Regulatory Impact Analysis of the Final Acid Rain Implementation Regulations

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EXECUTIVE SUMMARY

1. Background

Acid rain (and other forms of wet and dry acid deposition, including snow, fine particulates and gases) is suspected of causing serious damage in a variety of areas: aquatic and terrestrial ecosystems, construction and cultural materials (such as metals, wood, paint, and masonry), and public health. In addition, the gaseous pollutants that promote acid rain have been linked to local ozone buildup, suspended particulate matter, and reduced visibility. Of the three pollutants that are generally considered to be most heavily involved in the formation of acid rain, SO_2 and NO_x arise almost entirely from power plants and motor vehicles.

After more than a decade of clean air bills and proposals, President Bush signed the Clean Air Act (CAA) Amendments of 1990 (P.L. 101-549) into law on November 15, 1990. Title IV of the Clean Air Act (the acid rain title) set three major goals: (1) a reduction in SO_2 emissions of 10 million tons per year below 1980 levels by the year 2000; (2) a nationwide cap on SO_2 emissions beginning in the year 2000; and (3) a two million ton reduction in NO_x emissions. These goals are to be met through a two-phased program. In Phase I (beginning in 1995), part of the SO_2 and NO_x reductions are to be achieved through emissions reduction requirements at the largest, highest-emitting power plants. During Phase II, the SO_2 and NO_x reduction goals are to be reached through more stringent requirements at virtually all fossil fuel power plants and through other parts of the CAA amendments.

An important feature of the Acid Rain Program is a system of allowance allocation and trading. The provisions of Title IV that establish this system represent a significant departure from the more traditional "command and control" approach to regulation. Command and control regulations typically set specific emissions standards that must be met on a source-by-source basis. Under the Acid Rain Program, however, units at sources are not assigned rigid emissions limits. Instead, each unit is allocated transferable emissions "allowances," each of which permits the holder to emit one ton of SO_2. If the number of tons of SO_2 emitted by a unit exceeds its allocated allowances, it can still comply with the program by obtaining additional allowances from units whose emissions are smaller than their allowance allocations. This transferability creates a potential market for emissions allowances, in which allowances may be bought, sold, auctioned, and banked from year to year by SO_2 emitting units or by any party outside of the regulated community. The flexibility allowed by this system is expected to lower the costs of reducing emissions considerably, since the emissions reductions at the units with the lowest costs of control will be able to substitute for the more costly emissions reductions by other units that would otherwise have been required.

The regulations covered by this regulatory impact analysis are

- permitting;
- the allowance system (including conservation and renewable resources, auctions, sales, and IPP guarantees); and
- emissions monitoring.

These provisions are essential to making the allowance trading program functional and effective. They ensure that emissions are accurately measured, the program's provisions can be enforced, and that allowances are generally available, even to those entities that do not receive allowance allocations. Other provisions enhance the overall goals of the Acid Rain Program by encouraging emissions reductions through reductions in electrical generation, the substitution of renewable resources for fossil fuels, and the inclusion of additional electricity sources.

2. Purpose and Scope of this Report

This regulatory impact analysis (RIA) was developed in response to Executive Order (EO) 12291, which requires Federal Agencies to assess the costs, benefits, and impacts of all "major" regulations. Under EO 12291, any regulation likely to result in an annual effect on the economy of $100 million or more is considered a "major" regulation. While the proposed regulations implementing the allowance allocation and trading system are expected to reduce costs rather than increase them, the net costs of emission reductions imposed by the statute itself are expected to be large enough to fit the definition of a major regulation. EPA has therefore decided to treat the proposed regulations as a major rule for the purposes of EO 12291.

In compliance with EO 12291, this RIA assesses costs, benefits and impacts for the important provisions of Title IV. Its scope excludes those parts of the program not yet completed: the NO_x-related provisions, and voluntary inclusions of additional sources (opt-in). Also excluded are analyses of a set of implementation issues (including the question of serialization of allowances; end-of-year "truing up" periods, and other issues related to permits and monitoring). While no dollar values could be assigned to these implementation issues, they are discussed in the preamble to the implementation regulations.

EPA divided its analysis of the Acid Rain Program into two parts. First, EPA analyzed the effects of the statute in the absence of any implementation regulations. This analysis was performed by defining and examining the "absent regulations" case, in which a 10 million ton reduction in SO_2 emissions is mandated by statute, but there are no implementation regulations to establish an acid rain program that allows for allowance trading, special compliance plans, or application for alternative monitoring programs. EPA compared this "absent regulations" case to a "pre-statute" case (in which no emissions reductions would be required) to show the incremental costs of the SO_2 reductions without the implementation regulations.

In the second part of the analysis, EPA examined a "regulatory" case that included both the SO_2 reductions and the implementation regulations. By comparing costs under the regulatory case to those under the absent regulations case, EPA was able to isolate the incremental savings provided by the regulations. At the same time, by combining the two parts of the analysis, EPA was able to show the total costs imposed by the Acid Rain Program (the statute and the regulations) as a whole.

3. Industries Affected by the Acid Rain Program

Title IV directly affects utility units providing power to generators that produce electricity commercially. Most utility units belong to the electric utility industry and are either investor-owned or publicly-owned, such as the Tennessee Valley Authority. The utility industry currently accounts for the vast majority of the generation capacity in the U.S. A growing share of generating capacity, however, is being owned by independent power producers (IPPs) and other entities outside of the conventionally-defined utility industry.

The characteristics of electric utilities vary widely in terms of institutional and regulatory arrangements, size, power plant types, fuel consumption, and power supply cost structure. Utilities are currently highly regulated at both the state and federal levels, but the regulatory climate is gradually shifting toward less regulation and more competition.

The electric utility industry is composed of about 3,000 companies. Most of these are municipally-owned utilities or rural electric cooperatives, which are generally very small in terms of electricity generation. A relatively small number of utilities (about 200) are investor-owned; these, however, account for about three-quarters of the total electricity generated in the U.S. Exhibit ES-1 provides an overview of the electricity generating sector.

Most U.S. electric utilities have monopolies (known as franchises) provided by state or local authorities and are the only supplier of electric power within their service territories. In exchange for the advantages conferred by the franchise, the utility subjects its rates to regulation by state authorities. Rates for investor owned utilities are set to allow them to recover all of their costs (so long as these costs were "prudently incurred") and make limited profits as well.

Phase I of the Acid Rain Program affects units owned by 61 different utilities, with a total installed capacity of 88,977 megawatts MW; Phase II affects units owned by 239 different utilities representing 471,445 MW of capacity. Exhibit ES-2 shows the breakdown of these utilities by size and type of owner.

Almost 70 percent of the electricity currently generated in the U.S. is produced using coal and other fossil fuels. The rest is produced using nuclear power, hydropower, or other energy sources that are not regulated by Title IV. Regional differences in fuel types are substantial: oil and gas fueled generation serve as the dominant capacity sources in several regions including New England and the Pacific, while coal is the most important source in other areas including the Midwest. The regional mix in fuel use has important implications for regional SO_2 emissions, acid rain control costs, and electric rate impacts.

A significant amount of electric generation capacity owned and operated by private developers, rather than by the regulated utilities, has come on line over the last decade. The total amount of generation from this capacity was about 199,000 MW, or seven percent of total U.S. utility generation. Plants burning natural gas, coal, and biomass are the most common types of generators outside of the conventionally-defined utility industry. Projects burning waste products also provide substantial capacity, as do plants utilizing hydro and wind resources.

In addition to the industries that are regulated under Title IV, a number of other industries could be affected indirectly. The coal industry is the most important example of an indirectly affected industry because of the fact that most of the coal industry's output is sold to utilities. Pollution control equipment manufactures, the bulk transportation industry, and some industries that use large quantities of electricity, could also be affected indirectly.

EXHIBIT ES-1
U.S. Installed Generating Capacity by Industry Type
(Gigawatts)

	1979	1986	1987	1988
Total U.S. Electric Utility Industry	598	710	718	724
Investor Owned Utilities	464	546	553	558
Municipals, Cooperatives, Federal, and Public Power	134	164	165	166
Total Non-Generating Industry	18	25	30	34

Source: "1988 Capacity and Generation of Non-Utility Sources of Energy," Edison Electric Institute, April, 1990.

Note: 1 gigawatt equals 1000 megawatts or 1 million kilowatts.

4. Costs of the Program

In estimating the effects of the Acid Rain Program, EPA divided costs into two broad categories: costs related to SO_2 emissions reductions, and costs related to regulatory implementation. Costs in these categories were estimated for the absent regulations case compared to the pre-statute case; for the regulatory case compared to the absent regulations case; and for the regulatory case compared to the pre-statute case. In addition, each case was estimated under a high and low scenario representing different assumptions about energy demand growth and other factors that could affect emissions. The time frame for the analysis of emissions reduction costs is the 18-year period from 1993 through 2010. To cover this period, EPA analyzed four discrete points in time: 1995 (the beginning of Phase I); 2000 (the beginning of Phase II); 2005; and 2010.

The costs of SO_2 emissions reductions were estimated with a detailed linear programming model that computes the utility industry's lowest cost responses to the emissions control requirements under each case. EPA estimated total costs (that is, the present discounted value of costs over the 18-year period 1993 through 2010) for both the absent regulations case and the regulatory case. The total costs of the SO_2 reductions mandated by the statute were estimated to range from $19.1 to $30.9 billion without the regulations, compared to only $9.5 to $17.1 billion with the regulations (see Exhibit ES-3a). Comparing the total costs with and without the regulations showed that a well-functioning allowance trading system would reduce the costs of the SO_2 emissions reductions mandated by the statute by $9.6 to $13.8 billion.

EXHIBIT ES-2
Characterization of Affected Existing Utility-Owned Units

Type of Ownership	Phase I			Phase II		
	# of Utilities	# of Units	Capacity (GW)	# of Utilities	# of Units	Capacity (GW)
Federal and Public Power Entities, State and District Systems	1	26	9	13	116	32
Cooperative Systems	5	15	4	27	89	23
Investor-Owned Systems	52	216	75	132	1,517	392
Municipal Systems	3	4	1	67	183	24
TOTALS	61	261	89	239	1,905	471

Source: National Allowance Data Base Version 1.0 and ICF Analysis of the Clean Air Act Amendment of 1990.

In addition to the costs of reducing SO_2 emissions, the implementation regulations would impose some additional costs. The auctions, direct sales, and IPP written guarantee provisions, which are intended to aid in the development of an allowance market and ensure the availability of allowances, would add between two and eight million dollars to the total costs of the regulations (where, again, the total costs were measured as the discounted present value of costs over the 18-year period from 1993 through 2010). Operating the conservation and renewable energy program would cost a total of between $1 and $2 million. The total costs of the allowance tracking system would also be relatively small, at $4 to $6 million, while the total costs to the regulated community of arranging allowance transactions could range from $200 to $400 million. The total costs of the continuous emissions monitoring program was estimated at approximately $2.4 billion. The monitoring costs, however, are actually lower in the regulatory case than in the absent regulations case. Finally, EPA estimated the total cost of the permits program to be $68 million.

Exhibit ES-3a presents the total cost estimates for the absent regulations case compared to the pre-statute case, the regulatory case compared to the absent regulations case; and the regulatory case compared to the pre-statute case. Overall, the acid rain statute (including the implementation regulations) imposes total costs (measured as the present value of costs from 1993 through 2010) of between $12.2 and $20.0 billion, while the acid rain regulations provide net savings of between $9.4 and $13.4 billion. Exhibit ES-3b shows costs and cost savings on an annualized basis.

EXHIBIT ES-3a
INCREMENTAL TOTAL COSTS AND COST SAVINGS
(1993 to 2010, in Millions of 1990 dollars)[a]

	Costs of SO_2 Reductions without Implementation Regulations[b]	Costs of SO_2 Reductions with Implementation Regulations[b]	Cost Savings Provided by Implementation Regulations[b]
Cost of SO_2 Reductions	**$19,100 to $30,900**	**$9,500 to $17,100**	**$9,600 to $13,800**
Implementation			
Allowance System[c]			
• Trans/Tracking	$0	$204 to $406	-$204 to -$406
• A/S/IPPG	$0	$2 to $8	-$2 to -$8
• Con/Ren Energy	$0	$1 to $2	-$1 to -$2
CEMS	$2,512	$2,395	$117
Permits	$0	$68	-$68
Subtotal:	**$2,512**	**$2,670 to $2,879**	**-$158 to -$367**
Total Costs/Savings	**$21,612 to $33,412**	**$12,170 to $19,979**	**$9,442 to $13,433**

a Total costs are present values of costs incurred in each year (with capital costs annualized at 7 percent per year) discounted to 1992 at 3 percent per year. Annualized costs are computed using the total costs and a discount rate of 3 percent per year.

b Ranges cover EPA Low Scenario and High Scenario.

c Includes: Allowance Transactions/Tracking, Auctions/Sales/ IPP Guarantees, and Conservation/Renewable Energy

EXHIBIT ES-3b
INCREMENTAL ANNUALIZED COSTS AND COST SAVINGS
(1993 to 2010, in Millions of 1990 dollars)[a]

	Costs of SO_2 Reductions without Implementation Regulations[b]	Costs of SO_2 Reductions with Implementation Regulations[b]	Cost Savings Provided by Implementation Regulations[b]
Cost of SO_2 Reductions	**$1,400 to $2,300**	**$700 to $1,300**	**$700 to $1,000**
Implementation			
Allowance System[c]			
• Trans/Tracking	$0	$14.8 to $29.5	-$14.8 to -$29.5
• A/S/IPPG	$0	$0.1 to $0.6	-$0.2 to -$0.6
• Con/Ren Energy	$0	$0.1	-$0.1
CEMS	$182.6	$174.1	-$8.5
Permits	$0	$4.9	-$4.9
Subtotal:	**$182.6**	**$194.0 to $209.2**	**-$11.5 to -$26.6**
Total Costs/Savings	**$1,583 to $2,483**	**$894 to $1,509**	**$689 to $973**

a Annualized costs are computed using the total costs and a discount rate of 3 percent per year. Total costs are present values of costs incurred in each year (with capital costs annualized at 7 percent per year) discounted to 1992 at 3 percent per year.

b Ranges cover EPA Low Scenario and High Scenario.

c Includes: Allowance Transactions/Tracking, Auctions/Sales/ IPP Guarantees, and Conservation/Renewable Energy

5. Impacts of the Acid Rain Program

EPA assessed the effects of the Acid Rain Program from four different perspectives: the impacts of the costs and cost savings on the regulated community as a whole; on different regions of the country; on entities outside the regulated community; and on smaller entities.

Nationwide Impacts on the Regulated Community

The annual Acid Rain Program costs, while large in absolute terms, are relatively small compared to the roughly $200 billion annual costs of generating electricity. As shown in Exhibit ES-4, the average costs (on a "levelized" basis) of generating electricity rise 0.5 to 0.7 percent under the absent regulations case for 1995 under the high and low scenarios, respectively. Average cost impacts for 2000, 2005, and 2010 are greater as a consequence of Phase II, but still less than two percent of total costs. As with any average, these average cost estimates take into account utilities with more significant cost impacts (*e.g.*, as high as ten percent or more in a few cases) along with many others that are largely unaffected or experience cost reductions under the absent regulations case.

The regulations provide cost reductions of less than a third of one percent of total generation costs in Phase I and generally less than one percent in Phase II. Savings of this magnitude amount to between one-fourth and two-thirds of the costs in the absent regulations case, depending on the year and the scenario.

The aggregate impact of these cost changes on the financial health (in terms of net income) of the electric utility industry is likely to be small. Because utility rates are tightly regulated, cost increases are generally passed through to electricity consumers as price increases. Costs for pollution control costs in particular have almost always been considered a necessary cost of power production, and so are especially likely to be passed through. The utilities' margins are therefore expected to be insulated to a certain extent from both cost increases and decreases.

EXHIBIT ES-4
AVERAGE NATIONWIDE PERCENTAGE CHANGE IN ELECTRICITY COSTS
(percent)

	COSTS OF ABSENT REGULATIONS CASE (incremental to pre-statute case)		COSTS OF REGULATORY CASE (incremental to pre-statute case)		COST SAVINGS OF REGULATORY CASE (incremental to absent regulations case)	
	Low Scenario	High Scenario	Low Scenario	High Scenario	Low Scenario	High Scenario
1995	0.5	0.7	0.3	0.4	0.2	0.3
2000	1.3	1.9	0.5	0.8	0.8	1.1
2005	1.4	1.7	1.0	1.2	0.4	0.5
2010	0.9	1.5	0.4	1.1	0.5	0.4

In addition, because utilities are structured as regulated monopolies (as discussed in Chapter 2), they are protected to a certain extent from losing customers to competitors with lower rates. However, increasing deregulation of the industry and competition from independent power and industrial cogeneration and self-generation make this protection somewhat limited in certain cases. Nonetheless, consumers' responses to levelized average U.S. price increases or decreases in the range of one-half to one percent may be considered insignificant by the utilities experiencing these responses. Even higher rate increases on the order of five to ten percent would probably not substantially reduce consumer demand.

Cost changes cannot always be passed through entirely, however, because Public Utility Commissions may disallow portions of the costs if it is determined that they were not prudently incurred. For this reason, the regulations will reduce the utilities' exposure to potential financial difficulties by minimizing the increase in their costs. Further, the regulations will tend to reduce impacts on utilities that arise from lags in the rate-setting process. Because cost increases are not always quickly translated into price increases, they can sometimes hurt profitability. By reducing cost impacts, the regulations can minimize the effects of the lags in the rate-setting process.

Regional Impacts

The impacts discussed above are nationwide averages, and do not represent the impacts faced by utilities in any one state or region. Given the significant differences in fuel mixes across regions and the differential effects of SO_2 controls on power plants using different fuels, regional impacts can be expected to vary widely.

Exhibit ES-5 shows the approximate percentage cost changes over the period 1995 through 2010 under the absent regulations and regulatory cases for the high scenario. The census regions are listed in order of cost impacts, from lowest to highest. In general, the regions with the highest cost impacts are those with the most affected coal-fired capacity and greatest required SO_2 reductions. While the savings provided by the implementation regulations do not follow exactly the same pattern, the four regions with the lowest costs do appear to have lower savings. Similarly, the four regions with the highest cost impacts under the absent regulations case all have relatively large savings under the regulatory case.

EXHIBIT ES-5
Costs of Absent Regulations and Savings with Regulations as a Percentage of Generation Costs[a]
(percent)

	REGION[b]	COSTS	SAVINGS
LOW COST, LOW SAVINGS	PACIFIC	0.2	0.2
	NEW ENGLAND	0.5	0.2
	LOWER SOUTH ATLANTIC	0.9	0.3
	MIDDLE ATLANTIC	1.1	0.3
MODERATE COST, HIGH SAVINGS	MOUNTAIN	1.3	0.8
	WEST SOUTH CENTRAL	1.5	1.1
HIGH COST, HIGH SAVINGS	EAST SOUTH CENTRAL	2.0	0.7
	WEST NORTH CENTRAL	2.1	0.8
	EAST NORTH CENTRAL	2.3	0.7
	UPPER SOUTH ATLANTIC	2.4	0.5

[a] Costs and savings were estimated by averaging estimates from 1995, 2000, 2005, and 2010 for the high scenario.
[b] Regions listed in order of lowest costs to highest costs.

Secondary Effects

Title IV's direct effects reach only the nation's electric generation industry. As previously discussed, however, the utilities are not likely to absorb much of the impact of the Acid Rain Program. Instead, the impacts are likely to be passed on to other sectors of the economy: electricity consumers, the coal industry, railroads and other transportation providers, oil and gas producers, and emissions control manufacturers.

The costs of emissions reductions are likely to be passed on through increased electricity rates. The increased costs will have very small impacts on the typical consumer: electricity is a minor part of household budgets, and the changes in electricity bills will be small even in percentage terms. Consumption will drop marginally as prices rise and consumers respond to avoid some of the increased costs. Reducing electricity usage will impose real, though small, costs on consumers, as they spend more to purchase energy-efficient appliances, and make other electricity-saving choices.

The increased electricity rates attributable to acid rain compliance could have more significant impacts on those industries that are unusually large consumers of electricity, such as steel and aluminum producers, though even in extreme cases total production costs for these industries will not rise more than a few percent. Cost savings provided by allowance trading will tend to mitigate somewhat the negative effects on industrial competitiveness and employment that might occur in the absent regulations case as a result of electricity rate increases.

Neither the absent regulations case nor the regulatory case is likely to result in a significant change in total consumption of coal for electricity generation. Considerable changes in the type of coal consumed may take place, as consumption shifts from high to low sulfur coals. Because the implementation regulations allow many utilities to choose to avoid scrubbing if they switch to low sulfur coal, coal production losses in high sulfur regions are likely to be higher in the regulatory case than in the absent regulations case in 2005 and 2010.

Changes in regional coal production caused by the Acid Rain Program will affect the railroad, trucking, and barge transportation industries as well as the coal industry. The total volume of rail and barge shipments of coal is expected to increase under the absent regulations case. The regulations will mitigate some of the increase in ton-miles hauled. Truck transportation of coal, on the other hand, is expected to decline.

Some utilities that are currently burning oil are expected to switch to gas in order to reduce SO_2 emissions (the SO_2 emission rate of natural gas is virtually zero). As a result, gas producers are likely to experience increased demand (and may receive higher prices) at the expense of oil producers.

The Acid Rain Program is expected to lead to increased retrofit scrubbing at coal-fired power plants. The increase in retrofit scrubbing will, in turn, lead to increased revenues for scrubber manufacturers, as well as increased revenues for lime/limestone producers whose products are commonly used in scrubbers. Because there will be less scrubbing under the regulatory case than the absent regulations case, revenues and employment in the air pollution control industry will not increase as much in the regulatory case.

Impacts on Small Entities

For purposes of assessing the impacts of the Acid Rain Program on smaller entities, EPA has adopted the SBA definition that a "small" electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year. Not all small utilities are affected by the acid rain title of CAA. Utilities will be unaffected if (1) all of their units are exempt (*e.g.*, units using non-fossil sources or existing simple gas turbines), or (2) they fall below statutory minimums for electric generating capacity (*i.e., existing capacity below* 25 MW). These unaffected utilities were excluded from the analysis of impacts on small entities; an attachment to this document covers impacts on utilities with new units under 25 MW capacity.

After excluding utilities exempt from the provisions of CAA, EPA determined that about 105 of the 241 Phase II affected utilities (about 44 percent) are small. (No small utilities are affected under Phase I). Collectively, affected small utilities accounted for about 5 percent of total 1988 electricity generation by affected utilities (*i.e.*, about 119 billion kilowatt-hours of electric power generation during 1988).

Small utilities differ from large utilities in several important respects: (1) ownership; (2) generation mix; and (3) cost of achieving emissions reductions. It is more common for small utilities to be operated by municipal governments than is the case for larger utilities: 60 percent (63 out of

105) of the small utilities are run by municipal governments, while the comparable figure for large utilities is only four percent (5 out of 132). Smaller utilities are more likely to depend exclusively on either oil/gas or coal, rather than a combination of oil/gas and coal at different units; very small utilities are more dependent on oil and gas as opposed to coal. In addition, emissions from smaller power plants tend to be relatively costly to control.

To examine the effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. To allow for differences across fuel types, two of the model utilities burn coal; two burn oil; and two burn natural gas. The two coal-fired utilities are relatively "dirty," the two oil-fired utilities have moderate SO_2 emissions rates, and the two gas-fired utilities have virtually no SO_2 emissions. EPA projected the most likely responses of these model utilities under the absent regulations case and the regulatory case, and used results from the analysis of the industry as a whole to predict the cost impacts of SO_2 reductions and the implementation regulations on each model small utility.

EPA concluded that the Acid Rain Program would have very little impact on most small entities, since they are either gas-fired (and therefore inherently low in emissions) or small enough to qualify to receive relatively large allocations of allowances. Some coal or oil-fired utilities that are ineligible to receive additional allowances, however, might face substantial increases in their costs (as high as ten to twenty percent in extreme cases) under the absent regulations case.

The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be in the range of 25 to 60 percent, which is similar to the savings for larger utilities. Absolute savings measured in average levelized cents per kwh, on the other hand, will typically be greater for small utilities (0.13 to 0.68 cents per kwh) than for larger utilities (0.08 cents per kwh).

Virtually all of the impacts on small businesses are caused by statutory provisions of the Clean Air Act. EPA is considering regulations that are intended to mitigate some of the burden on small businesses. For new small utilities (*i.e., less than or equal to* 25 MW), EPA will grant an exemption from the requirements of the Acid Rain Program if they can certify that they use very low sulfur fuel (*i.e., less than* .05 lbs SO_2/mmBtu) and that they have a utilization of less than 10 percent. EPA will do this to minimize the burden on small entities and because the emissions from small entities will be negligible. The statutory provisions, however, restrict the amount of relief that can be provided.

CHAPTER 1
INTRODUCTION

EPA has prepared this Regulatory Impact Analysis (RIA) to accompany the Agency's proposed regulations for the implementation of Title IV of the Clean Air Act as amended (42 U.S.C. 7651 *et seq.*), which imposes limits on emissions that cause acid rain. The RIA was developed in accordance with Executive Order (EO) 12291, which requires federal agencies to assess the costs, benefits, and impacts of all "major" regulations. Under EO 12291, a "major" regulation is defined as one likely to result in any of the following effects:

- An annual effect on the economy of $100 million or more;
- A major increase in prices for consumers;
- A major increase in costs to individual industries, geographic regions, or federal, state, or local government entities; or
- Significant adverse effects on competition, employment, productivity, innovation, or on the ability of U.S.-based enterprises to compete with foreign-based enterprises in domestic or export markets.

If a rule is determined to be major, the issuing agency must prepare an RIA and consider its results (to the extent permitted by authorizing legislation).

EPA does not anticipate major increases in prices, costs, or other significant adverse effects due to the proposed regulations for the implementation of Title IV. Instead, EPA expects that the flexibility provided by proposed regulations would result in a significant reduction in costs to the economy, when compared to the costs of compliance with statutory emissions control requirements in the absence of these regulations. Thus, EPA expects the proposed Title IV regulations to have beneficial rather than harmful effects. Because the expected magnitude of the total costs of the Acid Rain Program exceed $100 million per year, the proposed regulations are being treated as a major rule for the purposes of EO 12291.

1.1 ACID RAIN REGULATIONS

1.1.1 History of Acid Rain Problem and Response

The acidification of natural atmospheric precipitation, commonly called "acid rain," is of concern because of the potential adverse environmental impacts on natural ecosystems (including aquatic life, wildlife, vegetation, forests, and agriculture), materials (such as metals, wood, paint, and masonry), and general public health and welfare. In addition, the gaseous pollutants that are suspected of promoting acid rain are also thought to be linked to certain other atmospheric problems, such as local ozone buildup, suspended particulate matter, and reduced visibility.

Adverse effects of acid rain were initially observed in the late 1970s. Increasing Congressional interest led to the passage of the Acid Precipitation Act of 1980 (Title VII of the Energy Security Act of 1980, P.L. 96-294). This Act established an Interagency Task Force on Acid Precipitation,8 which developed and implemented a comprehensive National Acid Precipitation Assessment Program (NAPAP). This national program was designed to develop and progressively refine the scientific understanding of the causes and effects of acid rain.

It is generally believed that three main precursor pollutants, sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOC), are involved in the formation of acid rain. While only about 40 percent of VOC emissions are of anthropogenic origin, the majority of SO_2 and NO_x emissions are anthropogenic. For example, about 25 million tons of SO_2 are emitted annually in the U.S. result from human activity (about 70 percent from electricity generating power plants), versus less than 500 thousand tons of annual natural SO_2 emissions. As for NO_x, of 22 million tons emitted annually in the U.S. only about 3 million tons per year come from natural sources while about seven million tons come from power plants.

Concern over local environmental conditions led several states to pass legislation during the 1980s requiring curtailments or caps on statewide SO_2 (and, in some cases, NO_x) emissions. However, Congress and others felt that state laws would only be partially effective in reducing the impacts of acid rain. Furthermore, Canada became increasingly concerned with acid rain-related effects on its lakes and other ecosystems, which it attributed in part to sources in the United States. Because of acid rain's interregional (and international) nature, the debate over acid rain control moved towards federal acid rain legislation. As a result, during the 1980s, various bills and proposals for reducing SO_2 and NO_x emissions were put forth in Congress.

1.1.2 Clean Air Act Amendments of 1990: Summary of Acid Rain Provisions

After more than a decade of clean air bills and proposals, President Bush signed the Clean Air Act (CAA) Amendments of 1990 (P.L. 101-549) into law on November 15, 1990. The Amendments include 11 separate titles that cover nonattainment (*e.g.*, ozone and carbon monoxide problems), motor vehicles, air toxics, stratospheric ozone, and acid rain among other air pollution issues. Title IV, the acid rain title, sets three major goals adopted from the original Administration proposal: (1) a reduction of SO_2 emissions of 10 million tons per year below the 1980 level by the year 2000; (2) approximately a two million ton reduction from the 1980 level of NO_x emissions; and (3) a national cap on SO_2 emissions beginning in the year 2000.

In meeting the goals of a 10 million ton SO_2 reduction, cap on SO_2 emissions, and two million ton NO_x reduction, a two-phased program was developed. During Phase I (beginning in 1995) part of the SO_2 and NO_x reductions are to be achieved through emissions reduction requirements at 110 of the largest, highest-emitting power plants. During Phase II, the SO_2 and NO_x reduction goals are to be reached through more stringent requirements at virtually all fossil fuel utility units.[1] The rationale for this two-phased program was to achieve some reductions promptly while alerting a broad range of polluters to plan for a more significant reduction by 2000.

