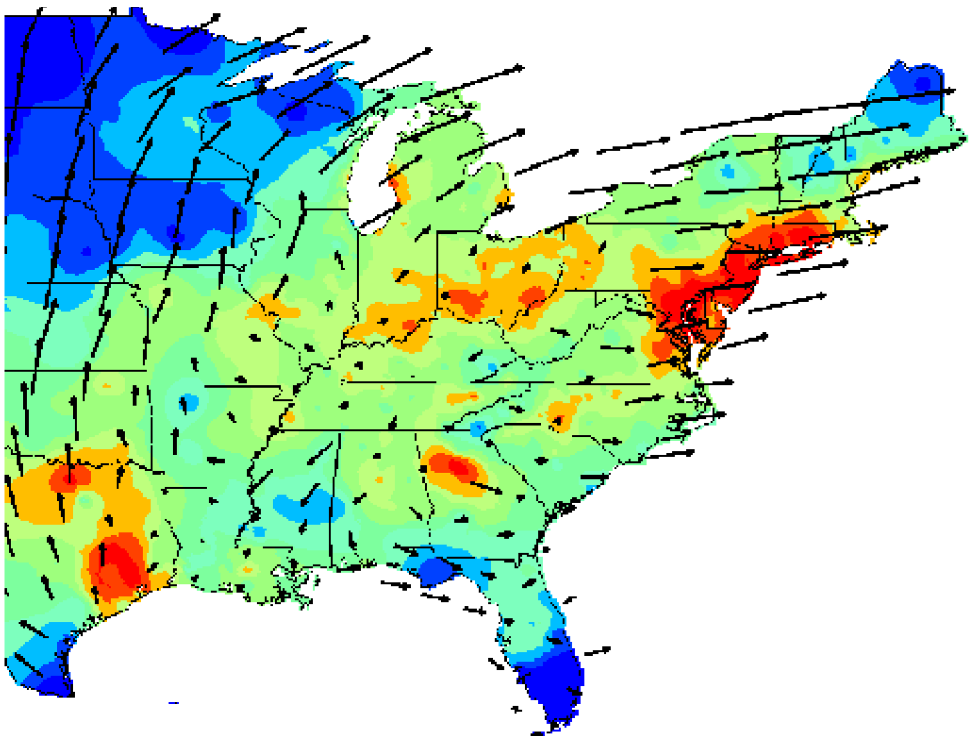
Supplemental
Ozone Transport Rulemaking
Regulatory Analysis



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

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Chapter 1. INTRODUCTION

Over two years, regulatory officials of the environmental agencies of 37 States and the District of Columbia examined the significance of the transport of ozone between Eastern States (See Figure 1-1). The transport of ozone that they examined results from chemical reactions in the atmosphere of nitrogen oxide (NO_x) emissions and volatile organic compound (VOC) emissions in these States.[1] The State regulatory staff conducted their efforts through the Ozone Transport Assessment Group (OTAG). The State representatives worked with members of the U.S. Environmental Protection Agency (EPA) and various stakeholders in OTAG's meetings to address the ozone transport issue. In July 1997, the States in OTAG reached a set of conclusions about the nature of the ozone transport problem in the Eastern United States and made recommendations to EPA on future course of action.

After a review of OTAG's analysis, findings, and recommendations, in the November 7, 1997 Notice of Proposed Rulemaking (NPR)[2], the Environmental Protection Agency (EPA) proposed a rule to limit the summer season[3] NO_x emissions in a group of States that the Agency believes are significant contributors to ozone in downwind areas. In the NPR, EPA proposed to require the selected States 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). For convenience, this rulemaking under Section 110 of the CAAA is referred to as the "ozone transport rulemaking." In order to limit summer season NO_x emissions in the selected States, EPA established a summer season NO_x budget (in tons of NO_x) for each of these States. These State-specific budgets were proposed in the NPR and costs associated with achieving these budgets were explained in an associated technical support document.[4] Since the NPR, EPA has made technical corrections to the population of sources on which the State-specific budgets are based and has developed a NO_x Model Cap and Trade Rule to provide an emissions trading framework within the ozone transport rulemaking. These recent developments are being proposed in a Supplemental Notice of Proposed Rulemaking (SNPR).

EPA prepared this regulatory analysis to support the Ozone Transport Rulemaking. This chapter identifies the environmental and regulatory issues that are addressed by the SNPR, describes how the SNPR will address these issues, and explains how the supporting analysis for the SNPR is organized in this report.

Environmental Problems from NO_x

NO_x emissions contribute to a wide range of health and environmental problems. Among these problems are ozone formation, acid deposition, nitrates in drinking water, excessive nitrogen loadings in waterways, and fine particle formation in the ambient air. The role of NO_x emissions in the formation of ozone during the summer season at concentrations that are harmful to human health and the environment has become one of the more important concerns about this pollutant.

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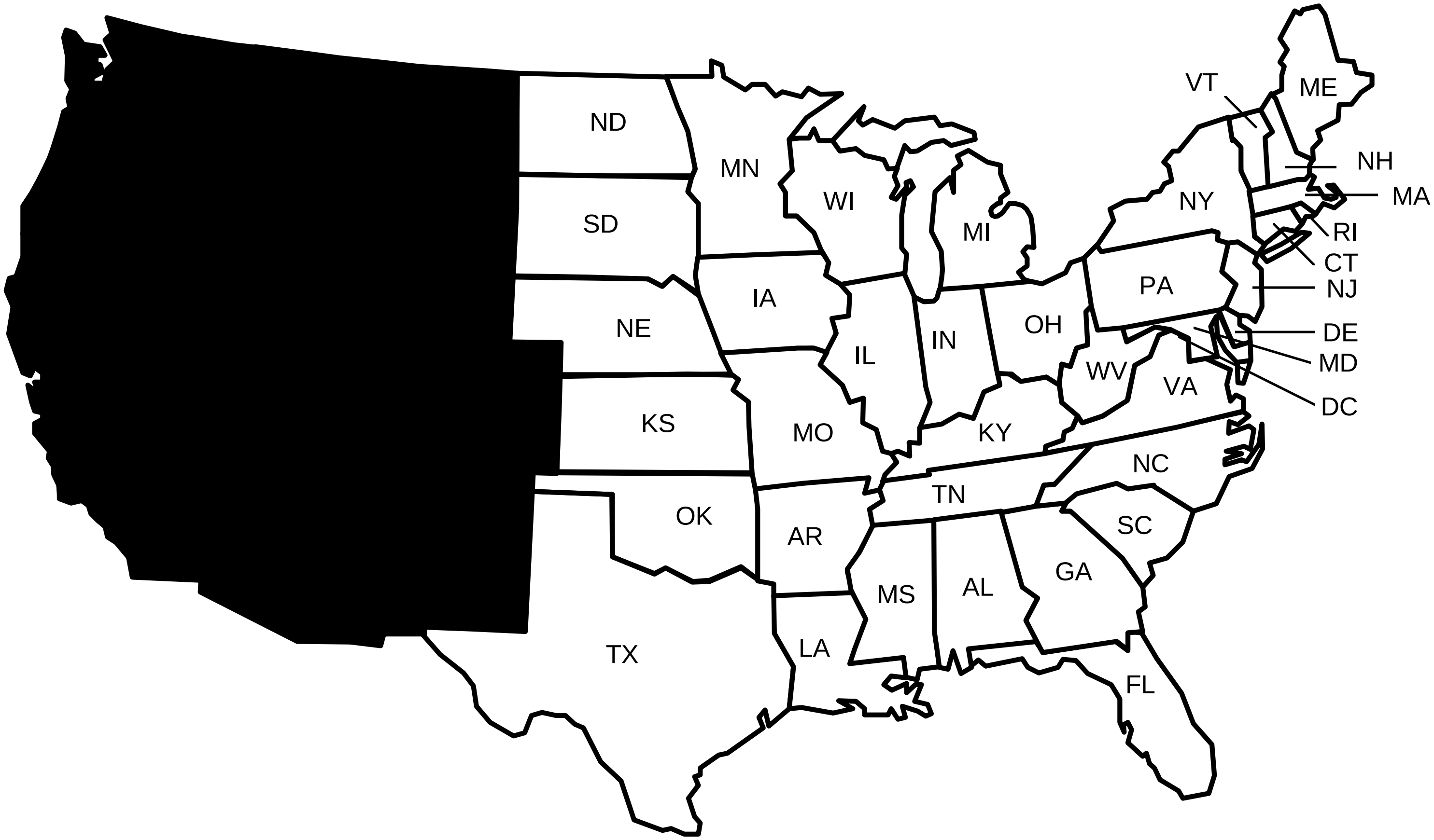
[1] The ozone transport that the States examined relates to the formation and transport of ozone in the troposphere (lowest atmospheric region) rather than the stratosphere (the upper atmospheric region). "Ozone" in this report refers to tropospheric ozone, also referred to as "ground-level ozone".

[2] See 62 **FR** 60318, November 7, 1997.

[3] Summer season is the period May 1 - September 30.

[4] U.S. Environmental Protection Agency, *Proposed Ozone Transport Rulemaking Regulatory Analysis*. Office of Air and Radiation, September 1997.

Figure 1-1
States in the Ozone Transport Assessment Group



Researchers have linked ozone concentrations to causing or aggravating several respiratory ailments, lung damage and decreased breathing capacity, premature mortality, and damage to vegetation (e.g. food crops). The Agency has documented the benefits of lowering the formation of ozone through NO_x control in the record supporting the recent revision of the National Ambient Air Quality Standards (NAAQS).[5] Further support can be found in studies prepared for the OTAG over the last two years.[6]

Many different sources emit NO_x. The largest NO_x sources are the electric power generation units, other (non-utility) stationary sources, area sources, non-road mobile sources, and highway vehicle sources (Appendix A provides a list of sources in each category). Most importantly, air quality modeling conducted by OTAG shows that the NO_x emissions from these sources and the ozone levels that result from them can be carried by the wind over long distances in the atmosphere. OTAG's analysis also showed that NO_x emissions from many parts of the Eastern U.S. can contribute significantly to the ozone problems of several downwind areas.

Regulatory Dilemma Associated with Ozone Transport

The existing and new NAAQS for ozone established levels necessary for protection of human health and the environment. Under the CAAA, attainment of these standards depends on the implementation of State-specific pollution control strategies contained in State Implementation Plans (SIPs) to reduce NO_x and/or VOC emissions in conjunction with EPA promulgation of national controls for some sources of pollution.

However, 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 controlled. As was discussed in the preamble of the NPR, the contribution of the upwind sources outside of nonattainment areas is large enough to produce this type of regulatory implementation problem. Furthermore, many States will find it hard, if not impossible, to avoid nonattainment with the new ozone NAAQS, or come into attainment with it in the future, unless mitigation of the ozone transport problem occurs. This dilemma has also raised concerns over the fairness of downwind areas having to cope with the pollution coming from areas upwind. These are the regulatory implementation problems that the Ozone Transport Rulemaking for NO_x addresses.

States could have independently formulated ozone transport mitigation approaches for themselves. Except for the Ozone Transport Region (the Northeastern States) covered by the CAAA, this type of action could lead to undesirable situations. First, some States could be faced with developing SIPs that would not lead to compliance in some serious and severe ozone nonattainment areas, because the States would deem the necessary measures too draconian. Other States might have to impose greater levels of very costly local controls to compensate for the transport of ozone into these areas. Second, in the absence of this rulemaking, EPA would have had to formulate regional ozone mitigation strategies in response to source-specific Section 126 petitions that have been filed by some States.[7] This type of action would likely create considerable confusion for the regulated community about what requirements they would need to meet. Also, significant levels of EPA and State resources would be used in addressing these petitions.

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[5] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule*, July 1997.

[6] A comprehensive treatment of the health and environmental issues regarding NO_x appears in EPA's *Nitrogen Oxides Impacts on Public Health and the Environment*, August 1997.

[7] The States of Connecticut, Maine, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont have filed Section 126 Petitions under the CAAA to control upwind stationary sources that are considered to be in part responsible for the petitioners' nonattainment status.

Proposed Solution

EPA prepared the proposed rule to mitigate these problems through a coordinated federal and State effort to address the ozone transport issue. The Ozone Transport Rulemaking is aimed at creating a more effective, efficient, and equitable approach for EPA and the States to provide attainment with the current and new ozone NAAQS.

EPA's rule proposal (NPR and SNPR) requires 22 States and the District of Columbia to amend their SIPs in two ways. First, each State needs to adopt a NO_x emissions budget that EPA has developed for them for the summer season[8] that the State's sources of NO_x emissions will not exceed beginning in 2003.[9] The NO_x emissions budget is actually composed of several components, each corresponding to a major NO_x source category. Second, the States are to develop compliance programs for each affected source category to ensure that the NO_x budget is met. These compliance programs would include the necessary pollution control measures; monitoring, reporting, and accounting procedures to ensure source emissions are not exceeding the State's NO_x budget; and enforcement requirements.

The States covered in the rule proposal are listed in Table 1-1 and shown in Figure 1-2. Notably, the Northeastern States in the table are part of the Ozone Transport Commission (OTC) in the Ozone Transport Region (OTR). NO_x sources in these States already face less stringent, but similar requirements, that they are in the process of implementing through the OTC Memorandum of Understanding (MOU). These States are italicized in the table.

Table 1-1
States Covered in the Ozone Transport Rulemaking

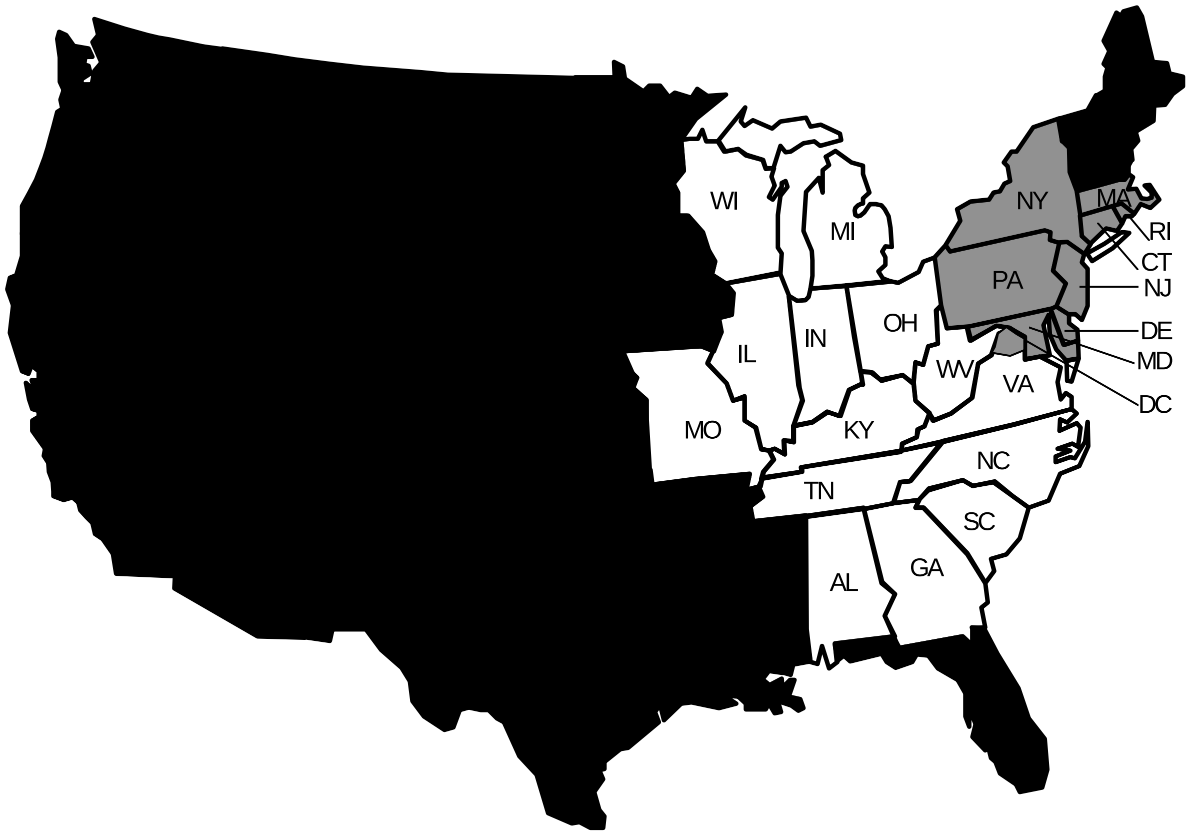
Alabama	*Maryland*	*Pennsylvania*
Connecticut	*Massachusetts*	*Rhode Island*
Delaware	Michigan	South Carolina
District of Columbia	Missouri	Tennessee
Georgia	*New Jersey*	Virginia*
Illinois	*New York*	West Virginia
Indiana	North Carolina	Wisconsin
Kentucky	Ohio	

Italicized states are in the Ozone Transport Region.
** 4 counties in Northern Virginia are in the OTR.*

[8] The summer season is defined in the rule proposal as May 1st through September 30th.

[9] In EPA's proposal, the States implement controls per approved SIPs by September 2002.

Figure 1-2
States Included in EPA's Ozone Transport Rulemaking



Ozone Transport Region States in the Ozone Transport Rulemaking

Other States in the Ozone Transport Rulemaking

EPA is proposing NO_x emissions budgets for the States that the Agency believes will have NO_x emissions in 2007 that will significantly contribute to the ozone levels in areas that are predicted to be in non-attainment with the current NAAQS for ozone, or will be in non-attainment with the new NAAQS for ozone. The NO_x budget for each State is composed of components for major source categories that are developed two ways. For the non-road and highway vehicle sources, the budget components are based on the EPA estimates of the effectiveness in each State of national measures that EPA is taking to control these mobile sources. For the electric generation units and other stationary sources, the budget components are based on applying further reasonable controls on these sources. A major factor in this determination is the cost-effectiveness of the control measures.

OTAG has recommended to EPA that a trading program be set up for large sources of NO_x to provide greater compliance flexibility and to lower overall compliance costs. Accordingly, in the SNPR, EPA is encouraging the States and the District of Columbia to join a trading program governed by a Model Cap and Trade Rule that EPA would administer. The Model Cap and Trade Rule would place a collective cap on NO_x emissions from electric generation units and other large boilers and combustion turbines and provide an allowance trading program similar to the CAAA Title IV SO_2 Allowance Trading Program already in place.

Coverage of Regulatory Analysis

The Ozone Transport Rulemaking establishes NO_x emissions budgets for each State based on application of reasonable control measures for mobile sources, electric power generation, and other stationary sources in each State. Since the Agency is already implementing through national requirements the mobile source reductions, EPA did not estimate their impacts in this regulatory analysis. Agency actions have been and will be addressed in separate rulemaking activities that are described below.

Mobile Source Controls

A number of EPA programs designed to reduce emissions from highway vehicles and nonroad engines, including NO_x emissions, have not yet been implemented. Some of these programs have been promulgated but have implementation dates which have not yet arrived. Other programs have been proposed but have not been promulgated. Table 1-2 lists some of these mobile source control programs and describes their status.

Table 1-2
Anticipated EPA Control Measures for Mobile Sources (Highway and Nonroad)

Category	**Measure**	**Current Status**
Highway	National Low-Emitting Vehicle Standards	Final; not yet implemented
Highway	2004 Heavy-Duty Vehicle Standards	Proposed
Highway	Federal Test Procedures (FTP) Revisions	Final; not yet implemented
Highway	Phase II RFG	Final; not yet implemented
Highway	Tier 2 Light-Duty Vehicle Standards	Under study
Nonroad	*Federal Small Engine Standards, Phase II*	*Proposed*
Nonroad	*Federal Marine Engine Standards (for diesels >50 hp)*	*Proposed*
Nonroad	Federal Locomotive Standards	Proposed
Nonroad	1997 Proposed Nonroad Diesel Engine Standards	Proposed

Italicized measures are included in the 2007 cost analysis baseline. FTP revisions and Tier 2 standards are not accounted for in the baseline cost analysis or the emissions budget.

All of the programs listed in Table 1-2 will be implemented on a nationwide basis. EPA continues to evaluate the need for additional federal controls on mobile source emissions and may propose additional measures as conditions warrant. In addition, EPA continues to encourage States to evaluate the appropriateness of mobile source emission control programs that can be implemented on a local or Statewide basis such as inspection and maintenance programs, reformulated gasoline, and clean-fuel fleets as part of their State Implementation Plans.

As described in the preamble to the Ozone Transport Rulemaking, the emission budgets for the mobile source sectors (highway vehicle emissions and nonroad emissions) were developed by estimating the emissions expected to result from the projected activity level in 2007. These emissions budgets assume the implementation of programs already reflected in SIPs and four additional programs expected to be implemented at the federal level. These additional programs are the National Low-Emitting Vehicle (NLEV) Standards, the 2004 Heavy-Duty Vehicle Standards, the Federal Locomotive Standards, and the nonroad Diesel Engine Standards. These four programs will be implemented even in the absence of the proposed Ozone Transport Rulemaking.

States and industry will not bear any additional mobile source control costs due to this rulemaking, unless a State chooses to implement additional mobile source programs under its own authority and to correspondingly limit the scope or reduce the stringency of new controls on stationary sources. The cost of such State-operated programs will depend on their specific design, which the Agency is unable to predict. EPA has therefore not included the costs of current or new federal mobile source controls in its analysis of the costs of the Ozone Transport Rulemaking. Information on the costs of the various proposed or promulgated federal measures can be found in the Federal Register notices for the respective measures.

