# TIME AND PLACE SPECIFIC POLICIES FOR CONTROLLING OZONE PRECURSOR NITROGEN OXIDES IN NEW ENGLAND'S ELECTRIC POWER SECTOR


by

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B.S. Systems Engineering, University of Virginia, 1991


Submitted to the Department of Civil and Environmental Engineering in Partial Fulfillment of the Requirements for the Degree of

MASTER OF SCIENCE
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# *ABSTRACT*

An analysis was done on the performance of time and place specific strategies for controlling ozone-precursor nitrogen oxides emissions in New England's electric power sector. Nitrogen oxides control technologies, minimum NOx dispatch, conservation, repowering, and new supply technologies were simulated over a twenty year period using an industry-standard production costing model.

The results showed that technology and operational NOx controls yielded less NOx emissions at lower cost than conservation, repowering, and new supply technologies. Minimum NOx dispatch was more cost-effective than technology controls for control periods up to seven months per year. However, this time period was sensitive to natural gas fuel costs, as high gas costs decreased the period length of equal cost-effectiveness to four and one half months. Further, operational controls could only achieve up to 17% reductions in NOx, while technology controls could achieve up to a 40% reduction from baseline levels.

In the case where about half of existing non-fossil capacity already had technology controls, minimum NOx dispatch was more cost-effective than additional technology controls regardless of the control period length.

Controlling emissions only in the upwind three states can achieve identical upwind emissions reductions at up to one third less cost than regional controls. The cost savings decrease dramatically as technology controls are added to existing units. These results could be very sensitive to transmissions and distribution constraints, not modeled in this study.

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# PREFACE

## PROTECTING LIFE AND ITS HOME THROUGH ENVIRONMENTAL QUALITY

Human perturbation of the earth's environment and ecosystem is widely believed to have reached an all time high. Since these changes result generally from population growth and increases in per capita human consumption, both current worldwide trends, human impacts will probably grow even larger.

The central problem is that many of these impacts have negative consequences on the health and welfare of living beings, especially humans, such as shorter lifetimes, more frequent illnesses, and even extinctions. In the past, nature has applied corrective mechanisms for preserving the earth's balance, and the life on it. Some previous scientific balancing acts could have included temperature changes, diseases, natural disasters, and biological evolution. However, it is reasonably uncertain that nature, or any other forces, can sustain life on earth in wake of the greatest ever perturbation of the ecosystem by its inhabitants.

However, for humans, most precautionary measures are either very expensive or very difficult to pursue. These barriers are magnified by the large uncertainty surrounding environmental issues. One such issue is the motivation of this study: excessive ground-level ozone concentrations. Although this is only one small part of the larger environmental picture, it can be addressed meaningfully with the time, resources, and means available. A systems approach would be more gratifying and possibly more fruitful. Perhaps this study illustrates the limitations in dealing with large scale, complex, environmental questions.

## ACKNOWLEDGMENTS

This thesis is part of a larger project at the Massachusetts Institute of Technology (MIT) Energy Lab, the New England Project. I am part of a team called the Analysis Group for Regional Electricity Alternatives (AGREA) that pursues two main goals through this project: to inform the debate

about electric power planning and policy in New England through rigorous modeling, analysis, and communications; and, to facilitate dialogue in the region amongst the various stakeholders in the electric power industry by organizing meetings several times per year attended by the utility, regulatory, environmental, business, and consumer communities. Started in 1988, the project has been funded by major electric utilities in the New England region.

I wholeheartedly thank all the people who especially helped this thesis become a worthwhile experience. The AGREA team of Steve Connors, Richard Tabors, Mort Webster, Scott Wright and Judi Cardell provided direction and support. Bob Grace and Praveen Amar helped keep me in touch with reality in New England. Denny Ellerman lended a sense of assurance and kept me in focus.

Most of all, my friends and family provided immeasurable inspiration and support. From housemates to bloodmates to officemates to soulmates, I love you all: Joe Bailey, Micha Berman, Melissa Bush, Josh Galper, Rosaline Gulati, Jonathan Kleinman, Juan Pablo Montero, Don Seville, Mom, Dad, Ed, Harriett, Amy, Gram and Pop, and Grandma Sarah. You share in the products of my work, since you comprise the essence of my life.

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# Chapter 1

## INTRODUCTION

### THE GROUND-LEVEL OZONE PROBLEM

Excessive concentrations of ground-level ozone have been shown to cause acute human respiratory problems, urban smog, damage to plant and animal life, as well as damage to agriculture and materials. At present, over half the U.S. population lives in areas considered to have unhealthy ozone levels (Grace 1993, p. 5). Even after twenty years of regulation and control efforts, much of the nation is still exposed to the serious health and welfare effects, especially in the northeast and California.

It is critical to note that ground-level ozone is a completely separate problem from the depletion of the stratospheric ozone layer. The lower atmosphere is defined as the area below about 10 km altitude, where ozone is harmful to human health. The upper atmosphere, defined as the area between 10 and 50 km altitude, is where ozone is beneficial to humans and other life by absorbing ultraviolet rays emitted by the sun (NRC 1991, p. 19). The high stability of the region (tropopause) between the two parts of the atmosphere prevents chemical mixing between them, so ozone is not exchanged (NRC 1991, p. 21).

One of the main factors causing excessive ground-level ozone formation is emissions of nitrogen oxides (NOx), namely nitrogen dioxide and nitric oxide. The negative consequences have led federal and state governments to control ambient ozone levels and/or human-caused NOx emissions, as well as other air pollutants. The most recent federal regulations were established by Congress in the 1990 Clean Air Act Amendments (CAAAs). Ground-level ozone attainment stands as one of the most difficult and urgent goals from this legislation. Under these regulations, states must attain ozone standards by a certain deadline, defined as 1999 in the six New England states. At present, these states have implemented a first phase ozone attainment strategy to be completed by

May 1995. However, it is highly possible that this initial effort will not bring the region into ozone compliance. Therefore, states are seriously considering second phase control strategies for post-1995 which could include additional controls in the electric power sector, a major source of NOx emissions.

This study seeks to compare the power sector impacts of alternative electric utility NOx control strategies in New England after 1995. Such strategies might include combustion and/or post-combustion control technologies, modified unit dispatching, fuel switching, demand-side management, or supply-side options. Then it analyzes what types of government policies would be best for encouraging desired NOx control strategies. The study does not investigate the air quality effects of NOx controls nor the impacts of NOx controls in other sectors, such as transportation or manufacturing. Its aim is to inform policymakers and planners about the power sector impacts of utility NOx control strategies and what policies could best encourage the most socially desirable strategies. The study supports the larger question of what should society do to address the ground-level ozone problem.

### Impacts of Nitrogen Oxides on Environmental Quality

Emissions of nitrogen oxides (NOx), namely nitrogen dioxide and nitric oxide, into the air contribute to two known environmental quality problems: ground-level ozone formation, and acid deposition. Both of these are local and regional problems, stretching on the order of zero to one thousand miles in scope, rather than tens of thousands of miles as for global problems.

Excessive ground-level ozone levels have been shown to cause human respiratory problems, photochemical smog, damage to plants and agricultural yields, as well as damage to certain materials. The extent of the problem is clarified by the fact that 140 million people, over half the U.S. population, lived in ozone nonattainment areas in 1991 (Grace 1993, p. 5). However, since the standard is based on a three year average, in any single year the population exposed to unhealthy ozone concentrations is lower, or 67 million in 1989 (NRC 1991, p. 2), still a large number.

Acid deposition has been shown to cause human health problems, premature deaths in fish populations, and damage to materials. While acid deposition has been reasonably controlled by regulating sulfur dioxide ($SO_2$) emissions, ozone formation has not. One of the reasons for this may be the high complexity of the ozone formation process. Another is the significant uncertainty of the precursor conditions in a given region that lead to ozone formation.

Ground-level ozone is formed through a complex set of chain reactions. A simplified presentation shows that volatile organic compounds (VOCs) react with nitrogen oxides (NOx) in the presence of sunlight to form ozone and other pollutants (Grace 1993, p. 7):

VOC + NOx + sunlight --> $O_3$ + other pollutants

Main intermediate precursors include OH radicals, molecular oxygen $O_2$, and oxygen atoms O, all present in ambient air (NRC 1991, p, 24). Weather conditions greatly affect the extent and rate of this process. Grace summarizes the meteorology well:

> Ultraviolet radiation from sunlight is necessary for the critical chemical reactions to occur. High temperatures serve to increase reaction rates. Vertical atmospheric stability prevents pollutant dispersion, allowing precursors to mix and react in the presence of sunlight. In addition, horizontal air movement (wind) determines the extent of dispersion and dilution, where ozone levels will reach unhealthy peaks, and thus who will be affected (Grace 1993, p. 7).

The two levers for human intervention in this photochemical process are to control NOx concentrations or to control VOC levels. A major recommendation of the National Research Council (NRC) study is that "to substantially reduce ozone concentrations in many urban, suburban, and rural areas of the United States, the control of NOx emissions will probably be necessary in addition to, or instead of, the control of VOCs" (NRC 1991, p. 11). However, the results of such NOx controls depend heavily on chemical and meteorological conditions, which vary by time and space. Thus, control strategies may achieve greater benefits and/or lower costs by reacting to the temporal and geographic nature of the problem.

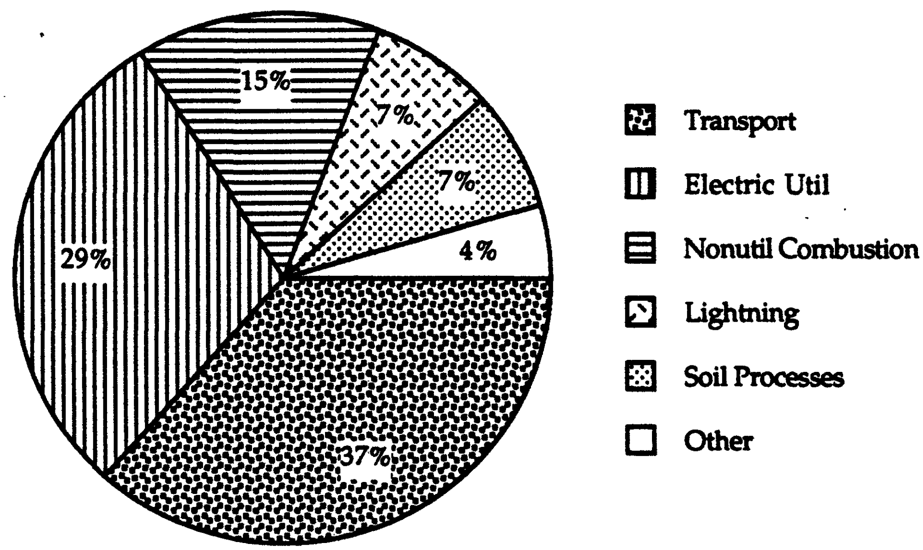
Many non-attainment regions in the U.S. exceed the ozone standard only several times during the year in certain areas. The ozone formation process, unlike the control regulations, is highly time and place specific, as it depends greatly on chemical and weather conditions. Therefore, opportunities may exist to increase the benefits and to reduce the costs of power plant NOx control by controlling precursor NOx and allowing nonprecursor NOx emissions. The states in the northeast region typically experience simultaneous ozone standard exceedences due to long-range transport of ozone and its precursors into and within the region. Thus, geographically-specific controls may not be effective on a regional scale.

However, these exceedences in the Northeast are very time specific. The number of days in which any state in the northeast transport region exceeds the standard is on the order of zero to forty. The maximum value of forty is only 10% of annual days and about 25% of the ozone season days, between May and September. The exceedences predominantly occur during multi-day episodes in this five month ozone season. From 1987-1993, for example, the number of episodes per season ranged from one to six, incorporating between two to eleven days each (OTC 1994, p. 8). Further, the number of days of ozone exceedences outside the episode periods ranged from zero to nine for any individual northeastern state in 1992 and 1993. Thus controlling ozone precursors around potential exceedence days, if detectable, could significantly reduce costs or increase benefits compared with all year strategies. Massachusetts has already differentiated between in-season and out-of-season NOx emissions in its NOx emissions trading regulations. The rules permit parties to trade NOx within the season, or from within season to outside season, but not from outside season to within season (MA DEP 1993, 310 CMR 153.7).

## THE ELECTRIC POWER SECTOR AS ONE MAJOR SOURCE OF NITROGEN OXIDES IN NEW ENGLAND

Two levers for human intervention in the ozone problem exist because humans cause a majority of the emissions of the two ozone precursors. Nitrogen oxides emissions result from the combustion of fossil fuels, as well as from two natural phenomena: lightning, and chemical and microbial processes in soil. Specific anthropogenic sources include the transportation sector, power plants, and industrial processes, with relative contributions shown Figure 1-1.

*Figure 1-1: Estimated Annual U.S. NOx Emissions Sources*
*Total Emissions = 6.7 teragrams of nitrogen/year, high uncertainty*
*(Source: NRC 1991)*




Fossil fuel combustion leads to the formation of NOx as nitrogen in both fuel and air reacts at high temperatures with molecular oxygen. In New England, the predominant regional air quality policy organization, Northeast States for Coordinated Air Use Management (NESCAUM), estimates that 20% of anthropogenic NOx emissions are from electric utilities, 60% are from transportation sources, and the remaining 20% is from industrial processes (NESCAUM 9-18-92, p. 1). Although mobile source emissions are three times as large as utility emissions, the latter are often easier to control due to the concentrated nature of emissions, centralized ownership, a tight regulatory framework, and a relatively small political influence compared with the transportation sector.

Volatile organic compound emissions differ greatly from NOx emissions in that around half of total U.S. VOC emissions come from biogenic sources, predominantly forests (45%), but also from agricultural crops (5%). The human related sources include incomplete combustion of fuel or fuel vaporization in the transportation sector (20%), use of organic solvents in industry (15%), evaporation in surface-coating industries (9%), and certain combustion sources (6%). (NRC 1991, p. 258).

Much recent debate on the ozone problem focuses on the relative costs and benefits of NOx emissions reductions versus VOC emissions reductions. Recent studies have shown that in the Northeast region, NOx-only controls reduce ozone in rural and urban areas both within and outside the region more than comparable VOC-only controls, a shift from previous thinking (NRC 1991, p, 363). However, VOC-only controls reduce ozone more in densely populated areas, such as New York City, but increase ozone levels downwind. Further, combined NOx-VOC control strategies achieve greater reductions than either alone within the northeast, except for dense urban areas where VOC-only controls are more effective, and only slightly greater ozone reductions outside the region (NRC 1991, p. 371). Thus, strong evidence has emerged that NOx controls are critical for ozone attainment in the Northeast, whether combined with VOC controls or not.

## History and Current Status of Ozone and Nitrogen Oxides Control in the Northeast

Due to its harmful effects, ozone is regulated at the federal level by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act of 1977. The act defines ozone attainment according to National Ambient Air Quality Standards (NAAQS). For ozone attainment, a state must essentially have no more than three maximum daily one-hour average ozone concentrations above 0.12 parts per million by volume (ppm) over a three year period. In 1991, over 140 million people lived in ozone non-attainment areas. The northeast U.S. has some of the highest ozone levels, and also greatly contributes to ozone problems elsewhere as a result of ozone transport. In the past, ozone abatement efforts have concentrated on reducing VOC levels. However, recent evidence shows that a combined

VOC/NOx strategy could be much more effective, as explained in the previous section. (NRC 1991, p. 11).

Consequently, the 1990 Clean Air Act Amendments (CAAAs) mandate both VOC and NOx reasonably available control technology (RACT) for existing emissions sources in non-attainment or transport regions. New sources are subject to the best available control technology (BACT), as these greater controls are more cost-effective when integrated into unit design before construction. As the primary source of national NOx emissions, and as an easy source to control, RACT limits may represent a first degree control for electric power plants.

The CAA compels states in nonattainment or transport regions to create State Implementation Plans (SIP) for achieving compliance. The act authorizes the EPA to approve SIPs or to replace rejected ones with Federal Implementation Plans (FIP). Recognizing the regional nature of the northeast's ozone problem, Congress created an Ozone Transport Commission (OTC) under the 1990 CAAAs. The OTC, composed of representatives from twelve states from Maine to Virginia and the District of Columbia, can develop recommendations for additional control measures beyond those mandated in the CAAAs. Individual states or the OTC may decide to more stringently control NOx emissions from existing power plants in order to achieve attainment, or they may opt for other control strategies, such as conservation, minimum-NOx dispatch, or non-fossil supply.

In the Northeast, ozone attainment must be achieved by 1999 according to the CAAAs. The first phase of northeast electric utility NOx control strategies, focused on meeting the RACT mandates, ends May 15, 1995. After that date, if the region is still not in ozone compliance, additional strategies would be necessary. Revised SIPs were due to EPA by November 15, 1992. Each individual state must demonstrate that its SIP achieves attainment by running computer simulations with an Urban Airshed Model (UAM). The models are expected to be ready for demonstrations in 1994.

A preliminary utility-sponsored UAM-based study released in October 1993, performed by Sigma Research Corporation, concluded that "emission reductions beyond those mandated by the CAAA for 2005 may be needed" (Sigma 1993, p. vii). Further, several air quality experts in the northeast have suggested through personal communication with the author that post-RACT strategies may need to reduce NOx emissions by an equal or greater amount than RACT already achieves in order to reach compliance. Hence, this thesis is very timely in informing the air quality community about post-RACT options in the electric utility sector.

## RESEARCH GOALS AND APPROACH

The main objectives of this study are the following:

- To compare the medium term, system-wide costs and benefits of alternative NOx control strategies on the electric power system in New England.
- To determine if seasonal and geographic NOx control strategies offer significant advantages over competing annual, region-wide strategies in New England.
- To determine if post-RACT combustion and post-combustion control technologies are more cost-effective than options without control technologies from a systemic perspective of the electric service industry in New England.
- To identify post-RACT policies that would best encourage utilities to pursue the most preferable control strategies.

The alternative control strategies are compared by multiple criteria. The most important criteria include:

| | |
|---|---|
| total costs | robustness across fuel cost futures |
| total NOx emissions | total CO2 emissions |
| ozone season NOx emissions | fuel diversity |

No attempt is made to reduce the multiple criteria to a single objective function, such as a monetary measure. This approach requires too many unfounded assumptions about the societal value of health and environmental impacts, the time value of money, probabilities of fuel cost or load futures, and other factors. Rather, the study uses multi-attribute tradeoff analysis (MATA) to highlight which strategies dominate others for pairwise cost-benefit tradeoffs. Further, this visual technique illustrates the how the performances of competing strategies change across fuel cost futures and other option sets besides NOx control ones.

Also, the study uses statistical analysis to gauge the magnitude of the trends highlighted by MATA. For example, such results can show the mean and the standard deviation of the difference in ozone season NOx emissions between two NOx control options. Finally, the sensitivity of the results to changes in input parameters from modified strategies can be tested by sensitivity analysis.

The performance attributes of each strategy are generated by an electric power system simulation model, called the Electric Generation Expansion Analysis System (EGEAS). This industry standard production-costing model simulates the twenty year operation of New England's electric power system. The different strategies are modeled by altering various input data. NOx control technologies are only one component, or option set, in forming power system strategies. Other option sets include new supply-side technologies, existing unit repowering and retirement, level of demand-side management (DSM), and fuel cost future. Combining one option from each of these five option sets yields a single strategy.

The policy analysis seeks to make recommendations by which the most desirable strategies would be encouraged while leaving substantial flexibility for future uncertainties. First, the degree to which time-specific policies would motivate utility behavior are discussed. Second, the degree to which place-specific policies would achieve desired results are discussed. Third, the implications of different policy tools on controlling ozone precursor nitrogen oxides emissions are elaborated.

# Chapter 2

## RESEARCH METHODOLOGY

### OVERVIEW

This project employs the methodology and tools of the MIT Energy Lab's Analysis Group for Regional Electricity Alternatives (AGREA). The systemic approach centers around simulating New England's electric power system over a twenty year period. Each simulation tests a different scenario, or combination of planning options and future uncertainties. The simulation tool is an industry standard production-costing model, called the Electric Generation Expansion Analysis System (EGEAS). EGEAS outputs costs, emissions, and other data for each simulation.

These data are examined using a technique called multi-attribute tradeoff analysis (MATA). This visual method compares many scenarios according to two criteria at a time, often cost and emissions. The resulting graphs can illustrate trends and the magnitude of tradeoffs between competing options.

The output data are analyzed more quantitatively through statistical analysis, simulation comparisons, and sensitivity analysis. The simulation methods, the modeling of options, and the analysis techniques are described further in this chapter.

### SIMULATION USING EGEAS ELECTRIC POWER SYSTEM PRODUCTION-COSTING MODEL

The main tool for this project is the power system simulation model, EGEAS. Operating on a DEC MicroVax computer, EGEAS simulates the operation and planning of the New England electric power system. These functions include dispatching units, building new supply, retiring existing generation, and meeting emissions constraints. EGEAS crudely approximates transmission costs and maintenance but does not model the transmission and distribution system. The model input data are specific to the individual plant level. Input data include unit heat rates, fuel costs, and hourly load for the New England region. Output data can be annual or seasonal, and include system costs, emissions, fuel usage, and reserve margins. Both input and output data are reality checked by a consortium of electric power stakeholders in the New England region, including utilities, regulators, environmentalists, and consumer groups, as part of AGREA's New England Project at the MIT Energy Lab. More detailed information about the modeling tool is contained in the EGEAS User's Manual, identified in the bibliography.

Each EGEAS simulation yields output data for one scenario. A scenario is a combination of a strategy and a set of future uncertainties. Each strategy consists of multiple operating and planning decisions. Each set of futures includes one outcome for each power system uncertainty, such as load growth or fuel costs. The way in which scenarios are created is described in the next section.

### FORMING SCENARIOS

For comprehensive analysis of many power system alternatives, hundreds or more scenarios are simulated and compared. Each scenario is a combination of one option from each of seven option sets and each of two uncertainties. The option sets include new supply technology mixes, level of existing fossil unit repowering and retirement, natural gas contracting of new units, level of existing unit retrofit NOx controls, NOx control policy, nuclear unit availability, and level of Demand-Side Management (DSM). The uncertainty sets include economy/load growth and fuel costs.

Each alternative within each option set has a code letter abbreviation. These alternatives and their letter codes are identified in Table 2-1. The code letters allow for cryptic, but pronounceable names for the scenarios, such as GISEVERYB or WASIRECYG. The individual options and uncertainties are described in the next section.

Table 2-1: Scenario Options and Uncertainties

Scenario Naming:
(TM)(EX)/(NC)(NOx)(NOxOp)/(-)(DSM)/(LD)(FCU)

| | |
|---|---|
| 5 | Technology Mixes/Supply-Side - TM |
| G | Gas/Oil |
| H | Gas/Oil and Clean Coal |
| W | Gas/Oil and Wind |
| D | Gas/Oil, Clean Coal and Wind |
| K | Gas/Oil, Clean Coal, Wind, and Biomass |
| 3 | Unit Longevity/Existing - EX |
| I | Life Extension |
| O | "Moderate" Repowering/Retirement |
| A | "Aggressive" Repowering/Retirement |
| 2 | Natural Gas Contracts - NC |
| S | All "Spot Price" Gas |
| M | 70% "Must Run" Gas |
| 3 | Existing Unit NOx Control Level - NOx |
| A | Phase I RACT |
| E | Firm Phase II Controls |
| I | Hard Phase II Controls |
| 7 | NOx Operational Control Policy - NOxOP |
| V | No Operational Policy |
| N | Annual Minimum NOx Dispatch |
| P | Annual Cap of 80% Reduction from 1990 |
| Q | Ozone Season Minimum NOx Dispatch |
| R | Ozone Season Cap of 80% Reduction from 1990 |
| S | Geographic Annual Minimum NOx Dispatch |
| W | Intermittent Minimum NOx Dispatch |
| 1 | Place Holder in Name (null) |
| E | nothing |
| 4 | Levels of DSM - DSM |
| N | No Utility Sponsored DSM° (Reference) |
| R | 1992 Utility Sponsored DSM Programs |
| D | Double 1992 Utility Conservation Programs |
| C | Triple Commercial & Industrial Conservation |
| 1 | Ecomony/Load Growth Uncertainty - LD |
| Y | Anticyclic Average Growth |
| 3 | Fuel Cost Uncertainty - FC |
| C | Competitive/Low Gas |
| B | Base/Stable Fuel Costs |
| G | Gas Constraint – Base Oil/High Gas Costs |

DEFINITIONS OF OPTIONS AND UNCERTAINTIES OTHER THAN NOX CONTROLS

Detailed descriptions of how each option and uncertainty are modeled are contained in AGREA's Background Information Packet of the New England Project, identified in the Reference section of this document. This section gives an overview of what each alternative means, and how it is represented in the simulations. All options and uncertainties are described here except the two related to NOx control, which are elaborated more thoroughly in the chapter entitled "Alternative NOx Control Strategies."

The new supply technology mix option determines the quantities and types of new plants that are built in each year over the twenty year simulation period. These options consist of fixed and variable capacity installation schedules. Fixed capacity refers to plants that are built according to a pre-determined schedule, regardless of any other factors, if they are part of the technology mix. Variable capacity refers to those plants which are built as needed by the simulation, so the year and size of their installation varies between scenarios.

The installation schedules for the fixed MW technologies are shown in Table 2-2. The cost and performance characteristics of the wind and biomass technologies are listed in Table 2-3.