Perhaps the most important feature of the acid rain title is the allowance allocation and trading provisions. These represent a significant departure from more traditional "command and control" regulation which sets emissions standards that must be met by each individual unit. The program allocates emission "allowances," which allow utilities to emit tons of SO_2 based on a national target for SO_2 reductions. Through the transfer of these allowances from one source to another in

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[1] A "unit" is an individual fossil-fuel burning device (either a turbine or a boiler) that drives an electrical generator. By contrast, a power plant consists of one or more units at a single site.

a free market, the targeted reductions can be achieved in the most cost-effective manner. Simply stated, the rules in this market are as follows:

(1) Each existing "affected" (defined in Table A of the Act for Phase I) unit is allocated and issued SO_2 allowances;

(2) All units, including new units, must have enough allowances each year to cover actual emissions; and

(3) Allowances may be bought, sold, and banked (saved) from year to year.

The major acid rain provisions are presented in Exhibit 1-1 and briefly summarized below.

- <u>Phase I SO_2 and NO_x Requirements</u> - In Phase I (beginning 1/1/1995)
  - SO_2 emission allowances are tradeable among affected sources across all states. Sources may also bank emission allowances and use them in a later year.
  - An additional 200,000 tons of allowances are allocated annually during Phase I to units in Illinois, Indiana and Ohio (except for the three Department of Energy (DOE) plants: Clifty Creek, Kyger Creek, Joppa Steam) based on their pro rata share of Phase I allowances.
  - Units affected in Phase I are required to install cost-effective NO_x control technology.
- <u>Phase I Technology Allowances</u> - Eligible Phase I extension units using qualifying Phase I technology (*i.e.*, 90 percent removal technology) receive two-year "extension allowances" during 1995-96, and additional allowances during 1997-99.
- <u>Phase II SO_2 and NO_x Requirements</u> - In Phase II (beginning 1/1/2000), almost all fossil fuel utility units that commenced operation or will commence operation prior to the end of 1995 are provided emission allowances, generally based on a 1.2 lb SO_2/mmBtu (or lower) emission rate.
  - SO_2 emission allowances are tradeable across the U.S. and may be banked.
  - New units coming on-line after December 31, 1992 and prior to the end of 1995 whose construction did not commence by December 31, 1990 are allocated emission allowances. Otherwise they must obtain allowances to offset their emissions.

EXHIBIT 1-1
Summary of Major Provisions of Acid Rain Title

	Phase One	Phase Two
Compliance Date:	1/1/1995	1/1/2000
SO_2 Requirements	Allowances according to Table A of the Clean Air Act.	Most units "affected" except those granted emission allowances based on a 1.2 lb/mmBtu SO_2 rate (or lower). New units on-line after 1992 and prior to the end of 1995.
NO_x Requirements	NO_x controls required at Phase I "affected" units.	NO_x controls required at all "affected" units.
Allowance Trading and Banking	Interstate trading of SO_2 allowances; allowance banking permitted.	Interstate trading of SO_2 allowances; allowance banking permitted.
Clean Coal/ Repowering	Financial incentives for clean coal demonstration projects.	Four-year deferral of requirements.
Phase I Extension Allowances for Technology	Extension allowances during 1995-1996, and additional allowances 1997-1999. Total credits limited to 3.5 million tons allocated on a first-come-first-served basis.	None
Monitoring	All Phase I units must be equipped with continuous emissions monitors, and must submit data quarterly.	All Phase II units must be equipped with continuous emissions monitors, and must submit data quarterly.
Permits	EPA will issue permits to owner/operators of power plants required to meet Phase I SO_2 requirements and the NO_x reduction requirements.	States with approved programs will issue permits to owner/operators of new units required to have SO_2 emission allowances and existing units 25 MW or greater.
Auctions, Direct Sales and IPP Written Guarantees	EPA will offer limited numbers of allowances through annual auctions and direct sales; independent power producers may qualify for guaranteed access to reserved allowances.	EPA will offer limited numbers of allowances through annual auctions and direct sales.
Conservation and Renewable Reserve	Up to 300,000 allowances awarded to utilities that reduce emissions through energy conservation or the use of renewable energy sources.	Up to 300,000 allowances awarded to utilities that reduce emissions through energy conservation or the use of renewable energy sources.

- NO_x controls are required.
- Units repowering with "clean coal" technologies are granted a deferral of up to 4 years of Phase Two requirements during which they receive extra "non-tradeable" allowances.

In addition to these provisions, Title IV contains provisions for

- Monitoring of emissions;
- Voluntary inclusions ("elections") of unaffected sources (existing utility units with less than 25 MW capacity, industrial boilers, and industrial process sources);
- Extra allowances for energy conservation and renewable energy;
- Sales of allowances through auctions, direct sales, and written guarantees for new independent power producers (IPPs); and
- Permits and compliance plans.

1.1.3 Types of Costs, Cost Savings, and Benefits Anticipated

The acid rain statute will result in increased costs to those entities regulated under the Act (*i.e.*, electric utilities and IPPs). These costs are in the form of (1) higher capital and operating costs as pollution control equipment is installed to meet the SO_2 and NO_x emissions reduction requirements, and (2) higher fuel costs as sources shift to more expensive, lower sulfur fuels. In addition to these direct costs, the statute is likely to result in shifts of production volume, employment, and income from high sulfur to lower sulfur coal producers, as well as shifts to natural gas producers, pipelines, and pollution control equipment manufacturers. The statute will also yield environmental benefits: the mandated reductions in SO_2 and NO_x emissions will result in less acid rain and sulfate exposure, and better visibility and local air quality.

Under a traditional command-and-control approach to environmental management, Congress, EPA, or a State regulatory agency would assign pollution control obligations that must be met by each source. This is generally accomplished by applying uniform emission limits or technology requirements to all sources that belong to common industrial source categories (*e.g.*, existing coal-fired power plants). While considerable analysis may be carried out to ensure that it is feasible for the sources in a given source category to meet the uniform requirements, the application of uniform standards often results in substantial cost inefficiencies. Allowance trading regulations, and the other implementation regulations (such as monitoring regulations) that make them possible would serve to improve efficiency and reduce the costs of compliance while leaving intact the environmental benefits intended by the statute.

The principle behind emissions allowance trading is straightforward. Instead of mandating fixed uniform emission reductions from each source, allowance trading permits the aggregate emission reductions to be achieved from sources in the most economically efficient manner. Thus, those sources that are relatively inexpensive to control can reduce emissions more than would be required under uniform standards. The surplus allowances from these extra emission reductions can then be traded to other sources that are more costly to control, allowing these latter sources to reduce emissions less than would be otherwise required, while still achieving the same level of aggregate emission reductions would be achieved.

The implementation regulations are expected to generate additional benefits in the long run in the form of improved pollution control technology. The ability to sell allowances generated by emissions control techniques that bring emissions well below targets will create incentives for research and development of new, more effective emissions control technologies. In a uniform requirements approach, utilities that have met their tonnage limits have no incentive to develop the ability to make further emissions reductions. Under the implementation regulations, even those meeting their tonnage limits have the incentive to develop cost-effective ways to cut emissions still more so they can sell more allowances. In the long run, these incentives may result in technological advances that make even tighter emissions standards feasible.

1.2 SCOPE OF THE REGULATORY IMPACT ANALYSIS

As discussed, the acid rain reduction provisions encompass an array of requirements including SO_2 and NO_x reductions, and SO_2 allowance trading and tracking. This RIA is limited to a subset of these provisions. Specifically, the focus of the RIA is to evaluate the effects of a set of four classes of regulations, termed the "implementation regulations:"

- SO_2 allowance system (tracking and trading regulations);
- SO_2 monitoring regulations;
- Permits; and
- Auctions, direct sales, and IPP written guarantee regulations.[2]

Collectively, this set of implementation regulations establishes and implements the allowance trading system. While the first element in the set provides directly for rules regarding how SO_2 emission trades are to be effectuated and recorded by EPA, the other elements are equally important in that the trading system could not be operated without them. An accurate and reliable system for monitoring emissions is required to determine how many allowances have been generated or used by individual units; a permit system ensures national consistency and accountability and makes the enforcement of the allowance system possible; and a system of auctions and sales offers assurances that allowance market develops smoothly and equitably. Thus, the implementation regulations must be viewed as a whole, and the costs and benefits associated with each separate part should be considered to arise jointly from all of them.

This section describes the factors considered in determining the scope of the regulatory impact analysis.

1.2.1 Consequences of SO_2 and NO_x Reductions are Not Considered

The central purpose of Title IV of CAA is to achieve significant reductions in SO_2 and NO_x of ten million and two million tons per year, respectively. Achieving these reductions will entail significant costs to the economy. Because these emissions reductions are required by the statute itself, independent of any EPA regulations, less emphasis is placed on the estimation of the costs of these emissions reductions under the command-and-control regime than would be necessary in the absence of the regulations. In keeping with the central purpose of EPA's proposed regulations -- to establish tradeable SO_2 emissions allowances and facilitate the development of markets for these

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2 EPA's analysis of the auctions, sales, and IPP guarantee programs are contained in a separate document: Economic Analysis of the Proposed Acid Rain Regulations for Auctions, Direct Sales, and IPP Written Guarantees. Office of Atmospheric and Indoor Air Programs, Acid Rain Division, U.S. Environmental Protection Agency, April 26, 1991.

allowances -- the focus of the RIA is on the economic effects of the allowance trading system and the related regulations necessary to the operation of the system.

Neither the costs nor the benefits of reductions in NO_x emissions, which are not included in the allowance trading system, are considered in this analysis.

1.2.2 Consideration of the Costs of the Implementation Regulations

The implementation regulations will bring with them both costs and cost savings. The costs will be related directly to emissions monitoring, tracking the ownership of allowances, ensuring that an adequate source of allowances is available, and bringing buyers and sellers of allowances together. The RIA, therefore, includes sections on the incremental costs of monitoring systems required under a trading system: the transactions costs (both to EPA and the regulated community) associated with actual allowance trades; costs of permits; and the costs to EPA and the regulated community of allowance auctions, direct sales, and allowance guarantees. The analysis attempts in every case to separate the costs imposed by the regulations themselves from costs that would have been borne under the statute in the absence of regulations.

1.2.3 Consideration of the Cost Savings of the Implementation Regulations

This RIA also considers the cost savings that will ensue when emissions sources that have high control costs are able to shift some of the burden of emissions reduction to the sources with low incremental control costs. The owners of both sources will gain as a result of a trade -- the allowance buyer will pay less for additional allowances than it would cost to increase its control effort, and the allowance seller will receive more for each allowance sold than the costs it incurs to generate the allowance. These cost savings are expected to outweigh the costs associated with implementing the regulations. Thus, the costs of complying with the statute through the implementation regulations are lower than the costs of complying with the statute in the absence of the implementation regulations.

1.2.4 Benefits

The regulations examined in the RIA are not expected to provide environmental benefits. Rather, they are intended to lower the costs of reaching essentially the same levels of emissions as required under the statute. For this reason, the RIA does not focus closely on the benefits of reducing emissions of pollutants related to acid rain. The benefits of reducing acid rain are discussed qualitatively, however, to provide a point of comparison for the estimates of the total costs of the regulations combined with the statutory reductions in emissions.

1.2.5 Implementation Options

This analysis assumes that a well-functioning market for allowances will develop. EPA is exploring a number of implementation issues, however, that will affect how well this market performs. Two issues are related to the administration of the allowance trading and tracking system: serialization (*i.e.*, numbering) of allowances; and an end-of-the-year "truing-up" period. Four issues relate to permits: bonus allowances for Phase I extension; reduced utilization/load shifting in Phase I; certification of designated representatives; and permit revisions. Finally, five issues involve monitoring: hourly *versus* daily data for quarterly reporting; incentive approaches for monitoring accuracy; incentive approaches for missing data; alternatives to SO_2, NO_x, and flow monitors for gas and oil units; and flow monitor requirements. These issues have not been treated in this RIA because of the difficulty of assigning dollar values to them. The advantages and disadvantages of the options relating to these issues are, however, discussed at length in the preamble to the implementation regulations.

1.3 ORGANIZATION OF THE REPORT

The remainder of the RIA is divided into five chapters:

Chapter 2 describes the community that would be subject to the regulations. The chapter investigates the number of firms in the community, firm size distributions, demand conditions, and recent trends affecting the regulated community.

Chapter 3 outlines the baselines used for the comparisons made in the analysis. In addition to a review of the time-frame considered in the RIA, this chapter introduces both pre-statute and absent regulations baselines. In addition, this chapter discusses issues related to the types of costs analyzed in the report.

Chapter 4 presents and compares the costs under the regulations to costs under the baseline cases (pre-statute and absent regulations). The chapter also breaks down the cost of regulatory implementation to both the EPA and the regulated community.

Chapter 5 provides the economic effects of the regulations on utilities and independent power producers and then discusses the regional impacts of the regulations. The chapter emphasizes the potential impacts on small power producers and explores the potential for mitigating any negative impacts.

Chapter 6 present a qualitative description of the expected environmental benefits of the statutory reductions in acid-rain-related emissions.

The appendices to the report provides a detailed description of the methodologies and computations used to develop estimates of costs and cost savings. Finally, the attachment describes the impacts of continuous emission monitoring system requirements on new small electric power generating units (i.e., those with a capacity of less than 25 MW).

CHAPTER 2
CHARACTERIZATION OF THE REGULATED COMMUNITY

This chapter provides background information on the industries that will be affected by Title IV of the Clean Air Act (CAA) Amendments of 1990. Title IV, designed to control nationwide emissions of sulfur dioxide and other acid rain precursors, applies to "utility units," which are defined to include units that serve a generator producing electricity for sale or that did so in 1985. Entities owning "utility units" generally belong either to:

- The electric utility industry (which includes investor-owned utilities and publicly-owned utility entities such as municipal systems and federal power entities like the Tennessee Valley Authority). The utility industry currently accounts for the vast majority of the generation capacity in the U.S. A substantial portion of this utility capacity is affected either by Phase I or Phase II of the CAA Amendments; or

- The non-utility generation industry (which includes qualifying facilities (QFs) under the Public Utility Regulatory Policies Act (PURPA) and other non-utility power producers called independent power producers (IPPs)). Existing non-utility generators are largely unaffected by Title IV because they are mostly exempt under provisions of the Amendments. However, as Exhibits 2-1 and 2-2 indicate, the non-utility sector is building much of the new generating capacity now under construction and is likely to continue to do so. Most future non-utility capacity commencing commercial operation on or after November 15, 1990 is subject to Title IV provisions.

This chapter is divided into two major sections that focus on the two industries respectively. Each section provides an overview (with definitions) of the industry structure, the economic regulations that apply to the industry sector, and the impact of Title IV on the industry. In addition, each section describes the current and projected demands for the industry's output and, therefore, its potential growth. The section on the electric utility industry also describes the variation in power costs and potential competition. Background on other affected industries is presented in Appendix 2A.

2.1 THE U.S. ELECTRIC UTILITY INDUSTRY

Companies comprising the U.S. electric utility industry (SIC code 4911) differ significantly in terms of institutional and regulatory arrangements, size, power plant types, fuel consumption, and power supply cost structure. These companies are currently highly regulated at both the state and federal levels, which protects them from open competition. However, the regulatory climate is gradually changing, with a shift toward less regulation and more competition.

EXHIBIT 2-1
U.S. Installed Generating Capacity by Industry Type
(Gigawatts)

	1979	1986	1987	1988
Total U.S. Electric Utility Industry	598	710	718	724
Investor Owned Utilities	464	546	553	558
Municipals, Cooperatives, Federal, and Public Power	134	164	165	166
Total Non-Generating Industry	18	25	30	34

Source: "1988 Capacity and Generation of Non-Utility Sources of Energy," Edison Electric Institute, April, 1990.

Note: 1 gigawatt equals 1000 megawatts or 1 million kilowatts.

EXHIBIT 2-2
Projected Additions to Electric Generation Capacity, 1988-2000
(Gigawatts)

Electric Utility Industry	48 to 98
Non-Utility Generating Industry	
-Qualifying Facilities Under PURPA	16 to 30
-Independent Power Producers	25 to 50
TOTAL	89 to 178

Source: ICF Analysis, based upon EPA's High Base Case and Low Base Case Assumptions and Forecasts

2.1.1 Overview of Industry Structure

The electric utility industry is composed of about 3,000 companies. There are four principal types of utilities:

- **Investor Owned Utilities (IOUs)** - The approximately 206 IOUs represent about seven percent of the total number of companies in the electric utility industry; however, they account for about three-quarters of the total electricity generated in the U.S. These companies own a similar share of total generation capacity. Part of this concentration is explained by the large economies of scale in generation and transmission of electricity.

- **Municipally Owned Utilities** - The 1,810 municipally owned electric utilities are generally very small in terms of generation and sales, and often own one or no power plants; however, there are some important exceptions, such as the Los Angeles Department of Water and Power, the City of San Antonio, and the Jacksonville Electric Authority.

- **Rural Electric Cooperatives** - Most of the 933 rural electric cooperatives, established to help electrify rural areas where transmission and distribution costs were high, are small and have no generating capacity. A few cooperatives also have generating capacity, but these cooperatives are usually owned by smaller distribution-only cooperatives. Both types of cooperatives are subsidized by the federal government.

- **Federal Public Power Districts (Including TVA)** - Most of the 77 federally owned utilities are primarily involved in flood control; electricity is a by-product of river flow control. Hence, most of their capacity is hydroelectric powerplants although there are some notable exceptions, especially the Tennessee Valley Authority (TVA), which is the nation's largest consumer of coal. These utilities usually sell their power wholesale to municipalities and other companies.

2.1.2 Utility Regulation

Most U.S. electric utilities have monopolies (known as franchises) provided by state or local authorities and are the only supplier of electric power within their service territories. In exchange for the advantages conferred by the franchise, the utility subjects its rates to regulation by state authorities and undertakes to serve the public's demand for power.

Rates for IOUs, which operate for profit, are theoretically set to allow them to recover all of their costs so long as these costs were "prudently incurred." The costs that may be recovered include non-capital cost items (*e.g.*, fuel, O&M, and administration), and the costs of capital investments including a reasonable profit (or "rate of return") on invested capital. This rate-making arrangement is known as "rate of return" or "cost-of-service" regulation.

Although the "cost-of-service" model of rate regulation is straightforward in concept, its implementation in recent years has been complicated by disputes between utilities and their ratepayers. For instance, substantial amounts of new nuclear and coal capacity came on-line in the late 1970s and early 1980s, even as electricity demand was slowing. Some of these plants were completed at costs that substantially exceeded earlier estimates. The "prudence" of incurring these costs was challenged in many jurisdictions, and regulators in many cases disallowed substantial portions of the costs incurred. As another example, though many jurisdictions have a more or less automatic pass-through of changing fuel costs, some jurisdictions have challenged the prudence of utilities that entered into long-term fuel contracts which turned out in hindsight not to benefit ratepayers.

Federal authorities also regulate electric utility companies. Federal regulation is primarily conducted by the Federal Energy Regulatory Commission (FERC) under the authority of the Federal Power Act (FPA) and is limited to (1) wholesale transactions, and (2) interstate transactions. Along with industry groups and local authorities, FERC shares responsibility for the regulation of the electricity transmission grid system, which covers practically the entire U.S. and Canada. In addition, the Securities and Exchange Commission (SEC) enforces the Public Utilities Holding Company Act (PUHCA), enacted in 1933, which segregates and protects utility finances from other corporate ventures.

2.1.3 Regulated Segments of the Industry Under the 1990 CAA Amendments

Title IV of the CAA Amendments affects only fossil-fuel burning "utility units;" hydroelectric and nuclear plants are not affected. In addition, the CAA Amendments provide an exemption for existing natural gas-fired turbines. As Exhibit 2-3 indicates, units owned by 61 different utilities, with a total installed capacity of 88,977 MW, are affected in Phase I. A majority of these plants, over 84 percent of installed capacity, are investor owned. Phase II affects units owned by 239 different utilities representing 471,445 MW of capacity. In Phase II, the 35 largest utilities, all but three of which are IOU's, account for over half of this capacity. The Phase II data in Exhibit 2-3 include Phase I affected units, all of which are also affected under Phase II.

2.1.4 Power Costs and Competition

Restrictions on SO_2 emissions under Title IV will have a significant impact on fuel-type and capital decisions for new powerplants. Decision-makers will have to consider projected fuel costs in conjunction with the related capital costs for the chosen fuel type. Presently, gas-fired combined cycle capacity requires the lowest capital investment of any baseload generation plant and, since gas prices are also relatively low, is the preferred type of new power. However, in the longer run (by the year 2000 and after), gas prices are expected to increase significantly and greater numbers of new coal plants are expected to be constructed.

Most electricity currently generated in the U.S. is produced at coal-fired powerplants (see Exhibit 2-4). In 1990, the breakdown of the 2,772 billion KWH of U.S. generation by fuel type was as follows:

- 56% coal-fired generation;
- 13% oil/gas-fired generation;
- 20% nuclear generation; and
- 11% hydro/other generation.

EXHIBIT 2-3
Characterization of Affected Existing Utility-Owned Units

Type of Ownership	Phase I			Phase II		
	# of Utilities	# of Units	Capacity (GW)	# of Utilities	# of Units	Capacity (GW)
Federal and Public Power Entities, State and District Systems	1	26	9	13	116	32
Cooperative Systems	5	15	4	27	89	23
Investor-Owned Systems	52	216	75	132	1,517	392
Municipal Systems	3	4	1	67	183	24
TOTALS	61	261	89	239	1,905	471

Source: National Allowance Data Base Version 1.0 and ICF Analysis of the Clean Air Act Amendment of 1990.

Actual and potential differences in variable generation costs are greatest between regions relying on oil and gas and regions relying on coal. For example, coal-fueled electricity production costs in Wyoming and North Dakota are as low as one cent per kilowatt-hour, whereas in Florida, where oil-fuel generation, at $20 per barrel, constitutes a large share of total capacity, electricity production costs are about three cents per kilowatt-hour. Oil and gas fueled generation are also the dominant capacity sources in other regions of the country, including New England, Texas, and the Pacific. The regional mix in fuel use has important implications for regional SO_2 emissions, acid rain control costs, and rate impacts.

While utilities currently provide over 95 percent of the power generated in the U.S., they face some competition because of alternatives available to their customers, including:

- **Self-Generation** - Large companies have self-generation or cogeneration options which may be cheaper than purchasing electricity from utilities;

- **Alternative Fuels** - Customers have a choice between gas/oil and electric;

- **Relocation** - Customers can relocate to areas of lower power cost; and

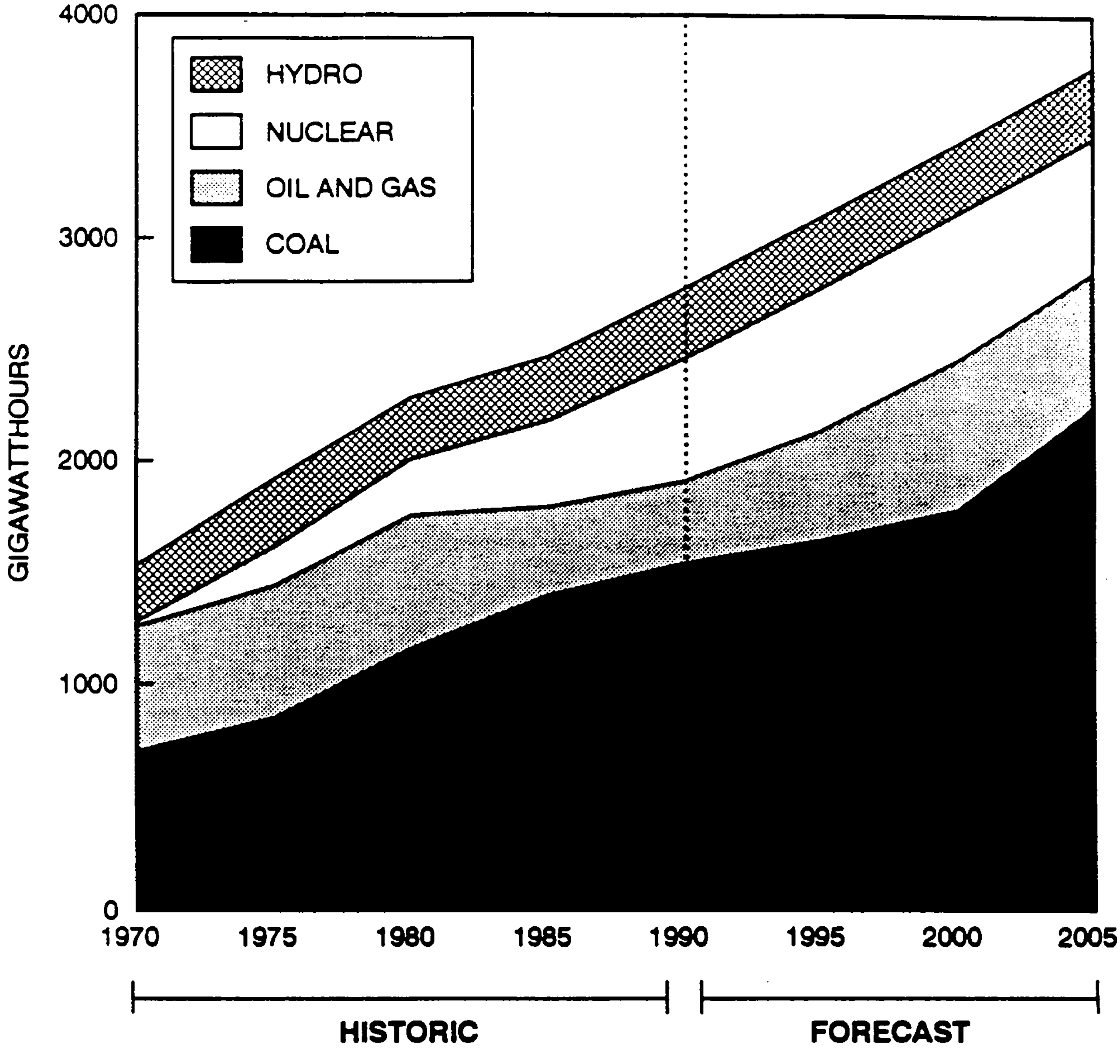
- **Wholesale Purchases** - Large customers, such as municipalities or other utilities, may switch power purchases to other nearby utilities.

2.1.5 Demand for Industry Output

Electric utility decisions about future capacity additions have been complicated by increasing uncertainty regarding electricity demand growth. As Exhibit 2-5 indicates, three major sectors dominate energy demand: residential, commercial, and industrial. Prior to the 1973 OPEC oil price rise, electricity demand had been steadily growing at very high rates of about 5-7 percent per year (see Exhibit 2-6). This rate of growth in demand decreased in the mid-1970s. In recent years, however, electricity demand has begun to increase again at about the rate of GNP, or about 2.5-4.5 percent per year.

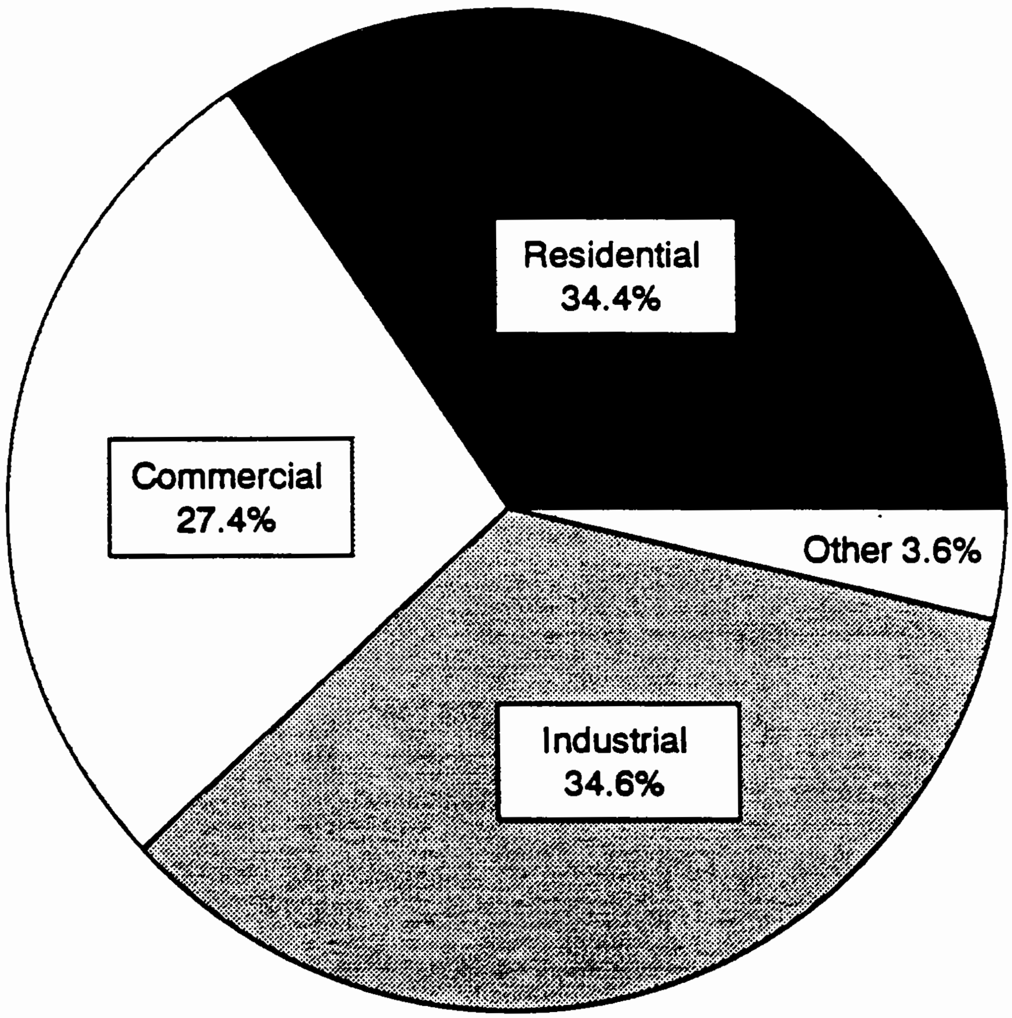
Although utilities are monopolies, their customers are still sensitive to rate increases and may cut back on their demand. With an increase in the competitiveness in electricity generation, large customers may also be able to respond to increased electricity rates by purchasing power from a utility other than the franchised utility.