Electric Generation Units and Other Stationary Sources Covered

The requirements on electric power plants and Other Stationary Sources[10] that should result from this EPA rule proposal should lead to new controls that are not in any national rulemaking. Therefore, EPA estimated the NO_x emissions reduction and annual incremental costs of meeting these controls. The costs for electric power plants are presented for the years 2003, 2005, 2007, and 2010, while for other stationary sources the costs are presented for the year 2007. The year 2003 is consistent with the first year that reductions are required to be made (i.e., controls are required to be in place), and limitations in the analytical framework for other stationary sources prevented EPA from assessing the costs for 2003. The year 2007 is consistent with the projection year that is used to establish the growth for the budget calculations in the Ozone Transport Rulemaking.

Costs Associated with NO_x Reductions

EPA has estimated the NO_x emissions reductions, total national annual control costs, and the cost-effectiveness of pollution control options that EPA is considering for each source category. The Agency's analysis of the cost-effectiveness of alternative control levels for each source category is one factor used by EPA to determine the level of NO_x reduction for each of these source categories. EPA also considered the cost-effectiveness of controls on these sources relative to controls on other source categories and other actions that EPA and the States have taken in the past.

Related OTAG Analysis

OTAG conducted considerable analysis on the emissions reductions, costs, and cost-effectiveness of a range of source control options during its two years of operation. Appendix B lists relevant OTAG papers and reports that helped EPA focus on options to consider in developing the Ozone Transport Rulemaking.

Organization of Report

This report has three additional chapters:

Chapter 2 Electric Power Industry provides an analysis of the emissions reductions, incremental annual costs, and cost-effectiveness of the proposed regulatory option on electric generation units in the States that are covered by the Ozone Transport Rulemaking. It also includes statistics on the number of power plants and capacity covered by this rule and describes the modeling approach used in this analysis.

Chapter 3 Other Stationary Sources covers an analysis of the emissions reductions, incremental annual costs, and cost-effectiveness of within-State approaches for these sources.

Chapter 4 Integrated Results combines the results of the emissions reductions and cost analysis for the options on which EPA based the budgets components for the Electric Power Industry and Other Stationary Sources. This chapter integrates the results of Chapter 2 and Chapter 3. It also provides a comparison of the cost-effectiveness of the proposed regulatory option in the broader context of other decisions that EPA and the States have made on NO_x reduction.

In addition to the above chapters, the report includes Appendices. Appendix A describes the categories of NO_x sources included in the Ozone Transport Rulemaking. Appendix B provides the selective bibliography of

[10] This category includes industrial, commercial, and institutional boilers, reciprocating engines, gas turbines, process heaters, cement kilns, furnaces at iron, steel, and glass-making operations, and nitric acid, adipic acid and other plants with industrial processes that produce NO_x.

OTAG documents related to NO_x control. Appendix C provides a list of pertinent acronyms and abbreviations. Appendix D provides the numerical data used to produce Figure 2-6. Appendix E discusses the effect of change in electricity generation forecast requirements.

Chapter 2. ELECTRIC POWER INDUSTRY

This chapter summarizes the analysis of the electric power industry that was conducted for the Supplemental Notice of Proposed Rulemaking (SNPR) addressing ozone transport under section 110 of the CAAA. The chapter begins with a description of the electric power industry and the portion of it that will be affected by the Ozone Transport Rulemaking. This is followed by an overview of the modeling methodology that was used for the base case and the proposed regulatory approach. The results of the base case are presented next, including a summary of changes from the previous base case[1]. The final section presents EPA's analysis of the impacts of the proposed regulatory approach on both costs and NO_x emissions.

The Electric Power Industry

Historically, most electric power has been provided by vertically integrated, privately-owned monopolies. The remainder of electric generation has been provided by a combination of publicly-owned entities including municipal utilities, rural electric cooperatives, federal agencies, and other public organizations. Beginning in the 1970s, electricity generation by non-utility, independent power producers and cogenerators began to occur.

During this period, the prices that privately-owned utilities could charge for electricity were regulated by State utility commissions. The price of electric power sold by publicly owned entities were controlled by utility governing boards, elected officials, or federal agencies. Under this traditional regulatory structure, owners of the electric generation capacity were granted regional monopolies over the generation, transmission, and distribution of electric sales to end-users. In this structure, utilities were permitted to recover the costs of prudent investments including an appropriate rate of return.

Recently, this traditional structure has been changing. Federal and State governments have taken steps to introduce deregulation at the wholesale level in electric power markets. Wholesale deregulation effectively opens up the electric transmission grid that connects electric utility regional monopolies. Congress provided the key impetus for these changes with its enactment of the Energy Policy Act of 1992 (EPAct). In particular, EPAct gave the Federal Energy Regulatory Commission (FERC) authority to require utilities who owned electric transmission assets to offer open, non-discriminatory transmission services to all parties. FERC used this authority to issue Order 888 to require open access to the transmission grid nationwide. These actions and regulatory changes are leading to a competitive market for electricity and power.

There has also been a growing movement towards retail deregulation of electric power markets at the State and Federal level. Several bills have been introduced in Congress to extend retail competition to the entire nation. While none of these bills has yet been enacted, a number of States are actively promoting and experimenting with retail competition. With retail access, customers would have the ability to choose the generation source and local retail supplier of electricity.

As discussed below, the impact of deregulation is incorporated into EPA's Base Case assumptions about the amount and cost of electric power transmission, regional reserve margins, coal plant availabilities, and other factors.

Power Plants Covered by the Ozone Transport Rulemaking

[1] Since EPA's analyses for the NPR, which were documented in *Proposed Ozone Transport Rulemaking Regulatory Analysis,* September 1997, there have been improvements to the modeling structure and updates of input data and assumptions. These changes will be documented in more detail in the document *Analyzing Electric Power Generation Under the CAAA*, March 1998.

As described in Chapter 1, the Ozone Transport Rulemaking will affect power plants in the District of Columbia and 22 States in the Eastern and Mid-Western United States. EPA estimates that 1,452 power plants will be operating in this area in the year 2000. In addition to electric utility power plants that produce only electricity, this number includes plants owned by independent power producers (IPPs). This number also includes plants that cogenerate electricity and steam (cogenerators), whether owned by utilities or IPPs.

Table 2-1 shows the distribution of these power plants by plant type. The focus of this analysis is on the 730 fossil fuel burning power plants that account for most of the NO_x emissions in the States covered by the Ozone Transport Rulemaking.

Table 2-1
Distribution of Electric Power Plants in 2000 in the States Covered by the Ozone Transport Rulemaking[2]

Category	GW Capacity	Number of Plants
Coal Steam	205	319
Combined-Cycle	12	69
Combustion Turbine	29	273
Oil/Gas Steam	37	69
Fossil Fueled Power Plants	**283**	**730**
Hydroelectric	23	594
Nuclear	66	44
Renewables	1	65
Pump Storage	17	19
All Power Plants	**390**	**1,452**

The remaining 722 power plants do not burn fossil fuels, and generally have little or no NO_x emissions. This non-fossil group includes 44 plants that burn fuels such as municipal solid waste or biomass, and do emit some NO_x. However, the Agency did not consider NO_x control for these facilities as part of this analysis[3]. The non-fossil power plants include hydroelectric, nuclear, renewables, and pump storage plants.

Of the fossil fuel burning plants, coal steam plants account for the largest share: 44 percent of the plants, and 72 percent of the capacity. Combustion turbines, which tend to be much smaller than coal steam units, account for an additional 37 percent of the fossil-fuel plants, but only 10 percent of fossil-fueled capacity. The remaining affected power plants consist of combined-cycles that use natural gas (9 percent of plants, 4 percent of capacity), and oil and gas steam plants (9 percent of plants, 13 percent of capacity).

[2] In reality, a single power plant may include more than one type of generating unit. For purposes of calculating the number of plants for Table 2-1, each power plant was categorized based on the unit type accounting for the most capacity at that site. For example, a plant with 200 MW of coal steam capacity and 50 of gas-fired combustion turbines would be categorized as a coal plant. For analytical purposes, and for purposes of the capacity data presented in Table 2-1 and elsewhere in this chapter, capacity is categorized at the unit level, not the plant level. For example, if a 250-MW plant has 200 MW of coal-fired capacity and 50 MW of gas-fired combustion turbine capacity, 200 MW will be included in the coal steam category, and 50 MW will be included in the combustion turbine category.

[3] These plants account for about three percent of the plants in the States covered by the Ozone Transport Rulemaking, but represent less than 1/3 of one percent of the capacity.

As illustrated in Figure 2-1, the States of New York, Ohio, Pennsylvania, and Indiana account for the highest shares of fossil-fueled electric generation capacity. Together, they account for approximately one-third of the total fossil-fueled capacity in the States covered by the Ozone Transport Rulemaking.

The States covered by the Ozone Transport Rulemaking account for over half of the total electric generation capacity in the contiguous U.S. These States also account for over half of all fossil fuel capacity. Of the fossil fuel capacity types, coal steam is particularly prevalent in the States covered by the Ozone Transport Rulemaking: 67 percent of total contiguous U.S. coal-fired capacity is located in this region. The States covered by the Ozone Transport Rulemaking also contain 42 percent of the total contiguous U.S. capacity for combined-cycle and over half of the combustion turbine capacity. However, this area accounts for only slightly more than one-quarter of total oil and gas steam generation capacity. Detailed capacity data is provided in Table 2-2.

Figure 2-1
State-by-State Distribution of Fossil Fuel-Fired Generation Capacity (GW) in 2000 in the States Covered by the Ozone Transport Rulemaking

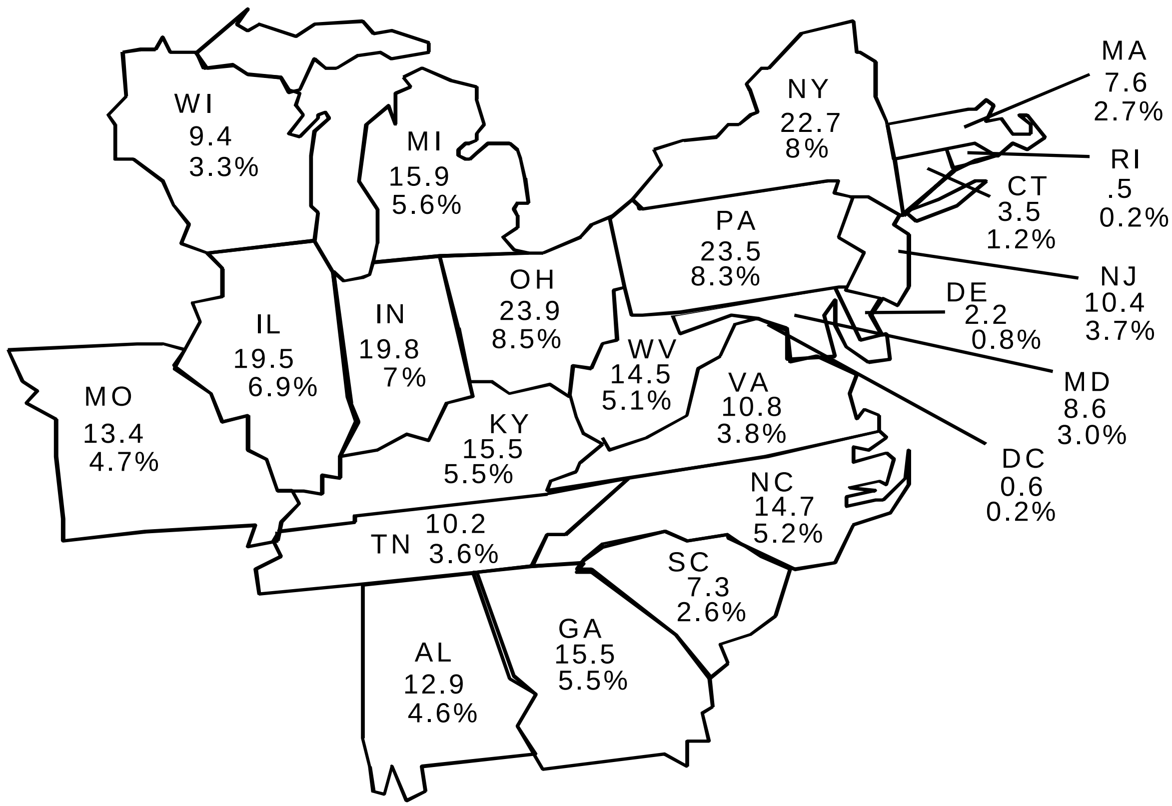


Table 2-2
Distribution of U.S. Electric Capacity in 2000

Category	States Covered by Ozone Transport Rulemaking (MW)	States Covered by Ozone Transport Rulemaking (% of U.S.)	Rest of Contiguous U.S. (MW)	Rest of Contiguous U.S. (% of U.S.)	Total Contiguous U.S. (MW)	Total Contiguous U.S. (% of U.S.)
Coal Steam	204,704	67%	102,974	33%	307,678	100%
Combined-Cycle	12,337	42%	16,839	58%	29,176	100%
Combustion Turbine	28,594	55%	23,264	45%	51,858	100%
Oil/Gas Steam	37,023	28%	94,554	72%	131,577	100%
Total Fossil Fuel	**282,658**	**54%**	**237,631**	**46%**	**520,289**	**100%**
Hydroelectric	23,251	25%	70,577	75%	93,828	100%
Nuclear	66,001	70%	28,901	30%	94,902	100%
Renewables	1,445	21%	5,467	79%	6,912	100%
Pumped Storage	17,347	75%	5,698	25%	23,045	100%
Total Capacity	**390,702**	**53%**	**348,274**	**47%**	**738,976**	**100%**

Methodology

This section describes the methodology that EPA used to analyze the regulatory option considered for the electric power generation sector. Further discussion of the methodology and assumptions can be found in EPA's report entitled *Analyzing Electric Power Generation under the CAAA*[4].

Modeling Approach

EPA used the Integrated Planning Model (IPM) to evaluate the emissions and cost impacts expected to result from the requirements of the Ozone Transport Rulemaking on the electric power generation sector. 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 NO_x emission policy and regulations as part of the Clean Air Power Initiative (CAPI) in 1996 and as a tool to analyze alternative trading and banking programs during the OTAG process in 1996 and 1997. IPM was also used in 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 commentors' 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 to accommodate commentors' recommendations.

The version of IPM, IPM 98, used by EPA represents the U.S. electric power market in 21 regions, as depicted in Figure 2-2. These regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC). IPM models the electric demand, generation, transmission, and distribution within each region as well as the transmission grid that connects the regions.

[4] See footnote 1 on page 2-1.

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 operations of coal-fired units in the future, 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.

Working with these existing model plants and representations of alternative new power plant options, IPM determines the least-cost means for supplying electric 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 considered for controlling the summer NO_x emissions in the States covered by the Ozone Transport Rulemaking. 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.

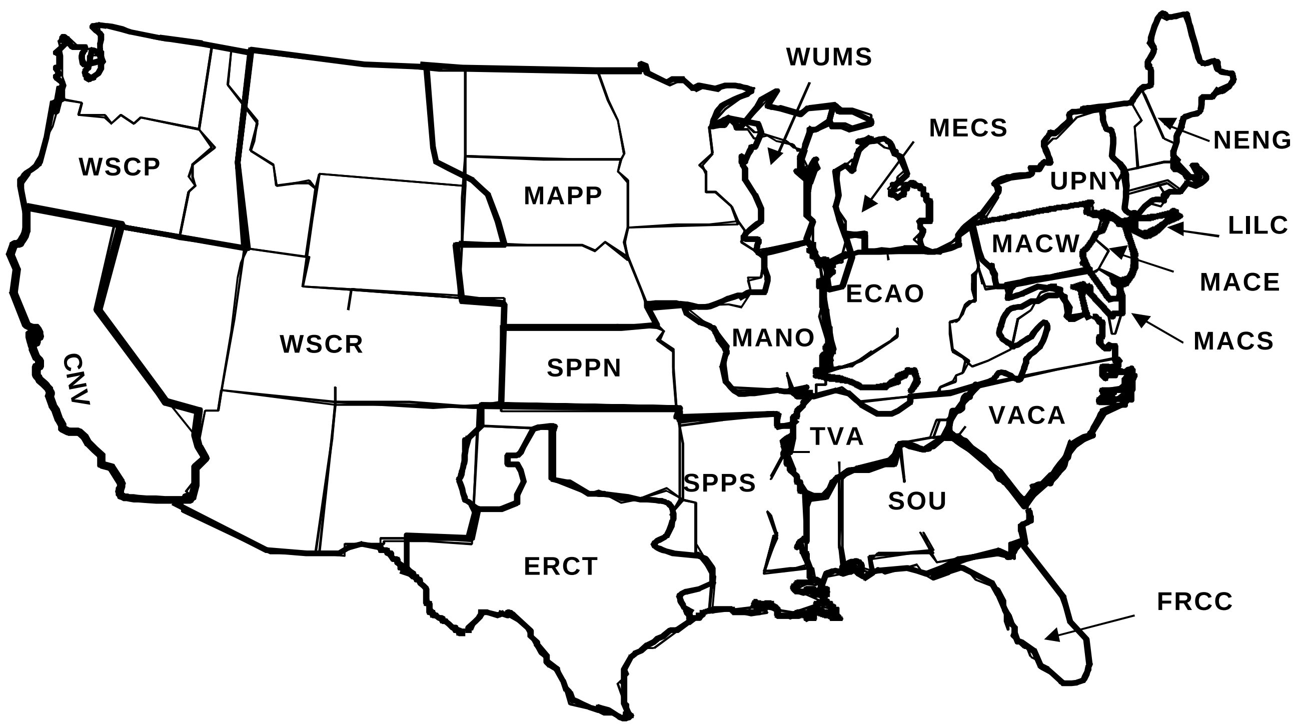
Pollution Control Retrofit - For example, installing selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or gas reburn (to reduce NO_x emissions), or flue gas desulfurization (to control SO_2 emissions).

Economic Retirement - For example, retiring an oil or gas steam plant.

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

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

Figure 2-2
Integrated Planning Model Regions in the Configuration Used by EPA



The model is not limited in scope to facilities owned by electric utilities, but also includes independent power producers that provide electricity to the power grid on a firm-contract basis, as well as IPP facilities larger than 25 MW 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 proposed regulatory approach would begin, these analyses also provide results for 2001, 2005, 2007, and 2010.

Assumptions

In applying IPM to analyze NO_x emission policy over the past two years, EPA has developed a set of data and assumptions that reflect the best available information on the electric market and operating factors. This 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.

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 sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls.

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

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

Macro Energy and Economic Assumptions

In developing the analysis for the Ozone Transport Rulemaking, EPA made assumptions about major macro energy and economic factors, as shown in Table 2-3. See Appendix No. 2 of EPA's 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, in order to be consistent with the Agency's recently published Regulatory Impact Analysis (RIA) of the National Ambient Air Quality Standards (NAAQS) for ozone and particulates. The factor used for this purpose was 0.83, which corresponds to the GDP implicit price deflator index published by the Bureau of Economic Analysis.

Table 2-3
Key Baseline Assumptions for Electricity Generation Forecast and Cost Analysis

Factor	Assumption
Discount Rate	6 percent
Conversion Factor from 1997 to 1990 Dollars	0.83
Electricity Demand Growth Rate (% per Year)[1]	1997-2000 = 1.6 2001-2010 = 1.8 > 2010 = 1.3
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 (GW)	2001 = 93 2003 = 90 2005 = 87 2007 = 86 2010 = 81 2020 = 50
Nuclear Capacity Factors (%)	2001 = 80 2003 = 80 2005 = 80 2007 = 82 2010 = 81 2020 = 83
World Oil Prices (1997$/BBL)	2001 = 19.20 2003 = 19.90 2005 = 20.50 2007 = 20.80 2010 = 21.20 2020 = 22.40
Wellhead Natural Gas Price (1997$ per mmBtu)[2]	2001 = 1.90 2003 = 1.95 2005 = 2.00 2007 = 2.00 2010 = 2.00
Coal Steam Power Plant Availability	1995 = 82% 2000 = 83.5% 2005/10/20 = 85%
Existing Power Plant Heat Rates	No change over time
Coal Mining Productivity Increases (% 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[2] (% change per year in the period 2000-2010)	-2.0%

Footnotes to Table 2-3:
[1] Before adjustment for Climate Change Action Plan improvements.
[2] Based on recent ICF analyses using updated coal mining productivity and supply for coal, and technology and supply assumptions for natural gas. Note that the natural gas prices are <u>not</u> an assumption in the model, but are a forecast of the model.

Electric Energy Cost and Performance Assumptions

In order to simulate the electric power market under Base Case conditions and for each of the regulatory options, assumptions were 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 were used in IPM to determine the least cost means for meeting projected future electricity requirements subject to the Base Case emission restrictions and the NO_x emission limits specified for each regulatory option.

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

<u>New Conventional Power Plants</u>

Conventional Pulverized Coal
Advanced Coal (IGCC)
Combined-cycle
Combustion Turbine
Nuclear

<u>New Renewable/Nontraditional Options</u>

Biomass IGCC
Solar Photovoltaics
Solar Thermal
Geothermal
Wind

Cost and performance projections were 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 relied 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:

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

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

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

Repowering Coal Steam to Integrated Gasification Combined-Cycle

Repowering Coal Steam to Gas Combined-Cycle

Repowering Oil/Gas Steam to Gas Combined-cycle

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

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 report, *Analyzing Electric Power Generation under the CAAA*.