Table 2-2: Installation Schedule of Fixed Capacity Technologies

| Year | Annual Wind | Annual Biomass | Cumulative Wind | Cumulative Biomass |
|---|---|---|---|---|
| 1995 | 52 | 100 | 52 | 100 |
| 1996 | 87 | 100 | 139 | 200 |
| 1997 | 105 | 100 | 244 | 300 |
| 1998 | 141 | 100 | 385 | 400 |
| 1999 | 139 | 100 | 524 | 500 |
| 2000 | 158 | 100 | 682 | 600 |
| 2001 | 193 | 100 | 875 | 700 |
| 2002 | 210 | 100 | 1085 | 800 |
| 2003 | 210 | 100 | 1295 | 900 |
| 2004 | 210 | 100 | 1505 | 1000 |
| | (MW/yr) | | (MW) | |

Table 2-3: New Supply Technology Cost and Performance Summary

| Technology Type | Nameplate Capacity | Full Load Heat Rate | Installation Cost | Fixed O&M | Variable O&M |
|---|---|---|---|---|---|
| ACT | 136 | 10,906 | 375.0 | 0.14 | 3.47 |
| ACC | 200 | 7,363 | 592.0 | 22.27 | 0.75 |
| | 400 | 7,352 | 543.0 | 14.39 | 0.75 |
| | 600 | 7,341 | 523.0 | 10.00 | 0.75 |
| IGCC | 200 | 8,855 | 2,154.6 | 45.39 | 1.62 |
| | 400 | 8,806 | 1,880.5 | 40.81 | 1.62 |
| | 600 | 8,757 | 1,710.4 | 40.81 | 1.62 |
| AFBC | 200 | 9,650 | 1,834.0 | 50.48 | 6.82 |
| | 400 | 9,720 | 1,639.0 | 43.29 | 6.82 |
| | 600 | 9,161 | 1,439.0 | 25.49 | 6.83 |
| Biomass – Steam | 50 | 14,200 | 2,504.8 | 55.49 | 5.49 |
| – FBC | 25 | 14,150 | 2,376.6 | 37.21 | 5.95 |
| | (MW) | (Btu/kWh) | (1991$/kW) | ('91$/kW-yr) | ('91$/MWh) |

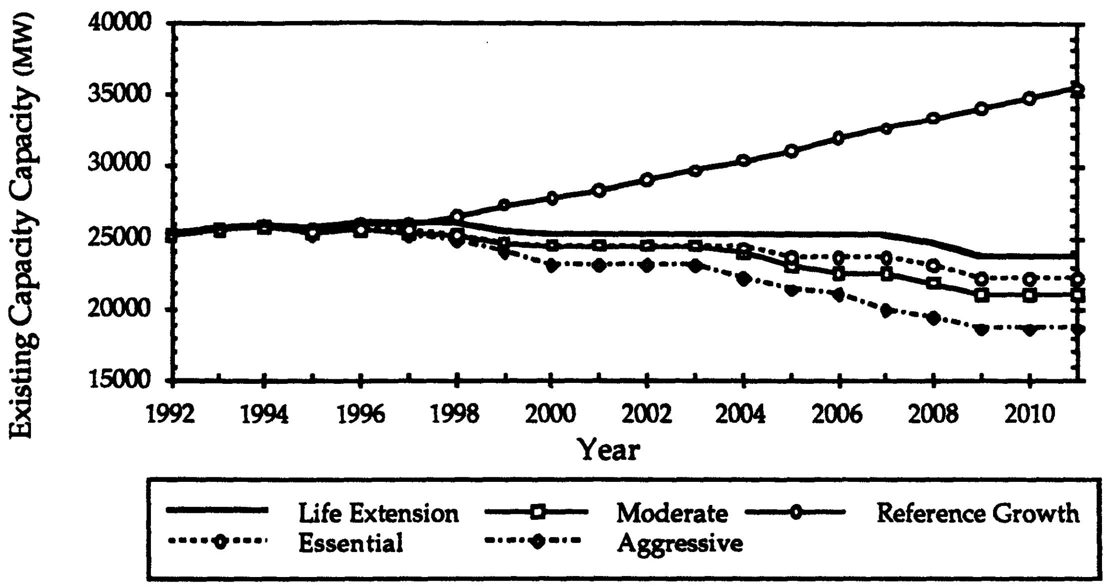
The variable capacity technologies are built as needed in relative proportions. The distribution of these variable capacity technologies for the different new supply mix options are shown in Table 2-4. The gas/oil plant technologies include advanced combustion turbine (ACT) and advanced combined cycle (ACC). The coal plant technologies include atmospheric fluidized bed (AFB) and integrated gasification combined cycle (IGCC). The cost and performance characteristics for the variable technologies are shown in Table 2-2.

Table 2-4: Definition of New Supply Technology Mix Options

| Technology Mix Option (New Sites only) | | Variable Capacity Technologies | | | | Fixed Capacity Techs. | | |
|---|---|---|---|---|---|---|---|---|
| | | Gas/Oil | | Clean Coal | | Renewables | | |
| | | ACT | ACC | IGCC | AFBC | Wind | PVs | Biomass |
| Gas/Oil Techs | G | 13% | 87% | - | - | - | - | - |
| Gas/Oil & Clean Coal Techs | H | 13% | 44% | 26% | 17% | - | - | - |
| Gas/Oil & Wind | W | 11% | 79% | - | - | 10% | - | - |
| Gas/Oil, Clean Coal, & Wind | D | 12% | 40% | 24% | 14% | 10% | - | - |
| G/O, Coal, Wind & Biomass | K | 11% | 39% | 23% | 13% | 10% | - | 4% |
| | | Target Technology Ratios by MWs | | | | Effective Technology Ratio | | |

The existing unit longevity option determines the extent and timing of existing fossil plant retirement and repowering. Under the Life Extension option, none of the existing 1992 capacity is retired except those plants which have been committed for retirement by the utilities. Under the Moderate option, 10% of existing capacity is retired or repowered by 2011. Under the Aggressive option, 20% is retired or repowered. The trajectories of existing capacity retirement for the various longevity options are shown in Figure 2-1. Units that are repowered are always replaced with plants of the same fuel type.

Figure 2-1: Existing Unit Trajectories by Existing Unit Longevity Option




The natural gas contracting options determine whether new natural gas-fired units are must-run, or economically dispatched as usual. The Spot Gas option lets new gas units get economically dispatched like most other plants. The Must-Run option indicates that utilities have firm gas contracts with suppliers that guarantee gas supply, often called "Take or Pay" contracts, so that new gas units must be operated, even if their are available units with lower variable costs. The cost of natural gas under this option remains the same as the "Spot" option.

The nuclear unit availability uncertainty determines whether or not two nuclear units are unexpectedly decommissioned before their scheduled lifetime. Under the Existing decommissioning schedule option, all nuclear units operate until their planned retirement date by the utilities. Under the Attrition option, two nuclear units are decommissioned early. A 500 MW unit is retired in 2000, and a 650 MW unit is retired in 2004.

The level of DSM options determine the extent and timing of utility-sponsored DSM program impacts. These programs include conservation and load management measures, and result in both energy savings and peak load reductions. A summary of these impacts and costs by option is shown in Table 2-5 and Table 2-6, respectively.

Table 2-5: Impact Summary of DSM Level Options

| *Level of Demand-Side Mgt.* | | *2011 Peak Demand* Peak | Growth | Peak Red. | % Red. |
|---|---|---|---|---|---|
| No Utility DSM: | N | 32408 | 2.51 | — | — |
| 1992 Reference DSM: | R | 29140 | 1.97 | 3268 | -10.08 |
| Double Conservation: | D | 26281 | 1.44 | 6127 | -18.91 |
| Triple C&I Conserv.: | C | 24170 | 1.02 | 8238 | -25.42 |
| | | (MWs) | (%/yr) | (ΔMWs) | (%Δ) |

| *Level of Demand-Side Mgt.* | | *2011 Electricity Demand* Demand | Growth | Savings | % Red. | *'92-'11 Cumulative Demand* Sales | Savings | % Red. |
|---|---|---|---|---|---|---|---|---|
| No Utility DSM: | N | 166,554 | 2.04 | — | — | 2,799 | — | — |
| 1992 Reference DSM: | R | 154,772 | 1.67 | 11782 | -7.07 | 2,625 | 173 | -6.20 |
| Double Conservation: | D | 142,730 | 1.26 | 23824 | -14.30 | 2,447 | 329 | -12.63 |
| Triple C&I Conserv.: | C | 134,894 | 0.97 | 31660 | -19.01 | 2,340 | 430 | -16.47 |
| | | (GWh) | (%/yr) | (GWhs) | (%Δ) | (TWhs) | (ΔTWhs) | (%Δ) |

Table 2-6: Average Levelized Cost of Conserved Energy for DSM Levels

| Level of DSM | Levelized Direct Measure Cost (1991 ¢/kWh) |
|---|---|
| Reference | 2.3 |
| Double | 2.9 |
| Triple C&I | 3.5 |

The economy/load growth uncertainties represent possible future demand trajectories for New England. The trajectories follow a sinusoidal path around a line that grows at about 1.8% per year. The electricity demand and peak load futures are shown in Figure 2-2 and Figure 2-3, respectively. The anticyclic load growth is the closest match to current trends, so it is used for all scenarios except sensitivities.

Figure 2-2: Electricity Demand Trajectories for Load Growth Futures

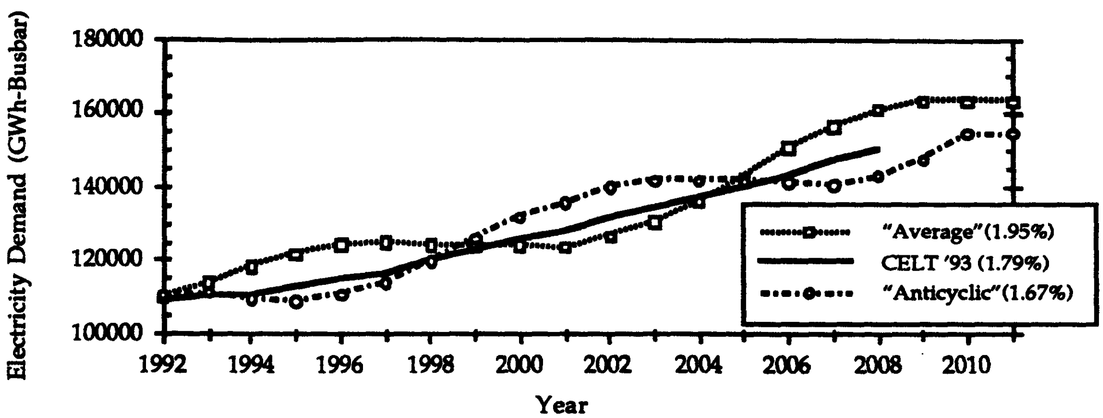
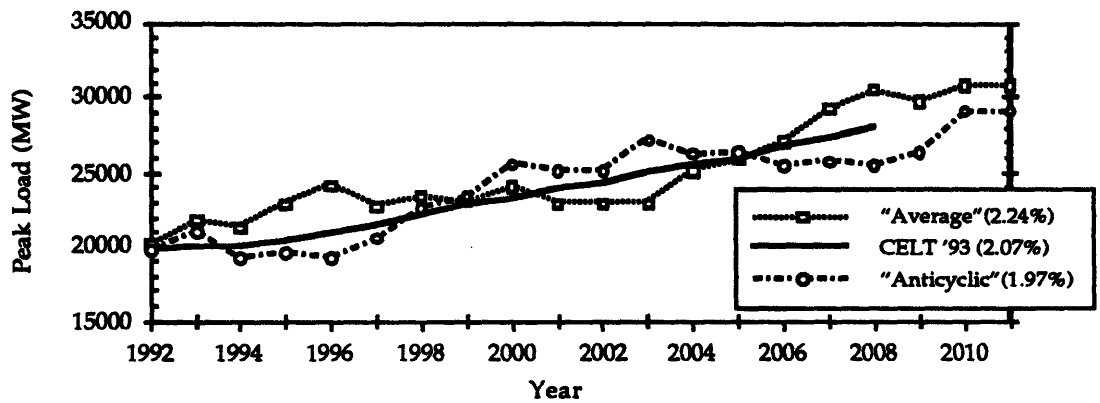
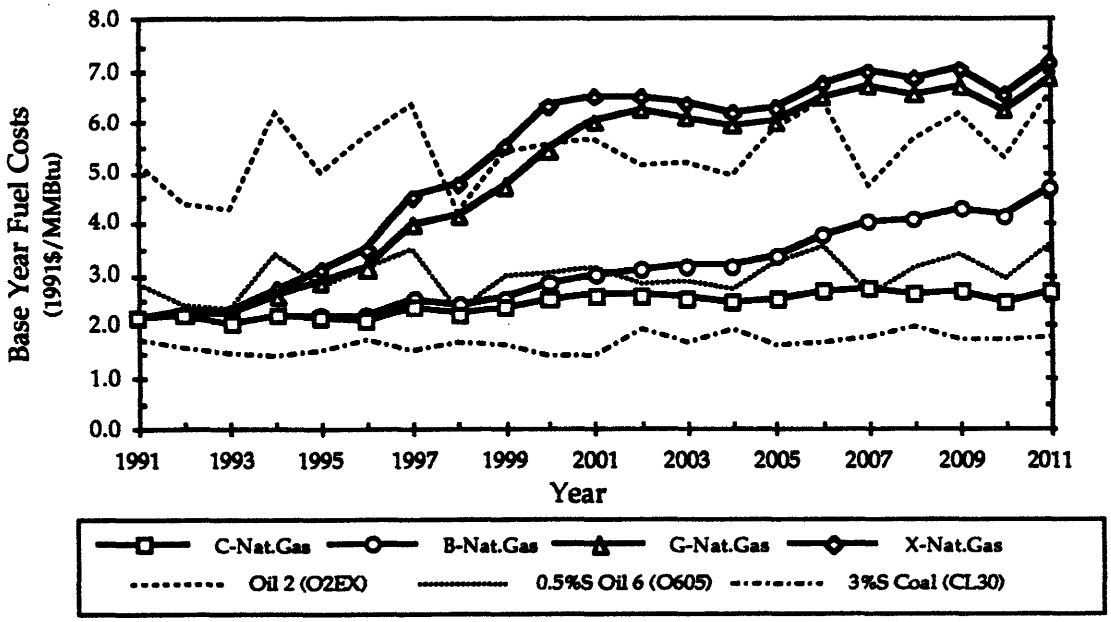



Figure 2-3: Peak Demand Trajectories for Load Growth Futures




The last uncertainty modeled is fuel cost uncertainty, specifically natural gas costs. Across all futures, each fuel type except natural gas has the same cost trajectory. Natural gas costs are the only values that vary between futures, from low to medium to high. These fuel cost futures that only differ by gas costs are shown in Figure 2-4 along with the fuel cost trajectories of the other fuel types. These trajectories reflect historical variability of the highly volatile fuel markets.

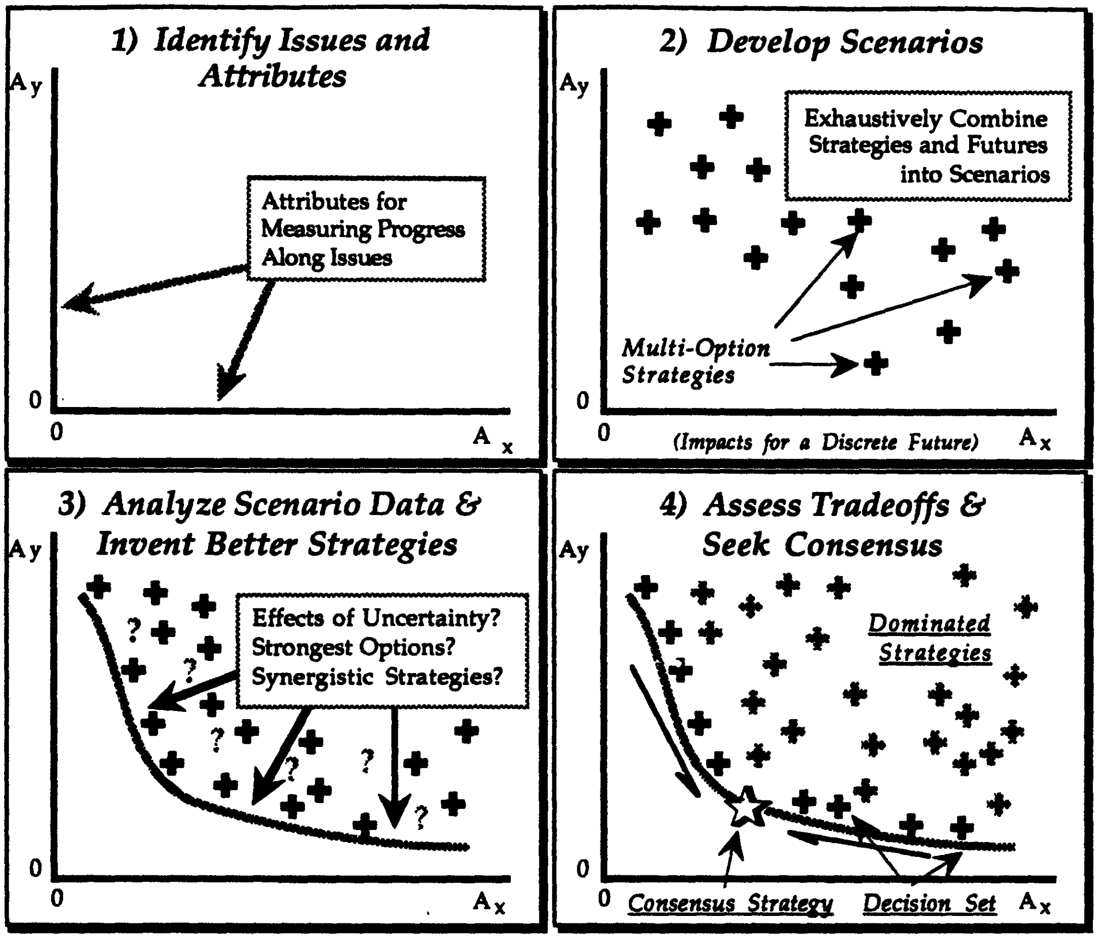
Figure 2-4: Fuel Cost Trajectories - Competitive, Base, and High Gas Cost Futures




SCENARIO BASED MULTI-ATTRIBUTE TRADEOFF ANALYSIS

Scenario based multi-attribute tradeoff analysis (MATA) is a technique that facilitates analysis of complex, controversial, and uncertain issues. It is the central tool used by the MIT AGREA to communicate simulation results and trends to broad audiences of utilities, regulators, environmentalists, and other parties. MATA essentially allows analysts to visually compare the performances of different strategies composed of a mix of supply and demand-side options. An illustration of the main steps in this method is shown if Figure 2-5.

Figure 2-5: Four Basic Steps in Scenario Based Multi-Attribute Tradeoff Analysis




The many attributes result from multiple stakeholders each having multiple objectives of differing priority. Each objective is measured according to some criterion, or attribute, such as total cost, NOx emissions, and percent of electricity generated with natural gas fuel. The scenarios are combinations of many options and uncertainties, as explained earlier. The tradeoff plot shows the effects of synergy between options, and the size of tradeoffs between competing criteria. Finally, stakeholders can reach consensus by deciding what tradeoffs are worthwhile, although this is consistently the most difficult step. MATA avoids reducing all criteria into a single objective function. Typically analysts compare two attributes at a time, although three are possible.

STATISTICAL AND SENSITIVITY ANALYSES

Finally, the large amount of output data that results from hundreds of simulations reporting hundreds of performance and descriptive attributes each provides an opportunity for quantitative analysis. Statistical analysis is used to describe the set of data for one attribute across all scenarios. After trends are identified, the effects of alternative input data to these results are tested via sensitivity analysis. This method usually involves rerunning the simulation model with altered input data, and comparing the new results with the initial data.

Lastly, it is also insightful to examine single year differences between scenarios, or year to year trends within scenarios, rather than data aggregated for the entire twenty year study period. Trajectory analysis is a method that allows for these annual comparisons, by graphing annual data or by calculating differences between these data in a table.

# Chapter 3

# ALTERNATIVE ELECTRIC UTILITY NOX CONTROL STRATEGIES

## OVERVIEW

NOx control methods for electric utilities can be classified into three main categories. They are supply-side technologies, demand-side management (DSM), and operational controls. Supply-side technologies are the most conventional form of control. Typical examples are combustion and post-combustion NOx control technologies, new unit or plant replacement technologies, and plant fuel switching. DSM options include end-use efficiency technologies and load management programs. Operational controls are predominantly unit dispatch and plant process controls. Many of these NOx control methods can be combined with each other to form integrated control strategies. Further, they can be implemented in a temporal or geographic manner to correspond to the ozone formation process. This chapter describes how these various control methods work, to what extent they can control NOx emissions, and how applicable they are to temporal and geographic strategies. Finally, the control strategies to be modeled are defined as combinations of some of these control methods.

## DESCRIPTION OF NOX CONTROL TECHNOLOGICAL ALTERNATIVES

Combustion and post-combustion control technologies are added to generating units to reduce NOx formation and end of process release, respectively. Combustion modifications include low-NOx burners (LNB), overfire air (OFA), reburning (REB), flue gas recirculation (FGR), two stage combustion (TSC), and steam injection (SI). Nitrogen oxides are formed during the combustion of fossil fuels from oxygen and nitrogen, the latter of which comes from one of two sources: air content (thermal NOx) and fuel content (fuel NOx). The following paragraphs explain how each NOx control method decreases emissions.

LNBs decrease both thermal NOx and fuel NOx formation by delaying the mix of fuel and air in the burner zone. This technology can be applied to oil, gas, and coal units. (STAPPA 1992, p. 11).

OFA involves air ports installed in the furnace that inject separated combustion air above the main burner zone. This results in more advanced forms of combustion which reduce NOx formation. OFA is applicable to oil, gas, and coal units. (STAPPA 1992, p. 11).

REB injects fuel "above the main burner zone and primary zone gases are passed through either a flame (reburning), in which case NO is destroyed, or a low oxygen-reducing zone (fuel staging), in which case NO is reduced to $N_2$." REB is mostly applied to coal units, but can be used for oil and gas units as well. (STAPPA 1992, p. 12).

FGR extracts a portion of the flue gas from the economizer or air heater outlet and returns it to the furnace through the furnace hopper, the burner windbox, or both. FGR displaces combustion air, which reduces the concentration of oxygen in the combustion zone. Moreover, FGR lowers the furnace gas temperature, decreasing thermal NOx formation. This method is only used for oil and gas plants. (STAPPA 1992, p. 13).

Other combustion control options exist, such as TSC and SI. The most popular ones have been described above.

Post-combustion controls, also called add-on controls or flue gas treatment controls, reduce NOx already formed during the combustion process into $N_2$ and water. The two most effective technologies are selective catalytic reduction (SCR) and nonselective catalytic reduction (SNCR). Post-combustion controls achieve greater reductions in NOx emissions than combustion modifications, especially when combined with combustion controls. (STAPPA 1992, p. 14)

SCRs inject an oxidation catalyst and a reducing agent, either ammonia or urea, into the post-combustion region to reduce NOx to molecular nitrogen and water. SNCRs inject only the reducing agent, not an oxidation catalyst, into the post-combustion region to reduce nitrogen oxides. (STAPPA 1992, p. 14).

Other supply-side technology options besides emissions control technologies include existing unit repowering or replacement, and new supply alternatives. Repowering or replacement is when a new plant is created on the site of an existing plant that undergoes major renovations. Existing plants are repowered to either become more efficient in using the same type of fuel, or to burn a different, cleaner type of fuel. Both cases result in fewer emissions per kWh generated. A repowering fuel change might replace oil and coal-fired units with gas-fired units. Additionally, single-fueled units can be converted to dual-fueled units so that plant operators can choose which fuel to burn at different times.

New supply alternatives include wind farms, photovoltaic generation, hydroelectric units, nuclear power, clean coal technology, biomass plants, as well as gas, oil, and regular coal technologies. As a method for controlling NOx emissions, lower-emitting technologies, such as renewables or natural gas plants for fossil generation, can be built rather than comparatively dirtier plants. However, cleaner plants are often more expensive than higher-emitting ones, or have other environmental externalities, such as land use for renewables or radiation risks with nuclear power.

Demand-side management (DSM) is a method that influences electricity demand so that fewer pollutants are emitted. This is achieved with one of two types of DSM: conservation or efficiency (hereafter called conservation), and load management. Conservation provides the same level of electric service while consuming less electricity by improving end-use efficiency. For example, replacing incandescent bulbs with compact fluorescent lamps provides the same amount of lighting, but uses less electricity. Lowering electricity demand decreases fuel consumption which decreases emissions. Conservation programs are often less expensive than supplying the original electricity demand, another incentive for DSM. Roughly three percent of New England's current electric service demand is met through conservation measures (MIT AGREA 1993, p. DSLP-4), while more than six percent is widely expected by 2010.

Load management, including peak load management, involves shifting demand from times of dirtier generation to times of cleaner generation, as total electricity demand remains the same. Load management can be achieved with time-of-use rates, interruptible load contracts, or other incentive measures. Load management originally started as peak load management, by which utilities shifted load from more expensive peak generation to less expensive intermediate or baseload generation. However, intermediate and baseload units are often higher-emitting than peak units.

Lastly, operational controls can also be used to control NOx emissions. Example operational controls include unit dispatch logic and plant maintenance. Normal unit dispatch logic is a least cost unit selection process subject to operating and transmission constraints while meeting total electricity demand. NOx controls could be introduced in the form of an operating constraint, such as a regional NOx emissions cap. Alternatively, the unit dispatch logic could be changed to a minimum-NOx dispatch, a form of environmental dispatch, to control emissions. This dispatch logic is analogous to a least cost dispatch subject to an operating constraint of zero NOx emissions with exorbitant penalties. The strong appeal of minimum-NOx dispatch as a NOx control option is that it can be applied intermittently and has no capital costs (Grace 1993, p. 37). This temporal attribute correlates well with the temporal nature of the ozone formation process, a focus of the next section.

## TEMPORAL AND GEOGRAPHIC OPPORTUNITIES AND CONSTRAINTS OF NOX CONTROL OPTIONS

Ozone exceedences in the northeast tend to happen in multi-day episodes over large land areas. Only a minority of days during the ozone season do areas in the northeast violate the NAAQS. For example, during 1988, the worst year for ozone in the last decade, the number of days in violation for the worst areas of the northeast were on the order of forty (OTC 1994, p. 8). This amount represents about 25% of the total number of days during the five month ozone season, and about 10% of the days in a year. Moreover, ozone and its precursors have residence times on the order of several days. Thus, there is strong incentive to control ozone during certain days or weeks, not all of the time as current regulations encourage.

Unit dispatch offers the greatest amount of control and flexibility in applying time-specific strategies. Human and computer controllers at the centers of the New England Power Pool continuously determine which plants operate at what times and at what capacities. The time horizon over which controllers change plant usage is on the order of minutes and hours. Further, this technique requires virtually no additional capital investment as it utilizes existing equipment and capabilities. Thus, unit dispatch is a highly flexible technique as it can be halted or expanded in response to weather and atmospheric chemistry conditions that change daily or even hourly.

Load management measures also offer a high degree of control and flexibility. Through such mechanisms as time-of-use rates and interruptible contracts, utilities can induce customers to decrease electricity demand in minutes or hours. However, the emissions impacts of these changes depends completely on the specific unit at the generation margin. In other words, under conventional least-cost dispatch, decreasing regional load reduces the output of the most expensive plant operating at the time. This plant could be a dirty, inefficient coal unit or a clean gas-fired unit, which would have greatly different emissions impacts. Moreover, there is a high probability that the displaced load would reappear within a few days or hours, still during the ozone episode. The emissions characteristics of the plant which generates the displaced electricity equally affect the net pollution result. All of these factors make load management a less predictable ozone mitigation control than unit dispatch.