EXHIBIT 2-4
U.S. ELECTRIC UTILITY GENERATION BY FUEL TYPE
HISTORICAL AND PROJECTED



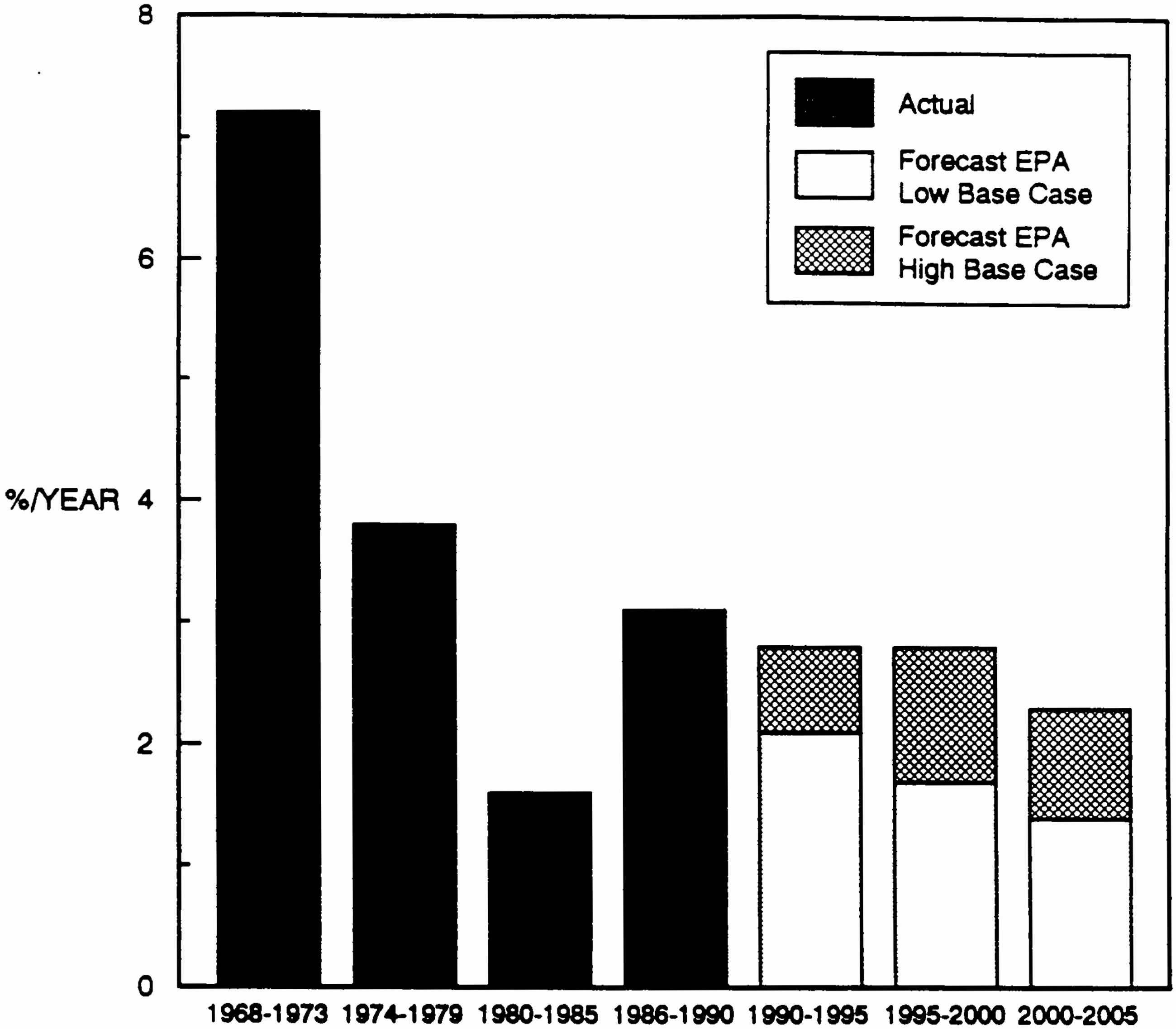
SOURCE: EIA/Monthly Energy Review 10/89, ICF CEUM Projections

EXHIBIT 2-5
U.S. Energy Demand by Sector - 1989



Source: Edison Electric Institute Statistical Yearbook 1989

EXHIBIT 2-6
U.S. ELECTRIC UTILITY ELECTRICITY DEMAND GROWTH



Source: EPA High and Low Base Case Forecasts. See Chapter 3 for more detail.

2.1.6 Recent Changes Affecting the Industry

Over the last decade, many utilities experienced serious financial problems associated with the inability to fully recover their costs, especially capital costs. Several factors contributed to these problems including inflation, higher financing costs, increased costs and cost overruns for new powerplants, unexpectedly sluggish demand growth, and excess generation capacity. These factors put a great strain on traditional cost-of-service ratemaking, as utilities realized that the long-held presumption of being able to recover all prudently incurred costs did not guarantee adequate financial returns. Many utilities argue that under the present system, cost-of-service regulation means that a utility earns no more than its regulated rate of return at best, and could earn significantly less under adverse circumstances. Regulators and other industry observers concede that traditional cost-of-service regulations do not appear to provide utilities with the correct incentives to lower costs and be innovative in providing service.

A parallel and distinct development affecting the utility industry was the enactment in 1978 of the Public Utility Regulatory Policies Act (PURPA). PURPA helped open the way for non-utility power producers and cogenerators to supply power to the public by requiring utilities to purchase cogenerated and other categories of power. PURPA set prices for the power supplied by the non-utilities at the utilities' "avoided cost," which is the amount of money it would have cost the utility to have produced the power themselves. The response to PURPA has been large and by 1988 over seven percent of U.S. electricity generation was supplied by non-utility producers. The PURPA experience has, in turn, set the stage for the establishment of an independent power industry, which is discussed in Section 2.2 below.

Finally, in addition to the Clean Air Act Amendments of 1990, other regulatory initiatives are likely to affect the industry in the future. For example, heightened concern over global warming may lead to restrictions on greenhouse gas emissions, which would affect utility investment decisions.

2.2 THE NON-UTILITY GENERATION INDUSTRY[1]

A significant quantity of electric generation capacity owned and operated by private developers, rather than by the regulated utilities, has come on line over the last decade. These "non-utility" generators, which are comprised of two classes of power producers, qualifying facilities (QFs) and Independent Power Producers (IPPs), have already established themselves as important players in the power generation industry and are likely to play an increased role through the 1990s.[2]

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1 The term "non-utility" industry is used to identify electric generating units that are owned by parties other than traditional utilities. As discussed in this section, a substantial number of the electric generating units that are part of the "non-utility" industry could be treated as "utility units" pursuant to the CAA Amendments of 1990 and subject to Title IV.

2 The industry includes plants that produce electricity entirely for on-site use (so-called "self-generators"). New plants, designed for on-site uses, will likely seek to get certified as QFs under PURPA, to the extent they meet the tests laid down for certification. This is because, as QFs, they will be legally entitled to receive non-discriminatory back-up service. There are, however, existing industrial generating plants that do not meet the tests of a QF. Furthermore, it is possible that some additional capacity of this type may be built by industry. In any event, capacity dedicated entirely to on-site use in not subject to Title IV.

2.2.1 Overview of Industry Structure

The non-utility generation industry is a relatively young industry characterized by a large number of companies, including many small companies (in terms of revenues and number of employees). The industry grew steadily in the 1980s and most observers expect this growth to continue in the 1990s. This industry attracted a large number of companies that have experience in one or more aspects of the power generation business. The industry now includes equipment vendors, electric utility subsidiaries, railroad companies, engineering and construction companies, and developers. A large number of electric utility subsidiaries are also active in developing a range of new projects.

As Exhibits 2-7 and 2-8 indicate, total non-utility capacity was estimated at about 34,000 MW in 1989. The total amount of generation from this capacity was about 199 billion KWH, or seven percent of total U.S. utility generation. However, electricity sales to the electric utilities account for about 89 billion KWH or 3.1 percent of total utility generation. The remaining electrical energy generated by the non-utility industry was used to meet on-site electrical needs.

PURPA created a special class of power producers called "Qualifying Facilities" (QFs). Some QFs are qualifying cogenerators (QF-Cogenerators) which produce both electricity and useful thermal energy in the same process. The remaining QFs are qualifying small power producers (QF-SPPs), which are below a certain size and fueled by renewable energy (including solar, hydropower, wind, or biomass) or waste fuels such as petroleum coke or used tires.[3] QFs sell considerable amounts of their power to electric utilities.

In recent years, FERC, which is responsible for implementing both PURPA and the FPA, has allowed power producers that do not meet the tests laid down for QFs to be exempt from cost-of-service regulation provided that the price they obtain for power sales is "market-based". Such non-QF power producers are commonly referred to as "independent power producers (IPPs)."[4]

Cogenerators (QF-Cogenerators): These are facilities which sequentially use energy, usually producing electric power and some form of useful thermal output such as steam. Thermal output from a cogenerator must be at least 5 percent of total energy output for the plant to receive QF status. In addition, oil- or gas-fired cogenerators effectively are required to meet various system configuration, heat utilization and efficiency standards.

Small Power Producers (QF-SPP): These are facilities which produce less than 80 MW of electric power primarily through the use of biomass, waste materials, geothermal energy or renewable resources such as wind, solar and hydroelectric resources. Although many benefits accruing to QFs are available to all QF-SPPs, the benefits of exemption from cost-of-service regulation under the FPA, as well as the exemption from PUHCA and certain State regulations were not available until recently to QF-SPPs that were larger than 30 MW except in cases where they were fueled by biomass

3 Congress enacted legislation in 1990 that will effectively lift the size limitation for QF-SPPs whose construction commences during the 1990s.

4 Note that currently IPPs represent a class of producers approved by FERC on a case-by-case basis. However, legislative proposals currently being considered both within the Administration and Congress would, by law, create a class of power producers called "exempt wholesale generators "that would enjoy at least some benefits similar to those enjoyed by QFs, without having to meet the operating or size constraints applicable to such QFs. Note that the CAA Amendments do contain a definition of IPP, but that definition is simply for the purpose of identifying "grandfathered" IPPs.

or geothermal. Legislation enacted in 1990 may effectively remove the size limitation of QF-SPPs for solar, wind, waste, or geothermal units commencing construction during a certain time window in the 1990s and make these QF-SPPs eligible for all benefits open to QF-Cogenerators.

Independent Power Producers (IPPs): IPPs are a relatively new class of non-utility generators whose purpose is primarily to generate power for sale to utilities (i.e., at wholesale). In electric market parlance, an IPP facility is one which, unlike most PURPA-QFs, is subject to rate regulation under the FPA, but intends to obtain an order from FERC effectively stating that FERC finds the IPP's rates to be just and reasonable under the FPA. Generally, FERC, in making this finding, will rely on a showing that the rates are "market-based" rather than cost-based. Therefore, the rates for IPPs are generally not determined in accordance with traditional rate-based, cost-of-service regulation. Under the CAA Amendments of 1990, IPP units are specifically defined as facilities which are used for the generation of electric energy, 80 percent or more of which is sold at wholesale; are non-recourse project-financed; and do not generate electric energy sold to any affiliate of the facility's owner or operator which could provide it with allowances. Thus, IPPs as understood in electric market parlance could also be IPPs under the CAA Amendments of 1990. Note, however, that certain affiliate entities could be viewed as IPPs in electric market parlance, but not be IPPs under the CAA Amendments of 1990. Moreover, there is a possibility that the current Congress will enact legislation as part of the National Energy Strategy (NES) that will define IPPs (or an equivalent such as exempt wholesale generators (EWG)) more precisely from an electric market perspective.

Fossil Fuels: Fossil fuels are not explicitly defined in the CAA Amendments. The term usually refers to petroleum, natural gas and coal. However, there is some ambiguity as to whether certain waste fuels such as bituminous coal wastes, refinery off-gases, or tires will be treated as fossil fuels for the purpose of the CAA Amendments[5].

The average size of a QF-Cogenerator is about 20 to 30 MW based on electric output. Gas-fired cogeneration projects, which collectively account for over 50 percent of total QF-Cogeneration capacity, average about 15 to 25 MW, while coal-based cogenerators average 50 to 70 MW based on electric output. Some coal and gas-fired QF-Cogenerators, however, are substantially larger than this average, with capacities exceeding 150 MW. Qualifying Facilities-Small Power Producers tend to be somewhat smaller than cogenerators, averaging about 5 to 20 MW in size. Note, however, that while there were 3,517 non-utility projects on line at the end of 1988, the 69 largest projects (over 100 MW) accounted for over 40 percent of the non-utility generation capacity (see Exhibit 2-7).

As Exhibit 2-8 shows, plants burning natural gas, coal, and biomass are the most common types of non-utility generators, collectively accounting for almost three-fourths of all non-utility capacity. Projects burning waste products also provide substantial capacity, as do plants utilizing hydro and wind resources.

2.2.2 Regulation of QFs and IPPs

Under PURPA, QFs enjoy benefits that enable them either to produce their own power for on-site needs or to sell back to the grid (or both). Specifically,

- If a QF produces power for use on-site (usually by construction of a cogeneration plant at an industrial site), it is eligible to receive back-up electric service at non-discriminatory rates.

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[5] Note that under FERC's implementation of PURPA, these fuels are treated as waste materials.

- If a QF sells electricity to the grid, the utility is obligated to purchase such power at its avoided cost or at a mutually acceptable negotiated rate.

- Even if QFs sell their power to the grid, they are not treated like other utilities. First, unlike traditional utilities, QFs are not subject to cost-of-service regulation. Second, most QFs are exempt from PUHCA.

EXHIBIT 2-7
Non-Utility Capacity by Project Size, by Census Division at December 31, 1988

Project Size (Megawatts)	Total Number of Projects	Total Capacity
Less than 1.0	2,037	339.1
1.0 to 9.9	868	3,247.2
10.0 to 49.9	455	10,668.0
50.0 to 99.9	88	5,988.2
100.0 and over	69	13,499.4
TOTAL	3,517	33,741.9

Source: "1988 Capacity and Generation of Non-Utility Sources of Energy," Edison Electric Institute, April 1990.

EXHIBIT 2-8
Non-Utility Capacity by Primary Energy Source, by Census Division at December 31, 1988

Primary Energy Source	Total Capacity
Coal	5,602.2
Oil	955.1
Gas	12,486.1
Biomass	6,642.3
Waste	3,155.9
Hydro	1,860.3
Wind	1,893.0
Solar	297.5
Geothermal	624.2
Other	225.2
TOTAL	33,741.9

Source: "1988 Capacity and Generation of Non-Utility Sources of Energy," Edison Electric Institute, April 1990.

2.2.3 Regulated Segments of the Industry Under the 1990 CAA

Exhibit 2-9 shows the sub-sectors of the IPP and QF market regulated under the CAA Amendments. QFs currently in commercial operation are not regulated under the Act. IPPs are not regulated if they have already entered into a power sales agreement with a utility, received a letter of intent from a utility to enter into a power sales agreement, or won a competitive bid at the time of the Act's enactment.

All future IPPs and QFs that burn fossil fuels are subject to the Act's provisions. However, cogenerators with less than 25 MW capacity, or those that sell less than one third of the power they generate to the grid, are not affected by the CAA Amendments, regardless of the type of fuel they burn. New renewable energy QFs might create allowances for utilities that purchase their power.

Exhibit 2-10 presents a "representative" estimate of the relative size of different segments that would be affected by the CAA Amendments. These estimates depend on the fundamentals driving the electricity market such as load growth, fuel prices, and utility behavior with respect to acquiring new capacity. The numbers in Exhibit 2-10, therefore, simply place in perspective the relative sizes of the different segments.[6] From the perspective of this RIA, the main purchasers of allowances will be new, coal-fired IPPs and perhaps a subset of waste-fired QF-SPPs if EPA determines they are affected.

2.2.4 Demand for Industry Outputs

The demand for new QF and IPP capacity will depend largely on electricity market developments. As Exhibit 2-11 shows, in each of the time periods 1988-1995 and 1995-2000, between 20 and 43 GW of QF/IPP capacity is projected to be brought on-line.

The ranges for projected QF/IPP additions are heavily dependent on electricity load growth. The higher levels of new QF/IPP capacity correspond to higher load growth, while the lower levels are based on lower load growth.

The economics of large QF-cogeneration and IPP projects undertaken to sell power to an electric utility depend strongly on electric market conditions. As discussed in Section 2.1 on the electric utility industry, there is uncertainty over the future demand for electricity. On the supply side, there is some hesitation on the part of electric utilities to commit to building large, rate-based plants in the face of uncertain demand and a still-evolving regulatory regime. Thus, the proportion of new electric capacity that will be IPP (as distinct from traditional rate-based) is uncertain. (Exhibit 2-10 provides a perspective on the need for new capacity over the 1990-2000 time frame and the extent to which IPPs and QFs might contribute to meeting that need. Such estimates are very dependent on scenario-specific assumptions).

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6 The proportion of IPP and rate-based capacity shown in Exhibit 2-10 represents a rough estimate based on the limited experience with IPPs.

EXHIBIT 2-9
PURPA-QF and IPP Plants Affected by Title IV

Category	Status	Subcategories	Affected?
QF-Cogenerators	Existing[a]		No
	Future	i) Burns non-fossil fuel	No
		ii) Sell <25 MW capacity or less than ⅓ of total capacity to grid.	No
		iii) All other	Yes
QF-SPP	Existing[a]		No
	Future	i) Burns non-fossil fuel	No
		ii) Burns fossil fuels[b]	Yes
IPP	Substantially Committed as of 11/15/90[c]		No
	Future	i) Burns non-fossil fuels	No
		ii) Burns fossil fuels	Yes

[a] Refers to both plants in commercial operation and those for which substantial commitments have been made as of November 15, 1990.

[b] It is conceivable that certain QF-SPPs that burn fuels treated as "waste fuels" under PURPA could be treated as fossil fuel units under the CAA Amendments of 1990. Plants burning coal wastes or petroleum coke are examples.

[c] IPPs in commercial operation as of November 15, 1990 and making substantial sales to the grid are subject to Title IV. As a practical matter, the amount of such capacity is small.

EXHIBIT 2-10
Representative Size of the Affected PURPA-QF and IPP Population Relative to the Total Changes in Capacity[1]

Segment	Estimated 1988 to 2000 Changes in Capacity (GW)		
	Traditional Rate-Based Units[2]	IPP[2]	Total
RATE-BASED OR IPP UNITS			
Primarily Gas-Fired Simple Cycle and Combined Cycle Systems	44 to 77	22 to 38	66 to 115
Coal-Fired Systems (conventional and fluidized bed)	4 to 21	3 to 12	7 to 33
TOTAL (Rate-Based and IPP	48 to 98	25 to 50	73 to 148
PURPA QF			
Gas-Fired Systems	N/A		8.0 to 14
Coal-Fired Systems			3.0 to 6
Oil-Fired Systems			0.5 to 0.9
Biomass -- Resource Recovery Systems			1.3 to 2.4
Biomass -- Wood; Agricultural			.8 to 1.5
Waste-Fired Systems (*e.g.*, anthracite culm, petroleum coke; tires)			1.6 to 3.0
Renewables (*e.g.*, hydro, geothermal, wind, and solar)			1.2 to 2.2

1 The estimates presented here are properly treated as a "representative" of future circumstances. They are based upon the EPA's High Base Case and Low Base Case.

2 The proportion of required new capacity that will get built as IPP capacity somewhat uncertain. It depends in large part on how regulators behave in the future with respect to cost-recovery, and how investors perceive such behavior.

EXHIBIT 2-11
Projected Demand for Non-Utility Capacity

Time Period	Utility Sales Growth	Required Total New Electric Capacity Additions (GW)	Projected QF/IPP Capacity Additions (GW)
1988 to 1995	2.4 to 2.8%	39 to 74	21 to 37
1995 to 2000	2.1 to 2.8%	50 to 104	20 to 43
2000 to 2005	1.7 to 2.3%	63 to 114	24 to 47
Total 1990 to 2005		152 to 292	65 to 127

Source: ICF analysis based upon EPA High Base and Low Base cases.

2.2.5 Future Trends

In the 1980s, state and federal regulators implemented policies designed to encourage cogeneration. In recent years, however, regulators have shifted their emphasis from "providing encouragement" to QFs to the "competitive procurement of electric supplies." It is in this context that IPPs have been approved on a case-by-case basis. In general, regulators at the federal and state levels have been receptive to the idea of allowing all non-utility suppliers to be essentially free from cost-of-service regulation, so long as their power sales rates are market-based (as, for instance, when prices are determined through a competitive bidding process).

These recent trends portend several major developments in the QF/IPP sector:

- It is reasonable to expect that a considerable proportion of future electric capacity will be IPP capacity, free from cost-of-service regulation. In addition, Congressional action to remove some of the regulatory hurdles faced by IPPs (*e.g.*, exemption from PUHCA jurisdiction) could increase IPP penetration even more.[7] In fact, if the establishment of affiliate IPPs is made easier by reducing their regulatory burdens, it is conceivable that some utilities may elect not

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[7] As noted previously, these IPPs may eventually be called "exempt wholesale generators".

to build any new facilities under cost-of-service regulation. Under such a scenario, IPPs (as a proportion of total builds) could exceed the Table 2-7 estimates substantially.

- PURPA-QFs will likely continue to exist, but will face increasing competition from IPPs. In some jurisdictions, certain classes of QFs may be allowed to obtain long-term power sales contracts outside of competitive bidding. For example, all QFs below some size range may be made eligible for such treatment.

- Measured in terms of market penetration, gas-fired cogeneration systems have fared well in the PURPA-QF market because of relatively low capital costs and the availability of attractively priced gas supplies. There is also a view that the attractiveness of gas-fired systems in the 25 to 75 MW range relative to coal systems has made them more appropriate for many cogeneration applications. Because IPPs face no size or operational constraints, this option will allow large coal-fired power projects (which presumably enjoy economies of scale) to compete with gas-fired cogeneration projects.

- The QF/IPP industry thus far has been made up of a very large number of firms. Many industry observers expect one or more waves of consolidation to occur in the 1990s with the more efficient companies acquiring projects and/or companies that (1) will enhance their efficiency through even greater economies of scale and scope, and (2) represent a good "strategic fit."

From the perspective of this RIA, the key issue is what new electricity producing projects will be affected by the CAA Amendments.

- The new, non-affiliate IPPs (which are the only ones included in the CAA Amendments definition) and new large QFs are, in general, going to be purchasers of allowances for their projects. These non-affiliate IPPs and large QFs would be no different from other traditional rate-based utility projects from a CAA standpoint except that the traditional rate-based utilities may be able to use allowances from their other plants without having to buy them in the market place. This seeming advantage, however, would be substantially mitigated if the market for allowances were well-developed and allowances were freely traded. Furthermore, large QF-Cogenerators with steam sales from the cogeneration project may be in a position to take advantage of the "opt-in" provisions of the CAA Amendments.

- While many small QFs (under 25 MW) would not be affected by the CAA Amendments of 1990 (see Exhibit 2-9), relatively small waste-fired projects (*e.g.* coal waste projects) determined to be affected units would have to purchase allowances (see Exhibit 2-9). The transactions costs associated with making suitable compliance arrangements for such small projects may be quite high. Thus, this segment may bear a high burden under the CAA Amendments.

CHAPTER 3
BASELINE AND COST METHODOLOGY ISSUES

This chapter provides a foundation for the presentation of cost estimates in Chapter 4 by covering two issues. The first section of the chapter discusses assumptions used in creating baselines for assessing the costs of the regulations. The second section describes the types of costs covered in the analysis, and the degree to which each cost type has been quantified.

3.1 BASELINE ISSUES

This first section of the chapter covers a series of baseline issues. The first of the four subsections below defines the specific regulatory and nonregulatory cases evaluated and compared in assessing the impacts of the regulations. The second subsection discusses the time period over which the baseline and regulatory cases were evaluated. The third subsection discusses the energy and economic assumptions used in defining two scenarios for emissions growth in the absence of acid rain regulation, and the final subsection presents the assumptions used in evaluating the effects of the statute in the absence of regulations.

3.1.1 Cases Examined

This RIA evaluates impacts under a "regulatory case" (which includes the acid rain implementation regulations described in Chapter 1) relative to two baseline cases: the "pre-statute" case and the "absent regulations" case. The pre-statute case assumes that no acid rain legislation was enacted, and that no further controls on SO_2 emissions will be imposed. The absent regulations case, in contrast, assumes that Title IV is in effect but that EPA promulgates no regulations for its implementation. Under the absent regulations case, SO_2 emissions must be reduced by 10 million tons, but there are no regulations to establish SO_2 allowances or an allowance trading system. By comparing costs under the pre-statute case to costs under the regulatory case, EPA is able to identify the costs of the statute and the implementation regulations combined. By comparing costs under the absent regulations case to costs under the regulatory case which permits allowance trading, EPA is able to measure the cost savings provided by the implementation regulations alone.

Exhibit 3-1 presents a summary description of the pre-statute, absent regulations, and regulatory cases evaluated in this report. Each case was evaluated under two scenarios: a high scenario and a low scenario. Thus, six situations (three cases under each scenario) were evaluated and compared in all.

EXHIBIT 3-1 Pre-Statute, Absent Regulations, and Regulatory Cases Evaluated				
Case	Description	Regulatory	Energy/Economic Assumptions	
			High	Low
Pre-statute	No Acid Rain/ SO_2 Reduction Requirements	No Acid Rain Regulations	X	X
Absent Regulations	SO_2 Reductions in 1995 and 2000 and After	Acid Rain Requirements without Implementation Regulations	X	X
Regulatory Case	SO_2 Reduction in 1995 and 2000 and After	With Implementation Regulations	X	X

3.1.2 Time Period Examined

All cases were evaluated over the 1995-2010 period with specific forecasts for the 1995, 2000, 2005, and 2010 periods. These time periods were chosen because they are the same as those used by EPA for its earlier legislative analyses and provide for an every-five-year snapshot of the incremental effects of the legislation and regulations. In addition, the specific forecast years correspond closely to important statutory deadlines under the acid rain title of the Clean Air Act Amendments of 1990 (CAA):

- Phase I requirements begin in 1995;
- Phase II requirements begin in 2000; and
- Phase II "bonus" allowances expire in 2010.

3.1.3 Energy and Economic Assumptions for High and Low Scenarios

To measure the economic impacts of Title IV of CAA, it is necessary to project estimated levels of utility air emissions in the absence of Title IV during the time period covered by the RIA. The levels of utility air emissions are expected to depend upon factors such as the electricity demand, alternative sources of electricity supply, and fuel costs. Because of the extent of uncertainty surrounding each of these factors, this analysis relies on high and low electricity growth forecasts to obtain a reasonable range of electric utility air emissions over the next two decades. In constructing the high and low scenarios, this analysis uses the energy and economic assumptions that were developed by EPA during the latter half of 1988 to evaluate the cost and economic impacts of the proposed acid rain regulations.[1] The assumptions are documented comprehensively in a May 1989 report, although a brief summary is also presented in Exhibit 3-2. Appendices 3A and 3B of this

[1] See 1989 EPA Base Case Forecasts, prepared by ICF Resources Inc. for the U.S. EPA, May 1989.

EXHIBIT 3-2
Major Assumptions for EPA High and Low Base Cases
(Used as the basis for high and low scenarios)

Energy/Economic Assumption	Time Period or Category	1989 EPA Base: Reference Case	
		High	Low
Crude Oil Prices (1988 $/bbl)	1995	18.00	25.00
	2000	22.00	29.00
	2005	25.00	31.50
	2010	29.50	34.00
Electricity Demand Growth (percent per year)	1988-2000	2.8	2.0
	2001-2010	2.3	1.4
Steam Power Plant Lifetimes (years)	Coal/Oil/Gas >50 MW	65	55
	Coal/Oil/Gas <50 MW	45	45
	Nuclear	35	40
Cogeneration (billions of kilowatt hours)	1995	175	195
	2000	208	291
	2005	255	382
	2010	313	474
New Non-Fossil Capacity (gigawatts)	2005	0	9
	2010	0	20
Repowered Coal Capacity* (gigawatts)	2000	0	4
	2005	6	20
	2010	10	38

* Includes 50 percent increase in capacity due to repowering, in addition to currently planned projects.

report may be referred to for additional information.

In general, the assumptions used in the low scenario result in a lower forecast of emissions growth than those used in the high scenario. In particular:

- Lower electricity demand results in lower coal power plant utilization and the construction of fewer new coal plants;

- Shorter fossil steam power plant lifetimes result in earlier retirements of higher-emitting existing coal units, which are generally replaced by new lower-emitting gas or scrubbed coal capacity;

- More repowering with clean coal technologies reduces SO_2 emissions rates at repowered plants; and

- More non-fossil capacity and cogeneration (which is usually gas-fired) reduces the amount of higher-emitting coal-fired capacity operated and built.

The implications of the differences between the high and low scenarios for the costs of the statute and the regulations are discussed at greater length in Section 3.2.3 below.

The change in utility/IPP SO_2 emissions over time is shown in Exhibit 3-3. As shown in that exhibit, the SO_2 emission forecasts for the pre-statute case between the high and low scenarios diverge considerably over time with a difference of 3.6 million tons, 17.1 versus 20.7 million tons, in 2000. The divergence in the forecasts is due to the difference in the aforementioned energy and economic assumptions.

