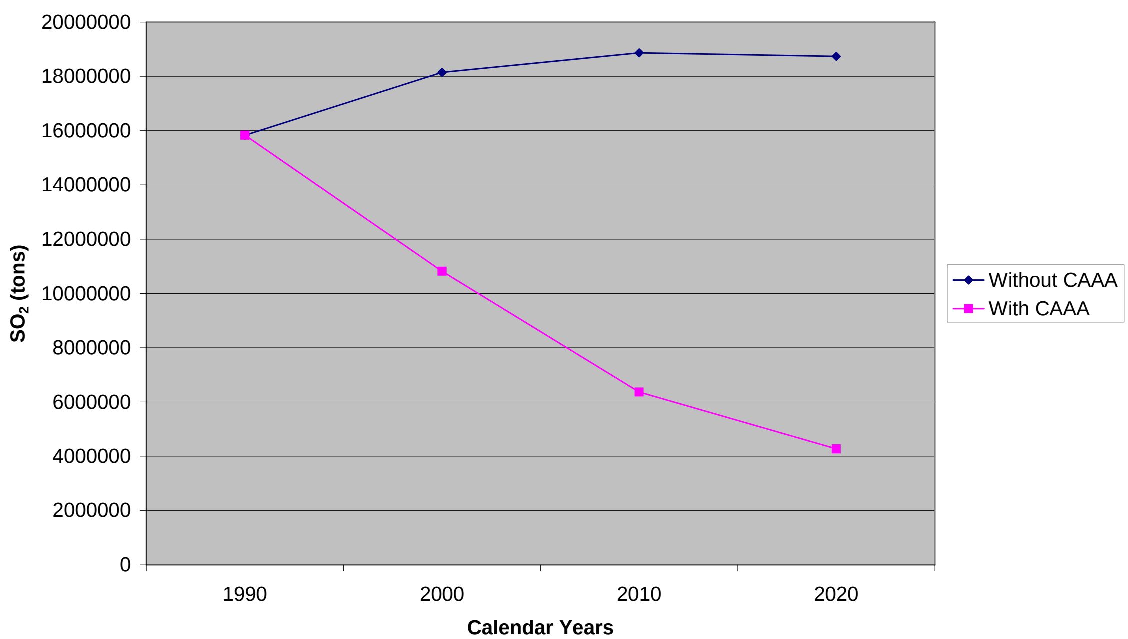
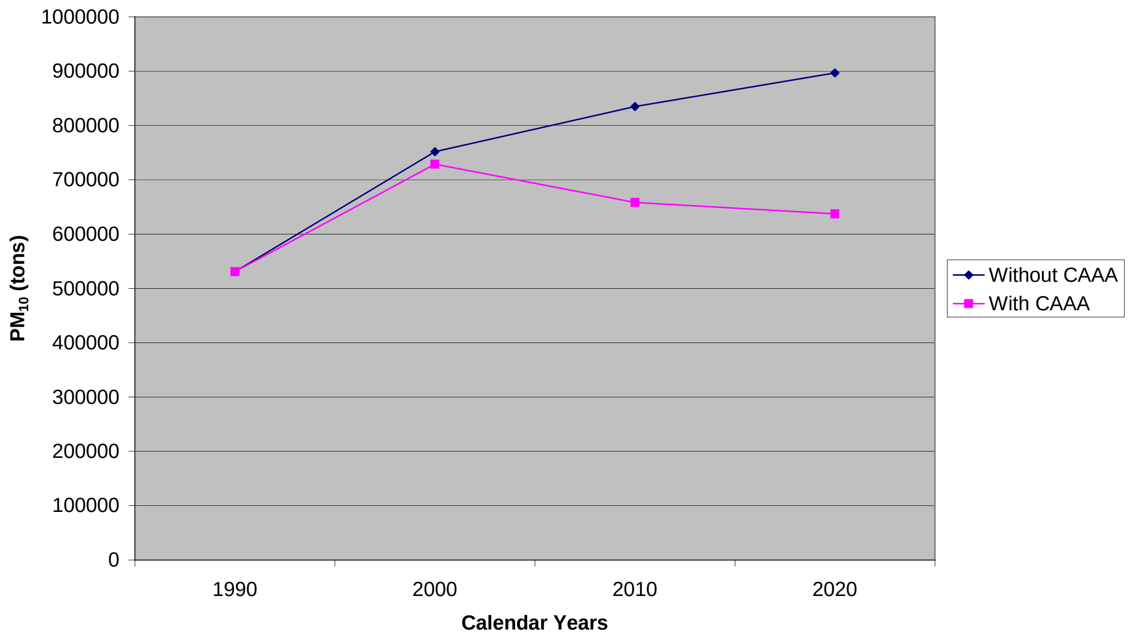


Exhibit 4-5 (continued)



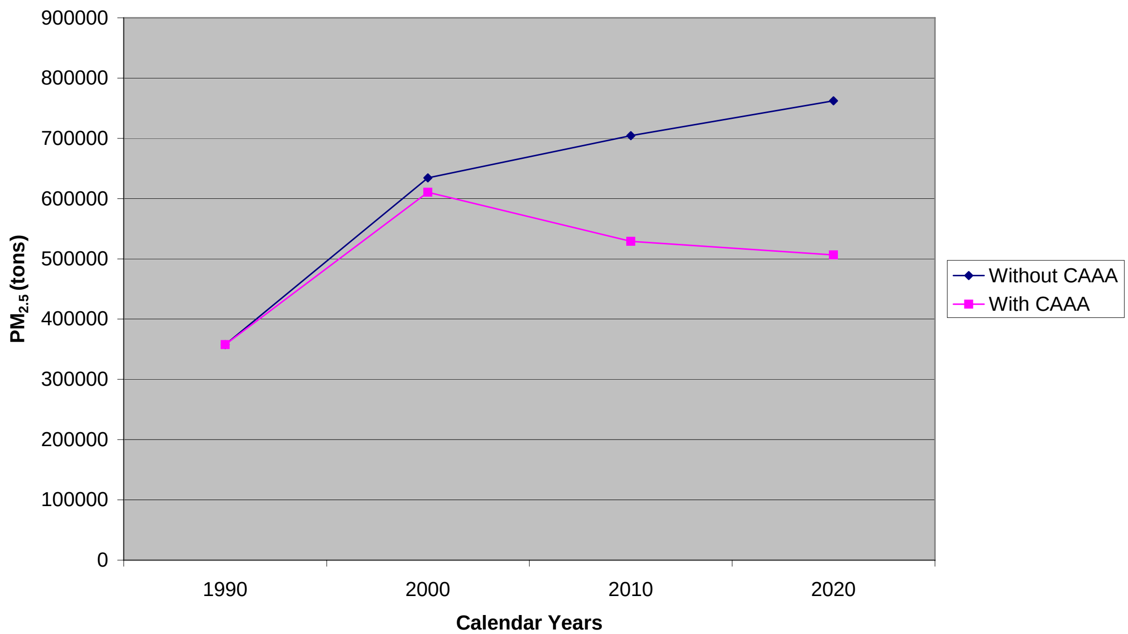
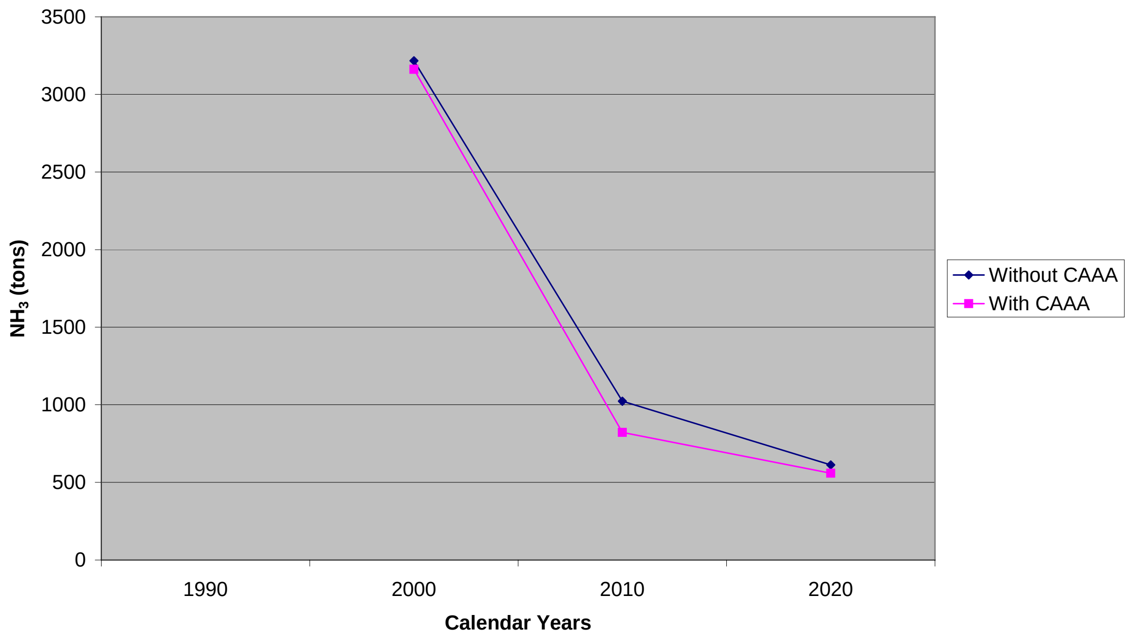


Exhibit 4-5 (continued)



CHAPTER 5 - NONROAD ENGINES/VEHICLES

Overview Of Approach

We developed nonroad engine and nonroad vehicle emission estimates using EPA's Office of Transportation and Air Quality's (OTAQ) NONROAD2004 model. Nonroad equipment categories not included in NONROAD (e.g., refueling emissions) are discussed in Chapter 7, 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 further below, 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 growth rates used here are consistent with the national NONROAD model data/assumptions that have been used in multiple EPA regulatory analyses. The Project Team is in the process of conducting a consistency check to evaluate the impact of this assumption. The consistency check involves comparing aggregate fuel consumption projections implicit in the NONROAD modeling with fuel consumption projections for this sector in *AEO 2005*.

We did revise the model's input assumptions, however, to address an acknowledged model limitation related to the regional disaggregation of growth rates. While the national growth rates from NONROAD were retained, the regionalization of the national rates was based on *AEO 2005* regional activity allocation factors for the present study. The overall approach for this sector therefore involved three steps: 1) revising existing model inputs to better reflect region-specific growth rates, consistent with the *AEO 2005* results used elsewhere in this study; 2) preparing State and county-specific input files to model local fuel programs for the *with-CAAA* scenario runs; and 3) modifying fleet emission rate inputs to remove the effect of CAAA-related standards for the *without-CAAA* runs. 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 SAB Council and AQMS reviews of the 2003 analytical plan.

Growth Projections

For most equipment types, NONROAD utilizes historical engine population estimates up through 1998 from a proprietary database developed by Power Systems Research (PSR). This database contains detailed information about each engine family sold in the United States, and provided EPA NONROAD model developers with data for estimating historical engine populations by market sector (e.g., 2-stroke lawn and garden equipment), application type (e.g., chain saws), fuel type (e.g., gasoline), horsepower (hp) range (e.g., 3 to 6 hp); and vintage (e.g., model year 1990 engines).[36] To develop projections of engine populations, EPA applies growth and retirement rate assumptions to the detailed engine population estimates for the final year of historical data. For most source categories, the NONROAD projection growth rates reflect a straight-line projection of the growth in national engine population estimates developed by PSR for the period 1989-1996. NONROAD retirement assumptions reflect year-specific scrappage rates derived from median engine life assumptions that differ by engine application and hp range. Therefore, post-1998 year NONROAD engine populations (and emissions) are generally estimated in the model by applying an internally consistent set of historical/forecast model data/assumptions.[37]

EPA has acknowledged that "…the current national growth factors used in the NONROAD model do not accurately portray nonroad equipment/emissions growth at the regional or State levels" (EPA, 2004e). To account for expected differences in regional growth rates, and to provide consistency with the projection basis used for other emitting sectors, the Project team incorporated regional growth projections into NONROAD. We specifically developed regional growth rates that reflect socioeconomic forecast data from the *Annual Energy Outlook 2005* (DOE, 2005), normalized to the NONROAD model national growth rates. The following describes how we computed these regional growth rates.

The AEO growth indicators used for making the regional adjustments were selected to match as closely as possible with the surrogate indicator used in NONROAD to make allocations of equipment growth to individuals counties. Exhibit 5-1 displays the NONROAD model county allocation surrogates and the *AEO 2005* indicators used to forecast/back-cast the base year county equipment populations for each year. For several categories, the AEO projections for the most representative surrogate indicator were only available at a national level (e.g., Wholesale Trade data for light commercial equipment). As shown in Exhibit 5-1, in those cases where regional growth rates were not available from the *AEO 2005* data, we used regional population projections.

The national NONROAD growth file ("NATION.GRW") was revised to incorporate first regional-level, and then by extension State-level growth rates using the following five steps:

(1) *Compute growth factors representing regional and national growth for each AEO 2005 surrogate indicator*. These growth factors were calculated by dividing the regional/national data for each forecast/back-cast year by the regional/national data for the base year.

(2) *Compile the national growth factors by equipment category/fuel type from the NATION.GRW file*. These growth factors were computed by dividing the national data for each forecast/back-cast year by the national data for the base year of 2000. In cases where growth data are not reported in the NATION.GRW file for a year of interest, the data were estimated by interpolating between the values for the two closest years (e.g., 2020 values were estimated from 2015 and 2025 values).

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[36] The vintage information is used to account for emission rates that differ for each model year engine.

[37] Emissions are computed using the engine population data, and assumptions as to load factors (average percentage of maximum rated horsepower at which engine is operated), number of operating hours per year, brake-specific fuel consumption (gallons/hp-hour), and emission rates (e.g., pounds of pollutant per gallon of fuel consumed).

Exhibit 5-1. AEO Regional Surrogate Indicators Used to Adjust NONROAD Growth Rates

NONROAD Equipment Category	**NONROAD County Allocation Surrogate**	**AEO 2005 Growth Surrogate[1]**
Lawn and Garden Residential	Number of single and double (duplex) family housing units from 1990 Census grown to 1997 using 1990-1997 change in county human population from U.S. Census Bureau.	Population
Lawn and Garden Commercial	Number of employees in landscape and horticultural services, County Business Patterns (CBP), SIC code 078.	Population
Residential Snowblowers	Same as residential lawn and garden, but allocation factors for counties with snowfall less than 15 inches set to zero.	Population
Commercial Snowblowers	Same as commercial lawn and garden, but allocation factors for counties with snowfall less than 15 inches set to zero.	Population
Construction	Categories (e.g., housing, commercial buildings, public works construction) of F.W. Dodge construction dollar value data weighted by 1998 Environ survey of construction equipment activity in Houston, TX and then totaled.	MFGO35 Construction (NAICS 23)
Agricultural	Harvested cropland (U.S. Census Bureau, *USA Counties* database).	MFGO30 Crop Production (NAICS 111)
Recreational Marine	Water surface area with different operating limits from shore for personal watercraft, outboards, and inboards.	Population
Recreational Land-Based (except snowmobiles and golf carts)	Number of camps and recreational vehicle park establishments (CBP SIC 7030).	Population
Snowmobiles	Snowfall limit of 40 inches and inverse human population. Direct human population used for Alaska.	Population
Golf Carts	Number of public golf courses (CBP SIC 7992).	Population
Aircraft Ground Support Equipment	Number of employees in Air Transportation (CBP SIC 45)	Population
Light Commercial	Number of wholesale establishments (CBP SIC 50).	Population
Industrial (excluding AC/Refrigeration Equipment)	Number of employees in manufacturing (CBP SIC 20).	Total Manufacturing Output (NAICS 31-33)
AC/Refrigeration Equipment	Human population.	Population
Logging	Number of employees in logging (CBP SIC 2410).	MFGO31 Other Ag, Forestry, Fishing & Hunting (NAICS 112-115)
Oil Field Equipment	Number of employees engaged in oil and gas extraction (CBP SIC 1300).	Oil production[1]
Railroad Maintenance Equipment	Human population.	Population
Underground Mining Equipment	Number of employees in coal mining (CBP SIC 1200).	MFGO32 Coal Mining (NAICS 2121)

NOTE: [1]Population represents EIA's National Energy Modeling System regional population projections.
[2]Compiled from Department of Energy's *Annual Energy Outlook 2005* (forecast data) and *Petroleum Supply Annual* (historical data).

(3) *Normalize the regional-level growth factors computed in step (1) to reflect the national growth rates reported in the NATION.GRW file*. This task was accomplished by multiplying the regional-level growth factors by the ratio of the national growth factor calculated from the NATION.GRW data from step (2) to the national growth factor calculated from the *AEO 2005* data from step (1)

(4) *Assign normalized regional growth factors to each State, and incorporate State-level growth factor data into the NATION.GRW file*. EPA OTAQ provided a revised NONROAD model test version executable that allows incorporation of up to 6,000 records per indicator code in the /GROWTH/ packet portion of the NATION.GRW file (Harvey, 2005).

(5) *Revise the crosswalk between NONROAD growth indicators and SCCs to reflect the use of regional growth indicators*.

After testing the updated NATION.GRW file to ensure it was producing the expected results, NONROAD model runs were conducted for each scenario year using this updated file.

Control Scenario Assumptions

This section describes the adjustments made to the NONROAD model inputs and/or results to accurately model: (a) 1990; (b) *without-CAAA* scenario for the years 2000, 2010, and 2020; and (c) *with-CAAA* scenario for the years 2000, 2010, and 2020.

Before conducting the modeling for these scenarios, however, appropriate temperature and fuel data inputs were compiled for each of the years of interest (1990, 2000, 2010 and 2020). Seasonal, State, or county-specific NONROAD model option files were prepared to generate nationwide emissions for each appropriate scenario. The NONROAD model uses ASCII format input files (termed *option* files) that specify the parameters for a specific model run, including ambient temperature and fuel characteristics for the modeled geographic area (e.g., State or county) and time period (e.g., summer season during the year 2000). 1990 and 2000 temperature input values for the *without-CAAA* model runs were based on Statewide average temperatures compiled for these specific years (EPA, 2004b). 2010 and 2020 temperature input values were based on a 30-year historical trend in Statewide average temperature.

The 1990 Statewide average seasonal RVP values were compiled and used as input values for the 2000, 2010, and 2020 model runs (EPA, 2004b). Several counties in California, Louisiana and New York had Stage II refueling programs established by 1990, so evaporative hydrocarbon reductions resulting from these programs were modeled for all *without-CAAA* runs. No oxygenated fuel programs were in place in 1990.

Using these option files, the Project team performed NONROAD model runs to generate seasonal emissions for each inventory year. Seasonal emissions outputs were summed to develop annual emission estimates at the county and SCC level for each scenario year.

Without-CAAA Scenario

For modeling a *without-CAAA* scenario for all years, the NONROAD model technology file (TECH.DAT) was revised to remove the effect of recent (since 1990) Federal nonroad control programs. A base technology with a sales fraction of 1 is reported for each equipment category or application for years prior to standard implementation (specified as year "1900"). The sales fraction input can be thought of as the market penetration for a given year for a particular emissions control technology. This fraction changes to account for sales of engines equipped with technologies needed to meet a specific standard for each implementation year. To ensure that the model applies emission rates corresponding to the "base" technology type for all *without-CAAA* runs, sales fractions for all other years besides "1900" were removed from the TECH.DAT file (i.e., they were set to 0 market penetration). The one exception to this was the T0 technology type for diesel engines. This technology type, which applies to engines sold in 1988 and after, was retained in the TECH.DAT files since this occurred prior to the CAAA, and was a result of the "spillover" of highway diesel control technology.

With-CAAA Scenario

Base-year fuel inputs were prepared to reflect seasonal Statewide average gasoline RVP, as well as county-specific inputs where local areas have program inputs that vary from Statewide defaults (e.g., RFG, Stage II, and oxygenated fuel programs). These inputs were derived from 2000 monthly fuel data compiled for the onroad mobile 1999 NEI (EPA, 2004b). Reid vapor pressure, Stage II control, and percent oxygen values for 2000 were assumed for 2010 and 2020 modeling runs.

Year-specific values for the nonroad diesel and gasoline fuel sulfur levels were also incorporated as shown in Exhibit 5-2. These are consistent with the fuel sulfur values used in support of EPA final rulemakings for the Tier 2 and gasoline sulfur standards (65 FR 6698, 2000) and the Clean Air Nonroad Diesel Rule (EPA, 2004c). Note that EPA estimates diesel land-based nonroad equipment to have lower diesel fuel sulfur levels than comparable diesel recreational marine vessels. NONROAD2004 requires multiple sets of runs to reflect more than one diesel fuel sulfur level. As such, SO_2 emissions output for diesel recreational marine were multiplied by the adjustment factors listed in Exhibit 5-2. The adjustment factors provide a ready means of modeling the differential fuel requirements for recreational marine versus land-based fuels. These adjustment factors were calculated based on the ratio of the recreational marine sulfur level to the land-based sulfur level, consistent with the assumption that SO_2 emissions are proportioned to fuel sulfur content. Increases in PM_{10} and $PM_{2.5}$ emissions for recreational marine would also result from higher fuel sulfur levels, but the Project Team determined that these increases would be relatively small and therefore no adjustments were made for emissions of these pollutants in this category.

Federal emission standards not incorporated by NONROAD2004 include permeation and evaporative emission standards for gasoline recreational and large S-I engines, respectively. Emission reductions due to the large S-I standard were developed to apply to the affected SCCs as a post-processing adjustment. Note that evaporative standards for recreational equipment only reduce permeation evaporative emissions, which are not currently modeled by NONROAD2004. Therefore, recreational equipment permeation emission standards were not modeled.

For the large S-I evaporative standard, base and control case future year inventories compiled by EPA were used to calculate emission reductions for 2010 and 2020 (EPA, 2002). These emission reductions vary by evaporative component, but for this analysis emissions were summed across all evaporative components to estimate emission reductions. Large S-I evaporative VOC emission reductions were estimated to be 59.7 percent in 2010, and 82 percent in 2020.

Exhibit 5-2. Fuel Sulfur Levels (Weight %) for Section 812 NONROAD Model Runs

	1990	2000		2010		2020	
		without-CAAA	*with-CAAA*	*without-CAAA*	*with-CAAA*	*without-CAAA*	*with-CAAA*
Gas Sulfur %	0.0339	0.0339	0.0339	0.0339	0.003	0.0339	0.003
CNG/LPG Sulfur %	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Diesel Sulfur % - Land Based	0.25	0.2284	0.2284	0.2284	0.017	0.2284	0.0011
Diesel Sulfur % - Rec Marine	0.264	0.264	0.264	0.264	0.0319	0.264	0.0055
Rec Marine SO_2 Adjustment[1]	*1.056*	*1.156*	*1.156*	*1.156*	*1.933*	*1.156*	*5.000*

NOTE: [1]Represents SO_2 emissions adjustments for diesel recreational marine SCCs 2282020005 and 2282020010.

Two rule penetration adjustments were applied to account for the fraction of the SCC-level emissions that are affected by the rule. Since the rule only affects S-I engines greater than 25 horsepower, the first adjustment was developed to estimate that fraction of the activity associated with these larger engines. The adjustment was based on 2002 national gasoline consumption results by horsepower and equipment category from NONROAD2004. We assumed the same rule penetration value for each projection year and for all applications within a category. Although rule penetration is likely to vary by year and application, we currently have no basis for estimating that variation. Exhibit 5-3 summarizes the horsepower-related rule penetration values by equipment category.

Exhibit 5-3. Horsepower Rule Penetration Values by Category for Large S-I Evaporative Standards

Fuel Type	Classification	Rule Penetration, %
Gasoline	Agricultural Equipment	40
	Airport Equipment	74
	Commercial Equipment	5
	Construction and Mining Equipment	14
	Industrial Equipment	59
	Commercial Lawn and Garden Equipment	7
	Railroad Equipment	4
	Recreational Equipment[1]	43
CNG	All Classifications	100
LPG	All Classifications	100

NOTE: [1]Applies to specialty vehicle carts only; other recreational equipment covered by recreational standards.

