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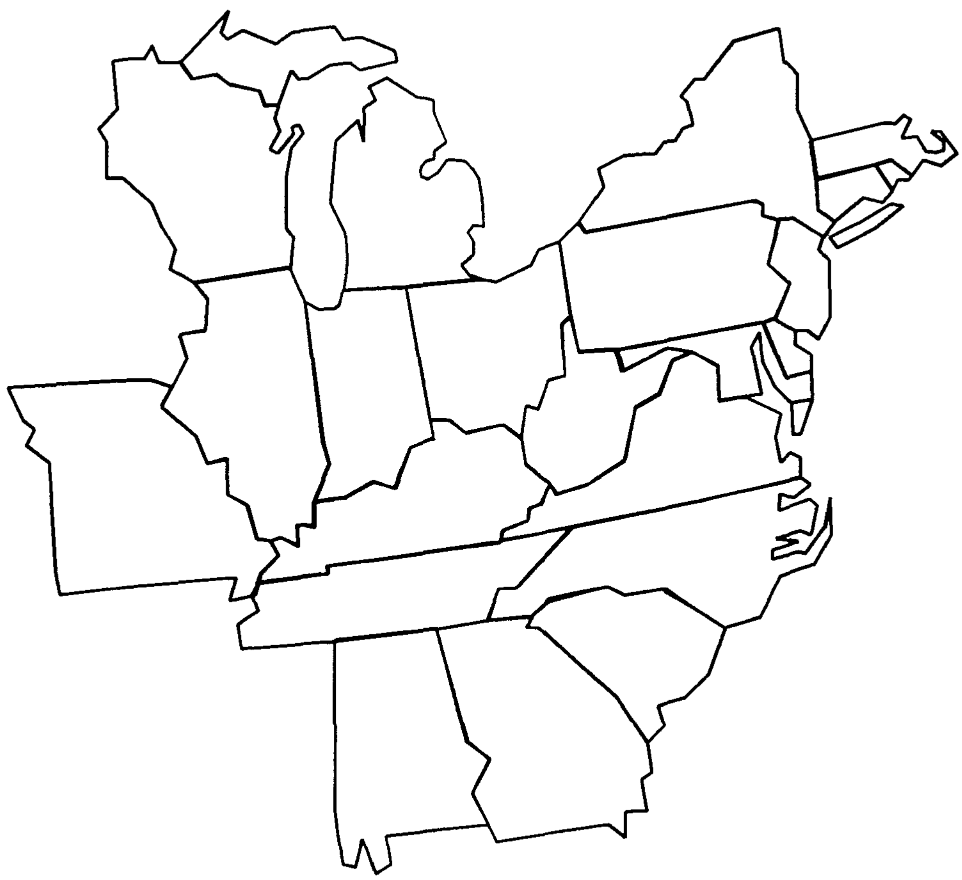
REGULATORY IMPACT ANALYSIS FOR THE NOx SIP CALL, FIP, AND SECTION 126 PETITIONS

Volume 1: Costs and Economic Impacts



REGULATORY IMPACT ANALYSIS FOR THE NOx SIP CALL, FIP, AND SECTION 126 PETITIONS

Volume 1: Costs and Economic Impacts

Prepared by

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EXECUTIVE SUMMARY

EPA has finalized the nitrogen oxides (NOx) State implementation plan (SIP) call rule The "NOx SIP call" requires selected eastern States to take actions to reduce emissions of NOx that contribute to nonattainment of ozone standards in downwind States. For the purposes of this analysis, EPA has modeled an illustrative State implementation scenario This Regulatory Impact Analysis (RIA) and associated analyses are intended to generally inform the public about the potential costs and economic impacts that may result from this scenario, but specific State actions will ultimately determine the actual costs and benefits of the NOx SIP call

At the same time that EPA promulgates the NOx SIP call, EPA is proposing NOx Federal implementation plans (FIPs) that may be needed if any State fails to comply with the final NOx SIP call EPA is also proposing a response to Section 126 petitions which were filed by eight northeastern States asking EPA to address air pollution transported from upwind States Pursuant to Executive Order 12866, this RIA presents the potential costs and economic impacts of these rulemakings

The existing 1-hour and new 8-hour national ambient air quality standards (NAAQS) for ozone set levels necessary for the protection of human health and the environment Under the Clean Air Act Amendments of 1990 (CAAA), attainment of these standards depends on the implementation of State-specific pollution control strategies contained in SIPs, in conjunction with EPA promulgation of national controls for some sources of pollution, to reduce NOx and volatile organic compound (VOC) emissions The NOx SIP call creates an effective, efficient and equitable approach for EPA and the States to promote attainment with the current and new ozone standards

In the NOx SIP call, EPA is setting ozone season NOx budgets for States that are in the SIP call region In nearly all cases, these budgets will require States to seek lower emissions from their sources to enable the State to meet its budget level To arrive at what the NOx budgets should be for the States, the Agency considered alternative levels of reductions that States could reasonably require of selected stationary sources to reduce their summer NOx emissions in the future The final set of sources that EPA based the State NOx budgets on includes large electricity generating units, industrial boilers and combustion turbines, stationary internal combustion engines, and cement manufacturing operations Table ES-1 lists the major regulatory alternatives that EPA considered for each of the above sectors when it determined State-level NOx emissions budgets in the NOx SIP call The shaded areas in the table show the options that EPA selected based largely on the Agency's determination (as explained in the preamble to this rulemaking) that the ozone season NOx controls for a sector were highly cost-effective and could be reasonably implemented in the near future For the electricity generating units and industrial boilers and combustion turbines, the Agency estimates the costs and emissions changes based on an emissions cap-and-trade program For the remaining sectors, EPA based its analysis on States placing direct controls on the units covered

In this rule, EPA has offered to administer an emissions trading program for the States. However, each State is free to join the program, or alternatively set up their own program to meet their NOx budget Therefore, the actual NOx SIP call costs could vary from those that EPA estimates for the approach on which it based the NOx budgets

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Select List of Acronyms and Abbreviations

ACT - Alternative Control Techniques
AEO - Annual Energy Outlook
AF - Air/Fuel Adjustment
AF RATIO - Air-to-Fuel Ratio
AFS - AIRS Facility System
AIM - Architectural and Industrial Maintenance
AIRS - Aerometric Information Retrieval System
ANPR - Advanced Notice of Proposed Rulemaking
b_{ext} - Total Atmospheric Light Extinction Coefficient
BACT - Best Available Control Technology
BBL - Barrel
CAA - Clean Air Act
CAAA - Clean Air Act Amendments of 1990
CAPI - Clean Air Power Initiative
CC - Combined Cycle
CCAP - Climate Change Action Plan
CEM - Continuous Emissions Monitoring
CI - Compression Ignition
CO - Carbon Dioxide
CTGs - Control Technique Guidelines
D&B - Dun & Bradstreet
DoD - Department of Defense
DOE - Department of Energy
DUNS -Dunn & Bradstreet Numbering System
ECOS - Environmental Council of States
EIA - Energy Information Administration
EIS - Environmental Impact Statement
EGUs - Electricity Generating Units
EIIP - Emission Inventory Improvement Program
EO - Executive Order
EPA - Environmental Protection Agency
ESEERCO - Empire State Electric Energy Research Corporation
ETS - Emissions Tracking System
FCM - Fuel Consumption Model
FGR - Flue Gas Reburning
FHWA - Federal Highway Administration
FINDS - Facility Index System
FIP - Federal Implementation Plan
FTE - Full Time Equivalent
g/bhp-hr - Grams per Brake Horsepower Hour
GDP - Gross Domestic Product
GLM - General Linear Model
GSA - General Services Administration
GW - Gigawatts
HPMS - Highway Performance Monitoring System

hr - Hour
IC - Internal Combustion
ICI - Industrial/Commercial/Institutional
ICR - Information Collection Request
IEc - Industrial Ecology
IGCC - Integrated Gasification Combined Cycle
IMPROVE - Interagency Monitoring for Protection of Visual Environments
IPM - Integrated Planning Model
IPPs - Independent Power Producers
IR - Ignition Timing Retardation
ISCST3 - Industrial Source Complex Short Term
Kg/ha - Kilograms Per Hectare
km^2 - Square Kilometer
kWh - Kilowatt Hour
LAER - Lowest Achievable Emissions Rates
lb - Pound
L-E - low emission
LNB - Low-NOx Burners
mills/kWh - Mills Per Kilowatt Hour
MM4 - Mesoscale Model. version 4
mmBtu - Millions of British Thermal Units
Mm- Megameter
MOU - Memorandum of Understanding
MW - Megawatts
MWe - Megawatt of Electricity
MWh - Megawatt Hours
NAA - Nonattainment Area
NAAQS - National Ambient Air Quality Standards
NAPAP - National Acid Precipitation Assessment Program
NATS - National Allowance Tracking System
NEEDS - National Electric Energy Data System
NEPA - National Environmental Protection Act
NERC - North American Electric Reliability Council
NET - National Emission Trends
NH_3 - Ammonia
NLEV - National Low Emission Vehicle
NOAA - National Oceanic and Atmospheric Administration
NOx - Oxides of Nitrogen
NPR - Notice of Proposed Rulemaking
NPS - Non-Point Source
NSPS - New Source Performance Standards
NSR - New Source Review
O_3 - Ozone
OMB - Office of Management and Budget
OMS - Office of Mobile Sources
O&M - Operation and Maintenance
OTAG - Ozone Transport Assessment Group
OT and WI - Oxygen Trim and Water Injection

OTC - Ozone Transport Commission
OTR - Ozone Transport Region
PM - Particulate Matter
ppm - Parts Per Million
PRA - Paperwork Reduction Act of 1995
PSD - Prevention of Significant Deterioration
RIA - Regulatory Impact Analysis
RACT- Reasonably Available Control Technology
RFA - Regulatory Flexibility Act
RVP - Reid Vapor Pressure
SBA - Small Business Administration
SBREFA - Small Business Regulatory Enforcement Fairness Act of 1996
SCR - Selective Catalytic Reduction
SI - Spark Ignition
SIC - Standard Industrial Classification
SNCR - Selective Non-Catalytic Reduction
SNPR - Supplemental Notice of Proposed Rulemaking
SO_2 - Sulfur Dioxide
SUBS - Statistics of U S Businesses
tpd - Tons Per Day
tpy - Tons Per Year
TRI - Toxics Release Inventory
TVA - Tennessee Valley Authority
UAM-V - Urban Airshed Model - Variable Scale
UMRA - Unfunded Mandates Reform Act
USDA - United States Department of Agriculture
VMT - Vehicle Miles Traveled
VOCs - Volatile Organic Compounds
VOS - Value of Shipments

Table ES-1
Regulatory Alternatives by Source Category Groupings for the NOx SIP Call

Electricity Generating Units (EGUs)--Emissions Budgets Based on a NOx Limit of:	Non-Electricity Generating Units (non-EGUs)	
	Industrial Boilers and Combustion Turbines--Emissions Budgets Based on a Reduction from Uncontrolled Levels of:	All Other Stationary Sources--Emissions Budgets Based on Highest Ozone Season NOx Reduction Achievable without a Source Paying More Than:
0.25 lb/mmBtu*	40%	$1,500/ton
0.20 lb/mmBtu		$2,000/ton
0.15 lb/mmBtu in Northeast, 0.20 lb/mmBtu in Midwest & Southeast	50%	$3,000/ton
0.12 lb/mmBtu in Northeast, 0.15 lb/mmBtu in Midwest, 0.20 lb/mmBtu in Southeast	**60%**	$4,000/ton
0.15 lb/mmBtu	70%	**$5,000/ton**
0.12 lb/mmBtu		

* See Chapter 1 for a breakdown of the States covered in the NOx SIP call

Emission Reductions, Costs, and Cost-effectiveness

Table ES-2 summarizes EPA estimates of the emission reductions, costs, and cost-effectiveness for the regulatory approach that EPA selected as the basis for the NOx SIP Call's NOx budgets (Please note Since these estimates were calculated EPA has fine-tuned its estimates of the NOx budgets and an addendum to this executive summary provides revised emission reduction, cost and cost-effectiveness information) Overall, 82% of the emission reductions expected under this regulatory alternative are expected to come from the electric power industry, at an average ozone season cost-effectiveness of $1,468 per ton The table indicates the estimates of direct control costs for sources including costs associated with emissions monitoring and reporting The table also indicates the total administrative costs to State governments and EPA In EPA's analysis to support this rule, the Agency has shown that for the electric power industry, the largest source of emissions for which it considered controls, a single trading program across the SIP call region can provide a similar reduction to what direct command-and-control requirements would accomplish, but do the job at lower cost For this reason, the Agency is encouraging States to participate in the trading program that it plans to administer

Table ES-2
Estimate of Emission Reductions, Total Annual Costs, and Cost-Effectiveness in 2007 of the EPA's Selected Approach to NOx SIP Call

Sector	Ozone Season NOx Emission Reductions (1,000 tons)	Total Annual Cost (millions 1990S)	Average Ozone Season Cost-Effectiveness (S per ozone season ton)
Electricity Generating Units [a]	938	$1,378	$1,468
Industrial Boilers and Turbines [b]	104	$153	$1,467
Internal Combustion Engines [c]	83	$100	$1,215
Cement Manufacturing [c]	16	$24	$1,458
Administrative Costs for EGUs		$6	
Administrative Costs to States and EPA		$2	
Total	**1,141**	**S1,660[d]**	

[a] Does not include additional monitoring costs (see later row)
[b] Includes additional monitoring and other administrative costs associated with participating in the NOx emissions trading program
[c] Includes additional monitoring and other administrative costs associated with the SIP call rule
[d] Numbers do not add due to rounding

Economic Impacts

EPA considered what the economic impacts could be, if States implemented the regulatory approach that EPA used to calculate the NOx SIP call budgets for electricity generating units Electricity prices could potentially rise in the NOx SIP call region by as much as 1.6 percent in 2007, if the power industry is pricing its power on the basis of marginal costs in a fully competitive environment The price increase will be less, if these assumptions regarding the nature of the competitive environment do not hold There will be more new electric generation capacity built in response to the rule than will retire early (there will be little generation capacity that closes) On net, EPA expects this NOx SIP call to create more new jobs (from pollution control operations and increased natural gas use) than it reduces (due to a small decline in forecasted coal demand)

The analysis of non-EGU sources indicates that fewer than 5% of potentially affected firms experience costs in excess of 1% of revenues, and just over 2% of potentially affected firms experience costs in excess of 3% of revenues EPA also examined the potential affect of the NOx SIP call on small entities that meet the Small Business Administration's definition of "small." The Agency adopted several ways of minimizing potential impacts on small entities for the final NOx SIP call rulemaking Of the nearly 1,200 small entities (both EGU and non-EGU) in the NOx SIP call region that have large NOx emissions sources, only 150 are potentially affected by the SIP call rule, and only 41 have potential compliance costs in excess of 1% of total revenues EPA expects States to use these results to help them design control strategies that will reduce or eliminate adverse impacts on small entities

Limitations

Evaluating the potential costs of a rulemaking provides one framework for policy makers and the public to assess policy alternatives Not all the potential costs can be captured in any analysis However, EPA is generally able to estimate reasonably well the costs of pollution controls based on today's control technology and assess the important impacts when it has sufficient information for its analysis. EPA compiled through the OTAG process and from many other sources sufficient information for this rulemaking There are, however, important limitations in the RIA analysis.

There are some data limitations in some aspects of the RIA, despite the Agency's extensive efforts to compile information for this rulemaking. While they exist, EPA believes that it has used the models and assumptions that are made to conduct its analysis in a reasonable way based on the available evidence, but this should be kept in mind when reviewing various aspects of the RIA's results

Another factor that adds to the uncertainty of the results is the potential for pollution control innovations that can occur over time It is impossible to estimate how much of an impact, if any, new technologies that are just now emerging may have in lowering the compliance costs for the NOx SIP call, which goes into effect in 2003 We can only recognize their possible influence

There is the uncertainty regarding future costs that exists due to the flexibility that occurs under the emissions cap-and-trade program that EPA is encouraging the States to set up. The analysis that EPA has done to date has been fairly conservative in considering the electric power industry and large industrial boilers and combustion turbines operating separately under their own trading programs In reality, they should enter the same trading pool and there should be greater efficiency and lower costs that result

Qualitative and more detailed discussions of the above and other uncertainties and limitations are included in the analysis Where information and data exists, quantitative characterizations of these uncertainties are included However, data limitations prevent an overall quantitative estimate of the uncertainty associated with final estimates Nevertheless, the reader should keep all of these uncertainties and limitations in mind when reviewing and interpreting the results

Addendum to Executive Summary

In response to comments, EPA has revised the State NOx budgets that it set for the electric power industry on the basis of .15 lbs/mmBtus in the final days of the rulemaking process The SIP call region budget was lowered from 564 thousand tons of NOx during the ozone season to 544 thousand tons of NOx The Agency also decided to create a "compliance supplement pool" for use in 2003 and allow banking with flow controls in the trading program that EPA is encouraging States to undertake

For the adjustment of the NOx budget to 544 thousand tons for the electricity generating units, the Agency estimates that there will be a reduction of ozone season NOx emissions by 958 thousand tons in 2007 at an annual cost of $1,440 million This is an average cost-effectiveness of $1,503 per ton of NOx reductions during the ozone season The total ozone season NOx emission reductions from the NOx SIP call if the States implement the program the way EPA used to set the budget is 1,161 thousand tons

An adjustment to the emissions inventory for the non-EGU sources was also made as a result of public comments The reanalysis following these emission inventory adjustments indicated only minor changes in the costs

Chapter 1. INTRODUCTION AND BACKGROUND

1.1 Introduction

This document presents the cost and economic impact estimates for a Regulatory Impact Analysis of the final NOx SIP call rule, which addresses regional transport issues related to ozone attainment[1]. This rule requires certain States to take action to reduce emissions of nitrogen oxides (NOx) that contribute to nonattainment of ozone standards in downwind States. This RIA also satisfies the analytical requirements for the proposed NOx Federal Implementation Plan (FIP) and Clean Air Act (CAA) section 126 petition actions. The proposed FIP may be needed if any State fails to revise its SIP to comply with the final NOx SIP call. The proposed action under CAA section 126 responds to petitions filed with EPA by eight Northeastern States requesting that EPA provide relief from emissions sources in several upwind States that may be contributing to ozone nonattainment in the petitioning States[2].

The Clean Air Act (CAA) requires States to demonstrate attainment of the National Ambient Air Quality Standards (NAAQS) for ozone. Many States have found it difficult to demonstrate attainment of the ozone NAAQS due to the widespread regional transport of ozone and its precursors, NOx and volatile organic compounds (VOCs). The Ozone Transport Assessment Group (OTAG) was established in 1995 to undertake an assessment of the regional transport problem in the Eastern half of the United States. OTAG was a collaborative process among 37 affected States, the District of Columbia, the U.S. Environmental Protection Agency (EPA), and interested members of the public, including environmental groups and industry representatives.

OTAG concluded that regional reductions in NOx emissions are needed to reduce the transport of ozone and its precursors. OTAG recommended that major sources of NOx emissions (utility and other stationary sources) be controlled under State NOx budgets, and also recommended development of an emissions trading program.

After a review of OTAG's analysis, findings, and recommendations, EPA proposed a rule to limit summer season NOx emissions in a group of States that the Agency believes are significant contributors to ozone in downwind areas.[3] In a November 7, 1997 Notice of Proposed Rulemaking (NPR), EPA made a determination that transport of ozone from certain States in the OTAG region[4] makes a significant contribution to nonattainment, or interferes with the maintenance of attainment, with the ozone NAAQS in downwind States (FR 1997a). EPA proposed a summer season NOx budget (in tons of NOx) for each of these States. These States will be required to amend their State Implementation Plans (SIPs) through a call-in procedure established in Section 110 of the Clean Air Act Amendments of 1990 (CAAA). In a May 1998

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[1] Ground level (or tropospheric) ozone is an air pollutant that forms when its two primary components, oxides of nitrogen and volatile organic compounds, combine in the presence of certain meteorological conditions.

[2] Unless necessary to provide specific emphasis, the term "NOx SIP call" will be used (rather than "FIP" or "section 126 petitions") throughout this report when referring to the regulatory framework that is analyzed and reported in this RIA. See section 1.4 for additional detail on the analytical relationship between these three regulatory actions.

[3] NOx emissions reductions were proposed for 22 States and the District of Columbia.

[4] The OTAG region consists of 37 States east of 104° W longitude.

Supplemental Notice of Proposed Rulemaking (SNPR). EPA made technical corrections to the State NOx budgets, and developed a proposed trading rule to provide for emissions trading (FR 1998a) The SNPR also included an analysis of the air quality impacts of the proposed rule The State NOx emissions budgets, trading rule, and related provisions are now being promulgated as a final rule

A technical background support document prepared for the November 7, 1997 NPR estimated costs and emissions reductions associated with an assumed strategy that States might take to achieving the proposed budgets (EPA, 1997a) These analyses were updated to reflect technical corrections to the population of sources and growth estimates on which the State-specific budgets were based and assess the effects of the proposed trading system, in an analysis supporting the April 1998 SNPR (EPA 1998a).

This document provides the cost and economic impact estimates for the Regulatory Impact Analysis (RIA) of the final rule This analysis expands and updates the previous analyses, to reflect the provisions of the final rule and to provide analysis of the potential economic impacts as well as the cost and emissions impacts associated with the rule

The remaining sections of this chapter address the following topics

1.2 Relevant requirements of the Clean Air Act,

1.3 Overview of the NOx SIP call rulemaking,

1.4 Relationship between the NOx SIP call, FIP, and section 126 actions,

1.5 Statement of need for the NOx SIP call,

1.6 Administrative requirements addressed by this RIA,

1.7 Structure of the RIA and organization of this document, and

1.8 References for Chapter 1

1.2 The Clean Air Act

The 1970 Clean Air Act Amendments required EPA to issue, periodically review, and, if necessary, revise, NAAQS for ubiquitous air pollutants (Sections 108 and 109). States are required to submit SIPs to attain those NAAQS, and Section 110 of the CAA lists minimum requirements that SIPs must meet Congress anticipated that all areas would attain the NAAQS by 1975 In 1977, the CAA was amended to provide additional time for areas to reach the NAAQS and included the requirement that States reach the NAAQS for ozone by 1982 or 1987. In addition, the 1977 amendments included provisions that required SIPs to consider adverse downwind effects and allowed downwind States to petition for tighter controls on upwind States that contribute to their NAAQS nonattainment status

In 1990, the Clean Air Act was again amended This section outlines requirements of the 1990 Clean Air Act Amendments (CAAA) related to NOx reductions and the NOx SIP call. The discussion includes the ozone and NOx requirements and a review of the guidelines for new or advanced air emissions control technologies

1.2.1 Ozone Requirements

The CAAA included provisions designed to address the continued nonattainment of the existing ozone NAAQS, specified requirements that would apply if EPA revised the existing standard, and addressed transport of air pollutants across State boundaries

In 1991 and 1992, areas not in attainment with the 1-hour ozone NAAQS were placed in one of five classifications, based on the degree of nonattainment Requirements for moving toward attainment, including definitions of "major source" for VOCs and NOx, attainment dates and new source offset ratios, were established for each of the five classifications Within an area known as the Northeast Ozone Transport Region (OTR), all sources emitting 50 tons or more of ozone forming pollutants a year are defined as "major sources," regardless of their current attainment classification Certain emissions limits apply to major sources, and even more stringent requirements apply for new major sources in nonattainment areas

Since passage of the 1990 CAAA, EPA has revised the NAAQS for ozone EPA is required to review the NAAQS at least every five years to determine whether, based on new research, revisions to the standards are necessary to continue to protect human health and the environment As a result of the most recent review, EPA revised the NAAQS for both particulate matter and ozone The previous ambient air quality standard for ozone was 0 12 ppm based on 1-hour averaging of monitoring results The revised standard was set at 0 08 ppm based on an 8- hour averaging period The 1-hr standard remains in effect until EPA determines that a given area has air quality meeting its 1-hour standard This is necessary to ensure continued progress in those areas and a smooth transition between the two standards

On July 16, 1997, President Clinton issued a directive to EPA on the implementation strategy for the new ozone and particulate NAAQS The goal of the implementation strategy is to provide flexible, common-sense, and cost-effective means for communities and businesses to comply with the new standard The EPA has issued proposed guidance for public comment on implementation of the revised standards (August 24, 1998, 63 FR 45060) Additional guidance will be proposed in October 1998 The August and October guidance will be combined and issued as one document in December 1998 The implementation strategy includes

Endorsement of a Regional Approach Citing EPA's work with the OTAG, the implementation strategy notes that ozone needs to be addressed as a regional problem The Directive indicates that, based on OTAG recommendations, EPA will propose a rule to provide a flexible, common-sense, and cost effective means for communities and businesses to comply with the new standards The strategy states that EPA will encourage and assist the States to develop a regional emissions cap-and-trade system, modeled on the current acid rain program, as a way to achieve reduction in NOx emissions at lower cost

Transitional Classifications Areas that attain the 1-hour standard but that do not attain the new 8-hour standard will be eligible for a specific "transitional" classification, if they participate in a regional strategy and/or submit early plans addressing the new standard EPA will revise its rules for new source review (NSR) and conformity so that States will be able to comply with the new standards with only minor revisions to the existing programs in such transitional areas Areas which will achieve attainment as a result of the regional strategy need not implement any additional local controls. Areas that will not achieve the 8-hour standard even with the regional strategy are eligible for transitional status if they submit revised SIPs in the year 2000 demonstrating attainment of the 8-hour standard on the same schedule as the regional transport requirements.

Cost-Effective Implementation Strategies EPA will encourage States to design strategies for both the PM and ozone standards that focus on getting low cost reductions and that limit the cost of control to under $10,000 per ton for all sources. EPA will encourage market-based strategies to lower the cost of attainment and stimulate technology innovation.

The NOx SIP call, therefore, plays an important role in the implementation strategy for the new ozone NAAQS, by instituting a regional strategy that will encourage cost-effective attainment of the new standard

1.2.2 NOx Control and Ozone Reduction

To address the CAAA provisions regarding continued nonattainment of the existing ozone NAAQS, EPA's post-1994 attainment strategy guidance for the 1-hour ozone standard called for continued emissions reductions within ozone nonattainment areas together with a national assessment of the ozone transport phenomenon Recognizing that no individual state or jurisdiction can effectively assess or resolve all of the issues relevant to ozone transport, the Environmental Council of States (ECOS) formed a national work group to address ozone pollution [5] OTAG was established to assist states east of the Mississippi River to attain federal ozone standards and to develop regional strategies to address regional transport problems [6] The multi-state, multi-stakeholder OTAG process included input from State and local governments, industry, environmental groups, and the Federal government. The stated goal of OTAG was to

> Identify and recommend a strategy to reduce transported ozone and its precursors which, in combination with other measures, will enable attainment and maintenance of the national ambient ozone standard in the OTAG region A number of criteria will be used to select the strategy including, but not limited to, cost effectiveness, feasibility, and impacts on ozone levels (OTAG, 1995)

OTAG's work included development of a comprehensive base-year (1990) emissions inventory for use in all OTAG analyses The inventory contained information provided by the States and reviewed by OTAG for point, area, and mobile sources State-specific growth factors were used to project emissions for the years 1999 and 2007, which represent the CAAA attainment dates for certain nonattainment areas Baseline 2007 emissions were also adjusted to reflect the effect of various controls required under existing regulatory programs or expected from future programs

OTAG then conducted modeling of NOx and ozone across the OTAG region for several scenarios using geographic and atmospheric models

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[5] ECOS is a national organization of environmental commissioners with members from the 50 States and territories

[6] Information on OTAG and copies of documents produces by the group can be accessed on-line at http //www epa gov/ttn/otag

Strategy Modeling OTAG Strategy Modeling was done in several phases, and included analysis of more than 25 emission control strategies OTAG found that domain wide emissions of NOx in the 2007 baseline are approximately 12 percent lower than 1990 and emissions of VOC are approximately 20 percent lower Thus, existing CAA programs are expected to produce a reduction in ozone concentrations in many nonattainment areas However, the analysis showed that some areas currently in nonattainment will likely remain so in the future and that new 8-hour nonattainment and/or maintenance problem areas may develop as a result of economic growth in some areas

Geographic Modeling OTAG conducted geographic modeling to isolate the effects of NOx reductions on specific subregions Among other results, OTAG found that a regional strategy focusing on NOx reductions across a broad portion of the region will help mitigate the ozone problem in many areas of the East Further, a regional NOx emissions reduction strategy coupled with local NOx and/or VOC reductions may be needed to achieve attainment and maintenance of the NAAQS in the region.

This analyses conducted by OTAG (OTAG 1997), as well as EPA's analyses in support of the new ozone NAAQS (EPA 1997b), showed the important role that reducing NOx emissions plays in the reduction of ozone levels The extensive air quality modeling performed by OTAG indicated that both ozone and NOx can be transported long distances, up to 500 miles While reductions in either NOx and VOCs may reduce ozone in localized urban areas, only NOx reductions would result in lower ozone levels across the region The OTAG analyses showed a correlation between the magnitude and location of NOx reductions and the magnitude of reductions in ozone levels in downwind areas OTAG, therefore, reached the following conclusion

> Regional NOx reductions are effective in producing ozone benefits, the more NOx reduced, the greater the benefit Ozone benefits are greatest where emission reductions are made and diminish with distance Elevated and low level NOx reductions are both effective (OTAG 1997, pp 51-52)

Based on the evidence of the relationship between NOx emissions and regional ozone levels, OTAG recommended that a range of NOx controls be applied in certain areas of the OTAG region A wide variety of sources are responsible for NOx emissions, including electricity generating units, other (non-utility) stationary sources, area sources, non-road mobile sources, and highway vehicle sources OTAG did not suggest any one "right" approach to reducing major source NOx emissions However, OTAG developed a number of specific recommendations for EPA pertinent to the NOx SIP call, including the following [7]

- OTAG-related controls should be implemented in the "fine grid" states [8]
- The range of utility NOx controls should fall between Clean Air Act controls and the less stringent of 85% reduction from the 1990 rate (lb/mmBtu) or 0 15 lbs of NOx /mmBtu summer heat input
- The stringency of controls for individual large non-utility point sources should be established in a manner equitably with utility controls, and RACT should be considered for individual medium non-

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[7] Summaries of the OTAG findings and recommendations are provided in OTAG 1997

[8] The fine grid states include those modeled using UAM-V at a grid resolution of 12 km^2 All other areas constitute the coarse grid which is modeled at a grid resolution of 36 km^2. Coarse grid states are Florida, Louisiana, Texas, Arkansas, Oklahoma, Kansas, Nebraska, North Dakota, South Dakota, and Minnesota

utility point sources where appropriate[9] OTAG recommended that EPA calculate statewide NOx tonnage budgets based on a specified relationship between control levels for coal-fired power plants and control targets (emission reduction percentages) for large and medium non-utility point sources

- OTAG stated that market-based approaches are recognized as having a number of benefits in relation to traditional command and control regulations, and that States have the option to select market systems that best suit their needs They described two basic approaches that States might use to implement NOx emissions market systems, and recommended that a joint State/EPA Workgroup be formed to develop design features and implementation provisions for market systems that could be selected by the States

OTAG also made recommendations that EPA develop and adopt a variety of specific national regulations that were assumed for the modeling to result in reduced emissions of VOCs and/or NOx, and to reach closure on the Tier 2 Motor Vehicle Study

The recommendations resulting from the extensive analysis and air quality modeling conducted by OTAG have played a major role in the design of the NOx SIP call

1.2.3 Title IV NOx Requirements

Title IV of the CAAA requires annual reductions in NOx emissions The Acid Rain NOx Program under Title IV incorporates a two-phased strategy to reduce NOx emissions In the first phase, starting January 1, 1996, some Group 1 boilers (i e , dry bottom wall-fired boilers and tangentially fired boilers) are required to comply with specific NOx emission limitations[10] In the second phase, starting January 1, 2000, the remaining Group 1 boilers must comply with more stringent NOx emission limits[11] Further, Group 2 boilers (i e , wet bottom wall-fired boilers, cyclones, boilers using cell-burner technology, and vertically fired boilers) must comply with recently established emission limits[12]

Compliance results for 1996 show that, from 1990 to 1996, the Phase I affected population's average NOx emission rate declined by 40 percent Overall NOx emission reductions between 1990 and 1996 for the affected boilers totaled about 340,000 tons, i e a reduction of 33 percent (EPA, 1997c) In Phase II , about 1 17 million tons per year of NOx reductions are projected to result from the Acid Rain NOx Program requirements (EPA, 1996)

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[9] OTAG provided specific definitions of large and medium point sources, for purposes of their recommendations

[10] The affected dry-bottom wall-fired boilers must meet a limitation of 0 50 lbs of NOx per mmBtu averaged over the year, and tangentially fired boilers must achieve a limitation of 0 45 lbs of NOx per mmBtu, again averaged over the year (FR 1995)

[11] Annual averages of 0 46 lb/mmBtu for dry-bottom wall-fired boilers and 0 40 lb/mmBtu for tangentially fired boilers

[12] The limits are 0.68 lb/mmBtu for cell burners, 0 86 lb/mmBtu for cyclones greater than 155 MWe, 0 84 lb/mmBtu for wet bottom boilers greater than 65 MWe, and 0 80 lb/mmBtu for vertically fired boilers (FR 1996a)

In developing State budgets for the NOx SIP call, EPA considered the NOx reductions committed to by Title IV NOx Program requirements

1.2.4 New Source Performance Standards

The EPA is under court order to promulgate a new source performance standard (NSPS) on fossil-fuel-fired utility and industrial boilers in September 1998, and subpart GG of Part 60 regulates NOx emissions from combustion turbines The final standards revise the NOx emission limits for steam generating units in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units). Only those electricity generating units and industrial steam generating units for which construction, modification, or reconstruction is commenced after July 9, 1997 would be affected by these revisions.

The NOx emission limit in the final rule for new subpart Da units is 201 nanograms per joule (ng/J) [1 6 lb/megawatt-hour (MWh)] gross energy output regardless of fuel type For existing sources that become subject to subpart Da through modification or reconstruction, the NOx emission limit is 0 15 lb/million Btu heat input For subpart Db units, the NOx emission limit being proposed is 87 ng/J (0 20 lb/million Btu) heat input from the combustion of any gaseous fuel, liquid fuel, or solid fuel, however, for low heat release rate units firing natural gas or distillate oil, the current NOx emission limit of 43 ng/J (0 10 lb/million Btu) heat input is unchanged

In developing the State budgets for the NOx SIP call, EPA considered the potential NOx reductions attributable to this NSPS

1.2.5 Reasonably Available Control Technology Requirements

In the 1977 amendments to the CAA Congress required that all SIPs for nonattainment areas contain reasonably available control measures (RACM) or reasonably available control technology (RACT) In the 1990 Amendments to the Act, Congress created RACT requirements specifically for ozone nonattainment areas under the 1-hour standard (see subpart 2 of part D of title I) Since 1977, EPA has defined RACT for ozone as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility The EPA historically has interpreted the RACT requirement in ozone nonattainment areas to apply independent of a State's ability to demonstrate that an area will attain the ozone standard, with certain exceptions

In the ozone-specific RACT requirement enacted in 1990, States were required to correct all existing deficiencies in RACT rules in marginal nonattainment areas to ensure the rules were adopted consistently on a national basis In addition, all nonattainment areas classified moderate and above were required to adopt RACT for each source category for which EPA issued a Control Techniques Guideline (CTG) Over the years, EPA has issued CTG documents to assist the States in determining RACT for VOCs. Each CTG contains information on available air pollution control techniques and provides a "presumptive norm" for RACT for a specific source category Finally, RACT for controlling NOx was also required in certain nonattainment areas classified moderate and above

In developing implementation guidance for the revised 8-hour NAAQS, EPA is addressing the RACM/RACT requirement under subpart 1 of part D of title I, rather than subpart 2 The EPA has proposed implementation guidance for the revised ozone NAAQS which addresses several issues, including RACM/RACT The proposed policy states that "For the 8-hour ozone NAAQS, if the [nonattainment] area is able to demonstrate attainment of the standard as expeditiously as practicable with emission control measures in the SIP, then RACM/RACT will be met and additional measures would not be required as being reasonably available" (August 24, 1998, 63 FR 45060) The policy will be finalized by December 31, 1998.

1.2.6 Northeast Ozone Transport Region

Section 184 of the CAAA delineated a multi state ozone transport region (OTR) in the Northeast and required specific additional NOx and VOC controls for all areas in this region (not only nonattainment areas). Section 184 also established the Ozone Transport Commission (OTC) for the purpose of assessing the degree of ozone transport in the OTR and recommending strategies to mitigate the interstate transport of pollution The OTR consists of the States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania; Rhode Island, Vermont, parts of northern Virginia, and the District of Columbia The OTC was first convened in 1991, and began analysis and evaluation of ozone reduction strategies for the region. They concluded that regional reductions of NOx emissions are particularly important in reducing ozone The OTR States confirmed that they would implement RACT on major stationary sources of NOx, and agreed to a phased approach for additional controls, beyond RACT, for power plants and other large fuel combustion sources

This agreement, known as the OTC Memorandum of Understanding (MOU) for stationary source NOx controls was approved on September 27, 1994 All OTC States, except Virginia, are signatories to the OTC NOx MOU The OTC NOx MOU establishes an emissions trading system to reduce the costs of compliance with the control requirements

In developing State budgets for the NOx SIP call, EPA considered the NOx reductions committed to by the OTR states in the OTC NOx MOU, along with the OTAG recommendations discussed above

1.3 Overview of the NOx SIP Call Rulemaking

EPA relied extensively on the OTAG analyses and recommendations in developing the NOx SIP call As recommended by OTAG, the rule establishes ozone season[13] NOx emission budgets for 22 States and the District of Columbia [14] The 23 jurisdictions will be required to amend their SIPs by the year 2000, to allocate emissions control requirements among sources and to develop compliance programs for each affected source category to ensure that the NOx budget is met These compliance programs should include, necessary pollution control measures; monitoring, reporting, and accounting procedures to ensure source emissions are not exceeding the State's NOx budget; and enforcement requirements

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[13] The ozone season for this rule is the period May 1 - September 30

[14] The States covered by the rule include Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin

Consistent with OTAG's recommendation that NOx emissions reductions be achieved primarily from large stationary sources in a trading program, EPA is encouraging States to consider additional controls on electricity generating units and other large stationary sources as a strategy for meeting statewide budgets State budgets were developed using assumptions consistent with such a strategy. The budget for each State was developed for components of major source categories. For non-road and highway vehicle sources, budgets are based on estimates of the effectiveness in each State of national measures that EPA is taking to control emissions from mobile sources For electricity generating units and other stationary sources, the budgets are based on applying further reasonable controls A major factor in determining controls is the cost-effectiveness of control measures

EPA also followed OTAG's recommendation in urging States to consider implementing market based systems to reduce the costs of complying with the new limits on NOx emissions EPA is encouraging the States and the District of Columbia to join a trading program administrated by EPA, which is reflected in a model NOx Budget Trading Rule This trading system would place a collective cap on NOx emissions from electricity generating units and other large boilers and combustion turbines, and provide for trading of allowances similar to the CAAA Title IV SO_2 Allowance Trading Program already in place

Chapter 2 of this report describes a number of regulatory alternatives that EPA considered in the development of this final rule

1.4 Relationship Between NOx SIP Call, FIP, and Section 126 Petitions

In conjunction with promulgating the NOx SIP call, EPA has begun efforts to respond to petitions filed by eight northeastern States (FR 1998b) These petitions were filed under section 126 of the CAA, which authorizes States to petition EPA to address air pollution transported from upwind States The petitions request that EPA make a finding that NOx emissions from certain major stationary sources significantly contribute to ozone nonattainment problems in the petitioning States If EPA makes such a finding, the Agency would be authorized to establish Federal emissions limits for these sources The petitions recommend control levels for EPA to consider In an April 30, 1998 Advanced Notice of Proposed Rulemaking (ANPR) (63 FR 24058), EPA presented a schedule for taking actions on the petitions, made a preliminary identification of upwind sources that may significantly contribute to 1-hour and 8-hour ozone nonattainment problems in the petitioning States (using information developed for the NOx SIP call NPR), and requested comment on legal and policy issues raised by section 126 of the CAA. In responding to the section 126 petitions, EPA intends to be consistent with the approaches taken in the NOx SIP call

At the same time that EPA promulgates the NOx SIP call rule, EPA is proposing NOx Federal Implementation Plans (FIPs) that may be needed if any State fails to comply with the final NOx SIP call rule The FIP requirements are intended to be consistent with the approaches taken in the final NOx SIP call, including a proposed federal NOx Budget Trading Program for electric utility sources and other large industrial boilers and combustion turbines

Since the final NOx SIP call and the proposed FIP and section 126 petition actions are generally consistent in the manner in which they assess affected emissions sources, EPA is preparing only a single RIA for all three actions Even though the facts of the analysis contained in this report do not differ significantly for any of the three actions, the results have slightly different interpretations In the case of the final NOx SIP call, the results in this report are illustrative of potential costs and economic impacts that may result from the

SIP call. The NOx SIP call itself does not directly impose regulatory requirements on emissions sources. Instead, the SIP call requires States to develop strategies to meet the State NOx budgets contained in the final NOx SIP call rule. States have discretion on which emissions sources to control to realize the required reductions. It is EPA's position that for the final NOx SIP call the analytical requirements associated with the Regulatory Flexibility Act (RFA)and the Unfunded Mandates Reform Act (UMRA) do not apply (see sections 1.6.2 and 1.6.3 below). Nonetheless, EPA has performed analyses consistent with the analytical requirements in the RFA and UMRA, and summarized the results of these analyses in the RIA.

However, the FIPs, if needed, and the section 126 petition responses will directly impose regulatory requirements on emissions sources. EPA is proposing to regulate sources under the FIP and section 126 petition actions with strategies that are modeled in this RIA. In these cases the results presented in the RIA reflect potential outcomes from direct federal regulation, and, depending on the outcome of the final actions, have a higher probability of reflecting the actual outcome of the rules. For the proposed FIP and section 126 actions, it is the EPA's position that the analytical requirements of the RFA and UMRA do apply. Accordingly, EPA has performed the required analyses for these proposals and summarized the results of these analyses in the RIA. These analyses will be updated as necessary as part of any final actions EPA takes on the FIP and section 126 petitions.

The proposed section 126 actions will potentially affect only a subset of the sources potentially affected by the broader NOx SIP call. Sources in Georgia, South Carolina, and Wisconsin are not affected by the proposed section 126 rule. Therefore, the costs and economic impacts associated with the proposed section 126 rule are likely to be smaller than for the final NOx SIP call. Since Georgia, South Carolina, and Wisconsin are affected under the final NOx SIP call, and would be subject to a final FIP if they fail to comply with the provisions of the final NOx SIP call, EPA did not see the need to separately address the potentially smaller costs and economic impacts for the proposed section 126 rule.

1.5 Statement of Need for the NOx SIP Call

The following sections discuss the statutory authority and legislative requirements of the NOx SIP call, health and welfare effects of NOx emissions, and the basis for the regulatory actions of the NOx SIP call.

1.5.1 Statutory Authority and Legislative Requirements

Section 110(a)(2)(D) provides that a SIP must contain provisions preventing its sources from contributing significantly to nonattainment or interfering with maintenance of the NAAQS in a downwind State. This section applies to all pollutants covered by NAAQS and all areas regardless of their attainment designation. Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement, as well as being inadequate to mitigate interstate transport as described in Sections 184 and 176A. Such a finding would require States to submit a SIP revision to correct the inadequacy within a specified period of time.