3.1.4 Regulatory Assumptions for Cases

As covered in Section 3.1.1, three cases are compared in this report. For two of these, the pre-statute and regulatory cases, the regulatory framework to be analyzed was relatively clear-cut. Under the pre-statute case, no federal regulations other than those in the CAA before 1990 were assumed. SO_2 is controlled for existing sources on a source-by-source basis through the existing state implementation plans of the Clean Air Act; newer sources must meet existing new source performance standards (NSPS); a continuation of existing state acid rain regulations (as in Massachusetts, New York, Wisconsin, and Minnesota, for example) was assumed as well.

For the absent regulations case, more developed assumptions were required because the statute does not completely describe in detail how its provisions would be applied in the absence of any regulations. The absent regulations case was developed using basically the same set of energy/economic and pollution control cost assumptions as in the pre-statute case (See Exhibit 3-4 and referenced appendices). The major difference between the absent regulations case and the pre-statute case is that the pre-statute case leaves out the impacts of acid rain legislation. The absent regulations case includes the impact of the acid rain requirements as stipulated in Title IV of the CAA. The assumptions in the absent regulations case are presented in Exhibit 3-5 with a brief discussion of each provided below:

- <u>SO_2 Reductions</u> — The same SO_2 reduction goals and requirements stipulated under Title IV are assumed under the absent regulations case.

- <u>NO_x Reductions</u> — No NO_x reductions were assumed in the absent regulations case or the regulatory case. This RIA focuses only on the impact of SO_2 reduction requirements and attendant regulations.

EXHIBIT 3-3
PRE-STATUTE UTILITY SO_2 EMISSIONS

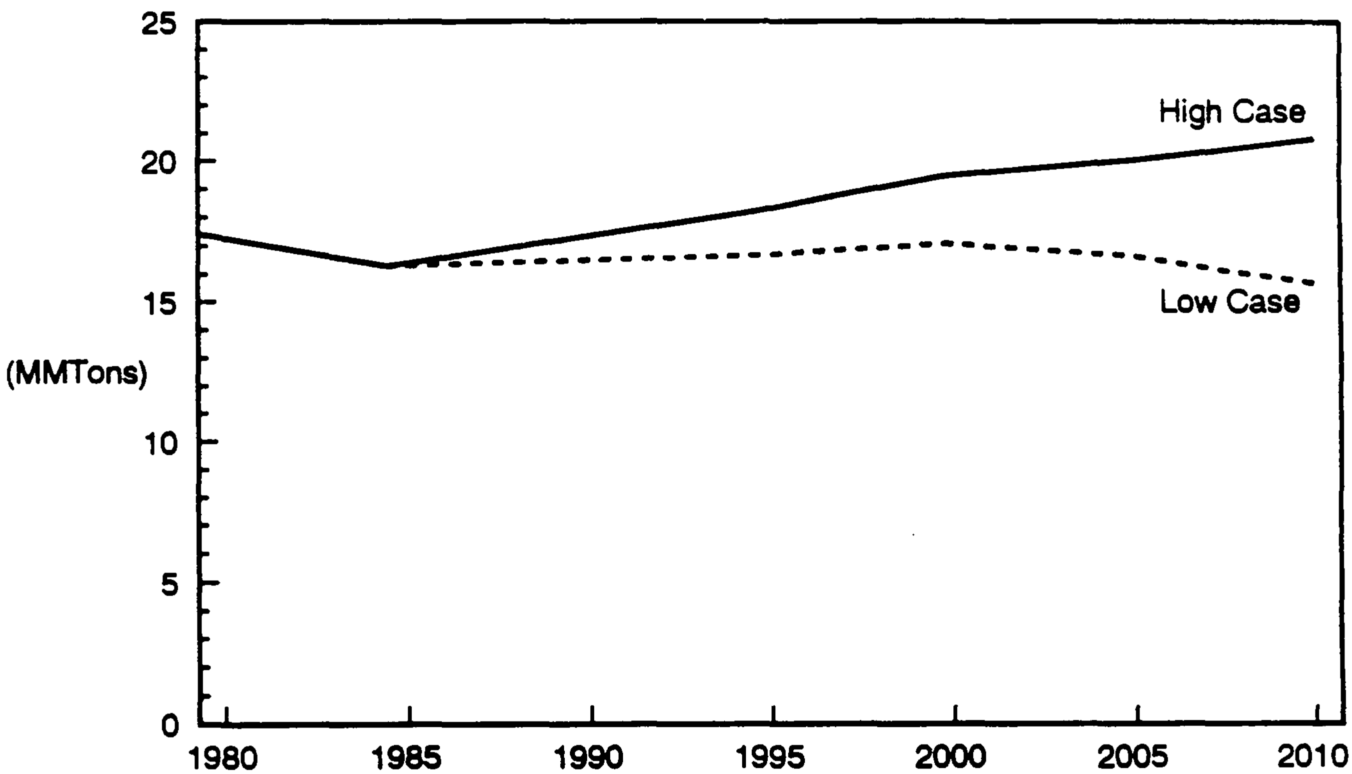

EXHIBIT 3-4 Energy and Economic Assumptions		
	Absent-Regulations Case	
	High Scenario	**Low Scenario**
Energy and Economic Assumptions	EPA High Assumptions (See Appendix 3A)	EPA Low Assumptions (See Appendix 3A)
Pollution Control Cost Assumptions		
Repowering	Same as High (See Appendix 3B)	Same as Low Plus Accelerated Repowering (See Appendix 3B)
Scrubbing Costs	Same as High and Low (See Appendix 3B)	
Regulatory Assumptions	Acid Rain Statute With <u>No</u> Trading of Allowances or Reallocation of Tonnage Limits Between Units	

- <u>Emissions Trading and Banking/SO_2 Tonnage Limits-Existing Units</u> — There would be no trading or banking of SO_2 emission allowances under the absent regulations case. Rather each <u>unit</u> would be required to meet an annual SO_2 tonnage limit (as set under Title IV).[2]

- <u>SO_2 Tonnage Limits-New (Post-1995) Units</u> — For new units that do not receive any allowances under the Act, a 95 percent removal New Source Performance Standards (NSPS) was assumed in lieu of the zero tonnage limit requirement. While a literal reading of the Act suggests that, in the absence of any implementation regulations, new units would have to meet a zero emissions target, this requirement would make it extremely onerous if not impossible for high growth states and utilities to meet energy demand within Phase II (2000) SO_2 requirements.[3] Accordingly, it was assumed by EPA that in the absence of implementation regulations, some provisions would have been made for economic growth, while limiting SO_2 emissions growth through a more stringent NSPS (*e.g.*, 95 percent removal in lieu of the current 70 to 90 percent removal requirement).

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[2] Annual tonnage limits under the baseline cases or SO_2 allowances under the regulatory cases were developed based on the statutory language of the Act and the National Allowance Data Base, version 1.0.

[3] Note that a zero tonnage limit would eliminate all new fossil fuel fired units (even natural gas emits very low levels of SO_2 emissions) making it extremely difficult to meet new growth needs.

EXHIBIT 3-5 **Absent Regulations Case — Assumptions on Emissions Requirements**		
	Phase I (1995)	**Phase II (2000)**
SO_2 Reductions below 1980 levels from Utilities and IPPs (in millions of tons)	3 to 4	8 to 8.5
NO_x Reductions[a]	None	None
Emission Trading/Banking	None	None
Phase I and II SO_2 Tonnage Limits - Existing Units	Same as Act: Tonnage Limits in Table A plus 200,000 Additional Tons	Same as Act
Phase II SO_2 Tonnage Limits - New (Post- Nov. 15, 1990) Units	----	95% Removal Assumed in Lieu of Zero Allowances
Phase I Technology Allowances	None	----
Conservation/Renewables Reserve	None	None
Allowance Auctions: Fixed Price Sales or Guarantees	None	None
Clean Coal Repowering Phase II Extension	----	Included
Phase I Minimum Fuel Constraints	Included[b]	----

[a] NO_x reduction requirements are not included in the absent regulations or the regulatory cases developed for this RIA.

[b] Minimum Fuel Constraints included as part of the permits and compliance plans under the Act.

- Phase I Technology Allowances — None of the 3.5 million ton Phase I Extension Reserve was assumed to be allocated. This reserve would provide for 3.5 million tons of additional allowances to units installing eligible control technology (90 percent SO_2 removal or greater) in Phase I.

- Conservation/Renewable Reserve: Auctions and Fixed Price Sales — Similar to the Phase I Reserve, no conservation and renewables reserve or auctions and fixed price sales were assumed in the absent regulations case. Consistent with this treatment, there was no assumed withholding from basic Phase I and II allowances (or tonnage limits) for either of these reserves or special sales. Similar to the Phase I extension reserve, emission allowances from either the auctions of fixed price sales or special reserves would not be allocated in the absent regulations case because they could not be traded or banked.

- Clean Coal Repowering Phase II Extension — As stipulated in Title IV, units that repower with clean coal technologies (*e.g.*, fluidized bed combustion, integrated gasifier combined cycle, etc.) receive a four year extension until December 31, 2003, during which time they receive additional emission allowances. Since these extra allowances apply only to the specific units that repower (and are non-tradeable), they were assumed to apply in the absent regulations case and were modeled as increases in the unit level tonnage limits.

- Phase I Minimum Fuel Constraints — Under Title IV, Phase I affected sources are restricted from reducing their utilization below "baseline" levels (*e.g.*, 1985-87 average fuel consumption) unless it occurs through conservation or energy efficiency, or the compensating source of generation becomes an "affected" unit. These minimum fuel constraints were included in the baseline cases.

3.2 COST ISSUES

This second section of the chapter discusses the cost categories examined in the analysis, the cost measures used, and the role of the high and low scenarios in dealing with uncertainty.

3.2.1 Types of Costs

Several broad classes of costs are considered to varying degrees in this regulatory analysis: real resource costs of administration to government; real resource costs of compliance to the regulated community; transfers between the regulated community and other sectors of society; and lost social welfare due to reduced output ("dead-weight" losses).

Real resource costs to the government are represented by the cost of additional staff to process applications or monitor compliance. Real resource costs to the regulated community are exemplified by the hardware-related costs of scrubbers and continuous emissions monitor systems (CEMS) added to power plants, costs of reporting and recordkeeping of emission levels, and the incremental costs of producing and transporting low-sulfur coal compared to high-sulfur coal.

Transfers occur where a loss to one segment of the economy represents a pure gain to another, and thus do not represent a net loss to the economy. In the context of the Acid Rain Program, transfers can occur when increased demand for low sulfur coal drives its price up more than the increase in the average cost of extracting and transporting the coal plus the value of the coal in other uses. In the short run, for example, there may be a limit to the rate at which coal can be mined and shipped. The increased demand for low sulfur coal brought about by the Acid Rain Program could allow a mine that was already operating at full capacity in the pre-regulation case to charge a higher price for the same coal even though its average production costs have not changed. In this case, nothing would change except that the utilities would pay more and the mine operator would receive more; there would be no change in real resource costs. Even in the long run (the time-frame considered in this analysis) the price of low sulfur coal could be driven up by increased demand if low sulfur coal resources were limited. Where resource owners receive high returns for the same coal-bearing land that would have been sold in the pre-statute case at low prices, there is a transfer rather than a resource cost. Higher coal prices that are a cost to electric utilities would represent a gain to the owners of coal resources; thus, net costs to society as a whole would not change.

Transfer costs, which are not true costs to society as a whole, have not been considered in detail in the analysis. A qualitative assessment of the direction and magnitude of transfers is included in Chapter 4.

The last category of costs is the dead-weight loss, which is an intangible loss in the value of the economy's production that results from reductions in outputs. The dead-weight loss resulting from a drop in output is measured as the difference between the true value to consumers of the lost output and the production cost savings realized when output is reduced. In cases in which changes in prices are significant, measuring dead-weight losses provides an important measure of the true costs of forcing consumers to turn to less valuable substitutes. This analysis does not consider dead-weight losses quantitatively because qualitative analysis shows them to be much smaller than the costs and cost savings resulting from the statute and the regulations.

In summary, this analysis explicitly provides measurement of the following costs:

- Costs of SO_2 reductions and emissions monitoring systems imposed by Title IV of CAA in the absence of implementation regulations by EPA;
- Cost savings due to the implementation regulations because they provide flexibility in achieving SO_2 reduction targets; and
- Costs of the implementation regulations to the federal government (administrative costs) and the cost to the regulated community of compliance (net of monitoring costs imposed by the statute).

3.2.2 Cost Measures Presented

Three cost measures are presented in this analysis, including annualized costs, levelized percent changes in electricity rates, and present values of total costs.

Annualized costs include the annual increases or changes in costs forecast for 1995, 2000, 2005, and 2010. They include fuel, operating, transaction, administrative, and capital costs. For comparison purposes, incremental capital investments are levelized over the book lifetime of the equipment (generally, 30 years) and are presented as annualized capital costs.

Levelized percent changes in electricity rates indicate the national and regional percent change in rates associated with the change in annualized pollution control costs.

EXHIBIT 4-7
Monitoring Equipment and Operation and Maintenance Cost Estimates[a]
(Thousands of 1990 Dollars)

Capital Equipment	Fixed Cost (per unit)
Base Equipment and Installation	$81.4
NO_x Monitor (CEMS)	20.6
O_2/CO_2 Monitor (CEMS)	10.8
SO_2 Monitor (CEMS)	22.5
Flow Monitor	19.7
Opacity Monitor (COM)	35.7
Data Acquisition System (DAS)	41.5
Customized DAS Software	70.0
Operation and Maintenance	**Annual Cost**
Relative Accuracy Test Audits	15.0
Labor	24.4
Calibration Gases[b]	30.0
Other Equipment O&M	9.3

a These estimates include the costs of installation, start-up and training, and certification in addition to the capital cost of the equipment.

b Calibration gases are not necessary for units using alternative methods of monitoring SO_2 emissions. These units, therefore, will only incur incremental calibration gas costs for other CEMS equipment ($15,000).

The costs to EPA under the regulatory options include the cost to conduct periodic plant inspections, and to process, review, and evaluate emissions data reports submitted by the utilities. EPA expects to conduct inspections at 11 plants (roughly 10 percent of the regulated community) in 1995, six plants (roughly five percent of the regulated community) from 1996 through 1999, and 37 plants (roughly five percent of the regulated community) each year starting in the year 2000. EPA assumes that a plant inspection will require an average of 60 hours at a cost of $34 per hour.[25] In addition, EPA assumes that an average of 30 minutes will be required to process, review, and evaluate the quarterly data reports from each of the affected plants.[26]

25 EPA estimate.

26 EPA estimate.

The present value of costs indicates the total costs over the entire 1995 to 2010 period, with costs in later years discounted to allow for the time value of money. For annual pollution control costs, a real discount rate of 5.4 percent per year is assumed to reflect the value of capital diverted from productive investments.[4] For costs to EPA and for costs to industry that do not displace productive investments, a lower social discount rate of three percent per year is assumed.

These measures provide a snapshot of costs over several forecast years, as well as the total cost impacts over the next twenty years.

3.2.3 Uncertainties and Sensitivity Analyses

Some of the major sources of uncertainties in the analysis and their effect on electric generating costs include the costs and availability of pollution control equipment; net growth in demand for electricity from fossil fuels plants; and prices of lower sulfur fuels. These sources of uncertainty are summarized below.

- Pollution Control Equipment Costs and Availability - The costs of conventional SO_2 removal equipment (*e.g.*, scrubbers) as well as the availability and costs of newer low-cost clean coal technologies (CCT) are uncertain and will have an important effect on the costs of the Acid Rain Program.

- Electricity Demand Growth/Nuclear Renewables - The growth in the demand for electricity generation over the next 10 to 20 years is also uncertain and will depend on economic and demographic factors, as well as improvements in energy efficiency and conservation. Electricity generation growth (along with the penetration of renewable or non-fossil fuel technologies and potential improvements to nuclear power plant reliability) will in large measure determine the utilization of existing coal and oil-fired units. It will also affect the rate of construction of new coal power plants in the future and hence, the amount of SO_2 emissions growth which will have to be offset under the acid rain requirements. Costs will be affected significantly as a result.

- Lower Sulfur Fuel Costs - The forecasted prices and price premiums between higher and lower sulfur fuels (*e.g.*, high and low sulfur coals, residual oil, and gas) will directly affect the costs of switching to lower sulfur fuels under the acid rain regulations.

The range of uncertainties in cost impacts due to the factors described above is captured through the use of the high and low emissions growth scenarios discussed earlier. The high and low scenarios also provide a range for the cost savings achieved due to the implementation regulations.

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4 EPA's two-stage discounting procedure suggests the use of a seven percent rate for annualizing capital expenses to convert them into consumption terms, and then a three percent rate for finding the present value of reduced consumption (a combination of the annualized capital expenses plus O&M expenses). The use of a discount rate of 5.4 percent, EPA's estimate of the utility industry's weighted average cost of capital produces present value estimates that are very similar to the explicit use of the two-stage approach because it is midway between the three percent rate appropriate for O&M expenses and the seven percent rate for capital.

Two areas of uncertainty or sensitivity are not, however, captured by the EPA high and low scenario assumptions. The first involves the uncertain ability to and cost of switching Eastern bituminous-only coal-fired boilers to switch to Western low-sulfur sub-bituminous coals. The second involves the potential penetration of low-cost sorbent injection and other retrofit clean coal technologies. In both cases, EPA has assumed conservatively for purposes of this RIA that these SO_2 control options would not be available. To the extent these options are available and economically feasible, the costs of the acid rain regulations would be lower and the cost savings associated with the implementation regulations would be higher than presented herein.

CHAPTER 4
COSTS

This chapter presents analyses of the costs of the emissions reductions with and without the use of transferable allowances and the costs of a variety of regulatory provisions associated with the implementation of the allowance system. The first section of the chapter discusses the types of costs incurred by the regulated community and the changes in the costs attributable to the statute and the regulations. The following sections address the costs of implementing the statute and the trading regulations. The first category of implementation costs presented are those related to conducting allowance trading. The chapter then presents estimates of the costs of allowance auctions, direct sales, and IPP written guarantees, followed by estimates of the costs of emissions monitoring, permits, and energy conservation/renewable energy. Where possible, implementation costs in each category are divided into costs to EPA and costs to the regulated community, and are presented in terms of annual costs and present value costs discounted to the time of promulgation of the regulations.

This chapter also provides a summary of the total costs of the statute and the regulations, including both the costs related to emissions reductions and the associated implementation costs.

4.1 COSTS OF SO_2 REDUCTIONS WITH AND WITHOUT TRADING

EPA estimated the cost changes associated with the statute and the regulations using ICF's Coal and Electric Utilities Model (CEUM).[1] CEUM is a detailed linear programming, engineering-economic model (see Exhibit 4-1), that contains coal supply, transportation, electric utility demand, transmission, and non-utility energy demand segments. It is linked with databases and other supporting models, including a Coal and Utilities Information System (CUIS), which contains data on all electric utility units.

The model estimates acid rain compliance costs and cost savings by considering the choices likely to be made at each power plant and across all power plants affected by the regulations. For every plant, the model calculates the costs of each strategy that could be used to meet a given set of emissions requirements while meeting the demand for electricity and other utility system operating constraints. The model determines which of the strategies costs the least, across all the power plant units within a utility system, and assumes that the operator of a power plant will choose the lowest cost combination of strategies. The selection of compliance strategies within the model automatically and simultaneously affects the prices of various types of coal and other fuels and vice versa. The model then reports total costs by adding up the costs of the strategies that are assumed to be chosen.

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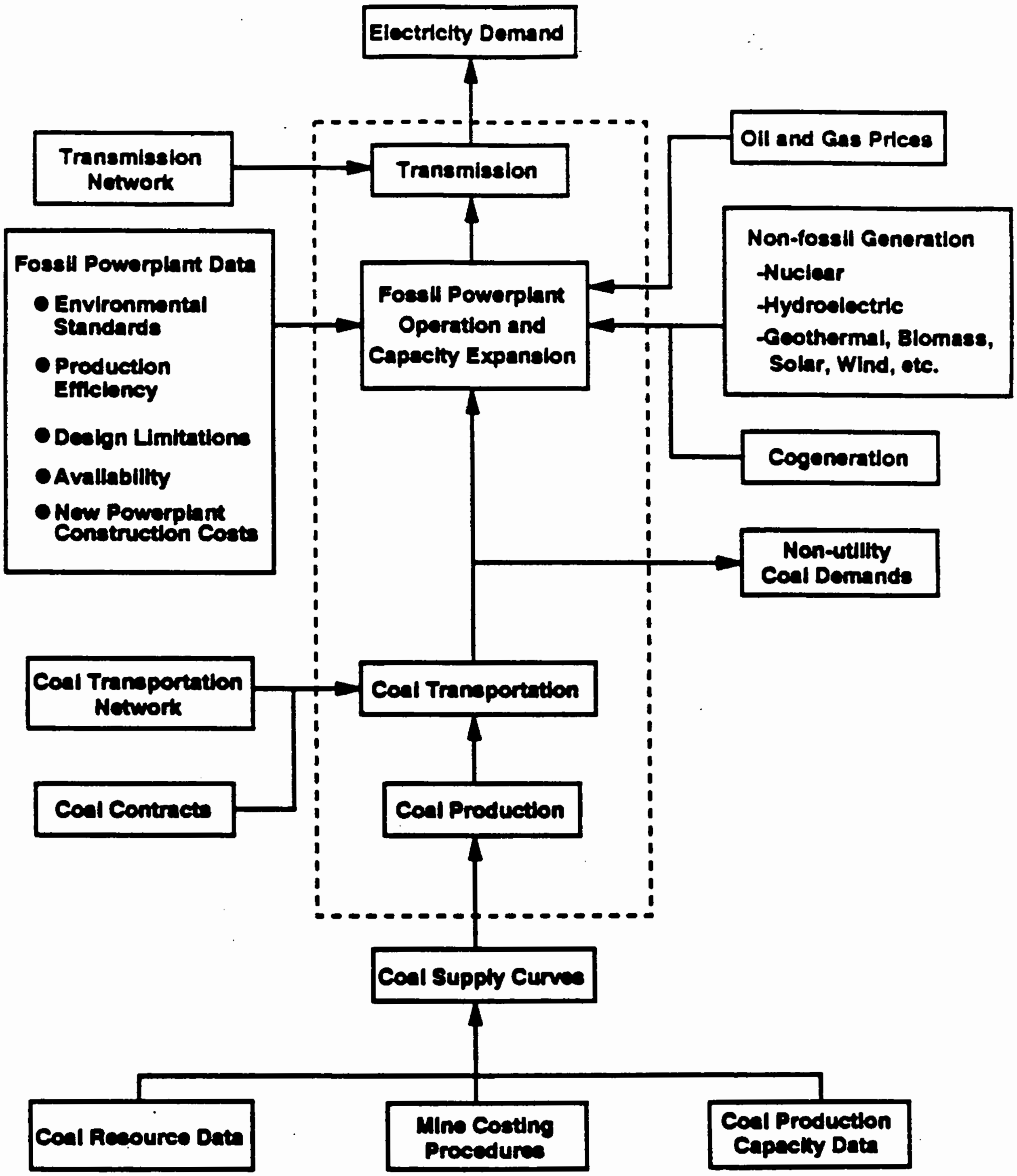
[1] CEUM was originally developed in 1975 as the National Coal Model and has been extensively refined and updated since then. ICF has used the model as a primary analytic tool in analyses for EPA, other federal agencies, and private companies for proposed acid rain policy initiatives and bills. The model has also been used in fuel price and energy market forecasting and planning studies, electric utility integrated capacity planning studies, and environmental compliance and pollution control technology assessment studies.

EXHIBIT 4-1

BASIC CEUM STRUCTURE



In addition to increases or decreases in fuel costs as a consequence of fuel switching, there are also capital costs associated with shifts to lower sulfur coals. For example, additional investment in particulate control equipment may be required to accommodate lower sulfur coals at certain power plants because of the inherent characteristics of the ash in lower sulfur coals. Also, some coal-fired power plants receive all of their coal shipments by truck from local mines. Receiving shipments from more distant coal mines (*e.g.*, Western low-sulfur mines) may require changes in coal handling facilities to receive coal by rail.

Switching to Lower Sulfur Oil or Natural Gas

Power plants burning higher sulfur residual oil may shift to lower sulfur residual oil, distillate, or natural gas in order to reduce SO_2 emissions. Lower sulfur oil is more expensive than higher sulfur oil because of the substantial capital and operating costs incurred by refineries in removing sulfur from their products. Gas can also be more expensive than oil, depending on market conditions.

In contrast to shifts from high to low sulfur coal, it is unlikely that shifts in oil or gas use by utilities will have significant effects on relative fuel prices. While the electricity generating sector consumes more than three quarters of total U.S. coal production, it accounts for less than one-quarter of natural gas demand in the U.S. and only a very small portion of worldwide oil demand. Thus, the oil and natural gas markets are unlikely to be affected by the moderate shifts in electric utility demand forecast under acid rain legislation. Some natural gas price increases, however, are likely to occur as electric utility natural gas demand increases.

Shifts in Power Plant Utilization

More intensive utilization of already low-emitting power plants matched by reduced utilization of higher-emitting power plants can be a cost-effective SO_2 reduction strategy in many instances. This strategy tends to increase the use (*i.e.*, the capacity factor) of power plants that already have scrubbers (often using medium or higher sulfur coals) or power plants using lower sulfur coals without scrubbers.

4.1.2 Cost Impacts

This section presents estimates of the costs associated with changes in SO_2 emissions under the statute and the implementation regulations. Three cost comparisons are presented:

- Costs under the absent regulations case as compared to the pre-statute case;
- Costs under the regulatory case, again compared to the pre-statute case; and
- Costs under the regulatory case compared to the absent regulations case.

The last cost comparison shows the incremental cost savings attributable to compliance with the implementation regulations relative to compliance with the statute by itself.

As discussed in Chapter 3, each cost comparison was made twice, once under the assumptions of the low scenario and once under the assumptions of the high scenario. The change in annualized cost impacts in three years (1995, 2000, and 2010) are presented and compared for both of these scenarios. In addition, the present values of costs are presented and discussed. The section also presents the SO_2 emission reduction impacts under the various cases and scenarios. More detailed emission and cost forecasts for these years and 2005 are presented in Appendix 4B.

Annual SO_2 Emission Reduction and Cost Impacts

Exhibit 4-2 presents the changes in annual costs and SO_2 emissions during Phase I (1995) and Phase II (2000 and 2010).[2] The first four columns of figures in the table show costs and emissions under the absent regulation case and the regulatory case relative to the pre-statute case. The last two columns show emissions and costs under the regulatory case relative to the absent regulation case.

During Phase I (1995), the SO_2 reductions forecast for the regulatory case are close to those forecast for the pre-statute case under both the high and low scenarios. Costs, however, are significantly lower in the regulatory trading case than under the absent regulations case. The cost savings provided by the regulations amount to $0.4-0.6 billion, or about a 40 percent reduction in the costs of the statute. These savings arise when units that have high emissions control costs are allowed to meet their regulatory obligations by reducing emissions less, or not at all, by purchasing allowances from units with lower control costs. These compliance cost savings for the difficult-to-control units more than outweigh the added control costs for additional emissions reductions by units with lower incremental control costs.

In Phase II (2000), the implementation regulations cut the annual costs of the statute even more substantially. Costs in the regulatory case are lower than in the absent regulations case by $2.1-2.8 billion, which is a savings of 60 to 65 percent. This reflects the even greater value of emissions trading as the reduction requirements become more stringent. Under the absent regulations case, virtually all power plants must consume very low sulfur coals or scrub to meet the Phase II unit-by-unit requirements. Emissions trading permits some power plants to overcontrol emissions and sell the allowances; the allowance purchasers, which have higher incremental control costs, are then able to reduce their compliance costs substantially. Cost savings from trading in this way represent improved efficiency in obtaining the same level of emissions reductions. In addition, some of the cost savings arise because SO_2 allowances are "banked" from Phase I in the regulatory case and are used to offset more costly reductions at the beginning of Phase II in 2000.

By 2010, the cost savings provided by the regulations compared to the absent regulations case are somewhat lower ($1.3-1.4 billion, which is a reduction in costs of 30 to 60 percent). This reduction occurs because banked SO_2 allowances are forecast to be used up by 2005 and thus annual SO_2 reduction requirements are about 0.1-0.5 million tons lower under the regulatory cases with trading than under the absent regulations case (instead of about 2.1-2.2 million tons lower as in 2000).

Present Value of Costs and Cumulative SO_2 Reductions

Exhibit 4-3 presents the total cumulative SO_2 reductions in the electric generating sector as well as the change in present value of costs. As shown in the figure, the present value of the costs resulting from the SO_2 reductions over the 1991 to 2010 period (in 1990 dollars) is estimated to be

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2 Existing units of 25 MW or less of capacity are not covered by the regulations, but new units less than 25 MW are covered. New units under 25 MW were not, however, considered in this analysis. Discussion of this small number of units is included in the attachment to this document.