A second rule penetration adjustment by SCC was also developed to account for that fraction of the SCC-level emissions associated with evaporative VOC relative to the total VOC emissions (i.e., exhaust plus evaporative). These rule penetration values varied by year and SCC. These adjustments enable the emission reductions to be applied directly to the SCC-level VOC emissions output from the NONROAD model as a post-processing step. See Exhibit 5-4 for the 2010 and 2020 SCC-specific evaporative rule penetration values and final control factors.

The following equation shows an example of how overall adjusted emission reductions were estimated for 4-stroke industrial forklifts in 2020:

$$ER_{ADJ} = RP_{hp} \times RP_{evap} \times ER$$

where:

ER_{ADJ} = adjusted emission reduction accounting for rule penetration
RP_{hp} = rule penetration for affected horsepower fraction
RP_{evap} = rule penetration for evaporative fraction of total VOC emissions
ER = evaporative emission reduction for affected engines

$$\begin{aligned} ER_{ADJ} &= 0.591 \times 0.567 \times 0.82 \\ &= 0.275 \\ &= 27.5 \text{ percent} \end{aligned}$$

Exhibit 5-4. VOC Evaporative Rule Penetration and Final Control Effectiveness Values by SCC for Large S-I VOC Evaporative Standards in 2010 and 2020

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2260001060	Specialty Vehicles/Carts	Recreational Equipment	2 Stroke	0.326	8.3	0.338	11.8
2260002006	Tampers/Rammers	Construction and Mining Equipment	2 Stroke	0.025	0.2	0.025	0.3
2260002009	Plate Compactors	Construction and Mining Equipment	2 Stroke	0.058	0.5	0.058	0.6
2260002021	Paving Equipment	Construction and Mining Equipment	2 Stroke	0.052	0.4	0.052	0.6
2260002027	Signal Boards/Light Plants	Construction and Mining Equipment	2 Stroke	0.029	0.2	0.029	0.3
2260002039	Concrete/Industrial Saws	Construction and Mining Equipment	2 Stroke	0.013	0.1	0.014	0.2
2260002054	Crushing/Proc. Equipment	Construction and Mining Equipment	2 Stroke	0.033	0.3	0.033	0.4
2260003030	Sweepers/Scrubbers	Industrial Equipment	2 Stroke	0.082	2.9	0.082	4.0
2260003040	Other General Industrial Eqp	Industrial Equipment	2 Stroke	0.059	2.1	0.059	2.8
2260004016	Rotary Tillers < 6 HP	Lawn and Garden Equipment (Com)	2 Stroke	0.167	0.7	0.171	1.0
2260004021	Chain Saws < 6 HP	Lawn and Garden Equipment (Com)	2 Stroke	0.183	0.7	0.183	1.0
2260004026	Trimmers/Edgers/Brush Cutter	Lawn and Garden Equipment (Com)	2 Stroke	0.210	0.9	0.210	1.2
2260004031	Leafblowers/Vacuums	Lawn and Garden Equipment (Com)	2 Stroke	0.070	0.3	0.070	0.4
2260004036	Snowblowers	Lawn and Garden Equipment (Com)	2 Stroke	0.037	0.2	0.037	0.2
2260004071	Commercial Turf Equipment	Lawn and Garden Equipment (Com)	2 Stroke	0.045	0.2	0.045	0.3
2260005035	Sprayers	Agricultural Equipment	2 Stroke	0.120	2.8	0.120	3.9
2260005050	Hydro Power Units	Agricultural Equipment	2 Stroke	0.052	1.2	0.052	1.7
2260006005	Generator Sets	Commercial Equipment	2 Stroke	0.109	0.3	0.109	0.5
2260006010	Pumps	Commercial Equipment	2 Stroke	0.079	0.2	0.080	0.3
2260006015	Air Compressors	Commercial Equipment	2 Stroke	0.059	0.2	0.059	0.2
2265001060	Specialty Vehicles/Carts	Recreational Equipment	4 Stroke	0.241	6.1	0.221	7.7
2265002003	Pavers	Construction and Mining Equipment	4 Stroke	0.139	1.1	0.130	1.5
2265002006	Tampers/Rammers	Construction and Mining Equipment	4 Stroke	0.142	1.2	0.143	1.6
2265002009	Plate Compactors	Construction and Mining Equipment	4 Stroke	0.103	0.8	0.106	1.2
2265002015	Rollers	Construction and Mining Equipment	4 Stroke	0.113	0.9	0.110	1.2
2265002021	Paving Equipment	Construction and Mining Equipment	4 Stroke	0.162	1.3	0.163	1.8
2265002024	Surfacing Equipment	Construction and Mining Equipment	4 Stroke	0.105	0.9	0.104	1.2
2265002027	Signal Boards/Light Plants	Construction and Mining Equipment	4 Stroke	0.091	0.7	0.091	1.0
2265002030	Trenchers	Construction and Mining Equipment	4 Stroke	0.127	1.0	0.117	1.3
2265002033	Bore/Drill Rigs	Construction and Mining Equipment	4 Stroke	0.190	1.5	0.192	2.1
2265002039	Concrete/Industrial Saws	Construction and Mining Equipment	4 Stroke	0.091	0.7	0.090	1.0
2265002042	Cement & Mortar Mixers	Construction and Mining Equipment	4 Stroke	0.231	1.9	0.268	3.0
2265002045	Cranes	Construction and Mining Equipment	4 Stroke	0.331	2.7	0.407	4.5
2265002054	Crushing/Proc. Equipment	Construction and Mining Equipment	4 Stroke	0.131	1.1	0.125	1.4

Exhibit 5-4 (continued)

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2265002057	Rough Terrain Forklifts	Construction and Mining Equipment	4 Stroke	0.358	2.9	0.573	6.4
2265002060	Rubber Tire Loaders	Construction and Mining Equipment	4 Stroke	0.365	3.0	0.633	7.1
2265002066	Tractors/Loaders/Backhoes	Construction and Mining Equipment	4 Stroke	0.095	0.8	0.094	1.0
2265002072	Skid Steer Loaders	Construction and Mining Equipment	4 Stroke	0.259	2.1	0.259	2.9
2265002078	Dumpers/Tenders	Construction and Mining Equipment	4 Stroke	0.254	2.1	0.278	3.1
2265002081	Other Construction Equipment	Construction and Mining Equipment	4 Stroke	0.370	3.0	0.517	5.8
2265003010	Aerial Lifts	Industrial Equipment	4 Stroke	0.300	10.6	0.319	15.4
2265003020	Forklifts	Industrial Equipment	4 Stroke	0.320	11.3	0.567	27.5
2265003030	Sweepers/Scrubbers	Industrial Equipment	4 Stroke	0.201	7.1	0.196	9.5
2265003040	Other General Industrial Eqp	Industrial Equipment	4 Stroke	0.112	3.9	0.109	5.3
2265003050	Other Material Handling Eqp	Industrial Equipment	4 Stroke	0.279	9.8	0.287	13.9
2265003060	AC\Refrigeration	Industrial Equipment	4 Stroke	0.108	3.8	0.108	5.2
2265003070	Terminal Tractors	Industrial Equipment	4 Stroke	0.387	13.6	0.559	27.1
2265004011	Lawn mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.288	1.2	0.289	1.6
2265004016	Rotary Tillers < 6 HP	Lawn and Garden Equipment (Com)	4 Stroke	0.289	1.2	0.356	2.0
2265004026	Trimmers/Edgers/Brush Cutter	Lawn and Garden Equipment (Com)	4 Stroke	0.488	2.0	0.491	2.7
2265004031	Leafblowers/Vacuums	Lawn and Garden Equipment (Com)	4 Stroke	0.335	1.4	0.339	1.9
2265004036	Snowblowers	Lawn and Garden Equipment (Com)	4 Stroke	0.332	1.4	0.332	1.9
2265004041	Rear Engine Riding Mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.171	0.7	0.171	1.0
2265004046	Front Mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.209	0.9	0.227	1.3
2265004051	Shredders < 6 HP	Lawn and Garden Equipment (Com)	4 Stroke	0.273	1.1	0.362	2.0
2265004056	Lawn & Garden Tractors	Lawn and Garden Equipment (Com)	4 Stroke	0.153	0.6	0.154	0.9
2265004066	Chippers/Stump Grinders	Lawn and Garden Equipment (Com)	4 Stroke	0.177	0.7	0.176	1.0
2265004071	Commercial Turf Equipment	Lawn and Garden Equipment (Com)	4 Stroke	0.121	0.5	0.122	0.7
2265004076	Other Lawn & Garden Eqp.	Lawn and Garden Equipment (Com)	4 Stroke	0.267	1.1	0.356	2.0
2265005010	2-Wheel Tractors	Agricultural Equipment	4 Stroke	0.110	2.6	0.110	3.6
2265005015	Agricultural Tractors	Agricultural Equipment	4 Stroke	0.250	5.9	0.271	8.8
2265005020	Combines	Agricultural Equipment	4 Stroke	0.513	12.1	0.624	20.3
2265005025	Balers	Agricultural Equipment	4 Stroke	0.575	13.6	0.690	22.4
2265005030	Agricultural Mowers	Agricultural Equipment	4 Stroke	0.147	3.5	0.151	4.9
2265005035	Sprayers	Agricultural Equipment	4 Stroke	0.280	6.6	0.310	10.1
2265005040	Tillers > 6 HP	Agricultural Equipment	4 Stroke	0.269	6.3	0.224	7.3
2265005045	Swathers	Agricultural Equipment	4 Stroke	0.512	12.1	0.623	20.2
2265005050	Hydro Power Units	Agricultural Equipment	4 Stroke	0.118	2.8	0.117	3.8
2265005055	Other Agricultural Equipment	Agricultural Equipment	4 Stroke	0.347	8.2	0.386	12.5
2265005060	Irrigation Sets	Agricultural Equipment	4 Stroke	0.348	8.2	0.470	15.2

Exhibit 5-4 (continued)

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2265006005	Generator Sets	Commercial Equipment	4 Stroke	0.239	0.7	0.246	1.0
2265006010	Pumps	Commercial Equipment	4 Stroke	0.199	0.6	0.197	0.8
2265006015	Air Compressors	Commercial Equipment	4 Stroke	0.168	0.5	0.161	0.7
2265006025	Welders	Commercial Equipment	4 Stroke	0.192	0.6	0.189	0.8
2265006030	Pressure Washers	Commercial Equipment	4 Stroke	0.206	0.6	0.207	0.9
2265008005	Airport Ground Support Equipment	Airport Equipment	4 Stroke	0.208	9.1	0.201	12.1
2265010010	Other Oil Field Equipment	Industrial Equipment	4 Stroke	0.065	2.3	0.065	3.1
2267001060	Specialty Vehicle Carts	Recreational Equipment	LPG	0.237	14.2	0.218	17.9
2267002003	Pavers	Construction and Mining Equipment	LPG	0.187	11.2	0.055	4.5
2267002015	Rollers	Construction and Mining Equipment	LPG	0.110	6.6	0.000	0.0
2267002021	Paving Equipment	Construction and Mining Equipment	LPG	0.222	13.3	0.160	13.1
2267002024	Surfacing Equipment	Construction and Mining Equipment	LPG	0.171	10.2	0.055	4.5
2267002030	Trenchers	Construction and Mining Equipment	LPG	0.191	11.4	0.050	4.1
2267002033	Bore/Drill Rigs	Construction and Mining Equipment	LPG	0.235	14.0	0.210	17.3
2267002039	Concrete/Industrial Saws	Construction and Mining Equipment	LPG	0.063	3.8	0.000	0.0
2267002045	Cranes	Construction and Mining Equipment	LPG	0.222	13.3	0.131	10.7
2267002054	Crushing/Proc. Equipment	Construction and Mining Equipment	LPG	0.220	13.1	0.127	10.4
2267002057	Rough Terrain Forklifts	Construction and Mining Equipment	LPG	0.201	12.0	0.065	5.3
2267002060	Rubber Tire Loaders	Construction and Mining Equipment	LPG	0.149	8.9	0.000	0.0
2267002066	Tractors/Loaders/Backhoes	Construction and Mining Equipment	LPG	0.099	5.9	0.000	0.0
2267002072	Skid Steer Loaders	Construction and Mining Equipment	LPG	0.211	12.6	0.122	10.0
2267002081	Other Construction Equipment	Construction and Mining Equipment	LPG	0.226	13.5	0.141	11.6
2267003010	Aerial Lifts	Industrial Equipment	LPG	0.221	13.2	0.143	11.7
2267003020	Forklifts	Industrial Equipment	LPG	0.144	8.6	0.000	0.0
2267003030	Sweepers/Scrubbers	Industrial Equipment	LPG	0.113	6.7	0.000	0.0
2267003040	Other General Industrial Equipment	Industrial Equipment	LPG	0.108	6.4	0.000	0.0
2267003050	Other Material Handling Equipment	Industrial Equipment	LPG	0.218	13.0	0.116	9.5
2267003070	Terminal Tractors	Industrial Equipment	LPG	0.039	2.3	0.000	0.0
2267004066	Chippers/Stump Grinders	Lawn and Garden Equipment (Com)	LPG	0.121	7.2	0.000	0.0
2267005050	Hydro Power Units	Agricultural Equipment	LPG	0.187	11.1	0.074	6.1
2267005055	Other Agricultural Equipment	Agricultural Equipment	LPG	0.237	14.2	0.220	18.0
2267005060	Irrigation Sets	Agricultural Equipment	LPG	0.123	7.4	0.000	0.0
2267006005	Generator Sets	Commercial Equipment	LPG	0.239	14.3	0.210	17.2
2267006010	Pumps	Commercial Equipment	LPG	0.226	13.5	0.148	12.1
2267006015	Air Compressors	Commercial Equipment	LPG	0.212	12.6	0.033	2.7
2267006025	Welders	Commercial Equipment	LPG	0.190	11.3	0.027	2.3

Exhibit 5-4 (continued)

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2267006030	Pressure Washers	Commercial Equipment	LPG	0.222	13.3	0.142	11.6
2267008005	Airport Ground Support Equipment	Airport Equipment	LPG	0.108	6.5	0.000	0.0
2268002081	Other Construction Equipment	Construction and Mining Equipment	CNG	0.225	13.5	0.139	11.4
2268003020	Forklifts	Industrial Equipment	CNG	0.148	8.8	0.000	0.0
2268003030	Sweepers/Scrubbers	Industrial Equipment	CNG	0.143	8.5	0.000	0.0
2268003040	Other General Industrial Equipment	Industrial Equipment	CNG	0.119	7.1	0.000	0.0
2268003060	AC\Refrigeration	Industrial Equipment	CNG	0.143	8.6	0.017	1.4
2268003070	Terminal Tractors	Industrial Equipment	CNG	0.043	2.5	0.000	0.0
2268005050	Hydro Power Units	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268005055	Other Agricultural Equipment	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268005060	Irrigation Sets	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268006005	Generator Sets	Commercial Equipment	CNG	0.240	14.4	0.218	17.8
2268006010	Pumps	Commercial Equipment	CNG	0.233	13.9	0.174	14.2
2268006015	Air Compressors	Commercial Equipment	CNG	0.215	12.9	0.043	3.5
2268010010	Other Oil Field Equipment	Industrial Equipment	CNG	0.000	0.0	0.000	0.0
2285004015	Railway Maintenance	Railroad Equipment	4 Stroke	0.184	0.4	0.183	0.6
2285006015	Railway Maintenance	Railroad Equipment	LPG	0.214	12.8	0.112	9.2

Additional Adjustments

Further adjustments were made to the NONROAD2004 output to ensure a consistent set of county FIPS codes across sectors and for all years. Exhibit 5-5 provides a summary of the adjustments made to remove invalid FIPS codes or add in new FIPS codes, as of 2002.

Emission Summary By Scenario

National (48-State) Tier 3 Summaries

A Tier 3 summary of national NONROAD model annual pollutant emissions for each scenario is presented in Exhibits 5-6a through 5-6f - the totals are presented graphically in Exhibit 5-7. These summaries do not include emissions for Alaska and Hawaii. For the *without-CAAA* scenario results, overall emissions increase between 1990 and 2000, and through 2010 and 2020. On the activity side, these emissions increase because of expected growth in equipment populations, though some categories show declines (e.g., gasoline industrial equipment). Because most nonroad engine emissions were not subject to regulation in 1990 before the CAAA were passed, emission rates for the *without CAAA* scenario are constant at 1990 levels for most engine types. In considering the *with-CAAA* scenarios for a given time period, pollutant emissions for specific nonroad categories either decrease or increase depending on the phase-in of Federal engine or fuel standards impacting emissions, and the effects of category-specific growth rates.

For the *with-CAAA* scenarios, overall VOC and CO nonroad emissions decrease between 1990 and 2000, and decrease further in 2010 and 2020. In some cases, the effects of growth outweigh the impact of VOC and CO emission standards (e.g., gasoline lawn and garden and light commercial between 2010 and 2020). Overall NO_x emissions generally decrease over time as well, (with the exception of gasoline lawn and garden and light commercial), and are lower for the *with-CAAA* case. This is due primarily to the large reductions in NO_x emissions from diesel engine standards. However, for gasoline nonroad equipment, NO_x emissions for the *with-CAAA* case relative to the *without-CAAA* case are higher for each year. This is due to the use of HC and CO-reducing technologies that control the air-fuel mixture in the cylinder, but result in increases in NO_x emissions due to the higher temperatures and increased supply of oxygen.

Overall $PM_{2.5}$ and PM_{10} emissions decrease over time from 1990 to 2020 for the *with-CAAA* scenarios. In addition to Federal engine standards that require reduced PM emission rates over time, the required reductions in diesel fuel sulfur levels impact PM sulfate levels and produce lower PM emissions from diesel engines.

Fuel-based emissions include SO_2 and NH_3 (see Exhibits 5-6f and 5-6g). Overall fuel consumption is estimated to increase for all categories over time, and in the absence of NH_3 controls, NH_3 emissions reflect this trend for both *with-* and *without-CAAA* scenarios. SO_2 is estimated based on the amount of fuel consumed, and also have a linear relationship to fuel sulfur content. EPA's Federal regulations require significant decreases in the fuel sulfur levels for gasoline and diesel engines, which results in the large differences shown between the *with-* and *without-CAAA* emissions.

Exhibit 5-5. FIPS County Code Corrections to NONROAD Model Output

Removal of Invalid FIPS Codes

State FIPS	State Name	Invalid County FIPS	Invalid County Name	Valid County FIPS	Valid County Name	Notes
30	Montana	113	Yellowstone Park	031	Gallatin County	Yellowstone Park emissions allocated to Gallatin County (50%) and Park County (50%)
				067	Park County	
51	Virginia	560	Clifton Forge City	005	Alleghany County	All emissions reported for Clifton Forge City were added to Alleghany County

Addition of Broomfield County, Colorado (08014) to Main Section 812 Study Databases

State FIPS	State Name	County FIPS	County Name	Ratio	Notes
08	Colorado	001	Adams County	0.041882	Ratios applied to county emissions to estimate proportion of emissions now in Broomfield county: county proportions added together to estimate total emissions in Broomfield Co; remainder subtracted each from four counties.
		013	Boulder County	0.073721	
		059	Jefferson County	0.002939	
		123	Weld County	0.000055	

Exhibit 5-6a. National NONROAD Model VOC Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	346,823	442,230	428,580	843,140	628,912	1,024,745	341,903
	construction	73,914	76,870	50,206	78,565	21,622	80,471	21,306
	industrial	80,901	38,109	22,888	22,521	6,229	9,779	2,457
	lawn & garden	970,573	1,160,782	786,848	1,417,831	430,648	1,679,121	476,166
	farm	16,746	16,779	12,580	18,664	8,165	20,334	6,565
	light commercial	232,486	296,918	165,219	398,902	101,397	501,643	122,842
	logging	10,555	14,560	11,729	20,623	7,612	26,861	9,635
	airport service	399	433	248	491	88	552	73
	railway maintenance	319	357	181	396	108	437	116
	recreational marine vessels	638,077	858,255	810,808	903,760	505,756	969,499	418,824
	Subtotal: Gasoline	**2,370,793**	**2,905,293**	**2,289,288**	**3,704,894**	**1,710,536**	**4,313,442**	**1,399,885**
Non-Road Diesel	recreational	506	603	577	746	557	874	426
	construction	94,930	112,750	92,003	139,838	61,557	168,560	37,633
	industrial	20,744	21,952	16,227	28,334	9,329	34,565	5,808
	lawn & garden	4,077	5,416	4,934	8,022	3,871	10,681	2,868
	farm	104,683	83,676	76,438	81,109	47,034	86,419	26,893
	light commercial	12,450	15,092	13,955	19,984	11,797	24,789	7,668
	logging	3,023	3,009	1,864	2,780	878	2,553	453
	airport service	1,107	1,185	945	1,719	660	2,318	460
	railway maintenance	583	686	626	855	546	1,049	340
	recreational marine vessels	1,171	1,463	1,450	1,902	1,668	2,338	1,611
	Subtotal: Diesel	**243,273**	**245,832**	**209,019**	**285,287**	**137,898**	**334,148**	**84,161**
Other	liquified petroleum gas	51,135	66,177	65,976	86,022	26,154	105,209	5,553
	compressed natural gas	510	509	508	593	135	701	46
	Subtotal: Other Fuels	**51,645**	**66,686**	**66,484**	**86,615**	**26,289**	**105,911**	**5,599**
Total: All Sources		**2,665,710**	**3,217,810**	**2,564,790**	**4,076,796**	**1,874,723**	**4,753,500**	**1,489,644**

Exhibit 5-6b. National NONROAD Model NO_x Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	7,172	7,963	11,130	13,469	15,502	15,830	22,056
	construction	4,031	4,194	6,760	4,308	3,922	4,414	3,282
	industrial	31,239	13,771	16,278	7,092	4,583	1,741	1,043
	lawn & garden	43,030	51,156	88,549	62,980	67,780	74,902	75,929
	farm	4,336	4,262	4,823	4,830	3,581	5,270	2,732
	light commercial	15,914	20,382	36,898	27,501	31,800	34,532	36,465
	logging	187	257	425	364	503	475	611
	airport service	168	182	214	208	70	233	39
	railway maintenance	27	30	60	33	42	37	43
	recreational marine vessels	29,810	32,794	35,531	35,264	52,570	37,784	63,533
	Subtotal: Gasoline	**135,914**	**134,992**	**200,668**	**156,050**	**180,352**	**175,219**	**205,733**
Non-Road Diesel	recreational	1,279	1,615	1,561	2,116	1,765	2,622	1,674
	construction	753,314	840,108	744,295	1,047,430	588,884	1,268,852	263,953
	industrial	158,895	157,801	135,989	201,531	108,414	243,762	57,951
	lawn & garden	21,675	30,594	29,061	47,685	34,097	65,201	30,570
	farm	631,861	588,629	555,425	650,033	464,898	723,882	280,010
	light commercial	59,400	75,657	72,340	103,580	79,063	131,469	63,609
	logging	39,367	30,544	23,735	28,139	11,551	25,843	1,485
	airport service	11,346	11,581	10,360	16,668	9,105	22,465	3,764
	railway maintenance	2,703	3,228	3,052	4,082	3,027	5,047	2,081
	recreational marine vessels	30,387	37,967	37,807	49,357	45,651	60,683	47,870
	Subtotal: Diesel	**1,710,227**	**1,777,723**	**1,613,623**	**2,150,621**	**1,346,456**	**2,549,825**	**752,967**
Other	liquified petroleum gas	189,965	246,230	245,483	321,015	106,456	393,403	35,384
	compressed natural gas	31,638	31,765	31,685	37,152	10,149	43,962	4,834
	Subtotal: Other Fuels	**221,604**	**277,996**	**277,168**	**358,167**	**116,605**	**437,365**	**40,218**
Total: All Sources		**2,067,745**	**2,190,711**	**2,091,459**	**2,664,838**	**1,643,413**	**3,162,409**	**998,918**