Conservation reduces electricity demand according to the specific load profile of the end-use being targeted. Unless planners know the magnitude and timing of conservation program impacts, the emissions benefits of these measures are also fairly uncertain. Further, the impacts could change significantly over time as usage patterns and plant loading order change.

Plant fuel switching allows monthly or seasonal control. This might correlate well with the general ozone season, but it does not provide control around multi-day ozone episodes. Further, most fossil plants burn only a single fuel, so substantial capital investment would be required to create a dual-fuel capability. Such investment could be wasted if fuel switching is not needed later in time.

Finally, supply-side technologies such as NOx control technologies and power generation technologies are the least adaptable to temporal strategies. These technologies require high capital investment, and are subject to unit dispatch for use. Further, generation technologies require years to install, depending partly on the rate of turnover of existing units. They are more important in a longer-range plan, and cannot be relied upon to achieve compliance by the 1999 deadline. Only about 25% of total NOx control technology costs are capital costs, but fixed operating and maintenance (FOM) costs are high compared with variable operating and maintenance (VOM) costs. Therefore, temporal strategies are not sensible for control technologies, since VOM, the criteria for unit dispatch decisions, is relatively low compared with plant VOM.

The other key dimension of ozone formation is space. All of the control methods identified can be applied geographically, although DSM is effective to a much lesser extent. Several of the alternatives, specifically unit dispatch, are subject to transmission constraints. At present, the most important issue regarding geographic controls in the northeast is the degree to which emissions locations can be correlated to ozone formation. The transport region may have such widespread mixing of ozone and its precursors that geographic controls make little sense. However, since large uncertainty still clouds this question, it is worthwhile to consider differentiation between upwind and downwind areas.

Unit dispatch again offers both high levels of control and substantial flexibility. If the power system is not near peak capacity, controllers can displace generation from upwind regions to downwind regions, displacing emissions as well. However, many episodes occur during the hottest days of the summer when weather conditions are favorable for ozone formation, just the time when the system is near peak capacity. On the other hand, geographic dispatch allows great flexibility to adapt to changing conditions in transportation, weather, or scientific understanding.

Supply-side technologies are very compatible with geographic strategies, since centralized, capital equipment is installed at designated locations to reside for long periods of time. However, if geographic conditions change, these investments are not flexible to be moved. Low-emitting generation technologies, fuel switching, and NOx control equipment can be targeted towards upwind regions, but their effects depend greatly on the extent of atmospheric mixing and transport, fairly uncertain at this time.

Finally, DSM measures are not so appropriate for geographic strategies because New England's power system is operated as a pool. Therefore, demand and supply distributions within the region are unrelated, save for transmission factors. Unless generation becomes more distributed, as current trends suggest, conservation and load management are not suitable spatial emissions controls.

### DEFINITION OF DIRECT NOX CONTROL OPTIONS TO BE ANALYZED

The comprehensive strategies analyzed in this study combine direct NOx control options with indirect ones. These indirect alternatives, such as new supply technology types, levels of existing unit repowering, and levels of DSM, are described in an earlier section. The only technology alternative discussed above that is not modeled is plant fuel switching, since the data requirements are large, and fuel switching is similar to a strategy that is already modeled, aggressive repowering/retirement combined with gas-only new supply mix. This section identifies the direct NOx control options that are integrated with indirect options to form comprehensive strategies. Two types of direct NOx control options are examined: existing unit NOx control technologies, including combustion and post-combustion controls; and NOx operational policies, including temporal and geographic caps and minimum NOx dispatch.

Several technical, economic, and modeling factors determine the range of existing unit NOx control alternatives tested in this thesis. The foremost criterion is the potential of each method for cost-effective NOx emissions control. Modeling assumptions for the cost and performance of the various NOx control technologies are shown in Table 3-1. Existing unit controls have been successfully implemented in New England, in other parts of the U.S., and abroad. Current northeast state responses to the 1990 CAAAs essentially mandate combustion control technologies through unit emissions limits, expressed as pounds of NOx per MMBtu consumed (lbs./MMBtu). These regulations, often called Phase I RACT (Reasonably Available Control Technologies), are the first step in New England towards achieving ozone compliance. States are in the process of determining whether additional steps are necessary to achieve ozone compliance by 1999, including options in both the electric power and transportation sectors.

## Table 3-1: Cost and Performance Assumptions for Modeling NOx Control Technologies

| | *NOx Emissions Performance* | | | *Control Costs* | | |
|---|---|---|---|---|---|---|
| Fuel Conversion System and Control Technologies | Min Level 100lb/MMBtu | Max Level 100lb/MMBtu | Maximum Reduction | Capital Cost $/kW | Var. O&M $/MWh | $/kWyear Fixed O&M |
| ***Pulverized Coal Boilers*** | | | | | | |
| Old Tangential - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Tangential - No Controls | 0.0060 | 0.0060 | # | 0.00 | 0.000 | 0.000 |
| Tangential + OFA | # | # | 20% | 1.99 | 0.006 | 0.049 |
| Tangential + LNB | 0.0038 | 0.0053 | # | 27.00 | 0.042 | 0.418 |
| Tangential + Reburning | # | # | 55% | 31.00 | 0.095 | 0.947 |
| Tangential + OFA + LNB | 0.0029 | 0.0046 | # | 23.00 | 0.074 | 0.741 |
| Old Wall - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Wall - No Controls | 0.0055 | 0.0055 | # | 0.00 | 0.000 | 0.000 |
| Wall + OFA | # | # | 20% | 1.99 | 0.006 | 0.061 |
| Wall + LNB | 0.0040 | 0.0060 | # | 27.00 | 0.042 | 0.418 |
| Wall + Reburning | # | # | 50% | 34.50 | 0.125 | 1.250 |
| Wall + LNB + OFA | 0.0034 | 0.0051 | # | 23.00 | 0.074 | 0.741 |
| Old Cyclone - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| Cyclone - Reburning | # | # | 43% | 38.00 | 0.125 | 1.250 |
| AFBC | 0.0020 | 0.0020 | # | 0.00 | 0.000 | 0.000 |
| Gasification - IGCC | 0.0003 | 0.0003 | # | 0.00 | 0.000 | 0.000 |
| Gasification - Fuel Cell | 0.0007 | 0.0007 | # | 0.00 | 0.000 | 0.000 |
| | *NOx Emissions Performance* | | | *Control Costs* | | |
| Fuel Conversion System and Control Technologies | Min Level 100lb/MMBtu | Max Level 100lb/MMBtu | Maximum Reduction | Capital Cost $/kW | Var. O&M $/MWh | $/kWyear Fixed O&M |
| ***All Fuels - Emissions Controls*** | | | | | | |
| NOx (Coal Stations) - SCR | # | # | 65% | 150.00 | 4.000 | 1.000 |
| NOx (Oil & Gas Stations) - SCR | # | # | 65% | 45.00 | 4.000 | 1.000 |
| NOx - SNCR | 0.0008 | 0.0040 | # | 25.00 | 0.756 | 0.191 |
| NOx - Steam Injection (Existing CCs) | # | # | 40% | 7.00 | 0.700 | 2.400 |
| SOx - Wet FGD | # | # | # | 230.00 | 4.100 | 0.000 |
| SOx - Dry FGD | # | # | # | 80.00 | 4.000 | 0.000 |
| ***Other*** | | | | | | |
| Conventional Biomass | # | # | 100% | 0.00 | 0.000 | 0.000 |
| Conventional Biomass (Phase II Controlled) | # | # | 60% | 27.00 | 0.042 | 0.418 |
| Hydro/Nuclear | # | # | 100% | 0.00 | 0.000 | 0.000 |
| Municipal Waste | # | # | 100% | 0.00 | 0.000 | 0.000 |
| Municipal Waste (RACT Controlled) | # | # | 60% | 27.00 | 0.042 | 0.418 |
| Biomass Fired Fluidized Bed | # | # | 77% | 0.00 | 0.000 | 0.000 |

## Table 3-1: Cost and Performance Assumptions for Modeling NOx Control Technologies (continued)

| Fuel Conversion System and Control Technologies | NOx Emissions Performance: Min Level 100lb/MMBtu | Max Level 100lb/MMBtu | Maximum Reduction | Control Costs: Capital Cost $/kW | Var. O&M $/MWh$ | Fixed O&M /kWyear |
|---|---|---|---|---|---|---|
| *Oil Fired* | | | | | | |
| Old Tangential - No Control | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Tangential - No Control | 0.0033 | 0.0033 | # | 0.00 | 0.000 | 0.000 |
| Tangential + TSC | # | # | 27% | 1.30 | 0.020 | 0.100 |
| Tangential + FGR | # | # | 35% | 11.00 | 0.239 | 0.184 |
| Tangential + LNB | 0.0016 | 0.0023 | # | 24.00 | 0.150 | 0.490 |
| Tangential+OFA+LNB+FGR | # | # | 52% | 65.00 | 0.340 | 1.090 |
| Tangential + TSC + FGR | # | # | 50% | 29.00 | 0.150 | 0.490 |
| Old Wall - No Control | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Wall - No Control | 0.0040 | 0.0040 | # | 0.00 | 0.000 | 0.000 |
| Wall + TSC | # | # | 35% | 1.30 | 0.020 | 0.100 |
| Wall + FGR | # | # | 45% | 11.00 | 0.239 | 0.184 |
| Wall + LNB | 0.0015 | 0.0034 | # | 24.00 | 0.150 | 0.490 |
| Wall + OFA + LNB + FGR | 0.0013 | 0.0030 | # | 65.00 | 0.340 | 1.090 |
| Wall +TSC +FGR | # | # | 55% | 29.00 | 0.150 | 0.490 |
| Cyclone - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| Cyclone/Wet Bot. + Reburning | # | # | 60% | 38.00 | 0.125 | 1.250 |
| Old Comb. Turbine - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Comb. Turbine - Steam Injection | 0.0018 | 0.0018 | # | 0.00 | 0.000 | 0.000 |
| Old Comb. Turbine - Steam Injection | # | # | 60% | 0.00 | 0.150 | 0.645 |
| Internal Combustion - IC | 0.0350 | 0.0350 | # | 0.00 | 0.000 | 0.000 |
| Combined Cycle Comb. Turbine (Old) | # | # | 0% | 0.00 | 0.000 | 0.000 |
| Combined Cycle Comb. Turbine (New) | 0.0016 | 0.0016 | # | 0.00 | 0.000 | 0.000 |
| *Gas Fired* | | | | | | |
| Old Tangential - No Control | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Tangential - No Control | 0.0037 | 0.0037 | # | 0.00 | 0.000 | 0.000 |
| Tangential + TSC | 0.0016 | 0.0024 | # | 1.30 | 0.020 | 0.100 |
| Tangential + FGR | 0.0015 | 0.0020 | # | 11.00 | 0.239 | 0.184 |
| Tangential + LNB | 0.0012 | 0.0019 | # | 24.00 | 0.150 | 0.490 |
| Tangential+OFA+LNB+FGR | 0.0009 | 0.0015 | # | 65.00 | 0.340 | 1.090 |
| Tangential + TSC + FGR | 0.0013 | 0.0019 | # | 29.00 | 0.150 | 0.490 |
| Old Wall - No Control | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Wall - No Control | 0.0041 | 0.0041 | # | 0.00 | 0.000 | 0.000 |
| Wall + TSC | 0.0016 | 0.0033 | # | 1.30 | 0.020 | 0.100 |
| Wall + FGR | 0.0014 | 0.0025 | # | 11.00 | 0.239 | 0.184 |
| Wall + LNB | 0.0012 | 0.0019 | # | 24.00 | 0.150 | 0.490 |
| Wall + OFA + LNB + FGR | 0.0008 | 0.0014 | # | 65.00 | 0.340 | 1.090 |
| Wall +TSC +FGR | 0.0014 | 0.0021 | # | 29.00 | 0.150 | 0.490 |
| Old Gas Turbine - No Controls | # | # | 0% | 0.00 | 0.000 | 0.000 |
| New Gas Turbine - Steam Injection | 0.0009 | 0.0009 | # | 0.00 | 0.000 | 0.000 |
| Old Gas Turbine - Steam Injection | # | # | 60% | 0.00 | 0.150 | 0.645 |
| Internal Combustion | 0.0300 | 0.0300 | # | 0.00 | 0.000 | 0.000 |
| Combined Cycle Gas Turbine (Old) | # | # | 0% | 0.00 | 0.000 | 0.000 |
| Combined Cycle Gas Turbine (New) | 0.0003 | 0.0003 | # | 0.00 | 0.000 | 0.000 |
| Fuel Cell - Gas or Distillate | 0.0004 | 0.0004 | # | | | |

Therefore, the first alternative modeled in the existing unit controls option set is Phase I RACT with no further controls, the status-quo option. The northeast regional air policy coordinators, NESCAUM, estimate that RACT controls will yield a 50% reduction in NOx emissions from 1990 levels by 1995 (NESCAUM April 1992, p. 1). The two other options modeled aim for incrementally higher reductions by retrofitting post-combustion technologies on existing units. Firm Phase II option aims for a 60% reduction, and Hard Phase II aims for an 80% reduction.

Phase I RACT is modeled according to the following methodology. Eligible units are retrofitted with combustion controls so that NESCAUM RACT emissions limits are achieved. Individual states actually set their own limits in State Implementation Plans (SIPs) submitted to the EPA, but they are all close to NESCAUM's recommendations. The precise NESCAUM limits, specified by fuel type and boiler configuration, are shown in Table 3-2. Ineligible units include those scheduled for retirement/repowering before 2000, and units that generate for less than 500 hours per year, essentially all combustion turbines. The RACT regulations also allow for offsetting, whereby utilities can average emissions rates among units to achieve the greatest cost-effectiveness. This was modeled by overcontrolling emissions on some units and undercontrolling on others.

Table 3-2: NESCAUM RACT Emissions Limits

| | Boiler Configuration | | | |
|---|---|---|---|---|
| | Tangential | Wall | Cyclone | Stokers |
| Fuel Type | (.lbs NOx / MMBtu) | | | |
| Gas Only | 0.20 | 0.20 | N/A | N/A |
| Gas/Oil | 0.25 | 0.25 | 0.43 | N/A |
| Coal Wet Bottom | 1.00 | 1.00 | 0.55 | N/A |
| Coal Dry Bottom | 0.38 | 0.43 | N/A | 0.30 |

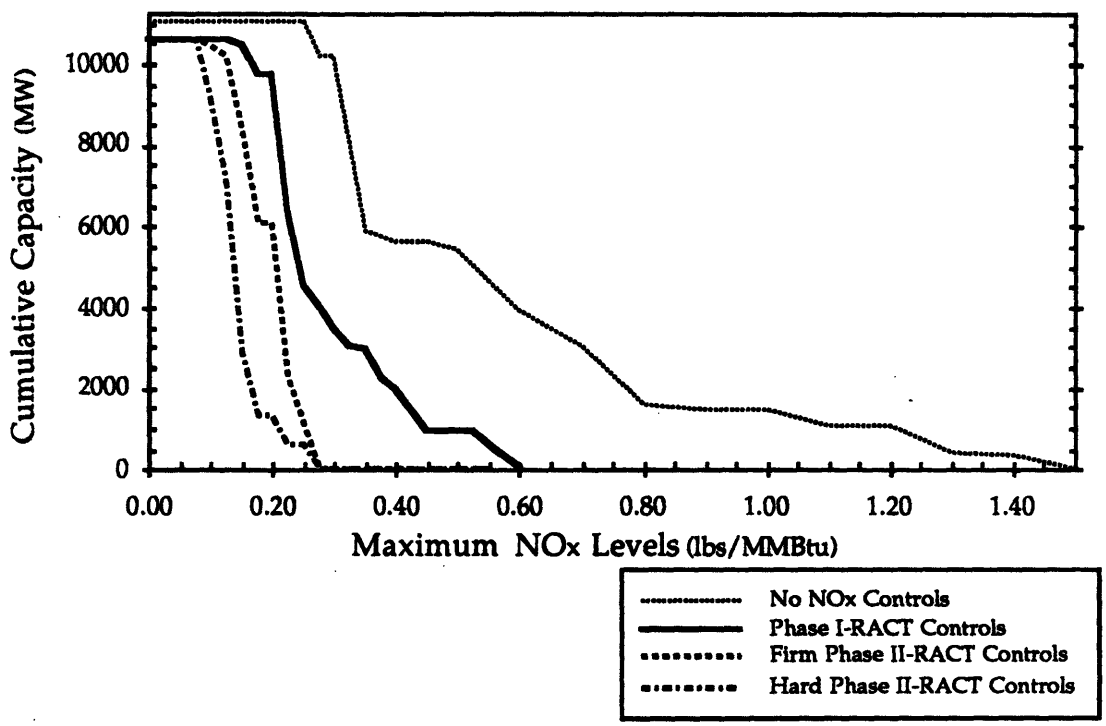
Source: NESCAUM, August 12, 1992

New units are also affected by the 1990 CAAAs. New plants must comply with a Lowest Available Emissions Reduction (LAER) standard and offset their emissions by a factor of 1.2 for every ton they emit. LAER is modeled as an SCR on all new units as a result of an AGREA Task Force meeting in December 1992. Offsets are modeled as a cost to the system that does not affect dispatch costs. It is estimated as $3500 per ton of NOx, the median value of reductions in the transportation sector (AGREA 1993, p. EMNO-5).

Phase II Firm and Hard levels are modeled according to an analogous methodology to the Phase I logic. The key difference is that post-combustion controls, SCRs and SNCRs, are applied to existing units rather than just combustion controls. These controls are retrofitted to achieve a system-wide 60% reduction for Phase II Firm, and 80% reduction for Phase II Hard.

The distribution of emissions levels by capacity is shown in Figure 3-1. The extent to which the various control technologies are retrofitted are summarized in Table 3-3.

Figure 3-1: Cumulative Capacity by NOx Emissions Rates



## Table 3-3: Application of NOx Control Technologies by Aggregate Capacity

| Phase I RACT - Installation Year | 1995 | |
|---|---|---|
| Control Technology | # Plants Ctrl. | Total MW Ctrl. |
| Low NOx Burners (LNB) | 12 | 2172 |
| Overfired Air (OFA) | 0 | 0 |
| Flue Gas Recycling (FGR) | 7 | 960 |
| Two Stage Combustion | 13 | 4267 |
| OFA & LNB & FGR | 2 | 773 |
| LNB & OFA | 7 | 1282 |
| Reburning | 2 | 500 |
| Steam Injection | 1 | 360 |
| Selective Catalytic Reduction | 0 | 0 |
| Selective Non-Catalytic Reduction | 0 | 0 |
| TOTAL | 44 | 10314 |

| Phase II Firm - Installation Year | 1995 | | 1998 | | 2000 | | TOTAL | |
|---|---|---|---|---|---|---|---|---|
| Control Technology | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. |
| Low NOx Burners (LNB) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overfired Air (OFA) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Flue Gas Recycling (FGR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Two Stage Combustion | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OFA & LNB & FGR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LNB & OFA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Reburning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Injection | 2 | 456 | 0 | 0 | 0 | 0 | 2 | 456 |
| Selective Catalytic Reduction | 6 | 1867 | 2 | 482 | 7 | 719 | 15 | 3068 |
| Selective Non-Catalytic Reduction | 4 | 533 | 0 | 0 | 6 | 1210 | 10 | 1743 |
| TOTAL - Utility System | 12 | 2856 | 2 | 482 | 13 | 1929 | 27 | 5267 |

Note: Also, 41 NUG units totaling 1101 MW capacity receive Low NOx Burners

| Phase II Hard - Installation Year | by 1995 | | 1997-1998 | | 1999-2001 | | TOTAL | |
|---|---|---|---|---|---|---|---|---|
| Control Technology | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. | # Plants Ctrl. | Total MW Ctrl. |
| Low NOx Burners (LNB) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overfired Air (OFA) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Flue Gas Recycling (FGR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Two Stage Combustion | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OFA & LNB & FGR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LNB & OFA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Reburning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Injection | 1 | 360 | 0 | 0 | 0 | 0 | 1 | 360 |
| Selective Catalytic Reduction | 15 | 3756 | 2 | 482 | 11 | 993 | 28 | 5231 |
| Selective Non-Catalytic Reduction | 9 | 2176 | 1 | 476 | 9 | 2366 | 19 | 5018 |
| TOTAL | 25 | 6292 | 3 | 958 | 20 | 3359 | 48 | 10609 |

Note: Also, 41 NUG units totaling 1101 MW capacity receive Low NOx Burners

In addition to NOx control technologies on units, the region can directly control NOx emissions through a system-wide operational policy. Such an approach would not care about how the region controlled emissions, but rather the timing, location, and amount of emissions released. This perspective pursues air quality goals more directly.

The broad and diverse operational policy options are designed to scope out the range of alternatives available. Unlike existing unit control options, each policy alternative is tailored to the temporal and/or geographic nature of the ozone problem. The policy instruments include emissions caps and minimum-NOx dispatch logic. A list of the options and their letter codes are shown in Table 3-4.

Table 3-4: Options for NOx Operational Control Policy

| Letter Code Abbreviation | NOx Operational Control Policy |
|---|---|
| V | No Operational Policy |
| N | Annual Minimum NOx Dispatch |
| P | Annual Cap of 80% |
| Q | Ozone Season Minimum NOx Dispatch |
| R | Ozone Season Cap of 80% |
| S | Geographic Annual Minimum NOx Dispatch |
| W | Intermittent Minimum NOx Dispatch |

Each operational control policy is distinguished by a temporal, geographic, and policy instrument element. The first option is the status-quo alternative, no operational policy, whereby the states decide that existing unit controls were sufficient for achieving ozone compliance.

The Annual Minimum option represents a policy whereby the entire region minimizes NOx emissions over the full year. This alternative is intended as a boundary option that demonstrates the lower limit for emissions by the power system. It is not very practical since the ozone season is approximately five months long, from May through September. The region would be paying for seven months worth of controls that provided minimal or no air quality benefits. Minimum NOx dispatch is also called environmental dispatch.

The Annual 80% Cap option also represents a policy whereby the entire region controls NOx over the full year, however it uses a cap rather than dispatch. Thus, it differs from the dispatch option only if dispatch can exceed this 80% target reduction. The cap equals 80% of 1990 New England regional emissions of 160,000 MTons, totaling 32,000 MTons of NOx.

The Seasonal Minimum option is similar to the Annual Minimum option described above, except that dispatch control is implemented only during the five month ozone season, not the entire year. Thus, the region is paying for emissions reductions during May through September, when air quality is significantly affected.

The Seasonal 80% Cap is similar to the Annual 80% Cap, except that the cap only applies to the five month ozone season. Thus, the cap equals 80% of 1990 May through September emissions, roughly 48,000 MTons, totaling 9600 MTons.

The Geographic Annual Minimum is similar to the Annual Minimum option, except that rather than controlling emissions over the entire region, it only controls over the upwind three states, Connecticut, Massachusetts, and Rhode Island. About 75% of 1990 NOx emissions come from these states. There is large uncertainty about the benefits from controlling upwind versus downwind emissions due to regional transport of ozone and its precursors. However, while atmospheric chemists obtain further information, this option illustrates the impacts of such option on the electric power system.

The Geographic Annual 80% Cap is similar to the Annual 80% Cap, except the former controls emissions only in the upwind states. The cap equals 120,000 MTons, or 80% of 1990 upwind emissions of 160,000 MTons.

Lastly, the most responsive operational control option is Intermittent Minimum NOx Dispatch. This option is similar to Seasonal Minimum, except that emissions are controlled only on days that could contribute to ozone exceedences, not over the entire five month season. The number of days of exceedences each year in New England has ranged from approximately eight to thirty (OTC 1994, p. 8) between 1987 and 1993. Taking twenty as a middle value, the region would control certain days before or after the exceedences that were potential exceedence days. So thirty-five days is a reasonable number for which minimum NOx dispatch would apply in an average year. For modeling purposes, these days are consecutive in the simulation, but correspond to scattered days throughout the actual ozone season.

# Chapter 4

## RESULTS

### OVERVIEW

To find understandable observations from the vast amount of performance data, the results are analyzed in several different ways. A summary of these results is provided in the last section of this chapter.

First, consistent with integrated-resource planning ideals, all of the strategies are compared with each other using multi-attribute tradeoff analysis (MATA). This technique captures the interaction and synergies between different options. It attempts to identify overall trends, highlighting the best performing options and strategies.

Second, to focus in on the impacts of individual options, scenarios that differ in only one or two options are compared with each other. This analysis shows the significance of single options on the trends identified with MATA. Both twenty year cumulative values and annual values are examined in this section.

Third, to capture the degree to which the above results depend on input assumptions, sensitivity analysis is performed on the most important input: natural gas fuel costs. Since minimum NOx dispatch options shift generation mostly from oil and coal units to natural gas units, the differential in fuel costs largely determines the cost of these operational control strategies. The impacts of both higher and lower natural gas costs are examined.

Over one hundred performance and descriptive attributes are computed for each scenario. The most important ones for this study are the the NOx emissions and cost criteria. Some attributes of secondary importance are also reported often in this analysis, regarding SO2 and CO2 emissions and natural gas use. The primary and secondary attributes are defined as follows:

| | |
|---|---|
| NPV Total Direct Costs (1991$B) | Net present value of 20 year total direct cost stream at 11.4% discount rate |
| Cumulative SO2 Emissions (millions of tons) | Sum over 20 years of total sulfur dioxide stack emissions |
| Cumulative CO2 Emissions (millions of tons) | Sum over 20 years of total carbon dioxide stack emissions |
| Cumulative NOx Emissions (millions of tons) | Sum over 20 years of total nitrogen oxides stack emissions |
| 2011 Gas Use as % of 1990 NE | Natural gas consumption in the power sector during the last year of study period, 2011, as a percentage of total natural gas consumption in New England in 1990 in all sectors |
| Upwind Episode NOx Emissions (thousands of tons) | Sum over 20 years of total nitrogen oxides stack emissions from units located in Connecticut, Rhode Island, and Massachusetts during 28 days per year associated with ozone episodes |
| Upwind Season NOx Emissions (thousands of tons) | Sum over 20 years of total nitrogen oxides stack emissions from units located in Connecticut, Rhode Island, and Massachusetts during the May to September ozone season |
| New England Episode NOx Emiss. (thousands of tons) | Sum over 20 years of total nitrogen oxides stack emissions from all units located in New England during 28 days per year associated with ozone episodes |
| New England Season NOx Emissions (thousands of tons) | Sum over 20 years of total nitrogen oxides stack emissions from all units located in New England during the May to September ozone season |

Other attributes measure capital and operating cost components, fuel usage by type of fuel, the annual changes in bills and rates, and other criteria. Reliability, normally a critical concern of power system planners, is comparable across all scenarios modeled. Thus, it is not considered in this analysis.