EXHIBIT 4-2

FORECASTED SO_2 EMISSION REDUCTIONS AND ANNUAL COST IMPACTS ON THE ELECTRIC GENERATING SECTOR

	PHASE I (1995)					
	Absent Regulations (No Trading)		Regulatory Case With Trading		Net Change (Trading-No Trading)	
	Low	High	Low	High	Low	High
SO_2 Emission Reductions (in millions of tons below 1980 levels)						
Electric Utility/IPP	-4.2	-2.5	-4.2	-2.8	+0.0	-0.3
Other Non-Utility[a]	-1.5	-1.5	-1.5	-1.5	-	-
TOTAL	-5.7	-4.0	-5.7	-4.3	+0.0	-0.3
Changes in Annualized Costs (in billions of 1990 $)	1.0	1.5	0.6	0.9	-0.4	-0.6

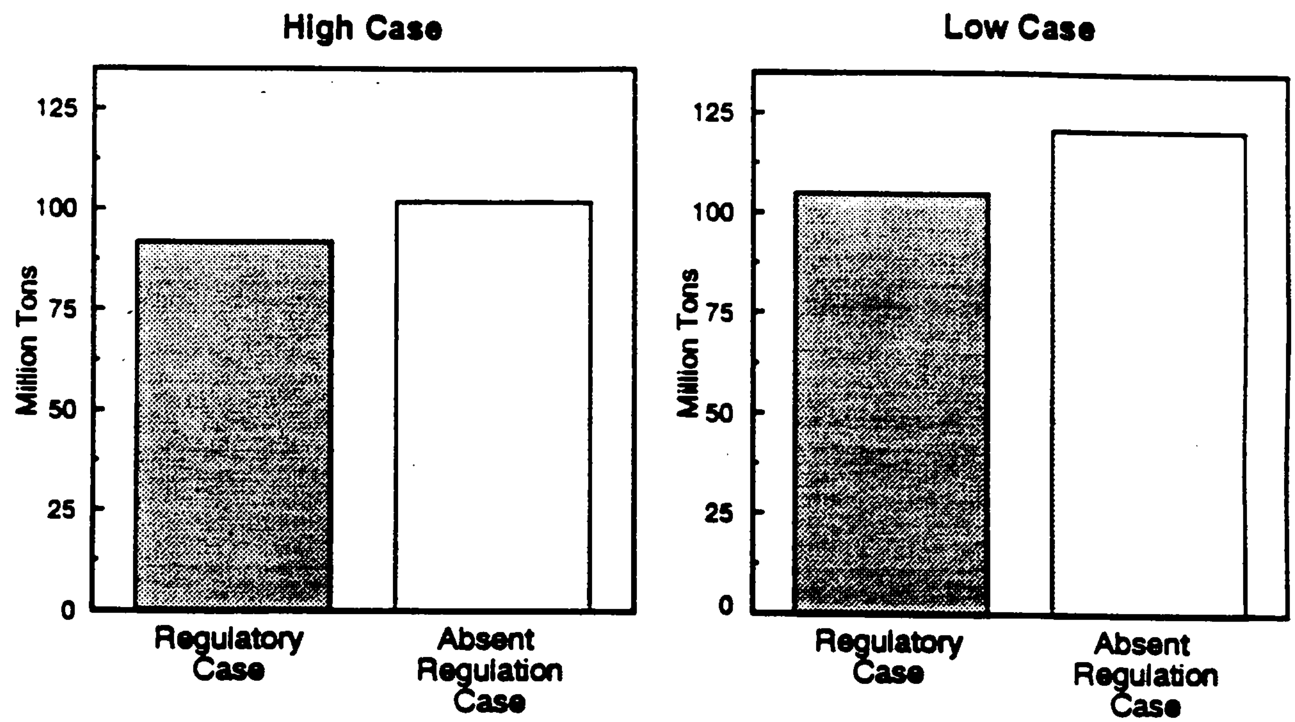
	Phase II (2000)					
	Absent Regulations (No Trading)		Regulatory Case With Trading		Net change (Trading-No Trading)	
	Low	High	Low	High	Low	High
SO_2 Emission Reductions (in millions of tons below 1980 levels)						
Electric Utility/IPP	-8.6	-8.1	-5.7	-5.7	+2.9	+2.4
Other Non-Utility[a]	-1.5	-1.5	-1.5	-1.5	-	-
TOTAL	-10.1	-9.6	-7.2	-7.2	+2.9	+2.4
Changes in Annualized Costs (in billions of 1990 $)	3.2	4.9	1.1	2.1	-2.1	-2.8

	Phase II (2010)					
	Absent Regulations (No Trading)		Regulatory Case With Trading		Net Change (Trading-No Trading)	
	Low	High	Low	High	Low	High
SO_2 Emission Reductions (in millions of tons below 1980 levels)						
Electric Utility/IPP	-9.1	-8.5	-8.5	-8.4	+0.6	+0.1
Other Non-Utility[a]	-1.5	-1.5	-1.5	-1.5	-	-
TOTAL	-10.6	-10.0	-10.0	-9.9	+0.6	+0.1
Changes in Annualized Costs (in billions of 1990 $)	2.3	5.1	1.0	3.7	-1.3	-1.4

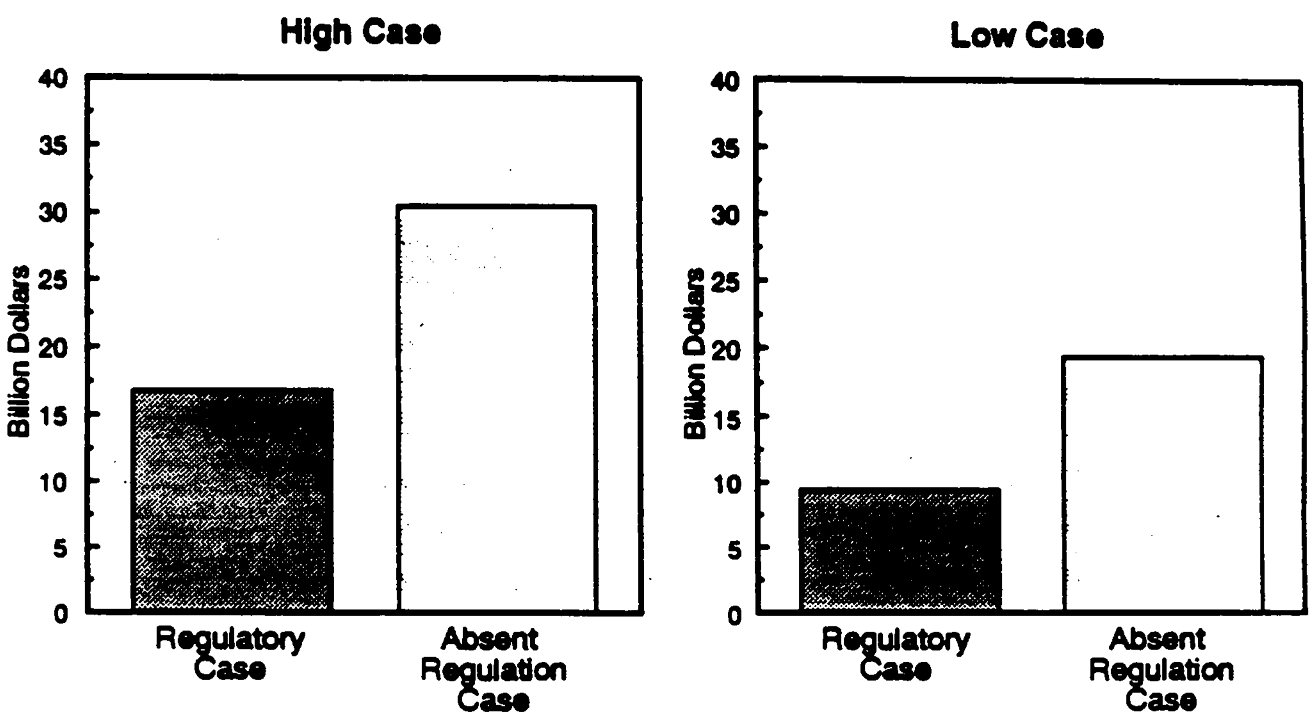
[a] EPA estimates assume a 1.1 million ton industrial reduction that has already occurred will be maintained plus an additional 0.4 million ton reduction expected from desulfurization of diesel fuel.

EXHIBIT 4-3

Cumulative SO2 Reductions Through 2010 (Below 1980)



Present Value Of Costs Through 2010 (Billions of 1990 Dollars)



only half as great under the regulatory case as under the absent regulations case. In other words, the implementation regulations allow a 50 percent reduction in the costs of the statute. These savings reflect the Phase I and Phase II cost savings discussed in the previous section.

Cumulative SO_2 reductions are about 10 to 16 million tons or about 10 to 15 percent lower in the regulatory cases than in the absent regulations case. This reflects several factors shown below in Exhibit 4-4.

EXHIBIT 4-4
COMPARISON OF CUMULATIVE SO_2 REDUCTIONS

	Cumulative SO_2 Reductions (million tons) (below 1980 levels)
Total Regulatory Case	92-105
No Phase I Extension Allowances	+3.5
No Cap on New Plant Emissions	-3 to -5
No Retirement Credits/Overcontrol	+9 to +18
Total Absent Regulations Case	102-121

First, there is no 3.5 million ton allowance reserve assumed in the absent regulations case (which is forecasted to be fully allocated to Phase I units with scrubbers in the regulatory case). Eliminating this reserve increases cumulative SO_2 reductions. Second, there are no credits for plant shutdowns or retirements since no trading is permitted and only unit-by-unit limits apply. Thus, when a unit retires, its emissions tonnage limit cannot be transferred to other power plants as permitted in the regulatory case. Third, some units are overcontrolled for economic reasons (*e.g.*, gas is used at units with higher emission limits because it is less costly). These factors are all partially offset by the fact that no "cap" on new plant emissions is assumed in the absent regulations case.

In sum, however, the present value of costs are reduced by about 50 percent because of emissions trading, while cumulative SO_2 reductions are 10-15 percent lower. Further, it should be stressed that the regulatory case with trading still achieves the 10 million ton SO_2 reduction goal of the legislation during Phase II. The "additional" reductions achieved in the absent regulations case are above and beyond the goal stipulated in the Act.

IMPLEMENTATION COSTS

The next four sections, 4.2, 4.3, 4.4, and 4.5, address the costs of the implementation regulations. Section 4.2 discusses costs related to conducting allowance trading. Section 4.3 provides the costs of allowance auctions, direct sales, and IPP written guarantees. Section 4.4 presents the costs of continuous emissions monitoring and Section 4.5 presents costs of permits. Finally, Section

4.6 provides a summary of the total costs of the statute and the regulations including both the costs related to emissions reduction and the associated implementation.

4.2 COSTS OF ALLOWANCE TRACKING AND TRANSFERS

Costs associated with the use of allowance markets can be separated into administrative costs and costs to participants. In reviewing the costs, it should be noted (as discussed in Section 4.1) that the administrative activities responsibile for these cots provide substantial savings as well in that they make the cost reducitons of the allownace system possible.

4.2.1 Administrative Costs to EPA

Administrative costs to EPA will include costs for developing and maintaining an allowance tracking system, and costs for executing allowance transfers among allowance accounts.

Allowance Tracking System

Section 403 of the Act requires EPA to establish a system for tracking allowances. This section estimates the cost to EPA of developing and maintaining an allowance tracking system. The allowance system regulations set the context for the allowance tracking system, which is currently being developed by EPA. Because the tracking system development is in a very preliminary stage, the associated costs contained in this section are presented as preliminary range estimates.

In order to track allowances, the allowance tracking system will need to include information on: 1) allowance allocations for each affected unit, 2) allowance transfers and deductions for emissions, 3) allowance holders, and 4) reported emissions from the unit. Also, to allow for the transfer of future year allowances, the allowance tracking system will contain allowance information for thirty years into the future. EPA plans to make the information compiled in the allowance tracking system available to the public by some means of electronic access.

Based on preliminary development, the estimated total cost for developing an operational allowance tracking system is between $800,000 and $1,500,000.[3] The annualized cost of development, if the system's costs are spread over the 18 years from 1993 through 2010, is between $60,000 and $110,000. Once in place, EPA will incur annual operation and maintenance (O&M) costs for running an electronic transmission network, system enhancement, general maintenance, and employee salaries. These O&M costs are estimated to range from $100,000 to $200,000 annually, for a present value of between $1,335,000 and $2,670,000.[4] The total cost for the allowance tracking system, then, including development and O&M costs, is estimated to range between $2,135,000 and $4,170,000, with an annualized range of between $160,000 and $310,000.

Allowance Transfer System

The Act requires EPA to receive and record allowance transfers. EPA will perform the following activities when an allowance transfer notification is submitted: 1) review the transfer information for completeness and to ensure all requirements are met, 2) record the transfer by

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3 EPA estimate.

4 EPA estimate.

deducting allowances from the transferror and adding them to the transferee, 3) notify both the transferror and transferee that either the transfer was recorded or why it was not recorded. The average estimated burden and cost for EPA to perform these activities for each transfer submission is one hour and $34 respectively[5].

For the purposes of this analysis, EPA is assuming that about 3,000 allowance transactions will be made per year starting in 1993 and that each one will require one hour for processing for a total of 3,000 hours of processing per year.[6] At a cost of $34 per hour, 3,000 hours per year will cost about $102,000 annually.[7] The present value of $102,000 per year for the 18 years, from 1993 through 2010, discounted at three percent per year to 1992, is approximately $1,400,000.

Total Administrative Costs

Adding the costs of allowance transfers to the costs for establishing and maintaining the tracking system yields total costs of between $3.5 million and $5.5 million. These estimates equal between $250,000 and $400,000 on an annual basis.

4.2.2 Participant Costs

Costs associated with participating in an allowance trading market can be divided into two components: market evaluation costs and transactions costs. First, potential participants must spend time and/or money to analyze their compliance strategies, evaluate the potential advantages of using the allowance market, and determine the number of allowances they would wish to buy or sell at various prices. Second, allowance purchasers will generally incur costs in finding allowance holders willing to sell the quantity of allowances they need. These costs may take the form of time spent contacting allowance holders and negotiating deals. These costs are more likely, however, to take the form of commissions paid to allowance brokers, who will specialize in collecting and analyzing information on supply and demand for allowances.

Costs to participants are difficult to project. Market evaluation costs are uncertain, depending in part on the complexity of compliance choices available to various affected entities and on the amount of effort spent evaluating the available choices. It is impossible to predict whether the addition of the option of trading allowances would increase or decrease the total costs of evaluating compliance options, because some utilities may find that the possibility of complying with emissions

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5 EPA estimate.

6 Number of affected sources is based on Economic Analysis of Proposed Regulations for Auctions, Direct Sales, and IPP Written Guarantees, p.5, note 3. The assumption of three transactions per entity is based on EPA judgment that sources will need to adjust their allowance holding throughout the year as emissions and economic factors change. Entities are assumed to participate in allowance trading even before they are directly affected in order to prepare themselves for compliance when they are affected. The estimate of 3,000 transactions per year is based on an estimate that there will be about 340 entities (240 utilities and 100 IPPs) affected in Phase II, and that each will make an average of three allowance sales per year (with some making more than three and others fewer than three), for a total of about 1,000 sales by affected units. In addition to these sales by affected units, EPA is assuming there will be an additional 2,000 sales by non-affected entities including brokers and other market participants).

7 The average total compensation rate of $34 per hour consists of 1991 direct compensation at the Grade 11, Step 3 level plus overhead costs [EPA, "Draft Information Collection Request for Proposed Title V Operating Permits Regulations," February 12, 1991].

standards by purchasing allowances eliminates the need to evaluate more complex technology-based compliance strategies.

While transactions costs are more predictable than evaluation costs, transactions costs are still subject to uncertainty, depending both on the volume of transactions and on the cost per transaction. Volumes can be predicted using the ICF Coal and Electric Utilities Model (CEUM) described in Section 4.1. Costs per transaction will depend heavily on the characteristics of the allowance market. If the market develops the characteristics of financial or commodities exchanges (*i.e.*, frequent transactions, publicly available information on prices and trading volumes) and if deals are not complicated by public utility commission involvement, then transactions costs should be comparable to the small commissions charged by stock brokers (as low as 0.25 percent).[8] At the other extreme, if trades are infrequent, advance approval of trades by public utility commissions is required, deals are complex, and summary price and volume information is kept secret, transactions costs may be much higher. An analogy might be drawn to the coal market, a market with differentiated products and private price information in which commissions have been in the range of one to seven percent of the value of each deal.

For any given trade, the transactions costs will also depend on the total value of the allowances exchanged. Because of the economies of scale for larger transactions, brokers generally charge less per unit for larger transactions. For example, one stock broker charges a commission of 5.2 percent to the buyer in a trade totalling $2,500; 0.8 percent for a trade worth $50,000; and only 0.33 percent for a $250,000 trade.[9] For this reason, the smallest participants in the market are likely to experience considerably higher transactions costs as a percentage of their trades.

Finally, transactions costs will be affected by the amount of market analysis and advice provided by allowance brokers along with the service of buying or selling allowances. Full-service stock brokers typically charge higher commissions than discount brokers who handle only transactions.

4.2.3 Assumptions Used to Project Participant Costs

For this analysis, EPA is assuming that a smoothly functioning and efficient market for allowances will develop (though for the purposes of sensitivity analysis a less efficient market will be assumed). EPA is, therefore, assuming that the average transactions costs as a percentage of the value of allowances traded will be comparable to the commissions in existing, efficient financial markets. On the assumption that a certain amount of brokering will involve market analysis and advice, EPA is assuming that transactions costs will average 1.5 percent of the value of trades. This average will be composed of lower costs (as low as 0.1 percent) for the largest trades accompanied by the least advice, and higher costs (up to five percent or more) for the smallest trades. Average costs of completed transactions are assumed to include all of the costs of negotiating allowance transactions, including preliminary negotiations that may not result in trades immediately.

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8 "At Your Service: a Directory of Information for Clients of Vanguard Discount Brokerage Services," The Vanguard Group, 1989.

9 Figures quoted are the total for the buyer and the seller, with no market analysis or advice provided, based on commissions quoted in "At Your Service: a Directory of Information for Clients of Vanguard Discount Brokerage Services," The Vanguard Group, 1989.

Transactions costs are assumed to be shared equally between buyers and sellers of allowances.[10]

For a sensitivity analysis, EPA also examines a case in which the market is much less efficient, with transactions costs averaging six percent across all trades, with even higher costs for small traders.[11]

The total value of trades among allowance users is assumed for this analysis to range between $1 billion and $2 billion annually.[12] There may be additional trades among brokers, speculators, and other individuals who are outside of the regulated community. The costs of these trades have not been included in the analysis for three reasons. First, any estimate of the number of transactions of this type would be highly uncertain. Second, the transactions costs per trade for brokers and other professional securities traders are likely to be low, given their access to the market and frequent contacts with potential traders. Finally, brokers and speculators are not part of the regulated community, and their participation in trades among themselves is voluntary.

4.2.4 Estimated Total Costs

Based on EPA's assumptions of transactions of between $1 billion and $2 billion in annual allowance trades and transactions costs of 1.5 percent, the annual transactions costs to participants will range between $15 and $30 million; annual costs to EPA of between $0.25 and $0.4 million raise the nationwide cost to between $15.25 and $30.4 million annually.[13] The present value of transactions costs to participants is equal to between $200 million and $400 million; administrative costs to EPA increase these totals to between $204 and $406 million.[14]

EPA estimates that transactions costs could be four times as great if the market for allowances is relatively inefficient and commissions average 6.0 percent rather than 1.5 percent. Annual costs under these assumptions would range between $60 million and $120 million, amounting to present values of between $800 and $1.6 billion.[15] The wide difference between the low and high

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10 In theory, the distribution of commissions between buyers and sellers depends on their relative price sensitivity. For example, if buyers and sellers are equally sensitive to price changes, then they will each absorb half of the commission. On the surface, it may appear that the seller is paying all of the commission, but market forces will tend to force the price up by one-half of the magnitude of the commission. This price change will shift half of the transactions cost to the buyers. EPA has not attempted to estimate the relative price sensitivity of buyers and sellers. Rather, their sensitivities have been assumed to be equal; thus, EPA is assuming that transactions costs are shared equally between buyers and sellers.

11 ICF estimate of transaction costs under market conditions similar to those in the coal market, where transactions costs have ranged between one and ten percent over time, depending on the size and complexity of the trade and the degree of risk.

12 Based on model results for interstate trades, scaled up to account for intrastate trades.

13 This figure is assumed to include $23,500 in EPA administrative costs, which are well within the rounding error of the estimated participant costs.

14 Present value was calculated as of 1992 using a discount rate of three percent per year, and 18 years of costs starting in 1993.

15 Transactions volumes are likely to be closer to the lower end of the range in an inefficient market, because some trades that would be worth making given a commission rate of 0.25 percent would be unprofitable if commissions were three percent or 10 percent.

transactions cost cases suggests the importance of encouraging the development of an efficient market.

4.3 COSTS OF AUCTIONS, SALES, AND INDEPENDENT POWER PRODUCER GUARANTEES

This section summarizes the costs of three programs under the proposed regulations which are intended to aid in the development of an allowance market and improve access to allowances for new entrants to the regulated community. These regulations are covered in a separate rulemaking, but are summarized here for completeness. These programs and their costs are covered in detail in a separate document, Economic Analysis of the Proposed Acid Rain Regulations for Auctions, Direct Sales, and IPP Written Guarantees. As with the administrative costs, the costs associated with these programs should be reviewed in light of their contribution to the integrity and success of the allowance system, with the substantial cost reductons it makes possible.

Section 416 of Title IV authorizes the Administrator to reserve allowances to sell through auctions, direct sale, and Independent Power Producer (IPP) written guarantees. The auctions, direct sale, and IPP guarantee provisions of Title IV are intended to provide some certainty that units will have a public source of allowances beyond those allocated initially for existing units. In addition, the auctions are expected to help signal price information to the allowance market early in the program.

4.3.1 Spot and Advance Auctions

Spot (for emission allowances to be used in the current year) and advance (for emission allowances to be used in future years) auctions will be held early in each calendar year to allow new and existing units time to plan for end-of-the-year compliance. In addition to the reserve allowances withheld specifically for the auction,[16] unsold allowances from the direct sales of the previous year will also be sold in the EPA auction. Other allowance holders will also be permitted to sell allowances through the EPA auctions; their allowances will be sold after the sale of the allowances EPA must withhold.

The proceeds from the sale of other allowances will be transferred at the time of the auction from the purchaser to the seller via EPA. EPA will also handle the transfer of proceeds to the original holders of the auctioned allowances withheld by EPA. Any unsold allowances will be returned to the original holders of those allowances.

EPA is required to report publicly on the results of each auction. To provide sufficient information for market participants to gauge the demand and the price range for allowances, EPA proposes to report the names of all bidders and their bids (successful and unsuccessful).

4.3.2 Direct Sales

The Clean Air Act as amended establishes a Direct Sales Subaccount of 50,000 allowances to be sold annually for $1,500 each (adjusted for inflation using the 1990 Consumer Price Index). EPA is required to offer 25,000 allowances every year in advance sales beginning in 1993, and 25,000

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16 The reserves will contain 50,000 allowances for the spot auction and 100,000 allowances for the advance auction for years 1993 to 1995, 150,000 and 100,000 respectively for years 1996 to 1999, and 100,000 each for years 2000 and beyond.

per year in spot sales beginning in 2000. However, the actual quantity of allowances available for direct sale will depend on the demand for allowances by the IPP guarantee program participants. Allowances for the IPP guarantee program will be taken from those set aside for advance sales before any are taken from the spot sales category; for this reason, the IPP guarantee program is expected to preempt the direct sale program at least until the year 2000.

Applicants for allowances through the direct sales program will have up to six months from the time of their application to submit a non-refundable deposit of 50 percent of the total purchase price after their request to purchase allowances is approved. The remainder of the price will be paid on or before the last day of the sale period. Because of the high price of allowances in the direct sales program, EPA does not expect either strong demand for allowances through the direct sale program, or the submission of non-refundable deposits; rather, purchasers are likely to wait until the end of the year before submitting applications.

Section 416 of the Act directs EPA to end the direct sale program if during any two consecutive years, fewer than 20 percent of the allowances (advance or spot) are sold. EPA currently expects the direct sale program to end two years after it is initiated.

4.3.3 IPP Written Guarantee

Under the IPP written guarantee program, EPA will offer "written guarantees" to certain IPPs planning to construct new facilities. The IPP written guarantees will provide the IPPs the right to purchase allowances every year for the useful life of the unit from the Direct Sale Subaccount before others are allowed to purchase. The IPP written guarantee is intended to provide new IPPs with a means of demonstrating to their lenders that they will have access to a sufficient number of allowances to fully operate planned facilities.

To qualify for a guarantee, an IPP must meet the definition of an owner or operator of a new independent power production facility and satisfy several additional requirements. The IPP must submit written offers to each utility affected under Phase I to purchase the required allowances at $750 each; record the responses to the offers; and certify on the application that none of the offers was unconditionally accepted within 180 days. Once a guarantee is awarded, the IPP must submit periodic statements certifying that the guarantee is still needed.

The aggregate annual cap for allowances reserved through IPP written guarantees will be set at 50,000. Allowances for the written guarantees will come from the advanced allowance category of the direct sale schedule first, and then from the spot allowance category.

Exhibit 4-5 summarizes the total costs of the three programs discussed in this report to EPA and to the participants. Details on these programs and the annual costs used to estimate the present value costs presented below are contained in <u>Economic Analysis of the Proposed Acid Rain Regulations for Auctions, Direct Sales, and IPP Written Guarantees</u> and <u>The Information Collection Request for the Acid Rain Program Under the Clean Air Act Amendments Title IV</u>.

4.4 COSTS OF CONTINUOUS EMISSIONS MONITORING SYSTEMS

CAA section 412 requires the use of continuous emissions monitoring systems (CEMS) at each affected unit's source of emissions. This part of the chapter presents estimates of the costs to

EXHIBIT 4-5
Estimated Present Value Costs of the Auction, Direct Sales, and IPP Written Guarantee Programs[a]
(Thousands of 1991 dollars)

		Auction	Direct Sales	IPP Written Guarantees	TOTAL
I.	Government Costs	$297 to 967	$21	$92	$410 to 1,080
II.	Participant Costs	$1,036 to 6,217	$12	$164	$1,212 to 6,393
III.	Total Costs	$1,336 to 7,184	$33	$256	$1,625 to 7,473

[a] Costs are discounted for 18 years (1993-2010) to the beginning of 1992 at a discount rate of 3 percent.

the regulated community and the federal government of the CEMS regulations under an absent regulations case and five regulatory cases.

4.4.1 Background

To ensure compliance with the emission reductions requirements established by Title IV, section 412 requires that owners and operators of sources subject to Title IV install and operate CEMS on each affected unit at the source, and quality assure the data for SO_2, NO_x, opacity, and volumetric flow at each such unit.

EPA is authorized under section 412 to promulgate regulations establishing requirements for CEMS, for any monitoring methods other than CEMS demonstrated to provide information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS, and for record keeping and reporting of information from such systems.

In reviewing the costs of the CEMS requirements, it must be noted that the integrity of the Acid Rain program hinges on the availability of the most accurate and reliable emissions data. Without quality assured data and reliable methods to achieve this quality assurance, it will be virtually impossible to ascertain the actual emissions of a utility. This causes greater uncertainty to the system as a whole. The uncertainty faced by utilities, EPA (in its role of enforcing the CAA), and consumers represents real economic costs.

As stated in Section 4.1, the cost/savings afforded by the allowance system are contingent upon the availability of accurate emissions data. Since the allowance system could represent potential revenues/assets for some utilities, it is critical to these utilities that emissions data from other utilities is quality assured and as accurate as possible. If a plant's CEMS is reporting emissions that are lower than actual emissions, a cost is incurred by both the utilities that have decreased their emissions below their limit and society as a whole. The utilities that have decreased their emissions below their required levels will suffer the cost of holding undervalued allowances and the loss of revenues that is represented by the difference. Society as a whole must bear the burden of emissions beyond the statutory requirements.

4.4.2 CEMS Regulatory Options

EPA has analyzed the costs of monitoring in the absence of regulation and under five CEMS regulatory options. These six cases differ from each other in (1) CEMS and flow monitoring hardware requirements, (2) acceptable monitoring methods other than CEMS, and (3) data reporting and record-keeping requirements.

The absent regulations case assumes that no further CEMS regulations are promulgated by EPA beyond the statutory requirements included in CAA, section 412. Under the statutory requirements, all affected units (Phases I and II) must install a SO_2 CEMS, a NO_x CEMS, a continuous opacity monitor (COM), and a volumetric flow monitor. No other monitoring methods are allowed, no performance standards are set, and no data reporting is required by law.

In contrast to the absent regulations case, the five regulatory options include operation and maintenance requirements and additional performance testing requirements. The Relative Accuracy Test Audit (RATA) is one of the main performance audits that takes place. Option 1 presents the most stringent regulatory case; Option 2 permits the use of other monitoring methods as an exception to CEMS; Option 3 exempts retiring plants from all monitoring requirements; Option 4 requires the use of standardized data reporting and record keeping procedures; and Option 5 combines all of the regulatory options:[17]

- Option 1 assumes no pre-approved monitoring methods other than CEMS. All affected sources are subject to operation and maintenance requirements and additional performance testing requirements.

- Option 2 is similar to Option 1 except for pre-approved excepted monitoring methods and COM exemption for gas-fired units and wet-scrubbed coal-fired units. Option 2 allows units burning oil and units burning 90 percent or more gas to use methods of monitoring SO_2 emissions and volumetric flow other than CEMS.[18] These gas- and oil-fired units are likely to get accurate measures of SO_2 emissions using an alternative method of monitoring because fluid fuels are easily measured using a fuel flow meter and are generally homogenous in terms of sulfur content. The gas units would also be exempt from the COM requirement because natural gas is a clean fuel with low opacity levels. Coal-fired units, if wet-scrubbed, are also exempt from the COM requirement because wet-scrubbed units emit large amounts of water vapor, which prevents meaningful measurements of opacity. All SO_2 emitters are subject to operation and maintenance requirements and additional performance testing requirements.

- Option 3 is similar to Option 1 except that units that retire before compliance deadline are exempted from all monitoring requirements.

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17 For all options, the regulations provide for case-by-case demonstrations for approval of alternatives, but no pre-approved excepted monitoring methods unless specified.

18 Units burning 90 percent or more gas may also be allowed to use monitoring methods other than CEMS for NO_x equivalent to CEMS; however, because NO_x generation is site specific, depending upon boiler configuration, any determination of equivalency for the use of an alternative must be made on a case-by-case basis.

Option 3 exempts all affected units retiring before January 1995 from all monitoring requirements because they will not be emitting SO_2 during the period of compliance. All affected sources are subject to operation and maintenance requirements and additional performance testing requirements.