1.5.2 Health and Welfare Effects of NOx Emissions[15]

NOx emissions contribute to the formation of ozone during the summer season Ozone is a major component of smog and is harmful to both human health and the environment Research has shown the following health effects of ozone

- Exposure to ambient ozone concentrations has been linked to increased hospital admissions for respiratory ailments, such as asthma Repeated exposure to ozone can make people more susceptible to respiratory infection and lung inflammation, and can aggravate preexisting respiratory diseases

- Children are at risk for the effects of ozone because they are active outside during the summer months when ozone levels are at their highest Adults who are outdoors and moderately active during the summer months are also at risk These individuals can experience a reduction in lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion

- Long-term exposures to ozone can cause repeated inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which could lead to premature aging of the lungs and/or chronic respiratory illnesses such as emphysema and chronic bronchitis

- Twenty-one peer reviewed epidemiology studies recently published suggest a possible association between ozone exposure and mortality

Ozone has also been shown to adversely affect vegetation, including reductions in agricultural and commercial forest yields, reduced growth and decreased survivability of tree seedlings, and increased tree and plant susceptibility to disease, pests and other environmental stresses

NOx emissions also contribute to fine particle matter formation (PM) Exposure to airborne PM has a wide range of adverse health effects The key health effects associated with PM include 1) premature mortality, 2) aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions and emergency room visits, school absences, work loss days, and restricted activity days), 3) changes in lung function and increased respiratory symptoms, 4) changes to lung tissues and structure, 5) altered respiratory defense mechanisms, and 6) chronic bronchitis Most of these effects have been consistently associated with ambient PM concentrations, which have been used as a measure of population exposure, in a number of community epidemiological studies Although mechanisms by which particles cause effects have not been elucidated, there is general agreement that the cardio-respiratory system is the major target of PM effects Particulate matter also is associated with welfare effects, which include visibility impairment, soiling, and materials damage

Based on its review of the scientific evidence, EPA established standards for $PM_{2.5}$ and retained the standards for PM_{10} The EPA revised the secondary (welfare-based) PM NAAQS by making them identical to the primary standards

Finally, NOx emissions contribute to a wide range of health and environmental problems independent of their contribution to ozone or PM formation. Among these problems are acid deposition,

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[15] A comprehensive discussion of health and environmental issues related to NOx appears in EPA, 1997d

nitrates in the drinking water, and nutrient loading in waterways, particularly in sensitive coastal estuaries where air deposition is a major portion of nitrogen loadings

1.5.3 Need for Regulatory Action

The existing and revised ambient air quality standards for ozone set levels necessary for the protection of human health and the environment. Under the CAA, attainment of these standards depends on the implementation of State-specific pollution control strategies contained in SIPs to reduce NOx and volatile organic compound emissions, in conjunction with EPA promulgation of national controls for some sources of pollution

It is clear that, even with planned national measures in place, several States cannot bring existing nonattainment areas into compliance with the current ozone standard, or avoid the application of very costly local control measures, unless the transport of ozone from other upwind areas is reduced Furthermore, many States will find it hard, if not impossible, to avoid nonattainment with the revised ozone NAAQS, or come into attainment with it in the future, unless mitigation of the ozone transport problem occurs This dilemma has raised concerns over the fairness of downwind areas having to cope with the pollution coming from areas upwind The current regulatory framework requires States to develop SIPs that demonstrate air quality improvements sufficient to reach specific attainment levels. States have no control over neighboring States' actions, and may be unable to meet their air quality goals due to pollutants transported across State lines The contribution of upwind sources outside of nonattainment areas creates a dilemma for States seeking to reach air quality goals

States could develop local ozone mitigation strategies to address the impact of transported ozone However, local efforts could lead to undesirable outcomes Some States might develop SIPs that do not achieve compliance in some serious and severe ozone nonattainment areas, because the States would deem local measures needed to achieve attainment as too draconian

The NOx SIP call is designed to mitigate these problems through a coordinated Federal and State effort to address regional ozone transport This rule will create a more effective, efficient and equitable approach for EPA and the States to promote attainment with the current and new ozone NAAQS

1.6 Requirements for this Regulatory Impact Analysis

This section describes various legislative and executive requirements that govern the analytical requirements for Federal rulemakings, and describes how each analytical requirement is addressed in this RIA

1.6.1 Executive Order 12866

Executive Order 12866, "Regulatory Planning and Review" (FR, 1993), requires EPA to provide the Office of Information and Regulatory Affairs of the Office of Management and Budget with an assessment of the costs and benefits of significant regulatory actions A "significant regulatory action" is defined as "any regulatory action that is likely to result in a rule that may

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities,

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency,

- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof, or

- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order" (FR, 1993)

For any such regulatory action, the Agency must provide a statement of the need for the proposed action, must examine alternative approaches, and must estimate social benefits and costs

EPA has determined that the NOx SIP call is a significant regulatory action because its effect on the economy is expected to exceed $100 million per year This RIA provides the cost and economic impact information required by E O 12866 for a significant regulatory action A separate document provides the benefits information required by the Executive Order

1.6.2 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996

The Regulatory Flexibility Act (RFA) of 1980 (PL 96-354) requires that agencies conduct a screening analysis to determine whether a regulation will have a significant impact on a substantial number of small entities, including small businesses, governments and organizations If a regulation will have such an impact, agencies must prepare a Regulatory Flexibility Analysis, and comply with a number of procedural requirements to solicit and consider flexible regulatory options that minimize adverse economic impacts on small entities The RFA's analytical and procedural requirements were strengthened by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996

For reasons explained more fully in the Federal Register notice for the final NOx SIP call, it is EPA's position that the RFA as amended by SBREFA does not apply to the final NOx SIP call, because the rule does not impose direct requirements on emissions sources States will ultimately decide what emissions limits are imposed for specific sources However, the EPA has determined that the RFA as amended by SBREFA does apply to both the proposed FIP and section 126 actions. Therefore, EPA has examined the potential for small entity impacts to provide policy makers and States with additional decision information.

The RFA and SBREFA require use of definitions of "small entities", including small businesses, governments and non-profits, published by the Small Business Administration (SBA) [16] Screening analyses of economic impacts presented in Chapters 6, 7, and 9 of this RIA examine potential impacts on small entities

[16] Where appropriate, agencies can propose and justify alternative definitions of "small entity " This RIA relies on the SBA definitions

1.6.3 Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act (UMRA) of 1995 (PL 104-4) was enacted to focus attention on federal mandates that require other governments and private parties to expend resources without federal funding, to ensure that Congress considers those costs before imposing mandates, and to encourage federal financial assistance for intergovernmental mandates. The Act establishes a number of procedural requirements The Congressional Budget Office is required to inform Congressional committees about the presence of federal mandates in legislation, and must estimate the total direct costs of mandates in a bill in any of the first five years of a mandate, if the total exceeds $50 million for intergovernmental mandates and $100 million for private-sector mandates

Section 202 of UMRA directs agencies to provide a qualitative and quantitative assessment of the anticipated costs and benefits of a Federal mandate that results in annual expenditures of $100 million or more The assessment should include costs and benefits to State, local, and tribal governments and the private sector, and identify any disproportionate budgetary impacts Section 205 of the Act requires agencies to identify and consider alternatives, including the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule

For reasons explained more fully in the Federal Register notice for the NOx SIP call, it is EPA's position that section 202 of UMRA does not apply to the final NOx SIP call, because the annual estimated costs of possible SIP submittals by States is less than $100 million and no Federal or private sector mandates are directly imposed However, EPA has determined that UMRA does apply to both the proposed FIP and proposed section 126 rules Chapter 8 of this RIA presents a summary of analyses of the potential impacts of the NOx SIP call on State and local governments, to support compliance with Section 202 of UMRA This analysis includes administrative requirements of State and local governments associated with revising SIPs and collecting and reporting data to EPA It also includes the compliance and administrative costs to emissions sources owned by government entities

1.6.4 Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) requires Federal agencies to be responsible and publicly accountable for reducing the burden of Federal paperwork on the public EPA has submitted an Information Collection Request (ICR) to the Office of Management and Budget (OMB) in compliance with the PRA The ICR explains the need for additional information collection requirements and provides respondent burden estimates for additional paperwork requirements to State and local governments associated with the NOx SIP call

1.6.5 Executive Order 12898

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. Disproportionate adverse impacts on these populations should be avoided. According to EPA guidance, agencies are to assess whether minority or low-income populations face risk or a rate of exposure to hazards that is significant (as defined by the National

Environmental Policy Act) and that "appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group." (EPA, 1996b) This guidance outlines EPA's Environmental Justice Strategy and discusses environmental justice issues, concerns, and goals identified by EPA and environmental justice advocates in relation to regulatory actions The NOx SIP call is expected to provide health and welfare benefits to eastern U.S. populations, regardless of race or income

1.6.6 Health Risks for Children

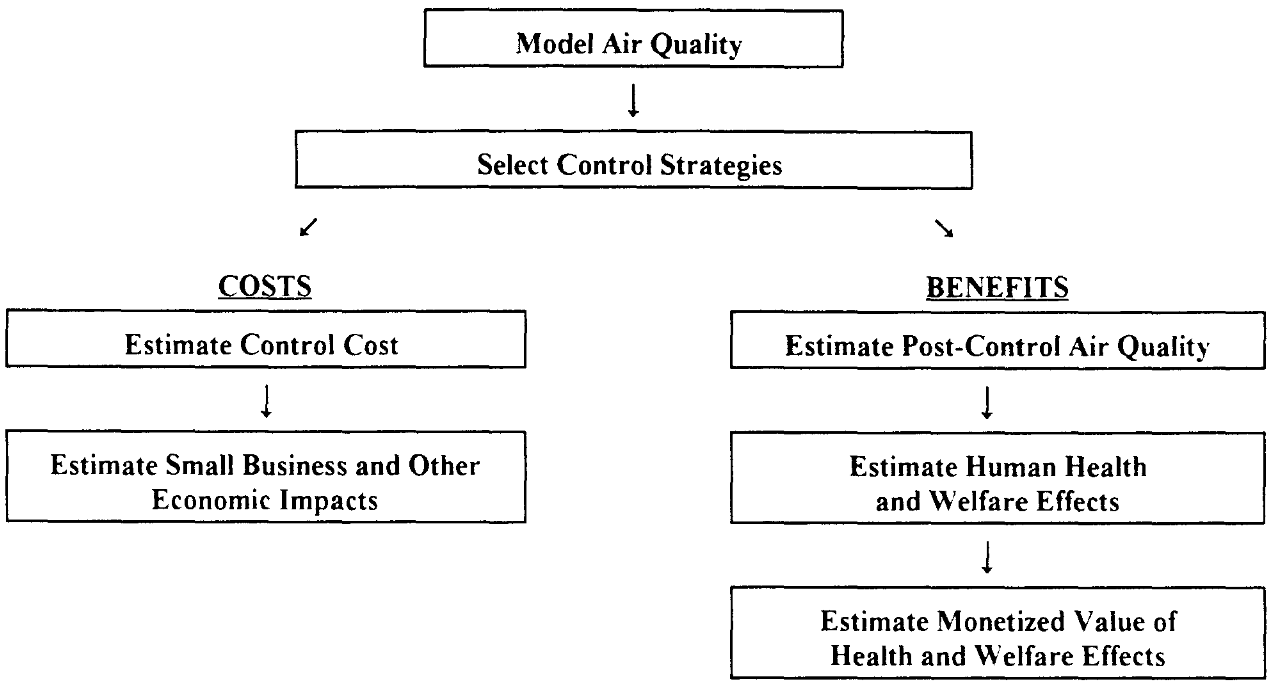
Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks," directs Federal agencies developing health and safety standards to include an evaluation of the health and safety effects of the regulations on children Regulatory actions covered under the Executive Order include rulemakings that are economically significant under Executive Order 12866, and that concern an environmental health risk or safety risk that the agency has reason to believe may disproportionately affect children EPA has developed internal guidelines for implementing the E.O 13045 (EPA, 1998b)

The NOx SIP call is a "significant economic action," because the annual costs are expected to exceed $100 million Both NOx and ozone formed by NOx are known to affect the health of children and other sensitive populations, which were addressed in the development of the new ozone NAAQS However, the NOx SIP call is not expected to have a disproportionate impact on children

1.7 Structure and Organization of the Regulatory Impact Analysis

The potential costs and economic impacts and benefits have been estimated for this rulemaking The flow chart in Figure 1-1 summarizes the analytical steps taken in developing the these estimates

Figure 1-1
Flowchart of Analytical Steps



The assessment of costs, economic impacts, and benefits consists of multiple analytical components, dependent upon emissions and air quality modeling. In order to estimate baseline air quality in the year 2007, emission inventories are developed for 1995 and then projected to 2007, based upon estimated national growth in industry earnings and other factors. Current CAAA-mandated controls (e.g., Title I reasonably available control measures, Title II mobile source controls, Title III air toxics controls, Title IV acid rain sulfur dioxide (SO_2) controls) are applied to these emissions to take account of emission reductions that should be achieved in 2007 as a result of implementation of the current PM and ozone requirements. These 2007 CAA emissions in turn are input to several air quality models that relate emission sources to area-specific pollutant concentrations. This modeled air quality is used as the base against which several alternative control options are measured and cost estimates developed. Given the estimated costs of the alternative regulatory control options, the potential economic impacts of these estimated costs on potentially affected industry sectors is subsequently analyzed.

The RIA analyses have been constructed such that costs are estimated incremental to those derived from the effects of implementing the CAAA in the year 2007. These analyses provide a "snapshot" of potential costs of this rulemaking in the context of implementation of CAA requirements between now and 2007 and the air quality effects that derive from economic and population growth.

States have discretion in how they achieve their NOx budgets, and different States may choose different strategies. The RIA must, therefore, be based on assumptions about how the States will choose to implement the NOx SIP call requirements. Consistent with EPA's recommendation that States focus on major stationary sources, this RIA assumes that States impose additional controls — incremental to those already required by other national programs that address NOx emissions — only for major stationary sources, and that States implement the cap-and-trade system for electricity generating units and industrial boiler and turbine sources. This assumption is illustrative of one cost-effective approach States could take to meeting the NOx SIP call budgets. States may choose different allocations of controls across major stationary sources than assumed here, or may choose to impose additional controls on area or mobile sources as well. Costs and economic impacts would differ from those estimated in this RIA to the extent that States' compliance strategies differ from the RIA assumptions.

Analysis of costs, changes in emissions, and economic impacts is conducted separately for two groups of sources: electricity generating units and other stationary sources. The Integrated Planning Model (IPM) allows analysis of trading and industry-level adjustments for electricity generating unit sources. Other stationary sources are analyzed separately, using assumptions about baseline conditions and control costs that are generally consistent with the IPM modeling assumptions used for electricity generating units.

Predicted changes in emissions due to the additional controls for electricity generating units and other stationary sources are then combined to estimate changes in air quality and to calculate the benefits of the NOx SIP call. These air quality and benefits analyses are discussed in a separate document.

The remainder of the RIA is organized in the following chapters and appendices:

- Chapter 2 presents a discussion of the regulatory alternatives considered by EPA for this rulemaking.

- Chapter 3 characterizes the regulated community, including the electric power industry, large industrial boilers and combustion turbines throughout industry, and other sources of NOx emissions throughout industry.

- Chapter 4 describes the methodology used to estimate costs, emissions reductions and economic impacts (including small entity impacts) for the electric power industry.

- Chapter 5 describes the methodology for estimating costs, emissions reductions and economic impacts (including small entity impacts) for other stationary sources.

- Chapter 6 presents the results of the analysis of costs, emission reductions, and economic impacts under each regulatory option for the electric power industry.

- Chapter 7 presents the estimated costs, emission reductions, and economic impacts for other stationary sources.

- Chapter 8 analyzes impacts on State and Federal governments, as implementers of the regulatory program and as owners of affected sources of NOx emissions, to provide the analyses required by UMRA; and

- Chapter 9 presents an integrated cost and small entity impacts summary associated with the NOx SIP call.

Where appropriate, each chapter includes a discussion of limitations of the analysis A series of appendices follow Chapter 9 and provide more detailed descriptions of specific methodologies and results

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Chapter 2. REGULATORY ALTERNATIVES

This chapter explains the various regulatory alternatives considered in this analysis Section 2 1 provides background on the elements that differentiate the options that were considered, and Section 2 2 defines the options that were analyzed and compared.

2.1 Elements Considered in Developing Regulatory Alternatives

EPA's NOx SIP call sets summer NOx emissions budgets for eastern States that the Agency has found significantly contribute to the nonattainment by other States of the pre-existing ozone standard (1-hour) and will contribute in the future to nonattainment by other States with the revised ozone standard (8-hour) EPA relied heavily on its estimation of the NOx reductions that the electric power industry and other stationary sources could provide cost-effectively in setting the State budgets Other factors, such as the feasibility of implementing controls in a reasonable time frame, also influenced the Agency's final decisions To estimate the cost-effectiveness of controls for various sources, the Agency considered several ways that controls could be implemented in the SIP call region However, States can place controls on their sources of NOx emissions differently than the approach that EPA used in the budget setting process, if they can show that control strategy will provide the same level of NOx reduction in the SIP call region

This section describes the elements that make up the various regulatory alternatives considered for this analysis The regulatory alternatives described in Section 2 2 represent various combinations of these elements Some elements of the rule remain the same for all the options considered Other elements are considered in varying combinations, including stringency of controls, geographic scope, affected sources and design of the trading system For all options analyzed, the timing of regulatory requirements was also considered, as this issue is critical in terms of feasibility of compliance and attainment of both the pre-existing ant the revised ozone standard

2.1.1 Type of Control

EPA had to decide on the types of regulatory approaches that the Agency wanted States to consider in their efforts to lower NOx emissions from various source categories EPA used those approaches in estimating the cost-effectiveness of ozone season NOx controls at various levels for different types of sources OTAG recommended that the Agency consider controls that allow for emissions trading, rather than traditional command-and-control regulation OTAG's analysis of trading programs had shown that there could be considerable savings from this type of approach for the electric power industry (OTAG, 1997)

EPA also demonstrated the potential savings from a NOx emissions trading program that could result in its regulatory analysis for the proposed NOx SIP call (EPA, 1997a) That analysis showed that in 2005 a command-and-control program for the electric power industry would cost about 30 percent more than a trading program in the NOx SIP call region For that reason, the Agency has focused heavily on developing regulatory approaches that States can use collectively that are based on allowance-based NOx emissions trading It was also clear from OTAG analysis and EPA's own work that further savings and flexibility could be gained from allowing banking as part of a trading program EPA's regulatory analysis over the last year has also considered banking options for inclusion in the Model Trading Rule for States (EPA, 1997b)

2.1.2 Geographic Scope

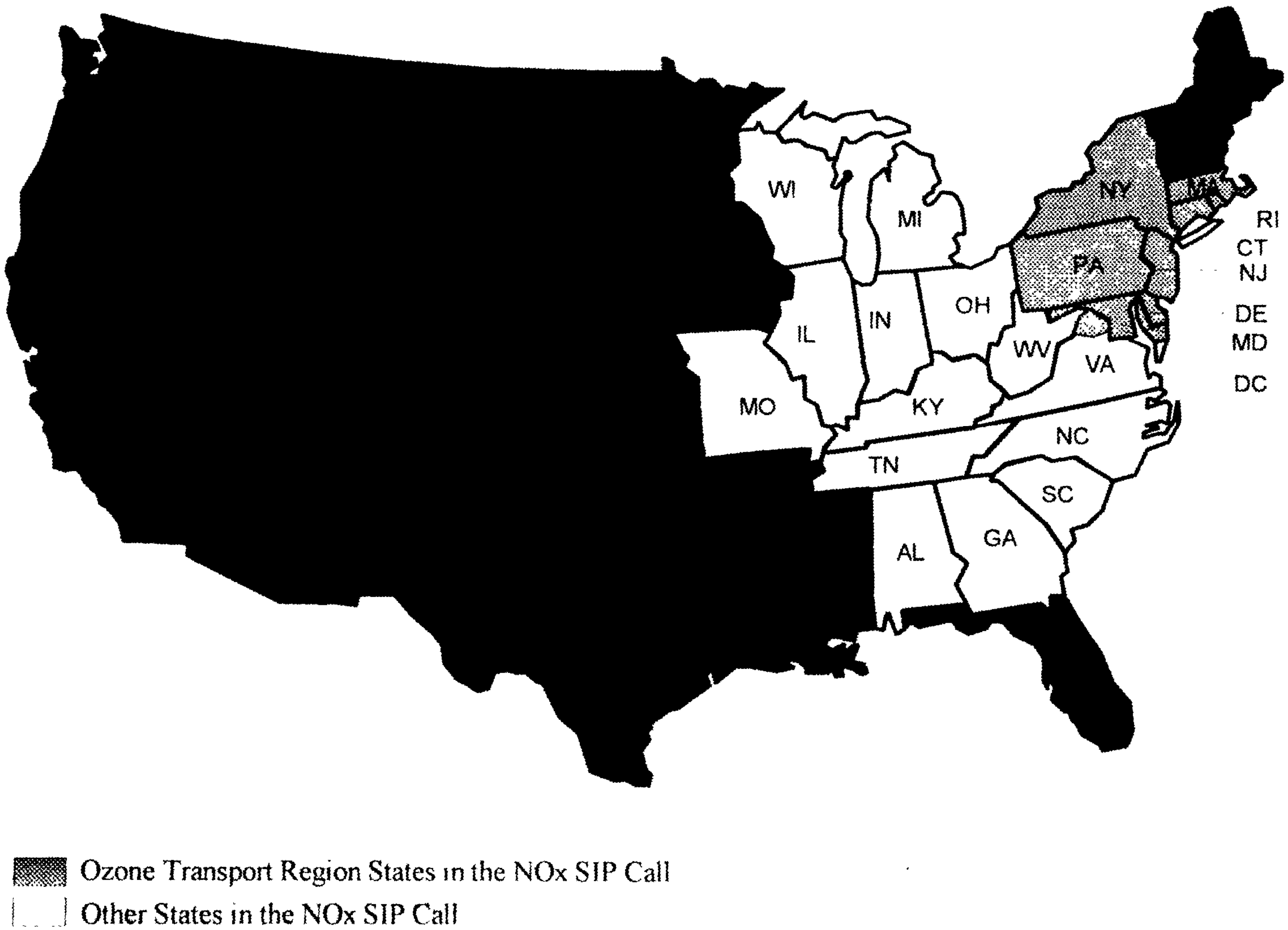
After considering OTAG's recommendations and other relevant information, EPA identified 22 States plus the District of Columbia (i.e., 23 jurisdictions) as significantly contributing to nonattainment with, or interfering with maintenance of, air quality standards in a downwind State. The SIP call region is shown in Figure 2-1 and consists of Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

The final rule reflects State NOx budgets that are developed using the same region-wide stringency targets and region-wide analyses of cost-effectiveness for all 23 jurisdictions. EPA also considered dividing the SIP call region into two or three subregions in an effort to make a distinction among the States that may contribute the most to the ozone transport problem and those where the wind patterns may be less likely to affect air quality in the other States. The SIP call region was divided into two regions--Northeast and Southeast, or into three regions--Northeast, Midwest, and Southeast. Different levels of stringency are then applied in the different regions, as described below.

The two region area consists of Connecticut, Delaware, District of Columbia, Massachusetts, Maryland, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Virginia, and West Virginia in the Northeast, and Alabama, Georgia, Illinois, Indiana, Kentucky, Michigan, Missouri, North Carolina, South Carolina, Tennessee, and Wisconsin in the Southeast.

The three region area consists of Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island in the Northeast, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Virginia, West Virginia, and Wisconsin in the Midwest, and Alabama, Georgia, North Carolina, South Carolina, and Tennessee in the Southeast.

Figure 2-1
States Included in EPA's NOx SIP call



2.1.3 Potentially-Affected Sources

EPA has developed State budgets based on the effects of additional controls (beyond those already required by the CAAA-related or reflected in existing SIPs) only for major stationary sources of NOx emissions These sources include (1) electricity generating utility boilers, (2) industrial, commercial and institutional boilers, (3) combustion turbines, (4) reciprocating internal combustion engines, (4) cement manufacturing operations, and (5) other industrial processes that emit NOx Only existing or planned CAAA-related controls are considered in calculating budgets for other sectors (area and mobile sources) that contribute to NOx emissions States ultimately have discretion to determine which sources to regulate to achieve the budget level

Analysis of costs and economic impacts in this RIA are based on a range of assumptions about which major stationary sources will actually be targeted for additional controls by the States in implementing the NOx SIP call The primary assumption in this analysis is that States will allocate NOx emissions reduction requirements to the largest electricity generating utility boilers, industrial, commercial and institutional boilers, combustion turbines; cement manufacturing units, and internal combustion engines Refer to Chapter 3 for further discussion of the assumptions regarding options for regulatory coverage

Large electricity generating units are defined as those generating more than 25 megawatts (MW) Large industrial boilers, combustion turbines, reciprocating internal combustion engines, and other industrial NOx sources are those capable of firing greater than 250 mmBtu/hour, or that emit greater than or equal to one ton of NOx per summer day.

2.1.4 Stringency of Control Level

In order to develop a cost-effective NOx reduction strategy as a basis for establishing State budgets, EPA considered various emission reduction levels for the affected sources for the summer ozone season defined as May 1 through September 30. For the electricity generating units (EGUs), EPA considered emissions budgets based on emission limits of 0.12 lb/mmBtu, 0 15 lb/mmBtu, 0.20 lb/mmBtu, and 0 25 lb/mmBtu [1] For the large industrial boilers and combustion turbines, EPA considered a uniform percent emission reduction from uncontrolled projected 2007 emission levels ranging from 40 percent to 70 percent For the remaining large nonutility sources, EPA considered source category-specific control levels corresponding to average ozone season cost-effectiveness cut-offs ranging from $1,500/ton to $5,000/ton

Taking into consideration the emission reductions and associated costs projected under each of the above scenarios, EPA identified cost-effective NOx reduction strategies Based on the reduced emissions achieved by this strategy, EPA then established State-specific budgets for ozone season NOx emissions Alternative budgets are calculated for the different stringency levels considered for EGUs. The details of NOx budget development can be found in the budget technical support document (EPA, 1998b)

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[1] Limits for each electricity generating unit are expressed as a specific NOx limit of pounds of NOx per mmBtu of summer heat input projected for 2007, the year which was the focus of OTAG's analysis (the year for which air quality modeling was done)

2.1.5 Effective Dates

States subject to the NOx SIP call must submit revised SIPs by September 1999 The affected sources in the States must implement NOx controls by May 2003, and EPA will assess how each State's SIP has actually performed in 2007.

2.1.6 Emissions Budget Trading System Design

To allow for use of the most cost-effective emission reduction alternatives, an emissions budget trading program is an optional component of the NOx SIP call. Each of the States subject to the NOx SIP call are encouraged to participate in this model NOx Budget Trading Program and thereby provide a mechanism for sources to achieve cost-effective NOx reductions. The trading unit is a NOx Allowance, equal to one ton of emitted NOx Details of the trading program are described in the Federal Register notice accompanying the final rule.

Under the NOx Budget Trading Program, each of the participating States would determine how its seasonal State trading program budget is allocated among its sources Each source would be given a certain quantity of NOx allowances If a source's actual NOx emissions exceed its allocated NOx allowances, the source may purchase additional allowances Conversely, if a source's actual NOx emissions are below its allocated NOx allowances, then it may sell the additional NOx allowances Such a program creates a competitive market for NOx allowances that encourages use of the most efficient means for reducing NOx emissions

For purposes of this analysis, trading may occur among any of the sources within the entire SIP call region or within each of the subregions If subregions are developed for the SIP call region, only intra-regional (within the region) trading would be allowed

Banking would allow sources that do not use all of their NOx allowances for a given year to save them for later use If banking is allowed, however, mechanisms such as flow controls can be put in place to limit the level of exceedance of the emissions cap Flow controls restrict the use of the banked NOx allowances by restricting their use at certain times or within certain areas. For example, a restriction may be placed on the banked allowances that allows only a set amount to be used during a defined time period

For this RIA, EPA analyzed a variety of trading options, and trading with banking only for the 15 trading option, where banking begins after the start of the program in 2003. Banking of "early" reductions was not modeled for the 0 15 option because earlier IPM analysis suggested that owners of electricity generating units would want to use it to a very limited degree to lower the costs of future compliance (EPA, 1997). The following considerations were part of the 1997 analysis

- Beginning in 2003 (and each year thereafter), the fossil fuel-fired electricity generating units over 25 MW in the SIP call region are assumed to hold NOx allowances during the summer ozone season equal to 489 thousand tons
- Electricity generating units could trade allowances without restrictions or bank them for later use or sale to another generation unit Trading could occur within the entire SIP call region
- Analysis with and without flow controls

EPA's analysis in 1997 was conducted using the 1996 version of the Integrated Planning Model (IPM) This model is described in EPA, 1996 EPA's analysis shows that on strict economic grounds, (i e , under minimization of the total direct operating costs over the simulation period) limited banking was forecasted by the IPM based on the scenarios described above However, EPA believes that some banking, which the IPM could not estimate, should occur when some power plants overcontrol their NOx emissions in order to bank allowances for use in years in which units experience utilization greater than forecasted More discussion of this issue can be found in Chapter 6

2.2 Definition of Regulatory Alternatives

Based on the elements described above, EPA defined specific options for this analysis This section provides descriptions of the regulatory alternatives considered by EPA for each key NOx stationary source segment These regulatory alternatives are summarized in Tables 2-1 (for electricity generating units), Table 2-2 (for industrial boilers and combustion turbines), and Table 2-3 (for other large stationary sources) The NOx Budget Trading Program described in the final rule covers electricity generating units, industrial boilers, and combustion turbines The NOx Budget Trading Program described in the final rule does not initially include other large stationary sources, however, provisions are made for inclusion of these sources should States, or the sources themselves, express a desire to participate

Costs and economic impacts for each of these source segments are evaluated separately using different analysis techniques The electricity generating units are evaluated using the latest version of IPM (IPM98), which optimizes nationwide delivery of electricity subject to the SIP call emissions constraint The industrial boilers and combustion turbines are evaluated using a least-cost analysis designed to reach the specified emissions budget level at the lowest possible overall cost Finally, all other stationary sources are evaluated at the individual source category level The goal of the cost analyses is to determine what levels of reductions are highly cost-effective for each segment

At the same time that EPA considered each of the alternatives in each of the tables in setting up State budgets for ozone season NOx emissions, the Agency reviewed the public comments that it received in the Spring and Summer of 1998 The led EPA to reestimate what the NOx emissions budget for the electric power industry would be in the 0 15 Trading case, and what the budget would be for the 60%/$5,000 combination of non-electricity generating source alternatives These alternatives are the basis for EPA's final approach to setting the budget The NOx budget for the electric power industry was lowered from 564 thousand ozone season tons to 544 thousand ozone season tons of NOx The NOx budget for the other large stationary sources was increased from 558 thousand to 559 thousand ozone season tons of NOx An addendum to the RIA presents the final cost results and contains a more thorough explanation of how the emissions cap will work

Table 2-1
Regulatory Alternatives for Electricity Generating Units (EGU)

Name of Alternative	State Emissions Budgets Based on Ozone Season NOx Limit of:	NOx Emissions Budget (Cap) in Ozone Season (1,000 tons)	Scope of Emissions Trading
0.25 Trading	0.25 lb/mmBtu	940	Region wide
0.20 Trading	0.20 lb/mmBtu	751	Region wide
0.15 Trading	0.15 lb/mmBtu	564	Region wide
0.12 Trading	0.12 lb/mmBtu	453	Region wide
Regionality-1	Northeast[a] 0.15 lb/mmBtu Southeast-Midwest[b] 0.20 lb/mmBtu	222 454	Intra-regional only
Regionality-2	Northeast[c] 0.12 lb/mmBtu Midwest[d] 0.15 lb/mmBtu Southeast[e] 0.20 lb/mmBtu	100 297 189	Intra-regional only

[a] Northeast: Connecticut, Delaware, District of Columbia, Massachusetts, Maryland, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Virginia, and West Virginia
[b] Southeast-Midwest: Alabama, Georgia, Illinois, Indiana, Kentucky, Michigan, Missouri, North Carolina, South Carolina, Tennessee, and Wisconsin
[c] Northeast: Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island
[d] Midwest: Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Virginia, West Virginia, and Wisconsin
[e] Southeast: Alabama, Georgia, North Carolina, South Carolina, and Tennessee

Table 2-2
Regulatory Alternatives for Non-EGU Sources in the NOx Budget Trading Program
(Large Industrial Boilers and Combustion Turbines)

Name of Alternative	State Emissions Budgets Based on Ozone Season NOx Reduction of:	Scope of Emissions Trading
40% Control	40% from uncontrolled 2007 baseline	Region wide
50% Control	50% from uncontrolled 2007 baseline	Region wide
60% Control	60% from uncontrolled 2007 baseline	Region wide
70% Control	70% from uncontrolled 2007 baseline	Region wide

Table 2-3
Regulatory Alternatives for Non-EGU Sources NOT in the NOx Budget Trading Program[a]

Name of Alternative	State Emissions Budgets Based on Source Category-Specific Evaluation of the Highest Reduction Achievable for Less Than:	Scope of Emissions Trading
$1.500/ton	$1,500/ton	Not applicable
$2.000/ton	$2,000/ton	Not applicable
$3,000/ton	$3,000/ton	Not applicable
$4.000/ton	$4,000/ton	Not applicable
$5,000/ton	$5.000/ton	Not applicable

[a] E g . industrial manufacturing processes

2.3 References

OTAG. 1997a *Draft of Costs of NOx Control Strategies on Electric Power Generation Using the Integrated Planning Model* For incorporation into the OTAG Final Report, June 1997.

OTAG. 1997b *Trading and Incentives Work Group Report - Draft of OTAG Final Report* Chapter 7. June 1997

U S Environmental Protection Agency. 1996 *Analyzing Electric Power Generation under the CAAA* Office of Air and Radiation. Washington. D C . July 1996

U S. Environmental Protection Agency. 1997a *Proposed Ozone Transport Rulemaking Regulatory Analysis* Office of Air and Radiation. Washington. D C . September 1997

U S Environmental Protection Agency. 1997b *Model NOx Cap and Trade Rule Workshop Working Papers* Office of Atmospheric Programs. Washington. D C . December 1997

U S Environmental Protection Agency. 1998a *Analyzing Electric Power Generation under the CAAA* Office of Air and Radiation. Washington. D C . March 1998

U S Environmental Protection Agency, 1998b *Development of Modeling Inventory and Budgets for Regional NOx SIP Call* Office of Air Quality Planning and Standards. Research Triangle Park. September 1998

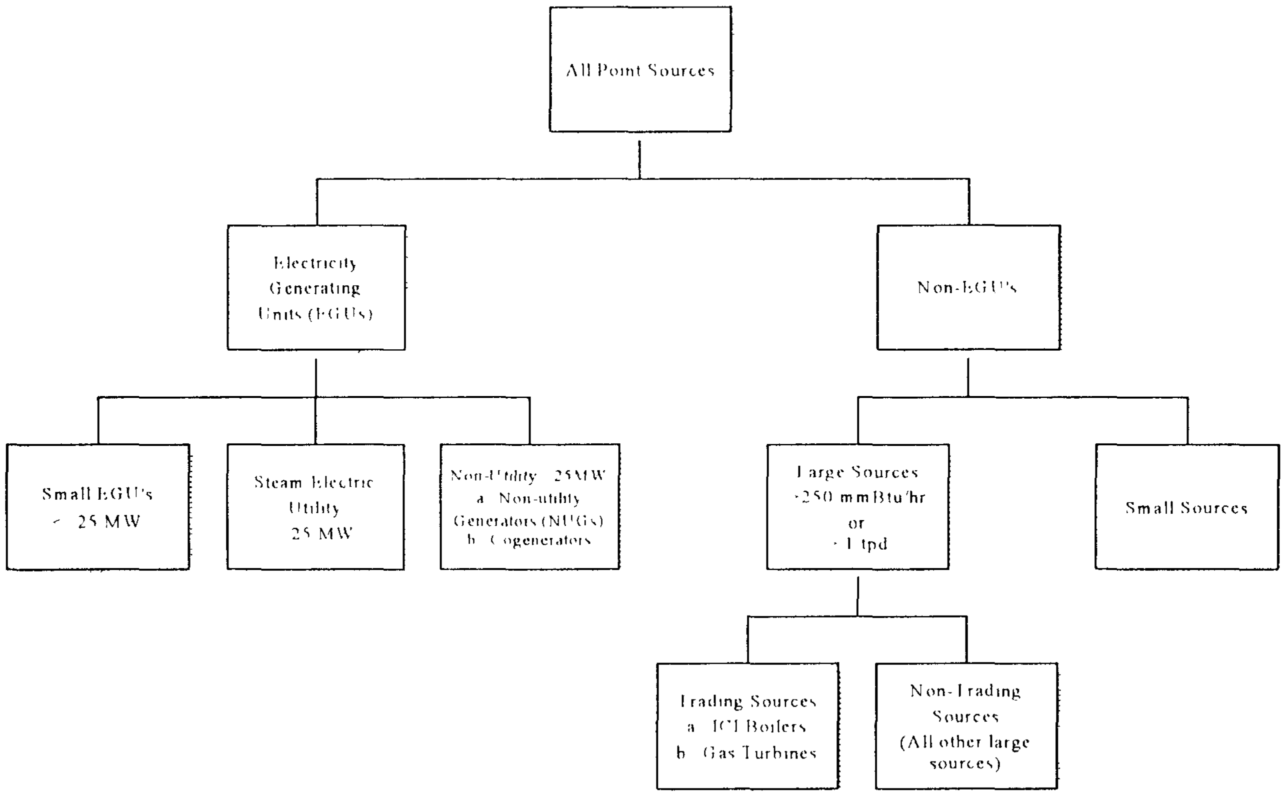
Chapter 3. PROFILE OF REGULATED ENTITIES

This chapter describes the sources potentially affected by the NOx SIP call Profiles of the sizes, types, locations, and NOx emissions characteristics of potentially affected electricity generating units, large industrial boilers and combustion turbines, and other stationary sources are presented The OTAG 1990 data base was the starting point for development of the inventory of sources considered in this report, and many updates to that database have been made by EPA (EPA, 1998) For the purpose of setting State emissions budgets under the NOx SIP call, EPA did not choose to apply new controls to all of the source types profiled in this chapter Under the NOx SIP call, States are free to choose which sources they will control in order to achieve the NOx budget specified in the NOx SIP call

Figure 3-1 illustrates how EPA has partitioned the universe of stationary sources for the analyses presented in this RIA EPA considered a number of factors in determining which sources to control for the purposes of establishing state emissions budgets First, as indicated in the proposed NOx SIP call, EPA has not assumed additional controls for sources defined as small In addition, EPA has determined that it would be inefficient to establish reductions for several non-EGU point source categories that emit a small amount of NOx relative to total point source NOx emissions These sources, found in 24 different source categories, comprise about 11 percent of total baseline large source non-EGU emissions, and about 6 percent of total baseline non-EGU emissions Further, for a number of sources, EPA was not able to identify an applicable control measure This group of sources is diverse and not subject to categorizing as part of the categories set out by EPA, and total emissions are low for this group The Agency has determined that the effort needed to collect adequate information on those sources (about 6,000 small and 258 large) would be time consuming, uncertain, and potentially affect less than five percent of total non-EGU baseline point source emissions, and therefore has not assumed any additional control for these sources for the purposes of setting State budgets Also, EPA has determined that municipal waste combustors should not be required to reduce emissions beyond those already required by the maximum achievable control technology (MACT) rules for NOx required under section 111 and 129 of the CAA Finally, the Agency is not assigning emissions reductions in this rulemaking for industrial boilers that are not fossil-fuel fired in order to be consistent with the treatment of fossil-fuel fired electricity generating units in the NOx Budget Trading Program

For the remaining source categories, EPA is basing emissions control decisions on the relative average cost-effectiveness of achieving NOx reductions during the ozone season The methodology used to analyze the cost and average cost-effectiveness of alternative control levels is discussed in Chapters 4 and 5 The analysis and results supporting these decisions are found in Chapters 6 and 7

Figure 3-1
Partitioning of NOx SIP Call Stationary Sources



3.1 Electricity Generating Units

In 1990, approximately 2.8 trillion kilowatt hours (kWh) of electricity were generated in the United States and were used in roughly equal proportions by industry, commercial establishments, and households. By 2005, EPA projects this total to increase to about 3.6 trillion kWh.[1] Most of this electricity, almost 70 percent, is generated at fossil-fuel-fired power plants, with coal accounting for most of the fossil fuel used in these plants.

More than 95 percent of the nation's generating capacity is owned by the electric utilities. Although utilities are generally granted monopolies for their service territories, the rates that the utilities may charge are regulated by the authorities that grant the monopoly (known as a "franchise"). Rates for investor-owned utilities have theoretically been set high enough to cover all reasonably incurred costs, including capital investments, and to provide an allowance for a reasonable rate of return on invested capital. This arrangement has insulated, to a large extent, most large producers of electricity from some of the effects of the market as well as from regulatory costs. A changing regulatory and economic environment, however, is eroding this insulation. In the future, utilities are expected to be much less able to pass on their emission control costs.

A significant portion of the nation's electricity generating industry is in the region affected by the NO_x SIP call. EPA estimates that 2,014 units will be operating in this region in the year 2000. In addition to electric utility power units that produce only electricity, this number includes units owned by independent power producers (IPPs). This number also includes units that co-generate electricity and steam (co-generators), whether owned by utilities or IPPs. Table 3-1 presents the number of fossil-fueled units by capacity range and type (i.e., coal, oil/gas steam, combined cycle, combustion turbine). Approximately 64 percent of the affected fossil-fueled electric utility units have capacities that are less than or equal to 100 megawatt (MW). Less than one percent are greater than 1,000 MW. Table 3-2 presents the distribution of these units as a percentage by type within each capacity range. About 41 percent of these units are coal powered, providing approximately 72 percent of fossil-fueled capacity. Approximately 45 percent are combustion turbines, which provide about 10 percent of the capacity of all these units. The table indicates that coal powered units make up the majority of the capacity of all units.

[1] EPA's generation requirement projections are based on an extension of the electric demand forecast of the North American Electric Reliability Council, adjusted for the impact of the Climate Change Action Plan.