### OVERALL TRENDS FROM TRADEOFF ANALYSIS

Tradeoff analysis reveals several general results. These are illustrated best through tradeoff graphs, shown in Figures 4-1 to 4-5. Supporting details are provided in Tables 4-1 to 4-3, which contain the key performance data of all strategies, the delta performances from the base case, GISAVERYB, and the % delta performances, respectively. The results for the geographic control strategies are better explained by examining only NOx control options. Thus, they are not discussed in this tradeoff analysis section, but they are discussed in the next section.

With regard to the likely two most important criteria, total direct costs and seasonal NOx emissions, NOx control technologies and operational controls are superior to DSM, repowering, and non-gas new supply. As Figure 4-1 shows, the strategies that employ only NOx control technologies and/or operational controls are both cheaper and cleaner than the other strategies. However, these other strategies yield different benefits, as will be discussed below, and cannot be eliminated as absolutely inferior alternatives.

Focusing in on the tradeoff frontier, as Figure 4-2 illustrates, reveals the relative cost-effectiveness, or tradeoffs, between the various strategies. This cost-effectiveness is represented by the slope of the lines connecting different strategies. The steeper the line, the lower the cost-effectiveness. Also, the frontier shows the minimum cost for achieving any specified level of seasonal NOx emissions.

To achieve progressively lower seasonal emissions, the minimum-cost strategies alternate between adding control technologies and using operational controls. Specifically, moving from right to left along the frontier, the strategies change from Phase I RACT with No Operational Control, to Phase I RACT with Seasonal Minimum, to Phase II Firm with No Operational Control, to Phase II Firm with Seasonal Minimum, to

Phase II Hard with No Operational Control, to Phase II Hard with Seasonal Minimum.

The only strategy with dramatically lower cost-effectiveness is the one with Phase II Hard and No Operational Control. As Figure 4-2 illustrates, this strategy costs significantly more than the one with Phase II Firm and Seasonal Minimum at approximately the same emissions level. Moreover, the latter strategy has some other advantages compared with the former, as will be explained below. These results suggest that wide applications of control technologies are greatly enhanced by concurrent operational controls.

Since control technologies have high capital and low operating expenses, they become less cost-effective the smaller the control period. In contrast, operational controls become relatively more cost-effective since they have low capital and high operating expenses. These results are illustrated in Figure 4-3, which has New England episode NOx emissions on the independent axis and Episode Minimum strategies highlighted. The general trends are the same as those observed in Figure 4-2. However, the control technology strategies became slightly less cost-effective compared with the operational controls. Again, Phase II Hard with No Operational Controls evidences poor cost-effectiveness compared with Phase II Firm with operational controls, in this case Episode Minimum.

From a systemic perspective, there are other important attributes in power system planning besides cost and seasonal NOx emissions. One of these is $CO_2$ emissions, a key component of global climate change issues. Figure 4-4 shows the performances of the strategies in terms of total direct costs and annual $CO_2$ emissions.

Clearly, all of the strategies with just technology controls and operational controls perform very poorly on $CO_2$ emissions. Compared with conservation and repowering strategies, these strategies trivially reduce $CO_2$ emissions. The major lever for mitigating $CO_2$ emissions is conservation, which displaces fossil generation altogether. Repowering yields some $CO_2$ emissions reductions, but at relatively high costs. The non-gas new supply mix has virtually no effect on $CO_2$ emissions since fossil fuels, coal and biomass in particular, are such large components of this option.

Similarly, the strategies with just technology controls and operational controls increase dependence on natural gas units, as Figure 4-5 shows. Repowering similarly increases gas use. The major levers for mitigating gas dependency are non-gas new supply and conservation. However, it is interesting to note that the direction in which operational controls change gas use depends highly on level of control technologies. Under Phase I RACT, operational controls yield the largest increase in gas use. Under Phase II Firm, they have virtually no effect. Under Phase II Hard, they actually decrease natural gas use.

These observations follow from the fact that most existing fossil-fueled units in New England are coal or oil plants. Therefore, as post-combustion controls make them lower-emitting NOx units than existing gas plants, they will be used more under minimum NOx dispatch.

Data describing the performances of all the strategies, as well as their differences and % differences from the base case, GISAVERYB, are shown in Tables 4-1 to 4-3, respectively. This overwhelming amount of data is examined piecemeal in the following two sections to identify the impacts of individual options.

*Figure 4-1: Tradeoff Graph for Total Direct Costs v. Cumulative New England Seasonal NOx Emissions*

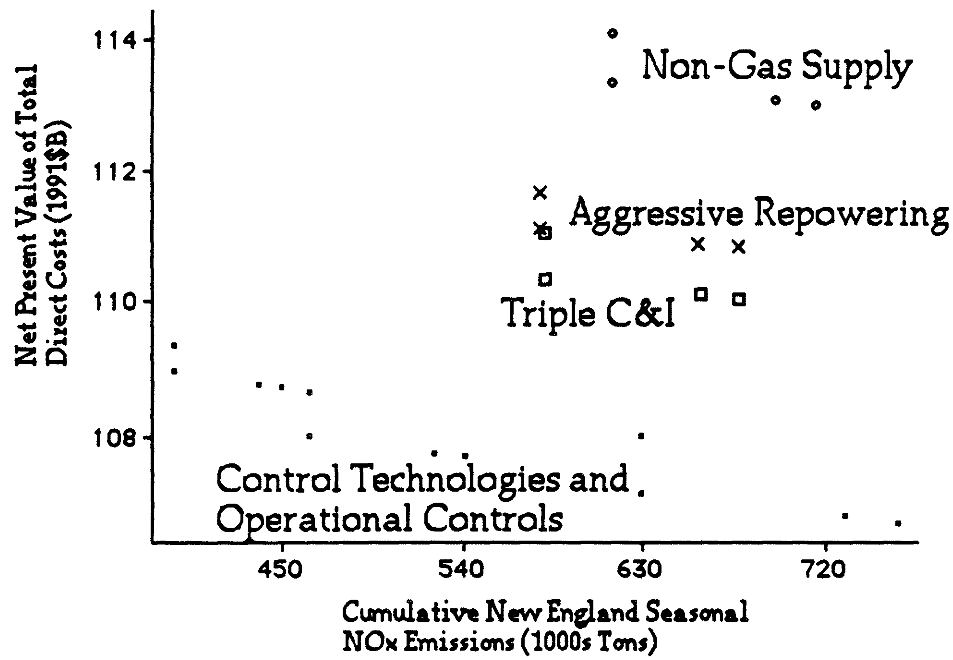



*Figure 4-2: Tradeoff Graph for Total Direct Costs v. Cumulative New England Seasonal NOx Emissions*

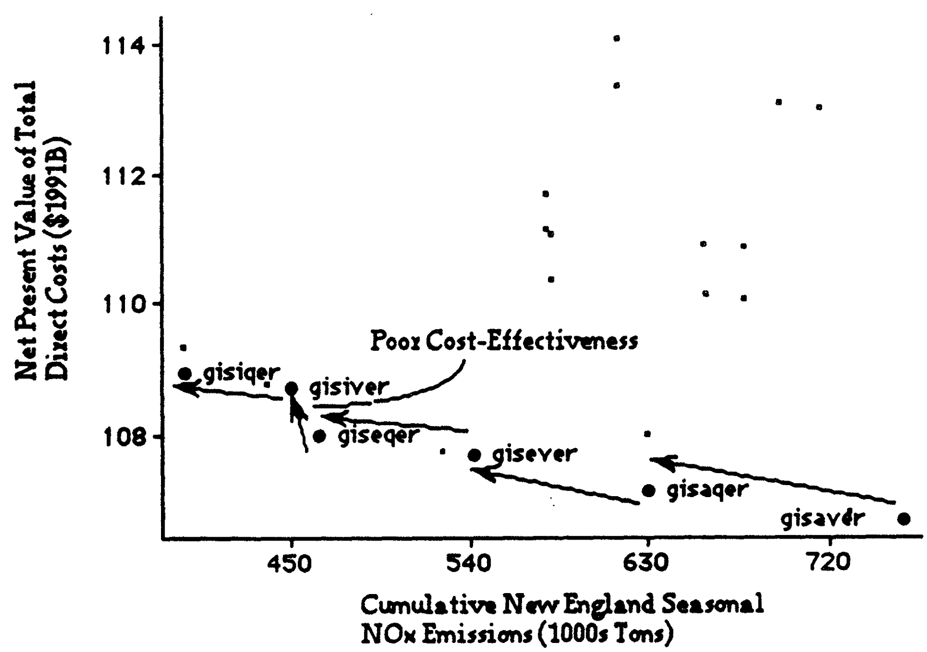


*Figure 4-3: Tradeoff Graph for Total Direct Costs v. Cumulative New England Episode NOx Emissions*

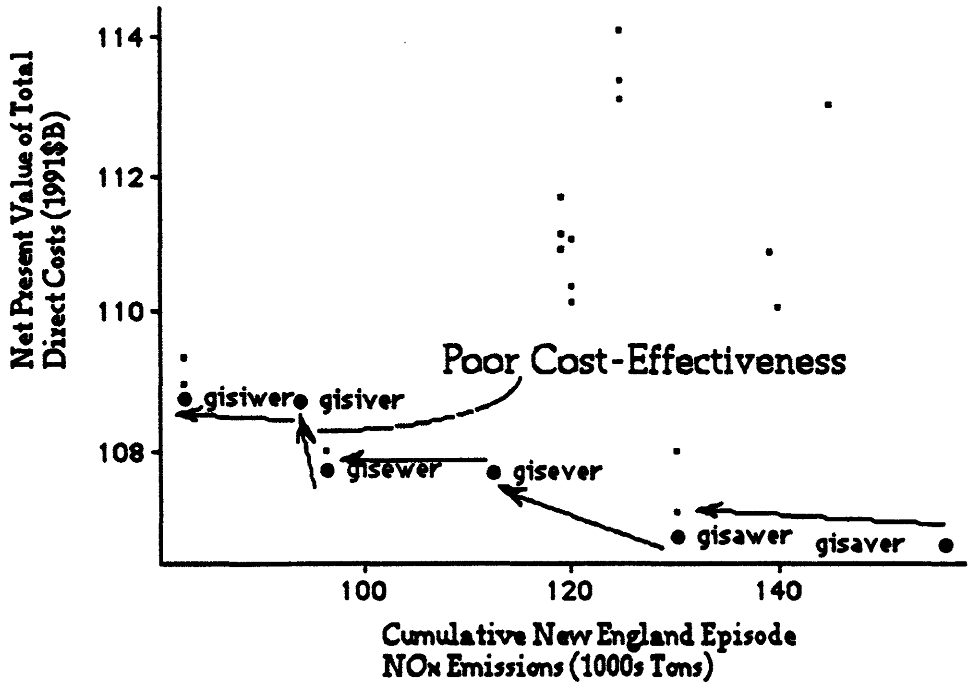



*Figure 4-4: Tradeoff Graph for Total Direct Costs v. Cumulative New England Annual CO2 Emissions*

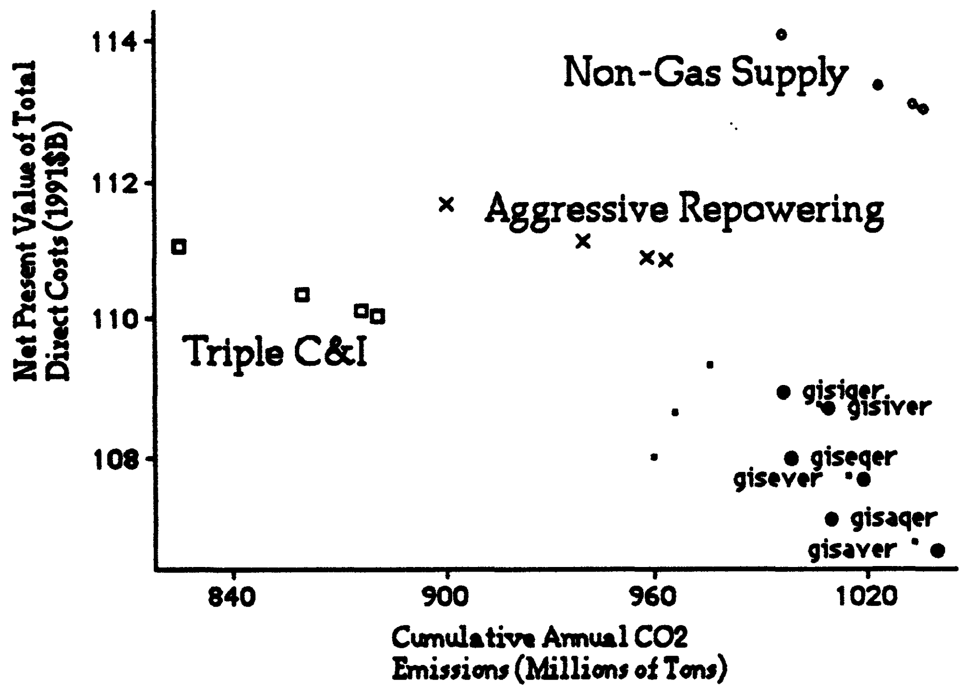
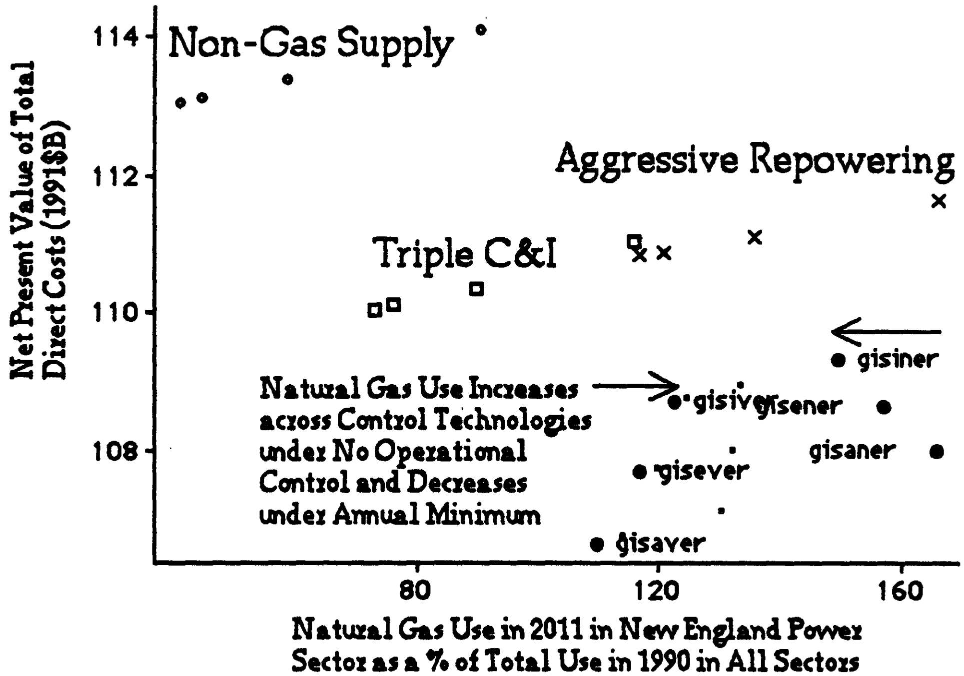


*Figure 4-5: Tradeoff Graph for Total Direct Costs v. Natural Gas Dependency in 2011*



## Table 4-1: Summary of Strategy Performances

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryb | 106.66 | 4.55 | 2.07 | 1039.70 | 109.99 | 121.53 | 590.62 | 155.92 | 756.30 |
| gisaweryb | 106.76 | 4.44 | 2.04 | 1033.70 | 114.15 | 95.73 | 564.81 | 130.29 | 730.67 |
| gisaqeryb | 107.11 | 4.02 | 1.94 | 1009.86 | 130.54 | 95.73 | 463.73 | 130.29 | 629.86 |
| giseveryb | 107.66 | 4.33 | 1.50 | 1018.81 | 116.93 | 83.49 | 402.34 | 112.40 | 541.48 |
| giseweryb | 107.73 | 4.24 | 1.48 | 1014.71 | 120.04 | 68.38 | 387.23 | 96.50 | 525.58 |
| gisaneryb | 107.98 | 3.07 | 1.73 | 960.19 | 165.53 | 95.73 | 463.73 | 130.29 | 629.86 |
| giseqeryb | 107.99 | 3.91 | 1.42 | 998.72 | 132.32 | 68.38 | 329.28 | 96.50 | 463.78 |
| giseneryb | 108.63 | 3.16 | 1.28 | 965.66 | 156.86 | 68.38 | 329.28 | 96.50 | 463.78 |
| gisiveryb | 108.72 | 4.21 | 1.25 | 1009.26 | 122.51 | 67.80 | 325.80 | 93.74 | 450.70 |
| gisiweryb | 108.76 | 4.16 | 1.24 | 1006.61 | 124.68 | 58.44 | 316.44 | 82.85 | 439.81 |
| gisiqeryb | 108.93 | 3.94 | 1.20 | 996.18 | 133.39 | 58.44 | 280.61 | 82.85 | 397.99 |
| gisineryb | 109.33 | 3.47 | 1.10 | 975.84 | 149.17 | 58.44 | 280.61 | 82.85 | 397.99 |
| gisavecyb | 110.05 | 4.08 | 1.89 | 880.48 | 73.00 | 110.79 | 536.95 | 140.02 | 677.61 |
| gisawecyb | 110.12 | 4.00 | 1.87 | 876.22 | 76.41 | 91.68 | 517.84 | 120.24 | 657.83 |
| gisaqecyb | 110.38 | 3.69 | 1.79 | 859.43 | 89.82 | 91.68 | 443.61 | 120.24 | 581.20 |
| gasaveryb | 110.89 | 3.45 | 1.85 | 962.72 | 117.08 | 105.35 | 512.63 | 139.28 | 677.21 |
| gasaweryb | 110.94 | 3.38 | 1.83 | 958.03 | 120.82 | 86.10 | 493.38 | 118.95 | 656.88 |
| gisanecyb | 111.06 | 3.01 | 1.62 | 825.07 | 115.98 | 91.68 | 443.61 | 120.24 | 581.20 |
| gasaqeryb | 111.15 | 3.10 | 1.75 | 939.79 | 135.66 | 86.10 | 420.30 | 118.95 | 578.60 |
| gasaneryb | 111.69 | 2.46 | 1.57 | 900.38 | 165.79 | 86.10 | 420.30 | 118.95 | 578.60 |
| kisaveryb | 113.04 | 4.09 | 1.96 | 1035.30 | 41.34 | 109.78 | 541.42 | 145.04 | 715.17 |
| kisaweryb | 113.11 | 4.02 | 1.94 | 1032.65 | 44.82 | 90.98 | 522.62 | 124.78 | 694.91 |
| kisaqeryb | 113.38 | 3.70 | 1.86 | 1022.29 | 58.78 | 90.98 | 448.10 | 124.78 | 614.82 |
| kisaneryb | 114.08 | 2.93 | 1.68 | 995.35 | 90.44 | 90.98 | 448.10 | 124.78 | 614.82 |

*Table 4-2: Summary of Strategy Performance Deltas Relative to Baseline (GISAVERYB)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisaweryb | 0.09 | -0.11 | -0.03 | -6.00 | 4.16 | -25.80 | -25.80 | -25.63 | -25.63 |
| gisaqeryb | 0.45 | -0.53 | -0.13 | -29.84 | 20.55 | -25.80 | -126.88 | -25.63 | -126.44 |
| giseveryb | 1.00 | -0.22 | -0.57 | -20.90 | 6.94 | -38.05 | -188.28 | -43.52 | -214.82 |
| giseweryb | 1.07 | -0.31 | -0.59 | -25.00 | 10.04 | -53.15 | -203.39 | -59.42 | -230.71 |
| gisaneryb | 1.31 | -1.48 | -0.34 | -79.51 | 55.54 | -25.80 | -126.88 | -25.63 | -126.44 |
| giseqeryb | 1.33 | -0.64 | -0.65 | -40.99 | 22.32 | -53.15 | -261.34 | -59.42 | -292.52 |
| giseneryb | 1.97 | -1.39 | -0.79 | -74.05 | 46.87 | -53.15 | -261.34 | -59.42 | -292.52 |
| gisiveryb | 2.06 | -0.34 | -0.82 | -30.44 | 12.52 | -53.74 | -264.81 | -62.18 | -305.60 |
| gisiweryb | 2.10 | -0.39 | -0.83 | -33.10 | 14.69 | -63.10 | -274.17 | -73.07 | -316.49 |
| gisiqeryb | 2.27 | -0.61 | -0.87 | -43.52 | 23.40 | -63.10 | -310.01 | -73.07 | -358.31 |
| gisineryb | 2.66 | -1.08 | -0.97 | -63.86 | 39.18 | -63.10 | -310.01 | -73.07 | -358.31 |
| gisavecyb | 3.38 | -0.47 | -0.18 | -159.22 | -36.99 | -10.75 | -53.66 | -15.90 | -78.68 |
| gisawecyb | 3.46 | -0.55 | -0.20 | -163.49 | -33.58 | -29.85 | -72.77 | -35.68 | -98.47 |
| gisaqecyb | 3.72 | -0.86 | -0.28 | -180.28 | -20.17 | -29.85 | -147.01 | -35.68 | -175.10 |
| gasaveryb | 4.22 | -1.10 | -0.22 | -76.99 | 7.09 | -16.19 | -77.99 | -16.64 | -79.08 |
| gasaweryb | 4.28 | -1.17 | -0.24 | -81.67 | 10.83 | -35.44 | -97.24 | -36.97 | -99.42 |
| gisanecyb | 4.40 | -1.54 | -0.45 | -214.64 | 5.99 | -29.85 | -147.01 | -35.68 | -175.10 |
| gasaqeryb | 4.49 | -1.45 | -0.32 | -99.92 | 25.67 | -35.44 | -170.32 | -36.97 | -177.70 |
| gasaneryb | 5.03 | -2.09 | -0.50 | -139.32 | 55.80 | -35.44 | -170.32 | -36.97 | -177.70 |
| kisaveryb | 6.38 | -0.46 | -0.11 | -4.41 | -68.65 | -11.76 | -49.20 | -10.88 | -41.13 |
| kisaweryb | 6.45 | -0.54 | -0.13 | -7.05 | -65.17 | -30.56 | -68.00 | -31.14 | -61.39 |
| kisaqeryb | 6.72 | -0.85 | -0.21 | -17.42 | -51.21 | -30.56 | -142.51 | -31.14 | -141.48 |
| kisaneryb | 7.41 | -1.62 | -0.39 | -44.36 | -19.55 | -30.56 | -142.51 | -31.14 | -141.48 |

*Table 4-3: Summary of Strategy Performance % Deltas Relative to Baseline (GISAVERYB)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions: Sulfur Dioxide | Cumulative Air Emissions: Nitrogen Oxides | Cumulative Air Emissions: Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions: Upwind Episode | NOx Cumulative 20 year emissions: Upwind Season | NOx Cumulative 20 year emissions: New Eng. Episode | NOx Cumulative 20 year emissions: New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| % Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisaweryb | 0.09% | -2.38% | -1.24% | -0.58% | 3.78% | -21.23% | -4.37% | -16.44% | -3.39% |
| gisaqeryb | 0.42% | -11.76% | -6.11% | -2.87% | 18.68% | -21.23% | -21.48% | -16.44% | -16.72% |
| giseveryb | 0.94% | -4.86% | -27.59% | -2.01% | 6.31% | -31.31% | -31.88% | -27.91% | -28.40% |
| giseweryb | 1.00% | -6.76% | -28.36% | -2.40% | 9.13% | -43.74% | -34.44% | -38.11% | -30.51% |
| gisaneryb | 1.23% | -32.46% | -16.65% | -7.65% | 50.49% | -21.23% | -21.48% | -16.44% | -16.72% |
| giseqeryb | 1.25% | -14.12% | -31.34% | -3.94% | 20.30% | -43.74% | -44.25% | -38.11% | -38.68% |
| giseneryb | 1.84% | -30.51% | -37.94% | -7.12% | 42.61% | -43.74% | -44.25% | -38.11% | -38.68% |
| gisiveryb | 1.93% | -7.40% | -39.59% | -2.93% | 11.38% | -44.22% | -44.84% | -39.88% | -40.41% |
| gisiweryb | 1.97% | -8.65% | -40.12% | -3.18% | 13.36% | -51.92% | -46.42% | -46.86% | -41.85% |
| gisiqeryb | 2.12% | -13.45% | -42.14% | -4.19% | 21.27% | -51.92% | -52.49% | -46.86% | -47.38% |
| gisineryb | 2.50% | -23.81% | -46.75% | -6.14% | 35.62% | -51.92% | -52.49% | -46.86% | -47.38% |
| gisavecyb | 3.17% | -10.40% | -8.69% | -15.31% | -33.63% | -8.84% | -9.09% | -10.20% | -10.40% |
| gisawecyb | 3.24% | -12.13% | -9.65% | -15.72% | -30.53% | -24.56% | -12.32% | -22.88% | -13.02% |
| gisaqecyb | 3.49% | -18.86% | -13.35% | -17.34% | -18.34% | -24.56% | -24.89% | -22.88% | -23.15% |
| gasaveryb | 3.96% | -24.19% | -10.83% | -7.40% | 6.45% | -13.32% | -13.20% | -10.67% | -10.46% |
| gasaweryb | 4.01% | -25.80% | -11.81% | -7.86% | 9.84% | -29.16% | -16.46% | -23.71% | -13.15% |
| gisanecyb | 4.12% | -33.94% | -21.53% | -20.64% | 5.44% | -24.56% | -24.89% | -22.88% | -23.15% |
| gasaqeryb | 4.21% | -31.86% | -15.59% | -9.61% | 23.34% | -29.16% | -28.84% | -23.71% | -23.50% |
| gasaneryb | 4.71% | -46.00% | -24.12% | -13.40% | 50.73% | -29.16% | -28.84% | -23.71% | -23.50% |
| kisaveryb | 5.98% | -10.03% | -5.12% | -0.42% | -62.42% | -9.67% | -8.33% | -6.98% | -5.44% |
| kisaweryb | 6.05% | -11.77% | -6.10% | -0.68% | -59.25% | -25.14% | -11.51% | -19.97% | -8.12% |
| kisaqeryb | 6.30% | -18.60% | -9.96% | -1.68% | -46.56% | -25.14% | -24.13% | -19.97% | -18.71% |
| kisaneryb | 6.95% | -35.60% | -19.08% | -4.27% | -17.78% | -25.14% | -24.13% | -19.97% | -18.71% |

PERFORMANCE OF STRATEGIES WITH ONLY NOx TECHNOLOGY CONTROLS AND/OR NOx OPERATIONAL CONTROLS

Individual strategies and options are always compared with a baseline strategy to measure deltas and % deltas from a consistent reference point. Usually the baseline strategy is GISAVERYB, the status-quo strategy, representing Gas/Oil new supply, Life Extension of existing units, Spot gas contracts, Phase I RACT NOx technology controls, No NOx Operational Control, Reference DSM, Anticyclic Average load growth, and Base/Stable fuel costs. In two groups of strategies, those with Phase II Firm and Phase II Hard technology controls, the baseline strategy is not GISAVERYB, but rather GISEVERYB and GISIVERYB, respectively. Using these baselines isolates the impacts of the operational control options.