Exhibit 5-6c. National NONROAD Model CO Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	1,726,365	1,940,823	1,809,891	2,960,070	2,664,655	3,464,464	2,648,120
	construction	738,938	766,913	642,736	784,773	651,296	803,753	653,784
	industrial	1,368,122	696,357	629,318	441,573	369,401	229,256	201,742
	lawn & garden	10,749,591	12,765,324	10,852,538	15,693,951	13,213,067	18,657,641	15,655,065
	farm	326,885	326,661	309,287	365,630	317,177	398,311	320,966
	light commercial	3,608,574	4,593,170	4,003,709	6,192,748	5,517,249	7,790,804	6,912,564
	logging	66,370	91,489	76,980	129,614	101,789	168,806	134,144
	airport service	6,110	6,611	5,956	7,524	4,579	8,449	4,375
	railway maintenance	6,483	7,233	6,290	8,056	7,388	8,888	8,096
	recreational marine vessels	1,650,978	2,020,735	1,940,670	2,177,771	1,921,147	2,334,301	1,915,526
	Subtotal: Gasoline	**20,248,417**	**23,215,316**	**20,277,375**	**28,761,711**	**24,767,750**	**33,864,674**	**28,454,382**
Non-Road Diesel	recreational	1,983	2,336	2,241	2,851	2,258	3,285	1,798
	construction	438,977	554,759	444,570	697,855	326,744	845,217	139,226
	industrial	80,541	90,588	66,495	117,536	57,435	143,649	15,665
	lawn & garden	14,388	18,495	17,208	26,519	16,303	34,843	12,408
	farm	432,928	387,736	348,671	413,434	240,266	457,847	125,334
	light commercial	46,820	54,469	51,283	70,189	49,658	85,308	33,688
	logging	18,446	17,528	9,493	16,186	4,992	14,865	605
	airport service	4,733	6,389	5,054	9,771	4,082	13,244	1,662
	railway maintenance	2,602	3,017	2,735	3,682	2,364	4,484	1,406
	recreational marine vessels	4,903	6,126	6,088	7,963	7,788	9,790	9,449
	Subtotal: Diesel	**1,046,321**	**1,141,443**	**953,839**	**1,365,987**	**711,890**	**1,612,532**	**341,240**
Other	liquified petroleum gas	753,409	974,512	971,559	1,265,448	690,742	1,546,639	181,347
	compressed natural gas	128,116	127,659	127,337	148,671	58,702	175,629	22,490
	Subtotal: Other Fuels	**881,525**	**1,102,171**	**1,098,895**	**1,414,119**	**749,444**	**1,722,268**	**203,838**
Total: All Sources		**22,176,262**	**25,458,930**	**22,330,110**	**31,541,817**	**26,229,083**	**37,199,473**	**28,999,459**

Exhibit 5-6d. National NONROAD Model PM_{10} Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	8,931	11,917	11,881	25,198	19,576	30,756	10,673
	construction	2,107	2,189	2,095	2,242	2,063	2,296	2,111
	industrial	852	383	223	216	104	81	43
	lawn & garden	19,272	23,100	21,332	28,255	22,807	33,406	26,748
	farm	165	165	124	185	120	201	129
	light commercial	2,230	2,841	2,258	3,830	2,368	4,818	2,964
	logging	385	531	556	752	784	979	1,020
	airport service	4	5	2	5	2	6	2
	railway maintenance	3	3	2	4	1	4	1
	recreational marine vessels	28,722	38,585	37,829	41,573	28,264	44,561	28,142
	Subtotal: Gasoline	**62,671**	**79,719**	**76,302**	**102,260**	**76,089**	**117,108**	**71,834**
Non-Road Diesel	recreational	317	364	355	433	350	482	281
	construction	91,957	84,244	74,451	100,987	51,136	121,569	20,623
	industrial	18,827	16,649	13,736	21,244	8,696	25,898	1,993
	lawn & garden	3,029	3,780	3,582	5,243	2,969	6,744	2,047
	farm	114,304	85,041	81,713	72,578	49,969	71,367	25,402
	light commercial	9,363	10,595	10,124	13,388	8,859	16,007	5,646
	logging	4,450	2,348	1,778	2,147	893	1,971	64
	airport service	1,252	1,027	913	1,347	643	1,796	239
	railway maintenance	503	521	500	543	398	616	246
	recreational marine vessels	846	1,025	1,019	1,333	826	1,638	761
	Subtotal: Diesel	**244,847**	**205,596**	**188,172**	**219,243**	**124,740**	**248,088**	**57,302**
Other	liquefied petroleum gas	892	1,155	1,152	1,506	1,501	1,845	1,839
	compressed natural gas	152	152	152	178	178	211	210
	Subtotal: Other Fuels	**1,043**	**1,307**	**1,304**	**1,684**	**1,679**	**2,055**	**2,049**
Total: All Sources		**308,562**	**286,623**	**265,778**	**323,187**	**202,507**	**367,252**	**131,185**

Exhibit 5-6e. National NONROAD Model $PM_{2.5}$ Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With--CAAA***
Non-Road Gasoline	recreational	8,217	10,964	10,931	23,182	18,010	28,295	9,819
	construction	1,939	2,014	1,928	2,062	1,898	2,113	1,942
	industrial	784	352	205	199	95	74	40
	lawn & garden	17,730	21,252	19,625	25,994	20,982	30,734	24,608
	farm	152	151	114	170	110	185	119
	light commercial	2,051	2,614	2,078	3,524	2,178	4,432	2,727
	logging	354	488	511	692	722	901	939
	airport service	4	4	2	5	2	6	2
	railway maintenance	3	3	2	3	1	4	1
	recreational marine vessels	26,425	35,498	34,803	38,247	26,003	40,996	25,891
	Subtotal: Gasoline	**57,658**	**73,342**	**70,198**	**94,079**	**70,001**	**107,740**	**66,087**
Non-Road Diesel	recreational	291	335	327	398	322	444	259
	construction	84,600	77,505	68,495	92,908	47,045	111,843	18,973
	industrial	17,321	15,317	12,637	19,545	8,000	23,826	1,833
	lawn & garden	2,786	3,478	3,296	4,824	2,731	6,204	1,883
	farm	105,160	78,238	75,176	66,772	45,972	65,657	23,370
	light commercial	8,614	9,747	9,314	12,317	8,151	14,726	5,194
	logging	4,094	2,160	1,635	1,975	822	1,814	59
	airport service	1,152	945	840	1,239	592	1,653	220
	railway maintenance	463	480	460	499	366	567	226
	recreational marine vessels	778	943	937	1,226	760	1,507	701
	Subtotal: Diesel	**225,259**	**189,149**	**173,118**	**201,704**	**114,760**	**228,241**	**52,718**
Other	liquified petroleum gas	892	1,155	1,152	1,506	1,501	1,845	1,839
	compressed natural gas	152	152	152	178	178	211	210
	Subtotal: Other Fuels	**1,043**	**1,307**	**1,304**	**1,684**	**1,679**	**2,055**	**2,049**
Total: All Sources		**283,960**	**263,798**	**244,620**	**297,466**	**186,440**	**338,036**	**120,854**

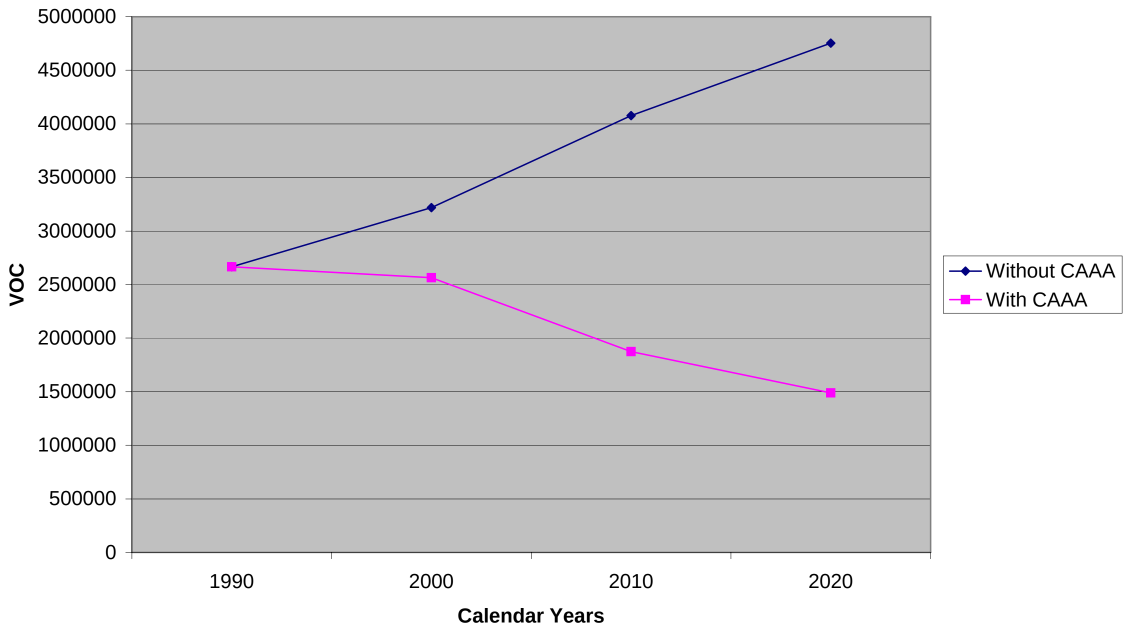
Exhibit 5-6f. National NONROAD Model SO_2 Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	1,239	1,409	1,390	2,266	200	2,718	244
	construction	280	291	273	298	22	305	22
	industrial	797	378	361	219	16	90	6
	lawn & garden	4,229	5,024	4,462	6,178	434	7,346	513
	farm	162	162	158	182	14	199	15
	light commercial	1,461	1,862	1,671	2,510	175	3,157	218
	logging	22	30	30	43	3	56	4
	airport service	4	4	4	5	0	5	0
	railway maintenance	3	3	3	3	0	4	0
	recreational marine vessels	1,774	2,186	2,184	2,355	204	2,524	221
	Subtotal: Gasoline	**9,971**	**11,349**	**10,537**	**14,059**	**1,069**	**16,404**	**1,245**
Non-Road Diesel	recreational	143	164	163	214	15	264	1
	construction	69,121	79,623	79,394	101,927	7,358	124,181	469
	industrial	14,400	16,192	16,164	21,015	1,519	25,574	92
	lawn & garden	2,343	3,056	3,043	4,801	346	6,565	28
	farm	52,211	50,712	50,693	61,125	4,422	70,101	293
	light commercial	6,589	7,875	7,854	10,906	788	13,934	59
	logging	3,362	2,850	2,845	2,632	190	2,417	8
	airport service	780	1,019	1,018	1,579	114	2,144	8
	railway maintenance	235	280	278	382	28	483	2
	recreational marine vessels	3,865	4,829	4,810	6,278	755	7,719	160
	Subtotal: Diesel	**153,048**	**166,601**	**166,262**	**210,859**	**15,535**	**253,381**	**1,122**
Other	liquified petroleum gas	206	267	267	349	295	427	346
	compressed natural gas	29	29	29	34	32	40	38
	Subtotal: Other Fuels	**235**	**296**	**296**	**383**	**327**	**467**	**384**
Total: All Sources		**163,254**	**178,247**	**177,095**	**225,300**	**16,930**	**270,252**	**2,750**

Exhibit 5-6g. National NONROAD Model NH_3 Emissions, tons per year

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	92	106	105	176	168	212	187
	construction	20	21	19	22	16	22	17
	industrial	53	25	24	15	12	6	5
	lawn & garden	303	361	311	443	324	527	382
	farm	11	11	10	12	10	13	11
	light commercial	100	127	112	172	128	216	160
	logging	2	2	2	3	3	4	3
	airport service	0	0	0	0	0	0	0
	railway maintenance	0	0	0	0	0	0	0
	recreational marine vessels	134	168	167	181	161	194	169
	Total: Gasoline	**715**	**822**	**750**	**1,025**	**822**	**1,195**	**933**
Non-Road Diesel	recreational	1	1	1	1	1	2	2
	construction	368	464	462	594	591	723	721
	industrial	77	94	94	122	122	149	148
	lawn & garden	12	18	18	28	28	38	38
	farm	279	296	296	356	356	408	408
	light commercial	35	46	46	64	63	81	81
	logging	18	17	17	15	15	14	14
	airport service	4	6	6	9	9	12	12
	railway maintenance	1	2	2	2	2	3	3
	recreational marine vessels	19	24	24	32	31	39	39
	Total: Diesel	**815**	**967**	**964**	**1,223**	**1,220**	**1,470**	**1,465**
Other	liquified petroleum gas	0	0	0	0	0	0	0
	compressed natural gas	0	0	0	0	0	0	0
	Total: Other Fuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total: All Sources		**1,530**	**1,789**	**1,715**	**2,248**	**2,042**	**2,665**	**2,399**

Exhibit 5-7. *With-* and *Without-CAAA* Scenario Nonroad Emission Summaries by Pollutant



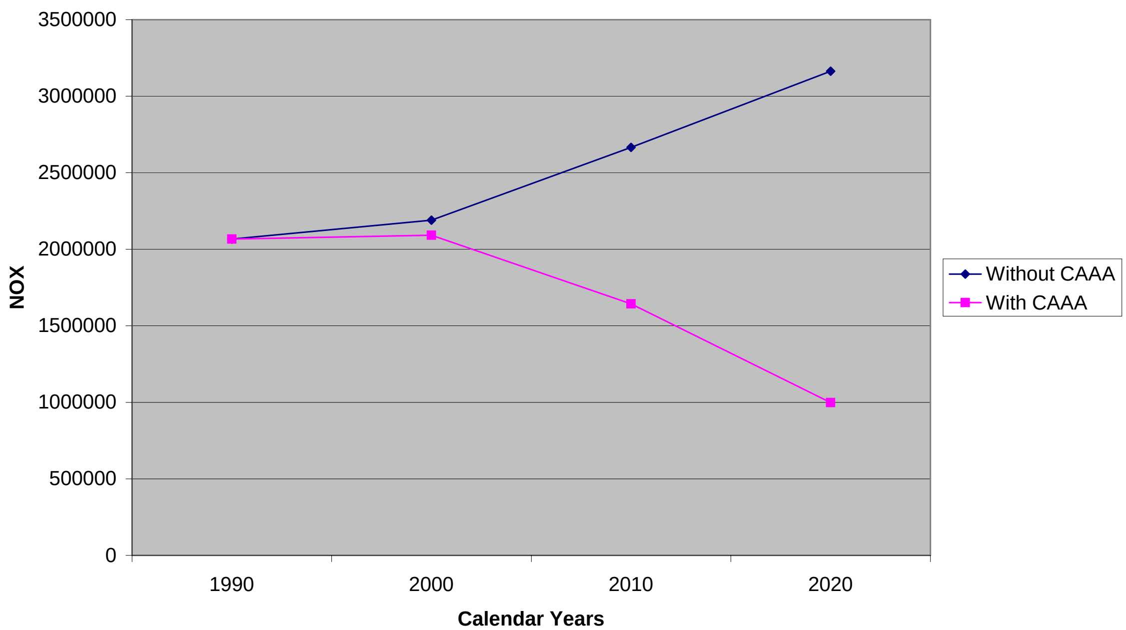
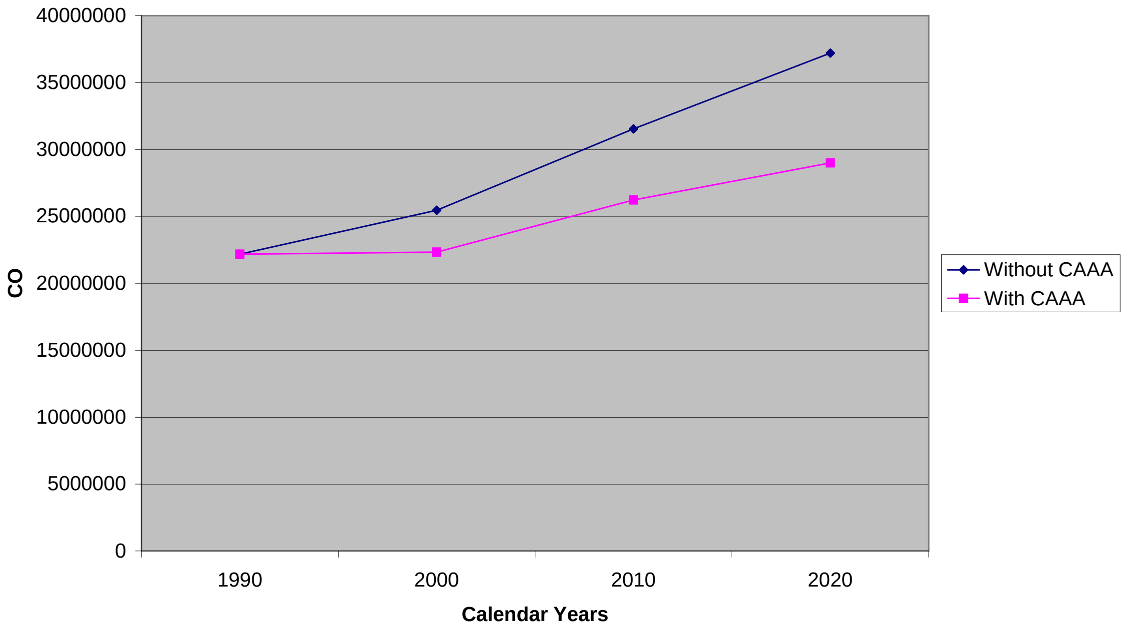


Exhibit 5-7 (continued)



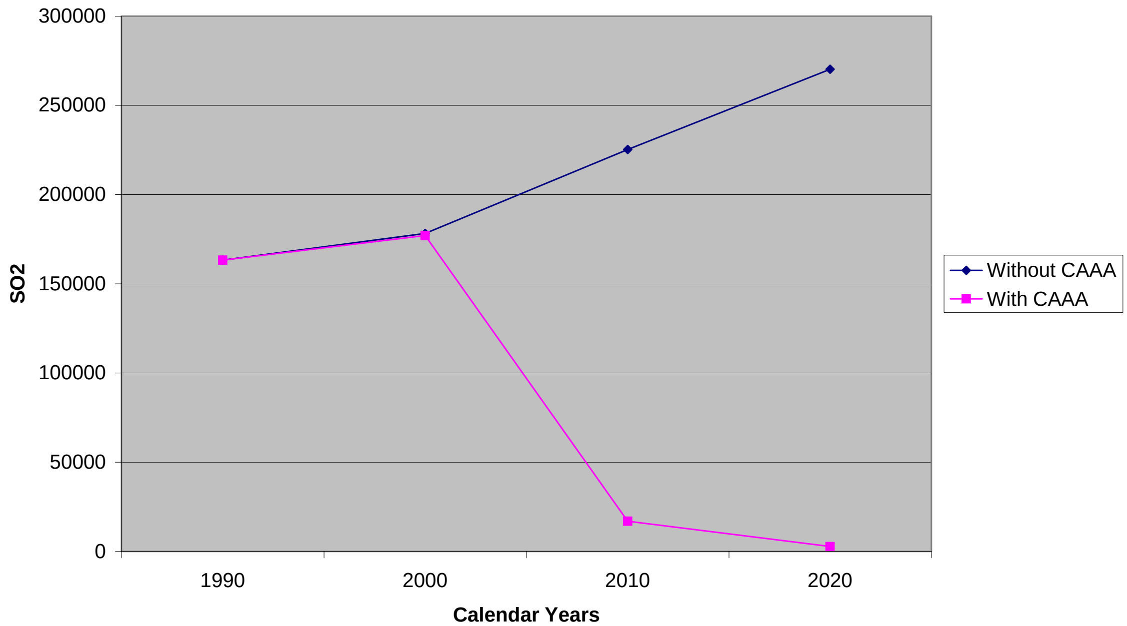
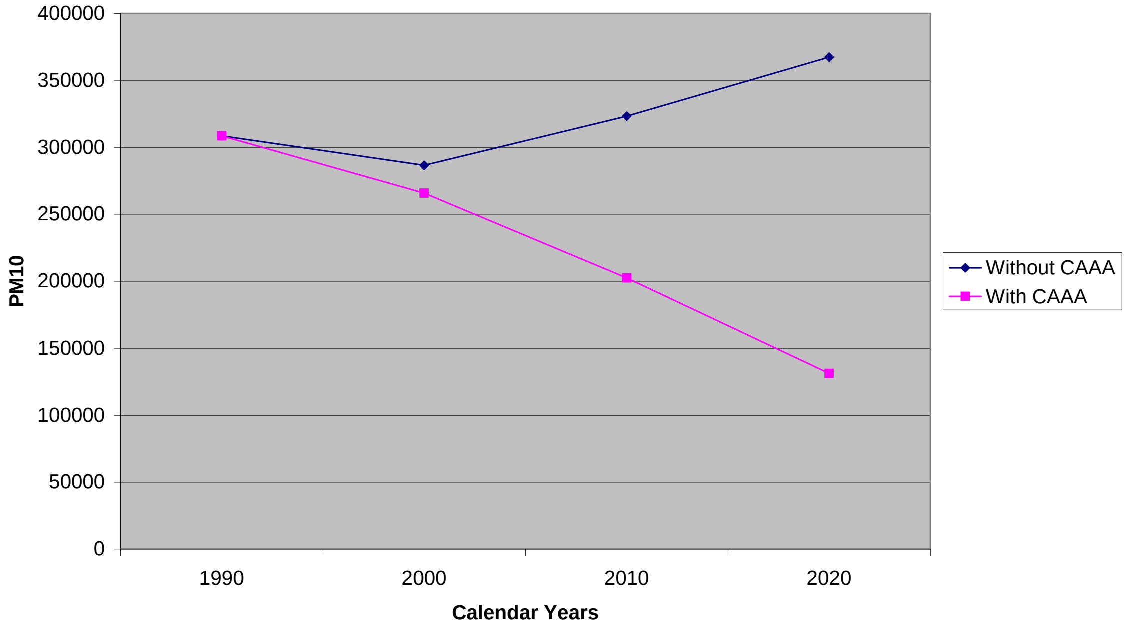


Exhibit 5-7 (continued)



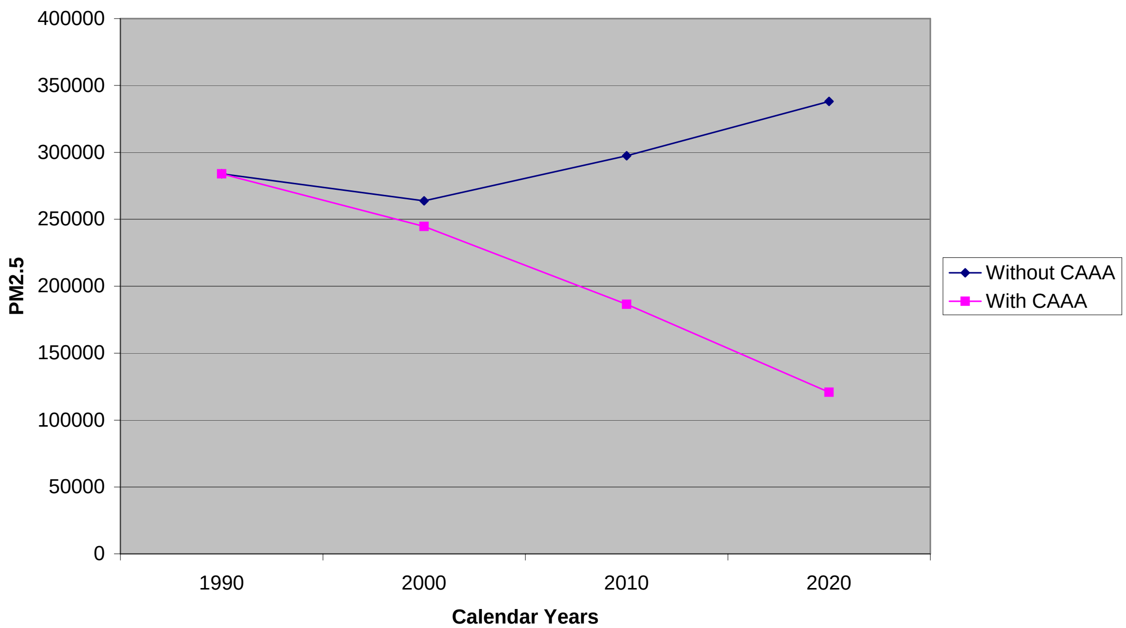
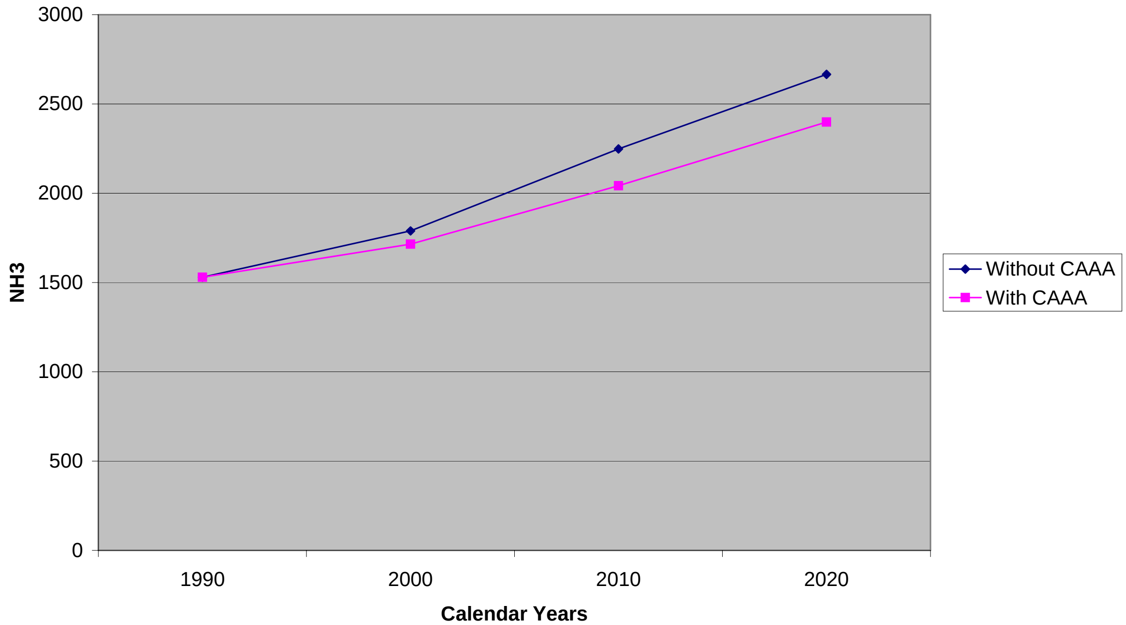


Exhibit 5-7 (continued)



California OFFROAD Modeling Summary

ARB has developed their own model for preparing nonroad emission inventories named OFFROAD. There is a separate model for California, in part, because California sets its own off-road equipment emission standards. EPA requested that the ARB provide OFFROAD-based inventories for both *with*- and *without-CAAA* controls for the years of interest. Controlled OFFROAD inventories were available from ARB, but OFFROAD-based emissions reflecting a *without-CAAA* scenario could not be provided. For consistency, EPA NONROAD model-based emissions for California were used for both the *with*- and *without-CAAA* scenario in this analysis.