Air Emission Rates under the Base Case

The emissions and cost impacts reported in the Results section below are calculated relative to Base Case (or baseline) assumptions about NO_x emissions. In the Base Case, EPA assumed that all existing federal and State regulations would apply. Thus, the Agency assumed that existing Title IV NO_x rules, both Phase I and Phase II, were in effect and Reasonable Available Control Technology (RACT) requirements, where applicable, were included. EPA assumed that existing regulations for new and recently-built power plants would also be in effect (e.g. EPA's New Source Performance Standards and controls based on Best Available Control Technology (BACT) and Lowest Achievable Emissions Rates (LAER)).

Phase I of the Ozone Transport Commission's Memorandum of Understanding (RACT requirements in the Ozone Transport Region (OTR)) was included in an **Initial Base Case** used to measure annual emission changes and incremental cost of controls under EPA's proposed regulatory approach. Phase II and Phase III of the OTC's MOU were not included in the Initial Base Case. For the proposed regulatory approach, EPA also assumed that only Phase I of the OTC's MOU would be in effect and that retrofitting of units would begin with RACT controls in place in the OTR.

However, the incremental cost impact of the Proposed Regulatory Approach was also adjusted to consider the incremental impact above Phase II and Phase III of the OTC's MOU. For this purpose, a separate limited analysis was conducted to quantify the cost impact of Phase II and Phase III of the OTR program. This incremental OTR cost was then subtracted from the cost of the Proposed Regulatory Approach to provide incremental costs relative to the **Final Base Case**. Since this proposal should replace the Phase II and Phase III requirements with a new Cap-and-Trade program, EPA used the results from the Initial Base Case analysis for estimating the cost-effectiveness of NO_x reduction from this rulemaking.

The Agency did not include in its analysis Vermont, New Hampshire, and Maine. The objective of the analysis was to provide a general sense of the emission reductions and costs that States in the OTR that are included in the Ozone Transport Rulemaking would have incurred, if they fully implemented their MOU obligations.

For more details on the Baseline assumptions made about air emission levels, see Appendix No.4 of EPA's report, *Analyzing Electric Power Generation under the CAAA*.

Pollution Control Performance and Cost Assumptions

EPA developed pollution control cost and performance estimates for the following options:

Coal-Fired Steam Electric Generating Units

Combustion Controls
Selective Catalytic Reduction (SCR)
Selective Non-Catalytic Reduction (SNCR)
Natural Gas Reburn
Oil and Gas-Fired Steam Generating Units
Selective Catalytic Reduction
Selective Non-Catalytic Reduction

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

In addition to including the pollution control cost and performance estimates described above, the costs analysis for the SNPR also takes into account the cost and performance of combustion controls installed beyond those resulting from implementation of Title IV and Title I (RACT) requirements. Note that Title IV NOx program permits an owner/operator to comply with the requirements by averaging the NOx emissions from some of 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 accounted for the cost of combustion controls beyond those needed for Title IV compliance in the following manner: (1) EPA identified the units that either are (in Phase I) or are likely to (in Phase II) under Title IV average their emissions with other controlled units, and (2) EPA reasoned that these uncontrolled units, for the purposes of this proposed rulemaking, will install the least expensive controls, i.e., combustion controls, in case requirements beyond Title IV were imposed on them. These units can further reduce their emissions by installing SCR, SNCR, or gas reburn, as described above. Additionally, using 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% or more) their Title IV mandated levels. For the purposes of analyses in this report, such sources were assumed to emit at their CEM-measured levels, not their applicable Title IV Standard.

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

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

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

Bechtel Power Corporation, draft technical study on the use of gas reburn to control NO_x at coal-fired electric generating units, June 1996

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

Limitations

This chapter presents EPA's best estimate of the cost and emission impacts of the proposed regulatory approach considered. However, there are several factors that could lead to cost and emission impacts above or below the reported impacts. Those factors include the following:

Speed of Deregulation - EPA has assumed that electric deregulation will continue to move ahead at a steady pace. The Agency has also assumed that deregulation will impact the electric 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 impact the electric system in different ways, the estimated costs and emission 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.

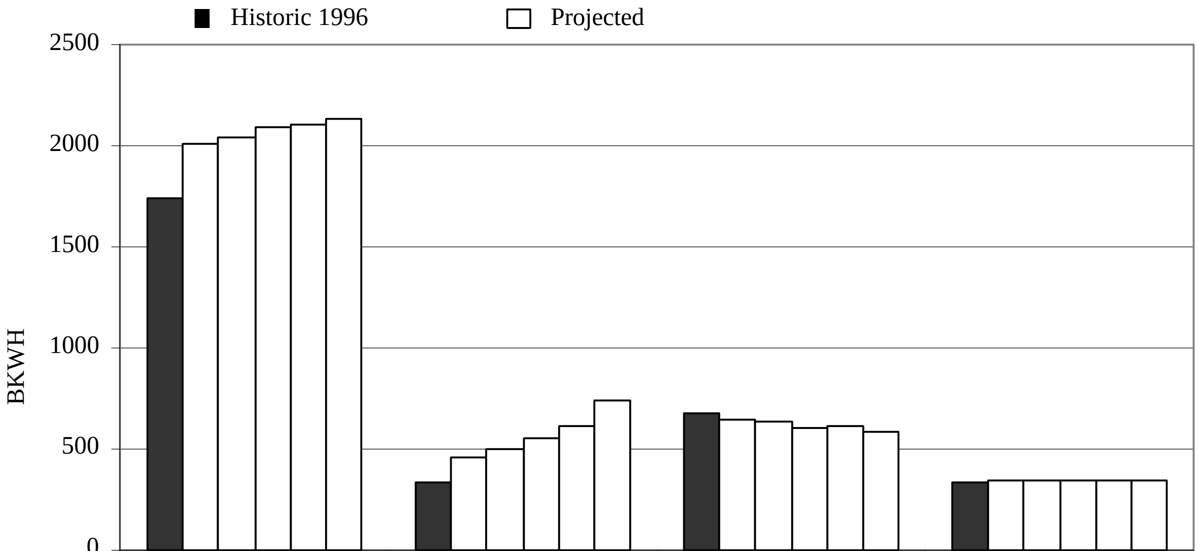
Regulatory Program Implementation - EPA has assumed that the regulatory program resulting from this Ozone Transport Rulemaking will be implemented smoothly and at specific points in time.

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 was 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 emission and cost impacts for the regulatory options analyzed.

Results of Initial Base Case

In 1996, net electricity generation in the continental U.S. totaled 3,077 billion kilowatt hours (BKWH); EPA projects that net generation in the continental U.S. will increase to 3,599 BKWH by the year 2005. (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.) Figure 2-3 shows EPA's Initial Base Case forecast of electricity generation by capacity type over the years 1996 through 2010. Increased generation requirements are met primarily by increased generation from fossil-fueled units. Under the Initial Base Case, generation from nuclear units declines over time, while generation from the remaining other types of capacity remains fairly constant.

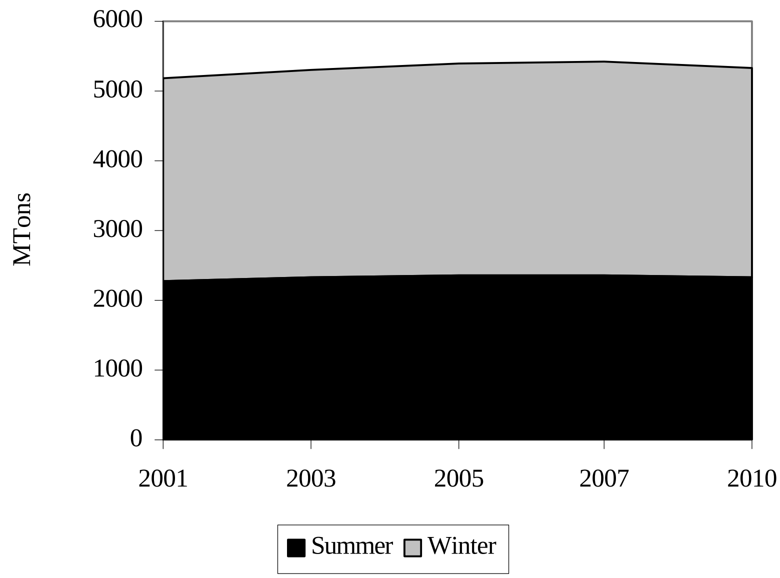
Figure 2-3
Initial Base Case: Forecast of Electric Generation by Major Fuel Category for the Contiguous U. S.
(Billion KWH)



	COAL	OIL/GAS	NUCLEAR	OTHER
1996	1737	330	675	335
2001	2010	454	648	345
2003	2044	505	633	345
2005	2095	550	609	345
2007	2105	612	613	345
2010	2133	741	580	347

Figure 2-4 shows projected annual NO_x emissions for the entire contiguous U.S. under the Initial Base Case forecast. Despite the projected increase in fossil-fueled generation, annual NO_x emissions in the Initial Base Case are projected to increase at a slower rate than generation. From 2001 to 2010, generation is projected to increase at an average annual rate of 1.0 percent, while NO_x emissions over the same period are projected to increase at an average annual rate of 0.3 percent. The slower rate of growth of emissions is due to a market-driven trend towards natural gas use, as well as improved generating efficiencies over time as older, less efficient units are replaced by newer, higher-efficiency units with lower emissions rates.

Figure 2-4
Initial Base Case: Forecast of Annual NO_x Emissions for the Contiguous U.S.
(Thousand Tons)



	2001	**2003**	**2005**	**2007**	**2010**
Summer	2284	2334	2364	2376	2331
Winter	2907	2982	3026	3050	3011
Total	5190	5315	5389	5426	5342

Note that the NO_x emissions shown in Figure 2-4 include emissions from non-fossil generating units that burn biomass or municipal solid waste; these non-fossil units account for approximately ½ of one percent of total NO_x emissions from the electricity sector.

Changes from the Previous Base Case

As noted in footnote 1 on page 2-1, the SNPR analyses include some improvements to the modeling structure, as well as updates of input data and assumptions. As a result of these changes, the Initial Base Case described above differs slightly from the previous Initial Base Case, which was developed for the NPR analysis.[5] The forecast of electricity generation for 2005 is now 1 percent higher than the previous forecast, while the forecast for 2010 is now 2 percent lower. The share of generation by fuel type is largely unchanged, although by 2010 coal accounts for a 3 percent higher share of generation, offset primarily by a decrease in oil and gas generation. The Initial Base Case forecast of NO_x emissions has increased by less than one percent for 2005, and decreased by one percent for 2010.

[5] The previous Initial Base Case was documented in *Proposed Ozone Transport Rulemaking Regulatory Analysis*, U.S. EPA Office of Air and Radiation, September 1997.

Proposed Regulatory Approach

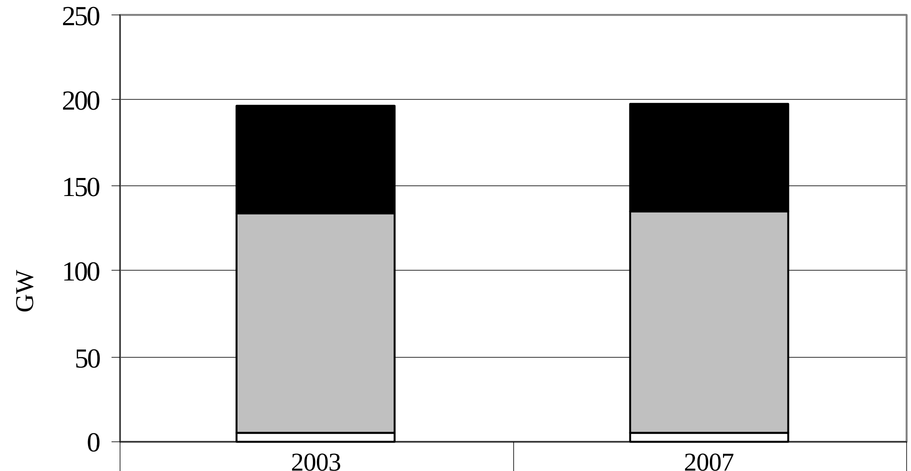
The Proposed Regulatory Approach is a summer-only cap-and-trade system with a specific NO_x budget. In the NPR, EPA determined that an average NO_x emissions level of 0.15 lb/mmBtu could be achieved cost-effectively in the 23 jurisdictions affected by the ozone transport rulemaking. EPA used this level to establish a budget of 489,000 summer tons in 2007 for the electricity generating units in these jurisdictions. Since the NPR, the emissions inventory of sources, the State-specific growth rates for the period 1996-2007, and the Integrated Planning Model (IPM) have been revised. Consequently, EPA has used the average NOx emissions level of 0.15 lb/mmBtu along with the revised emissions inventory and growth rates to arrive at a revised NO_x budget of 563,784 summer tons in 2007 for the electricity generating units in the 23 jurisdictions. The cost impact of this budget has been analyzed using the IPM.

System NO_x emissions can be reduced in several ways. One way is through dispatch decisions, by increasing generation from lower-emitting units, while decreasing the use of higher- NO_x units. For the States covered by the Ozone Transport Rulemaking, the model results did indicate lower levels of generation from fossil-fueled units under the proposed regulatory approach.

Regulations designed to reduce NO_x emissions are also likely to affect utility decisions regarding the construction of new generating capacity. NO_x regulations increase the attractiveness of importing power from States not covered by the Ozone Transport Rulemaking, and the model results for the proposed regulatory approach do indicate lower levels of capacity additions in the States covered by the Ozone Transport Rulemaking.

A third approach to reducing system NO_x emissions is to install emissions control technology. Figure 2-5 illustrates the cumulative NO_x control technology decisions (including unit retrofit decisions) through 2003 and through 2007 for the Proposed Regulatory Approach. Most notably, almost all of the retrofits are installed by 2003; relatively few additional investments occur in the period from 2004 to 2007.

Figure 2-5
Cumulative Emissions Control Technology and Capacity Retrofits in the States Covered by the Ozone Transport Rulemaking Under the Proposed Regulatory Approach (GW)



	2003	2007
Coal SCR	63	63
Coal SNCR	129	130
O/G SNCR	4	4
Coal to Gas Reburn	0.5	0.5

As mentioned above, some units may be selected by IPM for installation of multiple control technologies (e.g., SNCR and scrubber). Since each control technology is represented separately in Figure 2-5, capacity retrofitted with multiple control technologies will be double-counted. For that reason, the graphic should not be interpreted as representing the total amount of capacity selected for retrofit.

Given that the emission rates of combustion turbines are generally low and that they run a limited amount of time (even in the summer), these units do not add pollution controls to reduce NO_x emissions. No existing combined-cycle units are forecast to add pollution controls. Under the Proposed Regulatory Approach Case, combustion turbines account for 42 GW of generation capacity in 2003, and 43 GW of capacity in 2007. Combined cycles account for 12 GW of capacity in 2003, and 18 GW in 2007. Only coal and oil/gas steam units are forecasted to retrofit. In this case, coal accounts for 204 GW of electricity generation in 2003 and 203 GW in 2007, while oil/gas steam accounts for 34 GW in both 2003 and 2007.

Under the Proposed Regulatory Approach, the most common emissions-controlling retrofit was to install SNCR on coal-fired units. Almost 130 GW of coal capacity (64 percent) was retrofitted with SNCR. SCR retrofits were installed on 63 GW (31 percent) of coal-fired capacity. Less than 4 GW (12 percent) of oil/gas steam capacity was retrofitted, all with SNCR. The Proposed Regulatory Approach case also resulted in about 0.5 GW of coal-fired capacity retrofitted with gas reburn.

Almost all of the coal-fired capacity is retrofitted with some NO_x control equipment under the Proposed Regulatory Approach. However, most of the oil and gas steam units are not retrofitted with control technology. Many of the units that do not add controls have existing NO_x rates lower than 0.20 pounds of NO_x per mmMBtu of heat input.

NO_x Emissions

Table 2-4 summarizes the annual and summer season NO_x emissions for both the Initial Base Case and the Proposed Regulatory Approach.

EPA plans to work with the States on establishing a Cap-and-Trade system beginning in 2003 for large electric generators and other large boilers and combustion turbines. However, the Agency could not include large non-electric boilers in an integrated approach at this time. Therefore it estimated the costs of electric power generation in a trading system by itself.

As illustrated in Table 2-4, annual NO_x emissions from the electricity generation sector are reduced by more than summer NO_x emissions under the Proposed Regulatory Approach. The further decline in annual emissions reflects the fact that some compliance decisions, including repowering and economic retirement, will lead to year round NO_x emission reductions.

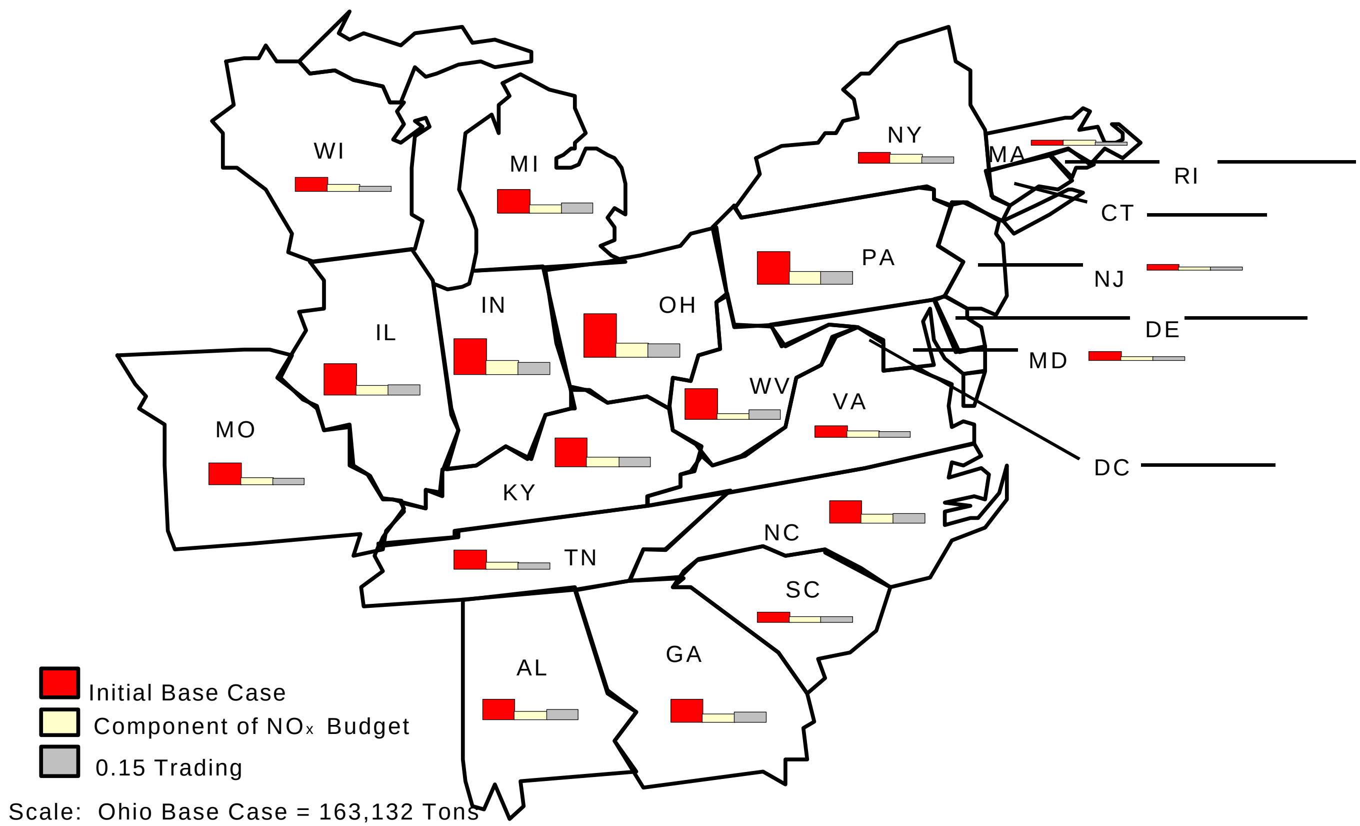
Table 2-4
Summer and Annual NO_x Emissions and Reductions in States Covered by the Ozone Transport Rulemaking*
(Thousands of Tons)

	2003	2005	2007	2010
Summer Season NO_x Emissions (thousand tons)				
Initial Base Case (OTC Phase I)	1462	1497	1502	1511
Proposed Regulatory Approach (0.15 cap-and-trade, summer only)	564	564	564	564
change from the Initial Base Case	-899	-933	-938	-948
Annual NO_x Emissions (thousand tons)				
Initial Base Case (OTC Phase I)	3401	3489	3512	3543
Proposed Regulatory Approach (0.15 cap-and-trade, summer only)	2274	2313	2329	2344
change from the Initial Base Case	-1127	-1176	-1183	-1199

** This table includes only those NO_x emissions from fossil-fueled units. Total NO_x emissions from non-fossil electric generating units in this region are not subject to the proposed regulatory approach, and are not included in this figure. Nationally, these non-fossil units emit approximately 25 thousand tons of NO_x per year, or ½ of one percent of total NOx emissions from the electric sector.*

Figure 2-6 compares the 2007 summer season NO_x emission levels in the Initial Base Case, the Proposed Regulatory Approach, and the component of the NO_x budget for each state that was estimated for the electric power industry. Consistent with the data in Table 2-4, this figure includes NO_x emissions from fossil-fueled units only.