The first set of comparisons examines the impacts of the different NOx operational policy options. These policy options are compared three times, under each of the three Existing Unit NOx Technology Control options. These results are shown in Table 4-4 to 4-6. For all three Existing Unit NOx Control options, minimum NOx strategies yield almost identical results to the NOx cap options, because minimum NOx strategies alone could not reduce NOx emissions below the strict caps. The caps were set at 80% reductions from 1990 emissions levels. It is likely that strategies combining operational controls and technology controls with conservation, repowering, and/or non-gas new supply would exceed this 80% target. However, these strategies would be extremely expensive at comparatively small NOx emissions savings.

The performances of the strategies in the first group, characterized by Phase I RACT, are summarized in Table 4-4. In combination with Phase I RACT, all operational options have similar average marginal emissions reductions and marginal costs.

Per four week period, as the performances of Intermittent and Annual Minimum, GISAWERYB and GISANERYB, show, operational controls increase four week period costs by 0.09 1991$B, or 1.2%, from the baseline. New England NOx emissions are decreased by 25.6 thousand tons per four weeks, or 16.4%. CO2 emissions are decreased by 6.0 million tons, or 7.7%, while SO2 emissions are decreased by 0.11 million tons, or 32.5%. In general, the % reduction in SO2 emissions is double that of NOx during the NOx control periods, while the % reduction in CO2 is half that of NOx. Natural gas use in 2011 increases by 55.5 percentage points, or 50.5%, per period of control.

The geographic control strategy offers considerable cost savings over the regional control if upwind NOx emissions are important and downwind emissions are not. Geographic Annual Minimum achieves nearly identical upwind NOx emissions during the period of control, whether annual, seasonal, or episodal. However, the cost decreases from 1.2% of total direct costs to 0.84%. At the same time, downwind NOx emissions increase, so that New England NOx emissions reductions decrease from 16.7% to 10.5%.

Under Phase II Firm, using GISEVERYB as a baseline, both the benefits and costs of NOx operational strategies are all smaller than under Phase I RACT. Benefits decrease by greater proportions that costs, so the cost-effectiveness of operational controls is less. The performance data are summarized in Table 4-5 for operational strategies under Phase II Firm.

Per four week period, as the performances of Intermittent and Annual Minimum, GISEWERYB and GISENERYB, show, operational controls increase four week period costs by 0.07 1991$B, or 0.9%, from the baseline. New England NOx emissions are decreased by 15.9 thousand tons per four weeks, or 14.1%. CO2 emissions are decreased by 4.1 million tons, or 5.2%, while SO2 emissions are decreased by 0.09 million tons, or 27.0%. The operational strategies reduce SO2 and CO2 emissions in slightly different proportions than under Phase I RACT. In general, the % reduction in SO2 emissions is a little less than double that of NOx during the NOx control periods, while the % reduction in CO2 is one third that of NOx.

Increases in natural gas use from operational controls are less under Phase II Firm than under Phase I RACT. Gas use rises by 40 percentage points, or 34.2%, compared with 50.5 and 55.5% under RACT. This result is explained in the above section on general trends by the fact that control technologies on existing non-gas units shift dispatch from gas to oil and coal units under operational controls.

The cost savings from a geographic control strategy is smaller under Phase II Firm thant under RACT, although it is still substantial. Geographic

Annual Minimum achieves nearly identical upwind NOx emissions during the period of control, whether annual, seasonal, or episodal. However, the cost decreases from 0.97% of total direct costs to 0.70%. At the same time, downwind NOx emissions increase, so that New England NOx emissions reductions decrease from 14.3% to 7.4%.

Under Phase II Hard, using GISIVERYB as a baseline, both the benefits and costs of NOx operational controls are even smaller than under Phase II Firm. Compared with Phase II Firm, benefits decrease by the same proportions as costs, so the cost-effectiveness remains the same. The performance data are summarized in Table 4-6 for operational strategies under Phase II Firm.

Per four week period, as the performances of Intermittent and Annual Minimum, GISIWERYB and GISINERYB, show, operational controls increase four week period costs by 0.04 1991$B, or 0.56%, from the baseline. New England NOx emissions are decreased by 10.9 thousand tons per four weeks, or 11.6%. CO2 emissions are decreased by 2.7 million tons, or 3.3%, while SO2 emissions are decreased by 0.06 million tons, or 17.7%. Again, the NOx operational strategies reduce SO2 and CO2 emissions in slightly different proportions than under Phase I RACT and Phase II Firm. In general, the % reduction in SO2 emissions is 1.5 times that of NOx during the NOx control periods, while the % reduction in CO2 is almost one fourth that of NOx.

Increases in natural gas use from operational controls are also less under Phase II Hard than under Phase I RACT or Phase II Firm, as even more control technologies on non-gas units shift generation from gas to oil and coal under operational control. Gas use rises by 26.7 percentage points, or 21.8%, per period of control.

There are essentially no cost savings from a geographic control strategy under Phase II Hard. While upwind emissions are about the same, the cost decreases from 0.56% of total direct costs to 0.53%. At the same time, downwind NOx emissions increase, so that New England NOx emissions reductions decrease from 11.9% to 4.6%.

*Table 4-4: Performance of Different NOx Operational Policies Combined with Phase I RACT (GISA-ERYB scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryb | 106.66 | 4.55 | 2.07 | 1039.70 | 110.0 | 121.53 | 590.62 | 155.92 | 756.30 |
| gisaweryb | 106.76 | 4.44 | 2.04 | 1033.70 | 114.1 | 95.73 | 564.81 | 130.29 | 730.67 |
| gisareryb | 107.11 | 4.02 | 1.94 | 1009.86 | 130.5 | 95.73 | 463.73 | 130.29 | 629.86 |
| gisaqeryb | 107.11 | 4.02 | 1.94 | 1009.86 | 130.5 | 95.73 | 463.73 | 130.29 | 629.86 |
| gisaseryb | 107.56 | 3.56 | 1.85 | 982.18 | 149.8 | 95.93 | 464.90 | 139.56 | 675.36 |
| gisaperyb | 107.98 | 3.07 | 1.73 | 960.19 | 165.5 | 95.73 | 463.73 | 130.29 | 629.86 |
| gisaneryb | 107.98 | 3.07 | 1.73 | 960.19 | 165.5 | 95.73 | 463.73 | 130.29 | 629.86 |
| Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisaweryb | 0.09 | -0.11 | -0.03 | -6.00 | 4.2 | -25.80 | -25.80 | -25.63 | -25.63 |
| gisareryb | 0.45 | -0.53 | -0.13 | -29.84 | 20.5 | -25.80 | -126.88 | -25.63 | -126.44 |
| gisaqeryb | 0.45 | -0.53 | -0.13 | -29.84 | 20.5 | -25.80 | -126.88 | -25.63 | -126.44 |
| gisaseryb | 0.90 | -0.99 | -0.22 | -57.52 | 39.9 | -25.60 | -125.72 | -16.36 | -80.94 |
| gisaperyb | 1.31 | -1.48 | -0.34 | -79.51 | 55.5 | -25.80 | -126.88 | -25.63 | -126.44 |
| gisaneryb | 1.31 | -1.48 | -0.34 | -79.51 | 55.5 | -25.80 | -126.88 | -25.63 | -126.44 |
| % Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisaweryb | 0.09% | -2.38% | -1.24% | -0.58% | 3.78% | -21.23% | -4.37% | -16.44% | -3.39% |
| gisareryb | 0.42% | -11.76% | -6.11% | -2.87% | 18.68% | -21.23% | -21.48% | -16.44% | -16.72% |
| gisaqeryb | 0.42% | -11.76% | -6.11% | -2.87% | 18.68% | -21.23% | -21.48% | -16.44% | -16.72% |
| gisaseryb | 0.84% | -21.83% | -10.50% | -5.53% | 36.23% | -21.07% | -21.29% | -10.49% | -10.70% |
| gisaperyb | 1.23% | -32.46% | -16.65% | -7.65% | 50.49% | -21.23% | -21.48% | -16.44% | -16.72% |
| gisaneryb | 1.23% | -32.46% | -16.65% | -7.65% | 50.49% | -21.23% | -21.48% | -16.44% | -16.72% |

*Table 4-5: Performance of Different NOx Operational Policies Combined with Phase II Firm (GISE-ERYB scenarios)*

| Scenario Name | NPV Direct: Total Direct | Cumulative Air Emissions: Sulfur Dioxide | Cumulative Air Emissions: Nitrogen Oxides | Cumulative Air Emissions: Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions: Upwind Episode | NOx Cumulative 20 year emissions: Upwind Season | NOx Cumulative 20 year emissions: New Eng. Episode | NOx Cumulative 20 year emissions: New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| giseveryb | 107.66 | 4.33 | 1.50 | 1018.81 | 116.9 | 83.49 | 402.34 | 112.40 | 541.48 |
| giseweryb | 107.73 | 4.24 | 1.48 | 1014.71 | 120.0 | 68.38 | 387.23 | 96.50 | 525.58 |
| gisereryb | 107.99 | 3.91 | 1.42 | 998.72 | 132.3 | 68.38 | 329.28 | 96.50 | 463.78 |
| giseqeryb | 107.99 | 3.91 | 1.42 | 998.72 | 132.3 | 68.38 | 329.28 | 96.50 | 463.78 |
| giseseryb | 108.37 | 3.54 | 1.39 | 979.05 | 146.9 | 68.31 | 328.57 | 104.12 | 500.94 |
| giseperyb | 108.63 | 3.16 | 1.28 | 965.66 | 156.9 | 68.38 | 329.28 | 96.50 | 463.78 |
| giseneryb | 108.63 | 3.16 | 1.28 | 965.66 | 156.9 | 68.38 | 329.28 | 96.50 | 463.78 |
| Delta from giseveryb | | | | | | | | | |
| giseveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| giseweryb | 0.07 | -0.09 | -0.02 | -4.10 | 3.1 | -15.11 | -15.11 | -15.90 | -15.90 |
| gisereryb | 0.33 | -0.42 | -0.08 | -20.09 | 15.4 | -15.11 | -73.05 | -15.90 | -77.70 |
| giseqeryb | 0.33 | -0.42 | -0.08 | -20.09 | 15.4 | -15.11 | -73.05 | -15.90 | -77.70 |
| giseseryb | 0.70 | -0.79 | -0.11 | -39.76 | 30.0 | -15.18 | -73.76 | -8.28 | -40.54 |
| giseperyb | 0.97 | -1.17 | -0.21 | -53.15 | 39.9 | -15.11 | -73.05 | -15.90 | -77.70 |
| giseneryb | 0.97 | -1.17 | -0.21 | -53.15 | 39.9 | -15.11 | -73.05 | -15.90 | -77.70 |
| % Delta from giseveryb | | | | | | | | | |
| giseveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| giseweryb | 0.06% | -2.00% | -1.06% | -0.40% | 2.66% | -18.09% | -3.75% | -14.14% | -2.94% |
| gisereryb | 0.31% | -9.73% | -5.18% | -1.97% | 13.16% | -18.09% | -18.16% | -14.14% | -14.35% |
| giseqeryb | 0.31% | -9.73% | -5.18% | -1.97% | 13.16% | -18.09% | -18.16% | -14.14% | -14.35% |
| giseseryb | 0.65% | -18.34% | -7.36% | -3.90% | 25.65% | -18.18% | -18.33% | -7.36% | -7.49% |
| giseperyb | 0.90% | -26.96% | -14.29% | -5.22% | 34.15% | -18.09% | -18.16% | -14.14% | -14.35% |
| giseneryb | 0.90% | -26.96% | -14.29% | -5.22% | 34.15% | -18.09% | -18.16% | -14.14% | -14.35% |

*Table 4-6: Performance of Different NOx Operational Policies Combined with Phase II Hard (GISI-ERYB scenarios)*

| Scenario Name | NPV Direct: Total Direct | Cumulative Air Emissions: Sulfur Dioxide | Cumulative Air Emissions: Nitrogen Oxides | Cumulative Air Emissions: Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions: Upwind Episode | NOx Cumulative 20 year emissions: Upwind Season | NOx Cumulative 20 year emissions: New Eng. Episode | NOx Cumulative 20 year emissions: New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991 $B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisiveryb | 108.72 | 4.21 | 1.25 | 1009.26 | 122.5 | 67.80 | 325.80 | 93.74 | 450.70 |
| gisiweryb | 108.76 | 4.16 | 1.24 | 1006.61 | 124.7 | 58.44 | 316.44 | 82.85 | 439.81 |
| gisireryb | 108.93 | 3.94 | 1.20 | 996.18 | 133.4 | 58.44 | 280.61 | 82.85 | 397.99 |
| gisiqeryb | 108.93 | 3.94 | 1.20 | 996.18 | 133.4 | 58.44 | 280.61 | 82.85 | 397.99 |
| gisiseryb | 109.30 | 3.57 | 1.19 | 977.02 | 144.8 | 58.09 | 279.04 | 89.46 | 429.92 |
| gisiperyb | 109.31 | 3.48 | 1.10 | 976.25 | 149.0 | 58.44 | 282.02 | 82.85 | 399.18 |
| gisineryb | 109.33 | 3.47 | 1.10 | 975.84 | 149.2 | 58.44 | 280.61 | 82.85 | 397.99 |
| Delta from gisiveryb | | | | | | | | | |
| gisiveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisiweryb | 0.04 | -0.06 | -0.01 | -2.66 | 2.2 | -9.36 | -9.36 | -10.89 | -10.89 |
| gisireryb | 0.21 | -0.28 | -0.05 | -13.08 | 10.9 | -9.36 | -45.19 | -10.89 | -52.71 |
| gisiqeryb | 0.21 | -0.28 | -0.05 | -13.08 | 10.9 | -9.36 | -45.19 | -10.89 | -52.71 |
| gisiseryb | 0.58 | -0.64 | -0.06 | -32.24 | 22.2 | -9.71 | -46.76 | -4.28 | -20.77 |
| gisiperyb | 0.59 | -0.73 | -0.15 | -33.01 | 26.4 | -9.36 | -43.78 | -10.89 | -51.52 |
| gisineryb | 0.61 | -0.75 | -0.15 | -33.42 | 26.7 | -9.36 | -45.19 | -10.89 | -52.71 |
| % Delta from gisiveryb | | | | | | | | | |
| gisiveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisiweryb | 0.04% | -1.34% | -0.87% | -0.26% | 1.77% | -13.80% | -2.87% | -11.62% | -2.42% |
| gisireryb | 0.19% | -6.53% | -4.21% | -1.30% | 8.88% | -13.80% | -13.87% | -11.62% | -11.70% |
| gisiqeryb | 0.19% | -6.53% | -4.21% | -1.30% | 8.88% | -13.80% | -13.87% | -11.62% | -11.70% |
| gisiseryb | 0.53% | -15.22% | -4.55% | -3.19% | 18.16% | -14.32% | -14.35% | -4.57% | -4.61% |
| gisiperyb | 0.54% | -17.41% | -11.69% | -3.27% | 21.59% | -13.80% | -13.44% | -11.62% | -11.43% |
| gisineryb | 0.56% | -17.72% | -11.85% | -3.31% | 21.76% | -13.80% | -13.87% | -11.62% | -11.70% |

To examine the impacts of the various operational control policies over time, rather than as a single twenty year cumulative value, trajectories are analyzed for six attributes. These key attributes include upwind episode NOx emissions, New England seasonal NOx emissions, New England annual NOx emissions, New England annual CO2 emissions, New England annual SO2 emissions, and total direct costs. Trajectories of the annual values and the annual % deltas from the base strategy are shown in Figures 4-6 to 4-17 for scenarios with Phase I RACT (GISA-ERYB scenarios).

The amount of upwind episode NOx reductions increases steadily over time, as No Policy emissions increase after 2006 while emissions from all other policies decrease after 2001. The % reduction from all operational policies linearly grows from around 10% in 1997 to 50% in 2011.

Similarly, the delta and % delta of New England seasonal NOx emissions reductions increase over time for the three options that minimize NOx during the ozone season. Emissions for No Policy and Intermittent increase after 2006, while emissions for the other options hold about constant after this same year. The % reduction for the strategies active during the season reaches 40% by the end of the twenty year period.

For annual NOx emissions, the amount and % reduction increases over time for the one seasonal and two annual minimum options. The % reduction reaches 40% by the end of the twenty year period. Emissions increase after 2006 for No Policy, Intermittent, and Seasonal. Emissions hold steady after 2006 for the two annual minimum options.

CO2 emissions increase over time for all strategies as fossil fuel generation increases with load growth. However, the % reduction from all operational controls increases slowly over time as well. The % reduction from the two annual minimum options jumps from 5% to 20% in 2007, but overall emission still rise in the latter years for these options.

SO2 emissions also respond to load growth, decreasing during flat load growth and increasing during increasing load growth. The % reduction from all operational strategies increases over time. For Annual Minimum, the % reduction reaches a very large 60% during the last five years of the study period.

Total direct costs increase in real terms over time for all strategies. The % increase in total direct costs for all the operational strategies reflects increases in natural gas costs, which rise from 1994 to 2004, and level off afterwards. The % delta for Annual Minimum remains around 2.5% by 2004.

All of the above trajectory results are similar for strategies with Phase II Firm and Phase II Hard instead of Phase I RACT. There are two main differences from the Phase I RACT observations. First, the magnitudes of the cost and emissions deltas from operational controls are smaller for the Phase II strategies as the power system baseline is cleaner and more expensive already. Second, Phase II technology controls achieve greater emissions reductions from 1995-2000 than does RACT, so NOx emissions levels remain flat rather than increase during these middle years of the study period. These observations are illustrated in Figures 4-18 to 4-29 below, showing the trajectory results for strategies with Phase II Hard.

*Figure 4-6: Upwind Episode NOx Emissions Trajectories for Operational NOx Options under Phase I RACT*

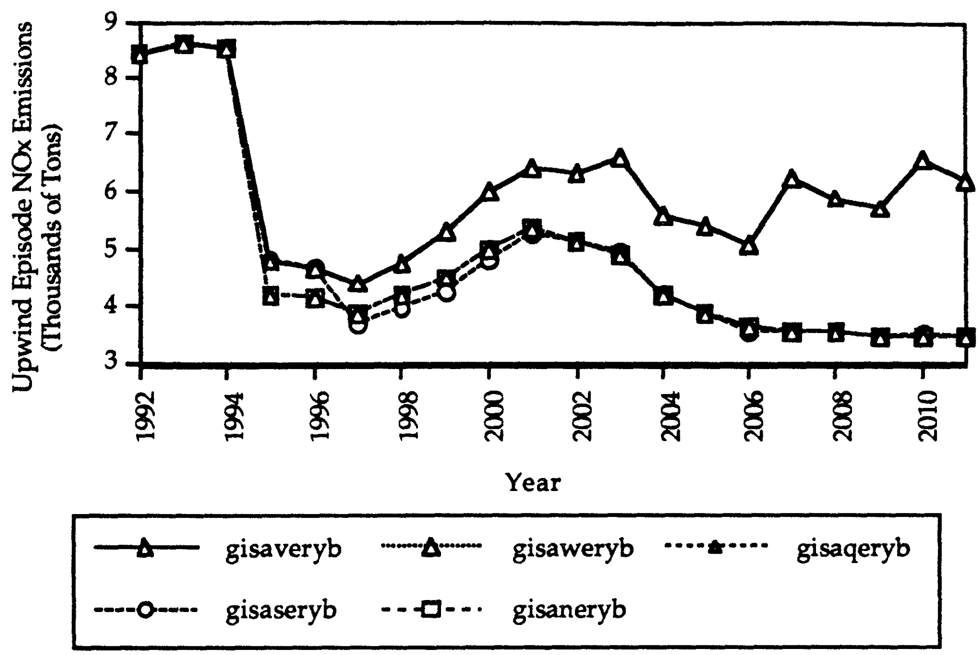



*Figure 4-7: % Deltas in Upwind Episode NOx Emissions Relative to No Policy for Operational NOx Options under Phase I RACT*

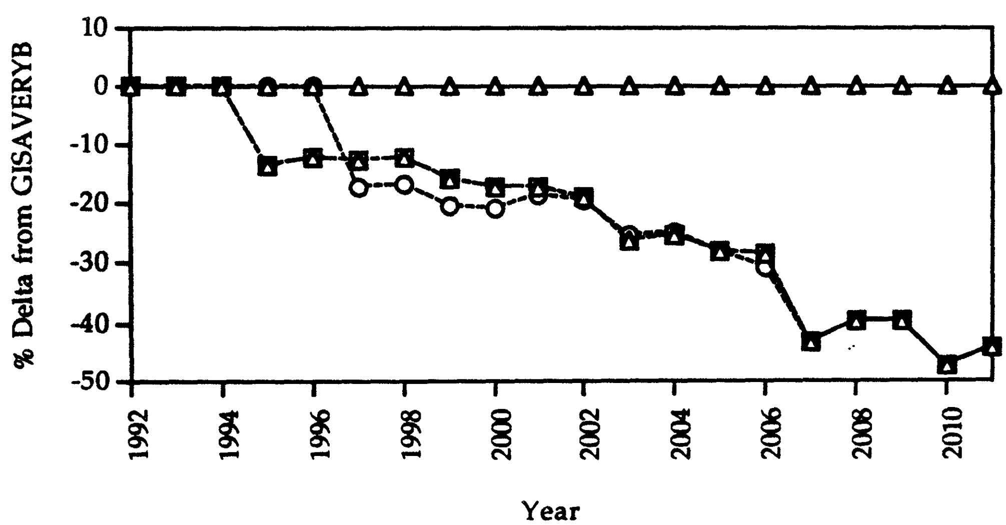


*Figure 4-8: New England Seasonal NOx Emissions Trajectories for Operational NOx Options under Phase I RACT*

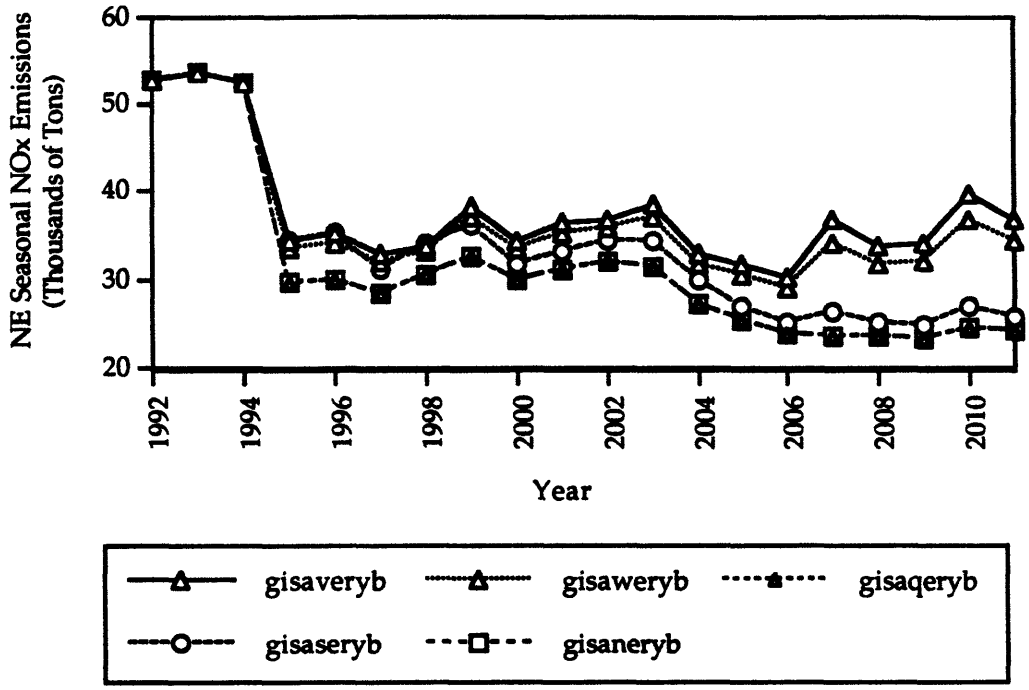



*Figure 4-9: % Deltas in New England Seasonal NOx Emissions Relative to No Policy for Operational NOx Options under Phase I RACT*

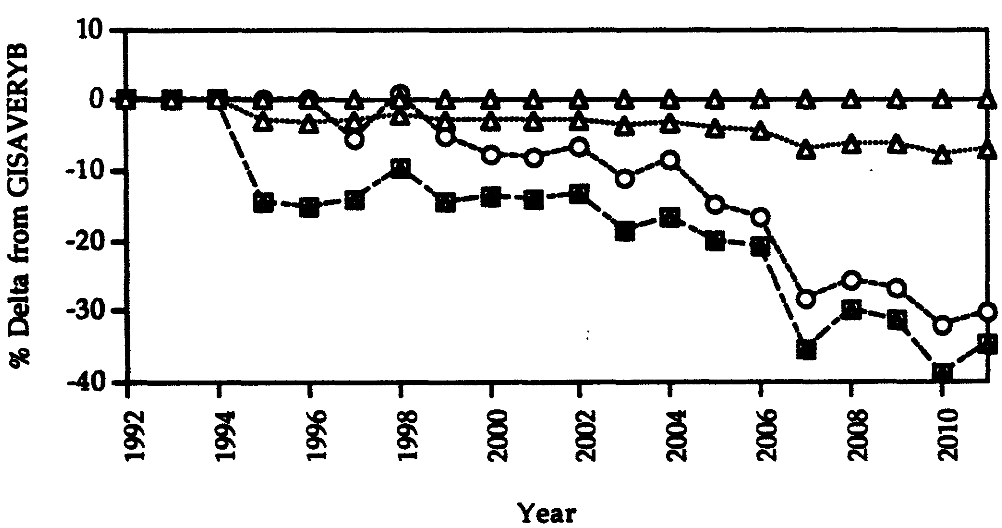


*Figure 4-10: New England Annual NOx Emissions Trajectories for Operational NOx Options under Phase I RACT*