To examine the difference between these two nonroad emission models, results obtained from the *with-CAAA* NONROAD model runs for California were compared with Statewide nonroad controlled inventories based on ARB's OFFROAD model. Controlled emissions inventories for California were obtained from ARB's *Emission Inventory Data - Almanac Emission Projection Data* (ARB, 2005). The results of these comparisons at a Tier 3 source category level are shown in Exhibits 5-8a through 5-8e for VOC, NO_x, CO, $PM_{2.5}$, and SO_2. It should be noted that ARB did not estimate or report emissions for certain categories of engines included in EPA's NONROAD model, including gasoline and diesel railway maintenance, diesel recreational vehicles, and all liquefied petroleum gas engines.

ARB estimates total VOC emissions for each scenario year to be approximately 30 to 40 percent lower than NONROAD, and estimates CO emissions to be 50 to 75 percent lower than NONROAD. ARB also estimates $PM_{2.5}$ emissions to be about 10 percent lower than NONROAD on average for all years except 1990, which shows slightly higher $PM_{2.5}$ emissions based on OFFROAD. ARB's NO_x estimates are considerably higher in 1990 (+98 percent), and in 2000 (+45 percent), but are only about 20 percent higher than NONROAD for the years 2010 and 2020. Finally, ARB estimates SO_2 emissions to be 55 percent higher than NONROAD in 1990, and 163 percent higher in 2020. Overall, SO_2 emissions in 2000 and 2010 are much lower based on ARB's model (-93 percent and –52 percent, respectively). In the absence of uncontrolled data based on OFFROAD, the impact the ARB estimates would have on the differences between *with*- and *without-CAAA* cases for all 48-States cannot be determined. Note that California contributes approximately 10 percent of the total national emissions.

A more detailed evaluation and explanation of category-specific differences is documented in Appendix D. In summary, while the results in Exhibit 5-7 may initially seem troubling, the analysis in Appendix D suggests that the large discrepancies result mainly from differences in equipment activity, category-specific future emission standards, and variations in fuel input data (e.g., fuel sulfur content). Some of the differences are substantial when comparing all categories combined for a given pollutant. However, one large discrepancy for the gasoline lawn and garden category is attributable to outdated data on equipment populations. When updated with new survey data from California, the difference is expected to narrow substantially.

In addition, more stringent State-level fuel sulfur requirements in California than the rest of the U.S. explain the differences observed in SO_2 emission estimates. Using California's fuel sulfur levels specified by ARB in place of the national defaults for California would result in more comparable emissions for SO_2.

Overall, we conclude from this sensitivity analysis that, because the differences between NONROAD and OFFROAD for more categories can be explained, that it is reasonable to use the results of NONROAD modeling for California, with one exception: fuel sulfur content input data. The Project Team is currently working on updating the national estimates to employ the California fuel sulfur levels for California-based nonroad emissions sources.

Exhibit 5-8a. Comparison of Section 812 and ARB-Derived Annual VOC Emissions for California, tpy

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	15,142	22,241	47%	19,483	20,605	6%	34,635	21,391	-38%	17,870	24,626	38%
	construction	8,250	2,122	-74%	4,680	1,477	-68%	2,264	976	-57%	2,438	959	-61%
	industrial	7,098	3,050	-57%	2,052	2,815	37%	548	1,140	108%	180	759	322%
	lawn & garden	144,780	78,822	-46%	114,804	57,234	-50%	60,821	29,149	-52%	70,039	26,864	-62%
	farm	327	1,170	258%	295	982	233%	189	833	341%	163	688	322%
	light commercial	27,281	8,843	-68%	18,971	6,870	-64%	11,839	4,483	-62%	14,870	3,563	-76%
	logging	569	2,417	325%	517	1,163	125%	332	538	62%	434	538	24%
	airport service	55	208	278%	34	253	647%	12	98	728%	10	69	585%
	railway maintenance	37	NA	NA	20	NA	NA	12	NA	NA	14	NA	NA
	recreational marine vessels	44,212	37,822	-14%	54,546	52,821	-3%	33,368	28,580	-14%	27,583	16,755	-39%
Non-Road Diesel	recreational	49	NA	NA	56	NA	NA	56	NA	NA	44	NA	NA
	construction	10,591	17,968	70%	8,939	14,043	57%	7,035	8,487	21%	4,819	5,071	5%
	industrial	2,025	3,885	92%	1,707	3,408	100%	1,032	2,499	142%	705	1,227	74%
	lawn & garden	715	477	-33%	872	334	-62%	698	183	-74%	531	3	-99%
	farm	2,068	8,959	333%	1,831	7,250	296%	1,115	4,590	312%	706	2,136	202%
	light commercial	1,481	1,773	20%	1,688	1,531	-9%	1,472	1,153	-22%	988	536	-46%
	logging	162	1,059	552%	87	427	388%	40	222	456%	21	137	558%
	airport service	157	137	-13%	135	137	1%	97	122	26%	70	81	17%
	railway maintenance	70	NA	NA	76	NA	NA	68	NA	NA	44	NA	NA
	recreational marine vessels	84	194	132%	105	232	121%	125	276	122%	124	328	164%
Other	liquified petroleum gas	4,946	NA	NA	6,757	NA	NA	2,722	NA	NA	682	NA	NA
	compressed natural gas	40	10	-75%	50	11	-77%	14	6	-60%	6	4	-30%
		270,139	**191,156**	**-29%**	**237,704**	**171,592**	**-28%**	**158,493**	**104,727**	**-34%**	**142,339**	**84,345**	**-41%**

Exhibit 5-8b. Comparison of Section 812 and ARB-Derived Annual NO_x Emissions for California, tpy

		1990			2000			2010			2020		
Tier 2 Name	Tier 3 Name	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference
Non-Road Gasoline	recreational	457	1,191	161%	803	1,524	90%	1,115	1,792	61%	1,290	2,058	60%
	construction	437	1,096	151%	679	754	11%	464	889	91%	419	915	119%
	industrial	2,685	7,029	162%	1,686	7,265	331%	494	3,075	522%	93	2,328	2393%
	lawn & garden	6,436	2,073	-68%	14,710	2,524	-83%	11,158	3,030	-73%	12,902	2,558	-80%
	farm	82	1,201	1367%	137	821	499%	101	849	744%	84	918	994%
	light commercial	1,760	2,977	69%	4,655	2,951	-37%	4,154	3,237	-22%	4,949	3,335	-33%
	logging	10	97	910%	20	43	111%	24	61	155%	30	61	103%
	airport service	23	904	3895%	32	1,225	3775%	11	451	4158%	6	308	4923%
	railway maintenance	3	NA	NA	8	NA	NA	5	NA	NA	6	NA	NA
	recreational marine vessels	2,154	5,568	158%	2,949	7,268	146%	4,536	11,227	148%	5,678	9,452	66%
Non-Road Diesel	recreational	124	NA	NA	151	NA	NA	176	NA	NA	172	NA	NA
	construction	84,582	164,039	94%	71,672	121,026	69%	65,865	83,714	27%	34,626	51,937	50%
	industrial	15,115	27,362	81%	14,062	21,340	52%	11,969	15,774	32%	7,087	9,476	34%
	lawn & garden	3,799	2,260	-41%	5,135	2,452	-52%	6,169	531	-91%	5,674	8	-100%
	farm	12,618	72,901	478%	14,002	53,602	283%	11,969	35,101	193%	7,397	20,392	176%
	light commercial	7,069	12,864	82%	8,763	9,944	13%	9,913	7,680	-23%	8,237	4,860	-41%
	logging	2,150	10,448	386%	1,083	4,067	276%	527	2,376	351%	77	1,305	1586%
	airport service	1,611	1,601	-1%	1,479	1,478	0%	1,337	1,246	-7%	565	764	35%
	railway maintenance	323	NA	NA	370	NA	NA	379	NA	NA	268	NA	NA
	recreational marine vessels	2,168	856	-61%	2,729	965	-65%	3,410	1,149	-66%	3,700	1,368	-63%
Other	liquified petroleum gas	18,477	NA	NA	25,270	NA	NA	11,222	NA	NA	4,393	NA	NA
	compressed natural gas	2,485	10,924	340%	3,110	12,358	297%	1,094	5,695	420%	589	4,460	657%
		164,566	**325,389**	**98%**	**173,505**	**251,607**	**45%**	**146,092**	**177,877**	**22%**	**98,241**	**116,505**	**19%**

Exhibit 5-8c. Comparison of Section 812 and ARB-Derived Annual CO Emissions for California, tpy

		1990			2000			2010			2020		
Tier 2 Name	Tier 3 Name	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference
Non-Road Gasoline	recreational	98,688	106,244	8%	96,366	93,541	-3%	160,473	102,822	-36%	176,602	118,302	-33%
	construction	83,783	47,537	-43%	58,626	35,089	-40%	67,656	29,119	-57%	74,778	29,444	-61%
	industrial	121,507	59,249	-51%	54,906	50,429	-8%	30,699	48,266	57%	14,165	49,710	251%
	lawn & garden	1,589,716	510,820	-68%	1,549,253	362,430	-77%	1,934,951	243,456	-87%	2,363,369	266,472	-89%
	farm	6,504	31,424	383%	7,516	25,200	235%	8,052	22,991	186%	9,028	22,143	145%
	light commercial	433,437	190,600	-56%	460,887	151,119	-67%	658,655	129,187	-80%	855,475	120,297	-86%
	logging	3,608	16,740	364%	3,245	6,377	97%	4,235	4,326	2%	5,800	4,326	-25%
	airport service	874	3,511	302%	821	3,911	376%	648	3,123	382%	640	3,151	392%
	railway maintenance	781	NA	NA	728	NA	NA	886	NA	NA	1,006	NA	NA
	recreational marine vessels	117,353	205,463	75%	131,318	251,101	91%	134,459	219,049	63%	138,933	206,876	49%
Non-Road Diesel	recreational	192	NA	NA	217	NA	NA	225	NA	NA	184	NA	NA
	construction	49,164	81,941	67%	43,465	51,731	19%	36,640	40,544	11%	18,755	38,528	105%
	industrial	7,798	14,906	91%	6,911	11,904	72%	6,468	9,354	45%	1,879	8,031	327%
	lawn & garden	2,521	1,432	-43%	3,039	1,532	-50%	2,944	220	-93%	2,300	12	-99%
	farm	8,538	32,084	276%	8,487	24,555	189%	5,835	17,666	203%	3,166	14,864	370%
	light commercial	5,565	6,235	12%	6,198	5,103	-18%	6,207	4,261	-31%	4,341	3,676	-15%
	logging	998	4,465	347%	457	1,542	238%	221	1,184	436%	31	1,161	3654%
	airport service	672	748	11%	722	670	-7%	599	642	7%	249	647	160%
	railway maintenance	310	NA	NA	331	NA	NA	295	NA	NA	180	NA	NA
	recreational marine vessels	350	356	2%	439	426	-3%	582	507	-13%	731	603	-17%
Other	liquified petroleum gas	72,734	NA	NA	99,332	NA	NA	74,064	NA	NA	22,254	NA	NA
	compressed natural gas	9,924	25,791	160%	12,396	28,898	133%	6,298	32,073	409%	2,712	35,289	1201%
		2,615,018	**1,339,546**	**-49%**	**2,545,659**	**1,105,559**	**-57%**	**3,141,091**	**908,788**	**-71%**	**3,696,579**	**923,533**	**-75%**

Exhibit 5-8d. Comparison of Section 812 and ARB-Derived Annual $PM_{2.5}$ Emissions for California, tpy

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	401	66	-83%	577	77	-87%	1,104	89	-92%	551	102	-82%
	construction	218	19	-91%	183	176	-4%	204	226	11%	230	237	3%
	industrial	72	26	-64%	19	32	62%	9	36	290%	4	38	966%
	lawn & garden	2,762	1,151	-58%	3,065	1,051	-66%	3,389	706	-79%	4,099	823	-80%
	farm	3	8	156%	3	24	717%	3	33	988%	4	37	925%
	light commercial	244	74	-70%	252	211	-16%	274	336	23%	355	350	-2%
	logging	19	35	85%	23	29	30%	32	32	0%	43	32	-26%
	airport service	1	3	354%	0	4	1129%	0	5	1523%	0	5	1417%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	1,885	1,260	-33%	2,508	1,909	-24%	1,940	3,103	60%	2,000	3,687	84%
Non-Road Diesel	recreational	28	NA	NA	32	NA	NA	32	NA	NA	27	NA	NA
	construction	9,678	10,520	9%	6,813	7,089	4%	5,373	5,098	-5%	2,651	3,267	23%
	industrial	1,650	2,164	31%	1,318	1,659	26%	890	1,370	54%	215	780	263%
	lawn & garden	488	206	-58%	581	157	-73%	492	120	-76%	348	4	-99%
	farm	2,027	4,829	138%	1,743	3,218	85%	1,070	2,227	108%	577	1,296	125%
	light commercial	1,023	912	-11%	1,124	686	-39%	1,017	578	-43%	667	346	-48%
	logging	230	646	181%	76	225	194%	37	137	275%	3	83	2405%
	airport service	163	120	-26%	119	102	-14%	87	89	3%	33	54	64%
	railway maintenance	55	NA	NA	56	NA	NA	45	NA	NA	29	NA	NA
	recreational marine vessels	55	23	-59%	68	23	-65%	57	29	-48%	54	35	-34%
Other	liquified petroleum gas	86	NA	NA	118	NA	NA	167	NA	NA	229	NA	NA
	compressed natural gas	12	57	376%	15	66	341%	19	73	274%	25	80	218%
		21,101	**22,118**	**5%**	**18,692**	**16,738**	**-10%**	**16,240**	**14,287**	**-12%**	**12,142**	**11,254**	**-7%**

Exhibit 5-8e. Comparison of Section 812 and ARB-Derived Annual SO_2 Emissions for California, tpy

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	57	184	222%	63	43	-32%	10	48	355%	14	53	294%
	construction	31	12	-63%	26	10	-60%	2	11	387%	3	12	350%
	industrial	72	48	-33%	35	49	42%	2	54	3297%	1	57	9811%
	lawn & garden	624	127	-80%	666	150	-77%	67	170	155%	81	191	134%
	farm	3	10	209%	4	9	108%	0	10	2355%	0	10	2220%
	light commercial	174	53	-70%	203	55	-73%	22	61	179%	28	65	128%
	logging	1	5	326%	1	3	138%	0	3	2099%	0	3	1566%
	airport service	1	5	759%	1	7	1045%	0	8	16106%	0	9	15133%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	127	123	-3%	158	153	-3%	15	185	1112%	17	208	1118%
Non-Road Diesel	recreational	14	NA	NA	16	NA	NA	2	NA	NA	0	NA	NA
	construction	7,718	9,421	22%	7,470	86	-99%	786	96	-88%	56	100	79%
	industrial	1,405	1,508	7%	1,701	13	-99%	170	14	-92%	11	14	25%
	lawn & garden	411	0	-100%	538	0	-100%	63	0	-100%	5	0	-100%
	farm	1,054	7,047	569%	1,332	348	-74%	123	36	-71%	9	35	297%
	light commercial	784	700	-11%	952	6	-99%	99	7	-93%	8	7	-5%
	logging	181	1,037	472%	126	3	-98%	8	3	-63%	0	3	703%
	airport service	111	3	-97%	146	0	-100%	17	1	-93%	1	1	9%
	railway maintenance	28	NA	NA	34	NA	NA	3	NA	NA	0	NA	NA
	recreational marine vessels	276	2	-99%	347	0	-100%	56	0	-100%	12	0	-100%
Other	liquified petroleum gas	20	NA	NA	27	NA	NA	33	NA	NA	43	NA	NA
	compressed natural gas	2	6	163%	3	6	118%	3	7	98%	5	7	57%
		13,095	**20,291**	**55%**	**13,849**	**942**	**-93%**	**1,483**	**715**	**-52%**	**296**	**776**	**163%**

Construction Equipment Sensitivity Analyses

EPA's NONROAD model was recommended by the EPA SAB Council Air Quality Modeling Subcommittee (AQMS) to be the most appropriate tool for estimating non-road mobile source emissions outside of California. However, recent studies by States suggest that activity factors for construction vehicles may differ substantially from the values included in the NONROAD model. Based on these findings, the AQMS suggested that the project team conduct sensitivity analyses that specifically address this uncertainty. The Project Team therefore conducted a comparison of the NONROAD results with results of a sensitivity analysis incorporating three other regional/local studies. Appendix E presents the detailed results of that analysis, which we summarize briefly here.

Nonroad "activity factors" are comprised of several variables, including equipment population, engine horsepower and load factor, and annual hours of use. Some of the studies questioning the validity of the NONROAD activity factors concluded that NONROAD underestimates annual hours of use per unit of equipment and overestimates total equipment populations. Because these changes offset each other (at least partially), the overall effect on activity is unclear.

Based on the emission estimation equation, the relationship between emissions and each activity variable is linear. Activity for nonroad equipment is calculated using the following equation:

Activity = Power x Load Factor x Time x Pop

Activity	=	activity (horsepower [hp]-hours)
Power	=	average rated engine power (hp)
Load Factor	=	engine load factor (average proportion of rated power)
Time	=	hours of use (hours)
Pop	=	equipment population

The comparisons we conducted focus on base year emissions for 2000. Note that revisions to hours of use data also affect rates of scrappage and phase-in of new, cleaner engines, which will also affect future year emissions. To gauge the potential significance of these activity factors, the Project Team compared year 2000 emissions developed from default activity inputs included in NONROAD with emissions developed from revised inputs from three local construction activity studies. The three specific studies include: (1) Lake Michigan Air Directors Consortium (LADCO) Nonroad Emissions Inventory Project; (2) Clark County-Wide Inventory of Non-road Engines Project; and (3) Houston-Galveston Area Diesel Construction Emissions Project. We first generated annual emission estimates for the geographic areas covered by the surveys using NONROAD2004 and all default data inputs. We then adjusted the NONROAD model activity inputs using the reported survey results to generate revised emission estimates for comparison. This analysis focused on five priority construction equipment applications, or source classification codes (SCCs). In addition, because the base activity is the same for all pollutants, and differences in pollutant estimates are due to differences in emission rates, the analysis was limited to oxides of nitrogen (NOx) emissions.

In summary, this analysis shows that local surveys of nonroad equipment populations and activity produce NOx emission estimates that can be considerably higher or lower than estimates made using EPA's NONROAD model defaults. For both LADCO studies, overall NOx emissions are higher in the local area study than in the section 812 analysis, as emissions increases for the three largest equipment types outweigh decreases in those for the other two equipment types studied. For Clark County, much lower equipment populations for all surveyed source categories lead to a much lower estimate of construction equipment NOx emissions for the area. Finally, for the Houston area study, lower estimated equipment activity for four types contribute to an overall NOx emission decrease for the equipment types studied.

Assuming that national populations estimated by NONROAD are a reliable measure of the total in-use national engine populations, which we believe is reasonable based on our review of the PSR survey data, then lower estimates of equipment populations based on surveys in certain areas would be expected to be offset by increases in other areas, and vice versa. The PSR survey was conducted to generate national estimates, however, so the differences observed at the local level suggest that there is considerable variability in the construction equipment emission estimates for any individual geographic area that might not be adequately addressed by careful activity factor allocation schemes. In addition, the differences also imply that use of NONROAD default data might lead to some errors in performing any local controls analysis to simulate how an area might respond to 8-hour ozone and PM2.5 NAAQS control requirements. Control decisions would be expected to be significantly different in areas like Clark County, NV depending on whether national defaults or local survey data are used to determine the importance of off-road construction equipment. We conclude that these results provide an important basis for conducting subsequent uncertainty analyses for impact of Federal nonroad sector regulations, in particular as we consider the identification of local controls to meet NAAQS requirements.

CHAPTER 6 - ON-ROAD VEHICLES

Overview Of Approach

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. 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. The impact of new 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 emissions 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.

The general procedure we applied for calculating historic and projection year on-road vehicle emissions was to multiply activity in the form of VMT by pollutant-specific emission factor estimates. Emission factors for these pollutants were generated using the EPA's latest motor vehicle emission factor model MOBILE6.2 (EPA, 2003). MOBILE supplies emissions factors in units of grams per mile traveled for each criteria pollutant, by vehicle class. The emissions factors generated are then applied to estimates of vehicle miles traveled, by class, to estimate total emissions for each pollutant. Because California's emission standards differ from those for the rest of the nation and cannot be accurately modeled with MOBILE6.2, emission factor estimates generated by the California Air Resources Board (ARB) were used for the California emission calculations in 2000, 2010, and 2020.[38]

Emission factors for all pollutants were developed for county-level groups with common control programs within each State. For each State, a single set of monthly average State-level temperatures are used for each year modeled. Control program inputs such as inspection and maintenance programs and fuel programs are specified at the county level. Temporally, emissions are calculated by month and summed to develop annual emission estimates. Two MOBILE6.2 input parameters, common to both the historical years and projection year modeling, are speed and temperature. Other parameters, which vary by scenario or year, are discussed under the sections describing the 1990 emissions and the control scenarios.