- Option 4 is similar to Option 1 except that it requires the use of EPA approved, standardized electronic reporting format for the Data Acquisition Systems (DAS) for reporting and record keeping. A standardized electronic reporting format is expected to reduce the costs to industry of reprogramming customized or off-the-shelf software by about 50 percent. In addition, standardized reporting could reduce EPA's administrative burden in processing quarterly emissions reports by about 50 percent.

- Option 5 combines Options 1, 2, 3 and 4 including the operation and maintenance requirements, additional performance testing requirements, the use of methods of monitoring SO_2 and volumetric flow by gas- and oil-fired units as an exception to CEMS, the exemption of gas-fired units and wet-scrubbed coal-fired units from the COM requirement, the exemption of all affected units retiring before January 1995, and the required use of EPA approved, standardized electronic reporting format for the Data Acquisition Systems. This option also assumes that new units below 25 MW would be exempted from the CEMS requirements and that gas- and oil-fired units with a capacity factor less than or equal to 10 percent would be allowed to use alternative methods of monitoring NO_x emissions. Option 5 represents the proposed CEMS rule.

Options 1, 2, and 3 also require data reporting and record-keeping but without the standardized electronic reporting format requirement. EPA will require that all affected units required to install CEMS update or install a DAS to record hourly CEMS and flow monitor data. Affected units without CEMS must record daily fuel sampling analysis data and install a DAS to record hourly fuel flow values. All affected units will be required to submit quarterly reports of their emissions data to EPA. EPA will also require certification and inspection of all data handling systems.

4.4.3 Assumptions about the Absent Regulations Case and the Regulatory Options

Under the absent regulations case, EPA assumes that all affected generating units would be required to purchase, install, and maintain CEMS (for SO_2 and NO_x), COM, and flow monitoring systems if they do not already have one in place.[19] The number of affected units and the additional

[19] According to the National Allowance Database (October 1990), there are 2,165 Phase II affected units (1,311 coal-fired units, 393 oil-fired units, and 461 gas-fired units). EPA assumes that 142 new diesel-fired units would come online between 1990 and 2000 for a total of 2,307 Phase II affected units. Gas-fired units are defined as units that burn gas at least 90 percent of the time. Although a single CEM may monitor multiple units, if several affected units contribute to a single source (i.e., stack), it is assumed for this analysis that a CEM is installed for each affected unit. This could be an overestimation of the number of monitors needed because some units share a common stack and a common CEMS.

monitoring equipment required for each were determined by using the National Allowance Database (October 1990) and Aerometric Information and Retrieval System (AIRS).

Exhibit 4-6 presents the number of affected units and the types of CEMS equipment needed under the statutory requirements. About 46 percent (1070 out of 2307) of all the affected units would be required to install all monitors while 90 percent (414 out of 461) of the gas-fired units and 87 percent (467 out of 535) of the oil-fired units will be required to install all monitors. In contrast, only about 14 percent (189 out of 1311) of the coal-fired units require all monitors.

Exhibit 4-7 presents the industry average CEMS cost estimates used for this analysis.[20] Purchase, installation, operation and maintenance cost estimates were provided by CEMS manufacturers.[21] Under the absent regulations case, absent CEMS performance standards, EPA assumes that most of the affected units will choose to purchase and install lower cost CEMS. If affected units are required to install all monitors, it is expected to cost about $302,200 in capital expenses and about $78,700 in annual operation and maintenance expenses per unit.

Because section 412 does not specify regular reporting, the absent regulations case assumes that no additional effort would be required for record keeping beyond what the DAS records.[22]

For the purposes of this analysis, EPA assumes that the preparation of quarterly reports and data quality assurance/quality control requirements will require about 160 hours each year (40 hours each quarter) for each plant.[23]

Under Option 2, EPA assumes that 461 gas-fired units and 535 oil-fired units would be allowed to use fuel sampling and analysis and a fuel flow meter instead of an SO_2 CEMS and flow monitor. The gas-fired units would also be exempt from the COM requirement. EPA also assumes that 10 existing coal-fired units with new wet-scrubbers would benefit from the COM exemption. Under Option 3, EPA assumes that 118 units will be retired prior to January 1995.[24]

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20 Engineering costs associated with CEM retrofit are not included in the analysis due to the difficulty in obtaining cost estimates. These retrofit engineering costs, however, are expected to be similar under the absent regulations case and the regulatory cases.

21 These cost estimates are based on data provided by Thermo Environmental Instruments, Inc.; Rosemount Analytical, Inc.; and KVB Inc. Fuel flow meter cost estimates are based on data provided by Jacksonville Electric Authority. Flow monitor cost estimates are based on information provided by KVB, Inc. and Environmental Measurement Research Corporation. DAS software and operation/maintenance costs are EPA estimates.

22 In the base case, EPA may submit a data request to the affected unit operators to obtain data as needed or inspect the data during a plant inspection. However, EPA assumes that no additional administrative time would be required to keep track of the emissions data.

23 EPA estimate. There are 110 plants in Phase I, and approximately 730 plants in Phase II.

24 All estimates of numbers of affected units are from the National Allowance Database, October 1990 (version 1.0). ICF estimates that, of the retired units, 37 units are coal-fired, 66 oil-fired, and 15 gas-fired. For the purposes of this analysis, EPA assumes that the distribution of any exempt group is the same as the regulated community as a whole in terms of the quantities and types of monitoring equipment that are currently in place. For example, under Option 3, it is assumed that the distribution of retired coal-fired units is the same as the distribution of all coal-fired units as presented in Exhibit 4-6.

EXHIBIT 4-6
Number of Affected Units and Monitoring Equipment Needed[a]

Coal-Fired Units								
Affected Units		Monitors Required						
Phase I	Phase II	Base Equip.	NO_x	O_2/CO_2	SO_2	Flow	COM	DAS
0	189	X	X	X	X	X	X	X
178	666	X	X	X	X	X	*	*
70	346	*	X	*	*	X	*	*
3	103	*	*	*	*	X	*	*
2	7	*	X	*	*	*	*	*
3	0	X	X	X	X	*	*	*
256	1311	**Subtotal Coal**						
Oil-Fired Units								
Affected Units		Monitors Required						
Phase I	Phase II	Base Equip.	NO_x	O_2/CO_2	SO_2	Flow	COM	DAS
0	467	X	X	X	A	A	X	X
5	55	X	X	X	A	A	*	*
0	2	*	X	*	*	X	X	*
0	1	*	*	*	*	X	*	*
0	6	*	*	*	A	A	*	*
0	4	*	*	*	A	A	X	*
5	535	**Subtotal Oil**						
Gas-Fired Units								
Affected Units		Monitors Required						
Phase I	Phase II	Base Equip.	NO_x	O_2/CO_2	SO_2	Flow	COM	DAS
0	414	X	X	X	A	A	E	X
0	16	X	X	X	A	A	*	*
0	1	*	*	*	*	X	E	*
0	1	*	X	*	A	A	*	*
0	29	*	*	*	A	A	E	*
0	461	**Subtotal Gas**						
261	2307	**Total All Fuels**						

* Monitors already present. No additional monitoring equipment required.
X Monitoring equipment required.
A Monitoring methods other than CEMS are available under Options 2 and 5.
E Exemptions from these monitoring requirements are given under Options 2 and 5.
[a] EPA estimates based on the National Allowance Database and AIRS. These are conservative estimates given that some sources with monitors installed do not report to the federal EPA.

4.4.4 Costs Incurred by the Regulated Community

The costs to the regulated community under the absent regulations case and the five regulatory options include costs associated with CEMS, flow monitoring, and data handling hardware, installation, maintenance, and costs associated with data recording and reporting.

CEMS, Flow Monitoring, and Data Handling Hardware Costs

EXHIBIT 4-8
Estimated Annualized Costs to the Regulated Community
(Millions of 1990 Dollars)

	Absent Regulations (per year)	Option 1 (per year)	Option 2 (per year)	Option 3 (per year)	Option 4 (per year)	Option 5 (per year)
Monitoring Equipment						
Coal-fired Units						
1993	20.8	23.5	23.5	23.5	23.5	23.5
1994-2010	110.8	125.9	125.9	124.9	125.2	124.1
Oil-fired Units						
1993	0.4	0.5	0.4	0.5	0.5	0.4
1994-2010	45.1	58.7	39.7	55.7	56.9	28.8
Gas-Fired Units						
1993	0	0	0	0	0	0
1994-2010	39.0	50.5	41.0	49.8	48.9	26.7
Subtotal						
1993	21.2	24.0	23.9	24.0	24.0	23.9
1994-2010	194.9	235.1	206.6	230.5	231.0	179.6
Data Reporting						
1993	0	6.6	6.6	6.6	6.6	6.6
1994	0	58.1	58.1	58.1	58.1	58.1
1995-2010	0	3.9	3.9	3.9	3.9	3.9
TOTAL						
1993	21.2	30.6	30.5	30.6	30.6	30.5
1994	194.9	293.2	264.7	288.6	289.1	237.7
1995-2010	194.9	239.0	210.5	234.4	234.9	183.5

The annual costs under each scenario for gas, oil, and coal units and for the regulated community as a whole are presented in Exhibit 4-8. The present value of the total hardware costs

EXHIBIT 4-9
Estimated Present Value Costs to the Regulated Community for the Time Period 1993-2010[a]
(Millions of 1990 Dollars)

	Absent Regulation Case	Option 1	Option 2	Option 3	Option 4	Option 5
Monitoring Equipment						
Coal-fired Units	1,436	1,632	1,632	1,619	1,623	1,610
Oil-fired Units	577	751	698	712	728	368
Gas-Fired Units	499	646	524	637	626	341
Subtotal	2,512	3,029	2,854	2,968	2,977	2,319
Data Reporting	0	105	105	105	105	75
TOTAL	2,512	3,134	2,959	3,073	3,082	2,394

[a] Costs are discounted for 18 years (1993-2010) to the beginning of 1992 at a discount rate of three percent.

to the regulated community are presented in Exhibit 4-9. The average costs per unit are presented in Exhibit 4-10.

Under the absent regulations case, the present value of the cost of installing a SO_2 CEMS, a NO_x CEMS, and a flow monitor at all units not presently equipped with these devices will be about $2,512 million for the period 1993-2010.[27] The annualized costs are $21.2 million for 1993 and $194.9 million each year for 1995-2010. The average cost per unit will be about $81,300 for 1993 and $90,000 each year for 1995-2010.

Under Option 1, the increase in the costs, attributable to relative accuracy testing audit and other necessary quality assurance and maintenance procedure expenses, raises the monitoring costs to the regulated community over the absent regulations case costs. The present value of the costs to the regulated community will be about $3,134 million for the 1993-2010 period. The annualized costs are $30.6 million for 1993, $293.2 million for 1994, and $239 million each year for 1995-2010. The average cost per unit will be about $95,800 for 1993, $130,300 for 1994, and $110,400 each year for 1995-2010. Option 1 is the most stringent and the most expensive regulatory option examined for this analysis.

Under Option 2, the costs to the regulated community are reduced from Option 1 through the use of excepted monitoring methods and COM exemption of gas-fired units and wet-scrubbed coal-fired units. These cost savings are outweighed, however, by the cost of quality assurance procedures vital to ensuring accurate, trustworthy emissions data. The present value of the costs to the regulated community under this option will be about $2,959 million for the 1993-2010 period. The annualized costs are $30.5 million for 1993, $264.7 million for 1994, and $210.5 million each year

[27] All present value costs are discounted back to the beginning of 1992 at a discount rate of three percent.

EXHIBIT 4-10
Average Annual Costs per Unit to the Regulated Community
(Thousands of 1990 Dollars Per Unit)

	Absent Regulations (per year)	Option 1 (per year)	Option 2 (per year)	Option 3 (per year)	Option 4 (per year)	Option 5 (per year)
Monitoring Equipment						
Coal-fired Units						
1993	81.3	91.9	91.9	91.6	91.9	91.6
1994-2010	84.5	96.0	96.0	95.3	95.5	94.7
Oil-fired Units						
1993	80.7	95.7	97.4	95.7	95.7	77.4
1994-2010	114.9	149.3	138.9	141.6	144.8	73.2
Gas-Fired Units						
1993	0	0	0	0	0	0
1994-2010	84.6	109.6	88.9	108.1	106.2	58.0
All Units						
1993	81.3	92.0	92.0	91.7	92.0	91.4
1994-2010	90.0	108.6	102.3	106.4	106.7	83.0
Data Reporting						
1993	0	3.8	3.8	3.8	3.8	3.8
1994	0	21.7	21.7	21.7	21.7	21.7
1995-2010	0	1.8	1.8	1.8	1.8	1.8
TOTAL						
1993	81.3	95.8	95.8	95.5	95.8	95.2
1994	90.0	130.3	124.0	128.1	128.4	104.7
1995-2010	90.0	110.4	104.1	108.2	108.5	84.8

for 1995-2010. The average cost per unit will be about $95,800 for 1993, $124,000 for 1994, and $104,100 each year for 1995-2010.

Under Option 3, the costs to the regulated community are reduced from Option 1 through the exemption of retiring plants from the CEMS/COM and flow monitor requirements. Again these cost savings are outweighed by the quality assurance procedure expenses. Overall, the present value of the costs to the regulated community under this option will be about $3,073 million for the 1993-2010 period. The annualized costs are about $30.6 million for 1993, $288.6 million for 1994, and $234.4 million annually for 1995-2010. The average cost per unit will be about $95,500 for 1993, $128,100 for 1994, and $108,200 each year for 1995-2010.

Under Option 4, the lower cost of the DAS with the EPA approved, standardized electronic reporting format reduces the costs to the regulated community. Overall, the present value of the costs to the regulated community under this option will be about $2,977 million for the 1993-2010 period. The annualized costs are $30.6 million for 1993, $289.1 million for 1994, and $3.082 million each year for 1995-2010. The average cost per unit will be about $95,800 for 1993, $128,400 for 1994, and $108,500 each year for 1995-2010.

Under Option 5, the proposed CEMS rule combining all of the elements of Options 1-4, the present value of the costs to the regulated community will be about $2,394 million for the 1993-2010 period. The annualized costs are about $30.5 million for 1993, $237.7 million for 1994, and $183.5 million annually for 1995-2010. The average cost per unit will be about $95,200 for 1993, $104,700 for 1994, and $84,800 each year for 1995-2010. Option 5 is the least expensive regulatory option examined for this analysis.

Monitor Certification, Data Recording and Reporting Costs

Under the absent regulations case, the affected utilities are not required to report emissions data to EPA. Thus, there are no costs for monitor certification, data recording or reporting associated with the absent regulations case.[28] The present value of the cost of monitor certification, data recording and reporting to the regulated community under each of the regulatory options is about $105 million for the 1993-2010 period.[29] The annual costs are expected to be about $6.6 million for 1993, $58.1 million for 1994, and about $3.9 million each year for 1995-2010. The average cost per unit will be about $25,200 for the period of 1993-1994, and about $1,800 each year for 1995-2010. Annual cost estimates are presented in Exhibit 4-8 and the total present value cost estimates are presented in Exhibit 4-9. The average costs per unit are presented in Exhibit 4-10.

Total Costs to the Regulated Community

The present value of the total costs to the regulated community under the absent regulations case is about $2,512 million for the period 1993-2010. The present value of the total costs to the regulated community under each of the regulatory options is about $3,134 million for Option 1, $3,040 million for Option 2, $3,073 million for Option 3, $3,082 million for Option 4, and $2,626 for Option 5.

4.4.5 Costs Incurred by EPA

The costs to EPA include the cost of conducting periodic plant inspections and processing and reviewing emissions data. EPA incurs no inspection and data evaluation costs under the absent regulations case. Under all regulatory options, the present value of the total cost to EPA of performing these activities is about $1.0 million for the 1993-2010 period.[30] The annual costs are expected to be about $5,400 for 1994, $58,200 for 1995, $46,900 each year for 1996-1999, and $110,200 each year for 2000-2010. The annual costs to EPA are presented in Exhibit 4-11, and the total present value costs are presented in Exhibit 4-12.

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[28] Electronic data collection and tracking costs are included in the CEM and DAS costs.

[29] Costs for monitor certification are based on EPA's estimates that monitor certification will cost $25,000 per unit, and a total of 2,307 units.

[30] Based on EPA's estimate that a plant inspection will require an average of 60 hours at a cost of $34 per hour. Options 4 and 5 include the cost savings of standardized emissions data reporting.

EXHIBIT 4-11
Estimated Annual Costs to EPA
(Thousands of 1990 Dollars)

	Absent Regulation Case	Option 1	Option 2	Option 3	Option 4	Option 5
Plant Inspections						
1995	0	22.4	22.4	21.8	22.4	21.8
1996-1999	0	11.2	11.2	10.9	11.2	10.9
2000-2010	0	74.4	74.4	74.4	74.4	74.4
Data Review and Evaluation						
1994	0	5.4	5.4	5.4	5.4	5.4
1995-2010	0	35.7	35.7	35.7	35.7	35.7
TOTAL						
1994	0	5.4	5.4	5.4	5.4	5.4
1995	0	58.2	58.2	57.6	58.2	57.6
1996-1999	0	46.9	46.9	46.7	46.9	46.7
2000-2010	0	110.2	110.2	110.2	110.2	110.2

EXHIBIT 4-12
Estimated Present Value Costs to EPA for the Time Period 1993-2010[a]
(Thousands of 1990 Dollars)

	Absent Regulation Case	Option 1	Option 2	Option 3	Option 4	Option 5
Plant Inspections	0	619	619	617	619	617
Data Review and Evaluation	0	416	416	416	416	416
TOTAL	0	1,035	1,035	1,033	1,035	1,033

[a] Costs are discounted for 18 years (1993-2010) to the beginning of 1992 at a discount rate of three percent.

4.4.6 Total Costs of the CEMS Regulations

Exhibit 4-13 summarizes the total costs associated with the absent regulations case and each of the three regulatory options examined. Option 5, the proposed rule, offers a savings of about $710 million from the most stringent regulatory case (Option 1). Furthermore, the cost of Option 5 is about $117 lower than the absent regulations case due to the more rational approach to monitoring sources that likely will have very low emissions, such as retired coal units and gas units with very low utilization.

EXHIBIT 4-13
Total Present Value CEMS Costs for the Time Period 1993-2010[a]
(Millions of 1990 Dollars)

	Absent Regulation Case	Option 1	Option 2	Option 3	Option 4	Option 5
Regulated Community Costs	2,512	3,104	2,959	3,043	3,052	2,394
EPA Costs	0	1	1	1	1	1
TOTAL COSTS	2,512	3,105	2,960	3,044	3,053	2,395

[a] Costs are discounted for 18 years (1993-2010) to the beginning of 1992 at a discount rate of three percent.

4.5 COSTS OF PERMITS

This section presents estimates of the labor requirements and costs to (1) federal and state governments to implement acid rain permit requirements, and (2) owners and operators of sources that must obtain permits under Title IV of CAA as amended.[31] As with other implementation activities, the costs of permits should be reviewed in light of the costs savings that a credible permit program makes possible.

4.5.1 Background

To ensure compliance with Title IV requirements, section 408 requires owners and operators of affected sources to obtain operating permits from EPA during Phase I and from states in the continental United States with approved Title V permit programs or from EPA during Phase II. Permits issued to implement this title will have terms of five years.

As provided in section 408, the permit program is to be implemented in two phases. Under the first phase, EPA will issue operating permits to owners and operators of power plants that are required to meet Phase I SO_2 and NO_x reduction requirements. First phase permits will be effective January 1, 1995 through December 31, 1999. Under the second phase, states with approved Title V

[31] Because permit fees to be collected from source owners and operators under state permit programs are required specifically by Title V, and because these fees were addressed in the Title V Regulatory Impact Analysis and no additional fees are required by or would result due to Title IV, examination of permit fees has been excluded from this analysis.

permit programs will issue permits that include acid rain provisions to owners and operators of (1) sources with new utility units, and (2) sources with existing electric utility units serving generators with a capacity of greater than 25 MW (*i.e.*, Phase II affected sources). Second phase permits will be effective for terms of five years, beginning January 1, 2000. If a state fails to adopt and implement a permit program approvable under Title V, EPA must issue permits to affected sources in Phase II.

To obtain permits, owners and operators must submit to the permitting authority a permit application for each affected source (*i.e.*, plant). The contents of the acid rain permit application will include the following for each affected unit at the source: (1) general information required for <u>all units</u>, and (2) a compliance plan with specific information, as appropriate, to support the use of any compliance options for SO_2 (*e.g.*, substitutions, Phase I extensions, repowering extensions) or for NO_x (*i.e.*, alternative emission limitations, emissions averaging, or extensions). The general information will include the identity of the designated representative, source and unit identification, operating information, emissions monitoring information, and an indication of the compliance strategy or strategies proposed for units.[32] In addition, a certificate of representation for the designated representative for the source must precede or accompany the application. The certificate of representation must state, among other things, that allowances and proceeds of transactions involving allowances will be held or distributed to the owners of units at the source, either in proportion to each owner's legal, equitable, or leasehold interest, or by some other contractual entitlement, and that the designated representative is authorized to fully bind the owners and operators with regard to Acid Rain Program matters.

The designated representative of the owners and operators of subject power plants must submit Phase I acid rain permit applications and proposed compliance plans to EPA no later than February 15, 1993. (Proposals to revise the permit application, proposed compliance plan, and final permit may be submitted at any time.) EPA must act on the compliance plan within six months of receipt. Designated representatives of Phase II sources must submit initial acid rain permit applications and proposed compliance plans to the state permitting authority, with copies to EPA, by January 1, 1996. States with approved permit programs must issue the permits to sources satisfying the permit requirements by December 31, 1997. In states without permit programs approved under Title V by July 1, 1996, EPA is required by Section 408 to act on the applications and issue permits by January 1, 1998. The designated representatives of sources that include new electric utility steam generating units must submit permit applications and proposed compliance plans to the appropriate permitting authority at least two years before the latter of (1) January 1, 2000, or (2) the date on which the unit commences operation, unless the new unit shares a common stack with a Phase I affected unit, is designated as a compensating unit, or was modified on or after enactment to serve a generator greater than 25 MW. In any of these cases, the designated representative must submit a permit application for the unit at an earlier date.

4.5.2 Assumptions

The estimates of labor requirements and costs to implement permit programs and obtain permits under Title IV depend on assumptions regarding participation, source burden, and timing.

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32 If the owners, operators, and designated representative of a unit plan to comply in timely fashion with the applicable SO_2 emission limitations by holding the requisite number of allowances and plan to comply in a timely fashion with the applicable NO_x emissions limitations, a certification to that effect is all that is required. If the owners, operators, and designated representative of a unit elect to use one or more of the compliance options authorized by the Act, the following specific information to support use of a proposed option is required: identification of units governed by the option, and of the designated representatives; notification and reporting requirements; and proposed emissions limitation and allowance allocation information.

Participation

Of the 110 sources expected to require permits under the first phase of the acid rain permit program, 83 sources are expected to require permits covering both SO_2 and NO_x emissions,[33] and 27 are expected to require permits covering only SO_2 emissions.[34] Under the second phase, 727 Phase II sources (which include sources under the first phase) are expected to require permits. Four hundred and thirty (430) of these sources are expected to require permits for both SO_2 and NO_x emissions,[35] and 297 sources are expected to require permits for SO_2 only.[36] Sources with new units and some new IPPs will also require permits under the second phase. For the purposes of projecting permit costs, EPA is estimating that roughly 100 of these projects will require permits. These projects all are assumed to obtain the needed allowances to start operating in the year 2000.[37] [38] For sources that are subject to both SO_2 and NO_x emission limitations, this analysis assumes that one permit will govern all pollutants regulated by the program emitted by a single source. This analysis assumes that all sources required to obtain acid rain permits under this title are large sources.[39]

Source Burden Estimates

Administrative burden costs are expected to be incurred by (1) owners, operators, and representatives of sources who apply for operating permits; (2) EPA, which must implement a federal permit program to issue first phase permits to sources, and which will provide oversight of state permit program implementation, permit issuance, data management, permit compliance, and enforcement for second phase permits; and (3) state authorities who assist EPA during Phase I implementation and review applications for and issue second phase permits.

Estimating the burden associated with permits is difficult because the burden to individual permit applicants of developing an application may vary widely depending upon the method of compliance chosen. Although all applicants for permits will be required to submit a general acid rain permit application form for each affected source that covers all affected units at the source, additional forms would be necessary if one or more compliance options are chosen by the source to meet the SO_2 or NO_x emissions limitations for any unit. Rather than trying to predict the number of applicants that will elect to use various combinations of compliance options for units, this analysis assumes average overall burden estimates for permits applicants, EPA, and states.

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33 Excludes Phase I plants with all wet bottom/cyclone Phase I units and excludes solely oil and gas plants.

34 Estimates of the number of sources that will be affected by the acid rain permits program were obtained from the National Allowance Data Base (version 1.0).

35 Assumes the January 1, 1997, regulations for nitrogen oxide emissions apply for all other coal boiler-type units, but excludes solely oil and gas plants.

36 Estimates of the number of sources were obtained from the National Allowance Data Base (version 1.0).

37 EPA estimates that these projects will require about 127,000 allowances per year to emit sulfur dioxide (or about 1,270 annually per project).

38 Additional sources may elect to be included under the "opt-in" program, and will be required to obtain permits. These sources have not been included in this analysis because the costs they incur are optional and because they will be covered under separate regulations.

39 Large sources are defined as those emitting more than 100 tons per year of any pollutant.

The labor burden estimates (per occurrence of a task where appropriate) used in this analysis for federal and state governments and permit applicants are the same as those used for large sources in the Regulatory Impact Analysis and Regulatory Flexibility Act Screening Analysis for Proposed Title V Operating Permits Regulations.[40] This analysis assumes that any incremental burden incurred by (1) permit applicants filing applications that include one or more of the acid rain compliance options, and (2) permitting authorities reviewing these applications and issuing permits, is included in these labor burden estimates. Burden estimates per task occurrence are assumed not to change over the time period of this analysis. In addition, the activities that will be performed and the burden on sources associated with obtaining a single permit are assumed to be the same under both the first and second phases of the permit program (although the actual burden on all affected sources in Phase II may be less since the program, including options, is greatly simplified by Phase II and because Phase I sources will be applying for a second time and will have a better understanding of the program and the application procedures).[41]

Timing of Costs

This analysis covers the period from January 1, 1992, through December 31, 2010, inclusive. Submission of a designated representative certificate of representation form and a permit application (along with the proposed compliance plan), application review, and permit issuance are generally required prior to the effective date of a permit. Although deadlines for submitting permit applications and issuing initial permits under both Phase I and Phase II exist (see section 4.5.1 above), the actual timing when (1) applications will be prepared, submitted, and reviewed, and (2) permits will be issued -- both for initial permit applications and future renewals of Phase II permits -- is uncertain. Because of this uncertainty and to simplify the analysis, it is assumed that all initial costs associated directly with obtaining and issuing each permit, which are non-recurring over the life of a permit, will be incurred at the end of the year the permit becomes effective, beginning in the year 1995 (*i.e.*, 1995, 2000, 2005, and 2010). Recurring costs will be incurred annually at the end of each year. (For more precise estimates of the timing of burden and costs to participants and EPA under the first three years of the acid rain permit program, see the Information Collection Request for Allowance Transfers, Energy Conservation and Renewable Energy Allowances, Acid Rain Permits, and Emissions Reporting Under the Clean Air Act Amendments Title IV.)

Because the first phase of the permit program is federally operated, this analysis assumes that no state burden will be incurred until the year 2000 (although in actuality states will develop personnel and procedures for program implementation during the 1992 to 1995 time period, and will be reviewing Phase II permits beginning in 1996).

4.5.3 Costs Associated with Permit Program Administration

Administrative burden costs to operate the Title IV acid rain permits program are incurred by EPA alone under the first phase of the permit program and by both EPA and state authorities that have delegated authority for the permit program under the second phase (beginning January 1, 2000). Administrative costs in this analysis account only for direct costs incurred once permitting

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40 Burden estimates for the Title V Regulatory Impact Analysis were provided by EPA.

41 These decreases in burden will be offset by increases in burden for units which were not affected for NO_x during Phase I and which may need to submit their applications for Phase II NO_x compliance at a later date than their general permit applications as specified in section 407(f). For sources with such units, the permit will be modified to include the NO_x requirements.

authorities begin accepting applications and issuing permits: Indirect costs related to program development, program monitoring, enforcement, and overhead have not been included because estimates of the burden and costs associated with these activities are still uncertain.

First Phase

The primary <u>non-recurring</u> tasks performed by EPA under the first phase of the permit program will be reviewing permit applications, notifying the public and affected states, and issuing proposed and final permits. The primary <u>recurring</u> activity performed by EPA under this phase will be reviewing quarterly and annual compliance certifications. Quarterly compliance certifications, other than the monitoring reports discussed in that section, will be submitted only for some units using a few of the specific compliance options. This burden is, therefore, speculative and is considered to be very small. Reviewing an initial permit application and issuing a permit is estimated to take an average of 60 hours. Reviewing certificates of representation is estimated to require one hour per occurrence. Reviewing quarterly and annual compliance certifications is estimated to take four hours per occurrence.[42] Therefore, the burden to EPA to administer the first phase of the permit program is estimated to be 65 hours per source the first year and 4 hours annually for subsequent years for each source. If 110 sources submit certificates of representation, permit applications and annual compliance certifications, EPA's permitting effort will be about 8,470 hours over five years (6,710 hours will be incurred the first year and 440 hours annually in the subsequent four years). EPA is also expected to incur costs in training state staff and for state program oversight. Some of these costs, though related to the second phase of the permit program, will be incurred during the first phase and are therefore included in the costs of the first phase. EPA estimates that training will require approximately two FTEs for two to three years; for simplicity, these costs are shown in Exhibit 4-14 as though they all occur during the first year. Program oversight is estimated to require roughly 10 FTEs (one in each of the ten EPA regions) for the entire period of the first and second phase. At 2,080 hours per FTE per year, training and oversight will require a total of 114,400 hours during the first phase. Assuming EPA's hourly rate is about $34 per hour, the total cost to EPA to administer the first phase of the permit program will be about $4,193,000. EPA's level of effort and costs under this phase of the permit program are presented in Exhibit 4-14.