Table 3-1
Distribution of Capacities of Potentially Affected Electricity Generating Utility Units by Type in the Year 2000

	Coal/Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total	
Boiler Capacity	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
0-25 MW	51	789	15	256	569	4,844	33	312	668	6,201
>25-100 MW	213	14,441	62	3,685	304	17,439	38	2,661	617	38,227
>100-200 MW	238	34,834	20	2,910	32	4,200	42	5,815	332	47,760
>200-400 MW	151	42,785	8	2,065	6	1,611	22	7,488	187	53,949
>400-600 MW	93	48,605	0	0	1	500	15	7,479	109	56,584
>600-800 MW	50	34,550	2	1,327	0	0	11	7,274	63	43,150
>800-1000MW	16	13,831	0	0	0	0	7	5,994	23	19,824
> 1000 MW	12	14,802	2	2,093	0	0	0	0	14	16,895
Total	824	204,635	109	12,337	912	28,594	168	37,023	2,013	282,589

Source IPM data ICF Resources

Table 3-2
Distribution of Capacities of Potentially Affected Electricity Generating Utility Units in the Year 2000

	Coal/Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total	
Unit Capacity (MW)	% of Units in Capacity Range	% of Capacity in Capacity Range	% of Units in Capacity Range	% of Capacity in Capacity Range	% of Units in Capacity Range	% of Capacity in Capacity Range	% of Units in Capacity Range	% of Capacity in Capacity Range	% of Units in Capacity Range	% of Capacity in Capacity Range
0-25	8	13	2	4	85	78	5	5	100	100
>25-100	35	38	10	10	49	46	6	7	100	100
>100-200	72	73	6	6	10	9	13	12	100	100
>200-400	81	79	4	4	3	3	12	14	100	100
>400-600	85	86	0	0	1	1	14	13	100	100
>600-800	79	80	3	3	0	0	17	17	100	100
>800-1000	70	70	0	0	0	0	30	30	100	100
> 1000	86	88	14	12	0	0	0	0	100	100
Total	41	72	5	4	45	10	8	13	100	100

Source IPM data, ICF Resources

Table 3-3 shows the geographic distribution and the total capacity of the affected electricity generating units by type (coal, combined cycle, combustion turbine, and oil/gas steam) among the States in the SIP call region Table 3-4 presents the same information in percentage terms All States except Rhode Island and the District of Columbia have coal-powered units and, for many States, coal-powered units make up the majority of the capacity of all units The District of Columbia and West Virginia do not have any combustion turbine units Further, many States do not have combined-cycle units

Table 3-5 shows the distribution of electricity generating units by type and by NOx emission rate. The rates in this table are based upon initial base case controls, which include existing Title IV controls, Reasonably Available Control Technology requirements, New Source Performance Standards (NSPS) for new and recently-built power plants, and implementation of Phase I of the Ozone Transport Commission Memorandum of Understanding (MOU) As shown in Table 3-5, over half of all the units analyzed fall in the range of 0 to 0.2 lbs NOx/mmBtu These units provide about one quarter of capacity in the SIP call region More than half of the capacity emits more than 0 4 lbs of NOx/mmBtu The table also shows that a significant majority of combined cycle, combustion turbine, and oil/gas steam units, in both number and capacity, fall in the lower ranges of NOx emission rates

Table 3-3
Distribution of Capacities of Affected
Electricity Generating Utility Units (>25 MW) by State
in the Year 2000

	Coal/Gas		**Combined Cycle**		**Combustion Turbine**		**Oil/Gas Steam**		**Total**	
State	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
Alabama	39	11.515	2	257	17	1,088	0	0	58	12.860
Connecticut	2	565	1	50	11	304	14	2.552	28	3.471
Delaware	7	996	2	287	8	311	4	571	21	2.165
D C	0	0	0	0	0	0	2	550	2	550
Georgia	34	13,141	0	0	35	2.105	5	301	74	15.547
Illinois	59	15.798	0	0	47	435	16	3,284	122	19.517
Indiana	68	18.899	0	0	27	927	2	12	97	19,838
Kentucky	55	13,944	0	0	15	1.391	1	115	71	15.450
Maryland	14	4,609	3	421	31	1.275	8	2.274	56	8.579
Massachusetts	10	1.748	13	1,125	38	757	12	3,866	73	7.496
Michigan	68	11,575	2	1.078	75	586	12	2.638	157	15.877
Missouri	43	10.899	1	98	137	2,371	2	60	183	13,428
New Jersey	9	2.055	23	2,741	43	3.339	17	2,292	92	10.426
New York	27	3.730	30	3.253	98	2.719	43	13,032	198	22.734
North Carolina	49	12.699	14	487	31	1.501	1	42	95	14 728
Ohio	90	22.201	3	196	47	1.287	8	207	148	23.891
Pennsylvania	74	18.380	7	437	39	1.200	15	3.393	135	23.411
Rhode Island	0	0	0	0	7	506	0	0	7	506
South Carolina	32	5.909	0	0	43	1.371	0	0	75	7.281
Tennessee	37	8.615	0	0	40	1.568	0	0	77	10.183
Virginia	32	5,762	8	1,907	51	1,300	6	1,834	97	10.803
West Virginia	36	14,485	0	0	0	0	0	0	36	14.485
Wisconsin	39	7,110	0	0	72	2,253	0	0	111	9,363
Total	824	204,635	109	12,337	912	28,594	168	37,023	2.013	282.589

Source IPM data. ICF Resources

Table 3-4
Distribution of Capacities of Affected Electricity Generating Utility Units by State by Percentage in the Year 2000

	Coal/Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total	
State	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units	% of Capacity
Alabama	67.2	89.5	3.4	2.0	29.3	8.5	0.0	0.0	100	100
Connecticut	7.1	16.3	3.6	1.4	39.3	8.7	50.0	73.5	100	100
Delaware	33.3	46.0	9.5	13.3	38.1	14.4	19.1	26.4	100	100
Dist. of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100	100
Georgia	46.0	84.5	0.0	0.0	47.3	13.5	6.8	1.9	100	100
Illinois	48.4	80.9	0.0	0.0	38.5	2.2	13.1	16.8	100	100
Indiana	70.1	95.3	0.0	0.0	27.8	4.6	2.0	0.1	100	100
Kentucky	77.5	90.3	0.0	0.0	21.1	9.0	1.4	0.7	100	100
Maryland	25.0	53.7	5.4	4.9	55.4	14.9	14.3	26.5	100	100
Massachusetts	13.7	23.3	17.8	15.0	52.1	10.1	16.4	51.6	100	100
Michigan	43.3	72.9	1.3	6.8	47.8	3.7	7.7	16.6	100	100
Missouri	23.5	81.2	0.6	0.7	74.9	17.7	1.1	0.5	100	100
New Jersey	9.8	19.7	25.0	26.3	46.7	32.0	18.5	22.0	100	100
New York	13.6	16.4	15.2	14.3	49.5	12.0	21.7	57.3	100	100
North Carolina	51.6	86.2	14.7	3.3	32.6	10.2	1.1	0.3	100	100
Ohio	60.8	92.9	2.0	0.8	31.8	5.4	5.4	0.9	100	100
Pennsylvania	54.8	78.5	5.2	1.9	28.9	5.1	11.1	14.5	100	100
Rhode Island	0.0	0.0	0.0	0.0	100.0	100.0	0.0	0.0	100	100
South Carolina	42.7	81.2	0.0	0.0	57.3	18.8	0.0	0.0	100	100
Tennessee	48.1	84.6	0.0	0.0	51.9	15.4	0.0	0.0	100	100
Virginia	33.0	53.3	8.2	17.7	52.6	12.0	6.2	17.0	100	100
West Virginia	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	100	100
Wisconsin	35.1	75.9	0.0	0.0	64.9	24.1	0.0	0.0	100	100

Source: IPM data, ICF Resources

Table 3-5
Distribution of Fossil-Fueled Units Analyzed for Rulemaking
by Initial Base Case NOx Emission Rate
in the Year 2000

Initial Base Case Emission	**Coal/Steam**		**Combined Cycle**		**Combustion Turbine**		**Oil/Gas Steam**		**Total**	
(lbs NOx/mmBtu)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
0 000-0 100	4	353	16	2,040	118	5,472	12	1,810	150	9,675
0 101-0 200	56	4,797	90	10,162	783	22,736	85	25,522	1,014	63,217
0 201-0 300	21	5,503	0	0	3	136	59	9,302	83	14,941
0 301-0 400	184	44,203	0	0	2	75	8	350	194	44,628
0 401-0 500	374	102,190	3	135	3	90	0	0	380	102,415
0 501-0 600	16	999	0	0	1	2	4	39	21	1,040
0 601-0 700	40	22,488	0	0	1	62	0	0	41	22,550
0 701-0 800	21	2,907	0	0	0	0	0	0	21	2,907
0 801-0 900	82	19,598	0	0	0	0	0	0	82	19,598
0 901-1 000	13	887	0	0	0	0	0	0	13	887
>1 000	13	779	0	0	1	21	0	0	14	800
Total	824	204,635	109	12,337	912	28,594	168	37,023	2,013	282,589

Source IPM data. ICF Resources

3.2 Industrial Boilers and Gas Turbines

This section provides information on industrial boilers and combustion turbines, including the types of fuels they use and their emissions, as well as a description of the industries that own them Sources are classified by unit design capacity Only large sources (as defined in Chapter 2) are assumed to be potentially affected by controls that may be implemented by a State to meet its NOx budget level

The following types of sources are described in this section

- **Industrial, Commercial, and Institutional Boilers** - Industrial/commercial/ institutional (ICI) boilers include steam and hot water generators with heat input capacities from 0 4 to 1,500 mmBtu/hr These boilers are used in a range of applications, from commercial space heating to process steam generation, in all major industrial sectors Although coal, oil, and natural gas are the primary fuels, many ICI boilers also burn a variety of industrial, municipal, and agricultural waste fuels

- **Stationary Combustion Turbines** - Turbines are used in electric power generators, in gas pipeline pump and compressor drives, and in various process industries This section includes turbines other than those used for electricity generation The primary fuels used are natural gas and distillate oil, although residual fuel oil is used in a few applications

Industrial boilers are owned and operated by a wide variety of industries, from traditional manufacturing to service industries like medical care and education. Thirty of the two-digit "major groups" in the Standard Industrial Classification (SIC) system include establishments with industrial boilers. The industries with the most industrial boilers are: chemicals, paper, petroleum, and primary metals. Table 3-6 shows the industry distribution of large industrial boilers and turbines in the 22 States plus D.C.

Table 3-7 presents a breakdown of industrial, commercial, and institutional boilers by primary fuel type. (All ICI boilers are referred to as industrial boilers in this RIA.) Natural gas fired boilers account for the largest percentage of industrial boilers, with 36 percent of all boilers. Coal and oil industrial boilers make up the rest of the industrial boilers, with 30 percent and 12 percent of total boilers respectively. Approximately 22 percent of the industrial boilers are listed as "other." Other industrial boilers include wood and wood wastes, pulping liquor, and waste gases. During the mid 1980s there was a trend towards use of dual-fuel boilers, where the preferred configuration was a natural gas system with a fuel oil back up.

Finally, Table 3-8 shows the distribution of large fossil-fuel fired industrial boilers and combustion turbines by state. For two industrial boilers, the data was not available to match a state with the source.

Table 3-6
Number of Fossil-Fuel Fired Industrial Boilers and Combustion Turbines by Industry[a]
1995 Data

SIC	Industry	Number of Boilers	Number of Turbines
10	Metal mining	1	0
20	Food and kindred products mfgr	50	0
21	Tobacco products mfgr	8	0
22	Textile mill products	11	0
24	Lumber & wood products, exc furniture	1	0
25	Furniture & fixtures	5	0
26	Paper and allied products	153	4
27	Printing & publishing	3	0
28	Chemicals & allied products	187	2
29	Petroleum refining and related industries	45	2
30	Rubber & plastics products	10	0
32	Stone, clay, glass & concrete products	5	0
33	Primary metal industries	138	0
34	Fabricated metal products, exc machinery & trans equip	5	0
35	Industrial & commercial machinery & computer equip	11	0
36	Electronic & other elec equip , exc computer equip	5	0
37	Transportation equipment	21	1
38	Measuring inst , photo, med & opt goods, clocks	4	0
39	Miscellaneous manufacturing industries	7	0
49	Electric, gas, and sanitary services	34	43
51	Wholesale Trade - nondurable goods	1	0
72	Personal services	1	0
79	Amusement and recreation services	3	0
80	Health services	6	0
89	Miscellaneous services	1	0
Federal Government		18	0
Other Government		7	0
Colleges/Universities		14	0
Total		*755*	*52*

Source Pechan-Avanti Group
a Excludes 90 large non-fossil fuel fired boilers and turbines

Table 3-7
Number of Large Fossil-Fuel Fired Boilers and Combustion Turbines by Fuel*
1995 Data

Source Type - Fuel Type	Number of Sources
ICI Boilers - Coal/Wall	166
ICI Boilers - Coal/FBC	6
ICI Boilers - Coal/Stoker	69
ICI Boilers - Coal/Cyclone	8
ICI Boilers - Residual Oil	75
ICI Boilers - Distillate Oil	26
ICI Boilers - Natural Gas	307
ICI Boilers - Process Gas	86
ICI Boilers - Coke	10
ICI Boilers - LPG	2
Total ICI Boilers	***755***
Combustion Turbines - Oil	22
Combustion Turbines - Natural Gas	28
Combustion Turbines - Jet Fuel	2
Total Combustion Turbines	***52***
Total ICI Boilers and Combustion Turbines	***807***

Source Pechan-Avanti Group
* Excludes 90 large non-fossil fuel fired boilers and turbines

Table 3-8
Number of Large Fossil-Fuel Fired Industrial Boilers and Combustion Turbines by State*
1995 Data

State	Number of Industrial Boilers	Number of Combustion Turbines
Alabama	51	1
Connecticut	12	2
Delaware	6	0
District of Columbia	5	0
Georgia	15	0
Illinois	64	7
Indiana	60	2
Kentucky	22	1
Maryland	7	0
Massachusetts	11	0
Michigan	38	5
Missouri	11	0
New Jersey	64	3
New York	48	23
North Carolina	23	0
Ohio	88	0
Pennsylvania	39	4
Rhode Island	0	0
South Carolina	36	1
Tennessee	49	2
Virginia	37	0
West Virginia	30	0
Wisconsin	36	1
Unknown	2	0
Total	**755**	**52**

Source Pechan-Avanti Group
* Excludes 90 large non-fossil fuel fired boilers and turbines

3.3 Other Stationary Sources

Other major stationary sources of NOx emissions include the following

- **Stationary Internal Combustion Engines** - These units generate electric power, pump gas or other fluids, or compress air for pneumatic machinery The primary nonutility application of internal combustion (IC) engines is in the natural gas industry to power compressors used for pipeline transportation, field gathering (collecting gas from wells), underground storage, and in gas processing plants Reciprocating engines are separated into three design classes 2-cycle (stroke) lean burn, 4-stroke lean burn, and 4-stroke rich burn Each of these have design differences that affect both baseline emissions as well as the potential for emissions control

- **Cement Manufacturing Operations** - There are four types of kilns that produce cement, long wet, long dry, kilns with a preheater, and kilns with a precalciner Long wet kilns use a production process where the raw materials are suspended in water to form a slurry Long dry kilns and kilns with a preheater or a precalciner use a dry production process, wherein raw cement materials are dried to a powder Each of these types of kilns have design differences that affect both baseline emissions as well as the potential for emissions control

- **Other Industrial Processes** - Some industrial processes emit NOx Examples include furnaces at iron and steel mills, glass furnaces, process heaters at chemical plants and petroleum refineries, nitric acid plants, and adipic acid plants

Tables 3-9 and 3-10 show the industry and state distribution, respectively, of the various types of large stationary sources, other than electricity generating units and industrial boilers and combustion turbines Note these figures do not include non-EGU sources for which EPA was unable to identify applicable control technologies (see section 3 4)

Table 3-9
Number of Large Other Stationary Sources by Industry
1995 Data

SIC	Industry	IC Engines	Cement Manu-facturing	Other Indus-trial Sources[b]	Total
14	Non-metal, non-fuel mining/quarrying	7	0	1	8
20	Food and kindred products mfgr	0	0	3	3
22	Textile mill products	0	0	6	6
24	Lumber & wood products, exc furniture	0	0	12	12
25	Furniture & fixtures	1	0	0	1
26	Paper and allied products	0	0	202	202
28	Chemicals & allied products	0	0	39	39
29	Petroleum refining and related industries	1	0	21	22
30	Rubber & plastics products	1	0	2	3
32	Stone, clay, glass & concrete products	0	58	45	103
33	Primary metal industries	0	0	72	72
35	Industrial & commercial machinery & computer equip	0	0	1	1
37	Transportation equipment	0	0	7	7
45	Transportation by air	0	0	1	1
49	Electric, gas, and sanitary services [a]	286	0	83	369
51	Wholesale Trade - nondurable goods	1	0	1	2
80	Health services	1	0	5	6
87	Engineering, accounting, research, mgmt, & related srvcs	0	0	3	3
89	Miscellaneous services	0	0	1	1
Federal Government		5	0	4	9
Other Government		2	0	17	19
Colleges/Universities		0	0	0	0
Total		**305**	**58**	**526**	**889**

Source Pechan-Avanti Group
[a] Non-EGU's classified within SIC 4911 are included in this estimate These are co-generation units that supply less than 50% of their generated power to the electric power grid
[b] Includes 90- large non-fossil fuel fired industrial boilers and combustion turbines

Table 3-10
Number of Large Other Stationary Sources by State
1995 Data

State	IC Engines	Cement Manufacturing	Other Industrial Sources[a]	Total
Alabama	36	5	88	129
Connecticut	0	0	7	7
Delaware	0	0	6	6
District of Columbia	0	0	0	0
Georgia	2	3	60	65
Illinois	30	2	31	63
Indiana	42	8	41	91
Kentucky	2	1	14	17
Maryland	3	9	16	28
Massachusetts	0	0	15	15
Michigan	47	5	48	100
Missouri	6	7	16	29
New Jersey	0	0	4	4
New York	0	3	22	25
North Carolina	6	0	28	34
Ohio	12	5	19	36
Pennsylvania	9	2	13	24
Rhode Island	0	0	0	0
South Carolina	11	0	48	59
Tennessee	48	3	34	85
Virginia	9	2	31	42
West Virginia	35	3	21	59
Wisconsin	7	0	23	30
Total	**305**	**58**	**526**	**889**

Source Pechan-Avanti Group
[a] Includes 90 large non-fossil fueled fired industrial boilers and combustion turbines

3.4 Other NOx Sources

A variety of sources of NOx emissions are not addressed in this RIA because it is assumed that they will not be subject to new controls in the States' revised SIPs Among the other stationary sources not addressed in this RIA are all small stationary sources (e g small industrial boilers), sources for which control information could not be identified, and sources already receiving highly cost-effective NOx controls under other rulemakings (e g , municipal waste combustors affected by the 1994 MACT standard) Other sources of NOx emissions which are assumed not to be subject to new controls include

- **Area Sources** - Area sources are small point sources that include open burning and small commercial, industrial and residential fuel combustion sources

- **Mobile Sources** - This category is divided into highway vehicles and nonroad sources Highway vehicle sources include cars, trucks, buses, and motorcycles with gas and diesel highway engines Nonroad sources include commercial marine engines, small engines such as lawn and garden equipment, and larger engines such as those used in construction equipment and locomotives

EPA did not identify additional controls beyond those in the 2007 baseline case for the area, mobile and nonroad source categories at less than $2,000 per ton, nor did EPA receive comments during the public comment period suggesting that such feasible, cost-effective controls should be implemented Therefore, EPA did not calculate additional emissions budget decreases nor propose rules for these source categories

There is a large, diverse set of non-EGU sources that meet the large source size definition for which EPA was not able to identify applicable control technologies Table 3-11 indicates the industries in which these sources operate, as well as the total number of non-EGU sources (i e , both those sources for which control technology is known and not known) in each industry

Table 3-11
Number of Total and "No Control" Non-EGU Sources by Industry
1995 Data

SIC	Industry	No Control Sources	Total Sources
10	Metal mining	4	4
13	Oil and gas extraction	1	1
14	Non-metal, non-fuel mining/quarrying	1	9
20	Food and kindred products mfgr	4	7
22	Textile Mill Products	0	6
24	Lumber & wood products, exc furniture	2	14
25	Furniture & fixtures	0	1
26	Paper and allied products	65	267
28	Chemicals & allied products	34	73
29	Petroleum refining and related industries	6	28
30	Rubber & plastics products	0	3
32	Stone, clay, glass & concrete products	7	110
33	Primary metal industries	49	111
34	Fabricated metal products, exc machinery & trans equip	2	2
35	Industrial & commercial machinery & computer equip	1	2
37	Transportation equipment	65	72
38	Measuring inst., photo, med & opt goods, clocks	1	1
45	Transportation by air	1	2
49	Electric, gas, and sanitary services[a]	7	376
51	Wholesale Trade - nondurable goods	2	3
80	Health services	1	7
87	Engineering, accounting, research, mgmt. & related srvcs	1	4
89	Miscellaneous services	1	2
Federal Government		2	11
Other Government		0	21
Colleges/Universities		1	1
Total		**258**	**1,138**

Source Pechan-Avanti Group
[a] Non-EGU's classified within SIC 4911 are included in this estimate These are co-generation units that supply less than 50% of their generated power to the electric power grid

3.5 Overview of Baseline Emissions

Table 3-12 provides an overview of the contribution of various NOx sources to total baseline NOx emissions in the 22 States and D C. This table shows that large sources that are potentially subject to new requirements under the SIP call (including electricity generating units, industrial boilers, combustion turbines, internal combustion engines, and cement manufacturing operations) account for approximately 43 percent of the total projected baseline emissions in these States

Table 3-12
Overview of 2007 Baseline Ozone Season NOx Emissions in the SIP Call Region

Source Category	Baseline Ozone Season NOx Emissions			Percent of Total Baseline Ozone Season NOx Emissions[a]
	Large Units	Small Units	Total	
Electricity Generating Units	1.497,061	4,714	1.501,775	35%
Industrial Boilers[b]	203.883	139.569	343,452	8%
Combustion Turbines	5.809	4.926	10.735	0 3%
Internal Combustion Engines	92.424	54.885	147.309	3%
Cement Manufacturing	42.701	13.868	56.569	1%
Other non-EGU Source Categories	101.964	41.268	143.232	3%
"No Control" Sources[c]	34.832	32.845	67,677	2%
Area/Mobile/Nonroad Sources	na	1,981.845	1.981,845	47%
Total	**na**	**na**	**4,252,594**	**100.0%**

Source ICF, Pechan-Avanti Group and SNPR
na = not estimated or not applicable
[a] Due to rounding percentages do not add to exactly 100%
[b] Includes baseline emissions for the 90 large non-fossil fuel fired industrial boilers that are not affected in this rule
[c] Non-EGU units for which EPA was not able to identify control measures

3.6 References

Abt Associates. Inc., 1998 *Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call* Prepared for the U S Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1998

U.S. Environmental Protection Agency, 1998 *Development of Modeling Inventory and Budgets for Regional NOx SIP Call.* Office of Air Quality Planning and Standards. Research Triangle Park, NC, September 1998

Chapter 4. METHODOLOGY FOR ESTIMATING EMISSIONS, COSTS, AND ECONOMIC IMPACTS FOR THE ELECTRIC POWER INDUSTRY

This chapter presents the methodology for estimating the costs, emission reductions, and impacts of the NOx SIP call for the electric power industry The chapter is divided into eight sections, beginning with an analytical overview in Section 4 1 Section 4 2 discusses the use of the Integrated Planning Model (IPM) for the analysis, including assumptions about the baseline and about technologies for power generation and emission control Allowance allocation and trading issues are presented in Section 4 3, and the estimation of administrative costs is discussed in Section 4 4 These discussions are followed by Sections 4.5 and 4 6, which outline the analysis of potential direct and indirect economic impacts Limitations of the analysis are presented in Section 4.7, and references are presented in Section 4 8 of the chapter.

4.1 Analytical Overview

The basic approach to estimating the potential effects of the NOx SIP call on electricity producers is to project their actions in the absence of the rule, project their actions if they were subject to the rule, and then compare the two sets of actions Subtracting the total costs of generating electricity in the absence of the rule from the total costs under the rule, for example, yields the total costs of the rule itself if States and sources follow the implementation approach modeled in this report Similarly, subtracting estimated emissions, generation, and capacity yield the effects of the rule in these three areas

The scope of these analyses is wide both geographically and in terms of time While the focus of the rule is on the 23 jurisdictions affected by the NOx SIP call, the analysis projects the actions of utilities (and non-utility generators) in all 48 contiguous States in order to capture effects that can spill out of one region into neighboring areas Rather than examining only a snapshot in time, the analysis covers a period starting in 2001 and running out to 2025 Examining the industry over many years makes it possible to take many important dynamic effects into account For example, the effects of efficiency gains over time and the choice between capital-intensive control measures and measures that increase operating costs can be investigated by projecting utility response over a long analytical period In addition, the effects of allowing the banking of emission reductions can be analyzed only in a dynamic framework

The actions of electricity generators over time are projected using the IPM, which is a detailed computer model of the electric power industry IPM is designed to find the most efficient (that is, the least-cost) way to satisfy the demand for electricity under a series of limitations or constraints The constraints under which IPM "produces" electricity can include a limit on tons of NOx emissions during the summer, and it is by setting this constraint that the effects of the NOx SIP call can be modeled Running IPM without a limit on tons of NOx emissions produces a picture of the baseline situation in which the NOx SIP call is not in effect Rerunning IPM after adding a constraint that limits emissions in the SIP call region to a specified number of summer tons (e.g , 564,000, under the 0 15 option) shows what the industry would do to comply with the NOx SIP call while keeping its costs as low as possible Additional runs with different sets of constraints are conducted to assess other options, while additional runs with different assumptions make it possible to test the sensitivity of the results More detail on how IPM operates is provided in Section 4 2 below and in *Analyzing Electric Power Generation Under the CAAA,* Office of Air and Radiation, U S Environmental Protection Agency, March 1998 This information and the model runs conducted for the analysis can also be found at an EPA website with the address: http //www epa gov/capi

The IPM runs for the baseline and the various options constitute the heart of the analysis Before the results can be presented, however, additional analyses must be conducted to interpret these runs For example, in some cases it is necessary to aggregate the detailed results into totals by State and region, or to divide the cost changes by emission changes to estimate cost effectiveness In addition, tracing the potential economic impacts of changes in costs and electricity prices beyond the electricity generating industry is outside of the scope of IPM, and must be done using standard techniques of economic impact assessment (discussed in Sections 4 5 and 4 6)

4.2 IPM Assumptions and Use

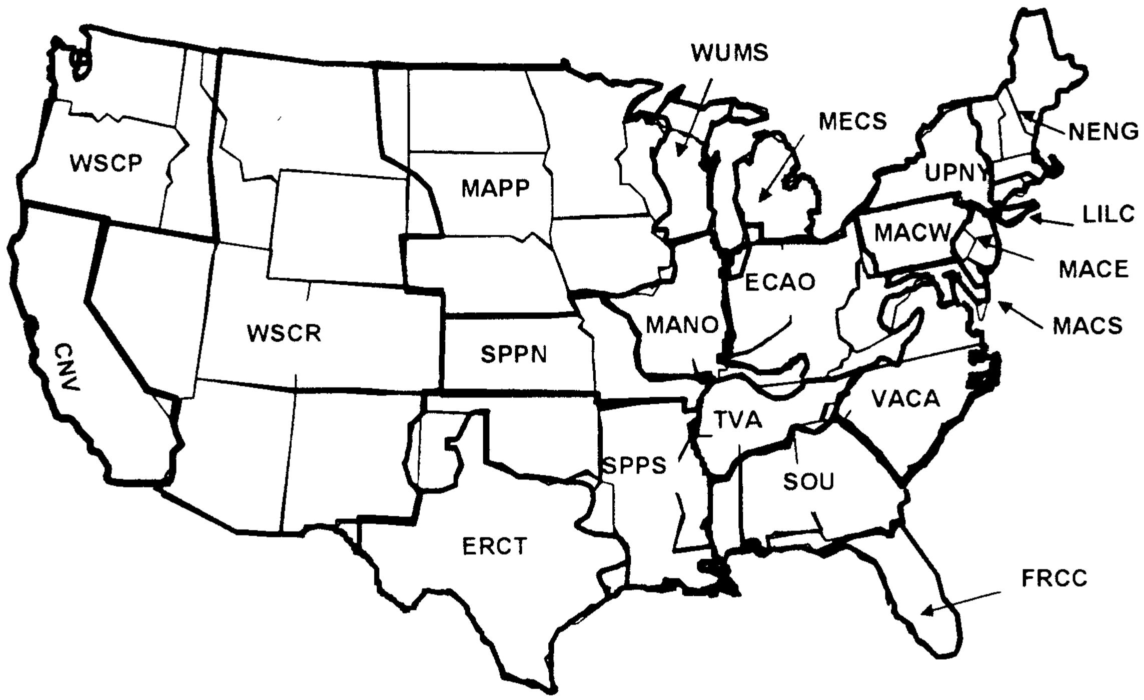
EPA uses IPM to evaluate the emissions and potential cost impacts expected to result from the requirements of the NOx SIP call on the electric power industry, based on EPA's illustrative implementation scenario IPM has been used for over ten years by electric utilities, trade associations, and government agencies both in the U S and abroad to address a wide range of electric power market issues The applications have included capacity planning, environmental policy and compliance planning, wholesale price forecasting, and asset valuation EPA has used IPM extensively for environmental policy and regulatory analysis In particular, EPA has used IPM to analyze NOx emission policy and regulations as part of the Clean Air Power Initiative (CAPI) in 1996, as an analysis tool for the Regulatory Impact Analysis of the National Ambient Air Quality Standards (NAAQS) for ozone and particulates in 1997, and as a tool to analyze alternative trading and banking programs during the OTAG process in 1996 and 1997 IPM was also used for the regulatory analysis of the NPR

IPM has undergone extensive review and validation over this ten-year period In April 1996, EPA requested participants in the CAPI process to comment on the Agency's new approach to forecasting electric power generation and selected air emissions EPA received many helpful comments and made a series of changes in its methodology and assumptions based on commenters' recommendations Most recently, IPM and EPA's modeling assumptions were reviewed as part of the OTAG process Again, changes were made to the methodology and assumptions based on commenters' recommendations

The version of IPM used by EPA (IPM98) represents the U S electric power market in 21 regions, as depicted in Figure 4-1 These regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC) IPM models the electricity demand, generation, transmission, and distribution within each region as well as the transmission grid that connects the regions

The model includes existing utility power plants as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market Data on the existing boiler and generator population, which consists of close to 8,000 records, are maintained in EPA's National Electric Energy Data System (NEEDS). In order to make the modeling more time and cost efficient, the individual boiler and generator data are aggregated into "model" plants EPA's application of the model has focused heavily on understanding the future operations of coal-fired units, which will have the greatest air emissions among the fossil-fired units The operation of other types of non-fossil fuel-fired generation capacity, including nuclear and renewables, are also simulated but at a higher degree of aggregation

Figure 4-1
Integrated Planning Model Regions in the Configuration Used by EPA



Working with these existing model plants and representations of alternative new power plant options, IPM determines the least-cost means for supplying electricity demand while limiting air emissions to remain below specified policy limits Multiple air emissions policies can be modeled simultaneously For example, IPM is used in this study to simulate compliance with existing CAAA Title IV SO_2 emission requirements as well as actions that EPA has considered for controlling the ozone season NOx emissions in the States covered by the NOx SIP call While determining the least-cost solution, IPM also determines the optimal compliance strategy for each model plant A wide range of compliance options are evaluated, including the following

- Fuel Switching - For example, switching from high sulfur coal to low sulfur coal.
- Repowering - For example, repowering an existing coal plant to a gas combined-cycle plant
- Pollution Control Retrofit - For example, installing selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or gas reburn (to reduce NOx emissions), or flue gas desulfurization (to control SO_2 emissions).
- Economic Retirement - For example, retiring an oil or gas steam plant

- Dispatch Adjustments - For example, running high-NOx cyclone units less often, and low NOx combined-cycle plants more often

IPM provides estimates of air emission changes, incremental electric power generation costs, changes in fuel use, and other potential impacts for each air pollution policy analyzed

The model is not limited in scope to facilities owned by electric utilities, but also includes independent power producers (IPP) that provide electricity to the power grid on a firm-contract basis, as well as IPP facilities larger than 25 megawatts that provide power on a non-firm basis

IPM simultaneously models over an extended time period, and reports results for selected years In addition to reporting for 2003, which is the year that the regulatory approach would begin, these analyses also provide results for 2001, 2005, 2007, and 2010

In using IPM to analyze NOx emission policy over the past two years, EPA has developed a set of data and assumptions that reflect the best available information on the electricity market and operating factors These data and assumptions can be grouped into the following four categories

- **Macro Energy and Economic Assumptions** - These assumptions are related primarily to electricity demand projections, fuel prices, power plant availability, heat rates, lifetimes, and capacity factors Also included in this category are discount rate and year dollar assumptions

- **Electric Technology Cost and Performance** - These assumptions are related to electric technology cost and performance for existing and new plants, as well as for existing plant refurbishment and repowering

- **Pollution Control Performance and Costs** - These assumptions primarily cover the performance and unit costs of pollution control technologies for NOx and SO_2

- **Air Emissions Rates under the Base Case** - These assumptions cover current EPA and State requirements that will affect emission levels from various facilities The focus has been on SO_2 and NOx controls

Each of these sets of data and assumptions are briefly discussed below More detail can be found in EPA's March 1998 report entitled *Analyzing Electric Power Generation under the CAAA*

4.2.1 Macro Energy and Economic Assumptions

In developing the analysis for the NOx SIP call, EPA makes assumptions about major macro energy and economic factors, as shown in Table 4-1 See Appendix No. 2 of EPA's March 1998 report *Analyzing Electric Power Generation under the CAAA* for details on most of the macro energy and economic factors

In this study, IPM's cost outputs are converted from real 1997 dollars to real 1990 dollars to be consistent with the cost analyses prepared for the proposed NOx SIP call and the Agency's recently published Regulatory Impact Analysis of the National Ambient Air Quality Standards for ozone and particulates The factor used for this purpose is 0 83, which corresponds to the gross domestic product implicit price deflator index published by the Bureau of Economic Analysis

Table 4-1
Key Baseline Assumptions for Electricity Generation

Factor	Assumption
Discount Rate (percent per year)	6
Conversion Factor from 1997 to 1990 Dollars	0.83
Electricity Demand Growth Rate (percent per year)[a]	1997-2000 = 1.6 2001-2010 = 1.8 > 2010 = 1.3
Reductions due to Climate Change Action Plan (Billion kwh) for sensitivity analysis in section 6.3.4	2001 = 100 2003 = 164 2005 = 228 2007 = 293 2010 = 389 >2019 = 608
Power Plant Lifetimes	Fossil Steam = 65 years if ≥ 50 MW = 45 years if < 50 MW Nuclear = 40 year license length Turbines = 30 years
U.S. Nuclear Capacity (gigawatts)	2001 = 93 2003 = 90 2005 = 87 2007 = 86 2010 = 81 2020 = 50
Nuclear Capacity Factors (percent)	2001 = 80 2003 = 80 2005 = 80 2007 = 82 2010 = 81 2020 = 83

Table 4-1 (continued)
Key Baseline Assumptions for Electricity Generation

Factor	Assumption
World Oil Prices (1997$ per BBL)	2001 = 19.20 2003 = 19.90 2005 = 20.50 2007 = 20.80 2010 = 21.20 2020 = 22.40
Wellhead Natural Gas Price (1997$ per mmBtu)[b]	2001 = 1.90 2003 = 1.95 2005 = 2.00 2007 = 2.00 2010 = 2.00
Coal Steam Power Plant Availability (percent)	1995 = 82 2000 = 83.5 2005/10/20 = 85
Existing Power Plant Heat Rates	No change over time
Coal Mining Productivity Increases (percent change per year)	1995-1999 = 3.1 2000-2004 = 2.8 2005-2009 = 2.4 2010-2014 = 2.1 2015-2025 = 2.1
Average Delivered Coal Prices[b] (percent change per year 2001-2010)	-2.0

[a] Does not include any adjustment for potential improvements related to the Climate Change Action Plan.
[b] Based on recent ICF analyses using updated coal mining productivity and supply for coal, and technology and supply assumptions for gas. Note that the natural gas prices are not an assumption in the model, but are a forecast of the model.

4.2.2 Electric Energy Cost and Performance Assumptions

In order to simulate the electric power market under baseline conditions and for each of the regulatory options, assumptions are made on the cost and performance of new power plants as well as for repowering existing power plants. These characterizations of new power plant cost and performance are used in IPM to determine the least cost means for meeting projected future electricity requirements subject to the baseline emission restrictions and the NOx emission limits specified for each regulatory option.

Power plant cost and performance assumptions are developed for the following new conventional and unconventional power plant types:

- New Conventional Power Plants
  - Conventional Pulverized Coal.
  - Advanced Coal (Integrated Gasification Combined Cycle - IGCC).

- Combined Cycle,
- Combustion Turbine, and
- Nuclear

- New Renewable/Nontraditional Options

  - Biomass IGCC,
  - Solar Photovoltaics,
  - Solar Thermal,
  - Geothermal; and
  - Wind

Cost and performance projections are developed for 2001, 2003, 2005, 2007, and 2010 in order to capture changes in technology over time. In general, the year 2001 estimates reflect generation technology that is close to or identical to existing technology, and the later year estimates reflect advancements in costs and performance. The Agency relies heavily on work that the Energy Information Administration did in support of the most recent *Annual Energy Outlooks* (AEO97 and AEO98). EIA had its approach peer-reviewed during its development.

In addition to the AEO, key data sources used to develop these assumptions are as follows:

EPRI, *TAG Technical Assessment Guide, Electricity Supply - 1993*, EPRI TR-102276-V1R7, June 1993,

SERI, *The Potential of Renewable Energy: An Interlaboratory White Paper*, SERI/TP-260-3674, March 1990, and

TVA, *Integrated Resource Plan Environmental Impact Statement*, Volume Two, Technical Documents, July 1995.

In addition to these assumptions on new power plants, EPA also develops assumptions on the cost and performance of repowering existing power plants. The following three types of repowering options are considered:

- Repowering Coal Steam to Integrated Gasification Combined-Cycle,

- Repowering Coal Steam to Gas Combined-Cycle, and

- Repowering Oil/Gas Steam to Gas Combined-cycle.

The key sources of data for this section are the repowering studies conducted by Bechtel Corporation, the TVA Integrated Resource Plan EIS, and the EIA life extension report.

For more details on the assumptions made about the cost and performance of new power plants and repowering of existing power plants, see Appendix No. 3 of EPA's March 1998 report *Analyzing Electric Power Generation under the CAAA*.

4.2.3 Pollution Control Performance and Cost Assumptions

EPA develops pollution control cost and performance estimates for the following options

- Coal-Fired Steam Electric Generating Units

  - Combustion Controls,
  - Selective Catalytic Reduction,
  - Selective Non-Catalytic Reduction, and
  - Natural Gas Reburn

- Oil and Gas-Fired Steam Generating Units

  - Selective Catalytic Reduction; and
  - Selective Non-Catalytic Reduction

EPA also develops cost and performance estimates for combining SCR or SNCR with coal plant scrubbers With these options, the IPM can determine if in some instances, it is optimal to place a scrubber and SCR or SNCR to reduce SO_2 emissions and NOx emissions from a given plant simultaneously In determining the least cost means for complying with a NOx regulatory policy, the model can choose from among these pollution control options and change the dispatch of model plants For example, the model in some cases can reduce the utilization of high NOx emitting units and increase the utilization of low NOx emitting units

In addition to including the pollution control cost and performance estimates described above, IPM also takes into account the cost and performance of combustion controls installed beyond those resulting from implementation of Title IV and Title I (Reasonable Available Control Technologies - RACT) requirements Note that the Title IV NOx program permits an owner/operator to comply with the requirements by averaging the NOx emissions from some units within the owner/operator system with emissions from other units also within the same system This emissions averaging permits an owner/operator to install controls on units that are cost-effective to control and average emissions from these units with emissions from units that are less cost-effective to control EPA accounts for the cost of combustion controls beyond those needed for Title IV compliance in the following manner (1) EPA identifies the units that either are (Phase I units) or are likely to (Phase II units) average their emissions with other controlled units, and (2) EPA reasons that these uncontrolled units, for the purposes of this proposed rulemaking, will install the least expensive controls, that is, combustion controls, where requirements beyond Title IV are imposed on them These units can further reduce their emissions by installing SCR, SNCR, or gas reburn, as described above Additionally, using continuous emissions monitoring (CEM) data, EPA found that some sources with a common owner or operator, that could average their emissions under Title IV, consistently emitted well below (20 percent or more) their Title IV mandated levels For the purposes of analyses in this report, such sources are assumed to emit at their actual CEM-measured levels, not their applicable Title IV Standard

These performance and pollution control cost assumptions for NOx are based on the following sources:

U S Environmental Protection Agency, *Regulatory Impact Analysis of NOx Regulations*, October 1996

Bechtel Power Corporation, *Cost Estimates for NOx Control Technologies Final Report*, February 1996

Bechtel Power Corporation, *Draft Technical Study on the Use of Gas Reburn to Control NOx at Coal-fired Electric Generating Units*, June 1996

Acurex Environmental Corporation, *Phase II NOx Controls for NESCAUM and MARAMA Region*, 1995

For more details on the assumptions made about pollution control cost and performance see Appendix No 5 of EPA's March 1998 report, *Analyzing Electric Power Generation under the CAAA*.

4.2.4 Air Emissions Rates under the Base Case

Assumptions about the other environmental rules that will be in effect with or without the NOx SIP call constitute a vital aspect of the baseline because even existing environmental initiatives will lead to NOx reductions in the future If the reductions that are projected to take place under these initiatives are not accounted for, the effects of the NOx SIP call in capping NOx emissions will be overestimated

Three sets of regulations affecting NOx emissions in the baseline are taken into account in this analysis First, EPA factors in regulations under Title I of the Clean Air Act, including RACT requirements for existing sources, EPA's New Source Performance Standards, and controls based on Best Available Control Technology (BACT) and Lowest Achievable Emissions Rates (LAER) that would be in effect for new sources The analysis also accounts for the NOx reductions from utility units under Phases I and II of Title IV's Acid Rain Program, which set rate limitations for most coal-fired generators greater than 25 MW of capacity

Finally, the control program agreed upon by the Ozone Transport Commission for the Ozone Transport Region is assumed to go forward in the baseline The OTC's Memorandum of Understanding envisions three progressively more stringent control requirements for sources in the OTR Phase I, Phase II, and Phase III Though EPA anticipates that all three of these phases will eventually be implemented in the baseline, cases including Phase I alone (i e , RACT controls in place in the OTR) are examined in some of the baseline analyses This baseline, which is referred to as the *Initial Base Case*, is the primary basis for comparison in this RIA Comparisons of the options to a *Final Base Case*, which assumes that Phase II and Phase III of the OTC's MOU will also go into effect, are also made in the RIA Because Phases II and III are estimated to cut NOx from electric generators, any comparison of an option to the Initial Base Case will appear to be more effective (and more costly) than a comparison of that option to the Final Base Case In considering the effects of the OTC's MOU, this analysis covers only the NOx controls in the SIP call region In considering the effects of the OTC's MOU, this analysis covers only the NOx controls in the SIP call region Thus NOx controls resulting from the OTC MOU in Maine, Vermont, and New Hampshire are not included

4.3 Allowance Allocations and Trading

For the purposes of this analysis, the NOx SIP call is assumed to be implemented through an emissions trading program The trading program works by allocating the limited rights to emit NOx in limited quantities during the summer, and allowing sources to choose the extent to which they will reduce emissions or purchase these limited rights or "allowances" For many aspects of the analysis, the initial distribution of the allowances is not important: the only relevant fact regarding the allowances is their total volume (segmented by region for the regional options), which determines the number of tons of NOx reductions required The reasons for this separation of the allowance allocations from the rest of the analysis, and the circumstances under which the allocation does become important, are described in Section 4 3.1 Assumptions about the trading of allowances are presented in Section 4.3.2

4.3.1 Purpose of Allowances and Assumptions about Allocations

IPM works by finding the least-cost method for producing electric power for the industry as a whole, assuming the entire industry in the area of the NOx SIP call is subject to an overall cap on ozone season NOx emissions The model places pollution controls or makes dispatch changes to electricity generating units that lead to the achievement of emission reductions at the lowest cost As a result, some firms' power plants are projected to be tightly controlled, at significant cost, while other firms' plants have no controls beyond those assumed in the baseline

Realistically, this pattern would not be seen unless some system existed to give incentives to the firms with the most cost-effective control possibilities to bear the greatest part of the control burden The NOx SIP call envisions that these incentives will take the form of compensation for allowances, which must be purchased by the firms that elect to under-control their plants' emissions Firms are assumed to either buy or sell allowances depending on their own costs of control in comparison to the market price of allowances As the price reacts to changes in demands and supplies of allowances, the market will help ensure that the costs of incremental reductions of NOx are the same for all participants

Projecting how the NOx emissions cap will be divided initially among firms through awards of allowances is not important for estimating the total costs of the NOx SIP call or the control methods that will be used if it can be assumed that the allowance market will be efficient If the market is efficient, the only effect of allocating more allowances to a given firm will be that a firm will be able to sell more allowances after controlling emissions to an efficient degree. Experience with the SO_2 allowance market under Title IV demonstrated that these markets can function efficiently, with significant trading volumes and minimal transaction costs (U S EPA, Forthcoming-Fall 1998)

The initial distribution of the allowances is, however, very important in assessing potential impacts and trading patterns If, for example, allowances are distributed in proportion to baseline NOx emissions, owners of coal plants would be able to sell many more allowances than if allowances are distributed in proportion to baseline generation

For this analysis, it is assumed that States will divide allowances only among affected sources, in proportion to their 1995 or 1996 fuel input, allowing both for growth in capacity and growth in electricity output to 2007. These assumptions are somewhat simplified versions of the allowance distribution system recommended by EPA for State consideration, which provides for shifts in allowance distributions over time in response to changing capacity use, unit closures, and new builds. These simplifications should have little effect on the analysis, which reflects the approach EPA recommends if a State allocates on the basis of input However, if the State allocates on an output basis or differs a great deal on the input approach from EPA's recommendation, the outcome could be much different

4.3.2 Trading Assumptions

As noted above, IPM calculates costs and emissions reduction choices as though there are no constraints on the transfer of allowances from source to source Implicitly, then, the analysis assumes a completely efficient, frictionless market for allowances More realistically, there will be some transaction costs incurred when allowances are transferred Based on the experience with the Title IV SO_2 allowance trading program, the cost of allowance transactions has been assumed to be 1 5 percent of the value of the transaction (U S EPA, Forthcoming-Fall 1998) The basis for this estimate is explained in Section 4 4 2 The effects of transaction costs of the magnitude estimated for the NOx SIP call on the total costs of the rule and the distribution of control efforts is likely to be negligible because many transferred allowances are between units within company systems, not between power companies, and most allowances are not transferred at all Also, transaction costs are expected to be a very small percentage of the value of those allowances that are transferred

4.4 Administrative Costs

Electric utilities, State and local air quality regulatory agencies, and EPA will incur administrative costs in addition to the costs of complying with the NOx SIP call The primary basis for determining the amount of these administrative costs is supporting data from EPA's Information Collection Request (ICR) (EPA,1998d) for the proposed Regional NOx Federal Implementation Plan (FIP) Even though this ICR is conducted for the FIP, EPA assumes that the unit costs would be identical for the NOx SIP call, though there could be changes in who bears the costs All of the administrative costs are annualized and presented in 1990 dollars for the year 2007

4.4.1 Administrative Costs to Affected Electric Generating Units

The owners or operators of affected electricity generating units will incur administrative costs associated with the following activities

- Monitoring emissions,
- Certifying compliance,
- Modifying permits, and
- Trading allowances.