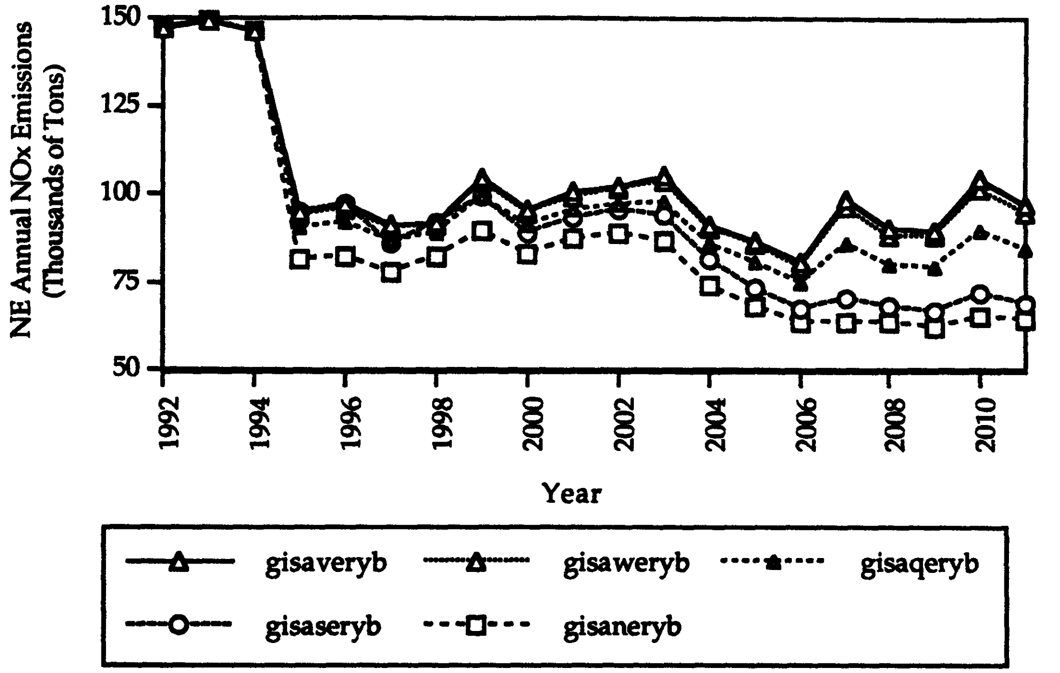



*Figure 4-11: % Deltas in New England Seasonal NOx Emissions Relative to No Policy for Operational NOx Options under Phase I RACT*

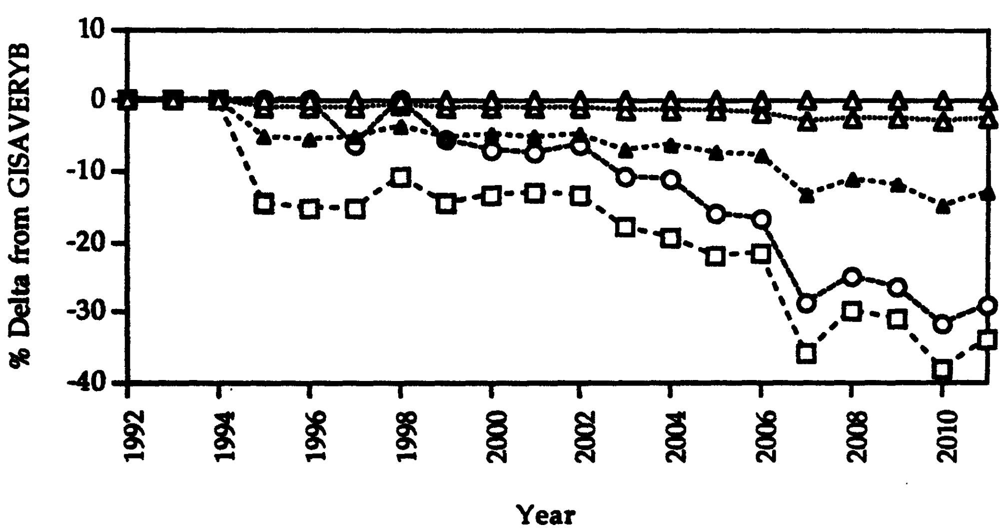


*Figure 4-12: New England Annual CO2 Emissions Trajectories for Operational NOx Options under Phase I RACT*

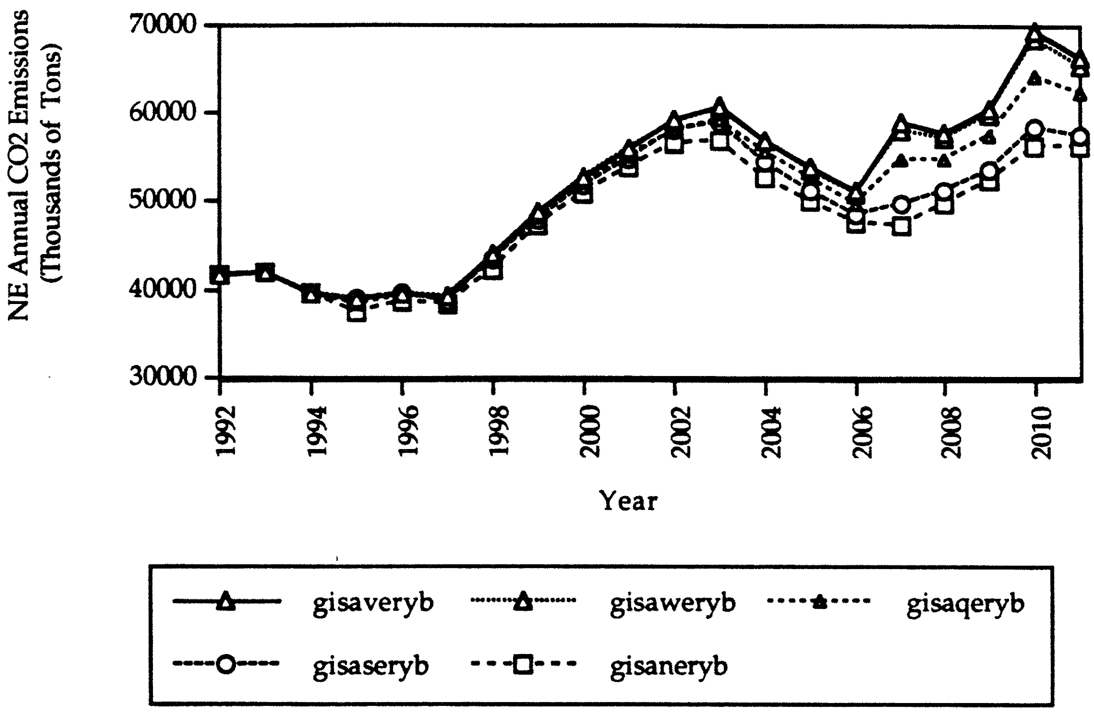



*Figure 4-13: % Deltas in New England Annual CO2 Emissions Relative to No Policy for Operational NOx Options under Phase I RACT*

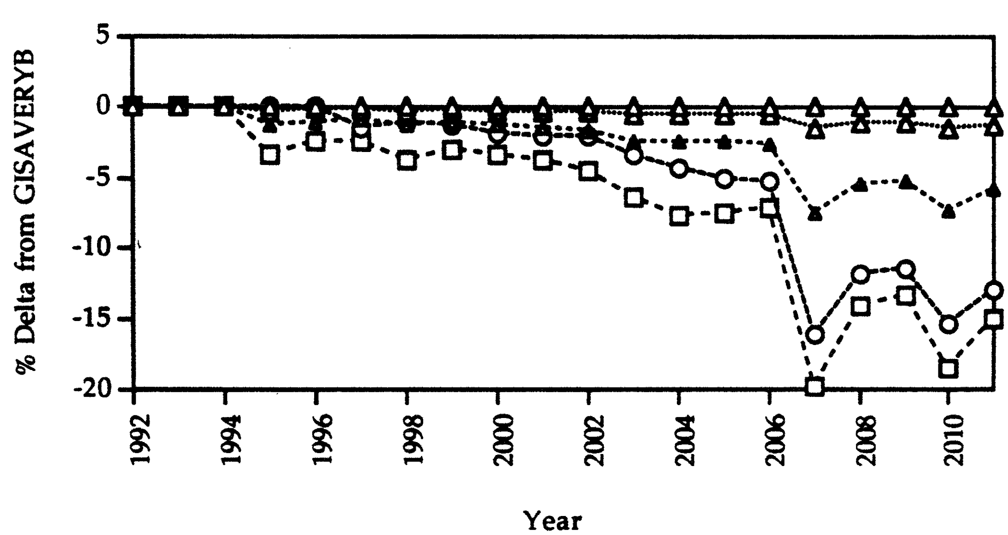


*Figure 4-14: New England Annual SO2 Emissions Trajectories for Operational NOx Options under Phase I RACT*

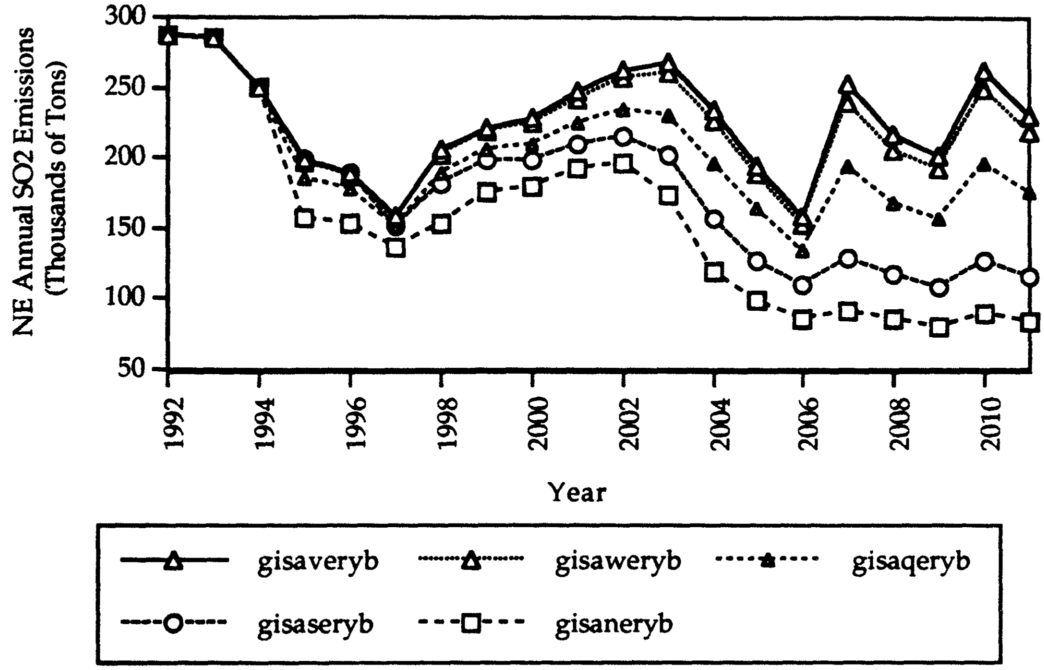



*Figure 4-15: % Deltas in New England Annual SO2 Emissions Relative to No Policy for Operational NOx Options under Phase I RACT*

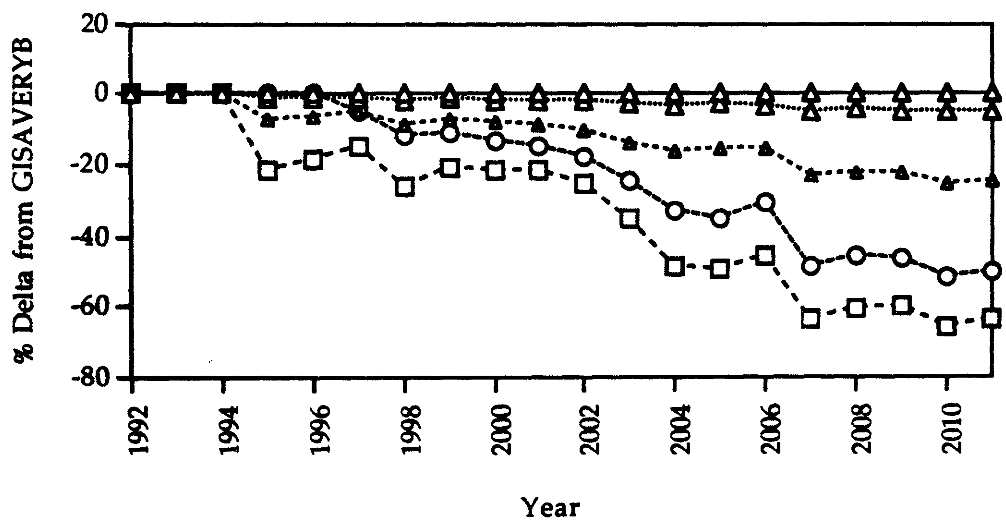


*Figure 4-16: Total Direct Cost Trajectories for Operational NOx Options under Phase I RACT*

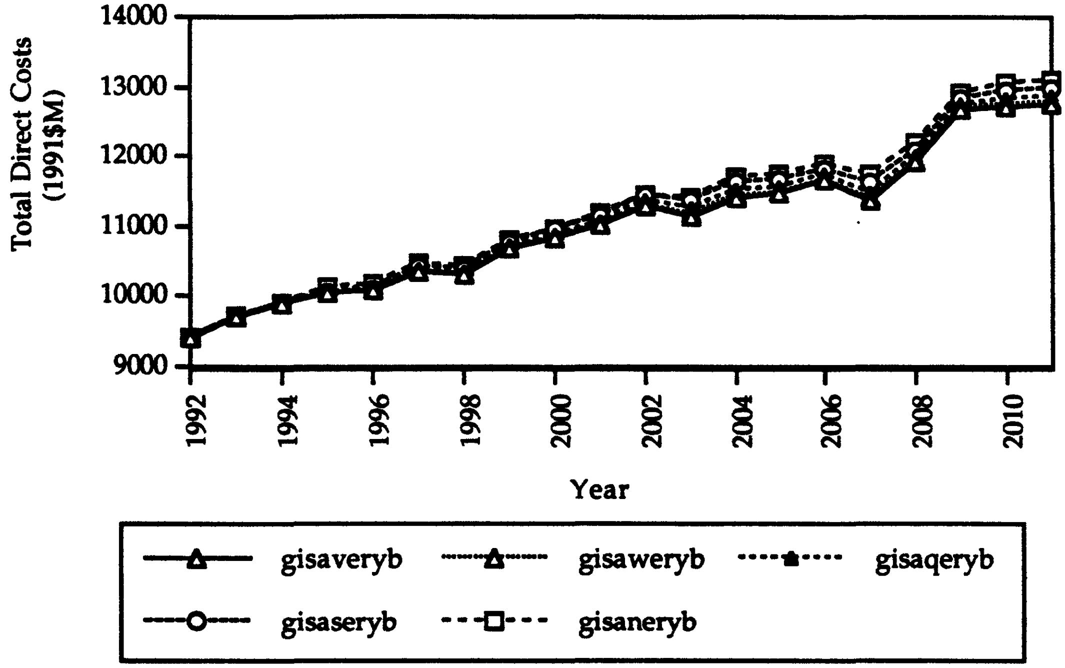



*Figure 4-17: % Deltas in Total Direct Costs Relative to No Policy for Operational NOx Options under Phase I RACT*

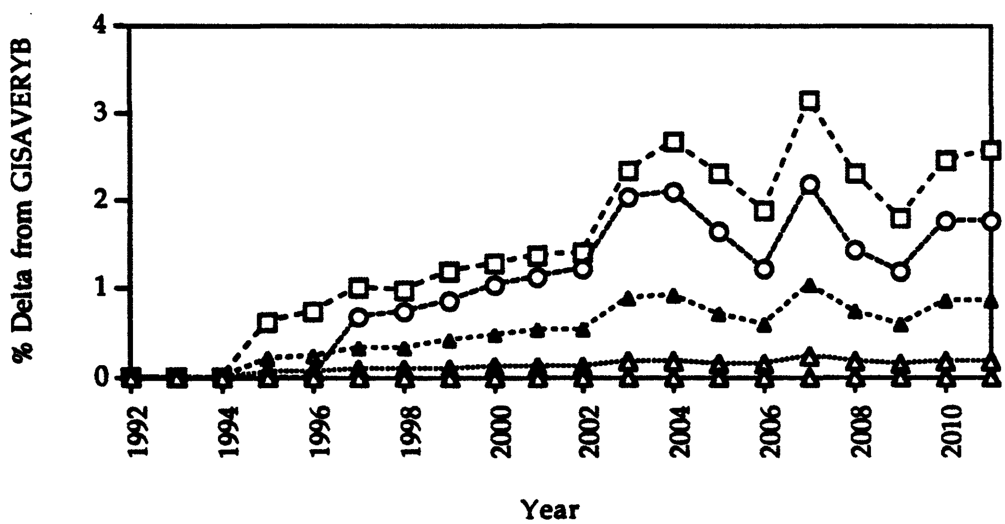


*Figure 4-18: Upwind Episode NOx Emissions Trajectories for Operational NOx Options under Phase II Hard*

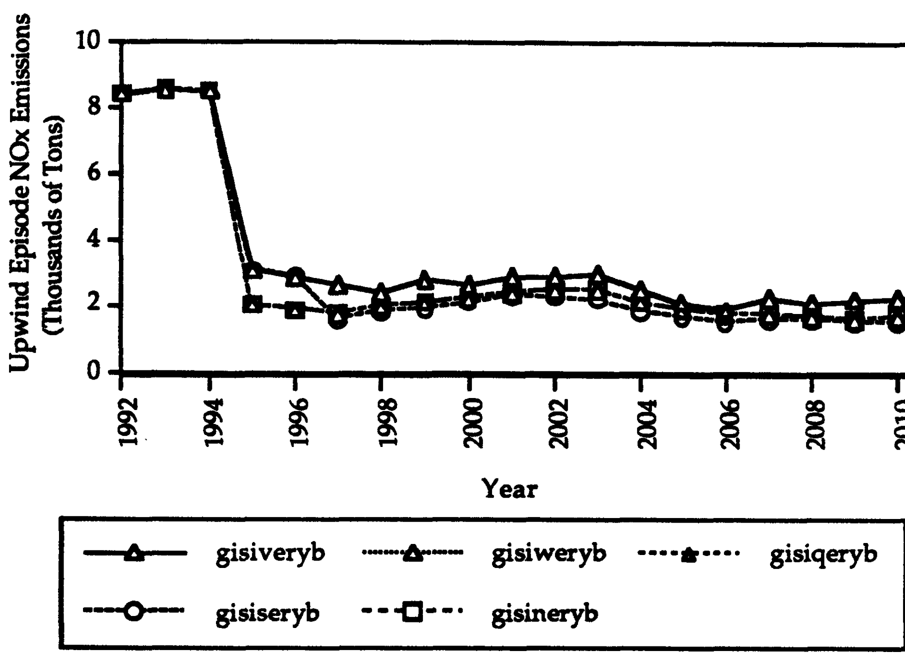



*Figure 4-19: % Deltas in Upwind Episode NOx Emissions Relative to No Policy for Operational NOx Options under Phase II Hard*

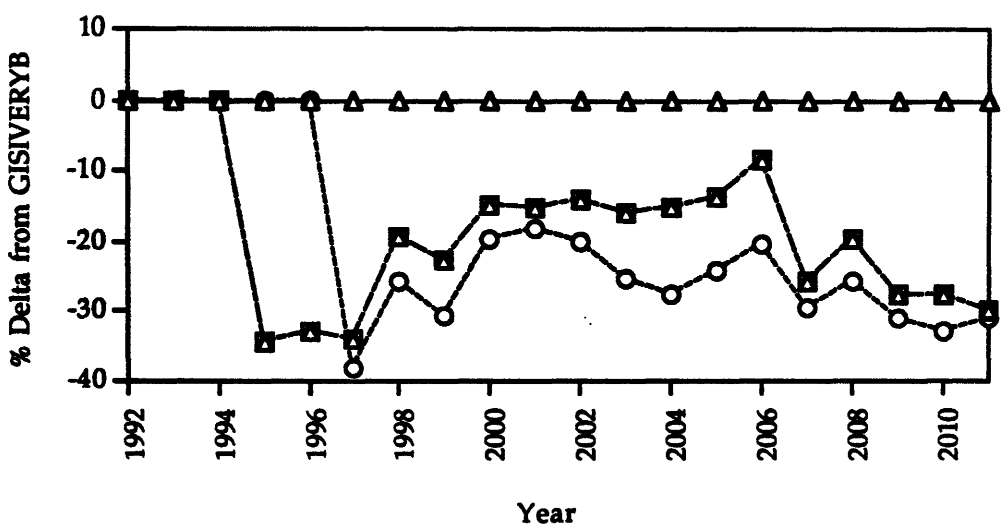


*Figure 4-20: New England Seasonal NOx Emissions Trajectories for Operational NOx Options under Phase II Hard*

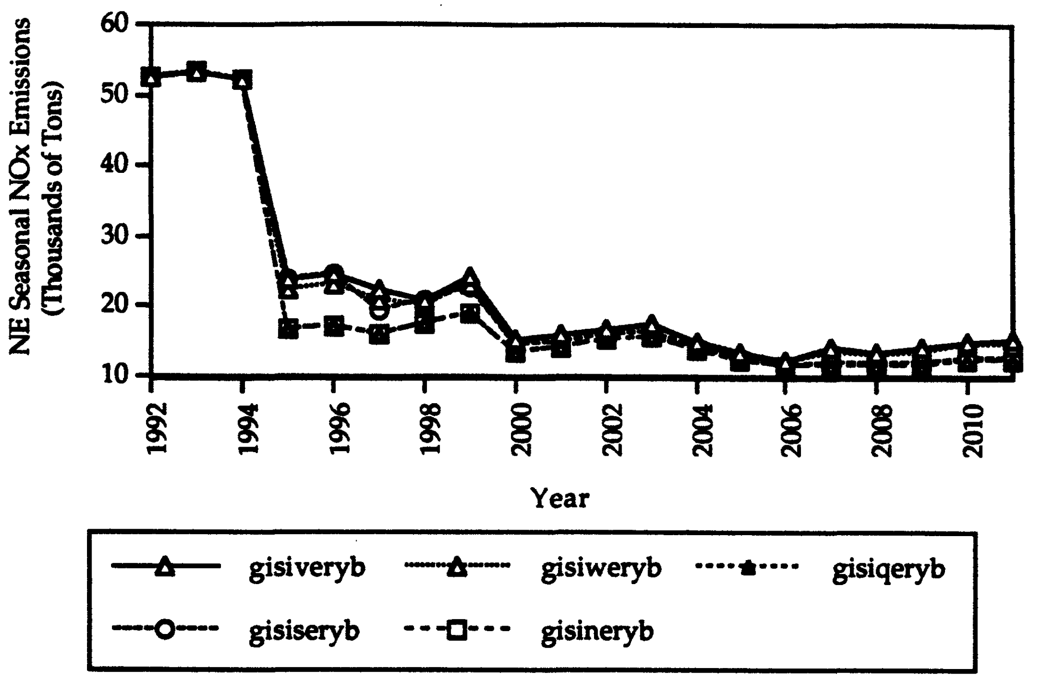



*Figure 4-21: % Deltas in New England Seasonal NOx Emissions Relative to No Policy for Operational NOx Options under Phase II Hard*

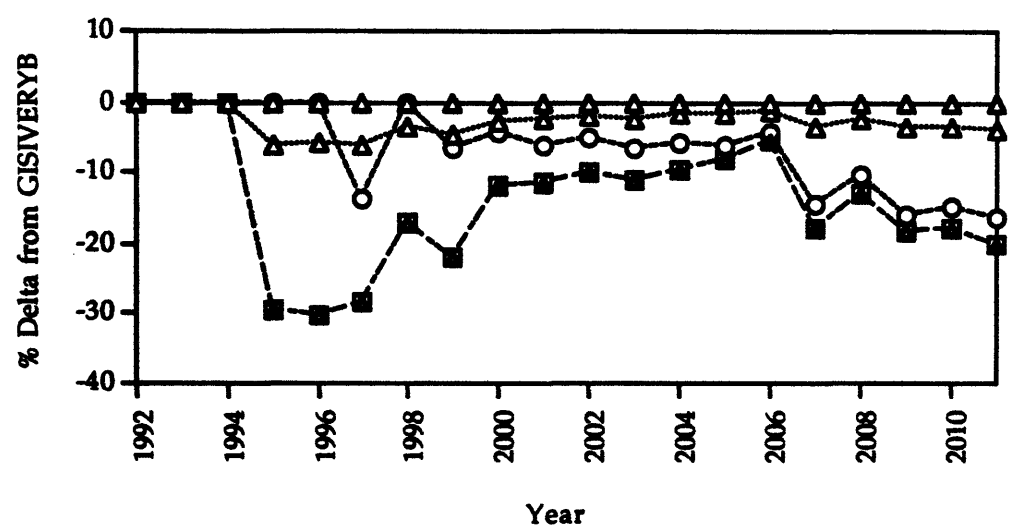


*Figure 4-22: New England Annual NOx Emissions Trajectories for Operational NOx Options under Phase II Hard*

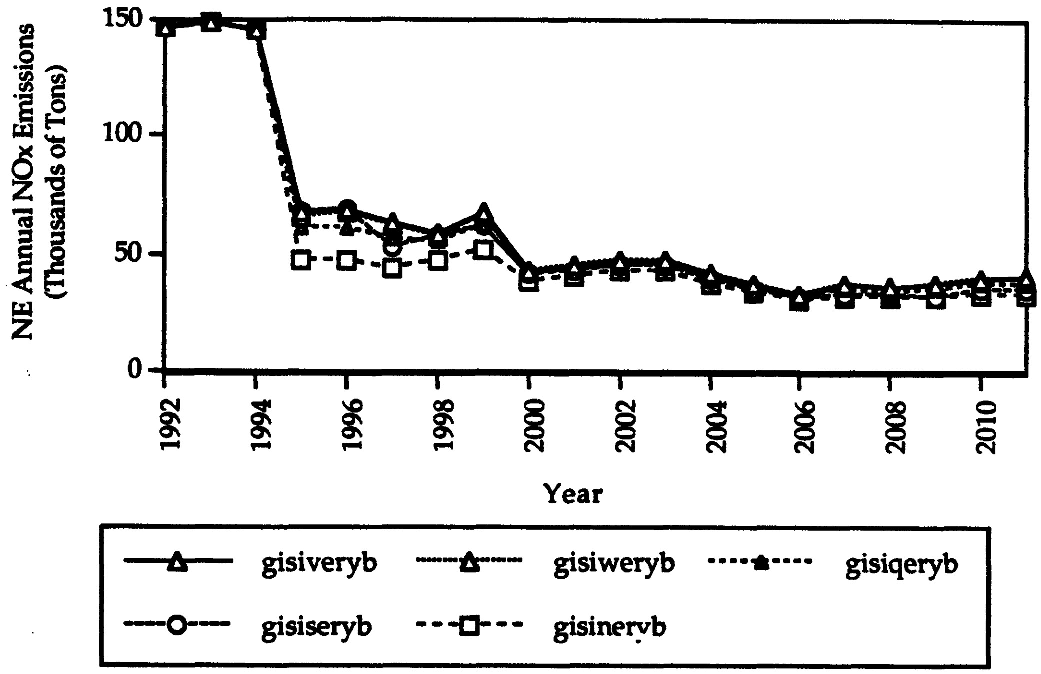



*Figure 4-23: % Deltas in New England Seasonal NOx Emissions Relative to No Policy for Operational NOx Options under Phase II Hard*