Speed

Emission factors were estimated for nine different travel speeds. These speeds were developed using Highway Performance Monitoring System average travel speed data for the years 1987 through 1990 (DOT, 2000). The average travel speed for each vehicle type/roadway functional classification combination varied less than one mile per hour over the four year span. To reduce the number of speeds to be modeled, the Highway Performance Monitoring System speeds were rounded to the nearest five

[38] Some non-California States have elected to adopt the California motor vehicle emission standards in accordance with Section 177 of the CAAA. The emission effects of these State adoptions have not been incorporated in this analysis, but we believe the impact of the California emissions standards on criteria pollutants, relative to the Federal standards adopted to date, are slight, because the Federal standards reflect virtually all but the most recent California standards.

miles per hour. The 1990 speeds are used for all projection years, as well. Exhibit 6-1 lists the speeds which are used for each vehicle type/functional road system combination. The SCC uniquely defines the vehicle type/roadway classification, and is thus used to determine which speed to model (the emission factor data base contains a speed indicator).

Temperature

Monthly temperatures at the State level are used as input to MOBILE6.2 for calculating the on-road vehicle emission factors. Actual 1990 and 2000 temperatures were used to estimate base year emission factors. For the projection years, 30-year average temperatures (BOC, 1992) are used. Temperatures for a representative city were chosen for each State.

Growth Projections

2000 VMT

The VMT data used to model the year 2000 started with the 2000 NEI VMT database. However, for State or local areas that had provided their own VMT data to EPA for use in the 1999 NEI, the resulting 1999 NEI VMT data were grown to 2000.

2010 and 2020 VMT Projections

The resultant 2000 VMT database was projected to 2010 and 2020 using the following data sources: the *AEO 2005* projections of national VMT; the *AEO 2005* State-level population projections; Woods and Poole county-level population projections; and EPA's MOBILE6.2 default VMT mixes by vehicle type.

The *AEO 2005* State-level population projections were first allocated to counties, as described in Chapter 2. The 2000, 2010, and 2020 national VMT data from the *AEO* were distributed among the 28 MOBILE6 vehicle classes. The *AEO* data are for three vehicle classes, as shown in Exhibit 6-2. For each of the three calendar years (2000, 2010, and 2020), a MOBILE6 run was generated using model defaults. The output database files provide the default VMT mix projected by the model for each of these three years. The 28 MOBILE6 vehicle categories were matched to the three vehicle categories used in the DOE *AEO* projections as shown in Exhibit 6-3. This table also shows the default MOBILE6 VMT fractions for the three years (EPA, 2003). Next, within each of the three DOE vehicle categories, the MOBILE6 VMT fractions were normalized such that the sum of the VMT fractions for all MOBILE6 vehicle classes within one of the DOE vehicle categories would sum to 1. These fractions are shown in Exhibit 6-3 in the columns labeled *VMT Fraction by DOE Vehicle Type*. Finally, the AEO VMT from Exhibit 6-2 for each of the three DOE vehicle classes was multiplied by the corresponding VMT fraction for each of the MOBILE6 vehicle classes included in the DOE vehicle class. The resulting VMT distribution by the 28 MOBILE6 vehicle types is shown in Exhibit 6-3 in the columns labeled *Allocated DOE VMT*. It should be noted that these VMT values were used in developing the VMT growth factors, but are not necessarily the resulting projected VMT data.

Exhibit 6-1. Average Speeds Modeled by Road Type and Vehicle Type (miles per hour)

	Rural						Urban					
	Interstate	Principal Arterial	Minor Arterial	Major Collector	Minor Collector	Local	Interstate	Other Freeways & Expressways	Principal Arterial	Minor Arterial	Collector	Local
Light-Duty Vehicle (LDV)	60	45	40	35	30	30	45	45	20	20	20	20
Light-Duty Truck (LDT)	55	45	40	35	30	30	45	45	20	20	20	20
Heavy-Duty Vehicle (HDV)	40	35	30	25	25	25	35	35	15	15	15	15

Exhibit 6-2. Actual and Projected VMT by Vehicle Class from Annual Energy Outlook and Comparison with First Prospective VMT

	National Annual Vehicle Miles Traveled (billion miles per year)			
Vehicle Class	**1990**	**2000**	**2010**	**2020**
LDVs less than 8,500 pounds		2,355	3,017	3,680
Commercial Light Trucks		69	78	96
Freight Trucks greater than 10,000 pounds		207	268	336
Totals	**1,989**	**2,631**	**3,363**	**4,112**
First Prospective VMT estimates	1,642	2,034	2,449	N/A

SOURCE: DOE, 2005; 2003.

Exhibit 6-3. Distribution of DOE VMT to MOBILE6 Vehicle Categories

DOE Vehicle Type	MOBILE6 Vehicle Type	2000 MOBILE6 Default VMT Fraction	2000 VMT Fraction by DOE Vehicle Type	2000 Allocated DOE VMT	2010 MOBILE6 Default VMT Fraction	2010 VMT Fraction by DOE Vehicle Type	2010 Allocated DOE VMT	2020 MOBILE6 Default VMT Fraction	2020 VMT Fraction by DOE Vehicle Type	2020 Allocated DOE VMT
LDVs	LDGV	0.484060	0.548795	1,292.41	0.347807	0.396094	1,195.02	0.278784	0.318275	1,171.25
	LDGT1	0.066848	0.075788	178.48	0.089850	0.102324	308.71	0.101366	0.115725	425.87
	LDGT2	0.222534	0.252294	594.15	0.299110	0.340636	1,027.70	0.337444	0.385245	1,417.70
	LDGT3	0.068224	0.077348	182.15	0.091532	0.104240	314.49	0.103245	0.117870	433.76
	LDGT4	0.031374	0.035570	83.77	0.042091	0.047935	144.62	0.047479	0.054205	199.47
	LDDV	0.001107	0.001255	2.96	0.000309	0.000352	1.06	0.000251	0.000287	1.06
	LDDT12	0.000264	0.000299	0.70	0.000009	0.000010	0.03	0.000000	0.000000	0.00
	LDDT34	0.001362	0.001544	3.64	0.001946	0.002216	6.69	0.002217	0.002531	9.31
	MC	0.006268	0.007106	16.73	0.005438	0.006193	18.68	0.005135	0.005862	21.57
Commercial Light Trucks	HDGV2B	0.028740	0.751451	51.85	0.030066	0.767460	59.86	0.030784	0.772458	74.16
	HDDV2B	0.009506	0.248549	17.15	0.009110	0.232540	18.14	0.009068	0.227542	21.84
Freight Trucks	HDGV3	0.001025	0.012858	2.66	0.001043	0.012607	3.38	0.001099	0.013048	4.38
	HDGV4	0.000581	0.007288	1.51	0.000350	0.004231	1.13	0.000306	0.003633	1.22
	HDGV5	0.001201	0.015066	3.12	0.001069	0.012921	3.46	0.001047	0.012431	4.18
	HDGV6	0.002582	0.032390	6.70	0.002288	0.027656	7.41	0.002258	0.026809	9.01
	HDGV7	0.001231	0.015443	3.20	0.000952	0.011507	3.08	0.000924	0.010970	3.69
	HDGV8A	0.000005	0.000063	0.01	0.000003	0.000036	0.01	0.000003	0.000036	0.01
	HDGV8B	0.000000	0.000000	0.00	0.000000	0.000000	0.00	0.000000	0.000000	0.00
	HDDV3	0.002798	0.035100	7.27	0.002805	0.033905	9.09	0.002831	0.033612	11.29
	HDDV4	0.002321	0.029116	6.03	0.002848	0.034424	9.23	0.003000	0.035618	11.97
	HDDV5	0.001009	0.012658	2.62	0.001337	0.016161	4.33	0.001444	0.017144	5.76
	HDDV6	0.005757	0.072220	14.95	0.006509	0.078676	21.09	0.006707	0.079631	26.76
	HDDV7	0.008666	0.108712	22.50	0.009397	0.113584	30.44	0.009607	0.114062	38.32
	HDDV8A	0.010881	0.136499	28.26	0.011212	0.135522	36.32	0.011397	0.135315	45.47
	HDDV8B	0.038808	0.486834	100.77	0.039986	0.483320	129.53	0.040622	0.482298	162.05
	HDGB	0.000583	0.007314	1.51	0.000165	0.001994	0.53	0.000083	0.000985	0.33
	HDDBT	0.000927	0.011629	2.41	0.000953	0.011519	3.09	0.000970	0.011517	3.87
	HDDBS	0.001340	0.016810	3.48	0.001815	0.021938	5.88	0.001928	0.022891	7.69

In addition to different growth rates by vehicle class, the VMT growth factors also account for differences in population growth in different areas of the country, relative to the overall U.S. population growth rates. The following equation illustrates our approach to calculating VMT growth factors for the 2010 and 2020 projection years.

*VMTGF(cy,py,vc) = (VMTNAT(py,vc)/VMTNAT(2000,vc)) * (POP(cy,py)/POP(cy,2000)) / (USPOP(py)/USPOP(2000))*

where:

VMTGF(cy,py,vc)	=	county-specific projection year VMT growth factor by vehicle class
VMTNAT(py,vc)	=	National VMT for projection year by vehicle class (from Exhibit 6-3)
VMTNAT(2000,vc)	=	National VMT for 2000 by vehicle class (from Exhibit 6-3)
POP(cy,py)	=	county-specific projection year population
POP(cy,2000)	=	county-specific population for 2000
USPOP(py)	=	U.S. population total for projection year
USPOP(2000)	=	U.S. population total for 2000

The resulting growth factors by county and MOBILE6 vehicle type were then multiplied by the corresponding VMT records in the 2000 VMT database.

1990 Emissions Estimates

The 1990 on-road vehicle emission estimates used for the Second Section 812 Prospective Analysis are those developed for EPA for a re-analysis of the 1990 NEI estimates (Pechan, 2004b), with one basic modification to VMT for some States.[39] The 1990 NEI VMT estimates are based on Federal Highway Administration VMT data summaries by State and functional road class, along with VMT estimates for urban areas within each State by functional road class. Two procedures were performed to convert this VMT data into a county/SCC-level format. First, each State's rural, small urban, and large urban VMT by functional roadway class were distributed to the county level based on population data. Second, the resulting county/functional roadway class VMT were allocated to the MOBILE6.2 vehicle classes. The resulting VMT estimates are county-level estimates segregated by vehicle type and roadway class.

To provide greater consistency with the more recent data used in the projection years, in this analysis the 1990 NEI VMT data were replaced for States or counties with State or locally provided VMT data in the 1999 NEI.[40] For these States or counties, adjusted 1990 VMT data were calculated by multiplying the 1990 NEI VMT by the ratio of the State-supplied VMT contained in the 1999 NEI Version 3 to the FHWA-based 1999 VMT, calculated in the same manner as the 1990 NEI VMT.

This 1990 emission inventory was developed at the county level of detail by month for temperature conditions, fuel parameters, and control programs in place in 1990. EPA's MOBILE6.2 model was used to generate 1990 on-road vehicle emission factors for all States by county groupings, roadway type, and month. The 1990 MOBILE6.2 emission factors were generated using historical State-

[39] Full documentation of the 1990 NEI on-road emission inventory can be found at ftp://ftp.epa.gov/EmisInventory/prelim2002nei/mobile/onroad/documentation/nei_onroad_jan04.pdf.

[40] Note that the 2002 NEI was not available at the time this portion of the VMT analysis was completed.

level monthly minimum and maximum daily temperatures, gasoline volatility (RVP) data, and I/M program information. The 1990 emission estimates were calculated by applying these emission factors to the VMT estimates. Emissions estimates are calculated at the county/vehicle type/roadway type level of detail.

Control Scenario Assumptions

2000 Emission Estimates

Onroad emission estimates for 2000 were calculated for a *without-CAAA* scenario and a *with-CAAA* scenario. As with 1990, the 2000 CAAA scenario was based on the 2000 NEI onroad emission inventory. Again, as with 1990, the VMT data for counties with State or locally supplied VMT data in the 1999 NEI Version 3 were first adjusted in the same manner that the 1990 VMT for these counties were adjusted, as discussed above. The MOBILE6 emission factors for the *with-CAAA* scenario included the effects of all CAA control programs including I/M, reformulated gasoline, RVP controls, oxygenated fuel, Tier 1 emission standards, and national LEV emission standards. Actual I/M programs and fuel programs in place in 2000 were modeled in the *with-CAAA* scenario. Also, States in the Northeast were modeled with the appropriate National LEV program inputs. The MOBILE6.2 defaults were used to account for all national CAA and CAAA emission programs, including Tier 1 emission standards. For the *without-CAAA* scenario, the MOBILE6 command "NO CAA" was used to turn off the effects of the CAAA control measures. The "NO CAA" command in MOBILE6.2 turns off all of the effects of the motor vehicle provisions of the 1990 CAAA authorized regulation, but leaves in place those regulations in place prior to 1990. In addition, emission factors in the *without-CAAA* scenario were modeled with I/M programs present in 1990 and the RVP levels modeled in 1990.

Temperatures were specific to 2000 historical conditions, again at the State and monthly level. The same speeds modeled in 1990 were used in 2000. These are discussed in more detail in the first section of this chapter. All remaining optional inputs, such as registration distributions or diesel sales fractions were set to the MOBILE6.2 defaults (i.e., none of the optional inputs were used other than those discussed above for the control programs).

Because California's emission standards differ from those in the rest of the country, data supplied by the ARB were used for that State for the 2000 *with-CAAA* scenario. ARB provided an on-road emission inventory for California with all control measures in place, along with the VMT used in calculating the inventory. Emission factors in this inventory were calculated using California's EMFAC model. These emission estimates have been incorporated into the *with-CAAA* emission scenario. However, only annual emission estimates were provided, so the SMOKE modeling files developed for California only contain annual emission estimates, while the modeling files for all remaining States have monthly emission estimates.[41]

Projection Year Emission Estimates

Projection year on-road emission inventories were calculated for 2010 and 2020 under a *without-CAAA* scenario and a *with-CAAA* scenario. The same VMT projections were used under both scenarios for a given target year; the development of VMT estimates is described above. MOBILE6.2 was used to calculate the emission factors for each of these scenarios, with the exception of California, under the *with-CAAA* scenarios. California is discussed separately below.

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[41] SMOKE is the emissions inventory processing model that is used to pre-process estimates for the purposes of generating air quality modeling input files.

Emission Factors

The emission factors used in the projection years were calculated using MOBILE6.2. The *without-CAAA* emission factors were calculated in the same manner as the 2000 *without-CAAA* emission factors, using 1990 I/M programs and 1990 fuel data. Again, the "NO CAA" command was used in the MOBILE6 input files to turn off the default national CAAA control programs. For the *with-CAAA* scenario, the MOBILE6.2 defaults account for all national CAA emission programs, including Tier 1 emission standards, national LEV, Tier 2 emission standards and gasoline sulfur levels, and heavy-duty emission standards and low sulfur gasoline. Actual I/M programs and fuel programs in place in 2000 were modeled in the *with-CAAA* scenarios. For both projection scenarios in 2010 and 2020, 30-year average temperatures (BOC, 1992) are used. Vehicle speeds are the same for all years and scenarios, using the data from Exhibit 6-1.

Adjustments for California

ARB provided projected on-road emission inventories and the corresponding VMT data for 2000 and 2010 with all control measures in place, again calculated using the EMFAC model. In order to maintain consistent growth assumptions for all States, these emission estimates were adjusted to use the VMT projected as discussed above for the State of California. To do this, the CARB emission estimates at the SCC level of detail were multiplied by the ratio of the AEO-based VMT projections to the CARB-provided VMT projections, at the SCC level of detail.

Unlike the *with-CAAA* projected emissions, the *without-CAAA* projected emissions for California were calculated using MOBILE6.2 emission factors, as ARB was unable to provide a No CAA emission scenario for the projection years. Due to the differences in the EMFAC and MOBILE6.2 model assumptions as well as the differences in the inputs to these models, the PM emissions in some cases were greater under the *with-CAAA* scenario. Since these were due to different modeling methods rather than actual emission increases under the CAA, the PM emissions for the California *without-CAAA* results were adjusted to reflect the proportional increment in emissions reduction that would have resulted if we were to rely only on MOBILE. To implement this adjustment, first the MOBILE6-based PM_{10} and $PM_{2.5}$ emissions calculated for California both *with-* and *without CAAA* were totaled by 8 vehicle types, with separate emission totals for exhaust, brake wear, and tire wear. The ratio of the *without-CAAA* emissions to the *with-CAAA* emissions by vehicle type and emission component was then calculated, to provide an increment in emissions that was not possible to estimate using EMFAC alone. These ratios were then applied to the California-based *with-CAAA* PM_{10} and $PM_{2.5}$ emissions to estimate a revised set of *without-CAAA* emissions of PM_{10} and $PM_{2.5}$ for California.

Emission Summary By Scenario

Exhibit 6-4 summarizes the on-road vehicle emissions in 1990 and in 2000, 2010, and 2020 with and without the effects of the CAAA. Emissions are shown by pollutant and vehicle category. In all cases, with the exception of ammonia, the total on-road emissions in the 2020 *with-CAAA* case, with CAAA authorized control measures in place, are below the 1990 emission levels, despite significant increases in VMT during this time period. In contrast, the 2020 *without-CAAA* emissions are greater than the 1990 total on-road emissions for NO_x, SO_2, and NH_3, and only modest emission decreases, attributable to pre-1990 provisions, occur for VOC, CO, PM_{10}, and $PM_{2.5}$.

For VOC, CO, and NO_x, the emissions from 1990 to each of the *with-CAAA* projection scenarios show steady declines over time, while the emissions in the *without-CAAA* projections initially decrease from 1990 levels, but then begin to increase. Several control programs in place in 1990 account for these initial declines including the Federal Motor Vehicle Control Program, Phase I RVP requirements, and I/M programs already in place in 1990. By 2000, several CAAA programs begin to reduce on-road emissions. These include: Phase II RVP requirements, the Tier 1 emission standards, evaporative control requirements, Federal reformulated gasoline, oxygenated gasoline, more stringent I/M requirements, and California LEV standards in California. After 2000, the national LEV emission standards, Phase II of the Federal reformulated gasoline program, local low RVP gasoline programs, the Tier 2 emission standards, low sulfur gasoline, heavy-duty vehicle emission standards, and low sulfur diesel fuel all contribute to lowering emissions.

The specific requirements of these various programs have an impact on when emissions will be reduced and from what vehicle types. For example, emission standards require time for fleet turnover to occur before significant effects from these requirements can be realized, whereas fuel programs bring immediate emission reductions once the new fuel is in place.

Exhibit 6-4 shows a decrease in NO_x emissions from HDDVs from 2000 to 2010 in the *with-CAAA* scenarios of 48 percent. NO_x emissions from these vehicles are reduced by an additional 68 percent from 2010 to 2020. The initial NO_x reductions are primarily due to the implementation of the earlier HDV emission standards, while the reductions from 2010 to 2020 are more a result of the HDV emission standards and low sulfur diesel fuel that are implemented starting in 2007. For comparison, light-duty gas vehicle (LDGV) NO_x emissions decrease by 63 percent from 2000 to 2010 and decrease an additional 61 percent from 2010 to 2020 with the effects of the CAA. The LDGV NO_x emissions are significantly affected by the Tier 2 NO_x emission standards and low sulfur gasoline, both of which began implementation in 2004. The effects of the Tier 2 emission standards continue to reduce NO_x emissions from 2010 to 2020 as more Tier 2 vehicles are purchased, replacing older, more-polluting vehicles. Reduction in LDGV VMT over this time period also contributes to the NO_x emission reductions. By examining the percentage reduction in a given year from the *without-CAAA* scenario to the *with-CAAA* scenario, the effects of VMT changes can be isolated, because the same VMT projections were used for both scenarios in a given target year. In 2010, we estimate LDGV NO_x emissions are 64 percent less and HDDV emissions are 47 percent less due to the CAAA. In 2020, NO_x emissions from both of these vehicle categories are 85 percent less due to the CAAA programs in place.

Exhibit 6-4. National Onroad Vehicle Emissions by Vehicle Type* (tpy)

Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
LDGV	5,606,477	3,211,214	2,869,586	2,506,018	1,029,969	2,478,590	483,884
LDGT1	1,547,385	1,409,353	1,229,018	1,975,235	822,159	2,694,542	624,092
LDGT2	1,053,084	709,179	655,476	816,237	477,329	1,089,319	345,039
HDGV	629,345	262,649	241,589	174,131	108,391	207,762	63,153
LDDV	17,671	4,602	4,491	925	360	924	124
LDDT	14,958	6,491	6,196	7,344	3,165	10,407	2,004
HDDV	412,785	245,200	214,815	226,901	144,345	271,504	120,538
MC	45,955	24,295	24,585	27,222	28,289	31,490	31,782
Total	9,327,660	5,872,983	5,245,756	5,734,012	2,614,007	6,784,539	1,670,617
NO_X							
LDGV	4,215,615	2,737,163	2,291,082	2,309,526	839,101	2,272,760	331,188
LDGT1	956,202	1,119,246	982,685	1,855,108	812,991	2,585,697	507,084
LDGT2	538,827	442,728	422,583	658,901	437,306	920,341	325,875
HDGV	564,006	440,794	431,095	446,893	220,028	540,431	81,067
LDDV	42,513	9,462	9,354	2,280	1,134	2,279	496
LDDT	22,397	10,260	9,933	13,335	8,540	18,721	8,139
HDDV	3,174,678	4,007,535	3,912,552	3,803,221	2,013,609	4,335,983	643,291
MC	21,757	14,921	14,454	16,655	16,352	19,208	18,702
Total	9,535,993	8,782,108	8,073,738	9,105,919	4,349,062	10,695,419	1,915,842
CO							
LDGV	66,548,696	42,635,956	36,159,393	34,299,363	18,394,463	33,861,137	13,124,394
LDGT1	19,616,735	21,536,217	17,810,223	31,585,003	15,218,908	42,866,174	14,894,501
LDGT2	12,411,894	9,875,050	8,628,313	11,661,901	6,607,649	15,419,371	6,512,334
HDGV	8,867,768	3,497,147	3,242,055	1,491,136	1,303,822	1,721,454	1,234,132
LDDV	38,056	9,897	9,901	2,370	2,000	2,365	1,347
LDDT	24,584	11,452	10,682	13,351	7,240	18,891	7,375
HDDV	1,795,952	1,297,603	1,104,483	1,243,538	644,349	1,434,882	235,625
MC	263,313	173,758	165,816	194,724	209,536	225,271	229,800
Total	109,566,997	79,037,081	67,130,866	80,491,386	42,387,967	95,549,545	36,239,508

Exhibit 6-4 (continued)

Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
SO_2							
LDGV	109,946	120,040	102,272	110,039	10,408	107,854	10,176
LDGT1	30,851	58,498	46,288	103,303	9,677	143,310	13,424
LDGT2	20,671	25,864	22,471	44,852	4,274	62,401	5,917
HDGV	16,280	15,264	13,253	16,245	1,517	19,734	1,839
LDDV	12,146	2,454	384	762	4	760	4
LDDT	5,081	4,205	698	6,934	34	9,846	48
HDDV	304,522	406,074	67,905	514,799	4,002	642,501	5,005
MC	567	368	321	411	38	475	44
Total	500,064	632,766	253,592	797,345	29,954	986,882	36,457
PM_{10}							
LDGV	56,446	52,175	50,887	47,882	41,714	46,838	40,827
LDGT1	16,958	21,837	21,187	39,470	31,679	55,238	43,947
LDGT2	13,961	9,413	9,211	13,143	10,617	18,216	14,508
HDGV	16,781	9,730	9,643	8,358	5,645	10,256	4,216
LDDV	10,525	1,700	1,593	193	148	146	74
LDDT	4,570	1,668	1,481	877	585	773	359
HDDV	264,829	150,105	126,425	118,860	63,379	136,739	31,116
MC	662	429	427	462	448	528	513
Total	384,733	247,056	220,854	229,246	154,216	268,733	135,559
$PM_{2.5}$							
LDGV	34,460	28,312	27,014	25,846	19,685	25,294	19,273
LDGT1	11,264	12,446	11,798	23,383	15,571	33,004	21,694
LDGT2	9,327	5,665	5,463	7,820	5,264	10,848	7,146
HDGV	11,207	7,035	6,949	6,440	3,853	8,106	2,434
LDDV	9,448	1,512	1,405	156	113	61	29
LDDT	4,122	1,484	1,297	695	429	653	233
HDDV	241,647	135,026	111,347	105,085	51,189	120,890	19,808
MC	377	244	242	266	252	297	282
Total	321,852	191,723	165,515	169,690	96,356	199,153	70,899

Exhibit 6-4 (continued)

Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
NH_3							
LDGV	115,100	175,817	175,722	165,082	163,695	161,755	159,947
LDGT1	21,435	66,000	65,989	119,239	118,961	165,416	164,925
LDGT2	9,439	20,688	20,688	39,428	39,428	55,095	55,095
HDGV	3,692	3,868	3,868	4,343	4,343	5,344	5,344
LDDV	169	36	36	13	13	13	13
LDDT	60	39	39	63	63	89	89
HDDV	4,012	5,994	5,994	7,774	7,774	9,743	9,743
MC	196	127	127	142	142	164	164
Total	154,103	272,569	272,464	336,083	334,417	397,618	395,319

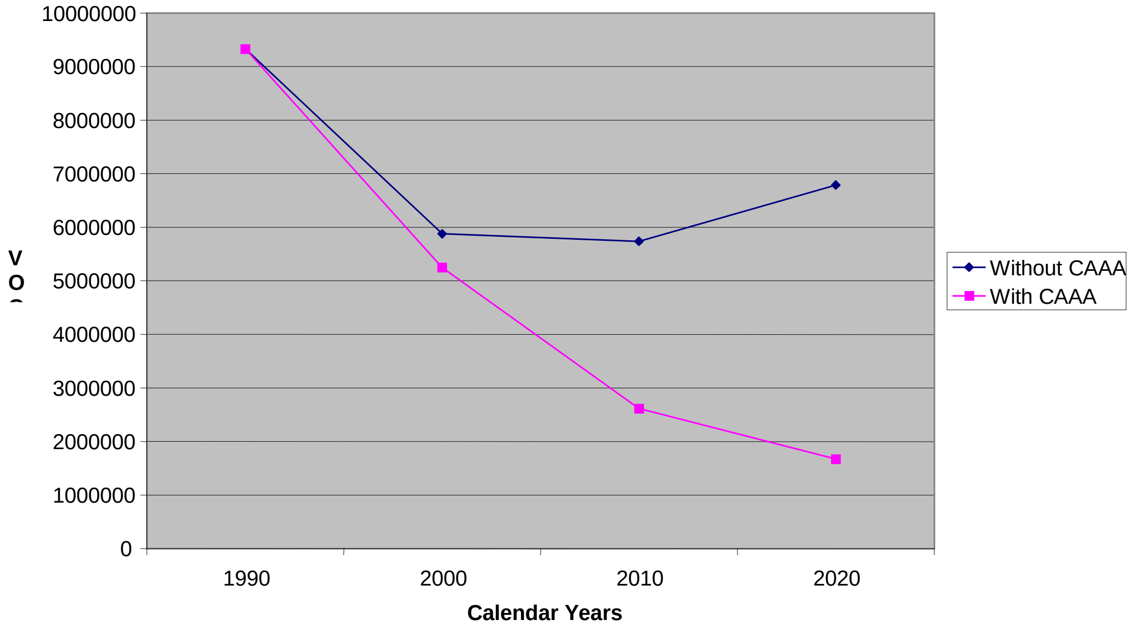
NOTE: *The totals reflect emissions for the 48 contiguous States, excluding Alaska and Hawaii. Totals may not add due to rounding.