Electricity generating units will be required to have in place monitoring equipment to measure their NOx emissions This is already required under Title IV for units covered by the SO_2 allowance program In addition, they will be required to submit a monitoring plan to the State or local agency for review and approval On a regular basis, they must also submit a report certifying compliance The sources will also be required to obtain air permits and, before beginning construction of the control technologies, the facilities may need a construction permit. The operating permit will also need revision to incorporate the revised emission limitations. These administrative costs are based on supporting data from EPA's ICR (EPA,1998d). In general, the administrative costs are equal to the unit costs multiplied by the number of affected electricity generating units.

Utilities will also incur transaction costs in trading allowances between companies. The methodology for estimating transaction costs is discussed next.

4.4.2 Transaction Costs of Trading Allowances

IPM calculates costs and emission reduction choices as though there are no constraints on the transfer of allowances from source to source. Implicitly, then, the analysis assumes a completely efficient, frictionless market for allowances. More realistically, there will be some transaction costs incurred when allowances are transferred. The transaction costs include the costs to gather information on the market, search for allowances, make bids and offers, negotiate terms and conditions of allowance transfer agreements, and ensure that the allowances transfer. Many companies will hire an emissions trading broker to perform these services, but the company will also incur other costs related to the decision-making process as well as costs of legal counsel.

For this analysis of the NOx market, EPA assumes that total transaction costs are approximately 1.5 percent of the value of the allowances traded. In reality, the percentage may vary depending upon the quantity of allowances traded, the familiarity of the traders with the market, and the overall maturity of the market. While total SO_2 transaction costs have declined over time, recent evidence suggests total SO_2 transaction costs range from one to two percent (U.S. EPA, Forthcoming-Fall 1998).[1] These total transaction cost estimates are for both buyer and seller combined and include brokerage fees and internal decision-making costs. The decline in total transaction costs is believed to be attributable to improved market maturity and trading familiarity. This analysis assumes an average total transaction cost of 1.5 percent for the NOx market, thus accounting for market variation over time. Here we are only counting inter-utility trading costs. There will also be intra-utility trading, but no costs are assigned to these trades.

The total value of allowances traded between companies under each option is equal to the product of the number of allowances and the price of an allowance estimated for each option. For this analysis, EPA projects the volume of allowances traded between units and between utilities and the value of each allowance. EPA estimates the total volume of allowance transactions for the 0.15 trading option by comparing IPM projections for emissions for each unit to an estimate of the allowances that the unit would receive under the NOx SIP call. Allowance allocations are assumed to be made based on the baseline fuel inputs of the units. The difference between each unit's emissions and the allocated allowances is assumed to be equal to the amount of each allowance transaction, either the quantity acquired or transferred to another. Then, the total quantity is found by summing all allowances acquired across all units. To determine the number of transactions occurring between companies, the emissions for each unit are summed on a utility-by-utility basis and compared to the sum of the allowances allocated to each unit on utility-by-utility basis. The difference of the two is equal to the total inter-utility transactions.

[1] These numbers are based on preliminary estimates and may change in the final report.

The number of transactions will be greater or fewer for each regulatory option based on the differences between the marginal cost functions at the various control levels as well as the shapes of these cost functions Transaction volumes are calculated for the 0.12, 0.15, and 0 20 trading options The price of allowances is assumed to be approximately equal to the marginal cost of NOx reductions, as estimated by IPM

Transaction costs were derived based on trading between firms operating utilities only Transaction costs for firms operating non-EGU sources were not estimated Since the transaction costs are only a very small component of total annual compliance costs of the NOx SIP Call for affected utilities, and will likely be a very small component of total annual compliance costs for affected non-EGUsources, the inclusion of non-EGU transaction costs should not significantly change the compliance costs estimate of the SIP Call

4.4.3 Administrative Costs to States and Local Governments

The following administrative costs will be incurred by State and local air quality regulatory agencies

- Certifying monitoring plans,
- Monitoring compliance by conducting audits, and
- Reviewing and approving permit modification applications

State or local agencies will need to certify monitoring plans prepared by affected sources States and local agencies will also monitor the compliance of electric generating units by reviewing the emissions data and conducting occasional audits It is assumed that States and local agencies will audit 10 percent of the electricity generating units These agencies will also be responsible for reviewing and approving permit applications for both construction permits (except in Prevention of Significant Deterioration (PSD) areas that have not been delegated the authority to implement the program) and operating permits For this analysis, the administrative costs associated with permitting are allocated to only the States and local agencies, because the costs associated with PSD permits reviewed and approved by the U S EPA are assumed to be minimal. The administrative costs attributable to the State and local governments are calculated by multiplying the unit costs and the number of affected units based on supporting data from EPA's ICR (EPA, 1998d)

4.4.4 Administrative Costs to the U.S. EPA

EPA's primary administrative costs are associated with upgrading the allowance tracking system, administrating the allowance tracking system, and collecting the NOx emissions monitoring data This effort is incremental to current EPA collection of NOx emissions data from acid rain units and certain OTC units that already provide emissions data EPA recently modified the allowance and emissions tracking systems for the Ozone Transport Commission's NOx Budget Program; therefore, these systems will require minimal upgrades to expand to the SIP call region These administrative costs incurred by EPA are equal to the unit costs multiplied by the number of affected electricity generating units and are based on supporting data from EPA's ICR (EPA, 1998d)

4.5 Direct Economic Impacts

The Agency analyzed the potential direct impacts of the rule on the electric power producers.

4.5.1 Potential Costs to Electric Power Producers Relative to Revenues

Costs of the NOx SIP call for this illustrative implementation approach are compared to the revenues of electric power producers at two levels industry-wide and to small entities Industry-wide comparisons are made by expressing the potential costs of the rule on a per-kilowatt hour basis, using IPM outputs on the generation of electricity from fossil fuel, and then comparing this increase in unit costs to average rates per kilowatt hour Data are obtained from EIA Form 861 to find revenues per kilowatt hour for utilities in the SIP call region

Potential costs to small entities are estimated in more detail Specific data on small utility revenues is collected from EIA Form 861, and total revenues for small non-utility owners is obtained from Dun & Bradstreet These revenue estimates are compared to cost estimates for individual units owned by each small entity The cost estimates take into account the least-cost means of compliance, including the option of allowance purchases, as discussed below

The IPM analysis focuses on estimating industry-wide costs and emission reductions Where it is necessary to derive rough estimates of potential costs for particular firms, the first step is to find the projected emission control choices made for each of the firm's units in the cost-minimizing solution The cost functions built into IPM can then be used to calculate the fixed and variable control costs for each unit, and these costs are summed across all of the units owned by the firm to yield total control costs

The next step in estimating potential costs to a given firm is to incorporate purchases or sales of allowances Estimates of the total summer NOx emissions from the firm's plants are compared to the firm's allocation of allowances (based on an allocation of the SIP-call-region-wide cap in proportion to baseline fuel use) This comparison gives the net purchases or sales of allowances, which must then be multiplied by an estimated allowance price Allowance price estimates are based on EPA estimates of the incremental costs per ton of reducing NOx It should be noted that these potential firm-by-firm impacts do not take account of changes in dispatching, and can therefore overstate net economic impacts on the potentially affected entities Allowance transaction costs are considered too small to be considered in this analysis

4.5.2 Assessment of Potential for Passing on Cost Increases

An assessment of the potential effects of the NOx SIP Call on electricity prices is conducted using estimates of changes in marginal cost combined with judgment on the effects of power industry restructuring on the competitiveness of the market. Potential changes in marginal costs of generation, weighted by demand segment (e.g., peak load or base load), are assumed to be passed on to consumers, under the simplifying assumption of perfectly inelastic demand for electricity and a competitive market This simplified estimate is used to provide an upper bound estimate of potential price increases. EPA recognizes that there will be price elasticity of demand effects, such that the quantity demanded will respond to price changes in both the short and long run. This elasticity of demand will limit the increase in prices It is recognized, however, that these assumptions may not hold at all times and in all States

4.5.3 Assessment of Potential for Closures and Additions

The chance that power plants might close as a result of the NOx SIP call is assessed using IPM, which determines whether it is more cost-effective to control the emissions from a given plant, buy allowances and continue to operate it, or close it down IPM is also used to project capacity additions, based on the costs of building new capacity in comparison to its value

4.6 Indirect Economic Impacts

The economic effects of the NOx SIP call can be transmitted through market interactions to entities that are not directly affected by its provisions. These potential indirect effects are analyzed using estimated changes in electricity rates, emission control technology, and fuel use. The effect of rising electricity rates is assessed by multiplying the per-kilowatt-hour increase by the number of kilowatts used by typical manufacturers or consumers, and comparing this increased cost to revenues or incomes. Data are obtained from the Census of Manufacturers, Bureau of the Census, and surveys by the U S Energy Information Administration Potential cost increases are assessed both in terms of nationwide averages and sensitive subgroups (including energy-intensive industries and low-income households)

Potential impacts on employment in the industries providing fuel and pollution control equipment are assessed by measuring changes in fuel and control equipment purchases in combination with projected labor productivity in these industries

4.7 Limitations of the Analysis

This analysis incorporates a fine-grained representation of the behavior of a large number of industrial entities, it covers both a long period of time and a wide geographical area As with any similar attempt to project the future in detail, it is subject to limitations and uncertainties. Thus, several factors could lead to cost and emissions impacts above or below the reported impacts Those factors include the following

- **Speed of Deregulation** - EPA has assumed that electric utility deregulation will continue to move ahead at a steady pace The Agency has also assumed that deregulation will affect the electricity market in specific ways including lower cost of transmission, higher coal plant availability, and lower reserve margins Should deregulation occur more quickly or more slowly than assumed, or affect the electricity system in different ways, the estimated costs and emissions impacts for these regulatory options may differ

- **Pollution Control Costs and Performance** - EPA has used estimates of pollution control costs and performance that reflect the current state-of-the-art However, technological progress stimulated by competition could lead to improvements in the performance and cost of pollution control technology in the future For this reason, the Agency's estimates of future cost impacts for the regulatory options considered could be overstated

- **Regulatory Program Implementation** - EPA has assumed that the regulatory program resulting from the NOx SIP call will be implemented smoothly and at specific points in time

- **Data Limitations** - EPA has constructed a database for this analysis that consists of information on virtually every boiler and generator in the U S The Agency has assembled the best information on each boiler and generator that is publicly available Inevitably, when working with information on such a large number of facilities, some units may not be represented correctly Improvements to the database could lead to changes in estimates of emissions and potential cost impacts for the regulatory options analyzed

4.8 References

Acurex Environmental Corporation, 1995. *Phase II NOx Controls for NESCAUM and MARAMA Region*

Bechtel Power Corporation, 1994 *Electric Utility Repowering Assessment, Final Report, July 1993-February 1994*

Bechtel Power Corporation, 1996a *Cost Estimates for NOx Control Technologies, Final Report* February 1996

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U.S. Environmental Protection Agency. 1998c. *Transaction Costs Associated with Emissions Trading*. Prepared by ICF Incorporated for the Climate Polity and Programs Division. Forthcoming, Fall 1998.

U S Environmental Protection Agency, 1998b *Feasibility of Installing NOx Control Technologies by May 2003* Offic of Atmospheric Programs, Acid Rain Division, Washington, D C., July 1998

U S Environmental Protection Agency, 1998d *Supporting Analysis for the Information Collection Request for the Federal Implementation Plan* Office of Air and Radiation, Washington, D C , September 1998

Chapter 5. METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS, COSTS AND ECONOMIC IMPACTS FOR NON-ELECTRICITY GENERATING UNITS

This chapter describes the methodologies used to estimated emission reductions, costs and economic impacts for stationary sources other than electricity generating units (EGUs) that are potentially affected by the NOx SIP call Section 5 1 provides an analytical overview for the methodologies described in this chapter Section 5 2 describes the available NOx control technologies for two sets of sources industrial boilers and turbines, and other stationary sources [1] Section 5.3 presents information on control costs and describes the cost-effectiveness methodology, and Section 5 4 discusses administrative costs associated with the NOx SIP call Section 5.5 provides an overview of the economic impact analysis methodology and data sources used to conduct such an analysis, and Section 5 6 discusses the methodology for estimating small entity impacts Finally, Section 5 7 provides references for the chapter

5.1 Analytical Overview

The basic approach to estimating the potential effects of the NOx SIP call to other stationary sources is to project their actions in the absence of the rule, project their actions if they were subject to the rule, and then compare the two sets of actions The actions of other stationary sources in the absence of the rule is referred to as the 2007 CAAA baseline, or 2007 base case Total annual compliance costs and NOx emissions changes are estimated incremental to the base case

The geographic scope of these analyses is the 23 jurisdictions affected by the NOx SIP call The analyses provide results for 2007, the year in which all required emissions reduction strategies are to be fully implemented All results are presented in 1990 dollars

The potential emission reductions and control costs to other stationary sources affected by the NOx SIP call are estimated using a model that is primarily based on data and assumptions from Alternative Control Technology (ACT) documents prepared by EPA for many of the industries in this source category that are potentially affected by the rule The costs for SNCR and SCR control applications to industrial boilers are derived from a separate study that also serves as the basis for the cost estimates used in the Integrated Planning Model (IPM) for utility boilers For sources identified in the NOx budget trading program (industrial boilers and combustion turbines), this model estimates emission reductions and control costs for 2007 using a least-cost approach applied across the entire SIP call region For source not in the trading program (e g ,stationary IC engines and cement manufacturing operations) the model applies control measures at individual emissions units based on a cost ceiling calculated in terms of average cost-effectiveness The least cost approach used for the trading sources provides a proxy for State-level emissions trading programs free of transactions costs The approach for sources outside the trading program provides estimates of the costs for meeting each State's emissions budget under a command-and-control scenario

The least-cost analyses are performed for 4 different regulatory alternatives, and the command-and-control analyses are performed for 5 different regulatory alternatives More detail on the control technologies

[1] Other stationary sources refers to a large variety of non-electricity generating source types This analysis limits itself to two source types stationary reciprocating internal combustion engines, and cement manufacturing operations (including coal-fired cement kilns)

used to provide emission reductions are in Section 5.2 below and in *Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis*, September, 1998, and more detail on the control cost model operates is provided in Section 5 3 below and in the cost report previously mentioned

Monitoring and administrative (record keeping and reporting) costs are also estimated for potentially affected other stationary sources and are added to the control costs to provide an estimate of total compliance costs More detail on how these costs are estimated is provided in Section 5 4 below and in *Support for Revising ICR for Reporting Requirements for NOx SIP call*, September, 1998

Finally, the total compliance costs at the source level are aggregated to the establishment or plant level and further aggregated to the entity level, and are used to estimate the potential economic impacts associated with the entities potentially affected by the NOx SIP call These analyses consist of estimating compliance costs as a percentage of sales or revenues for affected entities (firms or institutions that own affected other stationary sources). The Agency also conducted analyses for the set of potentially affected small entities (using SBA size definitions) More detail on how these impacts are estimated is provided in Section 5 5 and Section 5 6 below and in *Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call*, September, 1998

5.2 NOx Control Technology

This section describes available technologies for controlling emissions of NOx for industrial, commercial and institutional (ICI) boilers[2] combustion and turbines (Section 5 2 1) as well as other non-EGU stationary sources (Section 5 2 2)

In general, low-NOx burners (LNB) is applied as the default control technology for industrial boilers and turbines due to its possible application to most any industrial burner application (Pechan, 1998) Other issues involved in choosing a control technology include ease of retrofit and reduction performance While all controls presented in this analysis are considered generally technically-feasible for each class of sources, source-specific cases may exist where a control technology is in fact not technically-feasible In their response to the NOx SIP call, States may wish to consider case-specific feasibility when establishing control requirements

5.2.1 NOx Control Technology for Industrial Boilers and Turbines

There are three types of control technologies considered for industrial boilers selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and low-NOx burners As stated above, the default control technology chosen was LNB due to its breadth of application In some cases, LNB accompanied by flue gas reburning (FGR) is applicable, such as when fuel-borne NOx emissions are expected to be of greater importance than thermal NOx emissions When circumstances suggest that combustion controls do not make sense as a control technology (e g , sintering processes, coke oven batteries) SNCR is the appropriate choice

[2] The terms "ICI boiler" and "industrial boiler" are used interchangeable in this RIA

Control technologies applicable to gas turbines include water injection (WI), steam injection, low-NOx burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and combinations of SCR with LNB, oxygen trim (OT), water injection, or steam injection Table 5-1 lists the control technologies available for non-EGU industrial boilers and combustion turbines by type of fuel

Table 5-1
Available NOx Control Technologies for Stationary Industrial Boiler and Combustion Turbine Sources

Source Type/Fuel Type	Available Control Technology
ICI Boilers - Coal/Wall	SNCR, LNB, SCR
ICI Boilers - Coal/FBC	SNCR - Urea
ICI Boilers - Coal/Stoker	SNCR
ICI Boilers - Coal/Cyclone	SNCR, Coal Reburn, NGR, SCR
ICI Boilers - Residual Oil	LNB, SNCR, LNB + FGR, SCR
ICI Boilers - Distillate Oil	LNB, SNCR, LNB + FGR, SCR
ICI Boilers - Natural Gas	LNB, SNCR, LNB + FGR, OT + WI, SCR
ICI Boilers - Process Gas	LNB, LNB + FGR, OT + WI, SCR
ICI Boilers - Coke	SNCR, LNB, SCR
ICI Boilers - LPG	LNB, SNCR, LNB + FGR, SCR
Combustion Turbines - Oil	Water Injection, SCR + Water Injection
Combustion Turbines - Natural Gas	Water Injection, Steam Injection, LNB, SCR + LNB, SCR + Steam Injection, SCR + Water Injection
Combustion Turbines - Jet Fuel	Water Injection, SCR + Water Injection

Source Pechan-Avanti Group

5.2.2 NOx Control Technology for Other Stationary Sources

Other stationary sources included in the analysis include reciprocating internal combustion (IC) engines and cement kilns used in the cement manufacturing process. In the case of IC engines, most are "lean burn" designs which are considered best available control technology (BACT) for NOx control Thus, it is assumed that no further add-on emissions controls are practical or necessary. NOx control technology available for cement kilns includes those available to industrial boilers and turbines, namely LNB, SCR, SNCR In addition, mid-kiln firing, ammonia-based SNCR, ignition retard (IR), adjustments of the air/fuel ratio (AF RATIO), and low emission engines (L-E) can be utilized where appropriate Table 5-2 lists the control technologies available for IC engines and cement kilns

Table 5-2
Available NOx Control Technologies for Other Non-EGU Stationary Sources

Source Type/Fuel Type	Available Control Technology
Internal Combustion Engines - Oil	IR, SCR
Internal Combustion Engines - Gas	IR, AF RATIO, AF + IR, L-E (Medium Speed), L-E (Low Speed). SCR
Internal Combustion Engines - Gas, Diesel. LPG	IR, SCR
Cement Manufacturing - Dry	Mid-Kiln Firing, LNB. SNCR - Urea Based, SNCR - Ammonia Based. SCR
Cement Manufacturing - Wet	Mid-Kiln Firing, LNB. SCR
In-Process. Bituminous Coal. Cement Kilns	SNCR - Urea based

Source Pechan-Avanti Group

5.3 Control Costs and Cost Effectiveness Methodology

This section describes the methods used to develop estimates of costs by control technology and by source category This section also describes the approaches used for each group of sources to assign control technologies to specific sources assumed to be potentially subject to new controls

Two types of costs will be incurred in association with the addition of NOx control technologies a one-time capital cost for new equipment installation. and increased annual operating and maintenance costs In general. economies of scale exist for pollution control technologies for both capital costs and operating and maintenance costs Thus. the size of the unit to which controls are applied will determine. in part. the cost of implementing the pollution control(s)

Control cost estimates by source size are developed using EPA's Alternative Control Techniques (ACT) Documents for each major source category [3] Additional control cost equations for SCR and SNCR are adapted from information originally developed for EGU sources for use in the IPM analysis (Pechan. 1998) All costs are converted from the original source year to 1990 dollars using the GDP price deflator Capital costs are annualized using a seven percent interest rate and an equipment life appropriate for each control technique, as specified in the relevant ACT Documents Table 5-3 lists the equipment life assumptions used in this analysis To take account of the effects of size on costs, cost equations are applied to estimate costs as a function of boiler design capacity Engineering judgement and knowledge of the affected industries was used to assign control cost equations to specific source types (Pechan. 1998)

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[3] The ACT Documents did not provide total O&M costs for combustion turbines The total was calculated by subtracting the annualized capital from the total annual cost This may have added some uncertainty, as both capital and total annual costs were rounded to the nearest thousand dollars in the ACT documents The ACT Document for IC engines also contained no O&M cost data Thus. operating and maintenance costs were back calculated for these sources as well

Table 5-3
Equipment Life for Various Non-EGU Control Technologies

Source Category/Control Technology	Equipment Life
ICI Boilers (All fuels)	
LNB, LNB + FGR, OT + WI	10
Coal Reburn, NGR	20
SCR, SNCR	20
Combustion Turbines (All fuels)	
All Controls	10
Stationary IC Engines (All fuels) All Controls	15
Cement Manufacturing (Wet & Dry Kilns, and Bituminous Coal-Fired Kilns) All Controls	15

Sources may be controlled or uncontrolled in the 2007 baseline. Controlled NOx sources tend to be those in ozone nonattainment areas, or in the Northeast ozone transport region, that are subject to RACT regulations. The cost analysis takes into account these baseline controls. Where sources are uncontrolled, all available controls are considered. For controlled sources, only those control alternatives that provide NOx emission reductions beyond the baseline level of control are considered.

Separate methods are used to determine what controls are applied for trading (industrial boiler and turbine) and non-trading sources. However, in both cases the allocation of controls across sources is based on the total annual costs per ton of NOx reduced in the ozone season for different controls.[4]

For trading sources, a least-cost analysis is conducted. A NOx emissions budget for the collection of large industrial boilers and turbines is established at different levels of stringency. The least costly controls, in terms of total annual cost per ozone season ton removed, across the entire set of possible source-control measure combinations are selected in order until the required NOx emission budget is achieved. Costs used in the least-cost modeling are based on source capacity, if capacity information is available, and on average dollar per ton costs if not.

For non-trading sources, a more conventional source-category specific cost analysis is conducted. Regulatory alternatives that place a limit on the cost per ton of reduction are examined, and the most effective NOx control technique that has a cost per ton below that limit is selected for each unit. The cost per ton reduction for these control techniques is then multiplied by the difference between 2007 baseline and controlled emissions, to estimate total annual costs for each source.

[4] Total annual cost is the sum of annualized capital costs and annual operating and maintenance costs.

5.4 Administrative Costs for Industrial Boilers and Turbines

In addition to control costs, potentially affected sources could incur administrative costs associated with the collection and reporting of NOx emissions Estimates are developed of the administrative costs for requirements beyond those that exist in the baseline. The additional requirements include one-time activities and annual activities

The one-time activity for an industry source to read and interpret the reporting requirements of the rule is estimated to be 1 hour for technical staff and 1 hour for managerial staff The effort to revise a Title V permit to incorporate NOx monitoring requirements of the final rule is estimated to be 0.8 hours of technical staff (i e , 4 hours annualized over 5-years)

Annual activity industry burden items associated with the collection and reporting of data include a requirement to submit a year-end compliance certification report The burden associated with this activity is estimated to be 2 hours of technical staff time, and 0 5 hour of managerial staff time for trading sources For non-trading sources, the burden estimate is 8 hours of technical staff time, and 2 hours of managerial staff time

Owners of sources that are eligible to participate in the emissions trading program and elect to do so will incur some administrative costs associated with the trading system Chapter 4 (Section 4 4) provides information on the administrative costs associated with trading for EGUs These same costs apply to industrial boilers and turbines and other stationary sources that participate in the trading program, and these costs are provided in Chapter 8 (Section 8 3)

5.5 Economic Impact Analysis

This section describes the methodology used to estmate economic impacts for establishements and firms that are potentially directly affected by the NOx SIP call These are distinguished from indirect impacts, which are impacts on related parties -- suppliers (including the pollution control industry), customers, or competitors of the potentially directly affected establishments -- that result from the rule Indirect impacts would also include impacts on local taxpayers where sources owned by local governments (e g , schools or municipal combustion units) are subject to increased costs

5.5.1 Overview of the Economic Impact Analysis Methodology[5]

Consistent with the analysis of electric power industry sources described in Chapter 4, this analysis examines the economic impacts of incremental costs incurred by potentially affected sources in the year 2007 No attempt is made to forecast changes in economic conditions between 1995 and 2007, however The financial characteristics of the establishments and firms affected by the rule are assumed to remain the same as reported in 1995 (the latest year for which Census data are currently available) To provide results in units comparable to the cost analyses prepared for the proposed NOx SIP call, costs are expressed in 1990 dollars

[5] A more detailed explanation of the methods and results for the economic impact analysis of non-EGU sources can be found in Abt, 1998

Therefore, the 1995 financial data used to assess economic impacts are adjusted to 1990 dollars using the overall GDP deflator [6]

Several industries and other sectors (e g , schools, colleges, hospitals and governments) are potentially subject to new controls as a result of the NOx SIP call States will ultimately decide what control measures are necessary to meet the NOx emissions budgets stipulated in the SIP call, so the exact sources that will face new controls is not known at this time Based on the simulated control scenarios that are used by EPA to develop the State emissions budgets, the economic impact analysis for non-EGU sources relies on a screening analysis to focus on the sectors that may potentially experience impacts More detailed analysis of market-level impacts and indirect impacts is needed only if the screening analysis shows that a substantial number of establishments in any industry might be subject to significant impacts The more detailed market-level analysis would assess the distribution of impacts among subsectors of the affected industry and their suppliers, customers and competitors

Potential economic impacts are assessed at both the plant and firm level Impacts at the plant, facility or establishment level are relevant for assessing the potential for plant closures, and to calculate aggregate impacts for specific industries [7] Impacts at the firm-level are evaluated to determine whether small entities may be significantly impacted as part of the illustrative implementation scenario, and to determine whether the combined effect of requirements at multiple establishments owned by the same firm would impose a significant burden at the firm level

The screening analysis is based on calculating the ratio of total annual compliance costs to annual sales (for businesses) or (for non-profits or governments) other measures of revenues or receipts Two screening thresholds are used one percent and three percent Where total annual costs represent less than one percent of annual sales or revenues, it is assumed that the rule will not cause significant burdens to the establishment or firm in question Establishments or firms that are predicted to incur costs of three percent of sales or revenues or more are assumed to be potential candidates for significant impacts under our illustrative implementation scenario Cases where annual costs equal between one and three percent of sales/receipts are borderline cases In an industry that operates with low profit margins, costs of this magnitude could represent an economic burden, while in higher-margin industries this level of costs would not impose significant impacts

The screening analysis does not indicate which establishments or firms will in fact experience significant economic burdens as a result of the NOx SIP call, for two reasons

- First, the NOx SIP call does not impose specific requirements on sources, but rather requires States to set NOx emissions limits that will achieve the aggregate NOx emissions budget established for each State States have discretion in how they choose to allocate required reductions across sources The actual allocation of reductions may differ from that assumed in this RIA In particular, States

[6] Note that the adjusted data represent 1995 economic conditions expressed in 1990 dollars, not 1990 economic conditions

[7] The terms plant, facility and establishment are used interchangeably to refer to a single location, which may include one or more emission sources subject to additional requirements under the NOx SIP call Costs estimated at the source level are aggregated to the facility level to provide the required inputs for the economic impact analysis In addition, a single firm may own multiple plants or establishments Firm-level analysis requires aggregating costs for multiple establishments owned by the same parent firm

may choose to impose less stringent limits in those cases where the limits assumed in this analysis would impose significant economic burdens

- Second, the affected firms may be able to recover some of the added costs by increasing prices to customers This outcome is more likely where a substantial number of firms in a given industry sector are affected and less likely if only a few firms in an industry sector incur costs [8] A detailed market-level analysis would be required to determine to what extent firms would be able to recover costs through price increases The screening analysis makes a worst-case assumption about impacts on profits — that all costs are borne by the directly-affected firms, and no costs are recovered through price increases

The economic impact screening analysis can therefore be viewed as providing a general indication of the potential for significant impacts for EPA's illustrative implementation scenario, rather than a prediction of specific outcomes The screening analysis can be used to eliminate establishments and industries which can safely be assumed not to experience significant impacts and highlight other cases for more detailed investigation The results may help States decide how to implement the requirements in ways that limit the most significant impacts identified in the screening analysis

5.5.2 Data Sources

The screening analysis relies on Dun & Bradstreet (D&B) data, where available, to determine the size of individual affected establishments and the entities that own them D&B DUNS identifiers are collected for as many of the potentially affected establishments as possible using EPA's FINDS (the Facility Indexing System) (EPA, 1998) and Toxic Release Inventory (TRI) (EPA, 1995) databases A D&B record for each potentially affected establishment is then accessed to identify the firm that owns the establishment (the D&B "ultimate") The D&B record also provided estimates of employment at the potentially affected establishment ("employment here") and employment and sales at the ultimate firm level [9]

The D&B employment data are used for two purposes

- To classify the firms owning potentially affected establishments as small or large, for those establishments in industries for which the SBA small-firm criteria are expressed in numbers of employees.

- To determine the size category for each potentially affected establishment, so that the appropriate Census economic data can be selected for the establishment-level impacts analysis

The D&B "ultimate" sales data are used to assess the ratio of total annual compliance costs to sales at the firm level

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[8] In the latter case, the affected firms would most likely not be able to raise their prices to recover costs because of competition from firms that do not incur the added costs

[9] In some cases, sales at the establishment level is also provided by D&B These data often in fact reflect sales at the firm level or some intermediate level in the firm organization, however, and were not believed to be consistent enough to be used in the analysis of economic impacts

Because reliable sales or revenue data are generally not available for individual establishments, the economic impact analysis relies on Census data to estimate average SIC establishment-level sales, revenues and receipts. Census data are reported for industries defined by 4-digit SIC codes. Many of the 4-digit SICs are very broad and include establishments of varying sizes and characteristics. Census data are also disaggregated by establishment- and firm-size. Where establishment employment data are available from D&B, they are used to select Census financial data for the size group as well as industry appropriate for each affected establishment.

Where D&B employment data are not available for individual establishments, Census data on the sales/revenues/receipts for the *average* establishment and for the *average small entity* (e.g., firm) in each industry (four-digit SIC) are used to screen for potentially significant impacts.

Total annual compliance costs described in Section 5.3 are before-tax costs, which is in general the appropriate measure for estimating the total social costs of the rule. To estimate economic impacts, however, the more relevant costs are after-tax costs. From the potentially affected establishment's perspective, the costs associated with the NOx SIP call are tax-deductible, as are other business expenses. The burden of these costs is therefore shared by the affected firms and the U.S. taxpayer in the form of lost tax revenues.

Fully adjusting for the tax consequences of the estimated costs would be complex, given the range of compliance options involved and the fact that some of the affected facilities are not subject to Federal corporate income taxes (e.g. government entities or non-profit hospitals and schools.) The economic impact analysis is therefore conducted using before-tax costs, which overstates impacts on establishments for which these costs are tax-deductible.

For three sectors, additional data sources are used to obtain financial data.

- For establishments owned by electric utilities (in particular, those in SICs 4911 and 4931), data are obtain from the Energy Information Administration (EIA). The EIA sources provide both total megawatt hours (MWh) generated and total sales for the parent electric utilities of the potentially affected establishments. The former are used to determine which establishments, 1996, were owned by small utilities (based on the SBA threshold of 4 million MWh), and the latter is used as the measure of firm-level sales.

- For colleges and universities, data on revenues (tuition and fees) are obtained from the National Center for Education and Statistics.[10]

- For government-owned sources, data on revenues and expenditures are obtained from the Census of Governments.

Census data are obtained from the Department of Census' Statistics of U.S. Businesses and the various 1992 Economic Censuses. Data on sales (value of shipments, receipts or revenues, depending on the sector) for the appropriate SIC and size category are divided by the number of establishments or firms, to provide the average sales/revenues/receipts per establishment or firm.

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[10] This measure of financial strength is used rather than a broader measure—which includes income from endowments—to provide a conservative screen for potential impacts.

5.6 Small Entity Economic Impacts

A small entities impact analysis is required to comply with RFA requirements, as described in Chapter 1 The analysis is designed to determine whether EPA can certify that the NOx SIP call will not impose "significant impacts on a substantial number of small entities." While the RFA does not apply to this action, as discussed in Chapter 1, EPA has elected to evaluate the potential impacts of the rule on small entities, based on assumptions about how the States could implement the requirements

The screening analysis described in Section 5 5 provides the information needed to assess whether the NOx SIP call might impose a significant impact on a substantial number of small entities if States were to directly adopt the illustrative implementation scenario examined in this RIA For businesses, the D&B data on firm-level employment and revenues are compared with the SBA size standards to determine which establishments are owned by small entities Additional data are collected to characterize the size of affected non-federal government, utility, and college and university entities, as described previously

Once it is determined which establishments are small using the SBA definitions, the firm-level screening analysis results are used to screen for potential small entity impacts The results of this screening analysis for sources other than electricity generating sources are combined with the results of the small entity analysis for electric utilities (described in Chapter 4) to provide an assessment of potential small entity impacts for the rule as a whole The results of the combined small entity analysis are provided in Chapter 9

5.7 References

Abt Associates, 1998 *Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call* Prepared for the U S Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1998

National Center for Education and Statistics, Integrated Post-Secondary Education Data System, FY 1994-95, unpublished

Pechan-Avanti Group, 1998 *Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis* Prepared for the U S Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1998

Support for Revising ICR for Reporting Requirements for NOx SIP call Technical Memorandum *Industry Indirect Burdens for NOx SIP Call* September 1998

U.S Census Bureau, 1992 Economic Censuses:
- Census of Agriculture (SICs 02, 07)
- Census of Mineral Industries (SICs 10 - 14)
- Census of Construction and Housing (SICs 16-17)
- Census of Manufacturers (SICs 20-39)
- Census of Transportation, Communications and Utilities (SICs 40-49)
- Census of Wholesale Trade (SIC 50-51)
- Census of Retail Trade (SICs 52-59)
- Census of Service Industries (SICs 70-89)
- Census of Governments (SICs 91-97)

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U S Environmental Protection Agency. 1998 *Facility Indexing System (FINDS)* Office of Information Resources Management. September 1998 (available from the U S EPA at http //www epa gov/enviro/finds/fnd_overview html)

Chapter 6. RESULTS OF COST, EMISSIONS, AND ECONOMIC IMPACT ANALYSES FOR THE ELECTRIC POWER INDUSTRY

This chapter summarizes the potential cost, NOx emission reductions, and economic impacts associated with the NOx SIP call for electricity generating sources. The results of various regulatory alternatives are presented and compared with each other and with one of two baselines. Section 6.1 introduces the annual cost and emission measures and compares four uniform regulatory alternatives (based on NOx emission rates of 0.25, 0.20, 0.15, and 0.12 lbs/mmBtu) to the Initial Base Case (as well as the Final Base Case). Section 6.2 compares the results under the 0.15 uniform (that is, NOx-SIP-call-region-wide) alternative to alternatives that restrict trading to two or three sub-regions, with emission rates that vary by sub-region. Section 6.3 presents the results of an analysis of alternative program designs and sensitivity analyses, in which the results for the 0.15 alternative are shown under various alternative assumptions regarding electricity demand, equipment life, control measure effectiveness, and the discount rate. Potential direct and indirect economic impacts of the rule are discussed in Sections 6.4 and 6.5 of this chapter, respectively. Finally, Section 6.6 presents administrative costs, and Section 6.7 contains references for the chapter.

The comparisons between alternatives, comparisons of major program alternatives, and the sensitivity analyses are made in reference to the 0.15 lb/mmBtu alternative because that alternative is the basis for the final NOx SIP call emissions budgets. For most of the comparisons, results are presented only for the year 2007. Limiting the presentation to a single year simplifies the exposition, and the similarity in costs and emission reductions from year to year ensures that little is lost by the simplification. The year 2007 is selected in part because many areas of the affected region are obligated to reach compliance with the one-hour ozone standard in that year. In addition, modeling predicts that annual compliance costs reach their peak near 2007, so presenting only that year avoids understating the costs of the rule.

6.1 Comparison of Uniform Alternatives to the Initial Base Case

EPA considered four geographically uniform alternatives in developing the NOx SIP call, each one based on a different allowable emissions rate. For example, the 0.15 alternative is based on limiting summer NOx emissions to 0.15 lb/mmBtu of fuel heat input during the summer season after allowing for growth in electricity demand to 2007. This alternative imposes a seasonal cap of 564 thousand tons of NOx. The 0.15 alternative provides the point of comparison for sensitivity and other analyses in this chapter. The Integrated Planning Model was used to generate predictions of the technology selection, costs, and emissions for electricity generating units under the various alternatives.

Trading is assumed to be allowed both within and among the 23 jurisdictions in the SIP call region. EPA examines the cost and emission reduction impacts of each of the uniform regulatory alternatives incremental to the Initial Base Case level. The Initial Base Case assumes compliance with RACT, BACT, and NSPS requirements, as well as Phase I of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU), as such it includes all currently applicable Federal or State NOx control measures. The Final Base Case assumes the controls included in the Initial Base Case, as well as Phase II and Phase III of the OTC MOU. In the Final Base Case, many units have already implemented SNCR and SCR controls to meet the more stringent requirements of the Final Base Case. This section presents the results of the cost and emissions reductions analyses and translates those results into measures of cost-effectiveness for the uniform regulatory alternatives. Section 6.1.5 of this chapter contains a comparison of the costs of the 0.15 trading alternative in the Initial and Final Base Cases.

6.1.1 Technology Selection

Tables 6-1 and 6-2 present emission control responses for coal and oil/gas fired boilers in the SIP call region under each of the uniform alternatives. If States choose to follow the implementation scenario that EPA has modeled, Table 6-3 shows additions to natural gas combined cycle capacity that will occur as part of compliance. Industry will increase its use of natural gas over coal to generate power as part of its approach to compliance. Some coal, oil, or gas-fired boilers will be retrofit with SCR, SNCR, or gas reburn. Others will have no incremental control technology added beyond the types of controls required under Title IV, BACT and OTC Phase I/RACT in the Initial Base Case. In addition, some boiler capacity will could close in response to the way States implement the NOx SIP call. Not shown in the table are combustion turbines and combined cycle units, which are not expected to be retrofit with additional controls in response to the NOx SIP call. IPM analysis does show, however, that about 2,000 to 4,000 MW of combined cycle capacity would be added, depending on the alternative. The IPM runs project that almost all of the control technology retrofits needed to reduce emissions to the cap under the uniform alternatives would come from the coal-fired boilers, which tend to be both larger and higher in baseline emissions than other types. As alternatives become more stringent, Title IV controls (i.e., combustion controls such as low NOx burners) are augmented with SNCR and then with SCR (which is capable of greater NOx reduction). The same general pattern is seen for the oil/gas- fired boilers, though the percentages of them that are retrofit with SNCR or SCR are smaller than for the coal boilers.

Table 6-1
Estimated Emission Control Responses for Coal-Fired Steam Units to the NOx SIP Call in 2007
(MW Capacity for the SIP Call Region)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Close Unit	18	16	113	183
Comply with BACT	4,158	4,158	4,158	4,158
Title IV NOx Controls Only [a]	97,895	40,242	4,545	4,879
Add SNCR	93,003	133,240	129,690	83,172
Add SCR	7,208	23,384	63,267	109,761
Add Gas Reburn	-	1,242	509	129

Source: ICF analysis.
[a] This row shows the MW capacity adding *only* Title IV NOx controls. Therefore, the numbers tend to decrease with increases in option stringency.