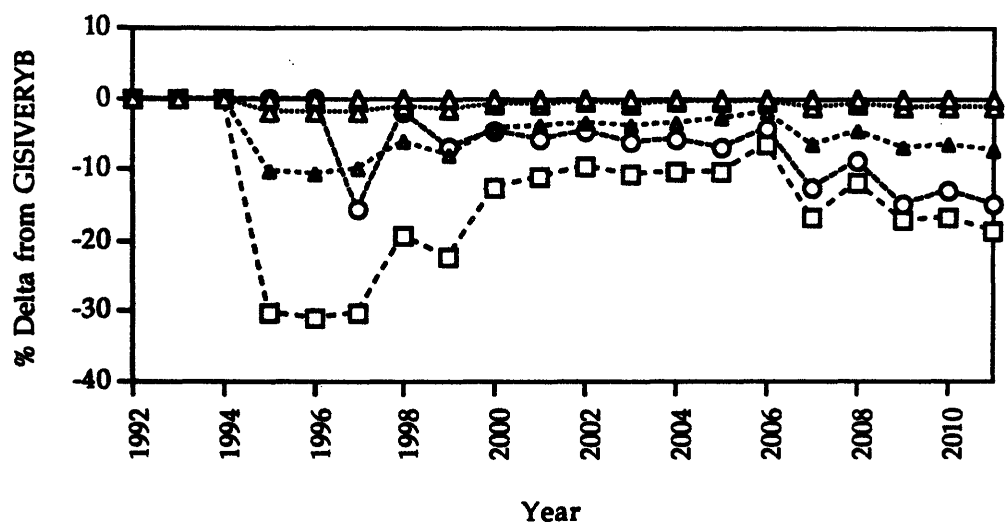


*Figure 4-24: New England Annual CO2 Emissions Trajectories for Operational NOx Options under Phase II Hard*

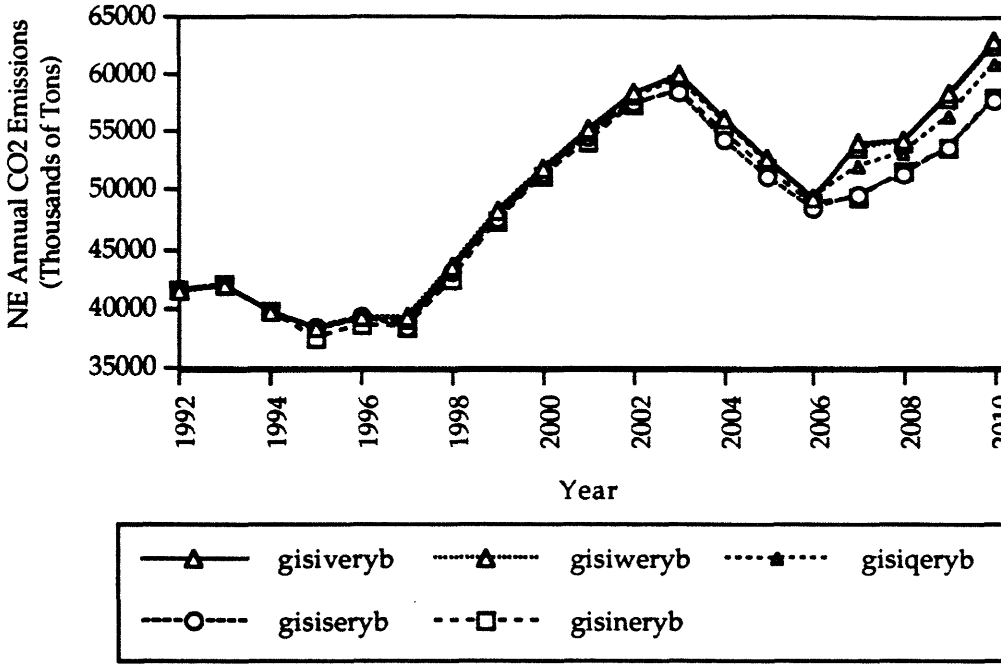



*Figure 4-25: % Deltas in New England Annual CO2 Emissions Relative to No Policy for Operational NOx Options under Phase II Hard*

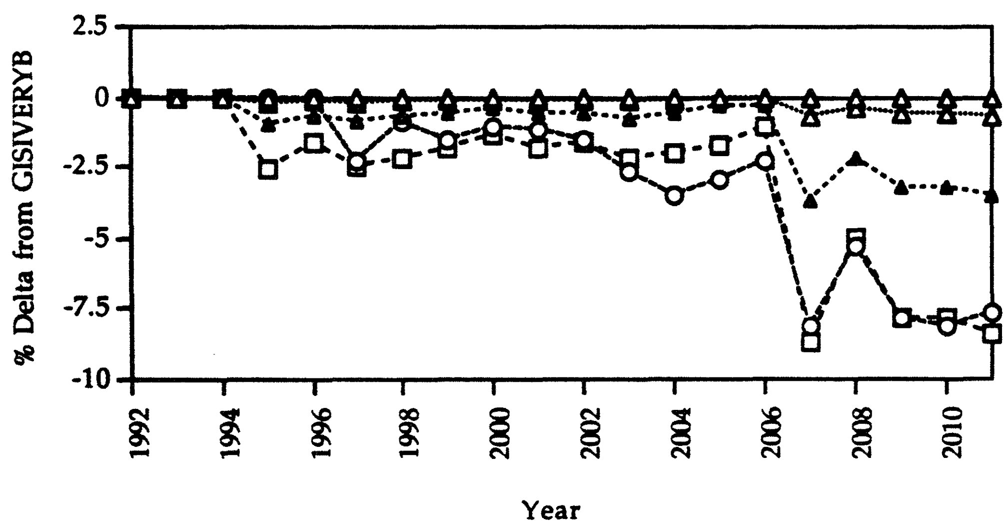


*Figure 4-26: New England Annual SO2 Emissions Trajectories for Operational NOx Options under Phase II Hard*

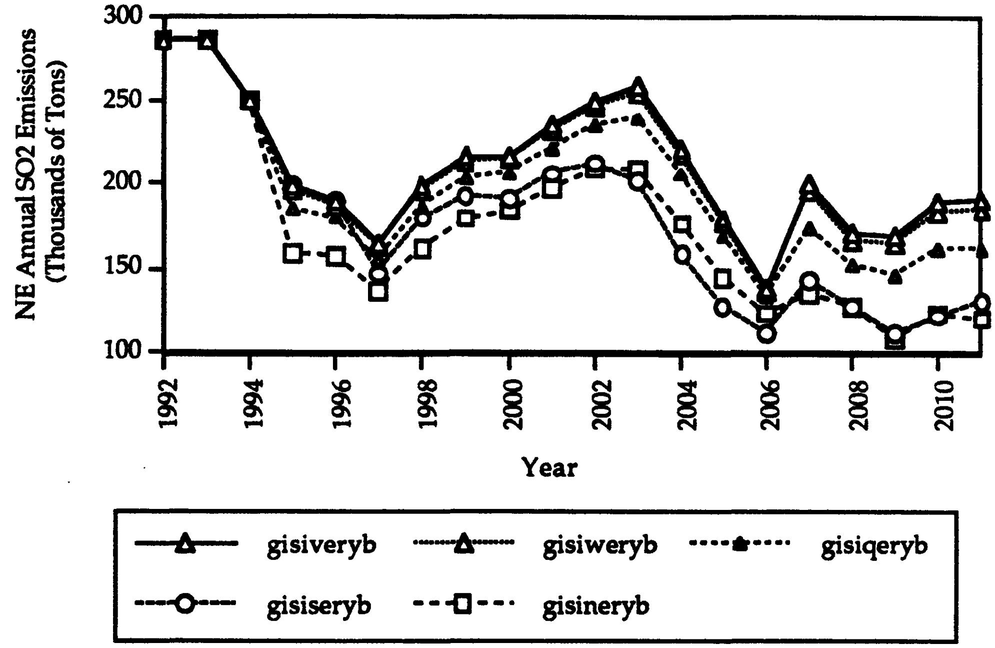



*Figure 4-27: % Deltas in New England Annual SO2 Emissions Relative to No Policy for Operational NOx Options under Phase II Hard*

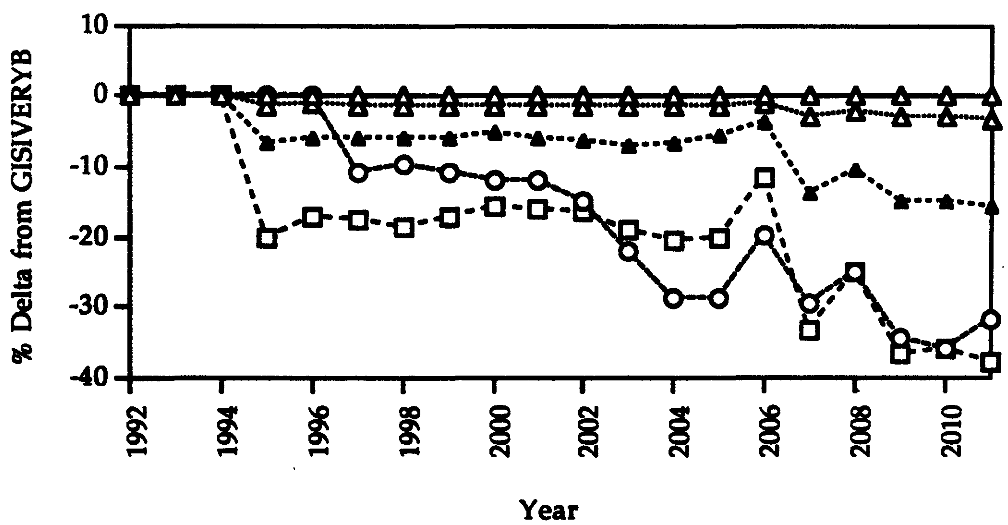


Figure 4-28: Total Direct Cost Trajectories for Operational NOx Options under Phase II Hard

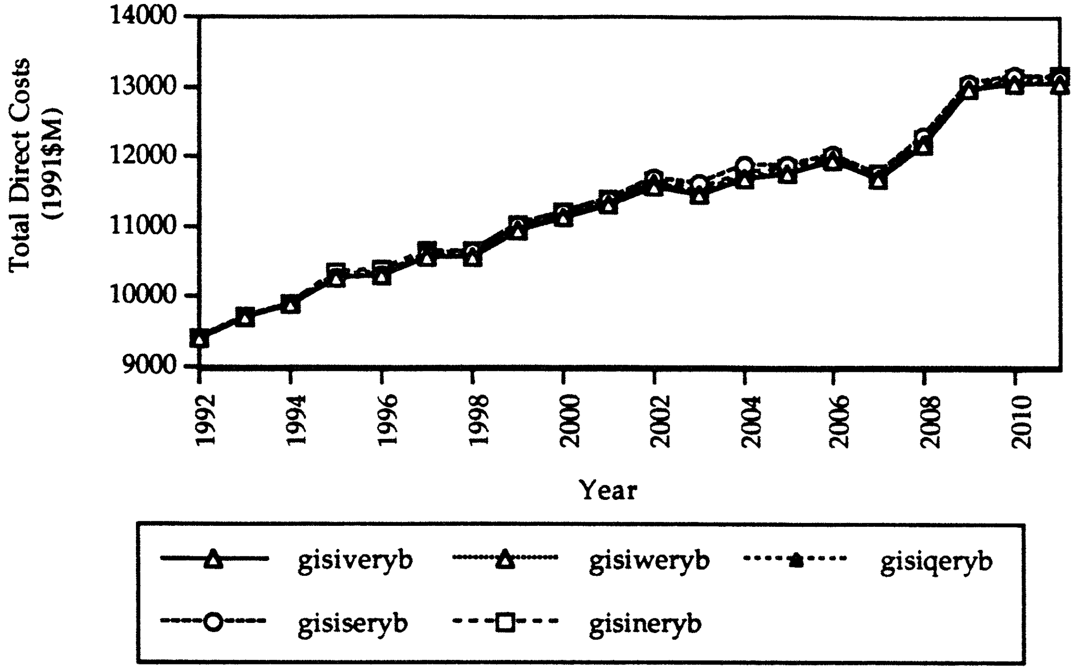
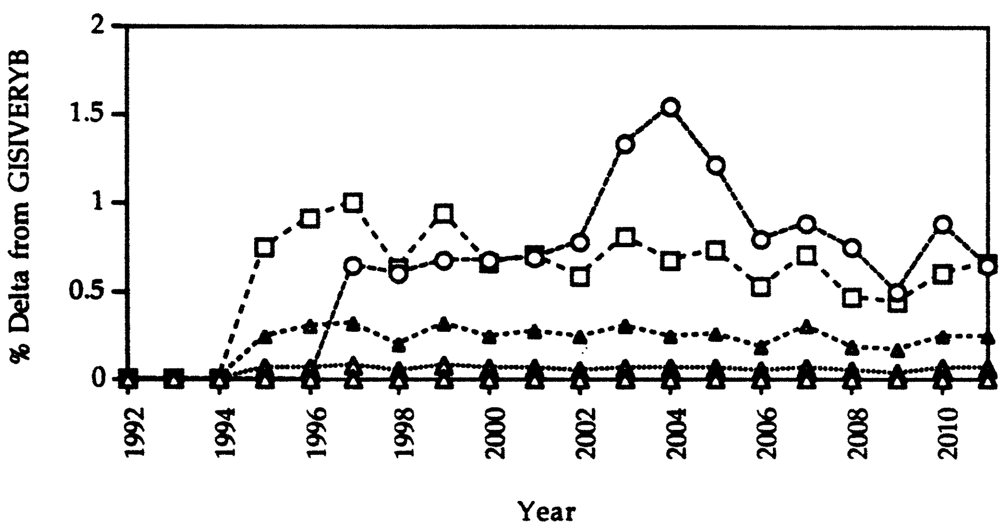



Figure 4-29: % Deltas in Total Direct Costs Relative to No Policy for Operational NOx Options under Phase II Hard



PERFORMANCE OF STRATEGIES WITH ADDITIONAL DEMAND-SIDE MANAGEMENT, REPOWERING, AND NEW SUPPLY TECHNOLOGIES

As discussed in the Research Methodology chapter, other alternatives for controlling NOx emissions include DSM, existing unit repowering, and new supply technologies. To test the bounds of each option set, the most extreme option is modeled from each set. Specifically, the most extreme options are Triple Commercial and Industrial Conservation (Triple C&I) for DSM; Aggressive Repowering; and a mix of Gas/Oil, Clean Coal, Wind, and Biomass for new supply technologies.

Strategies with each of these options are examined individually across all operational control options. Phase I RACT, the status-quo option for existing unit NOx technology controls, is used for all strategies. The performances of all these scenarios are then compared with the base case, GISAVERYB. The results for these strategies are shown in Tables 4-7 to 4-9, for the specified conservation, repowering, and new supply technologies, respectively.

Triple C&I conservation, with no additional existing unit NOx controls and no operational controls, achieves a 9-10% reduction in cumulative NOx emissions at a cost increase of 3.2%. However, it greatly reduces CO2 emissions by 15.3% and SO2 emissions by 10.4%, while decreasing dependence on natural gas by 33.6%.

The operational NOx control strategies achieve lower emissions reductions at a lower cost starting with Triple C&I instead of Reference DSM as the baseline strategy. Per four week period, operational controls reduce NOx emissions by 19.8 thousand tons, or 12.7%, significantly less than the 16.4% in the Reference DSM strategies. Costs are increased by about 1991$ 120 million, or 1.0%, also less than the 1.2% of the Reference DSM strategies. CO2 emissions are reduced by 4.27 million tons, or 5.3%, while SO2 emissions are reduced by 0.08 million tons, or 23.5%. Natural gas use in 2011 increases by 43.0 percentage points, or 39.1%.

Aggressive repowering, with no additional existing unit NOx controls and no operational controls, achieves a 11-13% reduction in cumulative NOx emissions at a cost increase of 4.0%. However, it increases dependence on natural gas by 6.5%, while reducing CO2 emissions by 7.4% and SO2 emissions by 24.2%. Thus, at considerably greater cost, Aggressive achieves slightly higher NOx reductions, dramatically less CO2 reductions, considerably higher SO2 reductions, and dramatically higher dependence on natural gas than Triple C&I.

As under Triple C&I, the operational NOx control strategies achieve lower emissions reductions at lower cost starting from Aggressive instead of Life Extension. Per four week period, operational controls reduce NOx emissions by 20.3 thousand tons, or 13.0%, significantly less than the 16.4% in the Life Extension strategies. Costs are increased by about 1991$ 60 million, or 0.75%, also less than the 1.2% of the Life Extension strategies. CO2 emissions are reduced by 4.7 million tons, or 6.0%, while SO2 emissions are reduced by 0.07 million tons, or 21.8%. Natural gas use in 2011 increases by 48.7 percentage points, or 44.3%.

Non-gas new supply, with no additional existing unit NOx controls and no operational controls, achieves a 5-10% reduction in cumulative NOx emissions at a cost increase of 6.0%. Further, it decreases dependence on natural gas by 62.4%, while reducing CO2 emissions by 0.4% and SO2 emissions by 10.0%. Thus, at considerably greater cost, Non-Gas New Supply achieves slightly lower NOx reductions, dramatically less CO2 reductions, considerably lower SO2 reductions, and dramatically lower dependence on natural gas than Triple C&I and Aggressive.

As under Triple C&I and Aggressive, the operational NOx control strategies achieve lower emissions reductions at lower cost starting from Non-Gas Supply instead of Gas/Oil. Per four week period, operational controls reduce NOx emissions by 20.2 thousand tons, or 13.0%, significantly less than the 16.4% in the Gas/Oil strategies. Costs are increased by about 1991$ 80 million, or 0.97%, also less than the 1.2% of the Gas/Oil strategies. CO2 emissions are reduced by 2.6 million tons, or 3.9%, while SO2 emissions are reduced by 0.08 million tons, or 25.6%. Natural gas use in 2011 increases by 49.1 percentage points, or 44.6%.

Table 4-7: *Performance of Different NOx Operational Policies Combined with Phase I RACT and Triple Commercial & Industrial Conservation (KISA-ECYB scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryb | 106.66 | 4.55 | 2.07 | 1039.70 | 110.0 | 121.53 | 590.62 | 155.92 | 756.30 |
| gisavecyb | 110.05 | 4.08 | 1.89 | 880.48 | 73.0 | 110.79 | 536.95 | 140.02 | 677.61 |
| gisawecyb | 110.12 | 4.00 | 1.87 | 876.22 | 76.4 | 91.68 | 517.84 | 120.24 | 657.83 |
| gisaqecyb | 110.38 | 3.69 | 1.79 | 859.43 | 89.8 | 91.68 | 443.61 | 120.24 | 581.20 |
| gisasecyb | 110.75 | 3.46 | 1.75 | 848.95 | 101.3 | 91.69 | 443.62 | 129.20 | 624.32 |
| gisanecyb | 111.06 | 3.01 | 1.62 | 825.07 | 116.0 | 91.68 | 443.61 | 120.24 | 581.20 |
| Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisavecyb | 3.38 | -0.47 | -0.18 | -159.22 | -37.0 | -10.75 | -53.66 | -15.90 | -78.68 |
| gisawecyb | 3.46 | -0.55 | -0.20 | -163.49 | -33.6 | -29.85 | -72.77 | -35.68 | -98.47 |
| gisaqecyb | 3.72 | -0.86 | -0.28 | -180.28 | -20.2 | -29.85 | -147.01 | -35.68 | -175.10 |
| gisasecyb | 4.09 | -1.09 | -0.32 | -190.75 | -8.7 | -29.85 | -147.00 | -26.72 | -131.98 |
| gisanecyb | 4.40 | -1.54 | -0.45 | -214.64 | 6.0 | -29.85 | -147.01 | -35.68 | -175.10 |
| % Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisavecyb | 3.17% | -10.40% | -8.69% | -15.31% | -33.63% | -8.84% | -9.09% | -10.20% | -10.40% |
| gisawecyb | 3.24% | -12.13% | -9.65% | -15.72% | -30.53% | -24.56% | -12.32% | -22.88% | -13.02% |
| gisaqecyb | 3.49% | -18.86% | -13.35% | -17.34% | -18.34% | -24.56% | -24.89% | -22.88% | -23.15% |
| gisasecyb | 3.83% | -23.91% | -15.53% | -18.35% | -7.90% | -24.56% | -24.89% | -17.14% | -17.45% |
| gisanecyb | 4.12% | -33.94% | -21.53% | -20.64% | 5.44% | -24.56% | -24.89% | -22.88% | -23.15% |

*Table 4-8: Performance of Different NOx Operational Policies Combined with Phase I RACT and Aggressive Repowering (GASA-ERYB scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryb | 106.66 | 4.55 | 2.07 | 1039.70 | 110.0 | 121.53 | 590.62 | 155.92 | 756.30 |
| gasaveryb | 110.89 | 3.45 | 1.85 | 962.72 | 117.1 | 105.35 | 512.63 | 139.28 | 677.21 |
| gasaweryb | 110.94 | 3.38 | 1.83 | 958.03 | 120.8 | 86.10 | 493.38 | 118.95 | 656.88 |
| gasaqeryb | 111.15 | 3.10 | 1.75 | 939.79 | 135.7 | 86.10 | 420.30 | 118.95 | 578.60 |
| gasaseryb | 111.37 | 2.74 | 1.67 | 921.52 | 145.5 | 87.05 | 424.85 | 125.93 | 611.75 |
| gasaneryb | 111.69 | 2.46 | 1.57 | 900.38 | 165.8 | 86.10 | 420.30 | 118.95 | 578.60 |
| Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gasaveryb | 4.22 | -1.10 | -0.22 | -76.99 | 7.1 | -16.19 | -77.99 | -16.64 | -79.08 |
| gasaweryb | 4.28 | -1.17 | -0.24 | -81.67 | 10.8 | -35.44 | -97.24 | -36.97 | -99.42 |
| gasaqeryb | 4.49 | -1.45 | -0.32 | -99.92 | 25.7 | -35.44 | -170.32 | -36.97 | -177.70 |
| gasaseryb | 4.71 | -1.81 | -0.40 | -118.19 | 35.5 | -34.49 | -165.77 | -29.99 | -144.55 |
| gasaneryb | 5.03 | -2.09 | -0.50 | -139.32 | 55.8 | -35.44 | -170.32 | -36.97 | -177.70 |
| % Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gasaveryb | 3.96% | -24.19% | -10.83% | -7.40% | 6.45% | -13.32% | -13.20% | -10.67% | -10.46% |
| gasaweryb | 4.01% | -25.80% | -11.81% | -7.86% | 9.84% | -29.16% | -16.46% | -23.71% | -13.15% |
| gasaqeryb | 4.21% | -31.86% | -15.59% | -9.61% | 23.34% | -29.16% | -28.84% | -23.71% | -23.50% |
| gasaseryb | 4.42% | -39.87% | -19.45% | -11.37% | 32.28% | -28.38% | -28.07% | -19.23% | -19.11% |
| gasaneryb | 4.71% | -46.00% | -24.12% | -13.40% | 50.73% | -29.16% | -28.84% | -23.71% | -23.50% |

*Table 4-9: Performance of Different NOx Operational Policies Combined with Phase I RACT and Non-Gas New Supply (KISA-ERYB scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryb | 106.66 | 4.55 | 2.07 | 1039.70 | 110.0 | 121.53 | 590.62 | 155.92 | 756.30 |
| kisaveryb | 113.04 | 4.09 | 1.96 | 1035.30 | 41.3 | 109.78 | 541.42 | 145.04 | 715.17 |
| kisaweryb | 113.11 | 4.02 | 1.94 | 1032.65 | 44.8 | 90.98 | 522.62 | 124.78 | 694.91 |
| kisaqeryb | 113.38 | 3.70 | 1.86 | 1022.29 | 58.8 | 90.98 | 448.10 | 124.78 | 614.82 |
| kisaseryb | 113.69 | 3.36 | 1.80 | 1004.48 | 62.2 | 90.97 | 448.57 | 133.78 | 659.25 |
| kisaneryb | 114.08 | 2.93 | 1.68 | 995.35 | 90.4 | 90.98 | 448.10 | 124.78 | 614.82 |
| Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| kisaveryb | 6.38 | -0.46 | -0.11 | -4.41 | -68.7 | -11.76 | -49.20 | -10.88 | -41.13 |
| kisaweryb | 6.45 | -0.54 | -0.13 | -7.05 | -65.2 | -30.56 | -68.00 | -31.14 | -61.39 |
| kisaqeryb | 6.72 | -0.85 | -0.21 | -17.42 | -51.2 | -30.56 | -142.51 | -31.14 | -141.48 |
| kisaseryb | 7.03 | -1.19 | -0.27 | -35.22 | -47.8 | -30.57 | -142.05 | -22.14 | -97.05 |
| kisaneryb | 7.41 | -1.62 | -0.39 | -44.36 | -19.6 | -30.56 | -142.51 | -31.14 | -141.48 |
| % Delta from gisaveryb | | | | | | | | | |
| gisaveryb | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| kisaveryb | 5.98% | -10.03% | -5.12% | -0.42% | -62.42% | -9.67% | -8.33% | -6.98% | -5.44% |
| kisaweryb | 6.05% | -11.77% | -6.10% | -0.68% | -59.25% | -25.14% | -11.51% | -19.97% | -8.12% |
| kisaqeryb | 6.30% | -18.60% | -9.96% | -1.68% | -46.56% | -25.14% | -24.13% | -19.97% | -18.71% |
| kisaseryb | 6.59% | -26.19% | -13.03% | -3.39% | -43.49% | -25.15% | -24.05% | -14.20% | -12.83% |
| kisaneryb | 6.95% | -35.60% | -19.08% | -4.27% | -17.78% | -25.14% | -24.13% | -19.97% | -18.71% |

SENSITIVITY OF RESULTS TO NATURAL GAS COSTS

With the existing generation mix in New England, minimum NOx dispatch essentially shifts generation from coal and oil plants to natural gas plants. Thus, the cost of such dispatch is highly dependent on natural gas fuel costs. This sensitivity analysis gauges the degree to which the above results change with natural gas costs. The analysis focuses in on the changes in costs and benefits from technology and operational NOx controls under lower and higher natural gas costs. The performances of the strategies for Low and High natural gas costs are shown in Tables 4-10 and 4-11, respectively. The performances under Base/Stable natural gas costs are shown in Table 4-1.