Reductions in SO_2 emissions are the direct result of changes in fuel sulfur content. Thus, when CAAA regulations affect the sulfur levels of gasoline or diesel fuel, an immediate corresponding decrease in SO_2 emissions occurs. However, as VMT increases, SO_2 emissions begin to increase again. Nonetheless, the *with-CAAA* SO_2 emissions in 2020 are 93 percent lower than the 1990 on-road SO_2 emissions and 94 percent lower than the *without-CAAA* SO_2 emissions in 2020.

NH_3 emissions show minimal changes in response to the CAAA control programs. In fact, NH_3 emission rates are lower on vehicles without catalysts than those with catalysts. This fact, in combination with increasing VMT, accounts for the significant increases in NH_3 emissions from 1990 to 2000 (*with-* or *without-CAAA*) as non-catalyst vehicles are phased out.

Exhibit 6-5 displays the onroad vehicle sector *with-* and *without-CAAA* emission summaries by pollutant in a graphic format.

Exhibit 6-5. *With-* and *Without-CAAA* Scenario Onroad Vehicle Emission Summaries by Pollutant



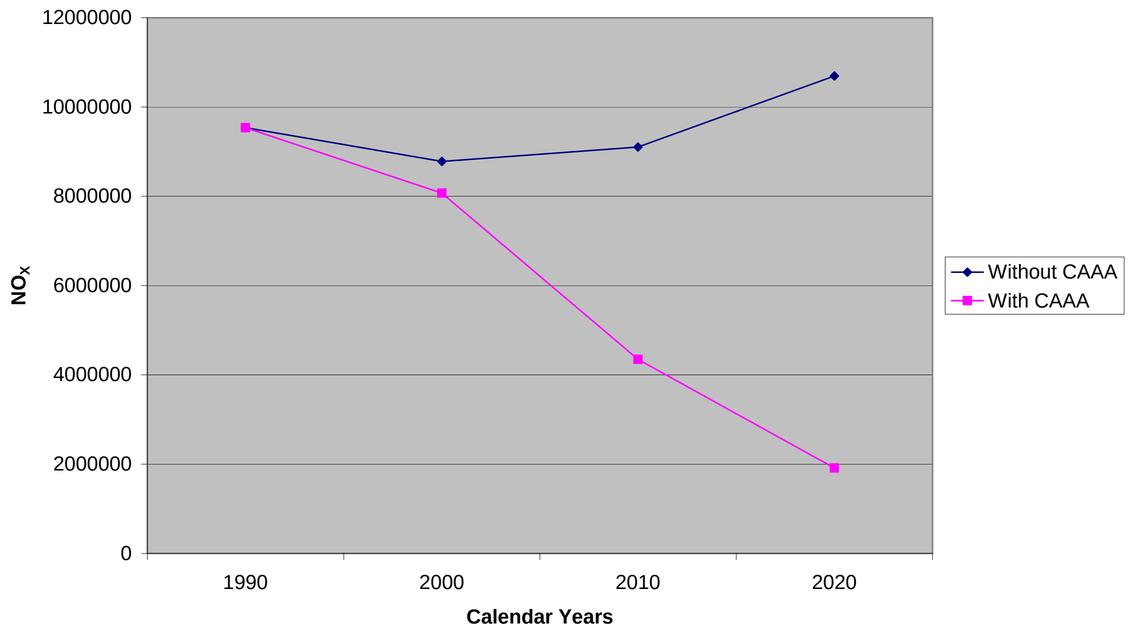
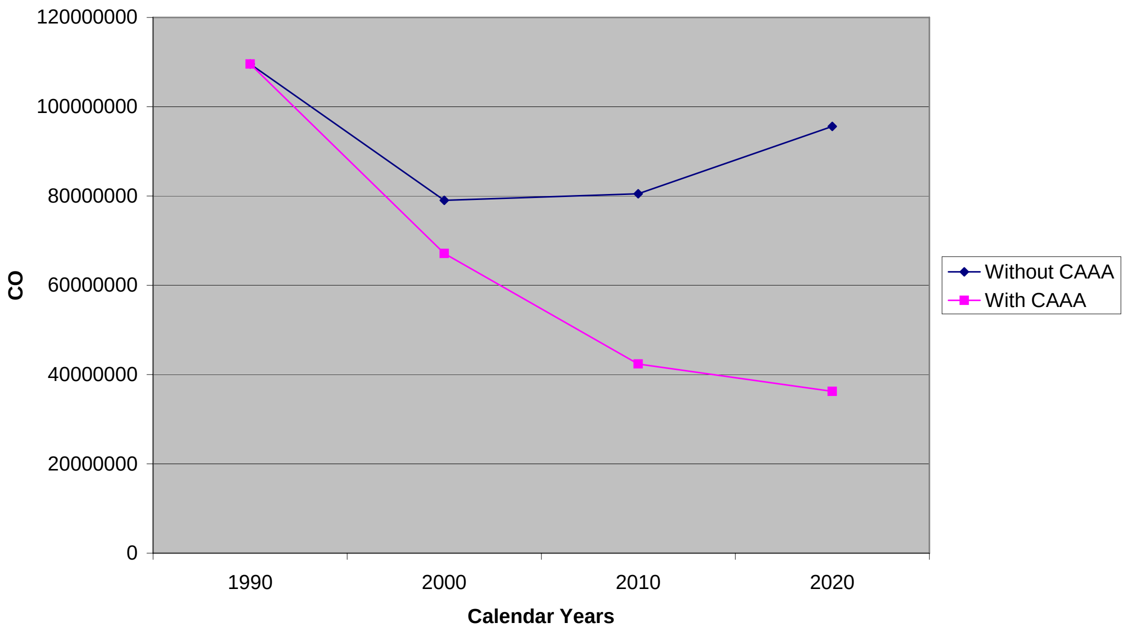


Exhibit 6-5 (continued)



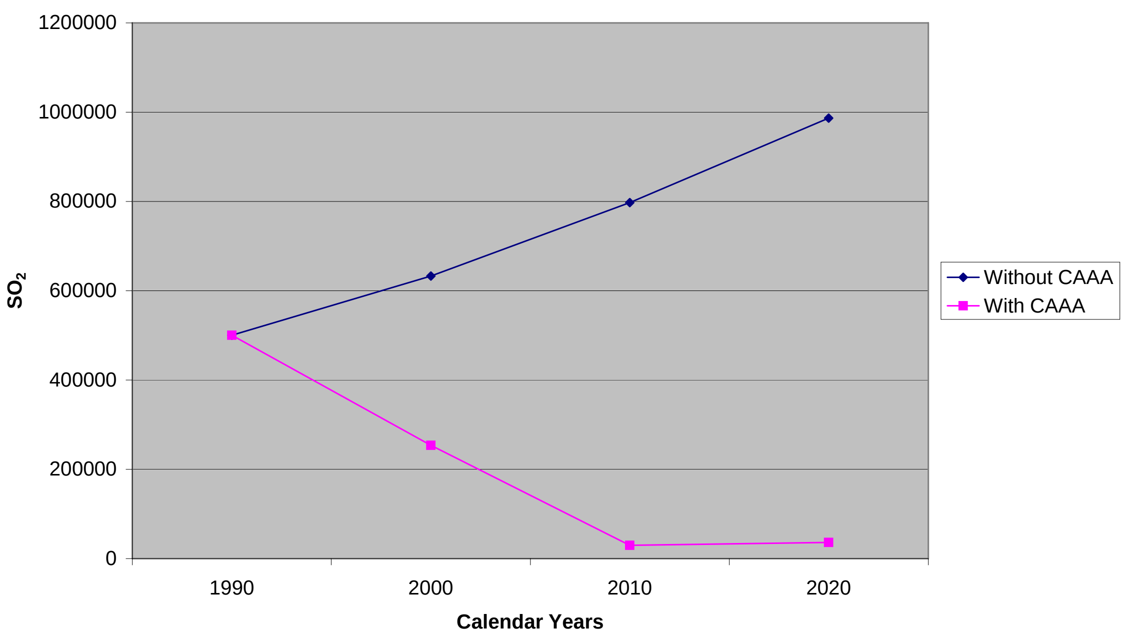
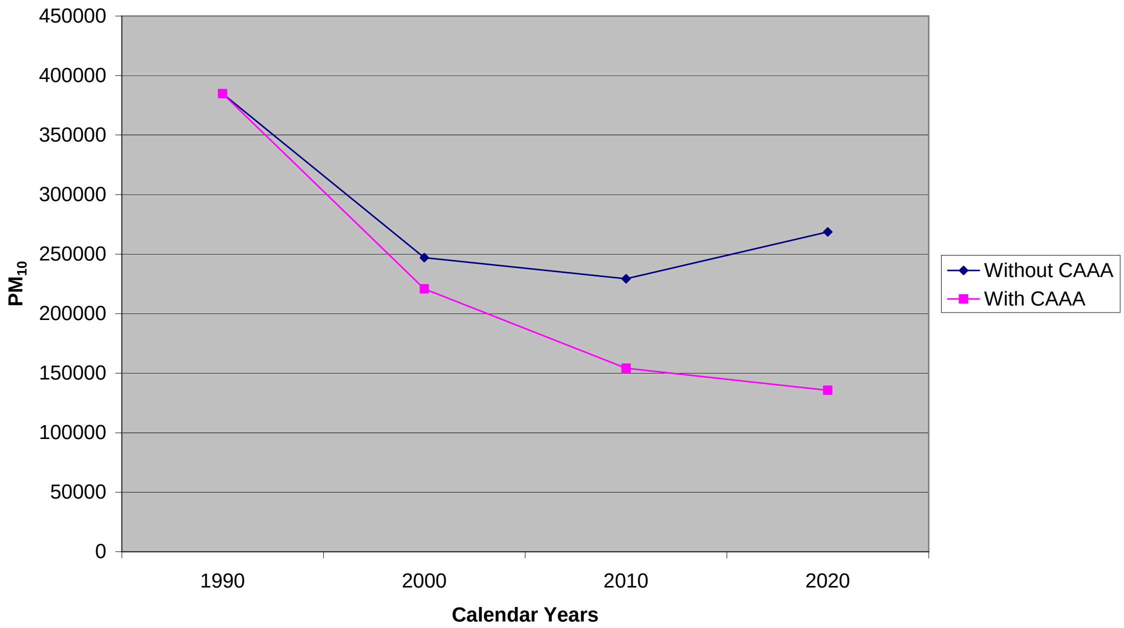


Exhibit 6-5 (continued)



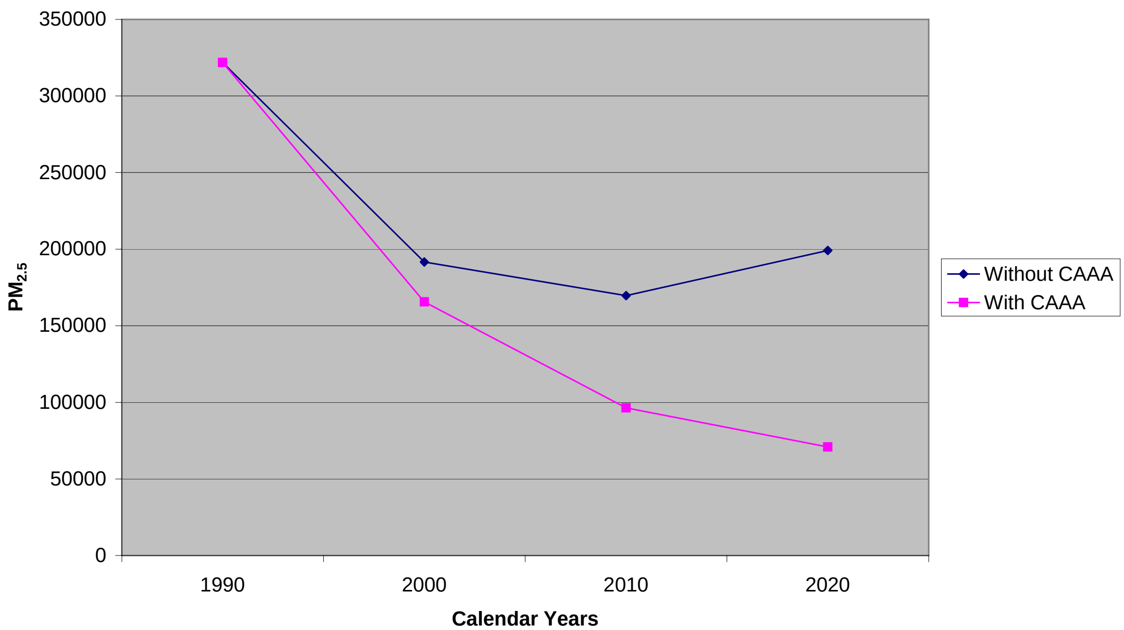
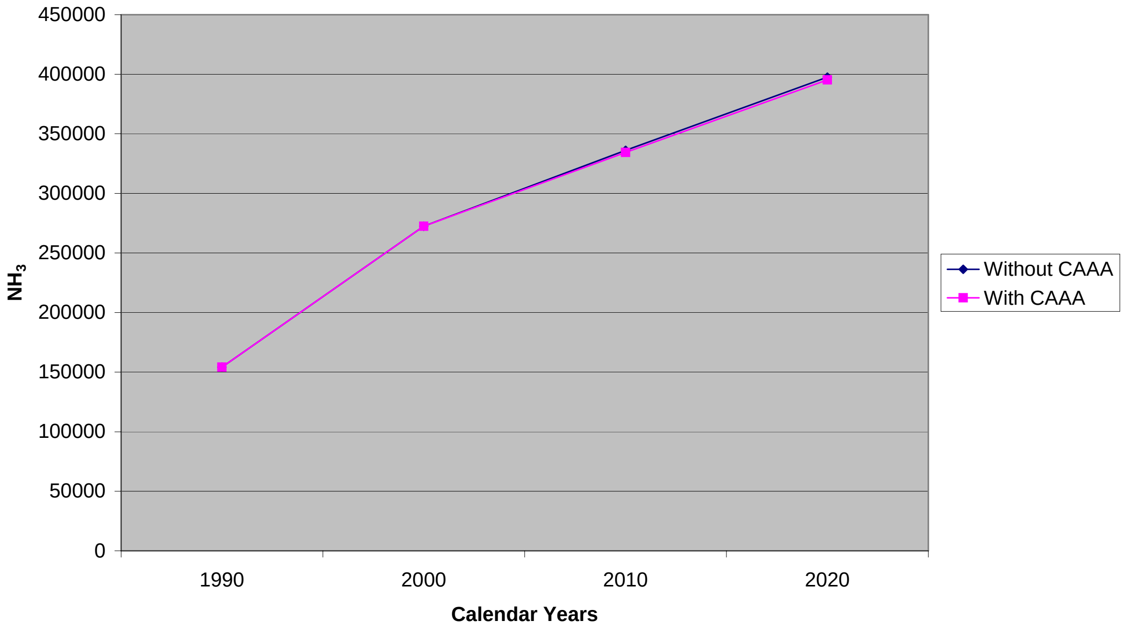


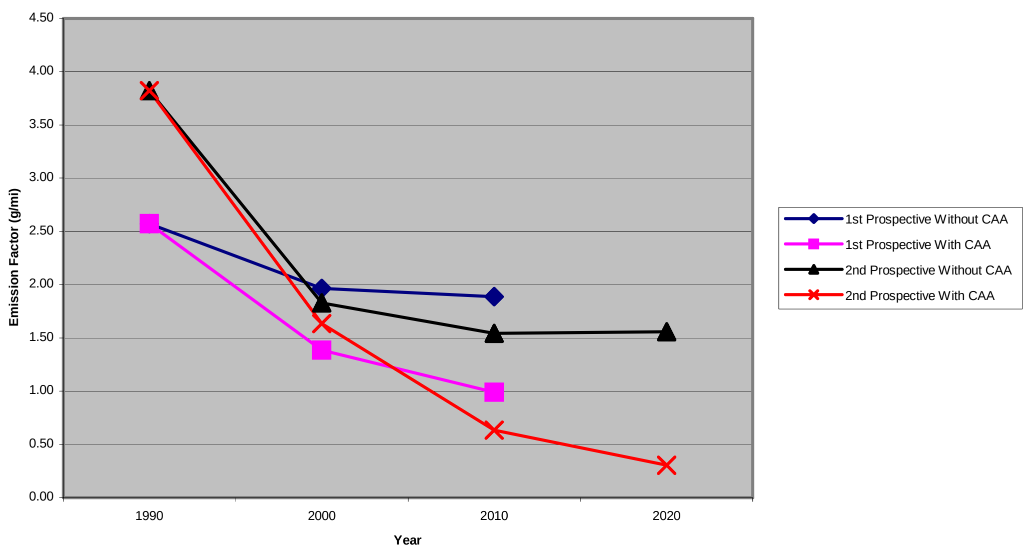
Exhibit 6-5 (continued)



When comparing the Exhibit 6-4 onroad emissions from the 2000 *with-CAAA* scenario to the corresponding emissions from the 2000 *without-CAAA* scenarios, only very minimal emission differences are observed in 2000 for VOC, CO, and NO_x. In contrast, similar comparisons using data from the first Section 812 Prospective Analysis showed much larger decreases from the *without-CAAA* to the *with-CAAA* scenarios in 2000. Several analyses were undertaken to determine if these emission calculations were correct, and if so, to determine what was causing the *with-CAAA* and *without-CAAA* emissions difference to be so small in 2000.

The initial step in this analysis involved comparing *equivalent emission factors* from the two analyses. The term *equivalent emission factors* represents the total national emissions from a given pollutant and vehicle type divided by the corresponding national VMT. Exhibit 6-5 illustrates the VOC *equivalent emission factors* for LDGVs from the first and second Section 812 Prospective Analyses. This figure clearly shows that a much greater reduction in VOC emissions was estimated in 2000 from the *without-CAAA* scenario to the *with-CAAA* scenario in the first prospective analysis than in the second. Note that the VMT estimates used in the first Prospective analysis are about 30 percent lower than the national VMT estimates in calendar year 2000 used in this study. However, this evaluation focuses on the relative differences between *with-* and *without-CAAA* estimates for each of the two Prospective studies rather than the magnitudes of their emission estimates.

Exhibit 6-6. VOC LDGV Equivalent Emission Factors for Section 812



The next step involved generating test runs of MOBILE6 to verify that the direct output of MOBILE6 agreed with these results. MOBILE6 inputs were generated for a single scenario. The inputs for the *without-CAAA* case were identical to those for the *with-CAAA* case, with the exception that the NO CLEAN AIR ACT command was turned on in the *without-CAAA* case. The resultant emission factors were in agreement with the equivalent emission factors shown in Exhibit 6-6. Next, the input files were modified to generate by-model-year emission factors. In reviewing the by-model-year emission factors, it was observed that the exhaust running emission factors for some model years were actually *lower* in the *without-CAAA* case than in the *with-CAAA* case. In the case of VOC exhaust emissions for LDGVs, this occurs beginning with the 1994 model year. In the example tested, in model year 2000, the *with-CAAA* emission factor was 47 percent *greater than* the *without-CAAA* emission factors.

EPA's Office of Transportation and Air Quality (OTAQ) provided some guidance in understanding and interpreting these results. The primary cause of these seemingly anomalous results is that MOBILE6 predicts that Tier 1 vehicles (those beginning to be phased in starting in 1994) and LEV vehicles that are exposed to high gasoline sulfur levels (as in the *without-CAAA* case in the calendar year 2000 run) will have exhaust running emission factors greater than Tier 0 vehicles both when new, and as they age. In other words, MOBILE6 assumes that Tier 0 vehicles tolerate high sulfur gasoline better than Tier 1 vehicles and thus retain more of their emission control capability. This MOBILE6 estimate was based on the fuel analysis done for the Tier 2 rule that justified the lowering of the allowed sulfur content of gasoline (EPA, 2001) beginning in calendar year 2004. Tier 1 and LEV exhaust running emission factors become significantly lower than those for Tier 0 vehicles once low sulfur gasolines are used. Since gasoline sulfur does not affect evaporative emissions, the net effect on inventories is still a benefit for the CAAA. However, it is just smaller than the effect that had been predicted by MOBILE5 (as seen in the first Section 812 Prospective analysis). The test results shown in EPA's analysis of the short-term effects of fuel sulfur on Tier 0, Tier 1, and LEV vehicles do correspond reasonably well with the test results obtained from MOBILE6. The increasing disbenefit of the CAAA from 1994 to 2000, seen in the by-model-year running exhaust emission factors output by MOBILE6, is caused by the increasing penetration of Tier 1 vehicles.