Table 6-2
Estimated Emission Control Responses for Oil/Gas-Fired Steam Units to the NOx SIP Call in 2007
(MW Capacity for the SIP Call Region)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Close Unit	182	181	201	151
No Further Controls Beyond OTC Phase I/RACT	33,564	33,253	29,890	23,624
Add SNCR	447	759	4,102	7,008
Add SCR	-	-	-	3,410

Source ICF analysis

Table 6-3
Estimated Emission Control Responses to the NOx SIP Call in 2007 -- Added Natural Gas Combined-Cycle
(MW Capacity for the SIP Call region)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Added Capacity of Combined Cycle[a]	1,895	1,798	2,200	4,156

Source ICF analysis
[a] Above level in the Initial Base Case which is 47,308 MW

6.1.2 Emissions

The control technologies presented in Tables 6-1 and 6-2, which result from the implementation scenario modeled by EPA, will reduce NOx emissions by hundreds of thousands of tons in the SIP call region Although the NOx SIP call focuses on ozone season NOx emissions, reductions of NOx emissions under the uniform alternatives will occur year-round because some of the control strategies (e g . combustion controls) function continuously For the 0 15 alternative in 2007, the annual reductions amount to 1,183 thousand tons over the Initial Base Case, with 245 thousand of those tons (21 percent) from outside the ozone season Table 6-4 shows the incremental ozone season tons of NOx emitted under each of the uniform alternatives compared to the Initial Base Case The rule requires sources to be in compliance starting in May 2003 From that point on, the emissions for electricity generating units are assumed to be capped under the scenarios modeled by EPA, resulting in 564 thousand tons of NOx per ozone season under the 0.15 alternative Initial Base Case emissions continue to increase after this point due to forecasted growth in electric power generation, while the cap remains constant As a result, the incremental NOx emission reductions grow yearly after 2003 Figure 6-1 shows State-by-State emissions results for each of the uniform trading alternatives, compared to the emissions under the Initial Base Case[1]. Figure 6-2 shows the emissions for the Initial Base Case, the State budget levels, and the IPM analysis results for the 0 15 trading

[1] The data used to develop Figure 6-1 is included in Appendix B, Table B-1

alternative[2] The incremental reduction in ozone season tons under the 0.15 alternative amounts to about 62 percent of baseline ozone season NOx emissions in the period between 2003 and 2010 — slightly less in the early years and slightly more in the later years. By contrast, the reductions in annual tons are less than 35 percent of baseline annual tons, because emission reductions in the winter months are only about 12 percent of baseline emissions. This disparity stems from the fact that the most widely used control strategies — SNCR and SCR — can be shut off at the end of each ozone season to limit operating costs. Most importantly, as Figure 6-2 shows, a uniform trading program can lead to reductions throughout the NOx SIP call domain that are comparable to what would occur under a command-and-control approach where States set emission rates for EGUs aimed at hitting each State's NOx budget level.

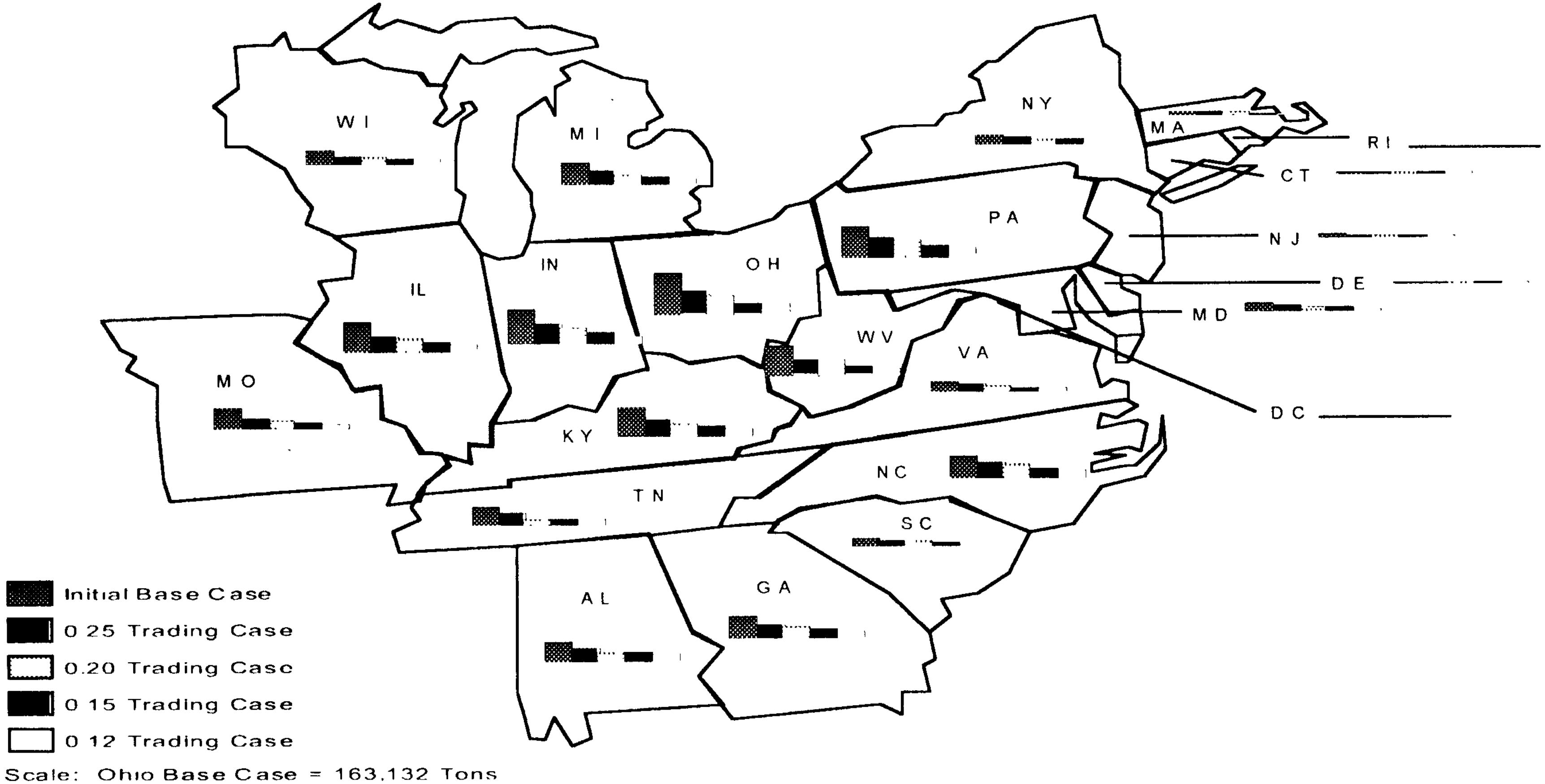
Table 6-4
Estimated Ozone Season NOx Emissions and Reductions
under the Uniform Trading Alternatives and the Initial Base Case
(1,000 tons)

Case/Alternative	2003	2005	2007	2010
Initial Base Case	1,462	1,497	1,502	1,511
0.25 Trading (Reduction)	940 (523)	940 (557)	940 (563)	940 (572)
0.20 Trading (Reduction)	751 (711)	751 (746)	751 (751)	751 (760)
0.15 Trading (Reduction)	564 (899)	564 (933)	564 (938)	564 (948)
0.12 Trading (Reduction)	453 (1,009)	453 (1,043)	453 (1,049)	453 (1,058)

Source: ICF analysis
Numbers do not sum due to rounding

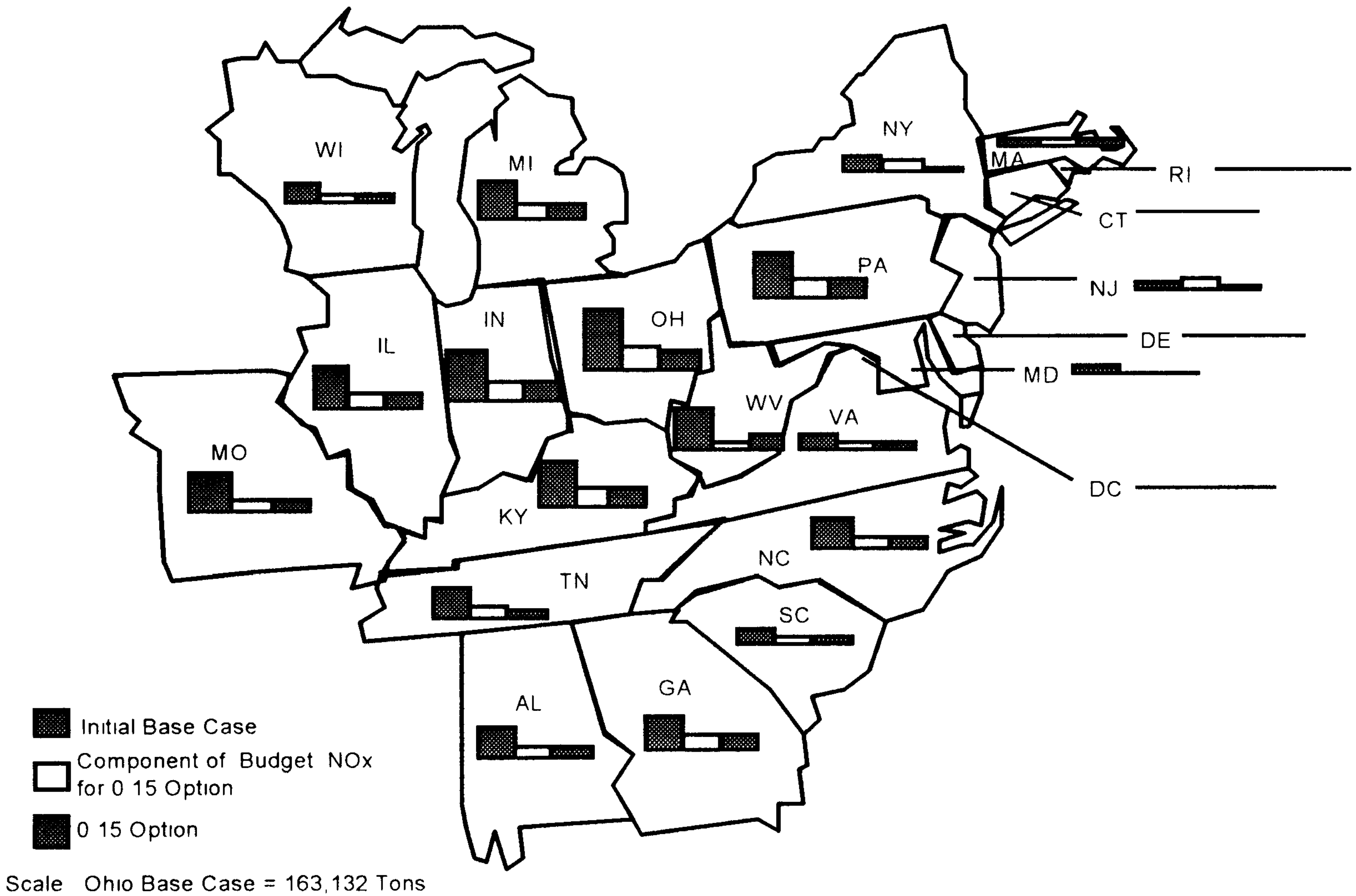
[2] The data used to develop Figure 6-2 is included in Appendix B, Table B-2

Figure 6-1
Ozone Season NOx Emissions in 2007 from the Electric Power Industry for States in the SIP Call Region: Uniform Trading Alternatives Compared to the Initial Base Case



Source: ICF Analysis

Figure 6-2
Ozone Season NOx Emissions in 2007 from the Electric Power Industry for States in the SIP Call Region: Uniform 0.15 Trading Alternative Compared to the Initial Base Case and the State Budget Component under the 0.15 lb/mmBtu Limit



6.1.3 Costs

EPA calculated the annual cost of the uniform alternatives incremental to the Initial Base Case level[3] Table 6-5 presents EPA's estimates of the total annual costs that the electric power industry could incur in the years 2003, 2005, 2007, and 2010 For each of the uniform alternatives, the incremental cost rises until 2007, but begins to fall in subsequent years Because of growth in demand for electricity, the fixed cap of 564,000 tons per ozone season becomes progressively tighter over time; as fuel input grows, the fixed allocation of allowances leads to a tighter and tighter effective limit This effective tightening tends to drive the costs of meeting the emissions cap higher over time Countering this tendency, on the other hand, is a reduction over time in the costs of new generation and control technologies, and the possibility of retrofitting existing plants to function as combined-cycle units By 2010, these improvements begin to dominate, and incremental costs begin to decline

Table 6-5
Incremental Annual Costs for Uniform Alternatives Relative to the Initial Base Case
(Compliance Costs above Initial Base Case, million 1990$)[a]

Alternative	2003	2005	2007	2010
0 25 Trading	$589	$628	$643	$632
0 20 Trading	$894	$935	$948	$932
0 15 Trading	$1,308	$1,354	$1,378	$1,341
0 12 Trading	$1,766	$1,816	$1,846	$1,757

Source ICF analysis
[a] Compliance costs do not include administrative monitoring or transaction costs which are minor in comparison to the total cost of the rule Units covered by Title IV will have monitoring devices in the baseline, which will reduce the incremental monitoring costs See Section 6 6

Trading

Some regulated sources have years of experience with inter-firm and intra-firm emissions trading In the mid-1980s, EPA published the Emissions Trading Policy Statement (51 FR 43831), which allowed sources to obtain emission credits for use as emission offsets and in bubbles In 1990, the Clean Air Act Amendments (CAAA) expanded the potential pool of sources that would need to obtain offsets The 1990 CAAA was also the advent of the acid rain SO_2 allowance market, under which the electric power industry learned to use emissions trading as a compliance strategy In addition, a variety of market-based programs have been implemented at the State and local levels Most recently, the Ozone Transport Commission adopted a Memorandum of Understanding committing the signatory States to the development and proposal of a regional NOx emissions cap-and-trade program, similar to the one proposed under the NOx SIP call Under these emissions trading programs, especially the allowance markets, the affected sources became familiar with emissions trading markets and the procedure for buying and selling allowances

[3] All cost data and cost-effectiveness calculations are presented in 1990 dollars

Sources are assumed to participate in the NOx allowance market to utilize the most cost-effective compliance option and because of experience gained with other trading programs The potentially affected sources are expected to trade allowances within their own company and/or with other companies For example, based on the IPM results for the 0.15 alternative, 641 units are projected to obtain about 78,000 allowances from the 506 units projected to provide excess allowances. Only 23 percent of the units (333 units) are expected to use only the allowances allocated to them. Table 6-6 shows the number of expected trades for individual units, including inter- and intra-firm transactions, under the 0.25, 0.15, and 0.12 uniform alternatives It is notable that a substantial number of trades could occur under each of the alternatives examined, with many units able to generate excess allowances for the use of other units The number of allowances traded between and within companies under each of the uniform alternatives varies somewhat under the 0 12 alternative, approximately 73,000 allowances may be traded, while under the 0 25 alternative, approximately 118,000 allowances may be traded Under the 0.15 alternative, about 37,000 of the 78,000 traded allowances (about half) are projected to be inter-firm trades Though EPA has estimated the volumes of inter-firm allowance trades only for the 0.15 alternative, the number of allowances traded among individual firms may vary from alternative to alternative

6.1.4 Cost-Effectiveness

The average cost-effectiveness of the regulatory alternatives is calculated from the Initial Base Case level Cost-effectiveness is calculated as the total annual costs of the alternative divided by ozone season emission reductions Table 6-7 shows the emissions change and the annual costs and cost-effectiveness that the EPA estimates for the potentially affected part of the electric power industry in the years 2003, 2005, 2007, and 2010 As shown in the table, the average costs per ozone season ton of NOx removed under the 0 15 alternative for each of the four years differ slightly, but for each year is less than $1,500 per ton of NOx removed The highest cost per ton removed is seen in 2007 The effects of the growth in electricity demand and the application of the fixed cap of ozone season tons of NOx on cost, described in the preceding section, explains the pattern in cost-effectiveness over time Comparing the change in total costs to the change in emissions, it can be seen that the cost per ozone season ton removed increases Thus, costs are rising faster than emission reductions, as more costly measures are pressed into service on smaller and less-intensively used units

The increasing per-ton cost can be seen more clearly by presenting the changes in costs and tons for each alternative *relative to the next-most-stringent alternative*, instead of relative to the base case This approach, which shows the incremental per-ton costs of just the *additional* tons of reductions as the alternatives grow more stringent, is presented in Table 6-8

Table 6-6
Number of Fossil Fuel-Fired Units in IPM Runs
Expected to Buy, Sell, or Do Nothing in the NOx SIP Call Trading Program[a]
(0.25, 0.15, and 0.12 Uniform Alternatives)

Fuel Type	Buy Allowances	Sell Allowances	Do Nothing
0.25 Trading			
Coal	517	265	0
Oil/Gas	9	123	10
Combined Cycle/ Combustion Turbine	15	207	335
Integrated Gasification/ Combined Cycle	0	1	0
Total	541	596	345
0.15 Trading			
Coal	507	275	0
Oil/Gas	39	91	10
Combined Cycle/ Combustion Turbine	95	139	323
Integrated Gasification/ Combined Cycle	0	1	0
Total	641	506	333
0.12 Trading			
Coal	462	320	0
Oil/Gas	38	92	10
Combined Cycle/ Combustion Turbine	112	130	315
Integrated Gasification/ Combined Cycle	0	1	0
Total	612	543	325

[a] Allowance transfers within companies are included among the purchases and sales though money would not necessarily change hands in these internal transactions

Table 6-7
Summary of Estimated Emission Reductions, Cost, and Cost-Effectiveness for the Uniform Alternatives of the NOx SIP Call: Selected Years

Year/Alternative	Reductions in Ozone Season NOx Emissions (1,000 tons)	Annual Cost above Initial Base Case (million 1990$)	Cost per Ozone Season Ton of NOx Removed (1990$/ton)
2003			
0.25 Trading	523	$589	$1,127
0.20 Trading	711	$894	$1,258
0.15 Trading	899	$1,308	$1,455
0.12 Trading	1,009	$1,766	$1,750
2005			
0.25 Trading	557	$628	$1,128
0.20 Trading	746	$935	$1,254
0.15 Trading	933	$1,354	$1,451
0.12 Trading	1,043	$1,816	$1,741
2007			
0.25 Trading	563	$643	$1,143
0.20 Trading	751	$948	$1,263
0.15 Trading	938	$1,378	$1,468
0.12 Trading	1,049	$1,846	$1,760
2010			
0.25 Trading	572	$632	$1,106
0.20 Trading	760	$932	$1,226
0.15 Trading	948	$1,341	$1,415
0.12 Trading	1,058	$1,757	$1,660

Source: ICF analysis
Because of rounding, the cost-effectiveness values do not equal the ratio of the costs to the NOx reductions shown in the table

Table 6-8
Comparison of Estimated 2007 Incremental Ozone Season NOx Emission Reduction, Cost, and Cost-Effectiveness for Different Regulatory Alternatives

Alternative	Reduction Incremental to Next-Most-Stringent Alternative (1,000 ozone season tons)	Cost, Incremental to Next-Most-Stringent Alternative (million 1990S)	Incremental Cost-Effectiveness, Relative to Next-Most-Stringent Alternative (1990S/ozone season ton)
0 25 Trading[a]	563	$643	$1.143
0 20 Trading	188	$305	$1,618
0 15 Trading	187	$430	$2,294
0 12 Trading	111	$468	$4.240

Source ICF analysis
Because of rounding, the cost-effectiveness values do not equal the ratio of the incremental costs to the NOx reductions shown in the table
[a] Compared to the Initial Base Case

6.1.5 Initial Base Case Compared to Final Base Case

The Initial Base Case assumes compliance with RACT, BACT, and NSPS requirements, as well as Phase I of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU) As such, it is best suited for estimating the cost of further controls above the requirements already in place The Final Base Case assumes the controls included in the Initial Base Case, as well as Phase II and Phase III of the OTC MOU In the Final Base Case, many units have already implemented SNCR and SCR controls to meet the more stringent requirements of the Final Base Case and will not need to spend as much to meet the NOx SIP call requirements For this reason, the cost of the NOx SIP call is lower when compared to the Final Base Case than to the Initial Base Case For example, the incremental annual cost of the 0 15 alternative is $1.250 million when compared to the Final Base Case, but $1.378 million compared to the Initial Base Case

6.2 Regional versus Uniform Approach to Trading

The uniform alternatives presented in the preceding section set State-by-State caps that are all based on the same nominal emission rate, and envision unrestricted trading of emission allowances among all SIP call States EPA also examined alternatives that attempt to target the emission reductions to the sources that might have the greatest impact on severe non-attainment areas downwind These regional trading alternatives set tighter caps for States closer to the Northeast, and less stringent caps for the Midwest and Southeast Because a trading system that allowed unrestricted trade of allowances from region to region would undermine the stratified caps set up by these regional alternatives, interstate trading is limited to States within the same regions

The remainder of this section compares the cost and emissions results under the 0.15 trading alternative with the two-region (Regionality 1) and three region (Regionality 2) alternatives in turn The comparisons place less emphasis on cost per ton of NOx removed, and more emphasis on showing the differences between alternatives in terms of emissions by region and the effects of trading Because the intent of the regional alternatives is to cost-effectively reduce ozone levels in severe nonattainment areas, the cost per ton of NOx removed is of secondary importance compared to the distribution of emission reductions

6.2.1 Comparison of Baseline and Uniform 0.15 Alternative to the Two-Region Alternative (Regionality 1)

The summary of the effects of the two-region alternative (Regionality 1) relative to the 0.15 trading alternative are shown in Table 6-9 The two-region alternative restricts trading to within two regions, split approximately along Northern and Southern boundaries [4] Because the two-region alternative reduces the stringency of the cap (to a nominal 0.20 lb/mmBtu) in the Region 1 while leaving it constant (at a nominal 0.15 lb/mmBtu) in Region 2, it results in smaller emission reductions in Region 2 compared to the 0.15 trading alternative Figure 6-3 shows the State-by-State emission results for the two-region alternative compared to the Initial Base Case [5]

The two-region alternative would be less costly than the 0 15 trading alternative, which is to be expected given its lower stringency The cost of the 0 15 trading alternative compared to the baseline is $1,378 million, while the cost of the two-region alternative is $1,118 million Thus, the incremental 111 7 thousand tons of ozone season NOx emissions eliminated in 2007 under the uniform 0.15 trading alternative relative to the two-region alternative would cost an additional $260 million

Table 6-9
Comparison of Ozone Season NOx Emission Reductions:
Uniform 0.15 Trading Alternative, and the Two-Region Alternative (Regionality 1)
(1,000 tons)

Incremental Measure (from Baseline)	Reductions Relative to Initial Baseline: 0.15 Trading	Reductions Relative to Initial Baseline: Two-Region Alternative	Incremental Effect of Two-Region Alternative	Reductions under Two-Region Alternative as a Percentage of 0.15 Trading
Total Tons Reduced	938	826	-112	88%
Tons reduced, Region 1 (0 15 lb/mmBtu)	351	340	-11	97%
Tons Reduced, Region 2 (0 20 lb/mmBtu)	587	486	-101	83%

Source ICF analysis

[4] The two-region area consists of Connecticut, Delaware, District of Columbia, Massachusetts, Maryland, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Virginia, and West Virginia in Region 1 (Northeast and Mid-Atlantic States), and Alabama, Georgia, Illinois, Indiana, Kentucky, Michigan, Missouri, North Carolina, South Carolina, Tennessee, and Wisconsin in Region 2 (Southeast and Midwest States)

[5] The State Budgets for the two-region alternative used in Figure 6-3 are calculated using the variable emission rates for each SIP call region The data used to develop Figure 6-3 is included in Appendix B, Table B-3

6.2.2 Comparison of Three-Region Alternative (Regionality 2) to Uniform 0.15 Alternative

The three-region alternative sets a cap based on 0 12 lb/mmBtu in Region 1, 0 15 lb/mmBtu in Region 2, and 0 20 lb/mmBtu in the Region 3.[6] The emission results under the three-region alternative are similar to those of the 0 15 alternative. States in the Northeast tend to reduce NOx emissions beyond the 0 15 lb/mmBtu levels as part of their compliance strategy Under the 0.15 alternative, these States will receive credits that they can sell to electricity generating units in the Southeast and Midwest Under the three-region alternative, the electricity generating units in the Northeast are held to a tighter standard than under the 0 15 alternative, and will not receive as many credits as under the 0 15 alternative

Tables 6-10 and 6-11 display the same information about emissions between alternatives, but in different forms Table 6-10 shows total reductions, while Table 6-11 shows differences Both of the first two columns of Table 6-10 refer to the 0.15 alternative The first column shows the total NOx reductions (in thousands of tons per year) assigned to each of three regions, based on the caps given to States within Region 1 (the Northeast), Region 2 (the Midwest), and Region 3 (the Southeast) These figures represent the emission reductions by region that would be provided by the 0 15 alternative in the year 2007 *if there is no interstate trading*, that is, if States are held to their emissions budgets The second column shows the projected emissions reductions under the 0 15 alternative, given the interstate trading projected by IPM for 2007 The fact that the total reduction, 938 thousand tons, is the same in both columns reflects the fact that trading redistributes emission reductions but does not change the total

The third column of Table 6-10 shows the tons of reductions by region under the three-region case, these figures represent the emissions under the different caps specified by EPA No interregional trading is allowed under this alternative Across the rows of Table 6-10, we see that overall reductions are lower under the regional alternative, but reductions in the Northeast and Midwest are higher than under the 0 15 alternative The Southeast, with a cap based on a limit of 0 20 lb/mmBtu, has emissions of over 37 thousand tons higher than the 0 15 alternative Figure 6-4 shows the State-by-State emission results for the three-region alternative compared to the Initial Base Case and the expected results if the State Budgets were set with the limit of 0 15 lb/mmBtu [7]

The effects of trading and differences between alternatives are also shown in Table 6-11 The first column shows the difference between emission reductions under the 0 15 trading alternative and the reductions that would be required given the State-by-State budgets if trading is not allowed This column shows that the pattern of trading under the 0 15 trading alternative would tend to reduce emissions in the Northeast by an additional 14 thousand tons compared to the State budgets, while allowing the other two regions to reduce their emissions less than required to meet the State budgets

The second column of Table 6-11 compares the results of the three-region alternative to 0 15 alternative without trading. The three-region alternative does not reduce total emissions by as much, emissions would be higher by 22 thousand tons in 2007 under the three-region alternative than under the 0.15

[6] The three-region area consists of Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island in Region 1(Northeast States), Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio. Virginia. West Virginia, and Wisconsin in Region 2 (Midwest and Adjacent OTR States), and Alabama, Georgia, North Carolina, South Carolina, and Tennessee in Region 3 (Southeast States)

[7] The data used to develop Figure 6-4 is included in Appendix B, Table B-3

alternative, largely as a result of higher emissions in the Southeast The three-region alternative does reduce emissions *in the Northeast* by almost 25 thousand tons more than under the 0 15 alternative before trading, while providing for smaller reductions in the Midwest and especially the Southeast

As shown in the third column of Table 6-10, the effects of the three-region alternative are smaller if the changes due to interregional trading in the 0 15 alternative are considered. The three-region alternative provides about 11 thousand additional tons of reductions in the Northeast compared to the 0 15 alternative after trading, and about five thousand extra tons of reductions in the Midwest The annual cost of the three-region alternative compared to the Initial Base Case is $1,349 million The savings for this alternative compared to the 0 15 alternative would be on the order of $29 million

Table 6-10
Comparison of 2007 Ozone Season NOx Emission Reductions:
0.15 State Budgets, Uniform 0.15 Trading, and the Three-Region Alternative (Regionality 2)
(1,000 tons)

Incremental Measure (from Initial Base Case)	Reductions under 0.15 State Budgets[a]	Reductions under Uniform 0.15 Trading	Reductions under Three-Region Alternative
Total Tons Reduced	938	938	916
Tons reduced, Region 1 (0 12 lb/mmBtu)	117	131	142
Tons reduced, Region 2 (0 15 lb/mmBtu)	607	603	607
Tons reduced, Region 3 (0 20 lb/mmBtu)	214	204	167

Source ICF analysis
[a] The State Budget levels were set with a 0 15 lb mmBtu rate and a ozone season cap of 564,000 tons This column shows Initial Base Case Emissions - State Budgets for each region Total emission reductions under the State Budgets are equal to the emission reductions under the 0 15 alternative

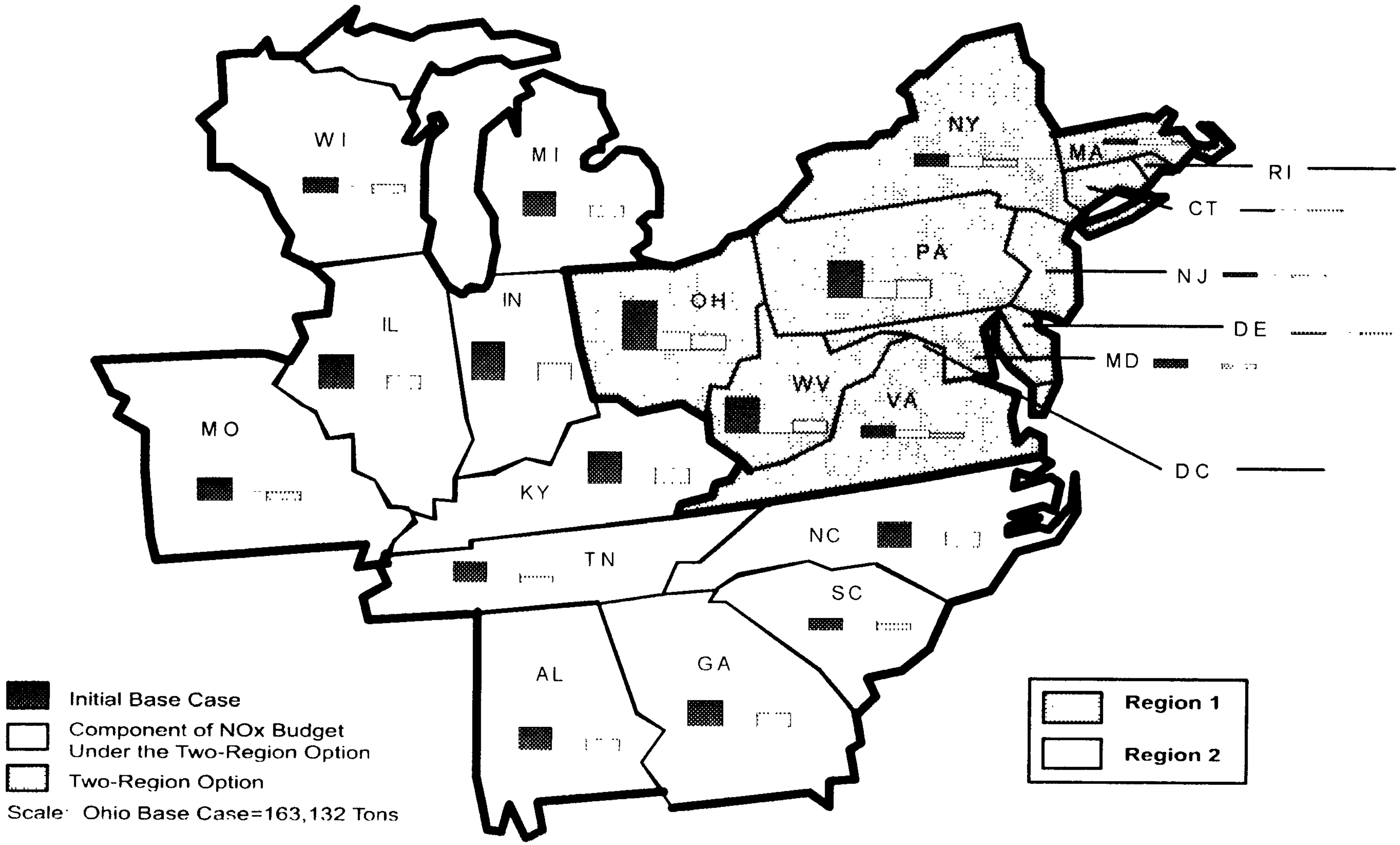
Table 6-11
Comparison of the Differences Between 2007 Ozone Season NOx Emissions for 0.15 State Budgets, Three-Region Alternative (Regionality 2), and Uniform 0.15 Trading
(1,000 tons)

Incremental Measure (from Baseline)	Reductions under 0.15 Trading Relative to State Budgets[a]	Reductions under Three-Region Alternative Relative to State Budgets[a]	Reductions under Three-Region Alternative Relative to 0.15 Trading
Total Tons Reduced	0.0	-22.0	-22.0
Tons reduced, Region 1 (0.12 lb/mmBtu)	13.8	24.7	10.9
Tons reduced, Region 2 (0.15 lb/mmBtu)	-4.4	0	4.5
Tons reduced, Region 3 (0.20 lb/mmBtu)	-9.3	-46.7	-37.4

Source: ICF analysis

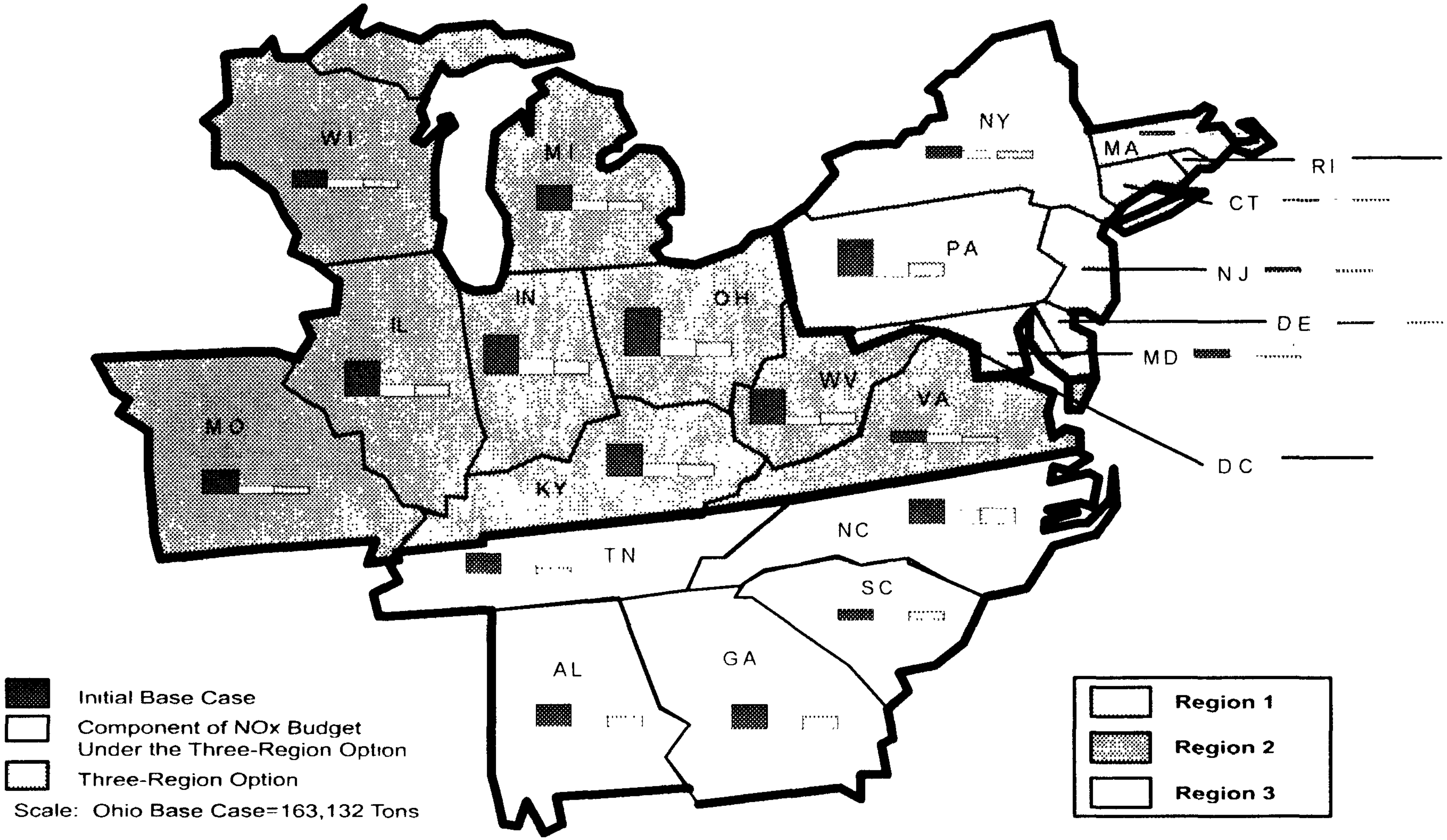
[a] The State budgets are listed in the SNPR for the 0.15 alternative and in Appendix B, Table B-1

Figure 6-3
Comparison of 2007 Ozone Season NOx Emissions in the Initial Base Case with the State Component of the NOx Budget Under the Two-Region Alternative and the Emissions Results from the Two-Region Alternative



Source: ICF Analysis

Figure 6-4
Comparison of 2007 Ozone Season NOx Emissions in the Initial Base Case with the State Component of the NOx Budget for the Three-Region Alternative and the Emissions Results from the Three-Region Alternative



Source: ICF Analysis

6.3 Other Program Designs and Sensitivity to Modeling Assumptions

This section compares the major program alternatives considered by EPA in the development of the NOx SIP call Section 6 3 1 contains a discussion of costs in the absence of interstate trading. Section 6.3 2 contains the results of the banking/no banking analysis, Section 6 3 3 presents an analysis of a 0.35 lbs/mmBtu alternative, and Section 6 3 4 presents IPM results for the 0 15 trading alternative under varying assumptions on technology, discount rate, and electricity demand

6.3.1 Costs without Interstate Trading

Another program option is to set State budgets based on a uniform emission rate and to restrict trading between sources within State boundaries Table 6-12 presents the results of the analysis restricting trading and shows the difference in outcomes under this "no interstate trading" case for the 0 15 lb/mmBtu alternative The cost increase for a program with 23 regions (where each of the jurisdictions covered by the NOx SIP call would be its own region and allowing trading only within each State or jurisdiction) compared to the 0 15 alternative is approximately two percent The cost difference is due to the fact that there are some differences in control costs within State boundaries, and effective trading can therefore occur within State boundaries This estimate of the difference in cost between the 0 15 trading alternative and the alternative that does not allow interstate trading is dependent on the assumption that all States will set up trading programs for electricity generating units within their boundaries If States adopt rate-based approaches, the cost could be expected to be higher, though this possibility was not explicitly modeled for this report [8] The distribution of emissions under the no interstate trading case, which is equal to the State budgets, is shown in Table 6-10

Table 6-12
Emission Reductions, Cost, and Cost-Effectiveness with and without Interstate Trading in 2007 for the SIP Call Region

Incremental Measure (from Base Case)	Region[a]	0.15 Alternative with Interstate Trading	0.15 Alternative without Interstate Trading	Effects of Preventing Interstate Trading
NOx Reductions (1,000 ozone season tons)	Region 1	131	117	- 14
	Region 2	603	607	4
	Region 3	204	214	9
	Region Total	938	938	0
Cost (million 1990$)	Region Total	$1,378	$1,407	$29
Average Cost per Ton (1990$)	Region Total	$1,468	$1,499	-

Source ICF analysis
[a] Regions 1, 2, and 3 are defined in Section 6.2 2

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[8] The effects of a program that did not allow trading within States was addressed in EPA September 1997

6.3.2 Banking

Under an allowance based emissions trading program with banking, sources can create reductions beyond required levels in one season, thus freeing up some allowances for use in a later season Each banked allowance represents one ton less emissions in the current season Banking is a cross-cutting option, because it can be used with any of the uniform or regional alternatives. Banking encourages early reductions, provides flexibility, and reduces cost for regulated sources. It also dispels the "use it or lose it" conception concerning the use of allowances, and accommodates changes in generation activity that may occur in response to interruptions of power supply from sources that do not emit NOx On the other hand, banking can create uncertainty about actual emissions in a given season

EPA considered several banking alternatives, including options with (1) no banking, (2) banking of emission reductions after the start of the program, (3) banking of "early" reductions (i e , those that come before the beginning of the program), (4) and banking from an earlier phase of the program to a later phase

Banking of "early" reductions was only modeled for the 0 15 alternative because earlier IPM analysis suggested that owners of electricity generating units would want to use it to a very limited degree to lower the costs of future compliance, although not all the important advantages of banking were incorpated into that analysis (EPA, 1997a) A two-phase banking program was also not modeled Table 6-13 presents IPM results for the 0 15 alternative with and without banking, where banking begins after the start of the program in 2003

Banking is most valuable for programs in which costs per ton removed rise over time, which is most likely to occur if the effective stringency of the regulations rises over time In the case of the NOx SIP call, the effective stringency rises only slightly over time as a result of a fixed emissions cap interacting with a growing demand for electricity Over time, however, anticipated improvements in technology (including combined-cycle retrofits) will counteract the effects of growth, so that the cost per ton removed is expected to fall eventually

Given the fact that costs per ton removed are expected to rise only slightly at first and then fall, it is not surprising that little banking was predicted by IPM in the 0 15 alternative with banking beginning in 2003 Both costs and the geographic distribution of emission reductions would be almost the same with or without a banking program

Table 6-13
Effects of Banking on Estimated Ozone Season NOx Emission Reductions, Incremental Cost, and Cost-Effectiveness for the 0.15 Trading Alternative

		2003	2005	2007	2010
Reductions of Ozone season NO_X Emissions (1,000 tons)	Without Banking	899	933	938	948
	With Banking Beginning in 2003	902	931	935	948
Costs, Incremental to Initial Base Case (million 1990$)	Without Banking	$1,308	$1,354	$1,378	$1,341
	With Banking Beginning in 2003	$1,326	$1,348	$1,358	$1,338
Average Cost/Ton of Ozone season NOx Removed (1990$)	Without Banking	$1,455	$1,451	$1,468	$1,415
	With Banking Beginning in 2003	$1,469	$1,448	$1,453	$1,412

Source ICF analysis

This analysis does not consider a banking plan in which emission reductions prior to 2003 could be used to ease the transition to the NOx SIP call, and help ensure that allowances were available for planning purposes early in the compliance period Under that type of banking program, more tons would be banked and the savings and other advantages (especially in terms of reduced uncertainty) would be greater Annual emissions starting in 2003, however, would be higher and less predictable than in programs that did not allow early emissions to be banked

6.3.3 Uniform 0.35 lb/mmBtu Trading Alternative

EPA analyzed the emissions and cost-effectiveness results of imposing a 0 35 lb/mmBtu standard for NOx, assuming no implementation of the OTC MOU Phases II and III (i e , the Initial Base Case) Under this scenario, no electricity generating units use post-combustion controls; rather, they add only Title IV controls The ozone season emissions reductions compared to the Initial Base Case in 2007 are an additional 187 thousand tons By comparison, the 0 15 trading alternative provides ozone season NOx emission reductions of 938 thousand tons The lower reductions in NOx emissions correspond to lower total and average costs Table 6-14 illustrates these results

Table 6-14
Comparison of Estimated 2007 Ozone Season NOx Emission Reductions, Incremental Cost, and Cost-Effectiveness Between Uniform 0.35 Trading Alternative and 0.15 Trading Alternative

	0.35 Trading	0.15 Trading	Incremental Effect
NOx Reduction (1,000 ozone season tons)	187	938	751
Annual Cost (million 1990$)	$217	$1,378	$1,161
Average Cost-Effectiveness (1990$/ozone season ton)	$1,165	$1,468	$303

Source ICF analysis
Numbers may not sum due to rounding

6.3.4 Sensitivity to IPM Assumptions

Sensitivity analyses on several key assumptions in the IPM analysis are presented in this section These analyses, which respond to many of the comments received on the proposed NOx SIP call, include the effects of a higher discount rate, lower SNCR effectiveness, shorter equipment life, and higher growth rates of demand were developed to assess the robustness of the results outlined above The sensitivity analyses are all evaluated relative to the uniform 0 15 trading alternative

Effects of Higher Discount Rate

This sensitivity analysis assumes that the after-tax cost of capital is eight percent per annum rather than the six percent rate that is assumed in the rest of the IPM modeling Table 6-15 presents cost and emission reduction differences between the two scenarios As shown, the incremental cost of the 0 15 trading alternative rises by about two percent when a higher discount rate is assumed Emission reductions are higher under the higher discount rate assumption, because the higher discount rate leads operators to delay installing new, lower-emitting units The delay in introducing new units leads to higher baseline emissions, and the need for greater reductions to reach the NOx SIP call cap

Table 6-15
Effects of Alternative Discount Rate Assumptions on the Emission Reductions and Cost in 2007 for the Uniform 0.15 Trading Alternative

	Expected Discount Rate (6%)	Higher Discount Rate (8%)	Incremental Effect
NOx Reduction (1,000 ozone season tons)	938	940	2
Incremental Annual Cost (million 1990$)	$1,378	$1,414	$36
Average Cost-Effectiveness (1990$/ozone season ton)	$1,468	$1,504	$36

Source ICF analysis

Effects of Lower SNCR Effectiveness

This scenario assumes that, on coal-fired boilers emitting below 0.50 lb/mmBtu, SNCR will reduce NOx by 30 percent rather than 40 percent assumed in the rest of the analyses Table 6-16 presents technology choices under the expected effectiveness scenario and the lower assumed effectiveness scenario, as well as the incremental change Table 6-17 presents cost differences between the two scenarios As shown, the incremental cost of the 0 15 trading alternative rises (by about 11 percent) when lower SNCR effectiveness is assumed Shifts in the application of technology also take place with lower SNCR effectiveness Table 6-17 shows that less capacity is retrofitted with SNCR when a lower effectiveness is assumed, and more capacity is retrofitted with SCR. EPA examined whether this potential increase in the installation of SCR would be feasible by 2003 and found that it would be feasible (EPA, 1998a) Also shown in Table 6-16 is a small increase in capacity of gas combined cycle units Costs increase in part because of the reduced cost-effectiveness of the SNCR units, and the consequent need to substitute more expensive control measures

Table 6-16
Emission Control Choices by 2007 under Lower SNCR Effectiveness: 0.15 Trading

MW of Capacity	Expected SNCR Effectiveness (40% reduction from coal-fired units with baseline NOx below 0.5 lb/mmBtu)	Lower SNCR Effectiveness (30% reduction from coal-fired units with baseline NOx below 0.5 lb/mmBtu)	Incremental Effect of Lower SNCR Effectiveness	
			Total MW	Percentage Change
SNCR	133,792	84,761	-49,031	-36 %
SCR[a]	63,267	93,638	30,371	47 %
Gas CC	20,443	20.997	554	2 7 %

Source ICF analysis
[a] In part because the increased need to install SCR is offset by reductions in SNCR installation, EPA's analysis of the feasibility of installing control technologies found that the necessary retrofits under this scenario could be accomplished See "Feasibility of Installing NOx Control Technologies by May 2003," U S EPA, July 1998

Table 6-17
Ozone Season NOx Emission Reductions, Incremental Cost, and Cost-Effectiveness in 2007 Under Lower SNCR Effectiveness: 0.15 Trading

	Expected SNCR Effectiveness (40% reduction from units with baseline NOx below 0.5 lb/mmBtu)	Lower SNCR Effectiveness (30% reduction from units with baseline NOx below 0.5 lb/mmBtu)	Incremental Effect of Lower SNCR Effectiveness
NOx Reduction (1,000 ozone season tons)	938	938	0
Annual Cost (million 1990$)	$1,378	$1,526	$148
Average Cost-Effectiveness (1990$/ozone season ton)	$1,468	$1,626	$158

Source ICF analysis

Effects of Shorter Equipment Life

This scenario assumes that all equipment life is 15 years rather than 20 years as assumed in the other analyses The changes in the technologies used to comply with the NOx SIP call under this scenario are similar to those seen for the higher discount rate scenario capital-intensive technologies are used less, with greater emphasis on dispatching changes Table 6-18 presents cost differences between the two scenarios As shown, the incremental cost of the 0 15 trading alternative would rise by six percent if equipment life were shorter than assumed by EPA

Table 6-18
Ozone Season NOx Emission Reductions, Incremental Cost, and Cost-Effectiveness in 2007
Assuming Shorter Equipment Life: 0.15 Trading

	Expected Life (20 years)	Lower Assumed Life (15 years)	Incremental Effect
NOx Reduction (1,000 ozone season tons)	938	941	3
Annual Cost (million 1990$)	$1,378	$1,461	$83
Average Cost-Effectiveness (1990$/ozone season ton)	$1,468	$1,552	$84

Source ICF analysis
Numbers may not sum due to rounding

Effects of Alternative Demand Scenarios

Tables 6-19 and 6-20 present the effects on projected cost and cost-effectiveness of changing electricity demand forecasts, using the 0.15 trading alternative as a basis for comparison. The first alternative scenario, shown in Table 6-19, assumes the full increase in demand projected by NERC, unlike EPA's baseline assumptions, this alternative does not allow for reductions related to the Climate Change Action Plan (CCAP)[9]. The second alternative scenario, shown in Table 6-20, assumes that retail competition (in addition to the already assumed wholesale competition) occurs throughout the country. Three main quantitative effects of retail competition were modeled: electricity price reductions, which will induce increases in electricity demand, initiation of time-of-day pricing, and increased retirement of nuclear generation units due to their inability to be competitive.