Figure 2-6
Summer NO_x Emissions in 2007 for States in the Ozone Transport Rulemaking: Initial Base Case, Proposed Regulatory Approach (0.15 Trading), and the State Component of the NO_x Budget for the Electric Power Industry



Costs

Table 2-5 summarizes the cost impacts of the proposed regulatory approach. Two sets of incremental costs are presented. The first set of costs lists the incremental costs to the electric power system using the Initial Base Case. The second set of costs is adjusted by subtracting out the estimated incremental costs for compliance with Phase II and Phase III of the OTC MOU. These incremental annual costs represent the Final Base Case results. EPA believes that these later results are the best estimate of the proposed Rule's costs to the electric power industry. The Ozone Transport Region already has set a timetable for implementing a trading system for NO_x that should occur irrespective of the current Ozone Transport Rulemaking. Table 2-6 provides a comparison between the costs based on Initial Base Cases with the old and the new electric demand growth forecasts, used in the NPR and SNPR, respectively.

Table 2-5
Annual Incremental Costs of NO_x Control Options on Electric Power Generation in States Covered in the Ozone Transport Rulemaking
(from Each Winter 1998 Base Case, millions of 1990$)

Baseline Used	2003	2005	2007	2010
Initial Base Case (OTC Phase I)	$1,308	$1,354	$1,378	$1,341
Final Base Case (OTC Phases II and III)	$1,182	$1,223	$1,250	$1,178

Table 2-6
Annual Incremental Costs of NO_x Control Options on Electric Power Generation in States Covered in the Ozone Transport Rulemaking
(from Initial Base Case, with Each Electric Demand Forecast, millions of 1990$)

Electric Demand Forecast Used	2003	2005	2007	2010
Winter 1998 Forecast (SNPR)	$1,308	$1,354	$1,378	$1,341
Summer 1996 Forecast (NPR)	$1,213	$1,279	$1,398	$1,331

Chapter 3. OTHER STATIONARY SOURCES

This chapter evaluates the NO_x emissions changes and costs of the proposed Ozone Transport Rulemaking when applied to Other (non-utility) Stationary Sources. This category includes business and other institutions with industrial boilers, process heaters, stationary gas turbines, reciprocating internal combustion engines, and other industrial processes that emit NO_x. The Ozone Transport Rulemaking proposed to apply a 70 percent reduction to large sources ($\geq$250 million British thermal units per hour) and reasonably available control technology (RACT) to medium size sources ($\geq$1 ton per day). This approach to controlling Other Stationary Sources is modeled after the recommendation made to EPA by the Ozone Transport Assessment Group (OTAG). An initial analysis of that proposal was included in the September 1997 document titled "Proposed Ozone Transport Rulemaking Regulatory Analysis." The analysis presented in this chapter is an update of the September 1997 analysis. The cost estimates in this chapter are reported in 1990 dollars, and reflect the estimated cost to comply in the year 2007, when all required emissions reduction strategies are to be fully implemented. All NO_x emission size classification determinations in this analysis are based on 1990 reported emissions.

Description of Other Stationary Sources

This category covers five types of point sources that OTAG identified as major NO_x emitters.

- **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 million British thermal units per hour (mmBtu/hr). These boilers are used in a variety of applications, ranging 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 Internal Combustion Engines -** These units generate electric power, pump gas or other fluids, or compress air for pneumatic machinery. The primary non-utility 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.

- **Stationary Gas Turbines -** They are used in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. The primary fuels used are natural gas and distillate oil, although residual fuel oil is used in a few applications.

- **Process Heaters -** They are direct-fired heaters used primarily in the petroleum refining and petrochemical industries. Process fluids are heated to temperatures above 400F in the radiative and convective sections of the heaters. Typical heater sizes at refineries might range from 40 to 300 mmBtu/hr capacity. The typical fuel is process gas.

- **Industrial Processes -** Some industrial processes emit NO_x. Examples include cement kilns, furnaces at iron and steel mills, glass furnaces, nitric acid plants, and adipic acid plants.

Throughout this analysis, definitions of source size are applied to emission points. In some cases, there are multiple Source Classification Codes (SCCs) for an emission point, and emissions from all SCCs are summed to determine the tons per day (tpd).

Proposed Regulatory Option

EPA proposed a control level for Other Stationary Sources that was designed to be consistent with the recommendations from the OTAG Policy Group. The OTAG Policy Group recommended that the stringency of controls for large non-utility point sources should be established in a manner equitable with electric utility controls. The proposed utility control level is 85 percent NO_x reduction for electric power plants, or a 0.15 lbs/mmBtu limit. The equivalent control target for the large non-utility point source sector, defined as sources $\geq$ 250 mmBtu/hr capacity (maximum hourly design rate), is a 70 percent reduction from uncontrolled levels. The equivalent control target for the medium non-utility point source sector is established by applying RACT-level controls to all non-utility NO_x sources with ozone season daily emissions $\geq$1.0 tpd. The application of these control levels to projected uncontrolled 2007 emissions levels establishes the proposed NO_x emissions budget for Other Stationary Sources.

Emissions Inventory Summary for Other Stationary Sources

Table 3-1 provides EPA's estimates of the population of potentially affected units by source category and emissions size in the 22 States and the District of Columbia control region. The source categories are ICI boilers, IC engines, gas turbines, process heaters, industrial processes (non-combustion), and all others. The 2007 NO_x Baseline Emissions (Level 0) in Table 3-1 account for NO_x RACT-level controls that are already supposed to be in place at major sources in non-waivered areas. The size distinctions in Table 3-1 are based on estimated 1990 emissions.

Table 3-1 shows that overall, there are only 1,125 sources (4 percent) in the Ozone Transport Rulemaking region above the 1.0 ozone season tpd applicability threshold of the proposed control option. The majority of these units are ICI boilers and IC engines.

There are over 14,000 ICI boilers in the Ozone Transport Rulemaking region. Just under 4 percent of these ICI boilers have NO_x baseline emissions that are greater than 1.0 tpd. There are over 1,600 reciprocating IC engines in the control region. Nearly 11 percent of these units have daily NO_x emissions greater than 1.0 tpd.

There are about 230 stationary gas turbines in the control region, but only 17 of these units have NO_x emissions of more than 1.0 tpd. It is not surprising that gas turbines are not well represented in the Other Stationary Source category, because the typical application for gas turbine technologies is at electric utilities.

Of the 1,550 process heaters in the control region, only 37 units have daily NO_x emissions greater than 1.0 tpd. The U.S. Environmental Protection Agency (EPA) Available Control Techniques (ACT) for NO_x emissions from process heaters indicates that the mean size of heaters at petroleum refineries is 72 mmBtu/hr. The predominant fuel used in process heaters is process gas, or natural gas, with an associated uncontrolled NO_x emission factor of 0.1 lbs per mmBtu. Thus, the average-sized process heater at a refinery, even operating at 100 percent utilization, will emit less than 0.1 tpd of NO_x.

Of all the source category groupings in Table 3-1, the non-combustion industrial process sources have the highest percentage of units (just over 11 percent) that emit more than 1.0 tpd of NO_x. There are over 1,800 industrial process sources in the control region. This source category includes lime and cement kilns, nitric acid plants, and metals manufacturing furnaces.

Table 3-1
Size Distribution of Different Types of Other Stationary Sources in the States Covered by the Ozone Transport Rulemaking

Source Type	Daily NO_x Range (1990 tpd)	Number of Sources	2007 NO_x Baseline Emissions* Daily (tpd)	Ozone Season (tons)	Annual (tpy)
All Other n.e.c.	0 - 0.25	7,177	138	21,179	50,524
All Other n.e.c.	0.25 - 1.0	354	174	26,624	63,514
All Other n.e.c.	1.0 - 2.0	80	115	17,519	41,793
All Other n.e.c.	2.0 - 5.0	62	176	26,895	64,161
All Other n.e.c.	5.0+	20	521	79,677	190,080
All Other n.e.c.		7,693	1,112	170,201	406,036
ICI Boilers	0 - 0.25	12,700	363	55,562	132,549
ICI Boilers	0.25 - 1.0	928	479	73,222	174,679
ICI Boilers	1.0 - 2.0	279	387	59,220	141,276
ICI Boilers	2.0 - 5.0	175	525	80,347	191,678
ICI Boilers	5.0+	71	809	123,782	295,296
ICI Boilers		14,153	2,556	391,095	933,003
IC Engines	0 - 0.25	982	70	10,731	25,600
IC Engines	0.25 - 1.0	467	231	35,388	84,423
IC Engines	1.0 - 2.0	102	135	20,618	49,187
IC Engines	2.0 - 5.0	59	191	29,255	69,791
IC Engines	5.0+	13	135	20,594	49,131
IC Engines		1,623	729	111,494	265,982
Gas Turbines	0 - 0.25	152	11	1,629	3,886
Gas Turbines	0.25 - 1.0	60	30	4,641	11,073
Gas Turbines	1.0 - 2.0	11	17	2,530	6,035
Gas Turbines	2.0 - 5.0	4	13	1,913	4,563
Gas Turbines	5.0+	2	45	6,826	16,284
Gas Turbines		229	94	14,434	34,435
Process Heaters	0 - 0.25	1,389	39	6,000	14,314
Process Heaters	0.25 - 1.0	124	62	9,522	22,716
Process Heaters	1.0 - 2.0	18	26	4,026	9,604
Process Heaters	2.0 - 5.0	10	33	5,087	12,135
Process Heaters	5.0+	9	115	17,612	42,017
Process Heaters		1,550	266	40,731	97,168

Source Type	Daily NO_x Range (1990 tpd)	Number of Sources	2007 NO_x Baseline Emissions* Daily (tpd)	Ozone Season (tons)	Annual (tpy)
Non-Combustion	0 - 0.25	1,309	37	5,654	13,489
Non-Combustion	0.25 - 1.0	312	174	26,670	63,625
Non-Combustion	1.0 - 2.0	110	150	22,924	54,689
Non-Combustion	2.0 - 5.0	72	215	32,902	78,492
Non-Combustion	5.0+	28	1,662	254,347	606,776
Non-Combustion		1,831	2,228	340,827	813,084
All Sources	0 - 0.25	23,709	658	100,755	240,362
All Sources	0.25 - 1.0	2,245	1,150	176,067	420,030
All Sources	1.0 - 2.0	600	830	126,837	302,584
All Sources	2.0 - 5.0	382	1,153	176,399	420,820
All Sources	5.0+	143	3,287	502,838	1,199,584
Total		**27,079**	**6,985**	**1,068,782**	**2,549,708**

** Ozone season and annual emissions are estimated by multiplying daily emissions by 153 and 365 days, respectively.*

Identifying Affected Sources

To assess the cost and emissions impact of the proposed regulatory option on Other Stationary Sources, EPA must identify non-utility sources that are above and below 250 mmBtu/hr capacity (maximum hourly design rate). Because the majority of the Other Stationary Source units in the OTAG data set do not include this capacity information, EPA has developed techniques to assign these capacities. The same procedure is used in the emissions analysis performed to supply regional modeling input files for the proposed rule.[1]

Using the 1990 National Emission Trends (NET) Inventory,[2] a default boiler capacity file is developed for all combustion source SCCs potentially affected by the proposed rule. This file contains mean and median boiler capacities as well as average daily NO_x emissions for 6-digit SCCs for records with known boiler capacities closest to 250 mmBtu/hr. Each non-utility point source in the OTAG inventory is matched to this default boiler capacity file by 6-digit SCC, and then four rules are applied to determine if boiler capacity is above or below 250 mmBtu/hr.

1. If both the mean and median boiler capacities from the NET summary are greater than 300 mmBtu/hr, the boiler capacity is assumed to be greater than 250 mmBtu/hr.

2. If both the mean and median boiler capacities from the NET summary are less than 200 mmBtu/hr, the boiler capacity is assumed to be less than 250 mmBtu/hr.

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[1] Pechan, 1997: E.H. Pechan & Associates, Inc., *OTAG Cost Parameters Applied to Non-Utility Strategies to Reduce Ozone Transport*, prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 30, 1997.

[2] EPA, 1996: U.S. Environmental Protection Agency, *National Air Pollutant Emission Trends, 1900-1995*, EPA-454/4-96-006, Office of Air Quality Planning and Standards, Research Triangle Park, NC, October 1996.

3. If either the mean or median boiler capacity is between 200 and 300 mmBtu/hr and the OTAG source's daily NO_x emissions are greater than the NET summary average daily NO_x emissions, the boiler capacity is assumed to be greater than 250 mmBtu/hr.

4. If no 6-digit SCC match is found to the NET boiler capacity summary file, the boiler capacity is assumed to be less than 250 mmBtu/hr.

NO_x Budget Component Calculation

The proposed State-level Other Stationary Source NO_x emissions are calculated based on:

1. 70 percent control on large ($\geq$250 mmBtu/hr) sources (measured from uncontrolled 2007 emissions).

2. RACT-level controls on all other NO_x sources $\geq$1.0 tpd of NO_x emissions (medium-sized sources).

3. Small source NO_x emissions are estimated using OTAG Base 1c scenario emission values.

To establish the proposed daily NO_x emissions budget components for Other Stationary Sources, EPA started with emission data files that included Thursday, Saturday, and Sunday emission estimates for three emission control scenarios: (1) current control levels projected to 2007, (2) OTAG scenario Base 1c with RACT-level controls applied in all non-waivered areas, and (3) OTAG scenario Level 0 with OTC Phase II NO_x MOU controls applied. EPA also used a file prepared by E.H. Pechan & Associates, Inc. for EPA/OTAG that contains estimates of NO_x emission reduction percentages by source and source category for current control levels, RACT, Level 1 and Level 2 controls. With this data, EPA used the following procedure to estimate daily NO_x budget emission levels:

1. Calculate typical weekday (represented by Thursday) and weekend day (Saturday and Sunday) uncontrolled emissions for 2007.

2. Apply the appropriate NO_x control efficiency (i.e., 70% or RACT) for the proposed regulatory option to each daily uncontrolled NO_x emission value.

3. Multiply controlled daily emissions by the number of days in the five month ozone season (109 weekdays, 22 Saturdays, and 22 Sundays).

4. Sum the three resulting daily values to obtain a five month ozone season emission estimate.

5. Divide the total seasonal NO_x emission value by 153 days to obtain average daily values.

The NO_x RACT control efficiency assumptions are summarized in Table 3-2. The estimated effect of applying NO_x RACT at any individual source is determined according to the following hierarchy:

1. For States in the Northeast Ozone Transport Region, where RACT-level NO_x emission rates are included for sources in the OTC NO_X Baseline Inventory, these emission rates are used. Where source-specific information is not provided in the OTC NO_X Baseline, default RACT percentage reductions and emission rate limits available from the OTC NO_x Baseline are applied.

Table 3-2

Ozone Transport Rulemaking
Other Stationary Source RACT Assumptions

Source Category	Expected RACT Control Strategy	Range of RACT Reductions (%)*
ICI Boilers - Coal/Wall	LNB	40-55
ICI Boilers - Coal/FBC	SNCR - Urea	75
ICI Boilers - Coal/Stoker	SNCR - Urea	50-58
ICI Boilers - Coal/Cyclone	Coal Reburn	50-58
ICI Boilers - Residual Oil	LNB	20-67
ICI Boilers - Distillate Oil	LNB	50
ICI Boilers - Natural Gas	LNB	42-81
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	40-55
ICI Boilers - MSW/Stoker	SNCR - Urea	55
Internal Combustion Engines - Oil	IR	12-40
Internal Combustion Engines - Gas	IR	20-80
Gas Turbines - Oil	Water Injection	66-68
Gas Turbines - Natural Gas	LNB	54-84
Process Heaters - Distillate Oil	LNB	45-74
Process Heaters - Residual Oil	LNB	37-73
Process Heaters - Natural Gas	LNB	50-75
Adipic Acid Manufacturing	Thermal Reduction	81
Nitric Acid Manufacturing	Extended Absorption	95
Glass Manufacturing - Container	LNB	40
Glass Manufacturing - Flat	LNB	40
Glass Manufacturing - Pressed/Blown	LNB	40
Cement Manufacturing - Dry	Mid-Kiln Firing	25-40
Cement Manufacturing - Wet	Mid-Kiln Firing	25
Iron & Steel Mills - Reheating	LNB	66
Iron & Steel Mills - Annealing	LNB	50
Iron & Steel Mills - Galvanizing	LNB	50
Municipal Waste Combustors	SNCR	45
Medical Waste Incinerators	SNCR	45

** Represents the range of expected NO_x reductions in the States with NO_x RACT regulations.*

2. Where source-specific data are not available in the emissions inventory, a RACT emission rate limit data base developed from an EPA summary of State NO_x RACT rules is applied This data base contains State (and in some cases, county) specific emission limits by source type.

3. National default NO_x RACT reduction percentages by SCC are applied to all other sources in areas with NO_x RACT requirements where NO_x emission limits are not available in 1. or 2. above.

Since the time of the analysis documented in the September 1997 report, EPA has made additional corrections to the calculation of emissions budgets. These corrections affect the proposed budget level. First, the starting non-utility NO_x emissions file has changed to include more non-utility sources. In the previous analysis, some non-utility NO_x emitters were inadvertently classified as utilities. Second, EPA has corrected a previous error in the way NO_x RACT is applied to medium-sized ($\geq$ 1.0 tpd) NO_x sources. Previously, NO_x RACT was incorrectly applied only in non-waivered areas. These changes make the NO_x budgets lower than before in most States. For the entire control region, the total NO_x budget for other stationary sources is now 324 tpd lower than in the previous analysis. Table 3-3 provides EPA's estimates of the State NO_x emission budget components for Other Stationary Sources for the proposed regulatory option.

Table 3-3
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission Budget Component*

State	Corrected Proposed Option		Original Proposed Option	
	NO_x Baseline (tpd)	NO_x Budget Component (tpd)	NO_x Baseline (tpd)	NO_x Budget Component (tpd)
Alabama	312	157	308	164
Connecticut	30	19	31	29
Delaware	23	15	34	21
DC	2	2	2	2
Georgia	220	158	222	134
Illinois	421	245	416	260
Indiana	336	182	336	233
Kentucky	124	78	123	80
Maryland	44	30	44	32
Massachusetts	70	44	70	50
Michigan	380	197	374	231
Missouri	82	53	80	53
New Jersey	221	121	213	175
New York	139	111	130	111
North Carolina	224	126	210	138
Ohio	337	207	333	214
Pennsylvania	445	361	420	390
Rhode Island	2	2	2	2
South Carolina	229	122	227	131
Tennessee	426	201	425	210
Virginia	163	72	153	101
West Virginia	279	136	271	205
Wisconsin	139	74	139	80
22 States and DC	**4,648**	**2,712**	**4,564**	**3,047**

** The ozone season NO_x emissions is calculated by multiplying the numbers in the table by 153 (days in the ozone season). Additional corrections to the budget were made after this analysis was completed. Please see the preamble to the SNPR Federal Register notice for final emissions budgets.*

Cost Analysis Methodology

In this report the EPA has estimated the annual cost of achieving the proposed NO_x budget component for Other Stationary Sources using two different approaches. The first approach, termed the *Least Cost* scenario, attempts to identify the mix of sources and control technologies that achieve the overall budget level in each State at the lowest possible control cost. The sources controlled under the Least Cost scenario may not be the same sources that are controlled for the purpose of establishing each State's emissions budget. The result of the Least Cost scenario is a proxy for State-level emissions trading programs free of transactions costs. The second approach, termed the *Command-and-Control* scenario, attempts to estimate the cost of controlling just those sources that were controlled for the purpose of establishing each State's emissions budget (i.e., medium and large sources).

EPA used a variety of data sources to develop the unit-level Other Stationary Sources control technology cost and performance levels used in this analysis. These sources are documented in the report that supports the 1997 NAAQS Regulatory Impact Analysis.[3] Since the OTAG data base lacks complete information on source size and operating parameters that are needed to use detailed cost equations, EPA has based control cost estimates on the average cost per ton of NO_x reduction for different control technologies for different types of industrial operations. The average cost per ton of NO_x reduction is primarily based on equations in the EPA Alternative Control Technology (ACT) documents for each type and size of emissions source.

Table 3-4 presents the control technologies, their associated reductions, and average cost per ton values used in this analysis. Appendix C explains some of the control technology abbreviations in the table. Note that the EPA ACT documents report NO_x cost-effectiveness ranges in dollars other than 1990. For application in this study, all cost per ton averages (which are shown in the three right-most columns of Table 3-4) are converted to 1990 dollars. The unit cost estimates from Table 3-4 are applied to each source that is controlled for the purpose of meeting each State-level emissions budget. Size ranges are established to distinguish small, medium, and large sources according to the scheme in Table 3-5. The cost-effectiveness ranges shown in Table 3-4 can be considered an indicator of the uncertainty in the cost estimates by source category, technology, and size.