Second Phase

Under the second phase of the permit program, states will have primary responsibility for reviewing initial permit applications and proposed compliance plans, notifying states that are within 50 miles of a source, issuing permits, transmitting copies of proposed permits and final permits to EPA, and processing permit revisions. These activities will be non-recurring over the 5-year life of the permits. Reviewing an initial permit application and proposed compliance plan and issuing a permit is estimated to take on average 60 hours. Notifying EPA and notifying applicable states are estimated to require two hours per occurrence for a total of four hours per source.[43] The primary recurring activity performed by states under this phase will be reviewing quarterly and annual compliance certifications. Reviewing quarterly and annual compliance certifications is estimated to

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42 The burden to EPA for processing permit revisions is uncertain and will depend upon the number and nature of the revisions. Because of the flexible compliance planning options available to sources at the time of permit application, and because of the flexible revision procedures proposed, EPA estimates the burden to EPA for permit revisions will be minimized. Permit revisions are optional and the quantity unknown. Therefore, an estimate of the burden associated with permit revisions had not been included.

43 The burden to states for processing permit revisions will be less significant on a per source basis than for EPA during Phase I because the program is greatly simplified. (See the previous footnote.)

EXHIBIT 4-14
Administrative Burden and Costs to EPA Under the First Phase of the Permit Program

Tasks	Hours Per Occurrence		Total Hours[a]		Total Burden Over Five Years	Total Costs Over Five Years[b]
	Initial	Recurring	First Year	Annually Subsequent Years		
1. Review certificates of representation and issue completeness notices.	1		110		110	$4,000
2. Review permit application, notify the public and affected states, and issue proposed and final permit.	60		6,600		6,600	$224,000
3. Review annual compliance certification		4	440	440	2,200	$75,000
4. Training State Staff			10,400		10,400	$354,000
5. Oversight of State Programs			20,800	20,800	104,000	$3,536,000
TOTAL			38,350	21,240	123,310	$4,193,000

a Assumes 110 sources are required to obtain permits.
b 1990 dollars. (Costs have been rounded to the nearest thousand dollars.)

take four hours per occurrence. Therefore, the burden to states as primary administrators of the second phase of the permit program is estimated to be 68 hours the first year and 4 hours annually for subsequent years for each source. If 727 Phase II sources and 100 new power plants submit permit applications and proposed compliance plans to state permit authorities, the total state effort will be about 66,987 hours over one 5-year permitting cycle (53,755 hours will be incurred the first year and 3,308 hours annually in subsequent years). Assuming that state administrative costs are equivalent to EPA costs (about $34 per hour), the total cost to states over one five-year permitting cycle are estimated to be about $2,277,000.

In its oversight role under the second phase of the permit program, assuming that all states will have approved permit programs, EPA will perform the non-recurring task of reviewing proposed permits issued by states. Reviewing a proposed permit is estimated to take 40 hours. If a total of 827 Phase II sources and new power plants submit permit applications and proposed compliance plans, EPA's total effort for permit review will be about 33,080 hours.

EPA's oversight of state programs will continue in the second phase, with one FTE in each of ten regions throughout the phase for a total of 104,000 hours for each five year permit cycle.[44] At $34 per hour, the cost of oversight for each five year permit cycle will total $3,536,000. At $34

44 Preliminary EPA estimate.

per hour. EPA's total costs over one five-year permitting cycle are expected to be about $4,661,000. In making these estimates, EPA assumes that no states will default.

The burden and costs to states and EPA for one five-year permitting cycle under the second phase of the permit program are presented in Exhibit 4-15. Based on the assumptions regarding the time frame of this analysis and a five-year permit life, burden and costs will be incurred for two full permitting cycles plus those for the first year of a third cycle (in the year 2010) during the period of this analysis. Therefore, the total labor burden to states and EPA under this phase is 523,212 hours over 11 years; the total costs over 11 years are estimated to be about $17,789,000.

EXHIBIT 4-15
Administrative Burden and Costs to States and EPA
For a 5-Year Period Under the Second Phase of the Permit Program[a]

Tasks	Hours Per Occurrence		Total Hours[b]		Total Burden Over Five Years	Total Costs Over Five Years[c]
	Initial	Recurring	First Year	Annually Subsequent Years		
States:						
1. Review certificates of representation and issue completeness notices	1		827		827	$28,000
2. Review permit application, notify EPA, the public, and affected states and issue proposed and final permit	60		49,620		49,620	$1,687,000
3. Review annual compliance certification		4	3,308	3,308	16,540	$562,000
STATE TOTAL			53,755	3,308	66,987	$2,277,000
EPA:						
1. Review proposed permit	40		33,080		33,080	$1,125,000
2. State program oversight			20,800	20,800	104,000	$3,536,000
EPA TOTAL			53,880	20,800	137,080	$4,661,000
OVERALL TOTAL			107,635	24,108	204,067	$6,938,000

[a] Assumes all 48 contiguous states have delegated permit programs.
[b] Assumes 827 sources (727 Phase II sources and 100 new power plants) are required to obtain permits.
[c] 1990 dollars. (Costs have been rounded to the nearest thousand dollars.)

Summary of Administrative Burden to States and EPA

The total administrative burden (first and second phases) of the acid rain permit program to states and EPA over the period of this analysis is summarized in Exhibit 4-16. The costs of the program to states and EPA over the period of this analysis are summarized in Exhibit 4-17. The aggregate burden to states and EPA is estimated to be 585,324 hours. As shown in Exhibit 4-18, the total costs to states and EPA are estimated to be about $21,731,000; the present value of these costs from 1995 through 2010 will be about $15,654,000 at a discount rate of three percent.[45] The average annualized costs per source to states and EPA are estimated to be about $7,600 under Phase I and $1,700 under Phase II.

EXHIBIT 4-16
Summary of the Administrative Burden to States and EPA
For the Acid Rain Permit Program

January 1, 1995 through December 31, 2010
(Hours)

Authority	First Phase[a]		Second Phase[b] (First 5 Years)		Second Phase[b] (Second 5 Years)		Total[c]
	Total First Year	Total Subsequent Four Years	Total First Year	Total Subsequent Four Years	Total First Year	Total Subsequent Four Years	
EPA	38,350	84,960	53,880	83,200	53,880	83,200	451,350
States			53,755	13,232	53,755	13,232	133,974
TOTAL HOURS	38,350	84,960	107,635	96,432	107,635	96,432	585,324

a Assumes 110 sources are required to obtain permits.
b Assumes 827 sources (727 Phase II sources and 100 new power plants) are required to obtain permits.
c Includes first year burden hours that will be incurred in the year 2010 during the third 5-year cycle under the second phase of the permit program.

4.5.4 Costs Associated with Program Participation

The primary non-recurring tasks performed by program participants to obtain permits under either phase of the permit program will be rule interpretation and compliance planning, information collection and analysis, designation of a representative of the owners and operators of each unit at a source, and permit application and proposed compliance plan development. Interpreting the rule and compliance planning is estimated to require 60 hours.[46] Collecting and analyzing relevant information is also expected to require on average 60 hours.[47] Designating a representative of the owners and operators of each unit at a source is estimated to take 50 hours.[48] Assembling the permit application and developing a proposed compliance plan is estimated to take on average 200 hours.[49] The principal recurring activity performed by program participants will be submitting

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45 EPA assumption. Costs are discounted back to January 1, 1992.

46 EPA estimate.

47 EPA estimate.

48 EPA estimate.

49 EPA estimate.

EXHIBIT 4-17
Summary of the Costs to States and EPA
For the Acid Rain Permit Program

January 1, 1995 through December 31, 2010
(Thousands of 1990 Dollars)

Authority	First Phase[1]		Second Phase[2] (First 5 Years)		Second Phase[2] (Second 5 Years)		Total[3]
	Total First Year	Total Subsequent Four Years	Total First Year	Total Subsequent Four Years	Total First Year	Total Subsequent Four Years	
EPA	1,304	2,889	1,832	2,829	1,832	2,829	15,347
States			1,828	450	1,828	450	6,384
TOTAL COST	1,304	2,889	3,660	3,279	3,660	3,279	21,731

[1] Assumes 110 sources are required to obtain permits.
[2] Assumes 827 sources (727 Phase II sources and 100 new power plants) are required to obtain permits.
[3] Includes first year costs that will be incurred in the year 2010 during the third 5-year cycle under the second phase of the permit program.

annual compliance certifications. (Some participants may incur an additional burden for quarterly reporting associated with the use of certain compliance options; however, this burden is optional, speculative, and expected to be very small.) Compliance certification is estimated to take 16 hours annually.[50]

If 110 sources participate in the permit program during the first phase, the total administrative burden will be about 66,370 hours over five years. Given the breakdown for each task between managerial, technical and secretarial hours as presented in the ICR, the cumulative total administrative cost to all 110 participants over the first phase of the permit program will be about $2,843,000.

If 827 Phase II sources (including new power plants) participate in the second phase of the permit program, the total burden to participants will be about 431,720 hours over a five-year permitting cycle. Given the breakdown for each task between managerial, technical and secretarial hours as presented in the ICR, the five-year total administrative costs to participants under the second phase of the permit program will be about $18,183,000. Assuming that two second phase permitting cycles and the first year of a third cycle will be completed within the time frame covered by this analysis, total administrative costs to permit program participants under this phase will be about $43,556,000.

The level of effort and costs to permit program participants are presented in Exhibit 4-18. The total administrative costs to participants for the 16-year period of this analysis will be about $46,399,000. In present value costs, the total administrative cost to participants will be about

[50] EPA estimate.

EXHIBIT 4-18
Administrative Burden and Costs to Participants Under the Acid Rain Permit Program

January 1, 1995 through December 31, 2010

Tasks	Hours Per Occurrence		Hours Per Source Per Permit Cycle		Total Hours		Total Burden[c]	Total Costs[d]
	Initial	Recurring	First Year	Annually Subsequent Years	Phase I[a]	Phase II[b] (One Cycle)		
1. Select a designated representative	35		35		11,900	28,945	98,735	$4,713,895
2. Prepare permit application	96		96		10,560	79,392	248,736	10,640,926
3. Apply for a reduced utilization plan	26		26		780	5,850	6,630	294,525
4. Apply for a substitution plan	8		8		160	1,200	3,760	171,550
5. Apply for a Phase I extension	56		56		896	0	896	39,792
6. Annual compliance certification		66	66	66	36,300	272,910	636,702	26,201,242
7. Excess Emissions		20	0	0	0	0	0	0
8. Permit Revisions		21	21	21	5,775	43,418	101,295	4,337,459
TOTAL	NA	NA	NA	NA	66,371	431,715	1,096,754	$46,399,389

[a] Assumes 340 entities (including 230 affected under Phase II but not under Phase I) designate a representative, 110 Phase I units apply for a permit, 30 sources apply for a reduced utilization plan, 20 sources apply for a substitution plan, and 16 sources apply for a Phase I extension. 110 sources submit an annual compliance certification, no sources have excess emissions because the incentives for compliance are so great, and 55 sources submit permit revisions.

[b] Assumes 827 sources (727 Phase II sources and 100 new IPPs) select a designated representative and apply for permits, 225 sources apply for a reduced utilization plan, 150 sources apply for a substitution plan, 827 sources submit an annual compliance certification, no sources have excess emissions because the incentives for compliance are so great, and 414 sources submit permit revisions.

[c] Equals to the sum of hours for (1) Phase I, (2) two full cycles under Phase II, and (3) the first year of the third cycle of Phase II (the year 2010).

[d] 1990 dollars.

$31,877,000 at a discount rate of three percent.[51] The average annualized costs per source to participants are estimated to be about $4,500 under Phase I and $3,200 under Phase II.

The total annualized administrative costs to respondents as well as EPA and states is summarized in Exhibit 4-19.

EXHIBIT 4-19
TOTAL ANNUALIZED ADMINISTRATIVE COSTS FOR THE ACID RAIN PERMIT PROGRAM

January 1, 1995 through December 31, 2010
(Thousands of 1990 Dollars)[a]

Authority	First Phase[b] (1995-1999)	Second Phase[c] (2000-2010)
EPA	$854	$1,025
States	$0	$792
Participants	$590	$4,040
TOTAL	$1,444	$5,857

[a] Costs rounded to the nearest thousand dollars.
[b] Assumes 110 sources are required to obtain permits.
[c] Assumes 827 sources are required to obtain permits.

4.6 ENERGY CONSERVATION AND RENEWABLE ENERGY

This section presents estimates of the level of effort and costs to utilities and EPA associated with obtaining and distributing allowances from the Conservation and Renewable Energy Reserve.

4.6.1 Background

Although the principal purpose of Title IV of the Clean Air Act is to reduce acid rain by requiring reductions in emissions of SO_2 and NO_x, it is also the purpose of this title to encourage energy conservation and pollution prevention as a long-range strategy for reducing air pollution and other adverse effects of energy production and use. As an incentive for electric utilities to (1) implement energy conservation measures and (2) use renewable energy, section 404(f) of Title IV establishes provisions for qualifying electric utilities to receive allowances for SO_2 emissions avoided through either of these two options. That is, for each ton of SO_2 emissions avoided by an electric utility through the use of qualified energy conservation measures or qualified renewable energy, the

[51] EPA assumption. Costs are discounted back to January 1, 1992.

utility shall be allocated a single allowance.[52] Allowances will be allocated on a first-come-first-served basis for energy saved by qualified conservation measures or generated by qualified renewable energy during the period between January 1, 1992 and December 31, 2000;[53] up to a total of 300,000 allowances for all utilities will be allocated from the Conservation and Renewable Energy Reserve. No allowances will be allocated for energy conservation measures or renewable energy that were operational before January 1, 1992.

To qualify to receive allowances for emissions avoided, an electric utility will have to meet the following requirements:

- Costs for the qualified energy conservation measures or qualified renewable energy are being paid directly by the electric utility or through purchase from another entity;

- Emissions of SO_2 avoided through the use of qualified energy conservation measures or qualified renewable energy are quantified according to EPA guidelines; and

- A least cost energy conservation and electric power plan is being implemented to the maximum extent practicable.[54]

In order to receive allowances for emissions avoided, each electric utility must submit to EPA (or the appropriate state regulatory authority) an application to receive allowances from the Conservation and Renewable Energy Reserve.[55] The application must include the following information:

- Designation of the qualified energy conservation measures implemented and the qualified renewable energy sources used for purposes of avoiding emissions during the previous calendar year;

- Verification of (1) installation of energy conservation measures and the energy savings attained,[56] and (2) plant operation using renew-

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[52] Under Title IV, a qualified energy conservation measure is defined as "a cost effective measure that increases the efficiency of the use of electricity provided by an electric utility to its customers;" qualified renewable energy is defined as "energy derived from biomass, solar, geothermal, or wind." Neither is to result in a net increase in SO_2 emissions. Illustrative lists of qualified energy conservation measures and renewable electric energy resources will be provided in EPA's Energy Conservation and Renewable Energy Reserve regulations.

[53] Because allowances will be awarded retrospectively, the earliest date on which applications for allowances will be accepted is January 1, 1993.

[54] A least-cost energy conservation and electric power plan must (1) contain a long-term resource plan which integrates demand-side and supply-side resources, (2) allow for public participation in the planning process, and (3) be approved by the appropriate state regulatory or rate-making authority.

[55] Only state-regulated electric utilities will submit applications for allowances to the state regulatory authority for review and approval. Electric utilities whose retail rates are not subject to the jurisdiction of a state regulatory authority will submit their applications directly to EPA for approval.

[56] A certification of energy savings methods and calculations will be included as part of the verification.

The model analyzes the effects of allowance trading and banking by including the possibility of allowance transactions as part of each power plant's strategy. For instance, in addition to various strategies discussed in the next section that could reduce a power plant's SO_2 emissions, the plant's operators could choose to purchase allowances instead. Alternatively, the plant could be equipped with scrubbers that would more than meet its emissions reduction targets; the extra allowances that would be generated as a result could either be sold at the market price or banked for future use. Each of these new strategies has a cost that will depend on the market price for allowances. Again, the model assumes that the lowest-cost strategies will be chosen across the utility system and calculates total costs by adding up the costs for each plant.

While the model shows clearly that the use of the allowance system can lower the costs of control substantially on a nationwide basis, it should be noted that both the allowance system and the cost savings it provides depends on the existence of credible mechanisms to ensure that emissions reductions and allowances are tracked and recorded fairly and accurately. Without these mechanisms, whose costs are described in sections 4.2, 4.3, 4.4, and 4.5, none of the cost savings shown in the section would be possible. For this reason, the cost savings described here can be attributed in large part to the elements of the Acid Rain Program concerning the administration of the allowance system, the auctions, direct sales and IPP guarantees, permits, and emissions monitoring.

A more detailed discussion of the Coal and Electric Utilities Model is presented in Appendix 4A.

4.1.1 Sulfur Dioxide Reduction Strategies and Their Costs

The increase in costs due to the acid rain title and the cost savings associated with the implementation regulations depend on the types of SO_2 reduction strategies likely to be employed by affected units and the market impacts associated with these strategies. The major types of reduction strategies and their likely impacts on costs are discussed below.

Installing Pollution Control Equipment

One major strategy for reducing SO_2 emissions is to install "scrubbers" or pollution control equipment. Equipment costs are functions of the type of control technology used as well as the SO_2 removal efficiency associated with the technology. The installation of pollution control equipment results in higher capital and operating costs. The use of the equipment also increases fuel costs; the operation of scrubbers, for example, results in additional steam and electricity requirements.

Switching to Lower Sulfur Coals

Switching to lower sulfur coals reduces SO_2 emissions, but results in higher costs because delivered low sulfur coal prices are typically higher than delivered high sulfur coal prices at most power plants. This is particularly true for many plants located in states in the Midwest where high sulfur coals are available locally while low sulfur coal supplies must be obtained from outside the state. Furthermore, increased demand for low sulfur coals will tend to push up prices for all users of low sulfur coal, as coal that is more expensive to mine is brought into the market to meet the demand. On the other hand, falling demand for high sulfur coals will tend to push high sulfur coal prices down as production is concentrated in low-cost mines. Thus, while power plants using large amounts of lower sulfur coals face increases in their fuel costs, many power plants that plan to use higher sulfur coals (because they are using or planning to use scrubbers to reduce emissions from these coals) will probably experience a reduction in their fuel costs.

able energy and the energy generation attributable to renewable energy input;[57]

- Calculations of the number of tons of emissions avoided (and allowances sought) by implementing conservation measures or using renewable energy; and

- Demonstration of qualification to receive allowances for emissions avoided. (The requirements to qualify to receive emissions are listed above.)

As applications are received by EPA, they will be registered chronologically by daily postmark. Within 30 days of receipt, each application will be reviewed to determine whether it meets all the necessary criteria to receive allowances from the Conservation and Renewable Energy Reserve. Utilities with qualifying applications will be allocated allowances until the Reserve is depleted.

If a sufficient number of allowances remain in the Reserve, each utility with a qualifying application will be allocated the number of allowances for which it applied. In the event that the number of allowances remaining is less than the amount for which the next qualifying applicant has applied, the applicant will receive the number of allowances remaining in the Reserve. In the event that the Reserve becomes over-subscribed by more than one applicant on a single day, the allowances remaining in the Reserve will be distributed on a *pro rata* basis to the applicants.

4.6.2 Assumptions

Estimates of the labor burden and costs associated with obtaining and distributing allowances from the Conservation and Renewable Energy Reserve are based on the assumptions below.

Participation

Predicting the number of utilities that will apply for allowances from the Reserve is difficult. According to a research project sponsored by the Electric Power Research Institute, about 40 percent of all electric utilities are expected to implement energy conservation programs before the year 2000.[58] Based on this expectation, as many as 145 electric utilities could file applications for allowances from the Reserve each year.[59] The actual number of utilities that apply for allowances, however, could vary significantly depending on the marginal value of Reserve allowances to utilities relative to the application costs to receive allowances. Because of the uncertainty regarding the number of utilities that will apply for allowances, cost estimates are presented in ranges. For this analysis, it is assumed that 40 to 125 applications will be submitted per year and that, on average, only one application for allowances will be submitted by any one utility in a particular year.[60]

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[57] Copies of certified plant operation records showing energy generation, plant size, and hours of operation during the applicable calendar year are required to verify plant operation using renewable energy.

[58] Electric Power Research Institute (EPRI) CU-6953, Impact of Demand-Side Management on Future Customer Electricity Demand: An Update, September, 1990.

[59] ICF estimate which assumes that one application would be submitted per utility for each year allowances from the Reserve are requested.

[60] EPA estimate.

Timing of Costs

This analysis covers the period from January 1, 1992, through December 31, 2010; the last date on which allowances from the Reserve may be available is January 2, 2010 (determined by statute). Because allowances will be awarded retrospectively for energy saved by qualified conservation measures or generated by qualified renewable energy after January 1, 1992 (and before December 31, 2000), the earliest date on which applications for allowances will be accepted is January 1, 1993. This analysis assumes that costs to applicants and EPA associated with obtaining and distributing allowances will be incurred at the end of the year, beginning in 1993.

The time period over which costs will be incurred depends not only on the number of applications for allowances that are completed and submitted, but also on the number of allowances requested per application (which is nearly impossible to predict) or projections of when the Reserve will be depleted. Based on estimates of the overall annual demand-side affect of conservation on future electricity demand from 1990 through 2010 provided in the EPRI report,[61] the Conservation and Renewable Energy Reserve will be depleted by the end of the year 2,000, if not sooner.[62] Therefore, this analysis assumes that at the high estimate of 125 applications per year, the Reserve will be depleted in eight years with each utility on average applying for 300 allowances. At the low estimate of 40 applications per year, assuming the average number of allowances for which each utility will apply is the same as under the high estimate (*i.e.*, about 300), allowances from the Reserve will be available through the last day of the program on January 2, 2010.

4.6.3 Costs Associated with Program Administration

Exhibit 4-20 depicts the annual burden and costs to EPA associated with distributing allowances from the Conservation and Renewable Energy Reserve. Tasks that will be performed by EPA related to the distribution of allowances from the Reserve include the following: (1) register applications and review applications for completeness; (2) perform substantive reviews of applications to determine whether all necessary criteria to receive allowances are met; and (3) transfer allowances from the Reserve or notify applicants of their failure to qualify for allowances from the Reserve. EPA estimates that registering applications and reviewing applications for completeness will require about 0.5 hour per application, performing substantive reviews of applications will take 2 hours per application, and transferring allowances from the Reserve or notifying applicants will take 0.5 hours per application. Assuming it will take EPA about 3 hours to process each application and transfer allowances (or notify applicants), the total administrative burden to EPA associated with distributing allowances from the Reserve will range between 2,160 hours over 18 years and 3,000 hours over eight years for processing 40 and 125 applications per year, respectively. At a cost of $34 per hour, the total cost to EPA will range between $73,440 and $102,000. At a discount rate of three percent,[63] the present value of these costs will be about $54,000 and $87,000 for processing 40 and 125 applications per year, respectively.

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61 See footnote 65.

62 ICF estimate.

63 EPA assumption. Costs are discounted back to the beginning of 1992.

EXHIBIT 4-20
Annual Administrative Burden and Costs to EPA
For Conservation and Renewable Energy Allowances[a]

Tasks	Burden Hours Per Application	Cost Per Application[b]	40 Applications Per Year[c]		125 Applications Per Year[d]	
			Total Burden (Hours)	Total Cost[e]	Total Burden (Hours)	Total Cost[e]
1. Register application and review application for completeness	0.5	$17	20	$680	62.5	$2,125
2. Perform substantive review of application	2	68	80	2,720	250	8,500
3. Transfer allowances from the Reserve or notify applicants	0.5	17	20	680	62.5	2,125
TOTAL:	3	$102	120	$4,080	375	$12,750

a Assumes the earliest date on which applications will be submitted is January 1, 1993.
b Based on an average rate of $47 per hour.
c Assumes applications will be submitted and processed for 18 years without depleting the Reserve.
d Assumes applications will be submitted and processed for 8 years, depleting the Reserve in the year 2000.
e 1990 dollars.

4.6.4 Costs Associated with Program Participation

Exhibit 4-21 depicts the annual participant burden and costs associated with obtaining allowances from the Conservation and Renewable Energy Reserve. Each utility applying for allowances from the Reserve will be required to perform the following tasks: (1) designate energy conservation measures implemented and renewable energy sources used to avoid emissions; (2) verify installation of energy conservation measures and plant operation using renewable energy and resulting benefits; (3) calculate the tons of emissions avoided; and (4) demonstrate qualification to receive allowances for emissions avoided. Because most states collect information on these activities from utilities already, the primary burden to utilities will be that associated with assembling and submitting to EPA the application to receive allowances from the Reserve. Assuming it will take each utility on average about 80 hours to assemble and submit an application to receive allowances from the Reserve to EPA,[64] the total burden to respondents will range between 57,600 hours over 18 years and 80,000 hours over eight years for assembling and submitting 40 and 125 applications per year, respectively. The total cost to utilities applying for allowances from the Conservation and Renewable Energy Reserve will range between $1,717,200 and $2,385,000. At a discount rate of three percent, the present value of these costs will be about $1,274,000 and $2,032,000 for assembling and submitting 40 and 125 applications per year, respectively.

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64 EPA estimate.

EXHIBIT 4-21
Annual Administrative Burden and Costs to Participants for Conservation and Renewable Energy Allowances[a]

Tasks	Burden Hours Per Application	Cost Per Application[b]	40 Applications Per Year[c]		125 Applications Per Year[d]	
			Total Burden (Hours)	Total Cost[e]	Total Burden (Hours)	Total Cost[e]
Assemble and submit an application to receive allowances from the Reserve						
Managerial	15	794	600	$31,760	1,875	$99,250
Technical	25	911	1,000	36,440	3,125	113,875
Secretarial	40	680	1,600	27,200	5,000	85,000
TOTAL:	80	$2,385	3,200	$95,400	10,000	$298,125

a Assumes the earliest date on which applications will be submitted is January 1, 1993.

b Based on total hourly compensation of $52.96 for managerial staff; $36.43 for technical staff, and $17.00 for secretarial staff. These figures were derived by updating the rates developed for the Comprehensive Assessment Information Rule (CAIR) to June 1991 using the Employment Cost Index (the initial CAIR rates are from a May 28, 1987 memorandum from Jeff Carnes of Centaur Associates to Brian Muehling of EPA).

c Assumes applications will be submitted and processed for 18 years without depleting the Reserve.

d Assumes applications will be submitted and processed for 8 years, depleting the Reserve in the year 2000.

e 1991 dollars.

4.7 SUMMARY OF COSTS

In general, the statute without allowance trading imposes substantial costs for SO_2 reductions, but relatively minor implementation costs. The allowance trading made possible by the implementation regulations reduces substantially the cost of SO_2 reductions. The implementation regulations themselves, however, will result in some costs which will offset the savings from trading. Estimates of these regulatory costs are summarized first, to allow a clearer comparison of the costs of the implementation regulations to the costs of the statute and the savings from trading.

Exhibit 4-22 summarizes the costs presented in sections 4.2 through 4.5 of this chapter. As the table illustrates, the majority of the costs consists of costs associated with allowance transaction and CEMS. The costs of the auction, direct sale, IPP written guarantee, permit, and energy conservation and renewable energy programs constitute a small fraction of the total costs.

Exhibit 4-23 places the implementation costs presented above into context by comparing them to the total costs of the statute and the savings provided by allowance trading.

EXHIBIT 4-22
COSTS OF IMPLEMENTATION REGULATIONS
(Millions of 1990 dollars)[a]

	Low Scenario	High Scenario
Allowance Transactions and Tracking	$204	$406
Auctions, Sales, and IPP Written Guarantees	2	7
CEMS[b]	2,395	2,395
Permits	68	68
Conservation and Renewable Energy	1	2
Total Costs	$2,670	$2,878

a These are present value costs, discounted to 1992 at 3 percent per year; capital costs annualized at 7 percent per year.
b Assumes Option 5 costs.

EXHIBIT 4-23
INCREMENTAL COSTS AND COST SAVINGS
(Billions of 1990 dollars)[a]

	Costs of Absent Regulation Case (incremental to pre-statute)[b]	Costs of Regulatory Case (incremental to pre-statute)[b]	Cost Savings of Regulatory Case (incremental to absent regulation)[b]
SO_2 Reductions	$19.1 to $30.9	$9.5 to $17.1	$9.6 to $13.8
Implementation[c]	$2.5	$2.7 to $2.9	-$0.2 to -$0.4
Total	$21.6 to $33.4	$12.2 to $20.0	$9.4 to $13.4

a These are present value costs, discounted to 1992 at 3 percent per year; capital costs are annualized at 7 percent per year.
b Ranges cover EPA Low Scenario and High Scenario.
c Includes transactions costs; costs of auctions, direct sales, and IPP written guarantees; CEMS costs; and permit costs.

The center column of Exhibit 4-23 shows the total costs of the statute and the regulations to be between $12.2 and $20.0 billion, depending on the scenario assumed. Of this total, about $3 billion are costs incurred because of the regulations. Costs in the absence of regulations, by contrast, would be between $21.6 and $33.4 billion under the low and high scenarios, respectively. The difference in costs between the regulatory and absent regulations cases, \$9.4 to \$13.4 billion, represents the cost savings for SO_2 reductions made possible by the regulations.

The last column of the exhibit shows in detail the incremental savings provided by the regulations. The allowance trading regulations allow the regulated community to save a total of between \$9.6 and \$13.8 billion in achieving the SO_2 emissions reductions mandated in the statute. These cost savings are offset to a small extent, between \$0.2 and \$0.4 billion, by the costs of implementation (net of the \$2.5 billion cost of CEMS required by the statute itself). The net savings provided by the allowance trading regulations still total \$9.4 billion in the low scenario, and \$13.4 billion in the high scenario.