Both of these alternative demand scenarios lead, in the Initial Base Case, to more electricity production from fossil-fueled units. Greater projected fossil-fueled production leads, in turn, to higher emissions in the Initial Base Case, and the need for greater reductions to meet a given emissions cap. The total cost and the cost-effectiveness are therefore higher under the alternative demand scenarios.

[9] The CCAP reductions are listed in Chapter 4, Table 4-1

Table 6-19
Effects of Assuming Full NERC Demand/No CCAP Reduction on the Effects of the NOx SIP Call in 2007: 0.15 Trading

	NOx Reduction (1,000 ozone season tons)	Annual Cost (million 1990S)	Cost-Effectiveness (1990S/ton)
Projected Demand	938	$1.378	$1,468
Full NERC Demand/ No CCAP Reduction	996	$1,502	$1.508
Increase Due to Alternative Assumption	58	$124	$40

Source ICF analysis
Numbers may not sum due to rounding

Table 6-20
Effects of Assuming Retail Competition--More Demand/Less Nuclear Power on the Effects of the NOx SIP Call in 2007: 0.15 Trading

	NOx Reduction (1,000 ozone season tons)	Annual Cost (million 1990S)	Cost-Effectiveness (1990S/ton)
Projected Demand	938	$1,378	$1.468
Retail Competition -- More Demand. Less Nuclear Power	996	$1.491	$1.498
Increase Due to Alternative Assumption	58	$113	$30

Source ICF analysis
Numbers may not sum due to rounding

6.4 Direct Economic Impacts

This section presents the results of the cost analyses from the perspective of potential economic impacts Direct impacts. which are presented in this section. are those borne by the entities that potentially incur costs because they are required to reduce emissions Indirect impacts. on the other hand. fall on entities that are affected through their interactions with the directly affected entities They are presented in Section 6.5

This section moves from the broadest level of impacts down to more specific assessments Costs of the rules relative to all electricity generation are presented first. followed by consideration of the potential distribution of costs across types of generators Finally, potential impacts on small owners of electricity generating units are summarized

6.4.1 Costs Relative to Electricity Generation and Revenues

Table 6-21 shows the potential impact of the compliance costs of the rule at the broadest level by comparing them to the total amount of electricity generated annually Annualized costs for the year 2007 are shown in the third row of the exhibit for four uniform alternatives. These costs are then compared to electricity generation to show costs in terms of mills (i e., tenths of cents) per kilowatt-hour. Also shown in the table is the fact that generation in the SIP call region is lower under each of the alternatives than in the base case Because power production will be growing over time with or without the NOx SIP call, producers in the SIP call region will still generate more power in 2007 than in the current year — the effect of the NOx SIP call will be to lower the rate of generation growth in the SIP call region and shift some of it to nearby States where power is less expensive to produce[10]. Furthermore, because some utilities will own capacity both inside and outside of the SIP call region, some of the shifts in generation will represent a shift within corporations, rather than a shift in output from one group of firms to another

Table 6-21
Generation Changes and Costs Compared to Generation in 2007 for Uniform Alternatives of Differing Stringency

	Initial Base Case	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Total Generation in SIP Call Region (millions MWhrs)	2,075	2,026	2,026[a]	2,018	1,995
Percent of National Power Generation	56%	55%	55%	55%	54%
Costs Relative to Initial Baseline (billion 1990$)	-	0 64	0 95	1 38	1 85
Cost per Unit (mills/kWh, 1990$)	-	0 31	0 47	0 68	0 93

Source ICF analysis and U S Energy Information Administration *Annual Energy Outlook 1998* December 1997
[a] Generation is lower under the 0 20 alternative than the 0 25 alternative, the difference is not apparent because of rounding

These potential costs can be put into perspective by comparing them to the typical revenues received by electricity suppliers Table 6-22 shows, for the same alternatives presented in the preceding exhibit, the incremental per-kilowatt cost of generation in comparison to an estimate of per-kilowatt-hour revenues received by utilities and other suppliers in the SIP call region Revenues, in turn, closely approximate the total costs of supplying electricity to the end-use customer (including amortization of equipment and a return on invested capital) [11] Table 6-22 shows that the potential costs of the rule are less than two percent of the revenues of electricity suppliers for all of the alternatives, and climb above one percent only for the 0 15 and

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[10] EPA did not analyze the potential change in electric demand (it is held constant), rather, EPA analyzed the change in the mix of suppliers that may result from implementation of the SIP call

[11] Table 6-22 shows the costs of the NOx SIP call in 2007 in comparison to 1996 revenues from electricity Per-unit revenues can be expected to change over time (as a result of increased competition in the industry), so the percentage impact of the rule will differ from the impact shown in the table

0.12 alternatives. Under traditional cost-of-service regulation, this potential cost increase could be expected to constitute the price increase as well.

Table 6-22
NOx SIP Call Compliance Costs by Alternative Compared to Revenues from Electricity in 2007 (1990$)

	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Average Per-unit Revenues, 23 Jurisdictions, Base Case (mills/kWh)[a]	60.00	60.00	60.00	60.00
Cost per Unit, all Generation in SIP Call Region (mills/kWh)	0.31	0.47	0.68	0.93
Cost as a Percentage of Revenues	0.52%	0.78%	1.13%	1.55%

Source: Average revenues per kWh calculated by ICF using EIA Form 861 for 1996; other figures calculated by ICF.
[a]The table shows the costs of the NOx SIP call in 2007 in comparison to current revenues from electricity. Per-unit revenues can be expected to change over time (as a result of increased competition in the industry), so the percentage impact of the rule will differ from the impact shown in the table.

Effects of Cost Changes on Electricity Producers

Whether potential costs of the magnitude shown in Tables 6-21 and 6-22 have a significant impact on electricity producers depends in part on whether the costs will be accompanied by offsetting price changes. In the past, because the electric power industry was tightly regulated, it was reasonable to assume that their commissions would have approved (perhaps after a lag) rate increases sufficient to cover the costs related to emission control programs. Alternatively, part of the rule-related increases in operating costs may have been reflected in fuel adjustment clauses. The lack of competition helped to limit the reduction in demand resulting from a rate increase. Utilities could thereby expect to continue receiving an adequate return on invested capital, and concerns about economic impacts were limited to the lag between cost and rate increases, and the impacts of the rate increases on electricity demand.

More recently, the restructuring of the industry and the prospect of competition among utilities and non-utility producers has added uncertainty to the task of projecting economic impacts on utilities. Competition at the wholesale level may complicate the process of passing on unusually high costs, while greater uncertainty over the speed of retail deregulation increases the difficulty of projecting the price impact on customers. This section discusses some potential effects of the restructuring process on the recovery of the costs of the rule by electricity generators.

The potential effects of the NOx SIP call on the electric power industry will depend in part on the timing of the rule relative to the progress of the restructuring process. The NOx SIP call is scheduled to go into effect by mid-2003. Competition at the wholesale level is already underway and will be fully implemented prior to 2003. Competition at the retail level is expected to spread widely by 2002, and to be largely complete by 2003 to 2005 (in the States where it occurs). Thus, for most of the period in which the NOx SIP call will impose costs, the assumptions of freely competitive markets should apply. The following discussion of effects on utilities, therefore, begins from a free-market perspective. Following that discussion, the effects of possible limits on competition early in the period are discussed.

Effects of Cost Increases Under Competition

In a world in which electricity prices are set by competitive market forces at both the wholesale and the retail level, theory predicts that the interaction of buyers and sellers will ensure that prices reflect the marginal costs of generation (that is, the incremental costs of producing another unit of output) [12] The need to limit NOx even as electricity output increases means that marginal costs of generation will rise: producing more electricity under the NOx SIP call might require using more reagent for SNCRs as capacity factors increase, or it might require the use of higher-cost fuels than are used under the Initial Base Case Assuming that the demand for electricity is relatively inelastic (which is a reasonable conservative assumption for the short run), the price of electricity is predicted to rise by up to the amount that marginal costs rise [13]

Because suppliers in a competitive market are not required to produce at a loss, this increase in prices can be expected to be high enough to at least cover the *variable* costs actually incurred by every producer Any kilowatt-hours that would have cost more to generate than the revenues they would bring in would not be produced The fact that price will be high enough to cover variable costs, however, does not by itself mean that there would be no impacts on generators. Some generating units might have unusually high variable costs for any given level of output; such units will not be used during time periods in which the market price of electricity is too low given their variable costs Overall, generators in the SIP call region are predicted to cut output during the ozone season by several percent, largely from power plants that would use control strategies with high marginal costs (e.g., combinations of SNCR and allowance purchases) The owners of these units would lose the net revenues they would have earned on those kilowatt-hours of output that they did not produce, if their State chose to implement the NOx SIP call as modeled by EPA

A more significant issue is that the adjustment of prices in response to changes in marginal costs does not guarantee that all increases in fixed costs will be covered Fixed costs (such as the capital costs of installing emission control systems) do not affect the free market equilibrium unless they are large enough to result in the retirement of plants as a way to avoid incurring unrecoverable costs Short of early retirement, which IPM does not project for any significant amount of capacity, there is no necessary connection between fixed costs and price changes

Some or all of the fixed costs of the rule can be recouped if the price increases exceed the average change in variable costs A relatively large increase in marginal costs could occur, for example, if generating units that are available for generating incremental power tend to be those with high variable costs of control (e g , those with SNCR and a need to purchase allowances for every additional mmBtu of fuel used) Because the change in the price of electricity will be determined by the increase in marginal costs for these marginal units, the price increase could be higher than the average increase in variable costs

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[12] The total price of electricity to consumers includes, in addition to the costs of energy, additional costs for transmission, distribution, and (where appropriate) charges for peak capacity Capacity charges were found not to be affected significantly under the 0.15 alternative, and transmission and distribution charges are assumed not to change in response to the NOx SIP call Thus, this analysis and discussion focuses on the marginal costs of producing energy, which are expected to rise as a result of the NOx SIP call

[13] A price increase could result in a more significant reduction in the quantity of electricity demanded in the long run than in the short run A reduction in electricity demand would lower the total costs of the NOx SIP call, and limit the size of the price increase, while reducing the revenues received by electricity producers These possible impacts have not been analyzed for this report

This pattern appears to fit the case of the 0 15 alternative Among coal-fired boilers, those units projected to retrofit with SNCR tend not to be used to the maximum extent possible (in part because their costs of operation are high). By contrast, the coal-fired boilers retrofit with SCR, which have lower increases in marginal cost, tend to be run almost continuously, and cannot contribute to further increases in output Thus, increases in electricity output tend to come from the under-utilized units retrofit with SNCR, and the marginal costs of electricity tend to reflect their high variable costs of control Based on model results, it appears that marginal-cost-based prices would rise by more than enough to cover *in aggregate* both the fixed and variable costs of the rule

There is, however, no guarantee or even expectation that the increased revenues will accrue in exact proportion to increased costs Rather, owners of units for which emissions are unusually low in the baseline (or for which costs of control are low) will tend to gain when prices rise as a result of the rule Conversely, owners of high-emitting units that are costly to control will not necessarily recover all of their increased costs The additional costs might then be borne by the owners of those units

Because of the restructuring process that is accompanying the shift from regulated to free market conditions, the identities of the owners of the units is somewhat uncertain The traditional, vertically integrated utility provides all of the functions of generation, transmission, distribution, and marketing services Under competition, some of these functions are likely to be split off utilities might sell off their generation capacity and/or turn over their marketing functions to other entities, possibly keeping their transmission and distribution functions The owners of the power plants, who will presumably be responsible for reducing emissions and for holding sufficient allowances, might well be entities other than the utilities that currently own them

Whether this change in ownership also means that any particularly high costs under the NOx SIP call will fall on the new owners is less clear To the extent that unrecoverable costs of compliance can be clearly predicted before the sale of the power plant, these potential costs will most likely be considered fully in the negotiations over the selling price That is, unusually high-emitting plants will tend to have lower market values than clean ones Only the costs that cannot be foreseen (resulting, perhaps, from unforeseen increases in allowance prices) will fall on the new owners A significant portion of the costs of the rule might then be borne by the current owners of those generation assets that will cost the most to control Because most utilities own a range of different types of generation capacity, with varying baseline NOx rates, some of the variability in costs can be expected to be canceled out high costs for high-emitting generation will be balanced in many cases by plants with low or zero emissions

Effects of Cost Increases during the Transition to Competition

As mentioned above, there may be cases in which electricity is sold at regulated retail prices for a period after the implementation of the NOx SIP call The effects of the regulations will ultimately depend on the decisions made by the utility regulators, and cannot therefore be predicted with assurance. Understanding the reason for the continued regulation of retail electricity prices might narrow the uncertainty over their possible effects

One of the main reasons that some retail price regulation will persist is to deal with the problem of "stranded costs" — fixed costs that were incurred under a regulated environment, for generation assets that would not be able to cover their full costs in a free market Regulatory responses to the problem of stranded costs vary by SIP call region and situation In some cases, the issue of stranded cost recovery has been separated from the issue of free market rates by including on utility bills a separate, non-by-passable charge to cover stranded costs The rest of the bill would be determined by the market, and could presumably take the effects of the NOx SIP call into account

In other cases, utility regulators have agreed to fix retail prices for the electricity sold by utilities that own these assets for a set period, rather than allowing the generating prices that customers will ultimately see to float down to free-market levels. If the utility is able to reduce its costs (of generation, or of purchasing power from other suppliers), while continuing to sell at a fixed rate, it will be able to cover some portion of its stranded costs In some cases, the utilities agree to provide a discount from previous regulated rates, so that consumers can realize some of the advantages of the free market even during the transition. If the terms of the agreed-upon rate freeze (including the size of the initial discount) do not take into account the additional costs associated with the NOx SIP call, the utility might be in the position of absorbing the costs of the rule for the length of the price freeze State utility regulators may need to be cognizant of the potential effects of the NOx SIP call on the need for stranded cost recovery

6.4.2 Potential Electricity Price Changes

As discussed above, a reasonable basis for projecting price changes in response to cost increases is the increase in marginal costs of electricity production Marginal cost changes (that is, cost changes that vary with firm or industry output) are key because they immediately affect the market equilibrium. If demand can be assumed to be relatively inelastic, microeconomic theory strongly suggests that almost all of a marginal cost increase will be quickly translated into increased prices Because electricity demand has been relatively inelastic, in the short run, the change in marginal costs resulting from the rules is a reasonable upper-bound estimate of the change in electricity prices in the short run

If all States implemented the NOx SIP call as illustratively modeled by EPA, annual average marginal costs of electricity production could rise by 1 0 mill/kWh in 2007, or about 1 6 percent of average revenues per kWh Overall, the marginal cost changes in 2007 fall in the middle of the changes over the period from 2003 to 2010.

Prices could rise by these same amounts as an upper bound estimate, to the extent that electricity demand is not completely inelastic, prices would not rise as much If prices were to go up on the order of the changes in marginal costs, total revenues to the electric power industry, in the absence of a change in generation, would rise by about $1 9 billion in 2007, and the *net* revenues to the industry after the increase in costs would be on the order of half of a billion dollars. Estimating economic impacts is made somewhat more complex by the fact that generation is projected to be lower in some years under the NOx SIP call than in the base case, by 2 8 percent in 2007 for the 0.15 alternative, for example This decline would require utilities within the SIP call region to purchase more power from outside the SIP call region (or import it from generating capacity they own outside the SIP call region), though this increased cost would be largely balanced out by savings of the costs of generation

6.4.3 Distribution of Cost Impacts Across Generation Types

Impacts on electricity producers will also depend heavily on the characteristics of their power plants Utilities with an unusually high percentage of capacity and generation from units that start out with low emission rates, or are relative inexpensive to control, will generally have lower costs per kilowatt-hour of electricity produced These utilities might include those that have already been regulated under other regulations, and therefore have low baseline emissions Other utilities may have a preponderance of small coal-fired boilers with high baseline emissions rates These utilities may have to install controls to reduce baseline emissions rates, and then may still have to purchase allowances in order to comply

Though costs per kilowatt hour can be different for every affected unit, it can be instructive to show costs for typical units in the most important generator categories. Table 6-23 presents IPM results for four types of units: combustion turbines; gas combined cycle; oil/gas-fired boilers; and coal-fired boilers Within each type, results are shown for small and large examples, where sizes are selected as the lower and upper quartiles of the size distribution, respectively The population is further subdivided into examples with low initial NOx rates (at the lower quartile of rates) and high initial NOx rates (at the upper quartile) Finally, for the boilers, examples for cases with SCR and SNCR are displayed

Costs, displayed in mills per kilowatt hours, are calculated by adding the cost of the control technology (if any) to the number of allowances that could be sold, times an estimate of the value of the allowances For the purposes of exposition, allowance prices are assumed to be $3,000 per ton, on the basis of the marginal cost of NOx reductions in the 0 15 trading alternative over the analytical period The number of allowances that could be sold is calculated by comparing controlled emission rates to an estimate of the allowances that would be allocated to the unit under the 0 15 alternative, and multiplying by an estimate of the fuel input to the unit over the ozone season The total net cost of compliance, considering both control measure costs and allowance costs or revenues, is then divided by estimated annual generation to yield an average cost per kWh

As seen in the table, typical combustion turbines and combined-cycle plants realize savings rather than costs from the rule (not counting administrative or monitoring costs) Because their emission rates are typically low even in the baseline (due in some cases to previously installed control devices), they are not assumed to be retrofitted with additional emission control devices

Oil and gas-fired boilers with low initial rates can experience savings analogous to those for combustion turbines and combined cycle units Oil and gas boilers with high rates can have net costs, with or without the addition of control technology If electricity prices rise appreciably (in step with changes in marginal costs, for example) as a result of the NOx SIP call, some owners of oil and gas-fired boilers would be better off because their control costs would be lower than the industry-wide increase in marginal costs

Coal-fired boilers, which provide the majority of fossil generation, can have costs in the range of one mill per kilowatt hour This cost is comparable to, though somewhat higher than, the average costs for all generation under the 0.15 alternative That cost increase, of 0 68 mills/kWh, is shown in Table 6-21 As shown in Table 6-23, costs can be expected to be higher for smaller units (1 0 - 1 6 mills/kWh) than for large units (0 4 - 1 0 mills/kWh). Costs will also tend to be higher for those units with higher baseline rates (including some Group 2 boilers, which were not required to reach low rates under Title IV)

Analysis of the IPM results also shows changes in capacity factors for some of the typical units in response to the NOx SIP call. Units that employ SNCR are most likely to reduce their capacity factors, and those with low controlled rates (either coal with SCR or gas turbine/CC) are likely to increase their capacity factors As discussed above, this pattern leaves the marginal units more likely to have high marginal costs of generation, because the units with available capacity face additional costs of purchasing reagent and allowances when they increase generation The units that reduce their capacity factors will lose the revenues that would have accompanied their lost output; on the other hand, they also save their variable costs of operation for those kilowatt hours

Table 6-23
Potential Net Cost (After Allowance Purchases/Sales) by Unit Type under 0.15 Trading Alternative in 2007 (mills/kWh, 1990$)

Unit Type	Small Units: Low Initial NOx Rate	Small Units: High Initial NOx Rate	Large Units: Low Initial NOx Rate		Large Units: High Initial NOx Rate	
Combustion Turbine	(Unaffected)	(Unaffected)	-1.3		-0.4	
Gas Combined Cycle	-1.3	-0.3	-2.0		-0.3	
Oil/Gas Fired Boiler	0.0	0.8	-0.5	-0.4 (SNCR)	0.5	0.1 (SNCR)
Coal Fired Boiler	1.0 (SNCR)	1.6 (SNCR)	0.9 (SCR)	0.4 (SNCR)	1.0 (SCR)	0.5 (SNCR)

Source: ICF analysis

6.4.4 Potential Impacts on Small Electricity Generators

To investigate the possibility that small utilities and other small affected entities could be adversely affected by the NOx SIP call, EPA has conducted a screening analysis of small entity impacts. That analysis reveals that a relatively small number of small utilities are potentially affected in this analysis, in part because coverage is limited to units greater than 25 MW, and in part because small utilities are more common in the western states that are outside the 23 jurisdictions named in the SIP call. Of almost 900 utilities nationwide that generate electricity, over 700 are considered small by SBA's definition (of less than 4 billion kWh per year). Fewer than 250 of these small utilities are found in the SIP call region, however, and of these only about 190 own fossil-fuel fired units. Excluding those utilities that have no units greater than 25 MW leaves 41 small potentially affected utilities.

Though many of these small utilities will be affected to a minor degree only, about half may experience cost increases that are greater that one percent of their electricity-based revenues under EPA's illustrative implementation scenario. The small utilities that may be more seriously affected tend to be those relying more heavily on coal-fired boilers, especially cyclones (which tend to have high uncontrolled emissions and are not subject to tight controls under Title IV), and those with units whose baseline NOx emission rates are unusually high. While these utilities constitute almost half of *affected* small utilities, they are less then ten percent of the small utilities that may be affected in the absence of the size cut-off established by EPA to limit impacts on small sources.

In a search for small non-utility generators, EPA identified approximately 100 affected units that generate electricity but are not owned by a utility. The owners of almost all of these units are identified using a data base of non-utility generators. Data collected on the revenues, SIC codes, and total generation of the owners or their parent companies are used to divide the owners into small and large entities. Those for whom data on size are unavailable are assumed to be small in order to estimate a conservative "worst case" scenario. In all, 73 small non-utility entities with units greater than 25 MW are analyzed.

Estimated costs of compliance are calculated under the conservative assumption that all small non-utility units comply through the purchase of allowances This approach would tend to overstate compliance costs because it does not consider cases in which emission reductions can be achieved at costs below the marginal cost of reductions in the SIP call region In the 0.15 trading alternative, 12 entities judged to be small are projected to face costs in excess of one percent of revenues under EPA's illustrative implementation scenario These 12 entities constitute about 16 percent of the 73 small non-utilities analyzed

Adding 20 small utilities to 12 small non-utility entities yields a total of 32 small entities in the trading program with projected costs in excess of one percent of revenues These 32 entities constitute about 27 percent of all small affected entities, though it would be an even smaller percentage if a 25 MW cut-off was not used

6.4.5 Potential for Closures and Additions of Capacity

A potentially important measure of the economic impacts of a rule is the number of potential closures predicted to result from the rule Closures occur when the costs of compliance are so high as to make the net present value of future operation negative, leading to the abandonment of a productive asset as the least-costly alternative New installations of capacity induced by the rule constitute another important measure

The results of the IPM analysis show that some capacity could be shut down or retired early as a result of the NOx SIP call, if the States implemented the SIP call as EPA modeled it At most, 183 MW of coal-fired capacity and 151 MW of oil/gas-fired capacity, out of a total of over 230,000 MW, are projected to close Thus, all but 0 7 percent of capacity would continue to operate under the NOx SIP call These potential closures will be more than offset (in terms of capacity) by an increase in combined-cycle units of between 1,798 and 4,156 MW (depending on the alternative)

6.5 Indirect Economic Impacts

In addition to impacts on the entities that are potentially directly affected by the rules, there will be some impacts on sectors of the economy that interact with the electricity generating industry This section briefly examines the potential effects on fuel suppliers, industrial users of electricity, and households

6.5.1 Potential Employment Impacts

Emission control devices will have to be installed as a result of the NOx SIP call Thus, the rule will generate an initial demand for workers to install emission control technology and a continuous demand for workers to operate and maintain the technology Tables 6-24 and 6-25 present the potential impact on employment in the control technology sector for the 0 15 trading alternative

Table 6-24
Potential Impact on Employment in the Control Technology Sector: 0.15 Trading (Construction and Installation)

Labor Required for Construction and Installation 2000 - 2003				Increased Annual Labor Demand, assuming construction and installation take three years (FTEs)
Combustion Controls (worker-years)	**SCR (worker-years)**	**SNCR (worker-years)**	**Total (worker-years)**	
6,511	21,535	14,312	42,358	14,119

Source ICF analysis

Table 6-25
Potential Impact of 0.15 Trading Alternative on Labor Requirements in the Control Technology Sector (O&M) in 2007 (Full-Time Equivalent)

SCR	SNCR	Total
316	669	985

Source ICF analysis
No additional O&M assumed to be required for combustion controls

The NOx SIP call may also affect demand for labor in the coal and natural gas sectors Coal produced is likely to decrease while natural gas production is likely to increase The resulting decrease in the demand for coal workers (which amounts to less than one percent of total coal mining employment) and increase in the demand for natural gas workers are presented in Tables 6-26 and 6-27 EPA did not estimate the potential additional indirect impact on labor demand for coal transportation workers, but it is expected to be smaller the than potential changes in production workers

Table 6-26
Potential Effects of 0.15 Trading Alternative on Coal Production and Employment Demand in 2007

	Total Nationwide Coal Production, Initial Base Case (million tons)	Change in Coal Production in Response to NOx SIP Call, 0.15 Alternative (million tons)	Labor Hours (thousands)	Change in Labor Requirement (FTE)
Eastern U S	511 7	-4 6	-809	-392
Western U S	513 7	-2.6	-113	-44

Source ICF analysis Assumes growth in output per worker to 11.734 tons yr for eastern miners, 58.433 tons yr for western miners See base case assumptions and EPA June 1997

Table 6-27
Potential Effects of 0.15 Trading Alternative on Natural Gas Production and Employment Demand in 2007

Initial Base Natural Gas Use (billions of cubic feet)	Increase in Natural Gas Use (billions of cubic feet)	Labor Demand (FTE per billion cubic feet per year)	Change in Labor Requirement (FTE)
1,928	80	7 48	600

Source ICF analysis

Table 6-28 presents the potential overall impact on labor demand in 2007. The increase in demand for control technology construction and installation workers is not taken into account in calculating the net change in labor demand because these workers are needed only during the construction and installation stage (the first three years) As shown, the labor demand in 2007 is likely to increase by 1,149 workers as a result of the NOx SIP call

Table 6-28
Summary of Potential Labor Demand Impacts of 0.15 Trading Alternative in 2007

Market Segment	Change in Labor Requirement (FTE)
Coal Production - East	-392
Coal Production - West	-44
Natural Gas Production	600
Emission Control Technology (O&M) [a]	985
Net Change	**1,149**

Source ICF analysis
[a] There will also be a labor requirement equivalent to 14,119 FTEs per year for pollution control system installation between 2001 and 2003

6.5.2 Potential Impacts on Industrial Users of Electricity

The potential costs of the NOx SIP call are expected to be passed along to electricity users through rate increases, as discussed in Section 6 4 Whether the rate increases significantly affect industrial users depends both on the size of the increases and the amount of electricity used, relative to industrial output Total net electricity use by manufacturing sectors in 1994 was 2,656 trillion Btu, which equals 778 billion kWh The value of total shipments from the manufacturing sector in 1995 was $3,119 billion (in 1990 dollars), of which $1,485 billion represented value added (as opposed to the value of purchased materials and other inputs) Thus, on average, the manufacturing sector used 0.25 kWh of electricity per dollar of output (or 0.52 kWh per dollar of value added) If the price of electricity rises by 1.0 mill/kWh in 2007, which is the generation-weighted increase in marginal costs, industry would experience a cost increase of 0.25 *

$1 0/1000 or a 0 03 cents for each dollar of shipments. or 0 05 cents for each dollar of value added The cost increases, then. would be a few hundredths of a percent of the value of output on average [14]

These calculations refer only to the average manufacturing entity. Some industries use considerably more electricity than others, meaning that the potential impacts could be more serious for some entities. Table 6-29 shows the electricity use, value added, and value of shipments for the six two-digit manufacturing industries that use the most electricity per dollar of value added Table 6-29 also shows the effect of a 1 0 mill increase in the electricity prices per kWh as a percentage of the two output measures As seen, even the costs for the most electricity-intensive two-digit industries is below a quarter of one percent Table 6-30 shows the electricity demand, value of shipments and the effect of an increase in electricity prices per kWh as a percentage of value of shipments for the four-digit manufacturing industries that use the most electricity per dollar of output. A total of nine industries at the four-digit level had costs greater than the industry with the highest costs at the two-digit level. Even for these few electricity-intensive industries, cost impacts would be less than one percent

[14] *1997 Statistical Abstract of the United States*, U.S Department of Commerce, Bureau of the Census, Tables 1219 and 930, pp 739 and 587

Table 6-29
Potential Impacts of Electricity Rate Increases in 2007 on Energy-Intensive Industries of .15 Trading Alternative
(by Two-Digit SIC Code, 1990S)

Industry	SIC Code	Net Electricity Use (billion kWh)	Total Output of Industry (billion 90S)		Electricity Used per Dollar of Output (kWh/90S)		Potential Increase of 1 mill/kWh[a] as a Percentage of Output	
			Value Added	Value of Shipments	Value Added	Value of Shipments	Value Added	Value of Shipments
Primary Metals	33	144	$61	$156	2 37	0 92	0 00%	0 09%
Petroleum and Coal Products	29	35	$28	$131	1 26	0 27	0 13%	0 03%
Textile Mill Products	22	33	$29	$70	1 15	0 47	0 12%	0 05%
Stone, Clay, and Glass Products	32	36	$37	$66	0 99	0 55	0 10%	0 05%
Paper and Allied Products	26	65	$70	$150	0 93	0 43	0 09%	0 04%
Chemicals and Allied Products	28	152	$171	$315	0 89	0 48	0 09%	0 05%
All Other Manufacturing		311	$1.091	$2.231	0 28	0 14	0 03%	0 01%

Source *1997 Statistical Abstract* table 930 and 1219, pp 587, 739-743, and ICF calculations One kWh assumed to be 3 412 Btu

[a] Potential increase under full competition in the electric power industry with marginal cost pricing Actual increase may be less if full competition does not occur (under cost of service pricing, the increase is estimated to be 0 7 mill kWh)

Table 6-30
Potential Impacts of Electricity Rate Increases in 2007 on Energy-Intensive Industries of .15 Trading Alternative
(by Four-Digit SIC Code, 1990$)

Name	SIC Code	Electricity Demand (million kWh)	Value of Shipments (million 1990$)	Electricity Demand per Dollar of Output (kWh/90$)	Potential Increase of 1 mill/kWh[a] as a Percentage of Value of Shipments
Industrial Gases	2813	22,816	$3,051	7.48	0.75%
Electrometallurgical Products, Except Steel	3313	4,797	$1,020	4.70	0.47%
Industrial Inorganic Chemicals, NEC	2819	42,786	$14,530	2.94	0.29%
Cement, Hydraulic	3241	10,789	$5,125	2.11	0.21%
Primary Smelting and Refining of Nonferrous Metals	3339	4,205	$2,509	1.68	0.17%
Lime	3274	1,151	$805	1.43	0.14%
Paper Mills	2621	37,503	$33,485	1.12	0.11%
Glass Containers	3221	4,268	$3,825	1.12	0.11%
Steel Works, Blast Furnaces (Including Coke)	3312	45,463	$45,587	1.00	0.10%

Source: EIA, *1996 Electric Sales and Revenue*, Dec 1997, Bureau of Economic Analyses, Shipments of Manufacturing Industries www.bea.doc.gov
[a] Potential increase under full competition in the electric power industry with marginal cost pricing. Actual increase may be less if full competition does not occur (under cost of service pricing the increase is estimated to be 0.7 mill/kWh)

6.5.3 Potential Impacts on Households

Impacts on household budgets will be smaller than the percentage increase in electricity prices, because electricity is only one component of expenditures. Households used 961 billion kWh of electricity in 1993, or an average of almost 10,000 kWh per household.[15] An increase of 1 mill/kWh would add about $10 annually to the average household budget. As median income per household was over $29,500 in 1995 (in 1990 dollars), the typical increase in electricity cost would take an additional 0.03 percent (that is, a thirtieth of one percent) from the income of a typical household.[16]

The impacts would be higher for households with unusually high electricity demand or unusually low incomes. Table 6-31 shows typical annual electricity bills for households in different parts of the income distribution, and the effect that an increase in electricity prices of 1.0 mill would have on their incomes.

[15] *1997 Statistical Abstract*, Table 929, p. 587

[16] *1997 Statistical Abstract*, Table 719, p. 466

Table 6-31
Potential Impacts of Electricity Rate Increases in 2007 on Households by Income Category of .15 Trading Alternative
(1990S)

Income Category	Assumed Annual Income	Typical Annual Electricity Bill	Electricity as a Percentage of Income	Potential Increase of 1 mill/kWh[a] as a Percentage of Income
Less than $15,000	$7,500	$544	7.3%	0 12%
$15.000 to $34.999	$25,000	$704	2 8%	0 05%
$35.000 to $74.999	$55.000	$832	1 5%	0 03%

Source *1997 Statistical Abstract*, Table 720. p 467. and ICF calculations, assuming an average price of electricity of 6 cents per kWh
[a] Potential increase under full competition in the electric power industry with marginal cost pricing Actual increase may be less if full competition does not occur (under cost of service pricing, the increase is estimated to be 0 7 mill kWh)

Table 6-31 shows that electricity use rises with income, but not in direct proportion households with very low incomes spend almost as much as those with substantially higher incomes Thus, electricity takes a larger percentage of income from the poor than from the rich Because of the size of the increase in electricity prices expected to result from the NOx SIP call is small, the effects on even the least-well-off households will be much smaller than one percent Most households are likely to see a net reduction in electricity rates over the coming decade as a result of the savings from restructuring, despite the increases from the NOx SIP call

Variations in impacts on residential consumers in different parts the SIP call region are also estimated under EPA's illustrative implementation scenario Because per-household electricity use varies from State to State, costs impacts by State vary as well The 1996 median electricity expenditures as a percentage of household income was 2 1 percent across the entire SIP call region For six States, electricity expenditures as a percentage of income was less than 1 5 percent, consumers in these States are likely to have relatively smaller cost increases On the other hand, the ratio of electricity expenditures to income was greater than 3 percent in a total of five States, with the highest ratio reaching 3 9 percent in Tennessee The NOx SIP call could have somewhat larger effects on consumers in these States, because any given increase in electricity prices will be applied to larger portions of their incomes Even in these States, though, the price increases likely to result from the NOx SIP call will be less than a tenth of one percent of income.[17]

[17] *1997 Statistical Abstract*, Table 722, p 468 *EIA Electric Sales and Revenue*, 1996, Tables 5 and 6, p 17-18

6.6 Administrative Costs

Administrative Costs to Electricity Generating Units

Administrative costs to operators of electricity generating units are associated with monitoring NOx emissions, reporting compliance information, permitting, and allowance trading. Table 6-32 presents the administrative costs to electricity generating units for emissions monitoring, reporting, and permitting The costs presented are incremental to costs in the Initial Base Case. EPA estimates that the average unit costs for emissions monitoring, compliance reporting, and permitting are $3,193, $621, and $353, respectively. The emissions and monitoring costs include capital and ongoing operations and maintenance costs. The emissions monitoring unit costs to sources vary depending upon the source type and on the monitoring requirements that the given source is already meeting A unit that is already subject to both the Title IV monitoring requirements and the requirements of the SIP call trading program will not have any additional administrative burdens imposed by the program, while a coal unit that is not currently subject to any monitoring and reporting requirements will incur administrative costs

Table 6-32
Potential Administrative Costs for Electricity Generating Units, 2007
(1990S)

	Emissions Monitoring	Compliance Reporting	Permitting
Average Unit Costs	$3,193	$621	$353
Annualized Costs[a]	$4.033	$785	$445

[a] EPA assumes 1.263 units have incremental compliance requirements
Source ICF Analysis
Numbers may not sum due to rounding

The number of units determines the need for permits and reporting All 1.995 units will incur compliance reporting and permitting costs A permit is required for each unit every five years The unit permitting costs in Table 6-32 may appear to be low because they have been annualized over the five year permit cycle EPA assumes that these costs will not vary among the regulatory alternatives considered because the number of units does not vary much by alternative

Table 6-33 presents the potential transaction costs to owners of electricity generating units for trading allowances under the different regulatory alternatives. Transaction costs are estimated to be 1 5 percent of the total values of the traded allowances

Table 6-33
Potential Allowance Trading Transaction Costs for Electricity Generating Units for the NOx SIP Call by Uniform Alternative

Alternatives (lbs/mmbtu)	Transaction Costs[a] (million 1990S)
0 25 Trading	$0 8
0 20 Trading	$1 0
0 15 Trading	$1 7
0 12 Trading	$3 3

[a] Total cost of allowance is included in compliance costs
Source ICF analysis

Total Administrative Costs

Table 6-34 presents the potential total annualized administrative costs to owners of electricity generating units by alternative The costs presented are incremental to the Initial Base Case The total administrative costs include monitoring, compliance reporting, permitting, and allowance trading transactions costs

Table 6-34
Potential Total Administrative Costs to Owners of Electricity Generating Units in 2007
(million 1990S)

Alternatives (lbs/mmbtu)	Total Annualized Administrative Costs
0 25 Trading	$5 3
0 20 Trading	$5 5
0 15 Trading	$6 2
0 12 Trading	$7 8

Source ICF analysis
Numbers may not sum due to rounding

6.7 References

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Chapter 7. RESULTS OF COST, EMISSIONS REDUCTIONS, AND ECONOMIC IMPACT ANALYSES FOR NON-ELECTRICITY GENERATING UNITS

This chapter presents the results of the cost and economic impact analyses for industrial boilers, combustion turbines and other stationary sources. The cost and economic impact analyses (including potential impacts to small entities and public sector entities) evaluate the potential impacts associated with this SIP call, based on assumptions about how the States will implement the requirements associated with meeting their NOx budgets. In an effort to narrow the scope of sources potentially affected by this rule, only large sources are potentially affected (see Chapter 3). In addition, the Agency considered other factors to reduce the number of sources including availability of control measure data, source category emissions relative to total baseline NOx emissions in the SIP call region, and the level of baseline emissions control. Additional source categories are eliminated from further consideration based on an analysis of the average cost-effectiveness of emissions control for the source category considering control, monitoring, and administrative costs. Prior to the cost-effectiveness analysis, the remaining groups of source categories are six: (1) industrial boilers and combustion turbines, (2) stationary internal combustion (IC) engines, (3) cement kilns, (4) process heaters, (5) glass manufacturing operations, and (6) commercial and industrial incinerators. The results of the average cost-effectiveness analysis for each of these remaining source category groups are found in Section 7.1. Section 7.2 describes the potential economic impacts of the preferred option and selected other options, and Section 7.3 analyzes the potential impacts on small entities in particular. The economic impact sections focus on detailed results for the preferred options and provides a brief comparison with the range of results for other options considered. More detailed results for the other options considered are provided in the economic impact analysis report (Abt, 1998). Finally, references for the chapter are provided in Section 7.4.

7.1 Compliance Costs and Cost-Effectiveness

Under the final NOx SIP call rulemaking, four regulatory alternatives are analyzed for the trading sources and five other alternatives are analyzed for the sources that are not in the trading program. Impacts are estimated as well as emissions reductions for the large (as defined in Chapter 3) trading sources (industrial boilers and combustion turbines) at regulatory alternatives based on 40%, 50%, 60%, and 70% reduction of NOx, respectively, from projected 2007 uncontrolled emissions. These alternatives apply the specified control level across the entire SIP call region. Impacts are estimated for sources not in the trading program under five cost per ton regulatory alternatives: $1,500, $2,000, $3,000, $4,000, and $5,000.[1] The potential costs of complying with the SIP call have two elements: implementation (the cost of emissions control), and administration (the cost of monitoring emissions, and the associated administrative costs of recordkeeping, and reporting).[2] The calculation of administration costs is presented later in Section 7.1.8.

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[1] Analysis of sources in the trading program consider trading occurring across the entire SIP call region. Analysis of sources not in the trading program considers at the source-level applying controls up to a specified cost per ton cutoff. For more details, refer to Chapter 5.