The values in Table 3-4 of this report have been updated since the September 1997 report that accompanied the original proposal. New cost information for applying selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) was developed by EPA's Acid Rain Division (ARD) and applied in this analysis. The new cost equations are more consistent with the utility boiler cost equations used in the Integrated Planning Model (IPM). For SCR and SNCR, the new cost equations are applied to the representative boiler sizes in the EPA ACT documents. For most source types and fuel types, the representative boiler sizes are 10, 25, 50, 100, 150, and 250 mmBtu/hr. The 10 to 100 mmBtu/hr sizes are used to estimate the representative cost range for small boilers. The 150 and 250 mmBtu/hr units are used to estimate costs for medium and large boilers respectively.

[3] Pechan, 1997: E.H. Pechan & Associates, Inc., *Additional Control Measure Evaluation for the Integrated Implementation of the Ozone and Particulate Matter National Ambient Air Quality Standards, and Regional Haze Program*, prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, July 17, 1997.

Table 3-4
Initial List of NO_x Control Technologies, Performance, and
Unit Costs Per Ton of NO_x Reduction for Other Stationary Sources

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Adipic Acid Manufacturing									
Adipic Acid Manufacturing	1A	Thermal Reduction	81	NA	NA	NA	485	485	485
Adipic Acid Manufacturing	1S	Thermal Reduction	81	NA	NA	NA	1,157	1,157	1,157
Adipic Acid Manufacturing	2A	Extended Absorption	86	NA	NA	NA	95	95	95
Adipic Acid Manufacturing	2S	Extended Absorption	86	NA	NA	NA	227	227	227
Ammonia - NG-Fired Reformers									
Ammonia - NG-Fired Reformers	1A	LNB	50	NA	NA	NA	2,165	2,165	2,165
Ammonia - NG-Fired Reformers	1S	LNB	50	NA	NA	NA	5,165	5,165	5,165
Ammonia - NG-Fired Reformers	2A	LNB + FGR	60	NA	NA	NA	3,635	3,635	3,635
Ammonia - NG-Fired Reformers	2S	LNB + FGR	60	NA	NA	NA	8,672	8,672	8,672
Ammonia - NG-Fired Reformers	3A	OT + WI	65	NA	NA	NA	735	735	735
Ammonia - NG-Fired Reformers	3S	OT + WI	65	NA	NA	NA	1,753	1,753	1,753
Ammonia - NG-Fired Reformers	4A	SCR - New	80	NA	NA	NA	2,580	1,400	1,400
Ammonia - NG-Fired Reformers	4S	SCR - New	80	NA	NA	NA	6,040	3,200	3,200
Ammonia - NG-Fired Reformers	5A	SNCR - New	50	NA	NA	NA	4,470	1,780	1,780
Ammonia - NG-Fired Reformers	5S	SNCR - New	50	NA	NA	NA	9,770	3,350	3,350
Cement Manufacturing - Dry									
Cement Manufacturing - Dry	1A	Mid-Kiln Firing	25	NA	NA	NA	540	540	540
Cement Manufacturing - Dry	1S	Mid-Kiln Firing	25	NA	NA	NA	1,288	1,288	1,288
Cement Manufacturing - Dry	2A	LNB	25	NA	NA	NA	670	670	670
Cement Manufacturing - Dry	2S	LNB	25	NA	NA	NA	1,598	1,598	1,598
Cement Manufacturing - Dry	3A	SNCR - Urea Based	50	NA	NA	NA	850	850	850

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category) Small*	Medium*	Large*	Average Cost Per Ton of NO_x Reduced in 1990$/ton** Small*	Medium*	Large*
Cement Manufacturing - Dry	3S	SNCR - Urea Based	50	NA	NA	NA	2,028	2,028	2,028
Cement Manufacturing - Dry	4A	SNCR - NH3 Based	50	NA	NA	NA	960	960	960
Cement Manufacturing - Dry	4S	SNCR - NH3 Based	50	NA	NA	NA	2,290	2,290	2,290
Cement Manufacturing - Dry	5A	SCR	80	NA	NA	NA	4,040	4,040	4,040
Cement Manufacturing - Dry	5S	SCR	80	NA	NA	NA	9,638	9,638	9,638
Cement Manufacturing - Wet									
Cement Manufacturing - Wet	1A	Mid-Kiln Firing	25	NA	NA	NA	490	490	490
Cement Manufacturing - Wet	1S	Mid-Kiln Firing	25	NA	NA	NA	1,169	1,169	1,169
Cement Manufacturing - Wet	2A	LNB	25	NA	NA	NA	640	640	640
Cement Manufacturing - Wet	2S	LNB	25	NA	NA	NA	1,527	1,527	1,527
Cement Manufacturing - Wet	3A	SCR	80	NA	NA	NA	3,370	3,370	3,370
Cement Manufacturing - Wet	3S	SCR	80	NA	NA	NA	8,040	8,040	8,040
Comm./Inst. Incinerators									
Comm./Inst. Incinerators	1A	SNCR	45	NA	NA	NA	2,670	2,670	2,670
Comm./Inst. Incinerators	1S	SNCR	45	NA	NA	NA	6,370	6,370	6,370
Gas Turbines - Jet Fuel									
Gas Turbines - Jet Fuel	1A	Water Injection	68	NA	NA	NA	1,213	1,213	1,213
Gas Turbines - Jet Fuel	1S	Water Injection	68	NA	NA	NA	2,894	2,894	2,894
Gas Turbines - Jet Fuel	2A	SCR + Water Injection	90	NA	NA	NA	5,400	5,400	5,400
Gas Turbines - Jet Fuel	2S	SCR + Water Injection	90	NA	NA	NA	12,882	12,882	12,882
Gas Turbines - Natural Gas									
Gas Turbines - Natural Gas	1	Water Injection	76	1,390 - 1,780	690 - 880	500 - 640	1,507	747	542
Gas Turbines - Natural Gas	2	Steam Injection	80	1,560 - 2,000	760 - 970	520 - 670	1,693	823	566
Gas Turbines - Natural Gas	3	LNB	84	530 - 800	240 - 370	130 - 200	632	290	157
Gas Turbines - Natural Gas	4	SCR + LNB	94	18,800 - 22,100	12,800 - 13,200	6,940 - 7,660	20,450	13,000	7,300

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Gas Turbines - Natural Gas	5	SCR + Steam Injection	95	9,500	3,840 - 10,400	3,480 - 3,580	9,500	7120	3530
Gas Turbines - Natural Gas	6	SCR + Water Injection	95	9,500 - 10,800	3,840 - 5,160	3,480 - 6,980	10,150	4,500	5,230
Gas Turbines - Oil									
Gas Turbines - Oil	1	Water Injection	68	1,000 - 1,300	560 - 710	440 - 560	1,094	604	476
Gas Turbines - Oil	2	SCR + Water Injection	90	8,340	2,690	2,430	8,340	2,690	2,430
Glass Manufacturing - Container									
Glass Manufacturing - Container	1A	Electric Boost	10	NA	NA	NA	7,505	7,505	7,505
Glass Manufacturing - Container	1S	Electric Boost	10	NA	NA	NA	17,904	17,904	17,904
Glass Manufacturing - Container	2A	Cullet Preheat	25	NA	NA	NA	970	970	970
Glass Manufacturing - Container	2S	Cullet Preheat	25	NA	NA	NA	2,314	2,314	2,314
Glass Manufacturing - Container	3A	LNB	40	NA	NA	NA	1,790	1,790	1,790
Glass Manufacturing - Container	3S	LNB	40	NA	NA	NA	4,270	4,270	4,270
Glass Manufacturing - Container	4A	SNCR	40	NA	NA	NA	1,865	1,865	1,865
Glass Manufacturing - Container	4S	SNCR	40	NA	NA	NA	4,449	4,449	4,449
Glass Manufacturing - Container	5A	SCR	75	NA	NA	NA	2,290	2,290	2,290
Glass Manufacturing - Container	5S	SCR	75	NA	NA	NA	5,463	5,463	5,463
Glass Manufacturing - Container	6A	OXY-Firing	85	NA	NA	NA	4,935	4,935	4,935
Glass Manufacturing - Container	6S	OXY-Firing	85	NA	NA	NA	11,773	11,773	11,773
Glass Manufacturing - Flat									
Glass Manufacturing - Flat	1A	Electric Boost	10	NA	NA	NA	2,420	2,420	2,420
Glass Manufacturing - Flat	1S	Electric Boost	10	NA	NA	NA	5,773	5,773	5,773
Glass Manufacturing - Flat	2A	LNB	40	NA	NA	NA	735	735	735
Glass Manufacturing - Flat	2S	LNB	40	NA	NA	NA	1,753	1,753	1,753
Glass Manufacturing - Flat	3A	SNCR	40	NA	NA	NA	775	775	775
Glass Manufacturing - Flat	3S	SNCR	40	NA	NA	NA	1,849	1,849	1,849

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Glass Manufacturing - Flat	4A	SCR	75	NA	NA	NA	745	745	745
Glass Manufacturing - Flat	4S	SCR	75	NA	NA	NA	1,777	1,777	1,777
Glass Manufacturing - Flat	5A	OXY-Firing	85	NA	NA	NA	2,000	2,000	2,000
Glass Manufacturing - Flat	5S	OXY-Firing	85	NA	NA	NA	4,771	4,771	4,771
Glass Manufacturing - Pressed/Blown									
Glass Manufacturing - Pressed/Blown	1A	Electric Boost	10	NA	NA	NA	9,220	9,220	9,220
Glass Manufacturing - Pressed/Blown	1S	Electric Boost	10	NA	NA	NA	21,995	21,995	21,995
Glass Manufacturing - Pressed/Blown	2A	Cullet Preheat	25	NA	NA	NA	830	830	830
Glass Manufacturing - Pressed/Blown	2S	Cullet Preheat	25	NA	NA	NA	1,980	1,980	1,980
Glass Manufacturing - Pressed/Blown	3A	LNB	40	NA	NA	NA	1,565	1,565	1,565
Glass Manufacturing - Pressed/Blown	3S	LNB	40	NA	NA	NA	3,733	3,733	3,733
Glass Manufacturing - Pressed/Blown	4A	SNCR	40	NA	NA	NA	1,650	1,650	1,650
Glass Manufacturing - Pressed/Blown	4S	SNCR	40	NA	NA	NA	3,936	3,936	3,936
Glass Manufacturing - Pressed/Blown	5A	SCR	75	NA	NA	NA	2,750	2,750	2,750
Glass Manufacturing - Pressed/Blown	5S	SCR	75	NA	NA	NA	6,560	6,560	6,560
Glass Manufacturing - Pressed/Blown	6A	OXY-Firing	85	NA	NA	NA	4,100	4,100	4,100
Glass Manufacturing - Pressed/Blown	6S	OXY-Firing	85	NA	NA	NA	9,781	9,781	9,781
ICI Boilers - Coal/Cyclone									
ICI Boilers - Coal/Cyclone	1A	SNCR - New	35	949	949	697 - 822	902	902	722
ICI Boilers - Coal/Cyclone	1S	SNCR - New	35	1,724	1,724	1,123 - 1,420	1,640	1,640	1,209
ICI Boilers - Coal/Cyclone	2	Coal Reburn	50	1,590 - 2,240	510 - 680	320 - 410	1,821	566	347
ICI Boilers - Coal/Cyclone	3A	SCR - New	80	905	905	711 - 812	861	861	724
ICI Boilers - Coal/Cyclone	3S	SCR - New	80	2,090	2,090	1,627 - 1,870	1,988	1,988	1,663
ICI Boilers - Coal/Cyclone	4	NGR	55	1,590 - 2,240	510 - 680	320 - 410	1,821	566	347
ICI Boilers - Coal/FBC									
ICI Boilers - Coal/FBC	1	SNCR - Urea	75	960 - 1,130	960 - 1,130	810 - 1,030	995	995	876
ICI Boilers - Coal/Stoker									
ICI Boilers - Coal/Stoker	1A	SNCR - New	40	1,851	1,851	1,360 - 1,603	1,762	1,762	1,410
ICI Boilers - Coal/Stoker	1S	SNCR - New	40	3,362	3,362	2,190 - 2,769	3,201	3,201	2,360

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
ICI Boilers - Coal/Wall									
ICI Boilers - Coal/Wall	1A	SNCR - New	45	1,234	1,234	907 - 1,068	1,175	1,175	940
ICI Boilers - Coal/Wall	1S	SNCR - New	45	2,242	2,242	1,460 - 1,846	2,134	2,134	1,574
ICI Boilers - Coal/Wall	3	LNB	50	1,340 - 1,760	1,340 - 1,760	980 - 1,530	1,476	1,476	1,195
ICI Boilers - Coal/Wall	4A	SCR - New	80	1,508	1,508	1,184 - 1,354	1,436	1,436	1,208
ICI Boilers - Coal/Wall	4S	SCR - New	80	3,483	3,483	2,712 - 3,116	3,316	3,316	2,774
ICI Boilers - Coke									
ICI Boilers - Coke	1A	SNCR - New	40	NA	NA	NA	1,180	1,180	940
ICI Boilers - Coke	1S	SNCR - New	40	NA	NA	NA	2,130	2,130	1,570
ICI Boilers - Coke	3A	LNB	50	NA	NA	NA	1,305	1,305	1,305
ICI Boilers - Coke	3S	LNB	50	NA	NA	NA	3,113	3,113	3,113
ICI Boilers - Coke	4A	SCR - New	70	NA	NA	NA	1,440	1,440	1,210
ICI Boilers - Coke	4S	SCR - New	70	NA	NA	NA	3,320	3,320	2,770
ICI Boilers - Distillate Oil									
ICI Boilers - Distillate Oil	1	LNB	50	370 - 3,440	280 - 1,310	280 - 1,310	1,814	757	757
ICI Boilers - Distillate Oil	2	LNB + FGR	60	800 - 5,900	580 - 2,250	580 - 2,250	3,189	1,347	1,347
ICI Boilers - Distillate Oil	3A	SCR - New	80	2,218 - 4,569	1,697 - 1,967	1,697 - 1,967	3,231	1,744	1,744
ICI Boilers - Distillate Oil	3S	SCR - New	80	5,124 - 10,733	3,881 - 4,525	3,881 - 4,525	7,548	4,001	4,001
ICI Boilers - Distillate Oil	4A	SNCR - New	50	2,860 - 8,408	2,040 - 2,444	2,040 - 2,444	5,364	2,134	2,134
ICI Boilers - Distillate Oil	4S	SNCR - New	50	5,703 - 18,936	3,745 - 4,709	3,745 - 4,709	11,728	4,024	4,024
ICI Boilers - Liquid Waste									
ICI Boilers - Liquid Waste	1A	LNB	50	NA	NA	NA	935	935	935
ICI Boilers - Liquid Waste	1S	LNB	50	NA	NA	NA	2,231	2,231	2,231
ICI Boilers - Liquid Waste	2A	LNB + FGR	60	NA	NA	NA	1,830	1,830	1,830
ICI Boilers - Liquid Waste	2S	LNB + FGR	60	NA	NA	NA	4,366	4,366	4,366
ICI Boilers - Liquid Waste	3A	SCR - New	80	NA	NA	NA	1,720	1,620	1,620
ICI Boilers - Liquid Waste	3S	SCR - New	80	NA	NA	NA	5,550	3,660	3,660
ICI Boilers - Liquid Waste	4A	SNCR - New	50	NA	NA	NA	2,980	1,190	1,190
ICI Boilers - Liquid Waste	4S	SNCR - New	50	NA	NA	NA	6,940	2,660	2,660
ICI Boilers - LPG									

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
ICI Boilers - LPG	1A	LNB	50	NA	NA	NA	1,770	1,770	1,770
ICI Boilers - LPG	1S	LNB	50	NA	NA	NA	4,223	4,223	4,223
ICI Boilers - LPG	2A	LNB + FGR	60	NA	NA	NA	3,085	3,085	3,085
ICI Boilers - LPG	2S	LNB + FGR	60	NA	NA	NA	7,360	7,360	7,360
ICI Boilers - LPG	3A	SCR - New	80	NA	NA	NA	3,230	1,740	1,740
ICI Boilers - LPG	3S	SCR - New	80	NA	NA	NA	7,550	4,000	4,000
ICI Boilers - LPG	4A	SNCR - New	50	NA	NA	NA	5,360	2,130	2,130
ICI Boilers - LPG	4S	SNCR - New	50	NA	NA	NA	11,730	4,020	4,020
ICI Boilers - MSW/Stoker									
ICI Boilers - MSW/Stoker	1	SNCR - Urea	55	3,390 - 3,800	1,690 - 2,790	1,470 - 2,270	3,422	2,132	1,780
ICI Boilers - Natural Gas									
ICI Boilers - Natural Gas	1	LNB	50	410 - 4,300	240 - 1,450	240 - 1,450	2,242	804	804
ICI Boilers - Natural Gas	2	LNB + FGR	60	1,540 - 7,630	650 - 2,730	650 - 2,730	4,365	1,609	1,609
ICI Boilers - Natural Gas	3	OT + WI	65	570 - 1,160	380 - 610	380 - 610	823	471	471
ICI Boilers - Natural Gas	4A	SCR - New	80	1,774 - 3,655	1,357 - 1,573	1,357 - 1,573	2,584	1,395	1,395
ICI Boilers - Natural Gas	4S	SCR - New	80	4,099 - 8,587	3,105 - 3,620	3,105 - 3,620	6,039	3,201	3,201
ICI Boilers - Natural Gas	5A	SNCR - New	50	2,384 - 7,006	1,700 - 2,036	1,700 - 2,036	4,470	1,778	1,778
ICI Boilers - Natural Gas	5S	SNCR - New	50	4,753 - 15,780	3,121 - 3,924	3,121 - 3,924	9,774	3,353	3,353
ICI Boilers - Process Gas									
ICI Boilers - Process Gas	1A	LNB	50	NA	NA	NA	2,165	2,165	2,165
ICI Boilers - Process Gas	1S	LNB	50	NA	NA	NA	5,165	5,165	5,165
ICI Boilers - Process Gas	2A	LNB + FGR	60	NA	NA	NA	3,635	3,635	3,635
ICI Boilers - Process Gas	2S	LNB + FGR	60	NA	NA	NA	8,672	8,672	8,672
ICI Boilers - Process Gas	3A	OT + WI	65	NA	NA	NA	735	735	735
ICI Boilers - Process Gas	3S	OT + WI	65	NA	NA	NA	1,753	1,753	1,753
ICI Boilers - Process Gas	4A	SCR - New	80	NA	NA	NA	2,580	1,400	1,400
ICI Boilers - Process Gas	4S	SCR - New	80	NA	NA	NA	6,040	3,200	3,200
ICI Boilers - Residual Oil									
ICI Boilers - Residual Oil	1	LNB	50	190 - 1,810	150 - 690	150 - 690	952	400	400
ICI Boilers - Residual Oil	2	LNB + FGR	60	640 - 3,320	520 - 1,400	520 - 1,400	1,885	914	914

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
ICI Boilers - Residual Oil	3A	SCR - New	80	1,183 - 2,437	1,625 - 1,769	1,625 - 1,769	1,723	1,616	1,616
ICI Boilers - Residual Oil	3S	SCR - New	80	4,335 - 7,327	3,673 - 4,016	3,673 - 4,017	5,551	3,660	3,660
ICI Boilers - Residual Oil	4A	SNCR - New	50	1,589 - 4,671	1,133 - 1,358	1,133 - 1,358	2,980	1,186	1,186
ICI Boilers - Residual Oil	4S	SNCR - New	50	3,609 - 10,961	2,522 - 3057	2,522 - 3057	6,935	2,656	2,656
ICI Boilers - Wood/Bark/FBC									
ICI Boilers - Wood/Bark/FBC	1	SNCR - Ammonia	55	1,560 - 1,750	1,560 - 1,750	1,110 - 1,650	1,576	1,576	1,314
ICI Boilers - Wood/Bark/Stoker									
ICI Boilers - Wood/Bark/Stoker	1	SNCR - Urea	55	1,810 - 3,130	1,080 - 2,380	890 - 2,000	2,351	1,647	1,376
Indust. Incinerators									
Indust. Incinerators	1A	SNCR	45	NA	NA	NA	2,670	2,670	2,670
Indust. Incinerators	1S	SNCR	45	NA	NA	NA	6,370	6,370	6,370
Internal Combustion Engines - Gas									
Internal Combustion Engines - Gas	1	IR	20	600 - 990	480 - 600	480 - 600	756	514	514
Internal Combustion Engines - Gas	2	IR	20	600 - 990	480 - 600	480 - 600	756	514	514
Internal Combustion Engines - Gas	3	IR	20	600 - 990	480 - 600	480 - 600	756	514	514
Internal Combustion Engines - Gas	4	AF RATIO	20	510 - 3,700	330 - 510	330 - 510	2,002	399	399
Internal Combustion Engines - Gas	5	AF RATIO	20	510 - 3,700	330 - 510	330 - 510	2,002	399	399
Internal Combustion Engines - Gas	6	AF RATIO	20	510 - 3,700	330 - 510	330 - 510	2,002	399	399
Internal Combustion Engines - Gas	7	AF + IR	30	600 - 3,500	400 - 600	400 - 600	1,950	476	476
Internal Combustion Engines - Gas	8	AF + IR	30	600 - 3,500	400 - 600	400 - 600	1,950	476	476
Internal Combustion Engines - Gas	9	AF + IR	30	600 - 3,500	400 - 600	400 - 600	1,950	476	476
Internal Combustion Engines - Gas	10	L-E (Medium Speed)	87	300 - 590	NA	NA	423	NA	NA
Internal Combustion Engines - Gas	11	L-E (Low Speed)	87	750 - 3,600	650 - 750	650 - 750	2,068	666	666
Internal Combustion Engines - Gas	12	NSCR	90	315 - 6,900	240 - 315	240 - 315	3,431	264	264
Internal Combustion Engines - Gas, Diesel, LPG									
Internal Combustion Engines - Gas, Diesel, LPG	1A	IR	25	NA	NA	NA	518	518	518