EPA's analysis also includes long-term sulfur effects and irreversibility effects of sulfur. However, these effects should not be of concern for the 2000 analysis. From the documentation (EPA, 2001), the long-term sulfur effects were only applied to LEV and cleaner vehicles. In 2000, these vehicles would only have been in place in the Northeast (and CA) and only a portion of the 1999 and 2000 vehicles there would have met the LEV standards. The irreversibility effects would have only been applied to 2004 and later vehicles, so this is not a concern.

CHAPTER 7 - NONPOINT SOURCES

Overview Of Approach

Nonpoint sources include a wide range of emissions categories, which are handled similiarly because of the common characteristic that they are relatively diffuse sources where we have no ready means to ascribe the emissions to a single well-defined geographic point (or stack). They include fuel combustion, agricultural, solvent utilization, gasoline refueling station, locomotive, and aircraft emissions, to name just a few.

The basic approach for estimating the effect of air pollution control programs on nonpoint source categories included identifying the source types whose emissions are expected to be influenced by Federal control programs, estimating how these programs might affect sources differently in different parts of the country, and then capturing the expected effects of State and local area regulations affecting nonpoint source categories. Programs in the national controls category include: Stage II (at the pump) emissions from service stations, residential woodstoves (NSPS), commercial marine vessels emission standards, and locomotive emission standards. Local/regional control programs included in this second group are measures "on-the-books" in 1-hour ozone nonattainment areas for VOC and NO_x control, and adoption of the Ozone Transport Commission model rules in the Northeast and Mid-Atlantic States.

This Chapter describes the core scenario analysis for this category of sources. The core scenario analysis does not include the additional emission reductions that might occur for nonpoint source categories to meet the requirements for the 8-hour ozone or $PM_{2.5}$ NAAQS. Measures to meet these NAAQS requirements are described in Chapter 8 [Note: Chapter 8 not available for this draft]. Activity growth factors used in the nonpoint source analysis are described in Chapter 2 of this report.

The chapter first reviews a series of adjustments that were made to update the 1990 emissions estimates to provide a more accurate basis for projection of the *without-CAAA* scenario estimates to 2000, 2010, and 2020. Next, we document several adjustments to the 2002 NEI to provide more accurate estimates of fine particulate matter emissions. We then review the emissions control factor estimates that were applied for projection years in two parts - national controls, and state/local controls. The chapter concludes with a summary of the emissions results for this sector.

1990 Emission Estimates

The 1990 EPA NEI is the primary data source used to estimate 1990 nonpoint source category emissions. Because there have been some significant revisions in the methods used to estimate criteria pollutant emissions since the 1990 NEI was created, the Project Team revised and updated 1990 estimates for the most significant source categories, so that observed differences in emissions among the scenario years would not be affected by artifacts of the methods used in the calculations. Resource limitations precluded the option to re-compute all 1990 nonpoint source emissions using 2002 NEI methods. Instead, 1990 emissions categories were identified using a two-step process. First priority source categories were ranked according to the total emissions estimates for all criteria air pollutants combined. Six priority source categories were identified in this first step. Priority source categories and revised 1990 emission estimation methods for the first step are described below:

1. Prescribed burning and wildfires – the 2002 NEI emission estimates were revised to reflect historical average activity levels. These historical emission levels are also used to represent 1990, 2010, and 2020 emissions.

2. Residential wood combustion – 1990 emissions for wood burning in residential fireplaces and woodstoves reflect 1990 levels of residential wood combustion relative to 2002 levels, and 100 percent use of non-certified residential wood combustion units. Control factors (efficiencies) for 1990 reflect the higher 1990 emission rates for residential wood combustion SCCs compared with the 2002 emission rates used to develop the 2002 NEI.

3. Railroad locomotives (diesel engines) – the 1990 activity levels for this source type were backcast from 1990 levels of railroad diesel consumption relative to 2002 levels. Emission rates in 1990 are also adjusted to reflect higher 1990 emission rates for certain SCCs relative to 2002 emission rates.

4. Agricultural tilling – the 1990 activity relative to 2002 accounted for differences in the number of planted acres in that year as well as the lower penetration of conservation tillage relative to conventional tillage.

5. Commercial marine vessels – the 1990 activity for this source type was estimated based on the ratio of 1990 levels of marine vessel distillate fuel consumption relative to 2002 levels.

6. Industrial coal combustion – the 1990 activity for this source type reflected 1990 levels of industrial coal consumption relative to 2002 levels.

In the second step, we identified and prepared new estimates for 1990 for source categories which had underrepresented ammonia emissions in the 1990 NEI. In some cases, these were categories with 0 emissions in 1990 but nonzero emissions in 2002. In other cases, these were categories where the trend in ammonia emissions was counterintuitive according to judgment of project team members - for example, a steep upward trend between 1990 and 2002 for a category where activity did not increase at the same rate and there is no immediate reason to suggest emission rates changed substantially. These instances are described below:

1. Agricultural field burning emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 agricultural crop production and 2002 agricultural crop production.

2. Open burning of land clearing debris emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 population and 2002 population.

3. Domestic animal and wild animal waste emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 to 2002 animal population estimates.

4. Agricultural crop fertilizer emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 to 2002 crop production (as the indicator for anhydrous ammonia and diammonium phosphate use) or fertilizer application-urea (as the indicator for urea).

5. Prescribed burning of rangeland emissions estimates for 1990 were estimated to be equal to those in the 2002 NEI.

6. For certain additional miscellaneous source categories with positive NH_3 emissions in the 2002 NEI, but zero NH_3 emissions in the 1990 NEI, the 1990 NH_3 emissions were set equal to the 2002 NH3 emissions.

Note that, in all instances where 1990 emissions categories were identified and updated, all of the criteria pollutant emissions from that source category were updated using the procedure stated above. In all other cases, for all other pollutants and source categories not listed above, the 1990 NEI nonpoint source emission inventory was used to estimate 1990 air pollutant emissions for this sector.

2000 Emission Estimates

Year 2000 *with-CAAA* criteria pollutant emissions for nonpoint sources are estimated using the EPA 2002 NEI final nonpoint source file. For this section 812 project, the Project Team added missing $PM_{2.5}$ primary emissions to the final 2002 nonpoint NEI that EPA delivered to Project Team member Pechan on January 6, 2006. This database augmentation was performed for source categories and counties for which the State or local agency provided PM_{10} primary emissions, but no corresponding $PM_{2.5}$ emissions. For this project, ratios were applied to the PM_{10} primary emissions to estimate $PM_{2.5}$ primary emissions. These ratios varied from 0.1 to 1.0 depending on the source category. The 0.1 ratio is applied to fugitive dust categories. Information about the derivation of these ratios and assignment to relevant source categories can be found on the EPA website, Technology Transfer Network, Clearinghouse for Inventories and Emission Factors (http://www.epa.gov/ttn/chief/net/2002inventory.html).

Control Scenario Assumptions

National Controls

This section describes how the future effects of Federal control programs on nonpoint source sector emissions were estimated.

Locomotives

Emission reduction impacts of the Federal locomotive engine standards are estimated in an EPA Regulatory Support Document (EPA, 1998). This document contains emission reduction information specific to Class I Operations, Class II/III Operations, Passenger Trains (Amtrak and Commuter Lines), and Switch (Yard) Locomotives. Year-specific percentage reduction estimates for selected pollutants are available for each locomotive sector for each year between 1999 and 2040. These emission reductions reflect the control technology efficiencies, as well as the expected rule penetration for the years of interest. Rule effectiveness was assumed to be 100 percent.

In addition, overall SO_2, PM_{10}, and $PM_{2.5}$ emission reductions associated with decreases in the diesel fuel sulfur content were also included. These were estimated from future base case and control case locomotive emission inventories prepared for EPA's regulatory impact analysis for the Clean Air Diesel Rule (EPA, 2004d). In the case of PM, since exhaust PM standards already apply to locomotives, a combined emission reduction was calculated for each future year that accounted for both the exhaust standards and reductions in PM sulfate due to the fuel sulfur limits.

Commercial Marine Vessels

EPA has promulgated two sets of commercial marine vessel 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 kilowatts, 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. For this analysis, overall emission reductions were estimated for each projection year of interest using information from the regulatory support documents prepared for these rulemakings (EPA, 1999; EPA, 2003). In addition to the EPA standards, beginning in 2000, marine diesel engines greater than or equal to 130 kilowatts are subject to an international NO_x emissions treaty (MARPOL) developed by the International Maritime Organization. The emission reductions reflect both the MARPOL and EPA standards.

Because the reductions vary by category of vessel, assumptions were made concerning the characterization of engines associated with diesel commercial marine vessel SCCs included in the base year inventory. For SCC 2280002100 (Marine Vessels, Commercial Diesel Port emissions), Category 2 engines were assumed. For SCC 2280002200 (Marine Vessels, Commercial Diesel Underway emissions), Category 3 engines were assumed.

Similar to locomotives, overall SO_2, PM_{10}, and $PM_{2.5}$ emission reductions associated with decreases in the diesel fuel sulfur content were also included based on information in EPA's regulatory impact analysis for the Clean Air Diesel Rule (EPA, 2004b).

Stage II-Onboard VRS

The control efficiency from refueling onroad vehicles will be greater in 2010 and 2020 than in 2002 due to vehicle turnover and the Federal requirement for onboard vapor recovery system (VRS) in onroad vehicles. Percentage reductions in VOC emissions from this control measure in 2010 and 2020, relative to 2002, were calculated using a sampling of MOBILE6 runs, including the effect of Stage II programs where they are in place. These resulting reduction factors were included in the nonpoint source sector control files.

Residential Wood Combustion

To account for the effect of the replacement of retired wood stoves/inserts that emit at pre-residential wood heater NSPS levels, control factors were developed for 2010 and 2020 by pollutant. These control factors were developed using an annual 2 percent retirement rate for wood stoves/fireplace inserts along with the pre- and post-NSPS wood stove and fireplace emission factors used in the 2002 NEI (EPA, 2005). SCC/year-specific weighted emission factors from the pre- and post-NSPS emission factors and estimates of the proportion of total wood consumption associated with pre- and post-NSPS units were developed for each base and forecast year. Control factors represent the ratio of the forecast year weighted emission factor for a given pollutant to the base year weighted emission factor for that pollutant. SCCs for "controlled" wood stoves and fireplace inserts have no control efficiency applied. Their future year emissions change in proportion to the activity growth rate.

State and Local Area Control Plans by Region

State and local area-specific control plans affecting nonpoint sources were incorporated in the 2010 and 2020 projections using the information developed by the five RPOs, or information from their respective work plans indicating what the primary regulations are that are influencing nonpoint source emission rates in this period.

MANE-VU

The focus of nonpoint source controls for this Northeast Mid-Atlantic State region is the effect of the OTC model rules on VOC emissions from the various solvent categories that these controls are designed to reduce.

Exhibit 7-1 displays the nonpoint source VOC solvent category post-2002 rule effectiveness, rule penetration, and control efficiency values that were applied in the OTC States to simulate the effects of adoption of the OTC model rules. Future year control efficiencies are contrasted with those expected to have been used in computing 2002 emissions in the OTC States. The values in Exhibit 7-1 are an approximation of what is occurring in these States during this time period because each State has added regulations to achieve such emission reductions according to their own individual schedules. In general, though, the timing of the model rule adoption for consumer products and AIM coatings is expected to occur after 2002, but before 2010 in most OTC States.

Exhibit 7-1. OTC State Model Rule VOC Solvent Category Control Information

Category	Year	Control Efficiency	Rule Penetration	Rule Effectiveness	Emission Reduction %
Consumer Products	Base (2002)	20	48.6	100	9.7
	Future (all post-2002)	34.2	48.6	100	16.6
AIM Coatings	Base (2002)	20	100	100	20
	Future (all post-2002)	44.8	100	100	44.8

The effects of adopting OTC model rules to reduce autobody refinishing and solvent cleaning (degreasing) emissions are expected to be included in OTC State 2002 emission inventories, so no post-2002 control factors are applied to the OTC States for these solvent categories.

Portable fuel container rules are also being adopted in the OTC States, with 2003 assumed as the average rule adoption date in these States. The VOC reduction benefits of portable fuel container rules within the OTC States are based on a 10-year rule penetration period and a 75 percent VOC control efficiency. Some States did not include portable fuel container emissions in their 2002 emission inventories.

To further reduce evaporative VOC emission at service stations, New Jersey has a new requirement that is expected to go from a required 90 percent Stage I VOC control efficiency in 2002 to a 98 percent control efficiency as they adopt ARB-type requirements. This change in Stage I requirements was included in the 2010 and 2020 emission projections.

VISTAS

For the VISTAS emission projections, this region reported that for stationary area sources (nonpoint), no State-supplied growth or control factors were provided (MACTEC, 2005). Thus, for all sources in this sector, growth and controls were applied based on controls initially identified for the CAIR and growth factors identified for the CAIR projections. VISTAS estimated the effect of controls for Stage II-service station emissions using linear interpolations of values developed for the EPA heavy-duty diesel rulemaking effort. Because Pechan developed a consistent approach for including the joint effects of Stage II control programs and onboard VRS on future year VOC emissions to be applied in this analysis, the VISTAS information was not used for this source category.

LADCO

Auto Body Refinishing/Mobile Equipment Repair and Refinishing (MERR)

For SCC 2401005000, a 29 percent additional VOC control efficiency was applied to all future year emissions in certain Wisconsin counties, where a more stringent than Federal standard MERR regulation applies. Base year 2002 emission estimates include the effects (37 percent VOC emission reduction) of the national VOC emission standards for automobile refinish coatings. With the 37 percent VOC emission reduction included in Wisconsin's base year emission estimates, this Wisconsin rule achieves a 55 percent reduction from uncontrolled VOC in future years. The Wisconsin counties where the auto body refinishing rule applies are: Kenosha, Kewaunee, Manitowoc, Milwaukee, Ozaukee, Racine, Sheboygan, Washington, and Waukesha.

Solvent Cleaning Operations

The LADCO Comparability Study's suggested cold cleaning-auto repair emission factor is 270 pounds of VOC per employee. In Illinois, the Chicago and Metro East areas of the State have a cold cleaning VOC regulation that is equivalent to what is required in the OTC model rule. The emission reduction credit for this regulation is a 66 percent reduction from uncontrolled levels. An equivalent regulation affecting the southern Indiana counties of Clark and Floyd is expected to achieve the same 66 percent VOC reduction. These emission reductions were applied in the following counties:

State	County Name	State	County Name
ILLINOIS	Cook	INDIANA	Clark
	Du Page		Floyd
	Kane		
	Lake		
	McHenry		
	Madison		
	Monroe		
	St. Clair		
	Will		

These control percentages were applied to SCCs 2415345000 (Miscellaneous Manufacturing [SIC code 39]: Cold Cleaning) and 2415360000 (Auto Repair Services [SIC 75]: Cold Cleaning).

Portable Fuel Containers

There is a portable fuel container rule in Illinois that will reduce VOC emissions from SCCs 2501011010 (Residential Portable Fuel Containers) and 2501012010 (Commercial Portable Fuel Containers) in future years. This rule is expected to reduce fuel container VOC emissions by 75 percent from pre-control levels. The turnover from old to new containers is expected to take 10 years. If the rule is implemented in 2005 as planned, then rule penetration for existing fuel containers will be 5 percent in the summer of 2005, 15 percent in the summer of 2006, 25 percent in the summer of 2007, etc. until 100 percent rule penetration is achieved by 2015.

CENRAP

Exhibit 7-2 summarizes the control factors that were developed and applied in the CENRAP States to simulate the effect on future emission rates where regulations are expected to produce post-2002 emission reductions. The subsections below explain how the individual State regulations were evaluated in order to develop the control efficiency values listed in Exhibit 7-2.

Exhibit 7-2. CENRAP State VOC Solvent Controls in 2010 and 2020

Counties	Pollutant	Control Efficiency* (%)	SCC	Description
KS: Johnson, Wyandotte	VOC	66	2415000000	Solvent Utilization: Degreasing: All Processes/All Industries
TX: Dallas, El Paso, Galveston, Hardin, Harris, Jefferson, Tarrant	VOC	35	2401005000	Auto Refinishing: SIC 7532
TX: Bastrop, Bexar, Caldwell, Comal, Gregg, Guadalupe, Hays, Nueces, Travis, Victoria, Williamson, Wilson	VOC	83	2415105000	Furniture and Fixtures (SIC 25): Open Top Degreasing
			2415110000	Primary Metal Industries (SIC 33): Open Top Degreasing
			2415120000	Fabricated Metal Products (SIC 34): Open Top Degreasing
			2415125000	Industrial Machinery and Equipment (SIC 35): Open Top Degreasing
			2415130000	Electronic and Other Elec. (SIC 36): Open Top Degreasing
			2415135000	Transportation Equipment (SIC 37): Open Top Degreasing
			2415140000	Instruments and Related Products (SIC 38): Open Top Degreasing
			2415145000	Miscellaneous Manufacturing (SIC 39): Open Top Degreasing
Statewide	VOC	17	2460400000	Solvent Utilization: Miscellaneous Non-industrial: Consumer and Commercial: All Automotive Aftermarket Products

NOTE: *These control efficiencies are all applied with a rule penetration of 100 percent and a rule effectiveness of 100 percent.

Kansas

Kansas Rule 28-19-714 contains a 1.0 millimeters mercury maximum vapor pressure requirement for solvent cleaning operations, effective September 2002. Based on an evaluation of the OTC model rule for this source category, a 1.0 millimeters mercury at 68°F maximum VOC vapor pressure requirement leads to an estimated 66 percent reduction in VOC emissions relative to the national rule for cold cleaners and vapor degreasers (Pechan, 2001). The Kansas rule also includes a higher (5.0 millimeters mercury at 68°F) maximum vapor pressure requirement for the cleaning of carburetors, but this difference may not be significant relative to the OTC rule. Conveyorized degreasers are required to achieve an overall VOC control efficiency of 65 percent or greater; however, the Kansas rule does not appear to include any additional requirements relative to the national rule (other than the maximum vapor pressure requirements). Therefore, a 66 percent post-2002 VOC control efficiency was applied in Johnson and Wyandotte Counties, based on data from the OTC model rule.

Louisiana

Title 33, Part III, Section 2125 specifies additional operational requirements for open top vapor degreasers not found in EPA's 1977 CTG. One requirement of the Louisiana Code specifies a minimum 85 percent VOC reduction efficiency for open top vapor degreasers not found in the CTG. Section 2125 was last amended in April 2004.

Texas

Open-top Vapor or Conveyorized Degreasers

The national rule for vapor degreasing is estimated to achieve VOC emission reductions of between 10 and 15 percent (Pechan, 2002). The Texas rule 115.412 requires VOC emission reductions of at least 85 percent from these sources for the following counties: Bastrop, Bexar, Caldwell, Comal, Gregg, Guadalupe, Hays, Nueces, Travis, Victoria, Williamson, and Wilson. Assuming that the baseline 2002 vapor degreasing emissions include a 10 percent reduction from the national rule and that a total control of 85 percent would be applied to comply with the Texas rule, the incremental reduction from the Texas rule, relative to the 2002 emissions, is 83 percent. This rule became effective in December 2004.

Mobile Equipment Repair and Refinishing

Texas rule 115.422 requires that coating application equipment have a transfer efficiency of at least 65 percent and requires the use of high volume low pressure spray guns. This rule applies in the following counties: Dallas, El Paso, Galveston, Hardin, Harris, Jefferson, and Tarrant. Based on an evaluation of the OTC model rule for this source category, the use of "high transfer efficiency" high volume low pressure spray guns is estimated to achieve a 35 percent VOC emission reduction relative to the national rule (Pechan, 2001). Spray gun controls are estimated to contribute an additional 3 percent VOC emission reduction. However, the Texas rule contains a less stringent requirement for the enclosure of spray guns and related parts. Therefore, a 35 percent post-2002 VOC control efficiency incremental to the national rule was applied in the counties listed above to account for this rule. This rule became effective in May 2002.

Consumer Products

The national rule limits the VOC content of windshield wiper fluid to 35 percent by weight (effective December 1998). The Texas rule 115.612 limits the VOC content to 23.5 percent by weight. This represents a 33 percent reduction in the VOC content (and as a result, emissions) from the 2002 baseline. A single SCC covers all "auto aftermarket products". The fraction of emissions from auto aftermarket products that can be attributed to auto wiper fluid was estimated to be 50 percent, based on the likelihood that the other major VOC-emitting auto aftermarket products (waxes, polishes and cleaning products) are consumed in lesser volumes than windshield wiper fluid. Thus, the reduction applied to VOC emissions from the SCC representing auto aftermarket products was 17 percent. This rule became effective in February 2004.

Portable Fuel Containers

Texas has a portable fuel container rule (Statewide). In TCEQ analyses, this has been modeled as a reduction in evaporative VOC emissions using lawn and garden equipment SCCs within EPA's NONROAD model. See the Nonroad chapter for information about how the rule effects were incorporated in the analysis.

Gas-fired Water Heaters, Small Boilers, and Process Heaters

A Texas Statewide rule, adopted as part of the April 2000 Dallas/Forth Worth SIP revision, reduces NO_x emissions from new natural gas-fired water heaters, small boilers, and process heaters sold and installed in Texas beginning in 2002. The rule applies to each new water heater, boiler, or process heater with a maximum rated capacity of up to 2.0 million British thermal units per hour. This is Rule 117.461. (It should be noted that this control on natural gas-fired water heaters may be overturned by the SB 473 prohibition on regulating water heater emissions.)

To simulate the effects of this rule in 2018, the following factors presented in Exhibit 7-3 were applied Statewide in Texas.

Exhibit 7-3. Texas Statewide NO_x Control Factors for Small Fuel Combustors

SCC	NO_x Control Efficiency	Rule Penetration	Rule Effectiveness	Emission Reduction
2103006000	75%	80%	100%	60%
2104006000	75%	80%	100%	60%

WRAP

Nonpoint source control factor development focused solely on California because there is little regulation of these source types in other western States.

In order to estimate the 2010 and 2020 emission benefits of air pollution emission regulations in California, a request was made to the California ARB to provide control factors that the ARB uses in its own emission projections. ARB staff provided a control factor file that was used in the Central California Ozone Study modeling effort. The Central California Ozone Study projections were based on the 1999 inventory, so the control factors are normalized to 1999. Because 2002 control factors were provided, the 2010 and 2020 control factors were normalized to a 2002 base year by Pechan for application in this section 812 study. This normalization divides the 2010 and 2020 control factors by the associated 2002 control factors for each pollutant and source category. The California file includes control factors by district, air basin, and county, with source categories designated by California's Emission Inventory Codes. The California file has both rule-specific and composite (with all rules applied) control factors. The composite control factors were used in this analysis.

Crosswalks were developed and applied to translate California's county codes into matching FIPS codes, and to link California's Emission Inventory Codes with EPA's SCCs. This allowed the California ARB control factors to be applied to the EPA NEI nonpoint database.

Emission Summary By Scenario

Exhibit 7-4 summarizes national nonpoint source category emissions for the 2000, 2010, and 2020 *with-CAAA* scenario. National VOC emissions are dominated by evaporative emissions from solvent utilization. While there is some additional regulation of these emissions after 2002 in areas with continuing ozone nonattainment, in most areas of the country, solvent utilization emissions grow after 2002 in proportion to activity indicators like population and employment. Another prominent VOC emitting source category is Fuel Combustion-Other, which is mostly residential fireplace and woodstove emissions. (Most highly efficient fuel combustors are low VOC emitters.) Fireplace and woodstove emissions are projected to decline after 2002 as NSPS-certified woodstoves replace non-certified stoves. Another prominent VOC-emitting source category with expected emissions declines in 2010 and 2020 is fuel storage and transport. Control programs that contribute to these emission reductions include onboard VRS on gasoline-powered vehicles and more stringent State and local programs to reduce emissions at various points in the gasoline distribution system. The onboard VRS-associated emission changes are mentioned here because they apply to service station refueling emissions, which are accounted for in the nonpoint source inventory.