[6] One category of costs -- the transaction costs associated with trading allowances -- is not included in the cost estimates discussed in these chapters. These costs will depend on the number of sources that elect to engage in trading. Analysis of EGUs with IPM indicates these costs are 1.5% of compliance costs, so they are expected to be small.

For each affected source category. EPA's estimates of emissions reductions and compliance costs reflect the Agency's framework for highly cost-effective NOx emissions reductions These proposed control measures are selected through a 2 step process First. EPA examined their technical feasibility. administrative feasibility. and average cost-effectiveness for NOx control applied in the ozone season across the SIP call region EPA then determined those measures feasibly achieve the greatest NOx reductions and are among the most reasonable in light of other actions undertaken or proposed by EPA and States to control NOx Based on this process. the Agency considers controls with an average cost-effectiveness. evaluated across all sources in a category group. of less than $2.000 per ozone season ton of NOx removed to be highly cost-effective and has calculated the amounts of emissions that States must prohibit based on application of these controls

7.1.1 Results for Industrial Boilers and Combustion Turbines

In EPA's analysis. large industrial boilers and combustions turbines are included in the NOx Budget Trading Program These sources will be allowed to participate in this interstate emissions trading program if States elect to include these sources in this program. Currently. the IPM model. discussed in Chapter 4. does not cover these sources. so EPA has conducted a least-cost analysis for this group of sources The least-cost analysis is EPA's attempt to simulate the outcome of an efficient emissions trading program by assigning control responsibility based on sources with the lowest control costs The least cost analysis only reflects the efficient allocation of control responsibility among the group of industrial boilers and turbines. and does not. therefore. take advantage of potentially more efficient outcomes that could occur if these sources were modeled in conjunction with the rest of the utility sources included in the NOx SIP Budget Trading Program

Table 7-1 shows the emissions reductions achieved in the least-cost analysis for each regulatory alternative The table indicates that the alternatives achieve incremental reductions from the 2007 Clean Air Act (CAA) baseline ranging from 31% to 66%

Table 7-1
2007 Ozone Season NOx Baseline Emissions and Emission Reductions for Large Industrial Boilers and Combustion Turbines[a]

Regulatory Alternative[b]	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
40% Control	292	194,445	133.630	60,815
50% Control	592	194.445	108,880	85.565
60% Control	803	194,445	90,193	104,252
70% Control	805	194,445	65.611	128,834

[a] The 2007 baseline emissions estimate reflects emissions from all 807 large sources (755 industrial boilers. 52 combustion turbines) in this source category, both controlled and uncontrolled Emissions estimates for 90 non-fossil fuel fired industrial boilers are not included

[b] Reductions from controlled 2007 baseline are less than the nominal percentage reduction from an uncontrolled 2007 baseline indicated in the regulatory alternative name

Table 7-2 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative The annual control costs range from $49.5 to $249 5 million. Annual monitoring and administrative costs depend on the number of covered sources, and since the number of sources is constant across the alternatives, this cost is also constant at $26 1 million The accompanying average cost-effectiveness results range from $1,243 to $2,140 per ozone season ton The 60% control level is the most stringent control level that meets EPA's framework for highly cost-effective ozone season NOx emissions reductions, and is selected as the basis for establishing State level emissions budgets

Table 7-2
2007 Cost and Cost-Effectiveness Results for Large Industrial Boilers and Combustion Turbines

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
40% Control	$49 5	$26 1	$75 6	$1,243
50% Control	87 6	26 1	113 7	1,329
60% Control	126 8	26 1	152 9	1,467
70% Control	249 5	26 1	275 7	2,140

7.1.2 Results for Internal Combustion (IC) Engines

The analysis of large internal combustion engines is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative Table 7-3 shows the emissions reductions achieved in the analysis for each regulatory alternative The table indicates that the alternatives achieve incremental reductions from the 2007 controlled baseline of roughly 89%

Table 7-3
2007 Ozone Season NOx Emission Reductions for Large Stationary IC Engines[a]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1,500/ton	290	92.424	9.857	82,567
$2.000/ton	304	92.424	9.840	82.584
$3.000/ton	304	92.424	9.840	82,584
$4,000/ton	304	92,424	9.840	82.584
$5,000/ton	304	92.424	9,801	82.623

[a] The 2007 baseline emissions estimate reflects emissions from all 305 large sources in this source category, both controlled and uncontrolled

Table 7-4 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative[3] All of the regulatory alternatives achieve similar results and all reflect control measures that meet EPA's framework for highly cost-effective ozone season NOx emission reductions EPA has selected the $5000/ton regulatory alternative as the basis for establishing State-level emissions budgets since this alternative provides the greatest emission reduction while being consistent with EPA's framework for highly cost-effective ozone season emissions reduction This alternative results in an average reduction of 90% from an uncontrolled 2007 baseline

[3] It should be noted that the monitoring and adminstrative costs estimated for these sources are overstated, since they reflect application of the provisions of Part 75 (primarily, installation of CEMs) Stationary IC engines will be allowed to comply with the less stringent provisions of Part 60

Table 7-4
2007 Cost and Cost-Effectiveness Results for Large Stationary IC Engines

Regulatory Alternative	Annual Control Cost (million 1990S)	Annual Monitoring and Administrative Costs (million 1990S)	Total Annual Costs (million 1990S)	Ozone Season Cost Effectiveness (S/ozone season ton)
$1.500/ton	$86 9	$12 4	$99 3	$1.203
$2.000/ton	86 9	13 3	100 2	1.213
$3,000/ton	86 9	13 3	100 2	1,213
$4.000/ton	86 9	13 3	100 2	1.213
$5.000/ton	87 1	13 3	100 4	1,215

7.1.3 Results for Cement Manufacturing (Cement Kilns)

The analysis of cement manufacturing operations is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative Table 7-5 shows the emissions reductions achieved in the analysis for each regulatory alternative The table indicates that all the alternatives achieve the same incremental reductions from the controlled 2007 baseline This reduction is approximately 38%

Table 7-5
2007 Ozone Season NOx Emission Reductions for Large Cement Manufacturing Operations (Cement Kilns)[a]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1,500/ton	57	42.701	26.312	16.389
$2.000/ton	57	42.701	26,312	16.389
$3.000/ton	57	42,701	26,312	16,389
$4,000/ton	57	42.701	26.312	16.389
$5.000/ton	57	42.701	26,312	16,389

[a] The 2007 baseline emissions estimate reflects emissions from all 58 large sources in this source category, both controlled and uncontrolled

Table 7-6 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative The annual control costs for all alternatives is $23.9 million, and is based on a combination of urea-based SNCR and combustion modifications Annual monitoring and administrative costs for all alternatives are $3 7 million [4] The accompanying average cost-effectiveness is $1.458 per ozone season ton, and the reductions from uncontrolled 2007 baseline emissions are just over 40%

While all the control levels meet EPA's criteria for highly effective ozone season NOx emissions reductions, there are additional factors that EPA has considered in establishing the final emissions budgets for this source category First, the grouping of all cement manufacturing operations (i e , wet, dry, and in-process-bituminous coal) in Tables 7-5 and 7-6 masks the fact that a significant portion of the large operations (21 of 58) in the analysis are not able to achieve cost-effective reductions with technologies more stringent than combustion modifications (e g , SNCR and SCR) EPA received numerous public comments confirming this result Based on evidence cited in the cement ACT document and in some comments on the SIP call proposals, EPA believes that a 30% reduction from uncontrolled levels would be within the cost-effectiveness range for reducing emissions at all types of cement kilns After reconsidering its own analysis, and considering public comments, EPA has decided to base the NOx budget level on the combustion modification technologies which can achieve up to 30% control The reader should note that due to the timing of this final decision, the cost and economic impact results presented in the remainder of this report reflect the $5,000/ton regulatory alternative rather than the 30% control assumption

Table 7-6
2007 Cost and Cost-Effectiveness Results for Large Cement Manufacturing Operations (Cement Kilns)

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	$20 2	$3 7	$23 9	$1,458
$2,000/ton	20 2	3 7	23 9	1,458
$3,000/ton	20 2	3 7	23 9	1,458
$4,000/ton	20 2	3 7	23 9	1,458
$5,000/ton	20 2	3 7	23 9	1,458

[4] It should be noted that the monitoring and administrative costs estimated for these sources are overstated, since they reflect application of the provisions of Part 75 (primarily, installation of CEMs) Cement kilns will be allowed to comply with the less stringent provisions of Part 60

7.1.4 Results for Glass Manufacturing

The analysis of large source glass manufacturing operations is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative Table 7-7 shows the emissions reductions achieved in the analysis for each regulatory alternative The table indicates that the alternatives achieve incremental reductions from the 2007 baseline ranging from 46% to 76%

Table 7-7
2007 Ozone Season NOx Emission Reductions for Large Glass Manufacturing Operations[a]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1.500/ton	12	8.545	4.622	3.923
$2.000/ton	16	8.545	4.361	4.184
$3.000/ton	25	8.545	3,941	4.604
$4.000/ton	25	8.545	3.415	5.130
$5.000/ton	25	8.545	2.029	6.516

[a] The 2007 baseline emissions estimate reflects emissions from all 25 large sources in this source category, both controlled and uncontrolled

Table 7-8 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative When emissions decreases are considered at all large glass manufacturing sources (regulatory alternatives greater than $3.000/ton of control). the resulting average cost-effectiveness exceeds EPA's $2.000 framework Only the 12 flat glass manufacturers are able to achieve cost-effective reductions (after considering administrative costs) with any technology If all large sources in this category were included in the NOx Budget Trading Program. the potential inequities in control capability across sources could be smoothed out but the average cost effectiveness would exceed EPA's $2.000 framework Therefore. this source category exceeds EPA's cost effectiveness framework and is not included in the assumed NOx emissions decreases for the Statewide budgets

Table 7-8
2007 Cost and Cost-Effectiveness Results for Large Glass Manufacturing Operations

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	na	na	na	na
$2,000/ton	na	na	na	na
$3,000/ton	7 2	2 1	9 3	2,020
$4,000/ton	9 8	2 1	12 0	2,339
$5,000/ton	28 9	2 1	31 0	4,758

7.1.5 Results for Process Heaters

The analysis of large process heaters is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative Table 7-9 shows the emissions reductions achieved in the analysis for each regulatory alternative The table indicates that the alternatives achieve incremental reductions from the 2007 baseline up to 75%

Table 7-9
2007 Ozone Season NOx Emission Reductions for Large Process Heaters[a]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1,500/ton	1	15,147	15,072	75
$2,000/ton	1	15,147	15,072	75
$3,000/ton	18	15,147	4,099	11,048
$4,000/ton	30	15,147	3,820	11,327
$5,000/ton	30	15,147	3,820	11,327

[a] The 2007 baseline emissions estimate reflects emissions from all large sources in this source category, both controlled and uncontrolled

Table 7-10 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative Annual monitoring and administrative costs are not estimated for this category of sources because it is evident from Table 7-10 that even without these additional costs there is no regulatory alternative that meets EPA's criteria for highly cost-effective ozone season NOx emissions reductions That is, when emissions decreases are considered at all large process heating sources (i e., regulatory alternatives applying greater than $4,000/ton of control), the resulting average cost-effectiveness clearly exceeds EPA's $2,000 framework Therefore, this source category exceeds EPA's cost effectiveness framework and is not included in the assumed NOx emissions decreases for the Statewide budgets

Table 7-10
2007 Cost and Cost-Effectiveness Results for Large Process Heaters

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs[a] (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	na	na	na	na
$2,000/ton	na	na	na	na
$3,000/ton	31 6	na	31 6	2,860
$4,000/ton	32 8	na	32 8	2,896
$5,000/ton	32 8	na	32 8	2,896

[a] Monitoring and administrative costs are not estimated for these sources since the domain-wide average control cost-effectiveness for the source category exceeds $2 000 per ozone season ton reduced, and therefore is not subject to additional control for this rulemaking

7.1.6 Results of Commercial and Institutional Incinerators

The analysis of large commercial and institutional incinerators is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative Table 7-11 shows the emissions reductions achieved in the analysis for each regulatory alternative The table indicates that the alternative achieve from incremental reductions from the 2007 baseline ranging from 0% to 45%

Table 7-11
2007 Ozone Season NOx Emission Reductions for Large Commercial and Industrial Incinerators[a]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1,500/ton	0	2,852	2,852	0
$2,000/ton	0	2,852	2,852	0
$3,000/ton	30	2,852	1,577	1,275
$4,000/ton	30	2,852	1,577	1,275
$5,000/ton	30	2,852	1,577	1,275

[a] The 2007 baseline emissions estimate reflects emissions from all 30 large sources in this source category, both controlled and uncontrolled

Table 7-12 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative Annual monitoring and administrative costs are not estimated for this category of sources because it is evident from Table 7-12 that even without these additional costs there is no regulatory alternative that meets EPA's framework for highly cost-effective ozone season NOx emissions reductions Therefore no additional reductions are assumed from this source category group for establishing State level emissions budgets

Table 7-12
2007 Cost and Cost-Effectiveness Results for Large Commercial and Industrial Incinerators

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	$0.0	na[a]	$0.0	N/A
$2,000/ton	0.0	na	0.0	N/A
$3,000/ton	2.7	na	2.7	2,118
$4,000/ton	2.7	na	2.7	2,118
$5,000/ton	2.7	na	2.7	2,118

[a] Monitoring and administrative costs are not estimated for these sources since the region-wide average control cost-effectiveness for the source category exceeds $2,000 per ozone season ton reduced, and therefore is not subject to additional reductions in this rulemaking

7.1.7 Summary of Results for Non-Electricity Generating Sources

Table 7-13 contains of summary emission reductions and costs associated with the final regulatory decisions arising from the cost-effectiveness analysis The final combination of regulatory alternatives achieves an ozone season NOx emission reduction of approximately 203,000 tons beyond the 2007 baseline This represents approximately a 62% reduction from baseline for these combined sources

Table 7-13
2007 Ozone Season Emission Reductions and Total Annual Compliance Costs for Non-Electricity Generating Sources Used to Establish State NOx Emissions Budgets under the NOx SIP Call [a]

Source Category	Baseline Ozone Season Emissions	Ozone Season Emissions After Control	Total Reduction in Ozone Season Emissions	Total Annual Compliance Costs (million 1990$)
Industrial Boilers	188,636	89,065	99,571	122 9
Combustion Turbines	5 809	1,128	4,681	4 0
Internal Combustion Engines	92,423	9,801	82,623	100 4
Cement Manufacturing	42,701	26,312	16,389	23 9
TOTAL	329,569	126,304	203,265	277 2

[a] Emissions estimates are for large sources only Baseline NOx emissions estimates for industrial boilers do not include emissions for the 90 non-fossil fuel fired boilers The emissions reduction estimates reflect the preferred alternative for other stationary sources (60% control of large industrial boilers and combustion turbines and control applied up to $5,000 per ton for stationary internal combustion engines and all cement kilns)

Table 7-14 indicates the control technologies represented by the final regulatory decisions arising from the cost-effectiveness analysis The table shows that combustion modifications, such as oxygen trim and water injection (OT + WI), are the dominant control technologies for boilers and turbines. Selective catalytic reduction (SCR) is the dominant technology for IC engines, and selective non-catalytic reduction (SNCR) is the dominant technology for cement manufacturing Overall, SCR is estimated to be applied to 23% of large non-EGU sources in EPA's analysis SNCR is applied to 21% of large units, and OT+WI is applied to 33% of large units

Table 7-14
Control Technologies Selected for Non-Electricity Generating Sources for Regulatory Alternatives Used to Establish State NOx Emissions Budgets under the NOx SIP Call [a]

Control Technology	60% Control for Industrial Boilers and Combustion Turbines	$5,000/ton Alternative for:		Total
		IC Engines	Cement Kilns	
SCR	80	187	0	267
SNCR	198	0	37	235
OT + WI	392	0	0	392
OTHER[b]	137	118	21	276
TOTAL	807	305	58	1,170

[a] These results represent the number of emissions units for which the specified control technology is applied in the control cost analysis State and source control decisions in response to the SIP call may differ
[b] Includes sources that are estimated NOT to apply addition controls

7.1.8 Adminstrative Costs for Non-Electricity Generating Units

The burden to other stationary source operators potentially resulting from implementation of the NOx SIP call rule are primarily associated with costs of installing and operating a continuous emissions monitoring system (CEMS) to monitor NOx mass emissions and demonstrate compliance with limits established by a State This burden includes the total time, effort, or financial resources expended by an operator to generate, maintain, retain, or disclose or provide information to or for a Federal or State agency

A large proportion of the other stationary sources are expected to install CEMS and/or upgrade their data acquisition and handling systems (DAHS) in order to participate in the NOx trading program For trading sources (industrial boilers and combustion turbines) subject to Title IV monitoring in the Ozone Transport Region (OTR), only administrative costs of recordkeeping and reporting were estimated These units will not potentially experience additional capital or operating and maintenance costs as a result of this rulemaking since they are already equipped with a CEMS meeting Part 75 Subpart H specifications However, Title IV units that are not in the OTR will likely require minor upgrades to their DAHS Therefore, the burden estimate associated with this rulemaking for these sources includes additional capital and operations and maintenance costs

For units not subject to Title IV monitoring but in the OTR, costs are estimated for upgrading the DAHS and performing annual quality assurance testing For trading units not subject to the Title IV monitoring and not in the OTR, additional costs may result from installing a NOx CEMS, or other approved monitoring system, and a DAHS The Part 75 NOx monitoring requirements vary depending on the fuel burned and the hours of operation For example, monitoring requirements are less stringent for gas/oil fired sources than for coal-fired sources, and are even less stringent for peaking units and low NOx mass emissions sources Similarly, the non-trading sources are assumed to experience additional costs from installing a NOx

CEMS, or other approved monitoring system, as well as a DAHS [5] Although not explicitly required in the NOx SIP call, it is assumed as a worst-case scenario that if controlled, a State would require a CEMS, or equivalent, for the non-trading sources

Table 7-15 presents estimates of the per-source annual administrative costs that other stationary source operators may experience, based on assumptions of how States will implement administrative requirements in response to this rulemaking These estimates are prepared for both trading and non-trading sources and included in the cost analysis results

Table 7-15
Average Per Source Annual Administrative Costs for Other Stationary Sources in 2007
(1990 dollars)

Source Category Group	Annual Monitoring Costs	Annual Reporting & Permitting Costs	Total Annual Administrative Costs
Industrial Boilers and Combustion Turbines	$27,201	$5,141	$32,342
IC Engines	$43,353	$253	$43,606
Cement Manufacturing	$63,540	$253	$63,793
Glass Manufacturing	$83,664	$253	$83,917

7.2 Potential Economic Impacts

This section presents the results of a screening-level economic impact analysis for industrial boilers and turbines and other stationary sources potentially affected by the rule The analysis estimates the potential impact on facilities and firms affected by the rule by comparing compliance costs to estimated sales or expenditures Facilities and firms for whom costs exceed three percent or sales or expenditures are identified as the most likely to experience significant impacts as a result of the rule Those for whom costs exceed one percent of sales or expenditures are also highlighted as potentially experiencing significant impacts Costs that represent less than one percent of sales or expenditures are not expected to impose significant impacts

While the RFA as amended by SBREFA does not apply to this rulemaking, the Agency elected to evaluate the potential impacts of the rule on potentially affected small entities, based on assumptions about how the States could implement the requirements associated with meeting their NOx budgets

The analysis of impacts is conducted at three levels establishment (or facility), firm and industry.

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[5] As indicated earlier, it should be noted that the monitoring and administrative costs estimated for the sources outside the trading program (stationary IC engines and all cement kilns) will be allowed to comply with the provisions of Part 60 The monitoring and administrative costs estimated for these sources reflect the requirements of Part 75 (primarily, installation of CEMs), which are more stringent than those in Part 60.

- Costs at the source level summarized in Section 7.2 are aggregated for each establishment, where an establishment owns more than one affected source. Establishment-level costs are then compared with estimated sales or expenditures for the average sized establishment in the relevant industry (4-digit SIC) and employee size category (small vs. large), as described in Chapter 5.

- Establishment-level impacts are summarized at the industry level, as defined by 4-digit SIC codes.

- Finally, costs are further aggregated to the firm level to account for the fact that some firms own more than one establishment affected by the rule. Firm-level costs are compared with firm sales, obtained for the most part from Dun & Bradstreet data, as described in Chapter 5. For governments, costs are compared with revenues, and for colleges and universities costs are compared with expenditures.

Individual potentially affected establishments and firms may have both industrial boilers and gas turbines (sources in the trading program) and other stationary sources (sources not in the trading program) affected by the rule. To assess economic impacts more thoroughly, it is therefore necessary to consider the trading and non-trading alternatives in combination.

Section 7.2.1 provides an overview of the potentially affected firms, facilities and sources in the affected universe. Detailed economic impacts are presented in Section 7.2.2 for the preferred regulatory alternative combination -- a 60% reduction from uncontrolled 2007 emissions for industrial boilers and combustion turbines and a $5,000/ton cost-effectiveness cap for other non-utility sources (denoted by "60%/$5,000"). Section 7.2.3 compares these results with results for two additional regulatory alternative combinations. The potential alternative combinations are shown in Table 7-16, with the regulatory alternative combinations examined in the economic impact analysis indicated with an "X". The alternative combinations that are analyzed capture the range of stringency considered by EPA, from the most stringent combination (70%/$5,000) to the least stringent combination (40%/$1,500).

Table 7-16
Potential Regulatory Alternative Combinations for Non-Electricity Generating Unit Economic Impact Analysis

		Regulatory Alternatives for Industrial Boilers and Combustion Turbines			
		40% Control	50% Control	60% Control	70% Control
Regulatory Alternatives for IC Engines and Cement Manufacturing	$1,500/ton	**X**			
	$2,000/ton				
	$3,000/ton				
	$4,000/ton				
	$5,000/ton			**X**	**X**

Throughout the discussion, economic impacts are presented separately by size of the potentially affected entity that owns the affected establishments Section 7.3 discusses firm-level impacts for potentially affected small entities in more detail Chapter 8 discusses impacts on potentially affected government-owned entities in more detail

7.2.1 Overview of Potentially Affected Sources, Establishments and Firms

Table 7-17 shows the number of firms potentially affected under the preferred alternative, by source category [6] Table 7-18 shows the same information by sector and by size of entity

Table 7-17
Number of Firms and Other Entities Potentially Affected, by Source Category

Source Type	Potentially Affected Firms/Entities	
	Total	Small
Industrial Boilers	221	28
Gas Turbines	22	1
Internal Combustion Engines	18	2
Cement Manufacturing	20	5

[6] One category of costs -- the transaction costs associated with trading allowances -- is not included in the cost estimates discussed in these chapters These costs will depend on the number of sources that elect to engage in trading Analysis of EGUs with IPM indicates these costs are 1 5% of compliance costs, so they are expected to be small

Table 7-18
Number of Firms Potentially Affected, by Sector and Size

Sector and Size of Entity	Potentially Affected Firms/Entities
Firms	253
of which, small entities	*36*
large entities	*176*
entity size unknown [a]	*41*
Federal government	1
Other government	7
Utility (SIC 4911, 4931) [b]	14
Colleges/universities	6
TOTAL	281

[a] Unknown size refers to entities whose employee size could not be determined
[b] These are primarily cogenerators that supply less than 50% of generated power to the electric power grid

7.2.2 Results for the Preferred Alternative Combination (60%/$5,000)

Firm/Entity-Level Impacts

Screening-level impact results at the firm level are summarized in Table 7-19 This table shows the number of potentially affected firms or entities at particular levels of firm-level costs as a percentage of firm sales, revenues or expenditures

Table 7-19 shows that, at the firm or entity-level, only a small percentage of the potentially affected firms or entities for which sales estimates are available (14 of 232 or six percent) experience costs above one percent of sales, and of these only eight of the 232 (three percent) experience costs above three percent of sales Five out of 36 identified potentially affected small entities may experience costs of three percent of sales or greater.

EPA expects that States implementing the SIP call will take these potential impacts into account in designing their implementation scenarios Industries with establishments having the potential for significant impacts are likely candidates to be excluded from control requirements.

Table 7-19
Number of Potentially Affected Firms by Firm Costs as a Percentage of Sales/Expenditures: 60%/$5,000

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
Firms/Non-Profits	184	13	4	6	46	253
Of which, small entities	*22*	*5*	*4*	*5*	*0*	*36*
large entities	*159*	*8*	*0*	*1*	*8*	*176*
entity-size unknown	*3*	*0*	*0*	*0*	*38*	*41*
Federal Government [a]	na	na	na	na	1	1
Other Government [a]	3	1	1	1	1	7
Utility [b]	10	1	1	1	1	14
Colleges/Universities	6	0	0	0	0	6
TOTAL	203	15	6	8	49	281

[a] Sales not available or (for the federal government) not applicable
[b] Co-generation units that supply less than 50% of generated power to the electric power grid

Establishment-Level Impacts

The 281 potentially affected firms are comprised of 546 establishments Establishment level impacts provide additional insights on individual facilities, which in some cases are seen as stand-alone profit centers Table 7-20 summarizes the results of the establishment-level analysis, by sector and firm size

Table 7-20 shows that impacts of the preferred regulatory alternative are somewhat variable The large majority of establishments (347) incur costs that represent one percent or less of estimated sales/expenditures, and of those 286 incur costs less than 0 5 percent of sales/expenditures Of the 110 establishments potentially incurring costs that exceed three percent of estimated sales/expenditures, only seven are owned by identified small entities One non-federal government and one utility establishment incur costs greater than three percent of revenues

EPA expects that States implementing the SIP call will take these potential impacts into account in designing their implementation scenarios Industries with establishments having the potential for significant impacts are likely candidates to be excluded from control requirements

Table 7-20
Number of Establishments by
Costs as a Percentage of Value of Shipments/Expenditures
and Sector and Firm Size:
60%/$5,000

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Total
Firms/Non-Profits	269	57	71	109	506
Of which, owned by small entities	*21*	*4*	*5*	*7*	*37*
owned by large entities	*226*	*49*	*55*	*98*	*428*
entity-size unknown	*22*	*4*	*11*	*4*	*41*
Federal Government [a]	na	na	na	na	12
Other Government [a]	3	1	1	1	7
Utility [b]	7	3	3	1	14
Colleges/Universities	7	0	0	0	7
TOTAL	286	61	75	111	546

[a] Revenues not available for one "other government" and 12 federal government establishments
[b] Co-generation units that supply less than 50% of generated power to the electric power grid

Industry-Level Impacts

Table 7-21 shows estimated impacts at the establishment level by industry (2 digit SIC code level) Table 7-21 shows that, for the most part, only a small number of establishments (usually less than 0 1 percent of the total) are potentially significantly impacted in any single industry compared to the total number of establishments for each potentially affected industry within the SIP call region The 546 affected establishments represent only 0 02 percent of all the establishments in the SIP call region (roughly 3 6 million) In most cases, potential impacts associated with the NOx SIP call are unlikely to result in any significant impacts at the industry level for potentially affected industries because the number of affected establishments are a very small proportion of the total in those industries In addition, because only a very few establishments may experience potentially significant costs in each industry, the rule is not likely to result in price increases to customers of the affected firms or other indirect economic impacts Furthermore, EPA expects that States implementing the SIP call will take these potential impacts into account in designing their implementation scenarios Industries with potentially significant impacts are likely candidates to be excluded from control requirements EPA has therefore concluded that a more detailed market-level impacts analysis is not needed for any of these industries

Table 7-21
Number of Establishments By Establishment-Level Costs
as a Percentage of Value of Shipments/Expenditures and Industry:
60%/$5,000

SIC	Industry/Sector	<0.5 %	0.5-1.0%	1-3 %	> 3%	Total	Percent of Establishments in SIP Call Region Potentially Affected at the 2- digit SIC Code Level
10	Metal mining	1	0	0	0	1	0.6
14	Non-metal, non-fuel mining/quarrying	0	0	2	3	5	0.2
20	Food and kindred products mfgr	35	1	0	3	39	0.4
21	Tobacco products mfgr	2	0	0	0	2	1.6
22	Textile mill products	5	0	1	1	7	0.1
24	Lumber & wood products, exc. furniture	0	0	0	1	1	<0.1
25	Furniture & fixtures	1	0	1	2	4	0.1
26	Paper and Allied Products	68	17	7	3	95	2.0
27	Printing & publishing	1	0	1	0	2	<0.1
28	Chemicals & allied products	58	11	9	5	83	1.0
29	Petroleum refining and related industries	18	2	1	1	22	1.6
30	Rubber & plastics	7	1	0	1	9	0.1

SIC	Industry/Sector	<0.5 %	0.5-1.0%	1-3 %	> 3%	Total	Percent of Establishments in SIP Call Region Potentially Affected at the 2- digit SIC Code Level
32	Stone, Clay, Glass and Concrete Products	4	6	23	7	43	0 5
33	Primary metals	35	5	2	2	44	0 9
34	Fabricated metal products, exc machinery & trans. equip	4	1	0	0	5	<0 1
35	Industrial & commercial machinery & computer equip	3	1	1	3	8	<0 1
36	Electronic & other elec equip , exc computer equip	4	0	0	0	4	<0 1
37	Transportation equipment	11	0	1	1	13	0 2
38	Measuring instr , photo, med & optical goods, clocks	1	0	0	0	1	<0 1
39	Miscellaneous manufacturing industries	1	1	1	0	3	<0.1
49	Electric, gas & sanitary services	12	14	22	75	123	1 2
51	Wholesale trade - nondurable goods	1	0	0	1	2	<0 1
72	Personal services	0	0	1	0	1	<0 1

SIC	Industry/Sector	<0.5 %	0.5-1.0%	1-3 %	> 3%	Total	Percent of Establishments in SIP Call Region Potentially Affected at the 2- digit SIC Code Level
79	Amusement and recreation services	0	0	1	0	1	<0.1
80	Health services	3	0	0	1	4	<0.1
89	Miscellaneous services	1	0	0	0	1	<0.1
Colleges/universities		7	0	0	0	7	<0.1
Federal government [a]		na	na	na	na	12	na
Other government [a]		3	1	1	1	6	na
TOTAL		286	61	75	111	546	<0.1

[b] Includes natural gas transmission establishments (SIC 4922) and electric utilities establishments (SIC 4911). Utilities having non-EGU sources affected by these alternatives have co-generation units that supply less than 50% of generated power to the electric power grid.
[a] Revenues not available for one "other government" and 12 federal government establishments.

7.2.3 Comparison by Regulatory Alternative

Tables 7-22 and 7-23 provide an overview of economic impacts for the three combinations of regulatory alternatives considered Table 7-22 presents results at the firm level, and Table 7-23 shows impacts at the establishment level

Table 7-22
Number of Firms by Firm Costs as a Percentage of Sales/Expenditures and by Regulatory Alternative

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
40%/$1,500	208	12	6	6	49	281
Preferred Alternative 60%/$5,000	203	15	6	8	49	281
70%/$5,000	198	14	10	10	49	281

[a] Sales not available or (for federal government) not applicable

Table 7-23
Number of Establishments by Establishment-Level Costs as a Percentage of Value of Shipments/Expenditures and by Regulatory Alternative

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
40%/$1,500	333	31	66	103	13	546
Preferred Alternative 60%/$5,000	286	61	75	111	13	546
70%/$5,000	252	66	88	127	13	546

[a] Sales not available or (for federal government) not applicable

The comparison among these regulatory alternatives shows a modest difference in potential economic impacts between the preferred alternative and either the least or most stringent combination of regulatory alternatives considered Only two additional firms and 17 additional establishments may incur costs above one percent of sales/expenditures for the preferred alternative compared to the least stringent regulatory alternative Applying the most stringent regulatory alternative results in an increase of six firms and 29 establishments that may incur costs above one percent of sales/expenditures when compared to the preferred alternative.

7.3 Small Entity Impacts

This section discusses potential impacts on small entities that may be affected by requirements related to the NOx SIP call Since States are ultimately charged with achieving reductions to meet their emissions budgets, they should seek to minimize impacts on small entities to the maximum extent practicable In this analysis, EPA has simulated State choices, so these impacts may or may not be respresentative of actual impacts once States make their own choices The information presented in this section may assist States in selecting control measures that minimize small entity impacts

Table 7-24 shows potential small entity impacts for the preferred alternative combination and the other two regulatory alternative combinations considered

Table 7-24
Number of Potentially Affected Small Entities by Cost as a Percentage of Sales/Expenditures by Regulatory Alternative

Regulatory Alternative	Total Small Entities Potentially Affected	<1%	1-3%	>3%
40%/$1,500	36	29	4	3
Preferred Alternative 60%/$5,000	36	27	4	5
70%/%5,000	36	24	5	7

This comparison shows that only a small absolute number of small entities is predicted to incur costs above one percent in any of the regulatory alternatives In addition, the preferred alternative only results in 2 additional potentially affected small entities with compliance costs greater than one percent of firm/entity sales or revenues, compared to the least stringent regulatory alternative States should carefully select control measures to avoid adverse impacts on these and other small entities to the extent practicable

The maximum number of potentially affected small entities that may be significantly impacted under the preferred alternative is 9, as shown in Table 7-24 Table 7-25 presents the industries (classified by 4 digit SIC code) that have potentially affected small entities with compliance costs greater than one percent of firm/entity sales or revenues for the preferred regulatory alternative, and the number of small entities in each industry potentially affected at this level of impact This calculation excludes entities for which firm/entity-level sales or revenues are not available (41 entities) and which could not be classified as small or large based on employment Some of these firms are likely to be small but the Agency can not estimate how many.

Table 7-25
Potentially Affected Small Entities that May Incur Compliance Costs of Greater Than 1 Percent of Sales/Revenues for the 60%/$5,000 Regulatory Alternative

SIC Code	Description of Affected Industry	Number of Potentially Affected Small Entities in Each Affected Industry
2033	Canned fruit, vegetables, preserves, jams, jellies	1
2075	Soybean oil mills	1
2434	Wood kitchen cabinets	1
2869	Industrial Organic Chemicals, n e c.	1
3241	Cement, hydraulic	5

7.4 References

Abt Associates. 1998 *Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call RIA* Prepared for the U S Environmental Protection Agency, Office of Air Quality Planning and Standards. September 1998

Pechan-Avanti Group *Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis* Prepared for the U S Environmental Protection Agency, Office of Air Quality Planning and Standards. September 1998

Chapter 8. IMPACTS ON GOVERNMENT ENTITIES

This chapter describes the potential impacts on State and local governments and the Federal government as a result of the NOx SIP call State and local governments will be required to submit additional reports and monitoring data to the U S EPA in order to track compliance with the rule. Section 8.1 discusses State planning requirements and data collection issues imposed under the NOx SIP call Section 8.2 presents impacts from potential administrative costs to States and EPA related to control of electricity generating units Section 8.3 presents impacts from potential administrative costs related to control of other stationary sources Section 8 4 presents potential compliance (control and administrative) costs to potentially affected government-owned entities References are listed in Section 8.5

8.1 State Requirements

Detailed estimates of incremental reporting and planning requirements, labor hours required to meet those requirements, and the costs of that labor are described in the Information Collection Request (ICR) prepared for this rulemaking [1]

States are required to report data annually for those point, area, nonroad mobile, and onroad mobile sources for which they adopt control measures to meet their NOx emissions budgets [2] These annual reports must include ozone season NOx emission inventories States must report a statewide inventory of all NOx sources every 3 years starting in the year 2003 for the 2002 inventory, and 2008 for the 2007 compliance demonstration inventory While the States are expected to use their existing emission inventory data collection and electronic reporting mechanisms for submitting the data to EPA, some modifications will be necessary to account for the reporting of ozone season emissions data

To minimize the reporting burden on State agencies, the reporting requirements for the final rule are based on existing annual and periodic emission inventory reporting requirements as much as possible However, since these new requirements are being established to support an ozone season reduction program and since existing provisions do not require the collection of ozone season inventories, some additional reporting will be required EPA requires that States report annually data for all point sources that are part of a control measure that is adopted for purposes of meeting the NOx budget If States act in accordance with OTAG recommendations for setting the emissions budgets, the sources controlled will all be point sources emitting $\geq$ 100 tons per year (tpy) of NOx The 100 tpy threshold is consistent with the NOx reporting threshold for the existing annual emission inventory However, the rule does allow States the option of defining the NOx point source threshold to be less than 100 tpy

EPA will allow the direct reporting of point source data from sources to EPA if the sources are subject to the monitoring and reporting requirements of Subpart H of 40 CFR Part 75 to satisfy this

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[1] The ICR also estimates burden hours and cost for administrative requirements for the regulated sources Regulated sources owned by government entities will incur these costs as well Estimates of government-owned regulated source administrative requirements are provided in Section 8 2

[2] Throughout remainder of this chapter, "State" is used to denote relevant state and local air quality planning organizations responsible for compliance with Clean Air Act requirements

requirement The direct reporting of data from sources to EPA will minimize the reporting burden on States Also, direct reporting will avoid duplication of effort for sources subject to the Part 75 requirements

Currently, there are no existing annual reporting requirements for area, nonroad mobile, and highway mobile source emissions For the purposes of the final rule, an area source is any anthropogenic source that is not included in the point, nonroad mobile, or onroad mobile source inventories. The EPA requires that States report annually area source NOx emissions for only those stationary area source categories for which States adopt control measures for the purpose of meeting their NOx budget For nonroad mobile and onroad mobile sources, EPA requires that States report annually NOx emissions for only those source categories for which the State adopts control measures that are more stringent than Federal measures for the purpose of meeting their NOx budget Based on the recommendations of OTAG, it is not expected that States will adopt area, nonroad mobile, or onroad mobile source control measures to meet their NOx budgets However, if one or more States do adopt such measures, annual reporting of emissions will be necessary to track the States' progress toward meeting their NOx budgets

The rule contains a requirement for States to report statewide point, area, nonroad mobile, and onroad mobile source NOx emissions data every 3 years starting with the inventory year 2002 The data reported would be ozone season emissions data for each third year and would include data from all source categories in the State regardless of whether sources are being controlled to meet a NOx budget This 3-year cycle reporting requirement coincides with the schedule for the existing periodic emission inventory reporting requirement for the States

EPA requires that in 2007, States submit to EPA statewide ozone season NOx emissions data from all NOx sources (point, area, nonroad mobile, and onroad mobile) within the State The data reporting requirements are identical to the reporting requirements for the 3-year cycle inventory, but would occur 1 year prior to the scheduled 3-year cycle inventory This one-time reporting requirement for a 2007 statewide inventory will allow evaluation of whether the NOx budgets are met for 2007 However, EPA will work with the States to minimize the incremental burden associated with preparing both a 2007 and a 2008 statewide inventory The incremental burden is associated with the area and mobile source inventories since States must already report point source data annually For area, nonroad mobile, and onroad mobile source data, States may project incremental changes in emissions from 2007 to 2008 to allow the 2008 inventory requirement to be more easily met and to reduce the burden on the States

8.1.1 Planning Requirements

Compliance with the reporting requirements falls into three categories of respondent activities: one-time actions, annual actions, and triennial actions Respondent States need to understand what activities are required, when they are to be completed, and decide on data collection methodology The remainder of this section discusses what activities are required to be done once, annually, and triennially. Section 8.1 2 describes new data required and collection processes

One-Time Activities

First, States will need to read and interpret the reporting requirements of the rule. Additionally, example ozone season emissions calculations must be prepared and submitted to EPA Depending on the complexity of these calculations, the amount of time required to comply would vary Another one-time activity involves a State modifying its emissions data bases to incorporate seven additional data items for point sources, five additional data items for area and nonroad mobile sources, and four additional data items for on-road mobile sources

A one-time effort is expected for the States to establish procedures to estimate statewide ozone season NOx emissions from stationary area sources Area source NOx emissions in the OTAG inventory are due to stationary fuel combustion, incineration and open burning, and wildfires and prescribed burning It is assumed that States would develop a spreadsheet or data base containing county-level activity indicators (e g , population, employment, forest acreage) to allocate activity data typically available at the State level to the county level It will also be necessary to account for any controls or seasonal restrictions that would impact NOx emissions

For onroad mobile sources, it will be necessary for States to prepare a procedure for estimating county-level VMT as input to EPA's MOBILE model It is assumed that States will distribute statewide VMT available from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System (HPMS) to the county level using a surrogate activity indicator such as population In addition, any onroad mobile source controls applicable to a county must be identified and accounted for in the emission estimates for a county

States must prepare and submit a statewide ozone season NOx emissions inventory of all controlled and uncontrolled sources for the year 2007 A 2007 statewide ozone season NOx emissions inventory for all point, area, nonroad mobile, and onroad mobile sources is required to allow evaluation of whether the NOx budgets are met for the year 2007 This one-time special inventory is necessary because the scheduled 3-year reporting cycle does not fall in the year 2007 States which must submit the 2007 inventory may project incremental changes in emissions from 2007 to 2008 to allow the 2008 inventory requirement to be more easily met and to reduce the burden on States which must submit full NOx inventories in consecutive years (i e , 2007 and 2008)

Finally, the State must review a Title V permit revision submitted by controlled sources The ICR lists these one-time activities and estimates for the managerial and technical manhours required to complete the tasks

Annual Activities

Annual State activities associated with reporting are as follows States must notify the appropriate EPA Regional Office when submitting an annual, triennial, and 2007 NOx inventory Technical staff are required to prepare and submit an electronic NOx emissions budget report Most of the data collection activities associated with the annual inventory are already being done to meet existing inventory requirements However, there is additional work associated with compiling and quality-assuring the ozone season inventory Estimates for the time needed to accomplish these reports and the costs associated with these reports are presented in the ICR

Triennial Activities

Every 3 years, States are required to submit ozone season emissions data for all point, area, nonroad mobile, and onroad mobile sources of NOx within the State States are already submitting a statewide emissions inventory of all point sources under the existing annual inventory requirements. However, additional time requirements are expected for States to develop statewide NOx stationary area source, nonroad mobile source, and onroad mobile source inventories every 3 years. Under the existing periodic SIP inventory requirements, emissions from these sectors were only determined for ozone nonattainment area counties. The incremental time for developing statewide ozone season inventories for all controlled and uncontrolled sources consists of hours allocated to the following activities

- For stationary area sources, collecting activity data needed to allocate State-level activity data to the county-level and estimating area source emissions,

- For nonroad mobile sources, estimating emissions according to EPA's NONROAD emission inventory model[3], and

- For onroad mobile sources, estimating emissions using EPA's MOBILE model[4]

States must compile a summary report of statewide NOx emissions for submittal to EPA. Depending upon current reporting practices, this activity may require little or no additional hours of labor

Table 8-1 summarizes the various reporting requirements for State during the period from 2003 to 2008. Estimates for the time needed to accomplish these reports and the costs associated with these reports are presented in the ICR

8.1.2 Data Collection

Many of the required emissions data elements are already being provided to the EPA under existing annual point source reporting requirements, as well as periodic SIP inventory reporting provisions for point, area and nonroad mobile, and onroad mobile sources. The EPA is also requiring States to provide an example ozone season calculation, along with sufficient information for EPA to verify the calculated value of ozone season emissions. This calculation, as well as two additional seasonal data elements (i.e., fuel heat content for point sources, activity/throughput level), will facilitate quality assurance review of the seasonal emissions data. Other data fields for providing the source of fuel heat content data, source of emissions data, source of emission factor, and source of activity throughput data will also assist EPA in their NOx budget verification procedures

The EPA is also requiring an "Area Designation" element for States that opt to establish an offset pool composed of actual emission reductions achieved through compliance with the SIP call NOx budgets where States will need to track whether they are obtaining creditable offsets as specified in Section 173(c) of the Act (which requires that major sources obtain offsets from areas with equal or higher nonattainment classification). The ICR lists the new data items required for point, area, nonroad mobile, and onroad mobile sources which are not currently required to be included in emission inventories reported to EPA.