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Internal Combustion Engines - Gas, Diesel, LPG	1S	IR	25	NA	NA	NA	1,236	1,236	1,236
Internal Combustion Engines - Gas, Diesel, LPG	2A	IR	25	NA	NA	NA	518	518	518
Internal Combustion Engines - Gas, Diesel, LPG	2S	IR	25	NA	NA	NA	1,236	1,236	1,236
Internal Combustion Engines - Gas, Diesel, LPG	3A	IR	25	NA	NA	NA	518	518	518
Internal Combustion Engines - Gas, Diesel, LPG	3S	IR	25	NA	NA	NA	1,236	1,236	1,236
Internal Combustion Engines - Gas, Diesel, LPG	4A	SCR	80	NA	NA	NA	1,540	1,540	1,540
Internal Combustion Engines - Gas, Diesel, LPG	4S	SCR	80	NA	NA	NA	3,674	3,674	3,674
Internal Combustion Engines - Oil									
Internal Combustion Engines - Oil	1	IR	25	440 - 2,900	330 - 440	330 - 440	1,588	366	366
Internal Combustion Engines - Oil	2	IR	25	440 - 2,900	330 - 440	330 - 440	1,588	366	366
Internal Combustion Engines - Oil	3	IR	25	440 - 2,900	330 - 440	330 - 440	1,588	366	366
Internal Combustion Engines - Oil	4	SCR	80	700 - 19,000	490 - 880	490 - 880	9,367	651	651

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category) Small*	Medium*	Large*	Average Cost Per Ton of NO_x Reduced in 1990$/ton** Small*	Medium*	Large*
Iron & Steel Mills - Annealing									
Iron & Steel Mills - Annealing	1A	LNB	50	NA	NA	NA	660	660	660
Iron & Steel Mills - Annealing	1S	LNB	50	NA	NA	NA	1,575	1,575	1,575
Iron & Steel Mills - Annealing	2A	LNB + FGR	60	NA	NA	NA	810	810	810
Iron & Steel Mills - Annealing	2S	LNB + FGR	60	NA	NA	NA	1,932	1,932	1,932
Iron & Steel Mills - Annealing	3A	SNCR	60	NA	NA	NA	1,860	1,860	1,860
Iron & Steel Mills - Annealing	3S	SNCR	60	NA	NA	NA	4,437	4,437	4,437
Iron & Steel Mills - Annealing	4A	LNB + SNCR	80	NA	NA	NA	1,690	1,690	1,690
Iron & Steel Mills - Annealing	4S	LNB + SNCR	80	NA	NA	NA	4,032	4,032	4,032
Iron & Steel Mills - Annealing	5A	SCR	85	NA	NA	NA	3,800	3,800	3,800
Iron & Steel Mills - Annealing	5S	SCR	85	NA	NA	NA	9,065	9,065	9,065
Iron & Steel Mills - Annealing	6A	LNB + SCR	90	NA	NA	NA	4,100	4,100	4,100
Iron & Steel Mills - Annealing	6S	LNB + SCR	90	NA	NA	NA	9,781	9,781	9,781
Iron & Steel Mills - Galvanizing									
Iron & Steel Mills - Galvanizing	1A	LNB	50	NA	NA	NA	440	440	440
Iron & Steel Mills - Galvanizing	1S	LNB	50	NA	NA	NA	1,050	1,050	1,050
Iron & Steel Mills - Galvanizing	2A	LNB + FGR	60	NA	NA	NA	580	580	580
Iron & Steel Mills - Galvanizing	2S	LNB + FGR	60	NA	NA	NA	1,384	1,384	1,384
Iron & Steel Mills - Reheating									
Iron & Steel Mills - Reheating	1A	LEA	13	NA	NA	NA	1,470	1,470	1,470
Iron & Steel Mills - Reheating	1S	LEA	13	NA	NA	NA	3,507	3,507	3,507
Iron & Steel Mills - Reheating	2A	LNB	66	NA	NA	NA	280	280	280
Iron & Steel Mills - Reheating	2S	LNB	66	NA	NA	NA	668	668	668
Iron & Steel Mills - Reheating	3A	LNB + FGR	77	NA	NA	NA	420	420	420
Iron & Steel Mills - Reheating	3S	LNB + FGR	77	NA	NA	NA	1,002	1,002	1,002
Lime Kilns									
Lime Kilns	1A	Mid-Kiln Firing	25	NA	NA	NA	540	540	540
Lime Kilns	1S	Mid-Kiln Firing	25	NA	NA	NA	1,288	1,288	1,288
Lime Kilns	2A	LNB	25	NA	NA	NA	670	670	670
Lime Kilns	2S	LNB	25	NA	NA	NA	1,598	1,598	1,598

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Lime Kilns	3A	SNCR - Urea Based	50	NA	NA	NA	850	850	850
Lime Kilns	3S	SNCR - Urea Based	50	NA	NA	NA	2,028	2,028	2,028
Lime Kilns	4A	SNCR - NH3 Based	50	NA	NA	NA	960	960	960
Lime Kilns	4S	SNCR - NH3 Based	50	NA	NA	NA	2,290	2,290	2,290
Lime Kilns	5A	SCR	80	NA	NA	NA	4,040	4,040	4,040
Lime Kilns	5S	SCR	80	NA	NA	NA	9,638	9,638	9,638
Municipal Waste Combustors									
Municipal Waste Combustors	1A	SNCR	45	NA	NA	NA	2,670	2,670	2,670
Municipal Waste Combustors	1S	SNCR	45	NA	NA	NA	6,370	6,370	6,370
Nitric Acid Manufacturing									
Nitric Acid Manufacturing	1A	Extended Absorption	95	NA	NA	NA	173	173	173
Nitric Acid Manufacturing	1S	Extended Absorption	95	NA	NA	NA	413	413	413
Nitric Acid Manufacturing	2A	SCR	97	NA	NA	NA	523	523	523
Nitric Acid Manufacturing	2S	SCR	97	NA	NA	NA	1,248	1,248	1,248
Nitric Acid Manufacturing	3A	NSCR	98	NA	NA	NA	601	601	601
Nitric Acid Manufacturing	3S	NSCR	98	NA	NA	NA	1,434	1,434	1,434
Process Heaters - Distillate Oil									
Process Heaters - Distillate Oil	1	LNB	45	4,220	1,180	1,180	4,085	1,142	1,142
Process Heaters - Distillate Oil	2	LNB + FGR	48	5,140	2,010	2,010	4,976	1,946	1,946
Process Heaters - Distillate Oil	3A	SNCR	60	3,780	2,000	2,000	3,659	1,936	1,936
Process Heaters - Distillate Oil	3S	SNCR	60	6,562	3,472	3,472	6,352	3,361	3,361
Process Heaters - Distillate Oil	4	ULNB	74	2,600	735	735	2,517	711	711
Process Heaters - Distillate Oil	5A	SCR	75	11,000	7,280	7,280	10,648	7,047	7,047
Process Heaters - Distillate Oil	5S	SCR	75	22,594	14,953	14,953	21,871	14,475	14,475
Process Heaters - Distillate Oil	6A	LNB + SNCR	78	4,340	2,230	2,230	4,201	2,159	2,159

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Process Heaters - Distillate Oil	6S	LNB + SNCR	78	7,999	4,110	4,110	7,743	3,978	3,978
Process Heaters - Distillate Oil	7A	LNB + SCR	92	10,900	6,340	6,340	10,551	6,137	6,137
Process Heaters - Distillate Oil	7S	LNB + SCR	92	22,421	13,041	13,041	21,704	12,624	12,624
Process Heaters - Natural Gas									
Process Heaters - Natural Gas	1	LNB	50	2,390 - 2,700	2,290 - 3,280	2,180	2,464	2,696	2,110
Process Heaters - Natural Gas	2	LNB + FGR	55	3,960 - 4,080	3,220 - 4,290	2,960	3,891	3,635	2,865
Process Heaters - Natural Gas	3A	SNCR	60	3,480 - 4,400	2,630 - 3,040	2,300	3,814	2,744	2,226
Process Heaters - Natural Gas	3S	SNCR	60	NA	NA	NA	6,934	4,989	4,048
Process Heaters - Natural Gas	4	ULNB	75	1,680 - 1,840	1,550 - 1,840	1,460	1,704	1,641	1,413
Process Heaters - Natural Gas	5A	SCR	75	14,800 - 18,700	11,200 - 12,900	9,730	16,214	11,664	9,419
Process Heaters - Natural Gas	5S	SCR	75	NA	NA	NA	30,839	22,186	17,914
Process Heaters - Natural Gas	6A	LNB + SNCR	80	4,300 - 4,790	3,410 - 4,330	3,080	4,400	3,746	2,981
Process Heaters - Natural Gas	6S	LNB + SNCR	80	NA	NA	NA	8,381	7,136	5,680
Process Heaters - Natural Gas	7A	LNB + SCR	88	14,200 - 17,400	10,900 - 12,900	9,580	15,294	11,519	9,273
Process Heaters - Natural Gas	7S	LNB + SCR	88	NA	NA	NA	30,359	22,866	18,408
Process Heaters - Other Fuel									
Process Heaters - Other Fuel	1A	LNB + FGR	34	NA	NA	NA	1,650	1,650	1,650
Process Heaters - Other Fuel	1S	LNB + FGR	34	NA	NA	NA	3,936	3,936	3,936
Process Heaters - Other Fuel	2A	LNB	37	NA	NA	NA	858	858	858
Process Heaters - Other Fuel	2S	LNB	37	NA	NA	NA	2,047	2,047	2,047
Process Heaters - Other Fuel	3A	SNCR	60	NA	NA	NA	1,280	1,280	1,280
Process Heaters - Other Fuel	3S	SNCR	60	NA	NA	NA	3,054	3,054	3,054
Process Heaters - Other Fuel	4A	ULNB	73	NA	NA	NA	442	442	442
Process Heaters - Other Fuel	4S	ULNB	73	NA	NA	NA	1,054	1,054	1,054
Process Heaters - Other Fuel	5A	LNB + SNCR	75	NA	NA	NA	1,450	1,450	1,450
Process Heaters - Other Fuel	5S	LNB + SNCR	75	NA	NA	NA	3,459	3,459	3,459
Process Heaters - Other Fuel	6A	SCR	75	NA	NA	NA	4,330	4,330	4,330
Process Heaters - Other Fuel	6S	SCR	75	NA	NA	NA	10,330	10,330	10,330
Process Heaters - Other Fuel	7A	LNB + SCR	91	NA	NA	NA	3,820	3,820	3,820
Process Heaters - Other Fuel	7S	LNB + SCR	91	NA	NA	NA	9,113	9,113	9,113

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Process Heaters - Process Gas									
Process Heaters - Process Gas	1A	LNB	50	NA	NA	NA	788	788	788
Process Heaters - Process Gas	1S	LNB	50	NA	NA	NA	1,880	1,880	1,880
Process Heaters - Process Gas	2A	LNB + FGR	55	NA	NA	NA	1,136	1,136	1,136
Process Heaters - Process Gas	2S	LNB + FGR	55	NA	NA	NA	2,710	2,710	2,710
Process Heaters - Process Gas	3A	SNCR	60	NA	NA	NA	981	981	981
Process Heaters - Process Gas	3S	SNCR	60	NA	NA	NA	2,340	2,340	2,340
Process Heaters - Process Gas	4A	ULNB	75	NA	NA	NA	532	532	532
Process Heaters - Process Gas	4S	ULNB	75	NA	NA	NA	1,269	1,269	1,269
Process Heaters - Process Gas	5A	SCR	75	NA	NA	NA	4,023	4,023	4,023
Process Heaters - Process Gas	5S	SCR	75	NA	NA	NA	9,597	9,597	9,597
Process Heaters - Process Gas	6A	LNB + SNCR	80	NA	NA	NA	1,229	1,229	1,229
Process Heaters - Process Gas	6S	LNB + SNCR	80	NA	NA	NA	2,932	2,932	2,932
Process Heaters - Process Gas	7A	LNB + SCR	88	NA	NA	NA	3,905	3,905	3,905
Process Heaters - Process Gas	7S	LNB + SCR	88	NA	NA	NA	9,316	9,316	9,316
Process Heaters - Residual Oil									
Process Heaters - Residual Oil	1	LNB + FGR	34	4,220	1,650	1,650	4,085	1,597	1,597
Process Heaters - Residual Oil	2	LNB	37	3,060	858	858	2,962	831	831
Process Heaters - Residual Oil	3A	SNCR	60	2,280	1,280	1,280	2,207	1,239	1,239
Process Heaters - Residual Oil	3S	SNCR	60	3,801	2,134	2,134	3,679	2,065	2,065
Process Heaters - Residual Oil	4	ULNB	73	1,560	442	442	1,510	428	428
Process Heaters - Residual Oil	5A	LNB + SNCR	75	2,740	1,450	1,450	2,652	1,404	1,404
Process Heaters - Residual Oil	5S	LNB + SNCR	75	4,888	2,587	2,587	4,732	2,504	2,504
Process Heaters - Residual Oil	6A	SCR	75	6,400	4,330	4,330	6,195	4,191	4,191
Process Heaters - Residual Oil	6S	SCR	75	13,107	8,868	8,868	12,688	8,584	8,584
Process Heaters - Residual Oil	7A	LNB + SCR	91	6,480	3,820	3,820	6,273	3,698	3,698
Process Heaters - Residual Oil	7S	LNB + SCR	91	13,297	7,839	7,839	12,871	7,588	7,588

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Space Heaters - Distillate Oil									
Space Heaters - Distillate Oil	1A	LNB	50	NA	NA	NA	1,770	1,770	1,770
Space Heaters - Distillate Oil	1S	LNB	50	NA	NA	NA	4,223	4,223	4,223
Space Heaters - Distillate Oil	2A	LNB + FGR	60	NA	NA	NA	3,085	3,085	3,085
Space Heaters - Distillate Oil	2S	LNB + FGR	60	NA	NA	NA	7,360	7,360	7,360
Space Heaters - Distillate Oil	3A	SCR - New	80	NA	NA	NA	3,230	1,740	1,740
Space Heaters - Distillate Oil	3S	SCR - New	80	NA	NA	NA	7,550	4,000	4,000
Space Heaters - Distillate Oil	4A	SNCR - New	50	NA	NA	NA	5,360	2,130	2,130
Space Heaters - Distillate Oil	4S	SNCR - New	50	NA	NA	NA	11,730	4,020	4,020
Space Heaters - Natural Gas									
Space Heaters - Natural Gas	1A	LNB	50	NA	NA	NA	2,165	2,165	2,165
Space Heaters - Natural Gas	1S	LNB	50	NA	NA	NA	5,165	5,165	5,165
Space Heaters - Natural Gas	2A	LNB + FGR	60	NA	NA	NA	3,635	3,635	3,635
Space Heaters - Natural Gas	2S	LNB + FGR	60	NA	NA	NA	8,672	8,672	8,672
Space Heaters - Natural Gas	3A	OT + WI	65	NA	NA	NA	735	735	735
Space Heaters - Natural Gas	3S	OT + WI	65	NA	NA	NA	1,753	1,753	1,753
Space Heaters - Natural Gas	4A	SCR - New	80	NA	NA	NA	2,580	1,400	1,400
Space Heaters - Natural Gas	4S	SCR - New	80	NA	NA	NA	6,040	3,200	3,200
Space Heaters - Natural Gas	5A	SNCR - New	50	NA	NA	NA	4,470	1,780	1,780
Space Heaters - Natural Gas	5S	SNCR - New	50	NA	NA	NA	9,770	3,350	3,350
Sulfate Pulping - Recovery Furnaces									
Sulfate Pulping - Recovery Furnaces	1A	LNB	50	NA	NA	NA	2,242	804	804
Sulfate Pulping - Recovery Furnaces	1S	LNB	50	NA	NA	NA	5,349	1,918	1,918
Sulfate Pulping - Recovery Furnaces	2A	LNB + FGR	60	NA	NA	NA	4,365	1,609	1,609
Sulfate Pulping - Recovery Furnaces	2S	LNB + FGR	60	NA	NA	NA	10,413	3,838	3,838
Sulfate Pulping - Recovery Furnaces	3A	OT + WI	65	NA	NA	NA	823	471	471

Source Type	Strategy Code+	Control Technology***	Percent Reduction (%)	Cost Per Ton of NO_x Reduced (Range for Size Category)			Average Cost Per Ton of NO_x Reduced in 1990$/ton**		
				Small*	Medium*	Large*	Small*	Medium*	Large*
Sulfate Pulping - Recovery Furnaces	3S	OT + WI	65	NA	NA	NA	1,206	704	704
Sulfate Pulping - Recovery Furnaces	4A	SCR - New	80	NA	NA	NA	2,580	1,400	1,400
Sulfate Pulping - Recovery Furnaces	4S	SCR - New	80	NA	NA	NA	6,040	3,200	3,200
Sulfate Pulping - Recovery Furnaces	5A	SNCR - New	50	NA	NA	NA	4,470	1,780	1,780
Sulfate Pulping - Recovery Furnaces	5S	SNCR - New	50	NA	NA	NA	9,770	3,350	3,350

+ Where EPA calculated both seasonal and annual cost per ton a "S" or "A" appears in this column. Where there is no "A" or "S", the cost per ton is an annual cost.
** Small, medium, and large source sizes are defined in Table 3-5.*
*** Average cost per ton of NO_X reduced calculated from EPA ACT documented ranges and converted to 1990 dollars. The range estimates provided in the table are from the year dollars (e.g. 1993$) used in the original report.*
**** Appendix C contains technology abbreviations.*
NA=Not Applicable, cost data was derived from a source that did not include ranges.

Table 3-5
Emission Size Ranges for Other Stationary Sources

Source Type	Small Unit	Medium Unit	Large Unit
ICI Boilers	< 100 mmBtu/hr	$\geq$ 100 mmBtu/hr & < 250 mmBtu/hr	$\geq$ 250 mmBtu/hr
Reciprocating IC Engines	< 4,000 horsepower (hp)	$\geq$ 4,000 hp & < 8,000 hp	$\geq$ 8,000 hp
Gas Turbines	< 10,000 hp	$\geq$ 10,000 hp & < 20,000 hp	$\geq$ 20,000 hp
Any Other Source	< 1 tpd	$\geq$ 1 tpd & < 2 tpd	$\geq$ 2 tpd

An example of how the Table 3-4 average NO_x cost-effectiveness values are calculated for a source category/control technology is provided below for low NO_x burners (LNBs) installed at a coal/wall-fired industrial, commercial, or institutional boiler.

1. For a medium-sized boiler, the cost-effectiveness range for LNB is $1,340 to $1,760 per ton. The average, or midpoint, of this cost-effectiveness range is $1,550.

2. The cost-effectiveness range is expressed in 1992 dollars. The cost index to convert from 1992 to 1990 dollars is 0.952, based on the Bureau of Labor Statistics Producer Price Index for finished goods/capital equipment.[4]

3. The average cost per ton for LNB at medium-sized coal/wall-fired ICI boilers is $1,550 * 0.952 = $1,476 per ton.

When the cost analysis is performed, the large, medium, and small cost-effectiveness values are selected, and applied, using the NO_x emission ranges shown in Table 3-4. Unit sizes (capacities) are not consistently reported in the OTAG emission data base, so the size distinctions could not be reliably applied in any other way.

Where NO_x controls can be operated in the ozone season, as well as year-round, at a firm's discretion, Table 3-4 indicates this in the strategy code column. An “A” indicates annual or year-round operation, and an “S” indicates a seasonal control strategy operation. Cost per ton ranges are not reported in Table 3-4 for seasonal strategies. The annual average cost per ton for the corresponding year-round strategy is used to calculate the seasonal average cost per ton. For seasonal controls, the annual cost estimate is derived by multiplying the average annual cost per ton by the potential 12 month NO_x emission reduction. The average annual cost effectiveness is calculated as the annual cost divided by the 5 month ozone season NO_x reductions.

Least Cost Scenario

While the budgets are determined by estimating specific control levels for specific technologies within each State, EPA’s proposal gives States the flexibility to decide how to control sources to meet the budget. In the Least Cost scenario the cost of meeting the Other Stationary Source budget component is minimized across all sources, including small emissions sources, in the Other Stationary Source category. This Least Cost approach can be interpreted as simulating several different regulatory approaches. It can represent a source-specific Command-and-Control approach with cost minimization as the sole goal (with no consideration of other factors

[4] "Producer Price Indexes, by stage of processing: 1960 to 1992. Finished goods, capital equipment," U.S. Bureau of the Census, Statistical Abstract of the United States: 1993 (113th edition) Washington, DC, 1993.

such as ease of administration). It can also represent the results of an intra-State trading program that works perfectly and imposes no administrative cost.