With Low natural gas costs, the total direct cost and NOx emissions of all strategies drop as the system economically dispatches more gas units and less coal and oil units than under Base/Stable. Therefore, the benefits and costs of all operational options would be lower. Both emissions reductions and delta costs from operational controls would be lower by about 50% under RACT and by 20% under Phase II Firm, so cost-effectiveness remains the same. For example, delta costs and seasonal emissions reductions for Seasonal Minimum under RACT would be 1991$ 450 million and 126.4 thousand tons under Base/Stable gas costs, and 1991$ 220 million and 64.5 thousand tons under Low gas costs. In both fuel cost cases, the absolute emissions levels are identical. This is expected because the system hardware is identical. Only the share of generation dispatched by least-cost versus least-emissions criteria differs.

The delta costs and benefits of Phase II Firm would not drop proportionally under the different fuel costs. For example, costs and NOx seasonal emissions reductions for Phase II Firm would be 1991$ 1 billion and 214.8 thousand tons under Base/Stable gas costs, and 1991$ 0.9 billion and 183 thousand tons under Low gas costs. Costs differ by 10% while emissions reductions differ by 16%, making technology controls slightly less cost-effective under lower gas fuel costs. However, the same strategies comprise the tradeoff frontier as technology and operational controls still yield greater emissions reductions at higher costs than less aggressive strategies.

With High natural gas costs, the total direct cost delta and the NOx emissions reduction of all strategies increase as the system economically dispatches less gas units and more coal and oil units than under Base/Stable. Therefore, the benefits and costs of all operational options would be higher, but not proportionally higher as under Low gas costs. Emissions reductions and delta costs from operational controls would be higher by about 60% and 140%, respectively, under RACT and by 25% and 50%, respectively, under Phase II Firm, so cost-effectiveness of operational controls significantly decreases. For example, delta costs and seasonal emissions reductions for Seasonal Minimum under RACT would be 1991$ 450 million and 126.4 thousand tons under Base/Stable gas costs, and 1991$ 1100 million and 200.4 thousand tons under High gas costs. In both fuel cost cases, the absolute emissions levels are again identical.

The delta costs and benefits of Phase II Firm would increase proportionally under the different fuel costs. For example, costs and NOx seasonal emissions reductions for Phase II Firm would be 1991$ 1.0 billion and 214.8 thousand tons under Base/Stable gas costs, and 1991$ 1.1 billion and 231.2 thousand tons under High gas costs. Costs and emissions reductions differ by about 10%, essentially staying at the same cost-effectiveness level.

While the frontier strategies were not sensitive to Low gas costs, they are sensitive to High gas costs. As Table 4-11 shows, operational control strategies become cost-equivalent to technology control strategies, but yield lower NOx reductions. Thus, with respect to NOx criteria, they are inferior to technology controls options. However, operational controls still achieve significantly greater $CO_2$ reductions, so they should not be discounted altogether.

*Table 4-10: Performance of Different NOx Operational Policies Under Low Natural Gas Costs (GIS--ERYC scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryc | 104.81 | 3.76 | 1.91 | 982.66 | 157.2 | 108.52 | 526.01 | 142.79 | 690.70 |
| gisaweryc | 104.86 | 3.71 | 1.89 | 981.01 | 157.8 | 95.41 | 512.91 | 129.40 | 677.31 |
| gisaqeryc | 105.03 | 3.52 | 1.84 | 974.52 | 160.1 | 95.41 | 462.58 | 129.40 | 626.22 |
| gisaseryc | 105.29 | 3.32 | 1.82 | 968.70 | 166.4 | 94.67 | 459.35 | 136.52 | 660.82 |
| gisaneryc | 105.49 | 3.04 | 1.72 | 958.34 | 168.3 | 95.41 | 462.58 | 129.40 | 626.22 |
| giseveryc | 105.70 | 3.65 | 1.42 | 972.58 | 161.1 | 76.51 | 368.22 | 105.62 | 507.67 |
| giseqeryc | 105.87 | 3.44 | 1.37 | 967.48 | 162.6 | 67.32 | 324.14 | 95.59 | 459.77 |
| Delta from gisaveryc | | | | | | | | | |
| gisaveryc | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisaweryc | 0.05 | -0.05 | -0.01 | -1.65 | 0.6 | -13.11 | -13.11 | -13.39 | -13.39 |
| gisaqeryc | 0.22 | -0.24 | -0.06 | -8.15 | 2.9 | -13.11 | -63.43 | -13.39 | -64.48 |
| gisaseryc | 0.48 | -0.44 | -0.09 | -13.96 | 9.2 | -13.85 | -66.66 | -6.27 | -29.88 |
| gisaneryc | 0.67 | -0.72 | -0.19 | -24.33 | 11.1 | -13.11 | -63.43 | -13.39 | -64.48 |
| giseveryc | 0.88 | -0.11 | -0.49 | -10.09 | 3.9 | -32.01 | -157.79 | -37.18 | -183.03 |
| giseqeryc | 1.06 | -0.32 | -0.54 | -15.19 | 5.4 | -41.20 | -201.87 | -47.20 | -230.93 |
| % Delta from gisaveryc | | | | | | | | | |
| gisaveryc | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisaweryc | 0.04% | -1.30% | -0.70% | -0.17% | 0.39% | -12.08% | -2.49% | -9.38% | -1.94% |
| gisaqeryc | 0.21% | -6.31% | -3.38% | -0.83% | 1.85% | -12.08% | -12.06% | -9.38% | -9.34% |
| gisaseryc | 0.46% | -11.69% | -4.76% | -1.42% | 5.84% | -12.76% | -12.67% | -4.39% | -4.33% |
| gisaneryc | 0.64% | -19.24% | -10.01% | -2.48% | 7.06% | -12.08% | -12.06% | -9.38% | -9.34% |
| giseveryc | 0.84% | -2.94% | -25.79% | -1.03% | 2.45% | -29.49% | -30.00% | -26.03% | -26.50% |
| giseqeryc | 1.01% | -8.56% | -28.30% | -1.55% | 3.45% | -37.97% | -38.38% | -33.05% | -33.43% |

*Table 4-11: Performance of Different NOx Operational Policies Under High Natural Gas Costs (GIS--ERYG scenarios)*

| Scenario Name | NPV Direct Total Direct | Cumulative Air Emissions Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide | 2011 Gas Use as % of 1990 NE | NOx Cumulative 20 year emissions Upwind Episode | Upwind Season | New Eng. Episode | New Eng. Season |
|---|---|---|---|---|---|---|---|---|---|
| Performance | (1991$B) | (Million Tons) | | | (%) | (1000s Tons) | | | |
| gisaveryg | 110.16 | 5.50 | 2.29 | 1125.75 | 66.3 | 134.20 | 656.34 | 172.89 | 842.14 |
| gisaweryg | 110.38 | 5.34 | 2.25 | 1114.14 | 72.7 | 98.57 | 620.71 | 132.74 | 801.99 |
| gisaqeryg | 111.26 | 4.71 | 2.09 | 1067.28 | 98.3 | 98.57 | 477.79 | 132.74 | 641.76 |
| giseveryg | 111.27 | 5.45 | 1.68 | 1119.56 | 67.7 | 94.11 | 456.56 | 126.32 | 610.92 |
| gisaseryg | 112.13 | 4.29 | 1.98 | 1033.64 | 113.0 | 102.17 | 495.61 | 149.07 | 723.20 |
| giseqeryg | 112.14 | 4.72 | 1.55 | 1066.60 | 98.4 | 71.11 | 342.15 | 98.79 | 474.36 |
| gisaneryg | 113.20 | 3.42 | 1.76 | 974.01 | 149.3 | 98.57 | 477.79 | 132.74 | 641.76 |
| Delta from gisaveryg | | | | | | | | | |
| gisaveryg | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | 0.00 | 0.00 | 0.00 | 0.00 |
| gisaweryg | 0.22 | -0.16 | -0.04 | -11.61 | 6.4 | -35.63 | -35.63 | -40.15 | -40.15 |
| gisaqeryg | 1.10 | -0.79 | -0.20 | -58.47 | 32.0 | -35.63 | -178.55 | -40.15 | -200.37 |
| giseveryg | 1.11 | -0.05 | -0.61 | -6.19 | 1.4 | -40.09 | -199.78 | -46.56 | -231.22 |
| gisaseryg | 1.97 | -1.21 | -0.31 | -92.11 | 46.7 | -32.03 | -160.74 | -23.82 | -118.94 |
| giseqeryg | 1.98 | -0.78 | -0.75 | -59.14 | 32.0 | -63.10 | -314.19 | -74.09 | -367.77 |
| gisaneryg | 3.04 | -2.08 | -0.53 | -151.74 | 83.0 | -35.63 | -178.55 | -40.15 | -200.37 |
| % Delta from gisaveryg | | | | | | | | | |
| gisaveryg | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| gisaweryg | 0.20% | -2.86% | -1.75% | -1.03% | 9.67% | -26.55% | -5.43% | -23.22% | -4.77% |
| gisaqeryg | 1.00% | -14.33% | -8.74% | -5.19% | 48.19% | -26.55% | -27.20% | -23.22% | -23.79% |
| giseveryg | 1.01% | -0.96% | -26.63% | -0.55% | 2.04% | -29.87% | -30.44% | -26.93% | -27.46% |
| gisaseryg | 1.79% | -22.05% | -13.62% | -8.18% | 70.33% | -23.87% | -24.49% | -13.78% | -14.12% |
| giseqeryg | 1.80% | -14.17% | -32.58% | -5.25% | 48.29% | -47.02% | -47.87% | -42.86% | -43.67% |
| gisaneryg | 2.76% | -37.76% | -23.24% | -13.48% | 125.08% | -26.55% | -27.20% | -23.22% | -23.79% |

# Chapter 5

## *POLICY ANALYSIS*

### OVERVIEW

The central issue discussed in this chapter is: can time and place specific policies encourage electric utilities to pursue the most effective NOx control strategies after 1995, when Phase I RACT is fully implemented. The U.S. Congress has established ozone standards and compliance deadlines. States in New England, as part of the Ozone Transport Region (OTR), must achieve compliance by 1999.

Through the Clean Air Act Amendments (CAAA) of 1990, Congress has made states individually responsible for developing compliance plans and for attaining compliance. However, recognizing the regional nature of ozone in the northeast, Congress also established the Ozone Transport Commission (OTC) to facilitate the coordination of strategies in the region. Most of the power plants in the region are located in upwind region consisting of Connecticut, Rhode Island, and Massachusetts. Thus, due to transport and the predominance of plants upwind, there is little incentive to differentiate NOx control policy for the electric power sector among the New England states. The policies discussed below apply uniformly to all New England states, except for the section on place-specific policies.

At present, states are trying to submit State Implementation Plans (SIPs) for Phase I RACT by November 1994, two years after the initial deadline. However, most stakeholders in the region, including the OTC, Northeast States for Coordinated Air Use Management (NESCAUM), air quality and electric utility regulators, and the electric utilities, have begun studying Phase II strategies.

These strategies appropriately consider transportation and industrial sector emissions as well as electric power sector emissions, which comprise only 20-30% of total regional NOx emissions. Clearly, air quality policies should integrate the various sectors and emissions types. However, this chapter only addresses the policies as they pertain to the electric power sector.

### TIME-SPECIFIC POLICIES

The time period over which NOx emissions are controlled is a critical factor in determining the most cost-effective way to address the ozone problem. Moreover, the time period determines the magnitude of control costs passed on to ratepayers.

The most cost-effective strategies for reducing ozone-precursor NOx emissions are combinations of technology controls and operational controls, no matter what the time period of control. Conservation, repowering, and new supply technologies are effective for reducing $CO_2$ emissions or natural gas dependency as they displace fossil generation, but are small levers for NOx control at relatively high cost. Thus, ozone control policies should always encourage technology and operational controls over the other options.

Technology controls achieve large reductions at high emissions levels, but operational controls are more cost-effective for moderate reductions. Further, operational controls achieve coicident $CO_2$ and $SO_2$ emissions reductions as they shift generation from oil and coal to natural gas units, whereas technology controls do not. Additional technology controls without operational controls are not cost-effective when the system already has a moderate degree of technology controls because uncontrolled units are likely to have lower capacity factors.

Thus, time-specific policies should be flexible to permit combinations of operational and technology controls which depend on the extent of existing technology controls and the target emissions levels. Under the considerable uncertainty of ozone formation in the northeast, target emissions levels and the time period of control may change in the future. Policies that accommodate new photochemistry information would be particularly effective over the long term.

Considering only NOx emissions reductions, operational controls are more cost-effective than technology controls up to a control period of about seven months, after which technology controls are more cost-effective. However, the time period at which cost-effectiveness is equal depends significantly on natural gas costs. Further, operational controls can achieve only half as much total emissions reductions as technology controls.

For a control period of about one month, operational controls are more than six times more cost-effective than technology controls. For a control period of one year, technology controls are about two times more cost-effective. However, at high gas costs as modeled, the control period at which cost-effectiveness is equal is four and one half months. At low gas costs, the control period length is also seven months. Operational controls can achieve up to 17% reductions beyond Phase I RACT levels whereas technology controls can achieve up to 40% reductions beyond RACT levels.

If the necessary control period is less than four and one half months, for example thirty days associated with ozone episodes, then operational controls should be the first response encouraged by policy. Technology controls will be necessary if the desired reductions are beyond the limits of those achievable through operational controls. A post-RACT NOx control policy with a control period between four and seven months should not mandate operational controls or technology controls unless decision makers have confidence in predictions for natural gas costs. If decision makers wish to control NOx emissions for a period greater than seven months, although seemingly inappropriate for the ozone formation process, then technology controls should be first promoted over operational controls.

It should be noted that the success of intermittent operational controls depends greatly on the ability to predict ozone episodes. A large number of false positive predictions could double or triple the control costs at no substantial air quality benefit. A large number of false negative predictions could allow ozone nonattainment despite the large control costs. Therefore, policymakers should seriously consider the degree to which planners can predict ozone precursor days for control before encouraging intermittent control strategies.

The cost-effectivenss of technology and operational controls varies considerably with natural gas costs. Low gas costs would yield the same cost-effectiveness for operational controls, but higher cost-effectiveness for technology controls. However, the strategies that comprise the tradeoff frontier remain the same.

High gas costs, as modeled, do change the performance of operational controls so that they become inferior to technology controls based on cost and NOx emissions. High gas costs lower the cost-effectivenss of operational controls and have no effect on the cost-effectivenss of technology controls. However, even though operational controls become inferior with regard to NOx emissions, they remain superior for coincident CO2 and SO2 emissions reductions.

There is another reason why operational controls should receive first priority over technology controls up to a control period of seven months. Operational controls are more cost-effective the lower the level of technology control. During any given period of control, the range of costs and benefits of operational controls are 0.57% to 1.23% for total direct costs, 7.2% to 16.7% for NOx emissions, 3.2% to 7.7% for CO2 emissions, 16.4% to 32.5% for SO2 emissions, and 24.2% to 50.5% for natural gas use in 2011. Starting from a Phase II Firm baseline, operational controls are more than thirteen times as cost-effective as additional technology controls for a one month control period, and more than three times as cost-effective for a five month control period.

Policies that seek other goals besides ozone and NOx control should consider conservation, repowering, and nonfossil supply options. However, these alternatives yield little benefits with respect to controlling ozone precursor NOx emissions. These options cannot be controlled over time, but have annual effects as do technology controls. NOx control policies should not necessarily discourage these other options, but should not support them either.

The effects of operational controls on natural gas use depends dramatically on the extent of existing unit control technologies. Since existing fossil generation is dominated by oil and coal units, additional control technologies allow these units to run more under operational controls. This mitigates the shift from oil and coal to gas-fired plants. For example, under Phase I RACT, operational controls increase gas use by 50%

in 2011, while under Phase II Hard, they increase gas use by 25%. The technology and operational controls are minor levers for reducing CO2 emissions. Conservation is a major lever, repowering a moderate lever, and non-gas supply has no impact unless it is dominated by nonfossil generation, which is not the case in this study.

Non-gas supply is major lever for reducing dependency on natural gas. Conservation is a moderate lever, while repowering has no effect. Operational controls considerably increase natural gas use, but this is mitigated significantly by control technologies on non-gas units. These control technologies combined with operational controls shift some generation from gas units to lower-NOx oil and coal units.

Triple C&I conservation, Aggressive repowering, and Non-Gas New Supply, when each is combined with operational controls, reduce the costs and benefits resulting from operational controls. However, none of these alternative levers significantly affects ultimate NOx emissions levels, and should not comprise part of NOx control policies.

Combined with Phase I RACT, operational controls keep NOx emissions flat after 2006, yielding a 40% reduction by 2011. CO2 emissions grow with fossil generation, so operational controls achieve only a 15% reduction by 2011. Operational controls keep SO2 emissions flat after 2006, achieving a 60% reduction by 2011. Total direct costs grow over time for all strategies, and operational controls raise costs by 2.5% by 2011.

Phase II Firm and Phase II Hard achieve large emissions reductions early in the study period, so operational controls keep these emissions flat after 1995. Emissions do not increase during the middle years, as they do under RACT and operational controls.

Over the medium term, the existing system becomes lower NOx emitting, so emissions levels can be held flat with either operational or technology controls, or both. Old units are retired, and new units, predominantly gas, have the lowest available emissions rate (LAER), so increased load is counterbalanced by cleaner generation. Therefore, policies that build off the CAAAs of 1990 will keep NOx emissions below a desired level after 2006 whether the promoted control technique is technology or operational controls.

## Place-Specific Policies

Around 75% of generation in New England occurs in the upwind region of Connecticut, Rhode Island, and Massachusetts. These three states are where the majority of both capacity and demand are located. Therefore, the results and policy recommendations for geographic controls are very similar to those for regional controls.

Geographic policies invite greater political conflict than regional strategies, because by nature they distribute costs and benefits more discriminantly and explicitly than regional policies. Policy makers should verify that the benefits to the region are worth any additional political costs that geographic policies might incur.

In general, place-specific policies save costs or increase benefits by prioritizing emissions for control according to their contribution to ozone formation. For operational controls, the magnitude of these cost savings depends dramatically on the extent of technology controls.

If plants have only combustion control technologies, minimizing NOx upwind instead of over the entire region decreases control costs by about 31%. Upwind emissions stay the same and regional emissions increase by 7%. When half the existing fossil capacity has post-combustion control technologies, geographic controls decrease control costs by about 27%. Upwind emissions stay the same and regional emissions increase by 8%. However, when almost all the existing fossil capacity has post-combustion control technologies, geographic controls decrease control costs by only 5%. Upwind emissions stay the same and regional emissions increase by 8%. These results may be especially sensitive to transmission constraints, which are not modeled in this study.

Thus, NOx control policies should distinguish areas within New England only if the extent of technology controls on fossil units is moderate to low. Moreover, decision makers should have confidence that the air quality and health benefits of NOx emissions reductions upwind are significantly greater than equivalent reductions downwind. At present, there is large uncertainty about the differential effects of NOx emissions within the northeast due to widespread transport and mixing.

Similar to time-specific policies, place-specific policies should not encourage conservation, repowering, or new-supply options for NOx control purposes. Although repowering and new supply alternatives can be geographically applied, whereas they cannot be temporally applied, they would be less cost-effective than geographically applied technology or operational controls.

Since the impacts of geographic control policies are subject to transmission and distribution constraints, it is not clear to what degree operational controls are more cost-effective than technology controls, or vice versa. This study shows that geographic minimum NOx dispatch could have cost savings over a regional strategy, but leaves undetermined the costs and benefits of geographic technology control strategies. The degree to which place-specific policies should favor operational or technology controls over each other would require further study.

POLICY INSTRUMENTS

It is useful to consider the policy tools that could be employed to encourage time and place specific strategies. On cursory consideration, emissions caps and market systems seem more appropriate than command and control methods, taxes, or plant emissions limits, which are used in Phase I RACT regulations.

From the perspective of achieving regional air quality goals, emissions caps and market systems offer the greatest promise, since they fix the total amount of emissions. However, their success depends on the ability of regulators to relate NOx levels to ozone formation. This has not been easy for photochemists.

If the costs of administering a NOx trading system are less than the efficiency gains over caps alone, then the trading system should be pursued. This analysis is beyond the scope of this study. However, the results could be similar to those describing the SO2 trading system, which will begin in full January 1, 1995.

Moreover, emissions caps and market systems are politically palatable, as SO2 trading has demonstrated. They do not disadvantage parties by generation mix, location, or size. They can favor the highest emitting parties, since baselines are often set according to historical emissions. Nonetheless, incremental pollution is penalized equally across sources, so marginal cost to the polluter is directly proportional to marginal contribution to the problem.

Both caps and market systems provide at least the highest degree of flexibility as the other policy options. They can adapt quickly to changes in control technology, fuel costs, conservation methods, or new supply technologies by comparing all options by emission reduction cost-effectiveness. They can adapt to changes in air quality goals or information by adjusting the levels of the caps. Such response is not as easy with technology mandates, taxes, or emissions limits.

Finally, caps and market systems encourage the largest extent of technological development since they give equal consideration to large reductions and small ones, as well as to supply-side and demand-side improvements. Moreover, they do not pre-determine the marginal cost of emissions reductions or the type of technology or operational controls, leaving an open door for innovation.

# *Chapter 6*

## *CONCLUSIONS*

### MAIN CONCLUSIONS

The key points resulting from this study, subject to input assumptions and modeling limitations, are the following:

1. The most cost-effective options for controlling NOx emissions are NOx control technologies and operational controls. However, these options achieve little coincident $CO_2$ emissions reductions, and operational controls greatly increase dependence on natural gas fuel.

Both technology controls and operational controls yield greater NOx emissions reductions at lower cost than conservation, repowering, or new supply technologies. However, conservation is much more cost-effective for reducing $CO_2$ emissions. NOx control technologies yield about a 2% coincident reduction in $CO_2$ emissions, while operational controls yield only an 8% reduction. Conservation can achieve up to a 15% reduction in $CO_2$ emissions.

Moreover, operational controls greatly increase natural gas use. In the year 2011, operational controls increase gas use between 25-50% , whereas technology controls only increase gas use by up to 11%.

2. Considering only NOx emissions reductions, operational controls are more cost-effective than technology controls up to a control period of about seven months, after which technology controls are more cost-effective. However, the time period at which cost-effectiveness is equal depends significantly on natural gas

costs. Further, operational controls can achieve only half as much total emissions reductions as technology controls.

For a control period of about one month, operational controls are more than six times more cost-effective than technology controls. For a control period of one year, technology controls are about two times more cost-effective. However, at high gas costs, the control period length at which cost-effectiveness is equal is four and one half months. At low gas costs, the control period length is also seven months. Operational controls can achieve up to 17% reductions beyond Phase I RACT levels whereas technology controls can achieve up to 40% reductions beyond RACT levels.

3. If more than half of existing fossil-fuel capacity already has technology controls, then operational controls are more cost-effective than additional technology controls for any length control period.

The units without technology controls are likely to be low capacity factor units. Therefore, control technologies, having high capital costs, are not cost-effective on units with relatively low capacity factors. Operational controls are more than thirteen times as cost-effective for a one month control period, and more than three times as cost-effective for a five month control period. Further, operational controls achieve moderate CO2 emissions reductions while increasing natural gas use.

4. The effects of operational controls on natural gas use depends dramatically on the extent of existing unit control technologies.

Since existing fossil generation is dominated by oil and coal units, additional control technologies allow these units to run more under operational controls. This mitigates the shift from oil and coal to gas-fired plants. For example, under Phase I RACT, operational controls increase gas use by 50% in 2011, while under Phase II Hard, they increase gas use by 25%.

5. The extent to which geographic controls decrease control costs and displace upwind emissions to downwind areas, compared with regional controls, depends dramatically on the extent of control technologies.

If plants have only combustion control technologies, minimizing NOx upwind instead of over the entire region decreases control costs by about 31%. Upwind emissions stay the same and regional emissions increase by 7%. When half the existing fossil capacity has post-combustion control technologies, geographic controls decrease control costs by about 27%. Upwind emissions stay the same and regional emissions increase by 8%. However, when almost all the existing fossil capacity has post-combustion control technologies, geographic controls decrease control costs by only 5%. Upwind emissions stay the same and regional emissions increase by 8%. These results may be especially sensitive to transmission constraints, which are not modeled in this study.

### AREAS FOR FURTHER STUDY

This study leads to some issues for further research. The most immediate is the sensitivity of the above results to changes in the costs or performances of control technologies. Other countries, such as Japan and Germany, are developing post-combustion controls that some U.S. utilities have found superior to similar U.S. technologies.

In modeling operational controls, it was assumed that enough excess capacity exists during days associated with ozone episodes or with the ozone season that unit dispatch can be significantly altered. There is a possibility that since many of the episode-associated days are characterized by high temperatures, the system already operates near peak load. If this were the case, then operational controls are severely restricted.

NOx emissions in this analysis were considered of equal importance across all geographic regions, except for an upwind and downwind differentiation. Although about 75% of current generation in New England is located in the upwind three states, more information about the relative impacts of downwind versus upwind state NOx emissions would help set priorities for control. Moreover, perhaps more specific geographic designations would more accurately differentiate NOx emissions by their contribution to ozone formation. For example, coastal emissions versus inland emissions may have different impacts, or emissions in eastern Connecticut versus western Connecticut may distinctly affect ozone levels.

To determine whether unit or area emissions caps versus market-based trading systems are more effective policy tools, research on the cost and efficiency differences between these alternatives would be informative. Lessons could be learned from the SO2 trading system, which starts January 1, 1995.

Finally, the electric power industry in the United States is undergoing considerable structural changes. Open access to transmission has begun; small and independent power producers are competing more extensively with the large-scale utilities; and retail wheeling is being considered, under which unregulated, marginal cost pricing would replace regulated, embedded-cost pricing. These changes could have major effects on the need and means for controlling environmental quality, including ozone and NOx concentrations. Further research could address the extent to which air quality would be affected and controlled under the variegated possibilities.

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