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[3] EPA's NONROAD model is currently under development by EPA's Office of Mobile Sources (OMS). A final version of the model is expected to be in use by States by 2003

[4] These estimates are based on a State using MOBILE6, which will be the next version of EPA's MOBILE model

Table 8-1
Schedule of Reporting Activities for Each Year During the Period 2003 through 2008[a]

Information Collection Activity	2003	2004	2005	2006	2007	2008
One-time (Annualized)						
Read the reporting requirements of the rule	✔					
Submit example ozone season emissions calculations to EPA [§51 122(g)]	✔					
Modify point, area, nonroad mobile, and onroad mobile source data bases to add data fields for additional data items [§51 122(c), (d), (e)]	✔					
Develop procedures by which to estimate stationary area source NOx emissions for triennial statewide reporting requirements [§51 122(b)(2), (3)]	✔					
Develop procedure for generating county-level vehicle miles traveled (VMT) [§51 122(b)(2), (3)]	✔					
Project 2007 area, nonroad mobile, and onroad mobile source inventories to 2008 to satisfy 3-year cycle requirement [§51 122(b)(2), (3)]						✔
Review Title V permit revisions from controlled sources [§51 121(h)(1)]	✔					✔
Annual						
Determine ozone season emissions for controlled sources [§51 122(c)(1), (2)]	✔	✔	✔	✔	✔	✔
Notify the appropriate EPA Regional Office when submitting annual, triennial, and 2007 NOx inventory [§51 122(h)]	✔	✔	✔	✔	✔	✔
Submit electronic NOx budget emissions report [§51 122(b)(1)]	✔	✔	✔	✔	✔	✔
Triennial						
Prepare statewide ozone season inventory for stationary area sources, including a determination of ozone season emissions for all sources [§51 122(b)(2)]	✔			✔		
Prepare statewide ozone season inventory for nonroad mobile sources, including a determination of ozone season emissions for all sources [§51 122(b)(2)]	✔			✔		
Prepare statewide ozone season inventory for onroad mobile sources, including a determination of ozone season emissions for all sources [§51 122(b)(2)]	✔			✔		
Compile summary report of statewide ozone season NOx emissions and account for sources that have been reporting directly to EPA [§51 122(b)(2), (h)]	✔			✔		

[a] Activities associated with developing an emissions inventory for a particular year are assumed to take place during the year following the inventory year (e g , activities for compiling a 2002 triennial inventory take place during 2003, and for 2007 inventory during 2008)

Source *Emission Reporting Requirements for Ozone SIP Revisions Relating to Statewide Budgets for NO_x Emissions*, September, 1998

Several options are currently available for data reporting

- State chooses to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) system using the AFS format for point sources.[5]

- State converts its emissions data into the Emissions Inventory Improvement Project/Electronic Data Interface (EIIP/EDI) format.[6]

- State submits its emissions data in a proprietary format based on the EIIP data model, or

- Annual reporting (except for third year reports) by sources submitting the data directly to EPA This option will be available to any source in a State that is both participating in a trading program meeting the requirements of Part 96 and that has agreed to submit data in this format The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option

8.2 Administrative Costs Associated with Units in the Trading Program

This section presents the estimates of administrative costs for State and Federal governments associated with control of electricity generating units

Administrative Costs - State Governments

Administrative costs to State governments include on-going auditing of sources, certification of monitoring plans, and handling of permits Table 8-2 presents the administrative costs to State governments for these activities if they choose to participate in the model Part 96 trading program These estimates include all units (both EGUs and non-EGUs) that are part of the required applicability for the trading program If a State chooses not to participate in the trading program, they would incur different administrative costs to implement another regulatory means of achieving the required emission reductions The magnitude of those costs would depend on the regulatory option chosen by the State The costs presented here are incremental to the Initial Base Case The unit cost for auditing is $1,698 (this assumes 60 hours per audit at $28.30 per hour) The total annual auditing costs to States, assuming that States audit 10 percent of the 1,995 potentially affected sources, is $339,600

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[5] This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified

[6] Through the EIIP, EPA is participating in a joint effort with State and local air pollution control agencies to establish a common format for exchanging data from one agency to another.

Table 8-2
Administrative Costs Associated with Implementing the Trading Program in States in the SIP call Region in 2007 (1990S)

	Emissions Monitoring		Permitting, Review and Approval
	Auditing	Certification of Monitoring Plans	
Unit Costs	$1,698	$0-566	$115
Total EGU Costs	256.568	238,852	173,765
Total non-EGU Costs	136,180	318,658	92,223
Total Annual Costs	$392,748	$557.510	$265.988

Source ICF Analysis

The unit costs to States for initial review of monitoring plans range from zero for units with currently approved monitoring plans to $566 (20 hours per certification at $28 30 an hour) for units without currently approved monitoring plans Total annual costs to States for certification and recertification of the monitoring plans for all units potentially affected by the NOx SIP call is $377.852 The unit costs for permitting activities for States includes the costs for States to review and approve applications for modifications as well as for new permits The annualized unit cost to States for permit activities is assumed to be $23 The total annual permitting activity costs to States, assuming 1.995 affected sources, is $45.885

Administrative Costs - EPA

The primary administrative costs to EPA are associated with administering the trading program The two main tasks involved in administering the trading program are administering the emissions tracking system (ETS), used to track emissions from affected units and administering the allowance tracking system (ATS) used to track owners of allowances

EPA estimates that the capital cost in modifying its existing ETS and ATS tracking systems which are used to support the federal SO_2 trading program under Title IV of the Act and the OTC NOx Budget Trading Program would be $250.000 and $500.000 respectively EPA also estimates that there would be ongoing operational expenses of approximately $100.000 annually to support each system

EPA estimates that it would take 0 5 hours to process each allowance transfer and expects approximately 8.050 transfers a year This assumes that EPA will have to make 1 transfer at the beginning of the year and one transfer at the end of the year for each unit. It also assumes that there will be approximately three private transfers made per affected unit In addition, it assumed no additional costs for units are part of the OTC NOx Budget Trading Program that EPA is already administering This was the average in 1997 for the SO_2 trading program This would require approximately 4,025 hours.

For processing emissions data, EPA estimates that it will spend 5 hours more for units already affected by the Acid Rain Program who are not part of the OTC NOx Budget Trading Program. For these 1.089 units, this will take 5,445 hours. EPA estimates it will spend 10 hours per unit for units that are not currently affected by either the Acid Rain Program or the OTC NOx Budget Trading Program For these 985 units, this will take 9.850 hours

Table 8-3
Administrative Costs Associated with EGUs and non-EGUs in the SIP Call Region to EPA in 2007 (1990S)[a]

	Capital Costs	Annual Fixed Operating Costs	Annual Labor (in hours)	Total Annual Costs in 2007
Emissions Tracking System	$250,000	$100,000	15,295	$786,000
Allowance Tracking System	$500,000	$100,000	4,025	$327,000
Total	$750,000	$200,000	19,320	$1,113,000

[a] These estimates account for participation by non-EGU sources in the NOx Budget Trading Program

Total Administrative Costs-Electricity Generating Units

The total EGU-related annual administrative costs of the rule to the States are roughly $800,000, and roughly $400,000 to EPA for the 0 15 trading option The costs presented are incremental to the Initial Base Case The differences in these costs between the regulatory alternatives examined is minimal since there is little change in the number of affected units overall

8.3 Administrative Costs Associated with Other Stationary Sources Not in the Trading Program

Many of the States have the mechanisms in place to support the reporting of emissions data to EPA under existing emission inventory requirements for these sources Therefore, the burden for State personnel to perform these activities (e g , collecting emissions data from sources, maintaining emission inventory records) are not estimated The States' burden associated with these sources for the final rulemaking is primarily to estimate and quality-assure ozone season emissions, and modify State data bases to report additional data items needed to verify ozone season emissions In addition, there will be additional effort involved in compiling statewide area, nonroad mobile, and highway mobile source ozone season NOx emission inventories every 3 years The information collection activities related to other stationary sources involve an average of 269 hours per year at an estimated cost of $7,140 per State, for total of 6,187 hours and $164,202 for the entire SIP call region This is the annual cost to States associated with this rulemaking for each year between 2003 and 2005 This is the first 3 year period during which States will be required to begin reporting under the rule

No other stationary source-related burden is expected to be imposed on EPA from implementation of this rulemaking other than additional operation of the emissions tracking system (ETS) and the national allowance tracking system (NATS) An estimate of this burden related to non-EGUs is presented in Table 8-3 along with the EGU-related burden to EPA from operating the ETS and NATS. The total annual cost in 2007 for this burden to EPA is estimated at roughly $850,000, based on the results in Table 8-3

8.4 Government-Owned Entities

This section summarizes compliance (control and administrative) costs incurred by government-owned other stationary sources that are assumed to require new controls under the NOx SIP call These costs include both control costs and administrative costs similar to those incurred by other regulated sources, including costs associated with trading These costs are a subset of the compliance costs presented in Chapter 7 The control costs are based on assumptions of how affected States will implement control measures to meet their NOx budgets set forth in this rulemaking While the Unfunded Mandates Reform Act does not apply to this action, the information on potential compliance costs to government-owned sources may assist the States in their efforts to develop SIPs that meet these new NOx budgets

Table 8-4 provides an overview of the government entities which own EGUs that may be affected by the 0 15 trading option

Table 8-4
2007 Annual Costs To Potentially Affected Government-Owned EGU NOx Emissions Sources
0.15 Trading Regulatory Alternative

Government Entity	Number of Sources	Annual Control Costs (thousands of 1990S)	Annual Administrative Costs (thousands of 1990S)	Total Compliance Costs (thousands of 1990S)
Federal Government[a]	1	na	na	na
State and Municipal Government	78	$45.100	$5.900	$51.000
TOTAL:	79	$45.100	$5.900	$51 000

[a] Control and administrative costs were not estimated for this source

As shown in Table 8-4, there are 79 potentially affected government-owned EGUs that may be affected under the 0 15 trading regulatory alternative These units may experience compliance costs of about $51 million in 2007

Table 8-5 provides an overview of the government entities which own non-EGUs that may be affected under the 60%/$5.000 options As shown in Table 8-5, there are 30 potentially affected government-owned non-EGU sources that may experience compliance costs of roughly $3 6 million dollars in 2007

Table 8-5
2007 Annual Costs To Potentially Affected Government-Owned NOx Emissions Sources
60%/$5,000

Government Entity	Number of Sources	Annual Control Costs (thousands of 1990S)	Annual Administrative Costs (thousands of 1990S)	Total Compliance Costs (thousands of 1990S)
Federal Government	23	$1,786	$727	$2.513
State Government - correctional facility	1	602	46	648
City Government- Refuse systems	1	0 5	8	9
Educational institution	1	30	1	31
Metropolitan water system	1	54	46	100
City. regional sewerage systems	3	176	136	312
TOTAL:	30	$2.649	$964	$3,613

Therefore. under the 0 15 trading alternative for EGUs and the 60%/$5.000 per ton alternative for non-EGUs. 109 sources or units owned by Federal. State. and local governments in the SIP call region may potentially be affected by control and administrative measures at an annual compliance cost of about $55 million in 2007 This compliance cost. however. is only 3 percent of the total compliance cost for these alternatives ($1 69 billion)

8.5 References

Abt Associates. 1998 *Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call* Prepared for the U S Environmental Protection Agency. Office of Air Quality Planning and Standards. September 1998

U S Environmental Protection Agency, 1998a ICR # 1857 01, *Emission Reporting Requirements for Ozone SIP Revisions Relating to Statewide Budgets for NO_x Emissions.* September. 1998

U S Environmental Protection Agency, 1998b *Unfunded Mandates Reform Act Analysis for the Proposed Federal Implementation Rule under the Clean Air Act Amendments Title I* Office of Air and Radiation. September 1998.

Chapter 9. INTEGRATED COST, EMISSIONS, AND SMALL ENTITY IMPACTS SUMMARY

This chapter presents EPA's estimates of the NOx emission reductions, potential compliance costs, average cost-effectiveness, and potential small entity impacts associated with the final NOx SIP call rulemaking It brings together the results presented in Chapters 6, 7, and 8 All of these results are based on the Agency's assumptions of how States in the NOx SIP call region could implement control strategies to meet the NOx budget levels set for them in this rulemaking The results are then compared to average cost-effectiveness estimates of other recent regulatory actions that require NOx reductions

Section 9 1 presents estimates of NOx emission reductions for potentially affected electricity generating and non-electricity generating sources. Section 9 2 presents estimates of compliance costs (control and administrative costs) and average cost-effectiveness for all these sources, and provides a table of average cost-effectiveness estimates for other recent regulatory actions that require NOx reductions for purposes of comparison Section 9 3 presents an integrated summary of potential small entity impacts

9.1 Emission Reductions

With this rulemaking, the EPA will establish ozone season NOx budgets for 22 States and the District of Columbia based on reducing emissions from electricity generating units and other stationary sources [1] The analysis of impacts is from a baseline that includes the existing Title IV NOx rules, Reasonably Available Control Technology (RACT) requirements, and New Source Performance Standards (NSPS) and controls for new and recently-built major NOx sources The baseline also includes implementation of Phase I (RACT requirements) of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU)[2]

Table 9-1 shows the NOx emissions levels and emissions reductions for selected combinations of alternatives that EPA has analyzed for potentially affected electricity generating units and other stationary sources These results bring together the six regulatory alternatives analyzed for potentially affected EGUs, and the three combination regulatory alternatives for non-electricity generating sources The non-EGU regulatory alternatives combine industrial boilers and combustion turbines with other stationary sources (stationary internal combustion engines, cement kilns) These alternatives are discussed in Chapter 2 and the results of the analysis are presented in Chapters 6 and 7 The alternatives selected for the final NOx SIP call are highlighted

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[1] This category includes industrial (industrial, commercial, and institutional) boilers and combustion turbines, stationary internal combustion engines, and cement manufacturing operations (cement kilns [wet, dry, and coal-fired]) For additional details on these source types see Chapter 3

[2] This baseline is discussed in greater detail in Chapter 4

Table 9-1
2007 Ozone Season NOx Emissions and Emission Reductions for Selected Combinations of Electricity Generating Units and Other Stationary Source Regulatory Alternatives from the Initial Base Case [a]
(thousands of NOx Tons)

Regulatory Alternatives		Electricity Generating Units (1,502 thousand baseline tons)					
		0.25 Trading	0.20 Trading	Regionality 1	Regionality 2	0.15 Trading	0.12 Trading
Other Stationary Sources (330 thousand baseline tons)	40% Control/ $1500 per Ton	1,111 (722)	922 (910)	847 (985)	757 (1,075)	735 (1,097)	624 (1,208)
	60% Control/ $5000 per Ton	1,067 (766)	878 (954)	803 (1,028)	713 (1,119)	**691 (1,141)**	580 (1,252)
	70% Control/ $5000 per Ton	1,041 (791)	853 (979)	778 (1,054)	688 (1,144)	666 (1,166)	555 (1,277)

[a] Emissions reductions are shown in parentheses. Controls on the electricity generating units occur through a Cap-and-Trade program described in the NOx Model Trading Rule and supporting information. Controls on Other Stationary Costs are determined using two approaches: 1) a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines, and 2) an approach that applied controls up to a cost cutoff expressed in annual costs per ozone season ton reduced, applied to large stationary IC engines, and cement manufacturing.

9.2 Compliance Costs and Cost-Effectiveness

Table 9-2 shows annual compliance control costs for selected combinations of regulatory alternatives that EPA has analyzed for potentially affected electricity generating units and other stationary sources Costs include direct control costs and adminstrative costs (monitoring, recordkeeping, and reporting) The alternatives selected for the final NOx SIP call rule are highlighted The costs for EGUs reflect emissions trading across States For non-EGUs, costs are determined using two approaches 1) a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines, and 2) an approach that applied controls up to a specified cost cutoff expressed in costs per ton reduced, applied to large stationary IC engines, and cement kilns

Table 9-3 provides the resulting 2007 ozone season average control cost-effectiveness values for the same selected combination of alternatives examined in the previous two tables The average control cost-effectiveness of ozone season NOx emission reductions is calculated as the change in total annual compliance costs relative to the Initial Base case divided by the change in ozone season NOx emissions relative to the Initial Base case This table shows the increase in average cost-effectiveness values as the combination of standards considered becomes more stringent It should be noted that these estimates are only presented to illustrate the average cost-effectiveness of different combinations of EGU and Other Stationary Source alternatives The decisions on control levels and the inclusion of individual source categories in this rulemaking were made by evaluating each category separately, not by using the summary of cost-effectiveness values in Table 9-3

OTAG recognized the value of market-based approaches to lowering emissions from power plants and large industrial sources The Agency agrees that using a market-based approach in the emission reduction program is desirable Accordingly, the Agency has proposed the NOx Model Trading Rule This rule provides for an emissions cap and allows for trading between sources in the all the jurisdictions covered, which are essential for this rule to be effective and administratively practicable The Agency wants to work with all affected jurisdictions covered by this rulemaking to establish such a program This is a major reason behind the Agency's effort at estimating NOx control costs across the jurisdictions in the SIP call region for electric power generation units and cost minimization across the same domain for Other Stationary Sources Analytical limitations kept EPA from estimating the costs of a single cap-and-trade program for electricity generating sources and large industrial sources in the Other Stationary Sources category (e g , industrial boilers and combustion turbines) Given that the Agency could not estimate the costs of a single emissions trading program for these sources, the annual cost estimates for this rulemaking are likely to be overstated to the extent that costs could be reduced by trading between facilities in both groups. However, it should be noted that individual States may decide to achieve their NOx budget with other control techniques, thereby affecting their costs

Table 9-2
2007 Annual NOx SIP call Compliance Costs for Selected Combinations of Electricity Generating Unit and Other Stationary Source Regulatory Alternatives (millions of 1990 dollars)[a]

Regulatory Alternatives		Electricity Generating Units					
		0.25 Trading	**0.20 Trading**	**Regionality 1**	**Regionality 2**	**0.15 Trading**	**0.12 Trading**
Other Stationary Sources	**40% Control/ $1,500 per Ton**	$848	$1,153	$1,323	$1,554	$1,583	$2,051
	60% Control/ $5,000 per Ton	$925	$1,230	$1,400	$1,631	**$1,660**	$2,128
	70% Control/ $5,000 per Ton	$1,048	$1,353	$1,523	$1,754	$1,783	$2,251

[a] The decisions on control stringency and the inclusion of individual source categories in this rulemaking were not made using the summary of cost-effectiveness values in this table. Control on the electricity generating units occur through a Cap-and-Trade program described in the NOx Model Trading Rule and supporting information. Controls on Other Stationary Sources are applied using two approaches: 1) a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines, and 2) an approach that applied controls up to a cost cutoff expressed as costs per ton reduced, applied to large stationary IC engines, and cement manufacturing. Analytical limitations prevented EPA from estimating the costs of a single cap-and-trade program for electricity generating units and large industrial boilers and combustion turbines combined. Costs for these sources are likely to be lower than has been estimated in this RIA if States integrate electricity generating units and industrial boiler and combustion turbine programs in to a single trading program. It should be noted that individual States may decide to achieve their NOx budget with other control techniques, thereby affecting their costs.

Table 9-3
2007 Ozone Season Average Compliance Cost-Effectiveness for Selected Combinations of Electricity Generating Unit and Other Stationary Source Regulatory Alternatives
(1990 dollars per ton of NOx reduced in the ozone season)[a]

Regulatory Alternatives		Electricity Generating Units					
		0.25 Trading	0.20 Trading	Regionality 1	Regionality 2	0.15 Trading	0.12 Trading
Other Stationary Sources	**40% Control/ $1,500 per Ton**	$1,175	$1,267	$1,343	$1,446	$1,443	$1,698
	60% Control/ $5,000 per Ton	$1,208	$1,289	$1,362	$1,458	**$1,455**	$1,700
	70% Control/ $5,000 per Ton	$1,325	$1,382	$1,445	$1,533	$1,529	$1,763

[a]Controls on the electricity generating units occur through a Cap-and-Trade program described in the NOx Model Trading Rule and supporting information Controls on Other Stationary Sources were applied using two approaches 1) a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines, and 2) an approach that applied controls up to a cost cutoff expressed in costs per ton reduced, applied to large stationary IC engines, and cement manufacturing Analytical limitations prevented EPA from estimating the costs of a single cap-and-trade program for electricity generating units and large industrial boilers and combustion turbines combined Costs for these sources are likely to be lower than has been estimated in this RIA if States integrate electricity generating units and industrial boiler and combustion turbine programs in to a single trading program It should be noted that individual States may decide to achieve their NOx budget with other control techniques, thereby affecting their costs

9.2.1 Cost-Effectiveness Comparisons

Table 9-4 provides a reference list of measures that EPA and the States have undertaken to reduce NOx and their average cost per ton of NOx reduced The average annual cost per ton of NOx reduced from this rulemaking is included in the table Most of these measures fall in the $1,000 to $2,000 per ton range With few exceptions, the average cost-effectiveness of these measures is representative of the average cost-effectiveness of the types of controls EPA and the States have needed to adopt most recently since their previous planning efforts have already taken advantage of opportunities for even cheaper controls The Agency believes that the cost-effectiveness of measures that the cost-effectiveness of measures that it or States have adopted, or proposed to adopt, forms a good reference point for determining which of the available additional NOx control measures can most reasonably be interpreted by upwind States or jurisdictions that significantly contribute to ozone nonattainment

Table 9-4
Average Cost-Effectiveness of NOx Control Measures Recently Undertaken or Proposed (1990 dollars)

Control Measure	Average Cost per Ton of NOx Reduced
NOx RACT	$150 - 1,300
Phase II Reformulated Gasoline	$4,100[a]
State Implementation of the Ozone Transport Commission Memorandumof Understanding (OTC MOU)	$950 - $1,600
Proposed New Source Performance Standards (NSPS) for Fossil Steam Electric Generating Units	$1,290
Proposed NSPS for Industrial Boilers	$1,790
Final NOx SIP Call Rulemaking - Electricity Generating Units	$1,468[b]
Final NOx SIP Call Rulemaking - Other Stationary Sources	$1,365[c]

[a] Average cost representing the midpoint of $2,180 to $6,000 per ton, as described in EPA's response to the American Petroleum Institute's petition to waive the Federal Phase II RFG NOx standard This cost represents the projected additional cost of complying with the Phase II RFG Nox standards, beyond the cost of complying with the other standards for Phase II RFG

[b] Estimated average cost-effectiveness (including compliance costs) associated with the uniform 0 15 trading alternative

[c] Estimated average cost-effectiveness (including compliance costs) associated with the preferred alternative (60% control - industrial boilers and combustion turbines, control up to a cost cutoff of $5,000 ton - stationary IC engines, cement manufacturing)

There are also a number of less expensive measures recently undertaken by the Agency to reduce NOx emissions that do not appear in Table 9-4. These actions include (1) the Title IV NOx reduction program, (2) the federal locomotive standards, (3) the 1997 proposed federal nonroad diesel engine standards, (4) the federal heavy duty highway engine 2g/bhp-hr standards, and (5) the federal marine engine standards These actions do not provide a meaningful comparison to this rulemaking because they are believed to be among the lowest cost options for NOx control Since these options have been exhausted, the Agency must now focus on what other measure exist, at a potentially higher average cost-effectiveness value.

that can further reduce NOx emissions Table 9-4 is thereby useful as a reference for the next higher level of NOx reduction cost-effectiveness that the Agency considers reasonable to undertake

9.3 Integrated Small Entity Impacts

The Agency examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected States will implement control measures to meet their NOx budgets While the RFA as amended by SBREFA does not apply to this action, these impacts have been calculated in order to provide additional understanding of the nature of potential impacts, and additional information to the States as they prepare SIPs designed to meet the NOx budgets set by this rulemaking It is the Agency's position, however, that the RFA as amended by SBREFA does apply to the proposed NOx FIP and the proposed response to the section 126 petitions The Agency has prepared Initial Regulatory Flexibility Analyses (IRFAs) for both of these actions

Table 9-5 presents a summary of the potentially affected small entities in EPA's analysis Of the 191 small entities potentially affected, 41may experience compliance costs in excess of one percent of revenues, based on assumptions of how the affected States implement control measures to meet their NOx budgets as set forth in this rulemaking Potentially affected small entities experiencing compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the SIP call These 41 small entities constitute about 3 percent of the small entities in the SIP call region that own sources potentially affected by this rulemaking

EPA's estimates of other potential economic impacts for entities owning electricity generating units including changes in capacity, and changes in demand for electricity that could result from implementation of this SIP call are found in Chapter 6. Details on EPA's other estimates of potential economic impacts associated with this rulemaking to entities owning sources in the other stationary source category are found in Chapter 7

Table 9-5
Number of Potentially Affected Small Entities for the NOx SIP Call Rulemaking

Source Category/ Regulatory Alternative	Small Entities in the SIP call Region	Small Entities Potentially Affected[a]	Small Entities in the SIP Call Region with Compliance Costs > 1% of Sales/Revenues	Percentage of Small Entities in the SIP Call Region with Compliance Costs > 1% of Sales/Revenues
Electricity Generating Units 0 15 Trading	500	114	32[b]	6%
Other Stationary Sources 60% Control/ $5000/ton	700[c]	77	9	1%
TOTAL	1,200	191	41	3%

[a] These are small entities that own large sources in the source categories covered under this rulemaking

[b] The estimated costs of compliance are calculated assuming all small non-utility generators comply through purchasing allowances This approach tends to overstate compliance costs because cases in which emission reductions can be achieved below the marginal cost of reductions in the SIP call domain are not considered

[c] This represents the number of small entities in the SIP call region owning sources (small and large) in the source categories covered under this rulemaking

9.4 References

U S Environmental Protection Agency. 1998a *Initial Regulatory Flexibility Analysis for the Proposed Federal Implementation Plan Under the Clean Air Act* September. 1998

U S Environmental Protection Agency. 1998a *Initial Regulatory Flexibility Analysis for the Proposed Section 126 Petition Rulemaking Under the Clean Air Act* September. 1998

APPENDIX

to the

REGULATORY IMPACT ANALYSIS FOR THE NO_x SIP CALL, FIP, AND SECTION 126 PETITIONS

Volume 1: Costs and Economic Impacts

STATE-BY-STATE OZONE SEASON NOx EMISSIONS FOR ELECTRICITY GENERATING UNITS BY REGULATORY ALTERNATIVE

This appendix contains the state-by-state emissions data used to generate the map figures in Chapter 6 The source for this data is ICF analysis using the latest version of the Integrated Planning Model (IPM)

Table A-1
2007 Ozone Season Emissions Estimates for the Electric Power Industry for States in the SIP Call Region

State Name	Initial Base Case	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Alabama	76,926	52,084	39,937	37,440	26,689
Connecticut	5,636	3.867	3,866	3,267	2,772
Delaware	5.838	6,119	4,624	3.585	3,555
District of Columbia	3	8	7	10	16
Georgia	86.455	55.808	46,483	37.474	26.856
Illinois	119,311	65,988	51.650	37,928	28.917
Indiana	136,773	77.453	63.307	47.415	34.408
Kentucky	107.829	57,721	47,896	38.427	30.411
Maryland	32,603	23.317	16,194	13.864	11.193
Massachusetts	16.479	16.104	13.735	10,319	10.216
Michigan	86.600	58.825	42,692	34,950	26.970
Missouri	82,097	44.388	34.662	24.037	14.734
New York	39.199	31.832	26.818	24,093	21.838
New Jersey	18.352	13.316	12.302	8.838	8,198
North Carolina	84,815	59.255	50.088	34,556	29.945
Ohio	163,132	93.803	71.219	46,843	39.909
Pennsylvania	123,102	81.188	71,118	46.186	41.800
Rhode Island	1,082	1.071	1,071	1.071	974
South Carolina	36.299	27.453	22.093	17,965	13,695
Tennessee	70,908	46.459	24.211	23.706	20.162
Virginia	40,884	30,632	24.280	19.276	16,215
West Virginia	115,490	60.070	57.998	33.545	25.693
Wisconsin	51,962	32,838	24,998	18,967	18.286
TOTAL	**1,501,775**	**939,599**	**775,529**	**563,762**	**453,443**

Numbers may not sum due to rounding

Table A-2
Comparison of Electric Power Industry 2007 Ozone Season Emissions for the Initial Base Case, the 0.15 Budget Component, and the 0.15 Trading Alternative for States in the SIP Call Region

State Name	Initial BaseCase	0.15 State Budget	0.15 Trading
Alabama	76,926	30,644	37,440
Connecticut	5,636	5,245	3.267
Delaware	5,838	4,994	3,585
District of Columbia	3	152	10
Georgia	86,455	32.433	37,474
Illinois	119,311	36,570	37,928
Indiana	136,773	51,818	47,415
Kentucky	107.829	38.775	38,427
Maryland	32.603	12.971	13,864
Massachusetts	16.479	14,651	10.319
Michigan	86.600	29.458	34,950
Missouri	82,097	26.450	24.037
New York	39.199	31,222	24.093
New Jersey	18.352	8,191	8,838
North Carolina	84.815	32.691	34.556
Ohio	163.132	51.493	46,843
Pennsylvania	123.102	45.971	46,186
Rhode Island	1.082	1.609	1,071
South Carolina	36.299	19.842	17,965
Tennessee	70,908	26.225	23.706
Virginia	40.884	20.990	19,276
West Virginia	115,490	24.045	33,545
Wisconsin	51.962	17.345	18,967
TOTAL	**1,501,775**	**563,785**	**563,762**

Numbers may not sum due to rounding

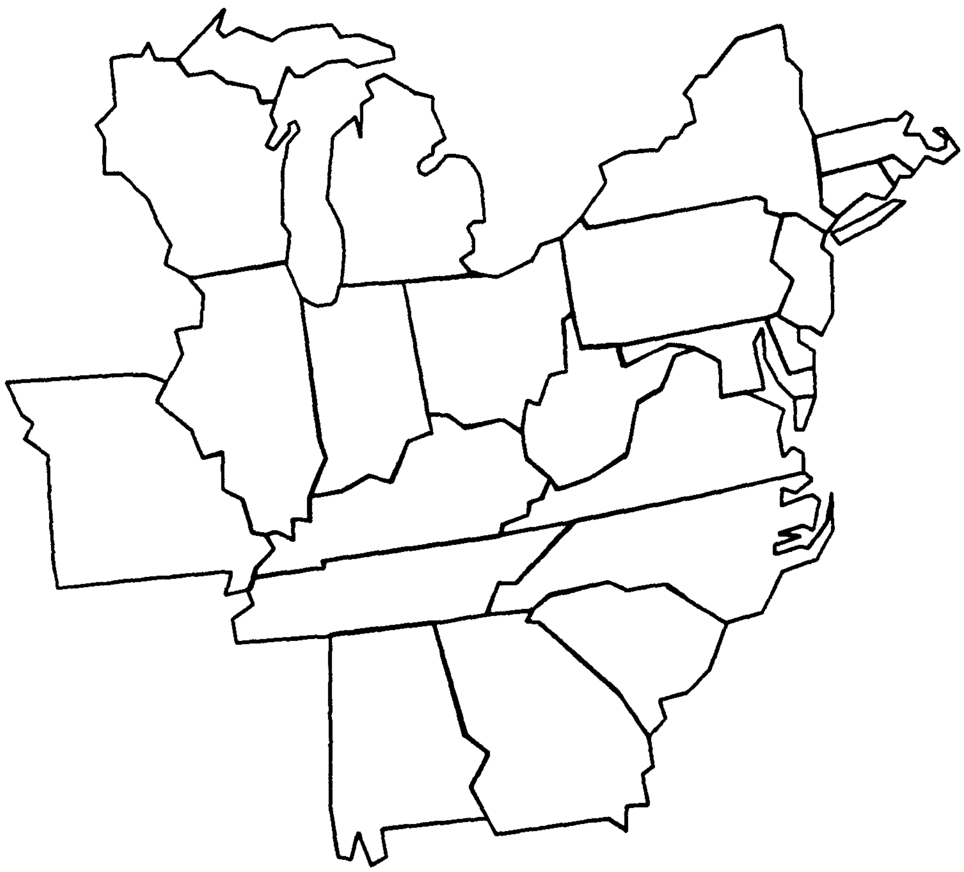
Table A-3
Comparison of State-by-State 2007 Ozone Season Emissions for the Initial Base Case, Regional Budgets, and Regional Alternatives

State Name	Initial Base Case	Two-Region Budget	Three-Region Budget	Two-Region Alternative	Three-Region Alternative
Alabama	76,926	40,835	40,835	40,048	40,048
Connecticut	5,636	5,245	4,199	3,267	2.783
Delaware	5,838	4,994	4,005	3,581	3,320
District of Columbia	3	152	122	10	11
Georgia	86,455	43.190	43,190	46.491	47,438
Illinois	119,311	48,418	36,570	49.977	38.259
Indiana	136.773	68,556	51.818	67.492	42.142
Kentucky	107.829	51.543	38,775	49,211	37,201
Maryland	32.603	12.971	10,380	13,236	10,947
Massachusetts	16,479	14.651	11.759	10.319	10,298
Michigan	86.600	38,747	29.458	42,753	35,994
Missouri	82.097	34.998	26.450	35.939	25.045
New York	39,199	31,222	25,066	24,652	22,657
New Jersey	18.352	8,191	6.598	8,765	7,902
North Carolina	84,815	43.093	43,093	50.365	51,293
Ohio	163.132	51.493	51.493	45.856	46.824
Pennsylvania	123.102	45.971	36.932	59,242	41,363
Rhode Island	1.082	1.609	1,290	1,071	1,071
South Carolina	36.299	26.455	26.455	22.874	25.239
Tennessee	70.908	34,967	34.967	23.736	24.520
Virginia	40,884	20,990	20.990	18.684	19,953
West Virginia	115,490	24,045	24,045	32,847	32,659
Wisconsin	51.962	23,009	17,345	24,995	18,828
Region 1 Subtotal [a]	—	**217,034**	**100,351**	**221,530**	**100,352**
Region 2 Subtotal [a]	—	**458,311**	**296,944**	**453,881**	**296,905**
Region 3 Subtotal [a]	—	—	**188,540**	—	**188,538**
TOTAL	**1,501,775**	**675,345**	**585,835**	**675,411**	**585,795**

Numbers may not sum due to rounding
[a] Regions for the two-region and three-region options are defined in Section 6 2.1 and 6 2 2

ADDENDUM
to the
REGULATORY IMPACT ANALYSIS FOR THE NOx SIP CALL, FIP, AND SECTION 126 PETITIONS

Volume 1: Costs and Economic Impacts



September 1998

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1.0 Introduction

This addendum to the Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions contains final cost and impact estimates for the implementation scenario used by EPA to establish the State emissions budgets For the electricity generating units (EGUs), the analysis reflects a revised emissions cap under the 0.15 trading alternative For the non-EGUs, the analysis reflects a revised emissions inventory

2.0 Addendum Analysis of the Revised NOx Cap on the 0.15 Trading Alternative for Electricity Generating Units

Since EPA conducted the main analyses documented in the RIA, the Agency has revised the NOx budget and recomputed the NOx cap for the 0 15 trading alternative The new emissions cap for the ozone season is approximately 544 thousand tons of NOx, which is about 20 thousand tons lower than the previous cap for this option The Agency made this change in response to comments that it received on the Supplemental Notice of Proposed Rulemaking on the 0.15 trading alternative EPA has also decided to allow banking of NOx emissions in the trading program with flow control Finally, the Agency has decided to allow State programs to promote early NOx reductions by both electricity generating units and non-EGUs (which allows them to make early NOx reductions in 2001 and 2002 that they "bank" for use in 2003) and to create a process whereby NOx sources that have problems installing pollution control equipment and purchasing NOx allowances to cover their emissions in 2003 can qualify to receive some NOx allowances from the State

This analysis examines the emissions, costs, and cost-effectiveness implications of the basic change to the NOx emissions cap to 544 thousand tons for EGUs for the 15 trading alternative Generally, for a trading program like the one that EPA is now working with the States to establish, the Agency expects little banking to occur based on the consideration of what the direct costs are of NOx reductions are today versus what they will be in the future How the early NOx reduction credit program and State-managed relief valve to address reliability concerns will actually work in the future is difficult to predict Given that they occur over a short time frame, their consideration is not necessary to gaining an understanding of the NOx SIP call's annual costs and cost-effectiveness to the electric power industry over time

Table 1 shows the results of the analysis of emissions and costs of the 0 15 uniform alternative relative to the Initial Base Case, using the revised cap Depending on the year, the emission reductions provided by the NOx SIP call under this option range between 919 and 968 thousand summer tons of NOx per year. These reductions come at an incremental cost of between $1,371 and $1,440 million, for an average cost-effectiveness of about $1,500 per ozone season ton

Table 1
Year-by-Year Comparison of the 0.15 Trading Alternative under the Revised Budget to the Initial Base Case: Estimated Emissions, Emission Reductions, Costs, and Cost-Effectiveness

	2003	2005	2007	2010
Emissions Under Initial Base Case (ozone season NOx emissions, thousands of tons)	1,462	1,497	1,502	1,511
Emissions, New Budget (ozone season NOx emissions, thousands of tons)	544	544	544	544
Emissions Reductions, Relative to Initial Base Case (Ozone season NOx emissions, thousands of tons)	919	953	958	968
Incremental Annual Cost, Relative to Initial Base Case (millions of 1990$)	$1,371	$1,414	$1,440	$1,411
Cost per Ozone Season Ton of NOx Removed, Relative to Initial Base Case (1990$)	$1,493	$1,484	$1,503	$1,458

Source ICF analysis

Table 2 shows how the analysis of the 0 15 trading alternative changes, in absolute and percentage terms, in response to the new cap Cutting 20 thousand ozone season tons of NOx from the cap lowers emissions by 3.5 percent and increases emission reductions by 2 1 percent. These additional reductions are accomplished through an increase in the use of SCR, which rises by about 10,000 MW, from 63,000 MW to 73,000 MW. As a result, estimated costs increase by about $62 million in 2007, which is an increase of about 4.5 percent of the incremental cost under the previous cap The cost per ton of NOx removed is higher under the new cap by about 2.4 percent. The comparisons are shown only for the year 2007, they are similar to the changes and percentage changes for the other years

Based on this reanalysis of the effects of the NOx SIP call for the 0.15 trading alternative using the revised budget, EPA has concluded that the comparisons across options presented in the RIA would not be materially affected by the change in the budget

Table 2
Comparison of the 0.15 Trading Alternative in 2007 under the Original and Revised Budgets: Estimated Emission Reductions, Costs, and Cost-Effectiveness

	Original Budget	Revised Budget	Incremental Change	Percentage Change
Emissions, Relative to Initial Base Case (summer NOx emissions, thousands of tons)	564	544	(20)	(3.5%)
Emission Reductions, Relative to Initial Base Case (summer NOx emissions, thousands of tons)	938	958	20	2.1%
Incremental Annual Cost, Relative to Initial Base Case (millions of 1990$)	$1,378	$1.440	$62	4.5%
Cost per Summer Ton of NOx Removed, Relative to Initial Base Case (1990$)	$1,468	$1,503	$35	2 4%

Source ICF analysis

2.0 Addendum Analysis on the Revised Non-EGU Emissions Inventory for Potentially Affected Units

Since the EPA conducted the main analysis documented in the RIA, the EPA has revised the non-EGU emissions inventory on the basis of comments received from the States and emissions sources This analysis examines the emissions, costs, and cost-effectiveness implications of the final inventory for the final regulatory alternatives The final regulatory alternative for non-EGU trading program sources (i e , industrial boilers and combustion turbines) is a 60% reduction from projected 2007 uncontrolled emission rates The final regulatory alternative for affected sources outside the trading program (i e., stationary internal combustion engines, and cement manufacturing operations) is based on a source category-specific evaluation of the highest emission reduction achievable for less than $5,000 per ozone season ton reduced

Table 3 contains the original and revised source counts, baseline emissions, and emission reductions for the final regulatory alternative affecting industrial boilers and turbines Table 4 shows the original and revised compliance costs (control costs plus administrative costs), and average cost-effectiveness for these sources Table 5 contains the original and revised source counts, baseline emissions, and emission reductions for the final regulatory alternative affecting IC engines and cement manufacturing Table 6 shows the original and revised compliance costs (control costs plus administrative costs), and average cost-effectiveness for these sources As shown, the differences in emissions, costs, and average cost-effectiveness are minor The most notable difference is the revised cost-effectiveness for cement manufacturing, which is nearly $200 per ton less than the original analysis

Based on this reanalysis of the effects of the NOx SIP call for these sources using the emissions inventory, EPA has concluded that the conclusions reached in the RIA would not be materially affected by the change in the budget

Table 3
Original and Revised Regulatory Alternative Emission Impacts for Industrial Boilers and Combustion Turbines: 60% Control

	Number of Potentially Affected Sources[a]	2007 Baseline NOx Emissions (ozone season tons)	2007 Post-Control NOx Emissions (ozone season tons)	2007 NOx Emission Reductions (ozone season tons)[b]
Original Analysis	803	194,445	90,193	104,252
Revised Analysis	799	196,147	89,653	106,494
Difference	(4)	1,702	(540)	2,242

[a] There are a total of 803 large sources now in these categories, both controlled and uncontrolled
[b] Reductions from controlled 2007 baseline are less than the nominal percentage reduction from an uncontrolled 2007 baseline indicated in the regulatory alternative name

Table 4
Original and Revised Regulatory Alternative Cost Estimates for Industrial Boilers and Combustion Turbines: 60% Control

	Annual Control Costs (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Average Cost-Effectiveness ($/ozone season ton)
Original Analysis	$126.8	$26.1	$152.9	$1,467
Revised Analysis	$132.2	$26.1	$158.3	$1,519
Difference	$5.4	$0	$5.4	$52

Table 5
Original and Revised Regulatory Alternative Emission Impacts Source NOT in the Trading Program: $5,000/ton Alternative

	Number of Potentially Affected Sources[a]	2007 Baseline NOx Emissions (ozone season tons)	2007 Post-Control NOx Emissions (ozone season tons)	2007 NOx Emission Reductions(ozone season tons)[b]
IC Engines				
Original Analysis	305	92,494	9,801	82,567
Revised Analysis	302	91,599	9,717	81,882
Difference	(3)	(895)	(84)	(685)
Cement Manufacturing				
Original Analysis	58	42,701	26,312	16,389
Revised Analysis	57	41,580	25,136	16,444
Difference	(1)	(1,121)	(1,176)	55

[a] There are a total of 302 large stationary IC engines and 57 large cement manfucturing sources in the revised analysis, both controlled and uncontrolled

[b] Reductions from controlled 2007 baseline are less than the nominal percentage reduction from an uncontrolled 2007 baseline indicated in the regulatory alternative name

Table 6
Original and Revised Regulatory Alternative Cost Estimates for Source NOT in the Trading Program: $5,000/ton Alternative

	Annual Control Costs (million 1990S)	Annual Monitoring and Administrative Costs (million 1990S)	Total Annual Costs (million 1990S)	Average Cost-Effectiveness (S/ozone season ton)
IC Engines				
Original Analysis	$87 1	$13 3	$100 4	$1,215
Revised Analysis	$86 3	$11 1	$97 4	$1.190
Difference	($0 8)	($2 2)	($3 0)	($25)
Cement Manufacturing				
Original Analysis	$20 2	$3 7	$23 9	$1.458
Revised Analysis	$20 0	$0 7	$20 7	$1,259
Difference	($0 2)	($3 0)	($3 2)	($199)

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

This report contains EPA's estimates of the annual costs and benefits of the final NOx SIP call and the proposed NOx FIP and CAA section 126 petition actions. The report also contains a brief profile of potentially affected sources and potential economic impacts.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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