In the Least Cost scenario, State-specific incremental control cost curves are developed. These curves are developed from the universe of unit-specific control options in each State, and do not contain unit-specific options that are inferior (i.e., options that are incrementally less cost-effective). The control strategies available within each State are sorted by incremental cost-effectiveness, and technologies are chosen until the State-level emission budget is met. Sorting units by incremental cost-effectiveness allows the control technology selection process to progress in an economically efficient manner. In constructing the incremental cost-effectiveness curves, year-round technologies and seasonal technologies are put on an equal footing by considering only those reductions that occur during the 5 month ozone season.

Command-and-Control Scenario

In the Command-and-Control scenario the cost of meeting the Other Stationary Source budget components is developed by matching actual control technologies to the emission limitations placed on the individual units that make up the proposed emissions budget. The emissions budget is developed for the proposed Ozone Transport Rule by applying 70 percent control on large ($\geq$250 mmBtu/hr) sources (measured from uncontrolled 2007 emissions), and RACT-level controls on all other sources $\geq$1.0 tpd of NO_x emissions (medium-sized sources). For an example of how technologies are matched to the emission limitation for the cost of the Command-and-Control scenario, refer back to Table 3-4. A large Coal/Wall-type ICI Boiler can achieve at least 70% control by applying SCR (80% reduction). Referring also to Table 3-5, a medium Coal/Wall-type ICI Boiler can achieve RACT-level control (40-55% reduction) by applying low-NOx burner (LNB) technology. This approach to estimating the cost of the proposed rule will result in a higher cost estimate than the Least Cost scenario.

Limitations

The most important limitation in this study is the lack of data on the sizes (capacities) of the point source NO_X emitters in the control region. This limits the study in three ways. First, it makes it difficult to estimate which units are subject to which control requirements. EPA may have over- or underestimated the number of large sources that are subject to the proposed 70 percent reduction requirement, and the number of medium-sized sources that are subject to the proposed RACT-level controls. Since EPA envisions that the large and medium sized non-utility boiler and gas turbine sources can be part of an emissions trading program with utility sources, EPA's utility-focused analysis may have slightly over- or underestimated the marginal cost of the trading program. Second, lack of size data limits the ability to evaluate how the cost-effectiveness of controls might vary according to the size and utilization of affected units. In this analysis, EPA assumes a direct correlation between uncontrolled emissions and source size. Low utilization sources may have low emissions, but in many cases, control costs are more directly related to source size (capacity) than other factors. Finally, there is uncertainty created by using data for a limited number of model facilities to estimate cost per ton across a wide spectrum of sources. There is no assurance that the cost per ton of applying a control technique at a 250 mmBtu/hr boiler that has a 65 percent capacity utilization is representative of the costs of a 100 mmBtu/hr boiler that runs at an average utilization of 20 percent.

Readers are strongly cautioned against using the <u>State-level</u> results to make judgments about prospective policy options because the unit cost information used in this study may not capture the differences in source mix and utilization that will occur in practice when firms make technology choices. Because the OTAG emissions data base lacks complete information about design capacities, the methods used to identify fuel combustors above and below 250 mmBtu/hr are very uncertain.

Results of Meeting the Budget for Other Stationary Sources

EPA expects that by 2003, States will require a level of control on Other stationary Sources necessary to meet the emissions budget in 2007. Therefore, there is practically no difference in the annual control cost for Other Stationary Sources for 2003 or 2007. Table 3-6 summarizes the results of the analysis evaluating the potential costs of the proposed option for the State NO_x budget component shown in Table 3-3 for Other Stationary Sources. The table contains the NO_x emission changes and annual incremental control cost totals in 2007 for both the Least Cost and the Command-and-Control scenarios.

There are over 13,000 sources controlled in the Least Cost scenario, and they are controlled for an average of $1,500 per ozone season ton. There are nearly 1,800 sources controlled in the Command-and-Control scenario, and they are controlled for an average of $3,700 per ozone season ton. The total annual cost of the Least Cost scenario is $456 million. The total annual cost of the Command-and-Control scenario is more than two and one-half times higher than the Least Cost scenario at $1,170 million. The cost and emission reduction estimates for the Least Cost scenario in this report differ from the comparable Least Cost scenario from the September 1997 report. This is due to the changes in the NO_x budget calculation for Other Stationary Sources. The budget in the supplemental proposal is lower than the original proposal in most States, making the new annual cost estimates higher than the original estimates. However, the new average cost per ton estimates are somewhat lower due to updates in the unit cost of control.

Tables 3-7 through 3-10 provide a more detailed reporting of the NO_x cost analysis results that are summarized in Table 3-6. For each scenario there are two tables. One table reports State-level results. The companion table reports numbers of controlled sources, emission reductions, and costs for each source category/control technology combination.

For example, Table 3-7 reports the State-level results for the Least Cost scenario based on the proposed NO_X budgets. This table shows the baseline and NO_x emission budgets for each State. The percentage difference between baseline and budget emission values can vary considerably by State. The resulting NO_x emission column shows the expected NO_x emissions by State after controls are applied, while the tpd reduction value is simply the difference between the baseline and resulting NO_x values. Table 3-7 also reports annual costs, and both ozone season and annual cost per ton values by State.

Table 3-8 shows the 22 States and DC control region results by source category and control technology for the Least Cost scenario. For each source category/control technology combination selected by the model, Table 3-8 reports the number of sources selected for control, NO_x reductions, and costs (total annual and cost-effectiveness). Table 3-8 shows that nearly two thirds of the 1,936 tpd NO_x emission reduction needed to meet the proposed budget is achieved by five control technologies: either (1) SNCR, or (2) SCR on coal/wall-fired boilers; either (3) low emission combustion retrofits, or (4) non-selective catalytic reduction for natural gas-fired internal combustion engines; and (5) oxygen trim plus water injection for natural gas-fired ICI boilers.

Low emission combustion control can be applied to both rich and lean burn IC engines. Rich burn engines operate at near stoichiometric air/fuel ratios. NO_x emissions can be greatly reduced by increasing the air/fuel ratio, so that the engine operates at a very lean air/fuel ratio. Extensive retrofit of the engine and ancillary systems is required to operate at the higher air/fuel ratios. Applicability of combustion modifications is limited only by the availability of a conversion kit from the manufacturer and application considerations. Applications that have substantial load swings, such as power generation applications that are not tied to the utility grid, or cyclically loaded engines, may not be able to use a low emission design. The EPA ACT document uses 2.0 grams per hp-hour as the controlled NO_x emission rate for low emission combustion applications. This is an emission reduction of 87-88 percent from uncontrolled levels according to the ACT.[5] In this study, it is estimated that these emission reductions can be achieved at a cost of $423 per ton (1990 dollars).

Cost-effectiveness estimates for package watertube boiler units fired by natural gas were lowest for LNB and WI plus OT. WI plus OT is considered cost competitive with LNB because of its low initial capital investment. In spite of the thermal efficiency loss of 0.5 to 1.0 percent associated with WI, this technique can be cost effective, especially for small boilers with a low capacity factor. Cost-effectiveness of WI plus OT ranges from $380 to $1,160 per ton of NO_x removed.[6] The $1,160 cost per ton value is for a 10 mmBtu/hr unit. The lowest cost per ton value is that estimated for a 250 mmBtu/hr boiler. The cost per ton value applied is this analysis is $471 per ton, which is the midpoint of the cost per ton range reported in the ACT document (converted to 1990 dollars) for medium and large-sized boilers.

[5]EPA, 1993: U.S. Environmental Protection Agency, *Alternative Control Techniques Document -- NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*, (EPA-453/R-93-032), Emission Standards Division, OAQPS, Research Triangle Park, NC (July 1993).

[6]EPA, 1994: U.S. Environmental Protection Agency, *Alternative Control Techniques Document -- NO_x Emissions from Industrial/Commercial Institutional (ICI) Boilers*, (EPA-453/R-94-022), Emission Standards Division, OAQPS, Research Triangle Park, NC (March 1994).

Table 3-6
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission and Cost Summary for 2007

Control Scenario	NO_x Emissions During the Ozone Season (1,000 tons)	Ozone Season Reduction (1,000 tons)	Number of Sources Controlled	Annual Cost (1990$)	Average Cost Per Ton of NO_x Reduced During the Ozone Season
Least Cost	409	303	13,373	$456	$1,506
Command-and-Control	394	317	1,774	$1,170	$3,687
OTAG Recommendation - Least Cost (from 9/97 report)	466	232	9,075	$385	$1,650

Table 3-7
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission and Cost Summary in 2007
Least Cost Scenario - State-Level Results

State	2007 NO_x Emissions					Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
	Baseline (tpd)	Budget (tpd)	Resulting NO_x (tpd)	Reduction (tpd)	Ozone Season Reduction (tons)		
Alabama	312	157	156	156	23,850	26,593,199	1,115
Connecticut	30	19	19	11	1,739	8,079,020	4,646
Delaware	23	15	15	8	1,254	2,434,723	1,941
DC	2	2	2	0	16	29,035	1,821
Georgia	220	158	158	62	9,527	6,618,420	695
Illinois	421	245	244	177	27,050	25,746,769	952
Indiana	336	182	181	155	23,732	41,409,598	1,745
Kentucky	124	78	77	46	7,111	10,093,519	1,419
Maryland	44	30	30	14	2,179	4,374,984	2,007
Massachusetts	70	44	43	27	4,133	15,479,560	3,745
Michigan	380	197	194	186	28,446	36,268,317	1,275
Missouri	82	53	53	28	4,358	3,751,704	861
New Jersey	221	121	121	100	15,250	14,384,081	943
New York	139	111	111	28	4,333	8,257,102	1,906
North Carolina	224	126	125	99	15,164	28,076,048	1,852
Ohio	337	207	207	130	19,893	20,049,928	1,008
Pennsylvania	445	361	361	84	12,857	9,639,916	750
Rhode Island	2	2	2	0	0	0	0
South Carolina	229	122	122	107	16,438	33,623,802	2,046
Tennessee	426	201	184	243	37,129	59,666,819	1,607
Virginia	163	72	72	91	13,853	35,141,913	2,537
West Virginia	279	136	121	157	24,097	47,823,635	1,985
Wisconsin	139	74	72	66	10,141	18,216,493	1,796
22 States and DC	**4,648**	**2,712**	**2,670**	**1,977**	**302,549**	**455,758,585**	**1,506**

Table 3-8
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission and Cost Summary in 2007
Least Cost Scenario - Source Category Results

Source Type	Control Technology	Number of Controlled Sources	2007 NO_x Reduction Daily (tpd)	2007 NO_x Reduction Ozone Season (tons)	Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
Adipic Acid Manufacturing	Extended Absorption	4	0	7	1,638	226
Ammonia - NG-Fired Reformers	OT + WI	2	2	296	514,866	1,742
Cement Manufacturing - Dry	Mid-Kiln Firing	9	7	1,113	1,425,364	1,280
Cement Manufacturing - Dry	SNCR - Urea Based	27	45	6,930	13,968,608	2,016
Cement Manufacturing - Wet	Mid-Kiln Firing	21	14	2,113	2,455,528	1,162
Comm./Inst. Incinerators	SNCR	25	10	1,458	9,228,943	6,331
Gas Turbines - Jet Fuel	Water Injection	5	1	80	229,622	2,876
Gas Turbines - Natural Gas	LNB	100	50	7,667	5,915,736	772
Gas Turbines - Oil	Water Injection	65	2	369	489,585	1,325
Gas Turbines - Oil	SCR + Water Injection	1	0	26	93,016	3,645
Glass Manufacturing - Containers	Cullet Preheat	22	4	550	1,265,925	2,300
Glass Manufacturing - Containers	SCR	13	4	674	3,662,374	5,430
Glass Manufacturing - Flat	SCR	20	22	3,393	5,992,851	1,766
Glass Manufacturing - Pressed	Cullet Preheat	32	3	482	948,728	1,968
ICI Boilers - Coal/Cyclone	NGR	6	15	2,234	1,838,083	823
ICI Boilers - Coal/Cyclone	SCR - New	16	30	4,628	7,738,297	1,672
ICI Boilers - Coal/FBC	SNCR - Urea	9	9	1,370	2,898,762	2,117
ICI Boilers - Coal/Stoker	SNCR - New	529	82	12,514	38,172,937	3,050
ICI Boilers - Coal/Wall	SNCR - New	190	157	24,093	42,105,748	1,748
ICI Boilers - Coal/Wall	SCR - New	101	160	24,491	70,020,510	2,859
ICI Boilers - Coke	SCR - New	2	0	45	147,265	3,300
ICI Boilers - Coke	SNCR - New	5	7	1,083	1,735,430	1,602
ICI Boilers - Distillate Oil	LNB	817	8	1,204	3,617,281	3,004
ICI Boilers - Distillate Oil	LNB + FGR	6	0	22	70,254	3,209
ICI Boilers - Distillate Oil	SCR - New	12	0	0	1,449	6,314

Source Type	Control Technology	Number of Controlled Sources	2007 NO_x Reduction		Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
			Daily (tpd)	Ozone Season (tons)		
ICI Boilers - Liquid Waste	LNB	14	0	67	148,328	2,219
ICI Boilers - Liquid Waste	SCR - New	2	0	2	8,677	5,506
ICI Boilers - LPG	LNB	24	0	20	84,126	4,223
ICI Boilers - MSW/Stoker	SNCR - Urea	5	1	114	586,932	5,135
ICI Boilers - Natural Gas	OT + WI	7,094	356	54,442	52,924,785	972
ICI Boilers - Natural Gas	SCR - New	90	1	228	833,585	3,660
ICI Boilers - Process Gas	OT + WI	113	19	2,911	5,071,906	1,742
ICI Boilers - Residual Oil	SCR - New	51	7	1,144	4,495,630	3,929
ICI Boilers - Residual Oil	LNB + FGR	25	0	29	106,307	3,702
ICI Boilers - Residual Oil	LNB	1,680	91	13,915	23,861,018	1,715
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	76	12	1,855	6,817,630	3,676
Indust. Incinerators	SNCR	19	0	36	229,371	6,336
Internal Combustion Engines - Gas	NSCR	127	313	47,861	14,365,951	300
Internal Combustion Engines - Gas	L-E (Medium Speed)	911	266	40,683	40,799,122	1,003
Internal Combustion Engines - Gas, Diesel, LPG	IR	50	0	52	64,323	1,230
Internal Combustion Engines - Gas, Diesel, LPG	SCR	9	0	55	200,282	3,651
Internal Combustion Engines - Oil	IR	124	1	123	462,637	3,772
Internal Combustion Engines - Oil	SCR	7	11	1,701	1,408,033	828
Iron & Steel Mills - Annealing	LNB + FGR	17	1	190	364,865	1,920
Iron & Steel Mills - Annealing	LNB + SNCR	1	0	0	331	4,327
Iron & Steel Mills - Annealing	LNB	11	0	55	85,876	1,567
Iron & Steel Mills - Galvanizing	LNB + FGR	10	4	606	833,710	1,376
Iron & Steel Mills - Reheating	LNB	14	7	1,097	728,411	664
Iron & Steel Mills - Reheating	LNB + FGR	56	29	4,501	4,482,154	996
Lime Kilns	Mid-Kiln Firing	25	4	637	815,025	1,280
Lime Kilns	SNCR - Urea Based	97	27	4,118	8,300,471	2,016
Municipal Waste Combustors	SNCR	23	8	1,197	7,578,433	6,331
Nitric Acid Manufacturing	SCR	1	0	0	78	1,275

Source Type	Control Technology	Number of Controlled Sources	2007 NO_x Reduction Daily (tpd)	2007 NO_x Reduction Ozone Season (tons)	Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
Nitric Acid Manufacturing	Extended Absorption	14	11	1,668	684,799	410
Nitric Acid Manufacturing	NSCR	2	1	85	121,461	1,426
Process Heaters - Distillate	ULNB	4	2	301	510,020	1,695
Process Heaters - Natural Gas	LNB + SNCR	6	0	0	612	6,667
Process Heaters - Natural Gas	ULNB	177	103	15,795	53,834,415	3,408
Process Heaters - Other Fuel	ULNB	1	0	1	1,053	1,043
Process Heaters - Process Gas	ULNB	62	7	1,067	1,346,488	1,261
Process Heaters - Residual Oil	ULNB	5	7	1,044	1,073,290	1,028
Space Heaters - Distillate Oil	LNB	10	0	10	42,609	4,220
Space Heaters - Distillate Oil	SCR - New	3	0	0	276	6,013
Space Heaters - Natural Gas	OT + WI	288	3	383	666,012	1,741
Space Heaters - Natural Gas	SCR - New	6	0	0	438	4,771
Sulfate Pulping - Recovery Furnaces	OT + WI	80	50	7,714	7,280,261	944
22 States and DC		**13,373**	**1,977**	**302,549**	**455,758,531**	**1,506**

Table 3-9
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission and Cost Summary in 2007
Command-and-Control Scenario - State-Level Results

	2007 NO_x Emissions						
State	**Baseline (tpd)**	**Budget (tpd)**	**Resulting NO_x (tpd)**	**Reductions (tpd)**	**Ozone Season Reduction (tons)**	**Annual Cost (1990$)**	**Ozone Season Cost Per Ton ($/ton)**
Alabama	312	157	154	159	24,264	100,620,060	4,147
Connecticut	30	19	23	8	1,202	7,155,744	5,953
Delaware	23	15	13	10	1,514	4,973,443	3,284
DC	2	2	2	0	60	140,667	2,360
Georgia	220	158	97	123	18,866	82,318,534	4,363
Illinois	421	245	247	174	26,691	96,123,523	3,601
Indiana	336	182	198	138	21,140	79,664,556	3,769
Kentucky	124	78	75	48	7,383	37,969,254	5,143
Maryland	44	30	30	15	2,240	11,528,560	5,147
Massachusetts	70	44	48	22	3,384	18,044,602	5,333
Michigan	380	197	190	190	29,002	103,191,462	3,558
Missouri	82	53	49	33	5,004	29,517,509	5,899
New Jersey	221	121	127	94	14,387	53,394,731	3,711
New York	139	111	106	33	5,022	21,761,489	4,333
North Carolina	224	126	136	88	13,454	45,517,242	3,383
Ohio	337	207	202	135	20,661	72,029,659	3,486
Pennsylvania	445	361	263	182	27,836	106,919,920	3,841
Rhode Island	2	2	2	0	0	0	0
South Carolina	229	122	120	109	16,742	65,415,704	3,907
Tennessee	426	201	193	233	35,630	106,526,288	2,990
Virginia	163	72	80	83	12,725	43,183,223	3,394
West Virginia	279	136	140	139	21,240	59,540,112	2,803
Wisconsin	139	74	81	58	8,873	24,487,334	2,760
22 State and DC	**4,648**	**2,712**	**2,574**	**2,074**	**317,321**	**1,170,023,616**	**3,687**

Table 3-10
Ozone Transport Rulemaking
Other Stationary Source NO_x Emission and Cost Summary
Command-and-Control Scenario - Source Category Results

Source Type	Control Technology	Number of Controlled Sources	2007 NO_x Reduction: Daily (tpd)	2007 NO_x Reduction: Ozone Season (tons)	Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
Ammonia - NG-Fired Reformers	SCR - New	3	5	701	2,256,643	3,221
Cement Manufacturing - Dry	SCR	51	134	20,473	196,115,160	9,579
Cement Manufacturing - Wet	SCR	32	64	9,774	78,100,335	7,991
Comm./Inst. Incinerators	SNCR	21	12	1,772	11,216,203	6,331
Gas Turbines - Oil	SCR + Water Injection	1	0	26	93,016	3,645
Gas Turbines - Natural Gas	Water Injection	23	31	4,765	4,604,309	966
Gas Turbines - Natural Gas	LNB	1	1	222	153,019	688
Glass Manufacturing - Container	LNB	8	5	834	3,541,164	4,244
Glass Manufacturing - Flat	LNB	16	16	2,511	4,374,197	1,742
Glass Manufacturing - Pressed	LNB	3	2	338	1,252,621	3,710
ICI Boilers - Coal/Cyclone	SCR - New	12	52	7,934	13,177,869	1,661
ICI Boilers - Coal/FBC	SNCR - Urea	5	9	1,415	3,005,351	2,124
ICI Boilers - Coal/Stoker	SNCR - New	89	57	8,773	26,241,722	2,991
ICI Boilers - Coal/Wall	SCR - New	201	451	68,995	199,639,367	2,894
ICI Boilers - Coal/Wall	LNB	5	7	1,126	3,318,766	2,948
ICI Boilers - Coke	SCR - New	17	24	3,610	10,180,003	2,820
ICI Boilers - Distillate Oil	SCR - New	41	18	2,773	17,254,795	6,221
ICI Boilers - LPG	SNCR - New	1	0	76	303,670	3,996
ICI Boilers - MSW/Stoker	SNCR - Urea	16	4	598	4,110,948	6,878
ICI Boilers - Natural Gas	LNB	5	15	2,345	4,469,631	1,906
ICI Boilers - Natural Gas	OT + WI	1	0	0	7	458
ICI Boilers - Natural Gas	SCR - New	396	301	46,053	200,075,141	4,344
ICI Boilers - Process Gas	SCR - New	51	27	4,094	17,771,331	4,341
ICI Boilers - Residual Oil	LNB	1	0	24	22,958	948

Source Type	Control Technology	Number of Controlled Sources	2007 NO_x Reduction		Annual Cost (1990$)	Ozone Season Cost Per Ton ($/ton)
			Daily (tpd)	Ozone Season (tons)		
ICI Boilers - Residual Oil	SCR - New	135	117	17,969	79,064,979	4,400
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	87	44	6,670	28,615,259	4,290
Indust. Incinerators	SNCR	1	0	24	149,297	6,332
Internal Combustion Engines - Gas	AF + IR	8	10	1,497	1,690,639	1,129
Internal Combustion Engines - Gas	L-E (Low Speed)	119	274	41,856	66,104,398	1,579
Internal Combustion Engines - Gas	L-E (Medium Speed)	166	108	16,573	16,620,648	1,003
Internal Combustion Engines - Oil	SCR	5	9	1,360	1,126,179	828
Internal Combustion Engines - Oil	IR	1	0	57	49,163	868
Iron & Steel Mills - Galvanizing	LNB + FGR	7	4	552	759,206	1,376
Iron & Steel Mills - Reheating	LNB + FGR	23	31	4,694	4,674,318	996
Lime Kilns	SCR	75	33	5,072	48,582,435	9,579
Municipal Waste Combustors	SNCR	22	16	2,487	15,747,485	6,331
Nitric Acid Manufacturing	Extended Absorption	2	4	676	277,621	410
Process Heaters - Distillated	ULNB	3	2	300	505,966	1,686
Process Heaters - Natural Gas	ULNB	35	115	17,550	60,100,307	3,425
Process Heaters - Process Gas	ULNB	2	1	214	269,421	1,261
Process Heaters - Residual Oil	ULNB	3	7	1,039	1,054,536	1,015
Sulfate Pulping - Recovery Furnaces	SCR - New	80	62	9,502	43,353,533	4,562
22 States and DC		**1,774**	**2,074**	**317,321**	**1,170,023,616**	**3,687**

Chapter 4. INTEGRATED RESULTS

This chapter presents EPA's estimates of the NO_x reductions and costs that are projected to result under EPA's Proposed Regulatory Approach described in Chapters 2 and 3. The results are then compared to average cost-effectiveness estimates of other recent regulatory actions that require NO_x reductions.