Exhibit 7-4 shows that national NO_x emissions for the nonpoint source sector are dominated by off-highway sources. This reflects the emissions from the three off-highway source categories that are not included in EPA's NONROAD, and are categorized as nonpoint sources in this study. These off-highway source categories are commercial marine vessels, railroad locomotives, and aircraft. NO_x emission reductions between 2002 and 2010 are a result of Federal emission standards for some commercial marine vessel engines and locomotive engines. Besides off-highway engines, the other nonpoint source NO_x emitters with more than 10 percent of total emissions for this sector are: industrial and other fuel combustion and petroleum and related industrial processes. These are all small fuel combustors that are exempt from regulations like the NO_x SIP Call because of their size. Their NO_x emissions are expected to increase slightly during the study time horizon.

SO_2 emissions for this sector are expected to stay relatively stable from 2002 to 2020. The dominant source type is industrial fuel combustion and these emissions represent coal and fuel oil combustion that occurs in sources that are not included in the 2002 NEI point source file. The off-highway sector SO_2 contribution is small because most of the off-highway source emissions are from diesel engines (commercial marine vessels and locomotives) or jet aircraft engines.

Exhibit 7-5 displays the nonpoint sector *with-* and *without-CAAA* emission summaries by pollutant in a graphic format. For all pollutants, the *without-CAAA* emissions are higher than the *with-CAAA* emissions in 2000, 2010, and 2020.

Exhibit 7-4. National Nonpoint Emissions by Major Source Category (tpy)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
Fuel Comb. Industrial	15,029	16,223	17,624	17,108	17,952	18,953	19,190
Fuel Comb. Other	3,156,003	2,400,854	1,691,902	1,823,554	1,524,048	1,794,511	1,298,647
Chemical & Allied Product	173,405	187,443	114,430	209,748	153,860	218,894	213,670
Metals Processing	179	236	464	248	512	280	561
Petroleum & Related Industrial	357,615	376,493	470,158	398,396	491,037	400,176	443,187
Other Industrial Processes	62,182	73,370	51,500	84,289	58,595	98,867	68,885
Solvent Utilization	4,863,848	6,348,703	3,944,392	7,644,429	4,316,349	9,464,581	5,163,533
Storage & Transport	1,158,090	1,376,173	994,188	1,636,205	987,959	1,902,905	1,064,821
Waste Disposal & Recycling	1,011,531	1,192,802	367,396	1,384,685	393,384	1,700,665	465,873
Off-highway	137,427	130,430	125,547	137,454	130,583	149,706	139,238
Miscellaneous	742,728	804,710	766,743	828,295	797,969	869,378	837,944
Total	**11,678,038**	**12,907,437**	**8,544,345**	**14,164,412**	**8,872,248**	**16,618,917**	**9,715,546**
NO_x							
Fuel Comb. Industrial	838,058	863,986	498,596	875,208	518,131	1,015,330	547,960
Fuel Comb. Other	1,082,355	1,108,717	622,214	1,174,461	654,693	1,220,892	686,385
Chemical & Allied Product	24	28	63	31	81	37	106
Metals Processing	180	237	85	249	95	281	103
Petroleum & Related Industrial	20,346	18,960	285,674	14,361	302,603	10,588	269,148
Other Industrial Processes	2,610	3,511	11,754	4,016	14,270	4,888	17,488
Solvent Utilization	73	87	111	99	146	113	197
Storage & Transport	187	207	7,297	236	8,451	260	9,491
Waste Disposal & Recycling	79,388	93,716	66,907	106,535	74,400	120,014	83,894
Off-highway	2,532,768	2,350,865	2,147,103	2,456,076	1,866,601	2,614,492	1,856,876
Miscellaneous	245,026	251,438	245,903	250,674	248,816	255,458	253,363
Total	**4,801,016**	**4,691,751**	**3,885,707**	**4,881,947**	**3,688,289**	**5,242,354**	**3,725,010**
CO							
Fuel Comb. Industrial	182,157	186,990	269,459	191,533	286,877	213,723	304,279
Fuel Comb. Other	6,335,314	4,731,812	3,701,704	3,503,159	3,316,622	3,354,619	3,707,426
Chemical & Allied Product	0	0	84	0	100	0	120
Metals Processing	232	306	292	322	347	363	387
Petroleum & Related Industrial	4,194	3,922	244,389	3,038	265,815	2,327	236,763
Other Industrial Processes	1,048	1,447	33,682	1,701	38,873	2,160	46,133
Solvent Utilization	70	103	74	144	98	193	133

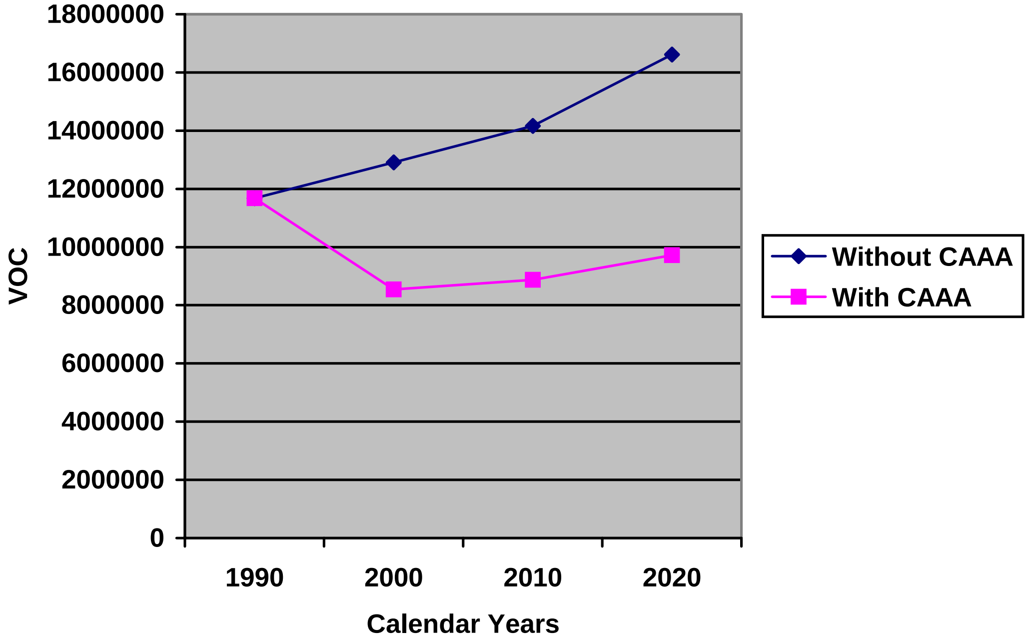
Exhibit 7-4 (continued)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
Storage & Transport	0	0	305	0	349	0	375
Waste Disposal & Recycling	1,928,678	2,253,854	1,505,769	2,531,177	1,655,137	2,809,782	1,839,997
Off-highway	792,054	787,254	754,253	820,093	812,626	901,170	900,455
Miscellaneous	8,270,979	8,638,838	8,103,956	8,710,268	8,228,264	8,986,925	8,415,419
Total	**17,514,727**	**16,604,526**	**14,613,968**	**15,761,435**	**14,605,108**	**16,271,263**	**15,451,487**
SO_2							
Fuel Comb. Industrial	1,315,488	1,048,514	934,833	1,398,198	975,997	1,931,700	984,238
Fuel Comb. Other	630,230	597,832	509,331	674,939	546,963	707,729	565,960
Chemical & Allied Product	0	0	9	0	13	0	19
Metals Processing	0	0	45	0	49	0	53
Petroleum & Related Industrial	1,431	1,335	417	989	433	713	499
Other Industrial Processes	1,743	2,294	2,934	2,664	3,675	3,349	4,631
Solvent Utilization	0	0	23	0	31	0	43
Storage & Transport	0	0	172	0	196	0	211
Waste Disposal & Recycling	20,802	26,879	10,834	33,300	12,970	40,821	15,799
Off-highway	376,179	379,025	290,920	339,491	211,288	363,685	243,341
Miscellaneous	123,724	123,778	125,765	122,843	126,013	123,577	126,956
Total	**2,469,598**	**2,179,658**	**1,875,282**	**2,572,423**	**1,877,630**	**3,171,573**	**1,941,752**
PM_{10}							
Fuel Comb. Industrial	39,452	32,047	747,314	43,796	754,486	61,934	741,892
Fuel Comb. Other	888,930	689,784	501,763	532,820	513,618	511,792	505,386
Chemical & Allied Product	0	0	37	0	45	0	53
Metals Processing	46	52	142	49	156	53	169
Petroleum & Related Industrial	1,563	1,458	510	1,080	504	778	556
Other Industrial Processes	355,481	417,111	717,399	470,678	836,306	531,454	936,797
Solvent Utilization	0	0	1,706	0	2,317	0	3,144
Storage & Transport	0	0	465	0	541	0	613
Waste Disposal & Recycling	351,670	405,534	271,352	451,152	297,430	497,957	329,534
Off-highway	111,917	107,330	98,654	106,726	76,702	115,387	86,225
Miscellaneous	23,405,979	23,650,232	16,990,504	23,050,330	16,362,837	24,189,241	16,410,890
Total	**25,155,038**	**25,303,549**	**19,329,848**	**24,656,631**	**18,844,942**	**25,908,596**	**19,015,260**
$PM_{2.5}$							
Fuel Comb. Industrial	13,729	12,306	186,522	16,436	190,237	23,592	189,348
Fuel Comb. Other	850,385	661,095	457,757	507,942	469,581	487,373	463,063
Chemical & Allied Product	0	0	24	0	28	0	34

Exhibit 7-4 (continued)

Source Category	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Metals Processing	35	39	85	37	93	40	101
Petroleum & Related Industrial	1,563	1,458	497	1,080	491	778	541
Other Industrial Processes	86,829	103,838	214,736	118,360	249,036	137,285	284,196
Solvent Utilization	0	0	1,694	0	2,300	0	3,121
Storage & Transport	0	0	460	0	534	0	606
Waste Disposal & Recycling	316,606	364,919	255,033	405,622	278,813	447,044	307,960
Off-highway	89,569	84,354	85,996	85,924	66,357	92,671	74,580
Miscellaneous	4,431,908	4,651,102	2,900,444	4,614,250	2,802,553	4,948,615	2,842,995
Total	**5,790,623**	**5,879,111**	**4,103,247**	**5,749,651**	**4,060,026**	**6,137,398**	**4,166,546**
NH_3							
Fuel Comb. Industrial	9,328	10,153	11,968	10,729	12,676	12,810	13,568
Fuel Comb. Other	27,143	22,214	19,105	18,961	20,176	18,738	20,464
Chemical & Allied Product	0	0	61	0	79	0	100
Metals Processing	0	0	5	0	6	0	7
Petroleum & Related Industrial	0	0	0	0	0	0	0
Other Industrial Processes	47,582	64,995	59,797	78,108	75,235	99,899	95,854
Solvent Utilization	0	0	59	0	69	0	80
Storage & Transport	0	0	22	0	22	0	23
Waste Disposal & Recycling	92,633	109,121	22,675	128,110	25,629	162,830	31,497
Off-highway	663	553	246	489	280	520	331
Miscellaneous	3,332,496	3,766,838	3,437,628	3,959,699	3,578,989	4,212,687	3,824,860
Total	**3,509,844**	**3,973,874**	**3,551,567**	**4,196,096**	**3,713,161**	**4,507,484**	**3,986,783**

Exhibit 7-5. *With-* and *Without-CAAA* Scenario Nonpoint Emission Summaries by Pollutant



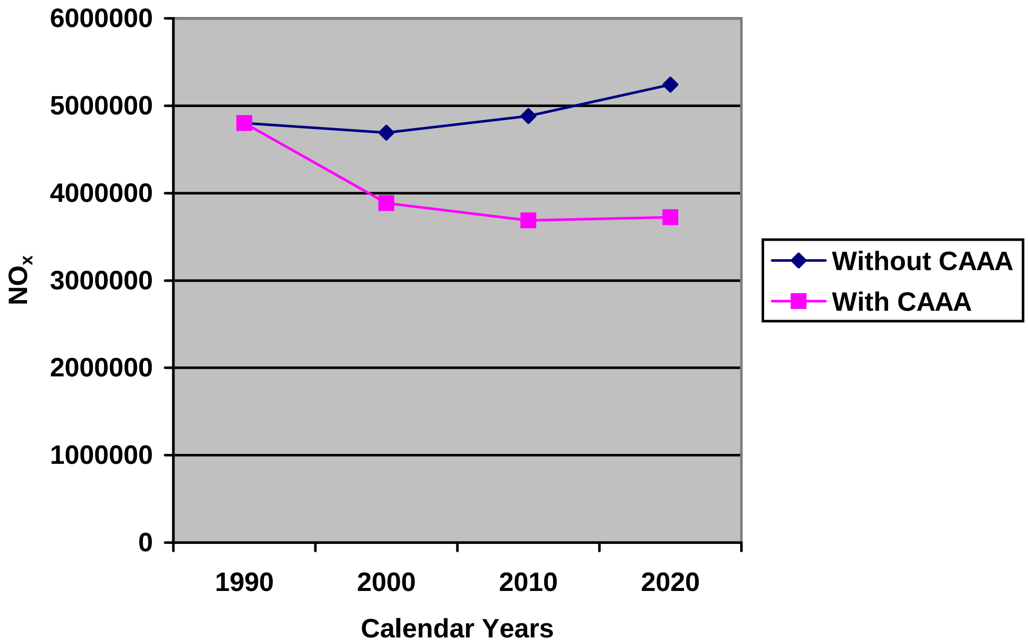
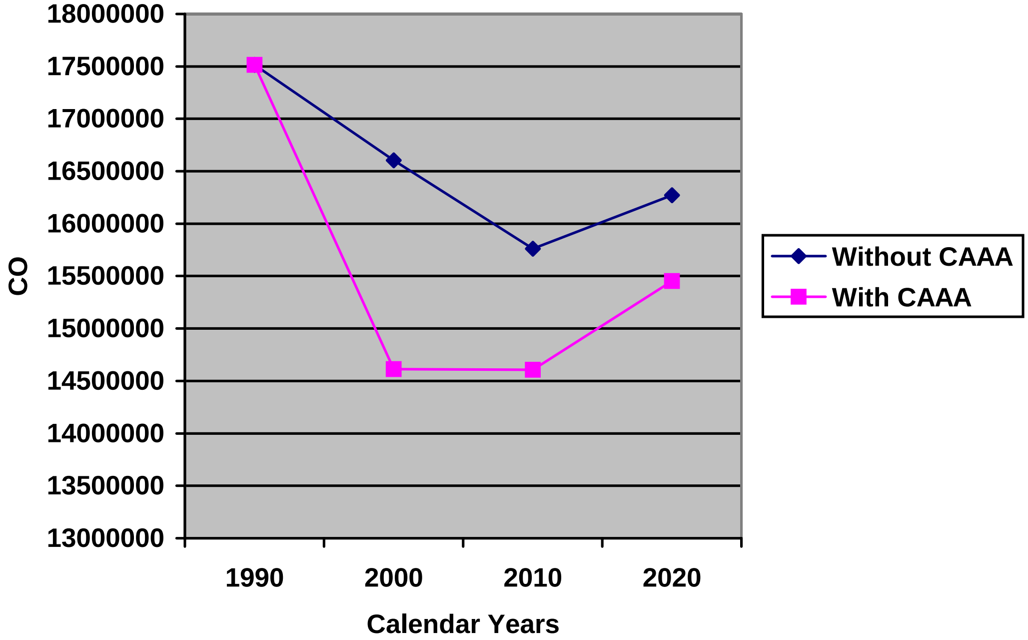


Exhibit 7-5 (continued)



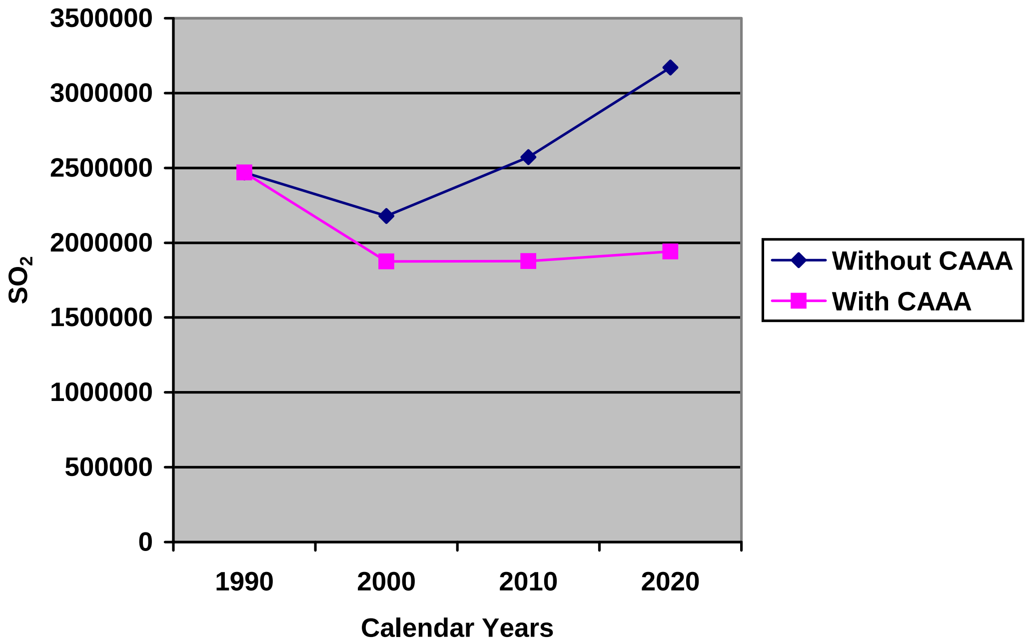
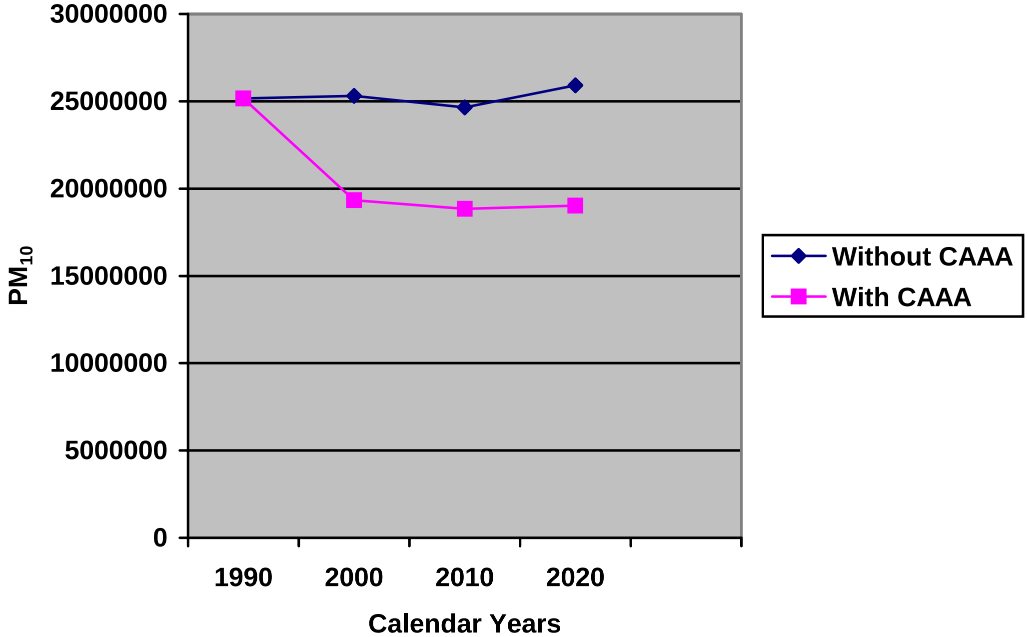


Exhibit 7-5 (continued)



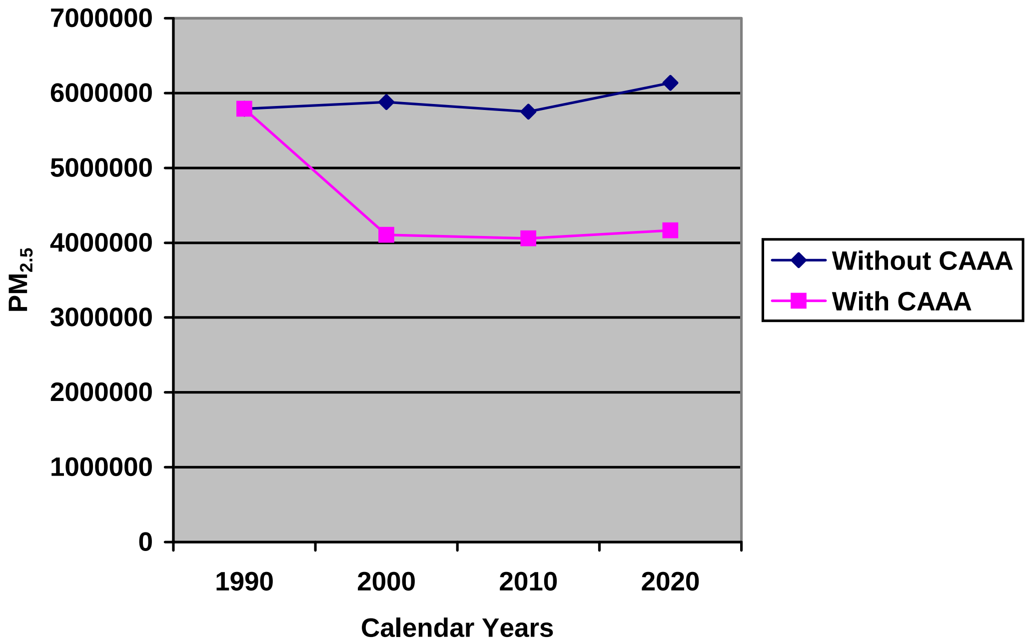
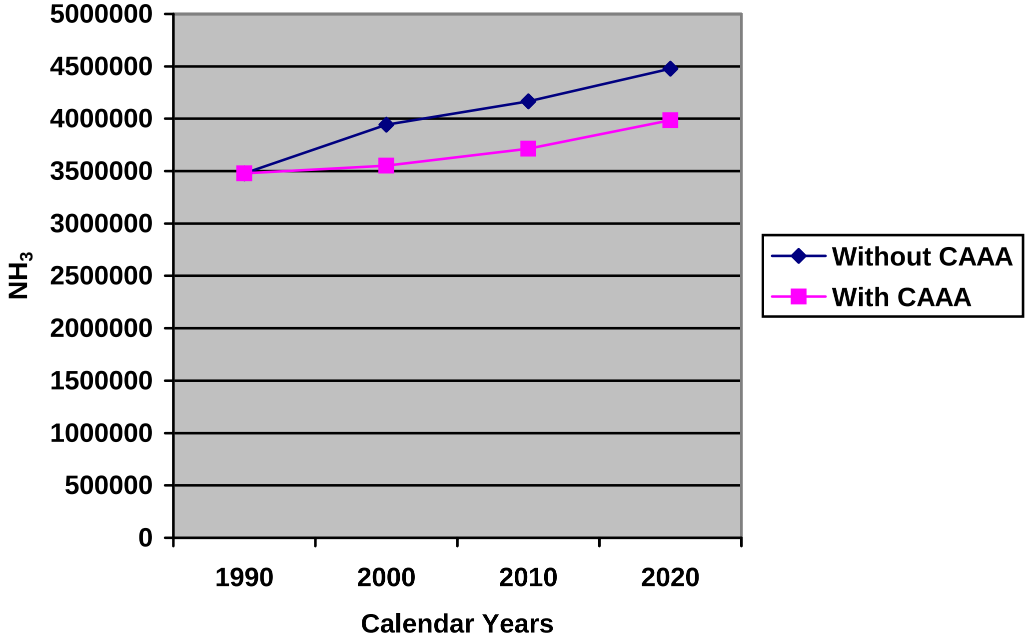


Exhibit 7-5 (continued)



CHAPTER 8 - LOCAL CONTROL FOR NAAQS COMPLIANCE

The analysis to be reported in this chapter is ongoing and will be incorporated in this report when completed. The local controls for NAAQS compliance analysis will evaluate the expected emission reductions of areas meeting the 8-hour ozone NAAQS requirements as well as the $PM_{2.5}$ NAAQS requirements. In addition, this chapter will also report the NO_x and SO_2 emission reductions associated with BART-eligible sources meeting the requirements of the recent EPA BART rule.

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