NO_x Reductions and Costs

Based on the analyses conducted by OTAG and other supplemental data, the Agency developed an approach for reducing the transport of ozone over long distances that requires reductions in NO_x emissions from major sources. Currently, the transport of ozone from one region to another makes compliance with the existing NAAQS difficult for certain nonattainment areas. Further, State efforts to reach attainment of the ozone standard through local measures can be very expensive. In essence, the Ozone Transport Rulemaking is a regulatory action designed to improve the effectiveness and efficiency of State and EPA efforts to attain and maintain the NAAQS.

OTAG recommended that EPA focus on requiring appropriate States to reduce summer NO_x emissions in three source categories: mobile sources, electricity generating sources, and Other Stationary Sources. The Agency adopted this approach in the Ozone Transport Rulemaking proposal and established summer season NO_x emissions budgets for 22 States and the District of Columbia. Notably, the Agency is already establishing the national requirements for mobile source reductions that OTAG recommended. Therefore, EPA did not estimate their impacts in this regulatory analysis. The Agency actions related to mobile sources have been and will be addressed in separate rulemaking activities that are described below.

EPA is proposing to establish a summer season NO_x emissions budgets for 22 States and the District of Columbia based on reducing emissions from the electric power industry and Other Stationary Sources.[1] This will lead to placement of NO_x controls on operating units in these two categories of sources, which the Agency has not examined in other specific rulemaking activities. Therefore, for electricity generating and other stationary sources, EPA has estimated the NO_x emissions reductions and incremental annual costs resulting from this proposed rule. For the analysis of the electric power industry, EPA used the Initial Base Case to estimate NOx emission reductions, and two base cases, the *Initial Base Case* and the *Final Base Case*[2]. to estimate the cost of NOx controls. Both cases include the existing Title IV NO_x rules, Reasonably Available Control (RACT) requirements, and New Source Performance Standards and controls for new and recently-built power plants. The Initial Base case also includes implementation of Phase I (RACT requirements) of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU). The Final Base Case assumes implementation of Phases II and III of the OTC MOU.

Table 4-1 shows the NO_x emissions levels that EPA predicts will occur for each source category in the Initial Base Case and after the States amend their SIPs to meet the source category specific NO_x emission budget subcomponents. Notably, some types of control technologies can be used on a seasonal basis and others have

[1] This category includes industrial, commercial, and institutional boilers, reciprocating engines, gas turbines, process heaters, cement kilns, furnaces at iron, steel, and glass-making operations, and nitric acid, adipic acid and other plants with industrial processes that produce NO_x.

[2] These base cases are discussed in greater detail in Chapter 2.

to be used year round. Because there are benefits from reducing NO_x throughout the year, the annual and seasonal changes in NO_x emissions are both reported.[3]

Table 4-1
No_x Emissions for the Electric Power Industry and Other Stationary Sources in the Initial Base Case and with the Ozone Transport Rulemaking*
(1,000 NOx Tons)

Year	Initial Base Case (Phase I OTC MOU)		With Ozone Transport Rulemaking	
	Summer Season	Annual	Summer Season	Annual
Electric Power Industry				
2003	1,462	3,401	564	2,274
2005	1,497	3,489	564	2,313
2007	1,502	3,512	564	2,329
2010	1,511	3,543	564	2,344
Other Stationary Sources				
2007	711	1,697	409	975
All Sources				
2007	2,213	5,209	973	3,304

** EPA considered partial (Phase I) implementation of the Ozone Transport Commission's Memorandum Understanding for the electric power industry. Controls on the electric power industry occur through a Cap-and-Trade program. Controls on Other Stationary Sources are assumed to occur by each State implementing an approach that applies least-cost controls. For this report, EPA was unable to develop estimates for Other Stationary Sources for any future year except 2007. Annual emissions for Other Stationary Sources are approximated by multiplying summer season emissions by 365/153.*

Table 4-2 shows the incremental annual costs that the Agency estimates the regulated community will incur. Costs for the electric power industry are estimated for 2003, the first year of NO_x reductions, 2005, 2007, the year for which the emissions budgets were estimated, and 2010. Costs for Other Stationary Sources are estimated for the year 2007. For this report, EPA was not able to analyze the incremental annual cost of compliance for Other Stationary Sources in any year other than 2007. As shown, in Table 4-2, annual compliance costs for the electric power industry vary by only 5 percent between 2003 and 2007, so it is reasonable to conclude that costs for Other Stationary Sources would not vary significantly between 2003 and 2007. The incremental annual costs presented in Table 4-2 reflect emissions trading across States for electric power generation units and cost minimization within States for Other Stationary Sources. The average cost-effectiveness of summer season NO_x reductions is calculated as the change in total annual costs relative to the Initial Base case divided by the change in summer season NO_x emissions relative to the Initial Base case. As shown, the average cost per summer ton of NO_x reduced for electric power industry is about $1,450. The average cost per summer ton of NO_x reduced for Other Stationary Sources is about $1,500.

[3] The summer season in this analysis is May 1 through September 30.

Table 4-2
Incremental Annual Costs and Summer Season Cost-Effectiveness of the Ozone Transport Rulemaking: Initial Base Case*

Year	Initial Base Case Summer Emissions (1,000 NO_x tons)	Proposed Regulatory Approach: Summer Emissions (1,000 NO_x tons)	Proposed Regulatory Approach: Summer NO_x Tons Reduced from Initial Base Case (1,000 NO_x tons)	Proposed Regulatory Approach: Annual Cost (Millions 1990$)	Average Summer Season Cost-Effectiveness ($/ton)
Electric Power Industry					
2003	1,462	564	899	1,308	$1,455
2005	1,497	564	933	1,354	$1,451
2007	1,502	564	938	1,378	$1,469
2010	1,511	564	948	1,341	$1,415
Other Stationary Sources					
2007	711	409	303	456	$1,506
All Sources					
2007	2,213	973	1,241	1,834	$1,478

** EPA considered partial (Phase I) implementation of the Ozone Transport Commission's Memorandum Understanding for the electric power industry. Controls on the electric power industry occur through a Cap-and-Trade program. Controls on Other Stationary Sources are assumed to occur by each State implementing an approach that applies least-cost controls. For this report, EPA was unable to develop estimates for Other Stationary Sources for any future year except 2007. Annual emissions for Other Stationary Sources are estimated by multiplying summer season emissions by 365/153. The average cost effectiveness for "All Sources" is calculated as an emission reduction weighted average of the cost-effectiveness in each sector for the year 2007.*

Table 4-3 presents information similar to Table 4-2 except all emission values are expressed in annual terms rather than ozone season terms. The average annual cost-effectiveness for the electric power industry is about $1,150 per ton of NO_x removed. The average annual cost-effectiveness for Other Stationary Sources is approximated to be about $640 per ton of NO_x removed.

Table 4-3
Incremental Annual Costs and
Annual Cost-Effectiveness
of the Ozone Transport Rulemaking: Initial Base Case*

Year	Initial Base Case Annual Emissions (1,000 NO_x tons)	Proposed Regulatory Approach			Average Annual Cost-Effectiveness ($/ton)
		Annual Emissions (1,000 NO_x tons)	Annual NO_x Tons Reduced from Initial Base Case (1,000 NO_x tons)	Annual Cost (Millions 1990$)	
Electric Power Industry					
2003	3,401	2,274	1,127	1,308	$1,160
2005	3,489	2,313	1,176	1,354	$1,151
2007	3,512	2,329	1,183	1,378	$1,165
2010	3,543	2,344	1,199	1,341	$1,118
Other Stationary Sources					
2007	1,673	961	712	456	$640
All Sources					
2007	5,185	3,290	1,895	1,834	$968

** EPA considered partial (Phase I) implementation of the Ozone Transport Commission's Memorandum Understanding for the electric power industry. Controls on the electric power industry occur through a Cap-and-Trade program. Controls on Other Stationary Sources are assumed to occur by each State implementing an approach that applies least-cost controls. For this report, EPA was unable to develop estimates for Other Stationary Sources for any future year except 2007. Annual emissions for Other Stationary Sources are estimated by multiplying summer season emissions from Table 3-7 by 360; this probably overstates annual $_{NOx}$ reductions, and understates annual cost-effectiveness. The average cost effectiveness for "All Sources" is calculated as an emission reduction weighted average of the cost-effectiveness in each sector for the year 2007.*

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 emissions reduction program is desirable. EPA believes that for such a program to be effective and administratively practicable, the program should have an emissions cap and allow trading between sources in all the States that are covered. The Agency wants to work with all States covered by this rulemaking to establish such a program. Therefore, EPA estimated the NO_x control costs using trading across States for electric power generation units and cost minimization within States for Other Stationary Sources. Analytical limitations kept EPA from estimating the costs of a single cap-and-trade program for electricity generating sources and larger industrial sources in the Other Stationary Sources category (e.g., industrial boilers and gas turbines). Given that the Agency could not estimate the costs of a single emissions trading program for these sources, the incremental 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. Further, the emissions trading analyses presented in this report do not include banking. Banking may result in overall lower costs and greater cost-effectiveness. However, it should be noted that individual States may decide to achieve their NOx budget with other control techniques, thereby affecting their costs.

Cost-Effectiveness Comparisons

Table 4-4 provides a reference list of measures that EPA and States have undertaken to reduce NO_x and their average annual costs per ton of NO_x reduced. The average annual cost per ton of NO_x reduced from the proposed Ozone Transport 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 States have needed to adopt most recently since their previous planning efforts have already taken advantage of opportunities for even cheaper controls. EPA believes 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 NO_x control measures can most reasonably be implemented by upwind States that significantly contribute to nonattainment.

Table 4-4
Average Cost-Effectiveness of NO_x Control
Measures Recently Undertaken or Proposed
(1990$)

Control Measure	Average Cost Per Ton of NO_x Removed
NO_x RACT	$ 150 - 1,300
Phase II Reformulated Gasoline	4,100*
State Implementation of the Ozone Transport Commission Memorandum of Understanding (OTC MOU)	950 - 1,600
Proposed New Source Performance Standards (NSPS) for Fossil Steam Electric Generation Units	1,290
Proposed NSPS for Industrial Boilers	1,790
Proposed Ozone Transport Rulemaking– Electric Power Industry	1,450
Proposed Ozone Transport Rulemaking– Other Stationary Sources**	1,500

** 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 NO_x standard. This cost represents the projected additional cost of complying with the Phase II RFG NO_x standards, beyond the cost of complying with the other standards for Phase II RFG.*
***Estimated average cost-effectiveness associated with the Least Cost scenario.*

There are also a number of less expensive measures recently undertaken by the Agency to reduce NO_x emission levels that do not appear in Table 4-4. These actions include: (1) the Title IV NO_x 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 the Ozone Transport Rulemaking because they are believed to be among the lowest cost options for NO_x control. Since these options have been exhausted, the Agency must now focus on what other measures exist, at a potentially higher average cost-effectiveness value, that can further reduce NO_x emissions. Table 4-4 is thereby useful as a reference for the next higher level of NO_x reduction cost-effectiveness that the Agency considers reasonable to undertake.

The Agency recognizes that any special effort to address ozone transport, such as this proposed rule, must be part of an integrated regulatory solution developed by EPA and States to provide national compliance with the existing 1-hour NAAQS and the new 8-hour NAAQS. In the future, it is likely that some localities will need to employ more expensive NOx and VOC reductions to come into attainment with the new 8-hour NAAQS. OTAG's air quality modeling showed that even with the most stringent control measures that were evaluated for NO_x and VOCs, not all areas would come into attainment with the current ozone NAAQS. It is also evident that without actions to address ozone transport, some areas will have "background levels" that will not allow even aggressive local controls to bring them into compliance, and others will face severe measures in an effort to do so. Therefore, EPA designed this proposed rule to complement local programs to address attainment with the ozone NAAQS. EPA recognizes the need to provide pollutant reductions where it would be more cost-effective to do so, rather than place all of the burden on localities. The recent Regulatory Impact Analysis in support of the new ozone standard shows that the last tons of NO_x and VOC reduction needed for meeting that standard in some areas can cost from $5,000 to $10,000 a ton to achieve.[4] Avoiding such expenditures in some areas affected by ozone transport is a major objective of the Ozone Transport Rulemaking.

[4] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule*, July 1997.

Appendices

Appendix A. Categories of NO_x Sources

There are four major categories of NO_x sources that the Ozone Transport Assessment Group evaluated. They are mobile sources, electric power industry, other stationary sources, and area sources. The types of operations and activities covered by each category are explained below.

Electric Power Industry - This category includes the electric generation units that use fossil fuels that are owned by electric utilities or independent power producers that sell power under contract to the electric power grid and are accounted for in the electric generation forecasts of the North American Electric Reliability Council (NERC). These generation units include coal-fired steam, oil-and gas-fired steam, combustion turbine, and combined-cycle natural gas units.

Other Stationary Sources - This category includes point sources outside of the electric power industry and not considered "area sources" as defined below. Point sources in this category include industrial, commercial and institutional boilers, reciprocating internal combustion engines, turbines, process heaters, cement kilns, and other industrial processes that produce NO_x.

Area Sources - Small point sources that include open burning and small commercial, industrial and residential fuel combustion devices.

Mobile Sources - This category divides into highway vehicle sources 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 construction equipment and locomotives.

Appendix B. Selective Bibliography of OTAG Documents Related to NO_x Control

The documents are organized by the Work Group of the Ozone Transport and Assessment Group that prepared them. Where there were multiple drafts of reports, the last version of the report available in early September 1997 was included in the bibliography. Most of these reports and many of the earlier draft materials can be retrieved from the Office of Air Quality and Standards (OAQPS) and Office of Atmospheric Programs (OAP) web sites[1] in sections covering OTAG.

Cost and Technology Options Work Group Documents

NO_x and VOC Control Packets - OTAG's Implementation Strategies and Issues Group, August 1996.

Mobile Sources Assessment: NO_x and VOC Reduction Technologies for Application by the Ozone Transport Assessment Group, July 1997.

Draft Assessment of Control Technologies for Reducing Nitrogen Oxide Emissions from Non-Utility Point Sources and Major Area Sources, January 1996.

Draft of Costs NO_x Control Strategies on Electric Power Generation Using the Integrated Planning Model, for incorporation into the OTAG Final Report, June 1997.

Memorandum from Bob Lopez, WI to OTAG Strategies and Controls Subcommittee entitled *Draft Summary Report and Tables Using a System Matrix Approach to Cost the OTAG Utility Control Scenarios*, June 1997.

Final States' Report on Electricity Utility Nitrogen Oxides Reduction Technology Options for Options for Application by the Ozone Transport Assessment Group, April 1996 prepared by Ken Colburn, New Hampshire.

Electric Utility Nitrogen Oxides Reduction Technology Options for the Application by the Ozone Transport Assessment Group, January 1996, prepared by the Utilities Air Regulatory Group.

Utility NO_x Control Cost Optimization and Rate Impact Estimation Matrix, versions of provided cost per ton range estimates based on research by the Cost and Technologies Options WorkGroup evaluations in 1996 and 1997, prepared by Robert Lopez, WI.

OTAG Cost Parameters Applied to Non - Utility Strategies to Reduce Ozone Transport, May 29, 1997, prepared by E.H. Pechan Associates.

Trading/Incentives Work Group Documents

Preliminary Analysis of Progressive Flow Control, September 1996.

Chapter 7 Trading and Incentives WorkGroup - Draft of OTAG Final Report, circa June 1997.

[1] The OAQPS web site is http://www.epa.gov/ttn and the OAP web site address is http://www.epa.gov.capi

Appendix C. Acronyms and Abbreviations

ACT	Alternative Control Technology
AF	air-fuel ratio
FGR	flue gas recirculation
hp	horsepower
IR	ignition retard
LE	low emission
LNB	low NO_x burners
NGR	natural gas recirculation
NSCR	non-selective catalytic reduction
OT	oxygen trim
OTAG	Ozone Transport Assessment Group
SCC	Source Classification Code
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
ULNB	ultra low NO_x burners
WI	water injection

Appendix D. Data for Figure 2-6

Table D-1
Electricity Generation Sector Summer NO_x Emissions in 2007
for States in the OTR: Intital Base Case and Policy Case

State Name	Initial Baseline NO_x Emissions (MTon)	State Component of NO_x Budget (MTon)	0.15 Trading (MTon)
Alabama	76.9	30.6	37.4
Connecticut	5.6	5.2	3.3
Delaware	5.8	5.0	3.6
District of Columbia	0.0	0.2	0.0
Georgia	86.5	32.4	37.5
Illinois	119.3	36.6	37.9
Indiana	136.8	51.8	47.4
Kentucky	107.8	38.8	38.4
Maryland	32.6	13.0	13.9
Massachusetts	16.5	14.7	10.3
Michigan	86.6	29.5	35.0
Missouri	82.1	26.5	24.0
New Jersey	18.4	8.2	8.8
New York	39.2	31.2	24.1
North Carolina	84.8	32.7	34.6
Ohio	163.1	51.5	46.8
Pennsylvania	123.1	46.0	46.2
Rhode Island	1.1	1.6	1.1
South Carolina	36.3	19.8	18.0
Tennessee	70.9	26.2	23.7
Virginia	40.9	21.0	19.3
West Virginia	115.5	17.3	33.5
Wisconsin	52.0	24.0	19.0
Total	**1501.8**	**563.8**	**563.8**

Note: Data include CC, CT, O/G, Coal, and AGM and BDW in Fine Grid.

Appendix E. Effect of Change in Electricity Generation Requirements Forecast

As a result of the revisions described in chapter 2, the emission and cost values presented in this report differ from the previous results contained in the NPR Analysis.[2] For example, in the NPR analysis, the cost effectiveness of achieving the 0.15 lb/mmBtu control level was about $1,700/ton while the current analysis estimates about $1,450/ton. The forecast for electricity generation for 2005 is now one percent higher than the previous forecast, while the forecast for 2010 is now two percent lower. The share of generation by fuel type is largely unchanged, although by 2010 coal accounts for a three percent higher share of generation, offset primarily by a decrease in oil and gas generation.

Table E-1 below presents a comparison of emissions, cost, and cost-effectiveness obtained using new and old electric generation forecasts for the years 2003, 2005, 2007, and 2010. As shown in the table, the average summer season cost-effectiveness values under the new generation forecasts do not differ substantially from values obtained using the old forecasts. The old generation forecasts result in slightly lower cost-effectiveness values for 2003 and 2005 and slightly higher cost-effectiveness values for 2007 and 2010.

Table E-1
Effect of Change in Generation Requirements Forecast,
Initial Base Case, Summer Season
(Emissions in 1,000 NO_x Tons, Costs in Millions 1990$)

Year	Initial Base Case Emissions (1,000 NO_x tons)	Proposed Regulatory Approach (0.15 cap-and-trade)		Summer Season Cost-Effectiveness ($/ton)
		Emissions	Cost	
New Generation Req. - 2003	1,462	564	1,308	1,455
Old Generation Req. - 2003	1,417	564	1,213	1,421
New Generation Req. - 2005	1,497	564	1,354	1,451
Old Generation Req. - 2005	1,469	564	1,279	1,413
New Generation Req. - 2007	1,502	564	1,378	1,468
Old Generation Req. - 2007	1,486	564	1,398	1,516
New Generation Req. - 2010	1,511	564	1,341	1,415
Old Generation Req. - 2010	1,502	564	1,331	1,419

[2] *Proposed Ozone Transport Rulemaking Regulatory Analysis*, U.S. EPA Office of Air and Radiation, September 1997.