CHAPTER 5
IMPACTS OF COST CHANGES

This chapter assesses the effects of the costs and cost savings presented in Chapter 4 from four different perspectives. The first section of the chapter evaluates the impacts of the costs and cost savings attributable to the Acid Rain Program on the regulated community as a whole. The second section examines regional differences in costs and savings. The third section provides a qualitative overview of the "secondary" impacts of the Acid Rain Program--that is, the effects on entities outside the regulated community. The final section examines the differential effects of the program on smaller entities.

5.1 Impacts on the Regulated Community

This section evaluates the costs identified in Chapter 4 in terms of their impacts on entities in the regulated community. The impact measures considered in the section include effects on costs, rates, sales, and net incomes.

5.1.1 Impacts on Regulated Utilities

The annual Acid Rain Program costs of between \$1.0 and \$5.1 billion and the cost savings of \$0.4 to \$2.8 billion, while large in absolute terms, are relatively small compared to the roughly \$200 billion annual costs of generating electricity.[1] As shown in Exhibit 5-1, the average costs (on a "levelized" basis) of generating electricity rise 0.5 to 0.7 percent under the absent regulations case for 1995 under the high and low scenarios, respectively.[2] [3] Average cost impacts for 2000, 2005, and 2010 are greater as a consequence of Phase II, but still less than two percent of total costs. As with any average, these average cost estimates take into account utilities with more significant cost impacts (*e.g.*, as high as ten percent or more in a few cases) along with many others that are largely unaffected or experience cost reductions under the absent regulations case. The highest cost impacts are likely to be among utilities with fairly small high sulfur coal-fired plants; these cases are discussed in section 5.4 of this chapter.

The regulations provide cost reductions of less than a third of one percent of total generation costs in Phase I and generally less than one percent in Phase II, as shown in Exhibit 5-1. Savings of this magnitude amount to between one-fourth and two-thirds of the costs in the absent regulations case, depending on the year and the scenario.

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1 See Exhibit 4-2 of Chapter 4.

2 In addition to cost changes related directly to emissions reductions, costs to utilities include transactions costs (under the regulatory case); costs of CEMS; costs of permits: and the costs of participation in auctions, direct sales, and IPP guarantees. These costs are insignificant compared to the cost impacts of SO_2 reductions (i.e., much less than one tenth of one percent of electricity generation costs).

3 Levelized cost impacts for a given year reflect changes in fuel and operating costs plus changes in capital costs that have been spread out over the life of the purchased capital equipment. Actual capital expenditures will be higher in the early years (and lower in later years) than suggested by the levelizing procedure.

The impacts of these cost changes on the financial health (in terms of net income) of the utilities is likely to be very small. As discussed in Chapter 2, utility rates are tightly regulated. Cost increases, so long as they are the result of prudent decisions, are generally passed through to electricity consumers as price increases. The utilities' margins are thereby insulated to a large degree from both cost increases and decreases.

EXHIBIT 5-1
AVERAGE NATIONWIDE PERCENTAGE CHANGE IN ELECTRICITY COSTS
(percent)

	COSTS OF ABSENT REGULATIONS CASE (incremental to pre-statute case)		COSTS OF REGULATORY CASE (incremental to pre-statute case)		COST SAVINGS OF REGULATORY CASE (incremental to absent regulations case)	
	Low Scenario	High Scenario	Low Scenario	High Scenario	Low Scenario	High Scenario
1995	0.5	0.7	0.3	0.4	0.2	0.3
2000	1.3	1.9	0.5	0.8	0.8	1.1
2005	1.4	1.7	1.0	1.2	0.4	0.5
2010	0.9	1.5	0.4	1.1	0.5	0.4

In addition, because utilities are structured as regulated monopolies (as discussed in Chapter 2), they are generally protected from losing customers to competitors with lower rates. While customers may reduce their total consumption of electricity in response to price increases (and, conversely, may increase consumption as prices fall), they tend to be relatively insensitive to price changes.[4] Consumers' responses to price increases or decreases in the range of one-half to one percent may be considered insignificant by the utilities experiencing these responses.

Cost changes cannot always be passed through entirely, however, because Public Utility Commissions may disallow portions of the costs if it is determined that they were not prudently incurred. The regulations will reduce the utilities' exposure to potential financial difficulties by minimizing the increase in their costs. Further, the regulations will tend to reduce impacts on utilities that arise from lags in the rate-setting process. Because cost increases are not always quickly translated into price increases, they can sometimes hurt profitability. By reducing cost impacts, the regulations can minimize the effects of the lags in the rate-setting process.

Some smaller utilities faced with the need to make capital investments in order to comply with the Acid Rain Program's requirements may have difficulty arranging financing for the investments. Capital costs are typically recovered through rate increases over the life of the purchased equipment.

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4 The observation that most customers are insensitive to changes in electricity rates may be changing, given the increasing deregulation of the industry in the new power generation markets, where there is sometimes considerable competition from industrial cogeneration, self-generation, and independent power producers.

However, the capital costs associated with SO_2 controls are relatively small compared to the total capital spending and cash flow in the utility sector, capital-related problems are likely to be relatively uncommon. To the extent that there are problems with capital availability, however, the flexibility afforded by the regulations should make a positive contribution. By purchasing allowances rather than emissions control equipment, a utility can avoid or delay a large investment.

5.1.2 Impacts on Independent Power Producers

The impacts of the statute and the regulations on IPPs are very difficult to predict in a quantitative manner. As discussed in Chapter 3, the statute makes no provision for any emissions by IPPs or other new units (except for units brought on line by the end of 1995). Rather than make the unrealistic assumption that new (post-1995) plants would be held to zero emissions in the absence of implementation regulations, EPA assumed for the purposes of the absent regulations case that IPPs would be allowed to enter the industry, but would be held to a strict emissions limit. Because the estimates of the cost changes for IPPs would be very sensitive to the specific emissions limit assumed in the absent regulations case (*e.g.*, if the emissions limit for IPPs were set equal to the existing new source performance standard, the statute would appear to have no impact on IPPs at all), EPA has not attempted to analyze IPP costs and savings quantitatively.

Qualitatively, the absent regulations case appears to create serious uncertainties for IPPs and in the extreme could mean the elimination of all new fossil fuel fired IPPs. The regulatory case, on the other hand, offers IPPs the opportunity to enter the industry through the purchase of allowances. In addition, the IPP guarantee program (as well as the auctions and direct sales programs) are likely to reduce the costs and impacts of the Acid Rain Program still further.

5.2 Distribution of Impacts by Region

The impacts discussed in the previous section are nationwide averages, and do not represent the impacts faced by utilities in any one state or region. Given the significant differences in fuel mixes across regions and the differential effects of SO_2 controls on power plants using different fuels, regional impacts can be expected to vary widely.

Regional differences in impacts, measured in terms of percentage changes in the cost of electricity generation, are shown in Exhibits 5-2a and 5-2b. Exhibit 5-2a shows cost increases by census region under the absent regulations case in the low and high scenarios (as described in Chapter 3). (The areas covered by the ten census regions are shown in Exhibit 5-3.) Costs for each of the four years analyzed in the RIA are presented in separate columns. Exhibit 5-2b presents the cost savings provided by the implementation regulations.

Under the high scenario, changes in costs in 1995 range from 0.0 percent in the Pacific region up to 1.5 percent in the East North Central. In general, this reflects the location of Phase I-affected power plants: there are no affected units in the Pacific region, for example, and proportionately the most affected capacity in the East North Central region. Cost savings in 1995 are as low as a <u>negative</u> 0.4 percent in the Upper South Atlantic region -- in other words, costs are temporarily <u>higher</u> with the implementation regulations in that region and at that time as a result of capital investments made during Phase I under the regulations -- these investments pay off in later years, resulting in net savings to the region. Savings in 1995 range as high as 1.3 percent in the West South Central.

Percentage impacts also vary widely within each region from one point in time to the next, generally reflecting the increasing reductions requirements between Phase I and Phase II. In the West North Central region, for instance, under the high scenario, costs rise from 0.9 percent in 1995 to 3.1 percent in 2000 before declining somewhat. In general, the regional cost and cost savings mirror the pattern of national costs over time discussed above. In Phase I (1995), the regional percentage increase in costs in the absent regulations case and the cost savings in the regulatory case are the lowest, reflecting the relatively moderate level of emissions reductions required in 1995. In Phase II (2000 - 2010), the cost impacts and cost savings are generally higher, reflecting the more significant emissions reduction requirements in the later years.

An important underlying pattern in these results appears if the variations over time are removed by averaging the percentage changes in costs over the entire forecast period (1995 - 2010). Exhibit 5-4 shows the approximate percentage cost changes over the period 1995 through 2010 under the absent regulations and regulatory cases for the high scenario. The census regions are listed in order of cost impacts, from lowest to highest. In general, the regions with the highest cost impacts are those with the most affected coal capacity and greatest required SO_2 reductions. While the savings provided by the implementation regulations do not follow exactly the same pattern, the four regions with the lowest costs do appear to have lower savings. Similarly, the four regions with the highest cost impacts under the absent regulations case all have relatively large savings under the regulatory case.

Exhibit 5-5 shows that the group of regions with the highest costs under the absent regulations case form a relatively cohesive geographic unit. The map also shows that the four high cost regions (the West North Central, East North Central, East South Central, and Upper South Atlantic--heavily shaded) are clustered around the upper Midwest. The four regions with low costs and generally lower savings under the regulatory case (the Pacific, Middle Atlantic, Lower South Atlantic, and New England regions--lightly shaded) are found in the periphery. Two regions with moderately high costs and high savings (the Mountain and West South Central regions) lie between the periphery and the center.

The high cost area of Exhibit 5-5 corresponds roughly to the region of greatest dependence on medium-to-high sulfur coal for electricity generation. In addition, these regions are generally required by the statute to achieve the greatest degrees of SO_2 reductions in absolute and percentage terms. It is not surprising that the rigid SO_2 limits of the absent regulations case would impose the greatest costs on this midwestern region. In addition, the greater flexibility allowed under the regulations (including both emissions trading and banking of extra technology allowances) can be expected to allow significant savings to this same group.

Trading programs can generate considerable profits for affected units or sources whose emissions are already low (in some cases below their allowance allocations), because of their ability to generate and sell allowances in the high cost area of Exhibit 5-5.

EXHIBIT 5-2a
PERCENTAGE CHANGE IN ELECTRICITY COSTS
FOR ABSENT REGULATIONS CASE INCREMENTAL TO PRE-STATUTE CASE
(percent)

	1995		2000		2005		2010	
	Low[a]	High[b]	Low[a]	High[b]	Low[a]	High[b]	Low[a]	High[b]
NEW ENGLAND	0.2	0.1	0.4	0.7	0.2	0.8	0.1	0.5
MIDDLE ATLANTIC	0.3	0.3	1.0	1.8	0.5	1.6	0.1	1.2
UPPER SOUTH ATLANTIC	0.8	0.7	3.0	4.4	2.5	3.1	1.2	2.2
LOWER SOUTH ATLANTIC	0.2	0.4	0.8	1.4	2.0	1.1	0.4	0.9
EAST NORTH CENTRAL	1.2	1.5	2.1	2.5	2.1	2.5	2.0	3.1
EAST SOUTH CENTRAL	0.8	1.0	2.6	3.3	2.7	2.4	1.0	2.0
WEST NORTH CENTRAL	0.8	0.9	2.1	3.1	2.9	2.5	2.4	2.7
WEST SOUTH CENTRAL	0.0	1.3	0.5	1.2	0.4	1.9	0.4	1.1
MOUNTAIN	-0.3	0.1	1.4	1.6	2.6	2.0	1.3	1.8
PACIFIC	0.0	0.0	0.2	0.1	0.1	0.3	0.3	0.3
TOTAL U.S.[c]	0.5	0.7	1.3	1.9	1.4	1.7	0.9	1.5

[a] Low refers Low Scenario.
[b] High refers to High Scenario.
[c] Total U.S. is an average across regions, weighted by electricity consumption.

EXHIBIT 5-2b

PERCENTAGE COST SAVINGS OF REGULATORY CASE INCREMENTAL TO ABSENT REGULATIONS CASE
(percent)

	1995		2000		2005		2010	
	Low[a]	High[b]	Low[a]	High[b]	Low[a]	High[b]	Low[a]	High[b]
NEW ENGLAND	0.2	0.2	0.5	0.3	0.5	0.1	0.3	0.1
MIDDLE ATLANTIC	0.0	0.0	0.7	0.9	-0.2	0.3	-0.1	0.2
UPPER SOUTH ATLANTIC	-0.3	-0.4	1.8	2.6	0.4	0.5	0.2	0.2
LOWER SOUTH ATLANTIC	0.3	0.3	0.6	0.5	0.4	0.2	0.5	0.2
EAST NORTH CENTRAL	0.2	0.3	1.1	1.9	0.6	0.5	0.8	0.9
EAST SOUTH CENTRAL	0.6	0.5	1.5	1.5	0.7	0.7	0.4	0.4
WEST NORTH CENTRAL	0.7	0.5	1.1	1.1	0.9	0.8	1.2	0.8
WEST SOUTH CENTRAL	-0.1	1.3	0.5	1.1	0.5	1.1	0.4	0.4
MOUNTAIN	-0.1	0.0	1.2	1.0	1.4	1.5	1.1	0.9
PACIFIC	0.0	0.0	0.2	0.2	0.2	0.2	0.3	0.2
TOTAL U.S.[b]	0.2	0.3	0.8	1.1	0.4	0.5	0.5	0.4

[a] Low refers Low Scenario.
[b] High refers to High Scenario.
[c] Total U.S. is an average across regions, weighted by electricity consumption.

EXHIBIT 5-3
U.S. CENSUS REGIONS

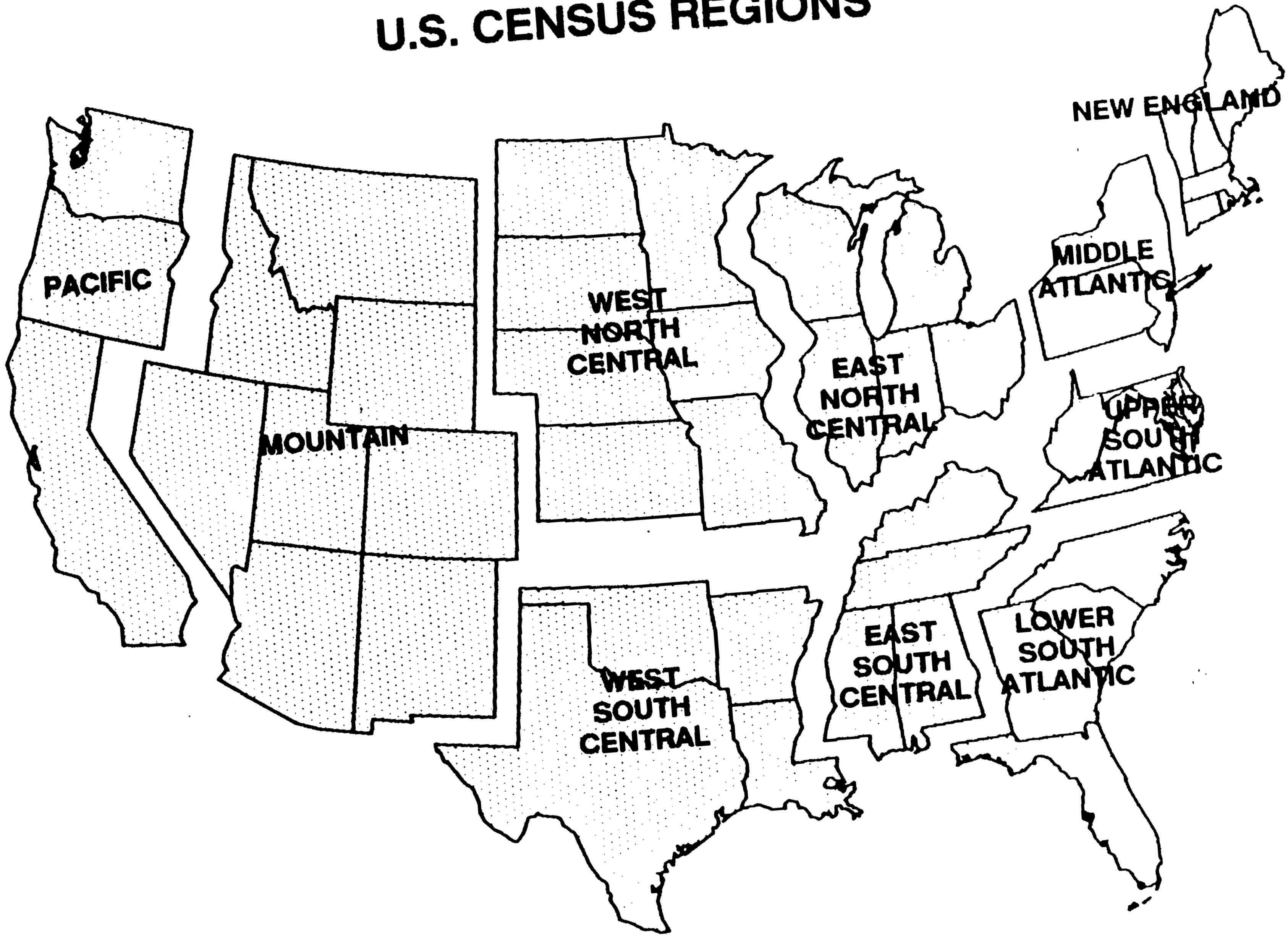


EXHIBIT 5-4
Costs of Absent Regulations and Savings with Regulations from 1995 through 2010 as a Percentage of Generation Costs[a]
(percent)

	REGION[b]	COSTS	SAVINGS
LOW COST, LOW SAVINGS	PACIFIC	0.2	0.2
	NEW ENGLAND	0.5	0.2
	LOWER SOUTH ATLANTIC	0.9	0.3
	MIDDLE ATLANTIC	1.1	0.3
MODERATE COST, HIGH SAVINGS	MOUNTAIN	1.3	0.8
	WEST SOUTH CENTRAL	1.5	1.1
HIGH COST, HIGH SAVINGS	EAST SOUTH CENTRAL	2.0	0.7
	WEST NORTH CENTRAL	2.1	0.8
	EAST NORTH CENTRAL	2.3	0.7
	UPPER SOUTH ATLANTIC	2.4	0.5

a Costs and savings were estimated by averaging estimates from 1995, 2000, 2005, and 2010 for the high scenario.
b Regions listed in order of lowest costs to highest costs.

5.3 Secondary Effects

Title IV's direct effects reach only the nation's electric utilities and IPPs. As discussed in section 5.1, however, the utilities are not likely to absorb much of the impacts of the Acid Rain Program. Instead, the impacts are likely to be passed on to other sectors of the economy: electricity consumers, the coal industry, railroads and other transportation providers, oil and gas producers, and emissions control manufacturers.

Although the other sectors have not been analyzed in detail in this analysis, EPA has attempted to identify the sectors that will experience the most significant secondary impacts, and made qualitative assessments of the nature and direction of the effects.

5.3.1 Impacts on Electricity Users

As discussed, the costs of emissions reductions are likely to be passed on through increases in electricity rates. The increased costs will have very small impacts on the typical consumer:

electricity is a minor part of household budgets, and the changes in electricity bills will be small even in percentage terms. Consumption will drop marginally as prices rise, as consumers respond to avoid some of the increased costs. Reducing electricity usage, though, will impose real costs on consumers, as they spend more to purchase energy-efficient appliances, and make other electricity-saving choices. These effects, as well, will be relatively small for the typical energy user.

The increased electricity rates attributable to acid rain compliance could have more significant impacts on those industries that are unusually large consumers of electricity, particularly to the extent that these consumers are served by utilities that are significantly affected. Some examples of large industrial sources that rely heavily on electricity include steel and aluminum producers. Substantial increases in the cost of electricity for these producers would probably lead to significant increases in the price of their final products, and a loss of market share and domestic employment. As a worst case, electricity costs constitute roughly 25 percent of the costs of the primary aluminum industry, the nation's most electricity-intensive industry. Even if this industry buys all of its electricity from a heavily-affected utility (*e.g.*, one with rate impacts of 10 to 15 percent), its total cost of producing aluminum would rise by only 25 percent of 10 to 15 percent, or two to four percent in all. For most industries, the cost impact will be much smaller.

The cost savings provided by allowance trading will tend to mitigate whatever negative effects on industrial competitiveness and employment occur in the absent regulations case.

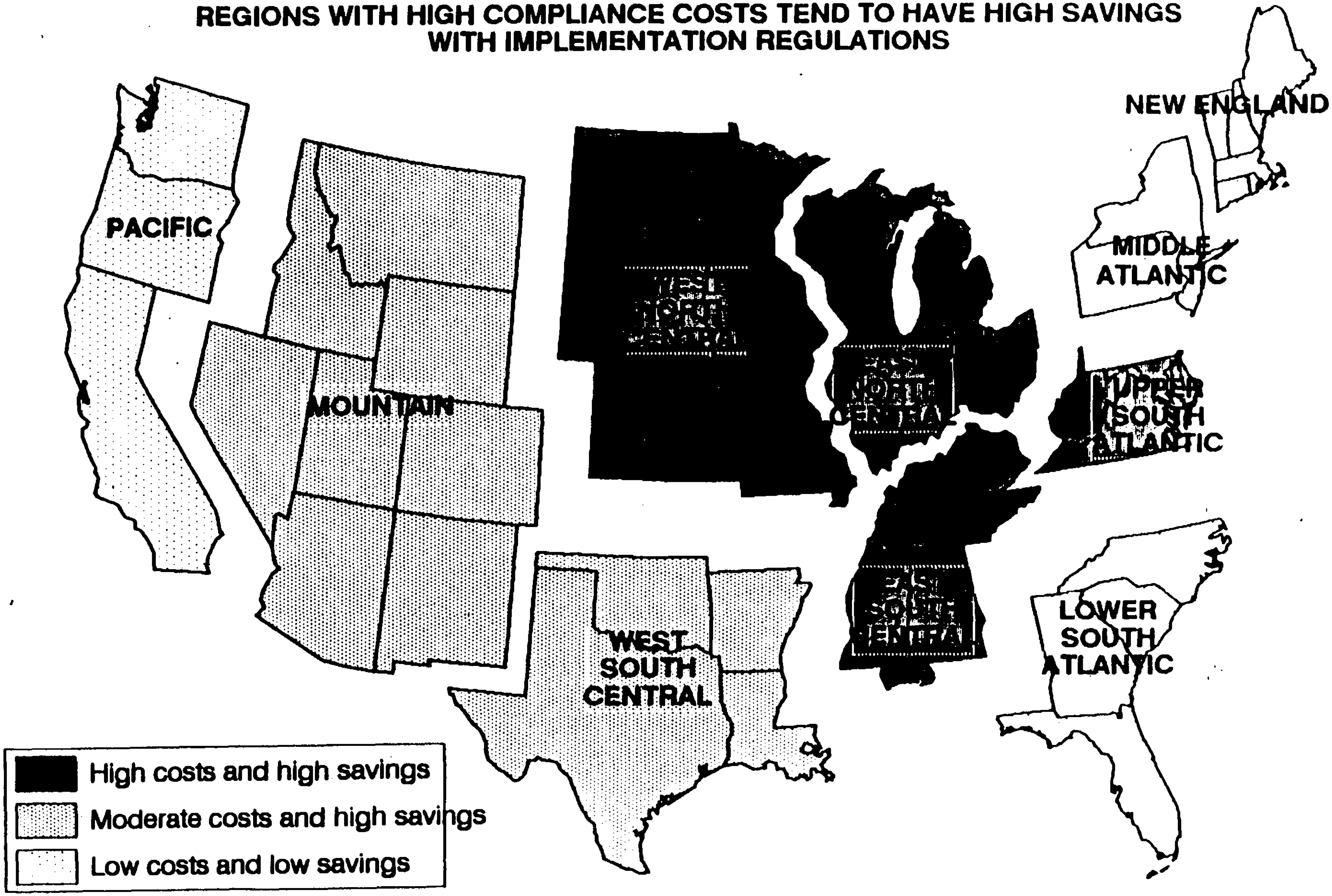
5.3.2 Coal Industry Impacts

Neither the absent regulations case nor the regulatory case is likely to result in a significant change in total consumption of coal (measured in Btu) for electricity generation. Considerable changes in the type of coal consumed may take place, as consumption shifts from high to low sulfur coals. This shift may result in increased coal production in low sulfur coal regions (*i.e.*, Central and Southern Appalachia and the West) and a decrease in coal production in high sulfur regions (*i.e.*, Northern Appalachia and the Midwest). Producers of low sulfur coal will benefit from both increased sales volumes and increased prices; high sulfur coal producers, on the other hand, will experience decreased sales and prices.

Under the absent regulations case, shifts from high to low sulfur coals would be mitigated by retrofit scrubbing. Many utilities will need to install scrubbers because switching to low sulfur coal would not lower their emissions enough to meet their individual emissions targets. Once they have installed scrubbers, these sources are likely to continue to burn high sulfur coal because of its lower cost and because scrubbers remove enough SO_2 to meet emissions targets. Because the implementation regulations allow many utilities to avoid scrubbing if they switch to low sulfur coal, coal production losses in high sulfur regions are likely to be higher in the regulatory case than in the absent regulations case in 2005 and 2010.

The net effect of acid rain compliance on total U.S. coal mining employment is not expected to be dramatic because total U.S. coal production is not expected to decrease significantly. The regional effect on coal mining employment, however, is expected to be quite significant. Large coal mining employment losses are expected in Northern Appalachia and the Midwest. Corresponding employment gains are expected in Central and Southern Appalachia and the West. These employment gains are expected to be somewhat smaller than the losses in high sulfur regions because output per worker is higher in the low sulfur regions (especially the West). This implies that the net change in coal mining employment attributable to the Acid Rain Program is likely to be negative.

EXHIBIT 5-5
REGIONAL IMPACTS
REGIONS WITH HIGH COMPLIANCE COSTS TEND TO HAVE HIGH SAVINGS WITH IMPLEMENTATION REGULATIONS



Regional shifts in coal mining employment would also be mitigated by retrofit scrubbing. As a result, employment losses in high sulfur regions are likely to be somewhat less in the absent regulations case (in which there is more retrofit scrubbing) than in the regulatory case in 2005 and 2010.

5.3.3 Transportation Impacts

Changes in regional coal production caused by the Acid Rain Program will affect the railroad industry as well as the coal industry. The total volume of rail shipments of coal (measured in ton-miles) is expected to increase under the absent regulations case. This is because many eastern power plants currently rely largely on coal from mines in their own region. As these power plants switch to lower sulfur coals, from Central and Southern Appalachia and the West, coal must be hauled greater distances. Railroads heavily involved in the high sulfur transportation market will experience decreased shipment demands, while railroads positioned to haul low sulfur coals will experience increased shipment demands.

Increased retrofit scrubbing will mitigate some of the increase in ton-miles hauled because scrubbed sources will continue to rely on less expensive regional coals. As a result, ton-mile increases are expected to be smaller in the absent regulation case than in the regulatory case in 2005 and 2010.

Barge transportation, like rail transportation, is expected to increase as a result of the Acid Rain Program. For example, there will be increased shipments of western coal moved by barge on the Great Lakes to Michigan, Wisconsin, Illinois, and Indiana. Truck transportation of coal, on the other hand, is expected to decline. This is because truck transportation is generally only economical for short hauls (*i.e.*, to power plants that rely on local high sulfur coals). Therefore, as more power plants switch to low sulfur coals they will rely more heavily on rail and barge transportation.

5.3.4 Impacts on Oil and Gas Use

Some utilities that are currently burning oil are expected to switch to gas in order to reduce SO_2 emissions (the SO_2 emission rate of natural gas is virtually zero). Many of these sources are currently "oil/gas fungible" (*i.e.*, are able to switch quickly and easily between oil and gas) and have access to gas pipelines. Others (*e.g.*, some sources in New England, New York and Florida) have limited pipeline access or face regional pipeline capacity limitations in the near term and would thus incur additional costs to switch from residual oil to natural gas. As a result, gas producers are likely to experience increased demand (and may receive higher prices) at the expense of oil producers.

After 2000 under the high scenario, gas utilization is expected to be somewhat higher in the regulatory case than in the absent regulations case because oil/gas steam sources in some regions may find it profitable to over-control (*i.e.*, reduce emissions below target levels) and sell or use the resulting allowances elsewhere.

5.3.5 Impacts on Manufacturers of Emissions Control Equipment

The Acid Rain Program will lead to increased retrofit scrubbing at coal-fired power plants. The increase in retrofit scrubbing will, in turn, lead to increased revenues for scrubber manufacturers, as well as increased revenues for lime/limestone producers (lime/limestone are common catalytic reagents used in wet scrubbing systems). This could also lead to increased employment in the air pollution equipment industry.

As mentioned earlier, more retrofit scrubbing is expected in the absent regulations case than in the regulatory case. This is because many sources cannot easily switch to low sulfur coals because (1) they are not easily accessible by rail, (2) they are "minemouth" plants (*i.e.*, located very near a coal mine and receiving their coal by truck or conveyer) or (3) they have boiler designs that are not compatible with eastern low sulfur coals.[5]

5.4 Impacts on Small Entities

This section provides an assessment of the differential effects of the regulations on small entities. The first subsection presents a description of the federal requirements for a small entity analysis. The next subsection provides a definition of a small entity for the purposes of this report and a characterization of the population of small entities. The third subsection presents estimates of the costs and savings under the absent regulations case and the regulatory case for six model utilities that, taken together, represent the most important characteristics of the small utility population. The fourth subsection discusses the potential differences between the impacts on small utilities that are owned by municipalities and other small utilities. Finally, the fifth subsection summarizes the conclusions of the small entity analysis.

5.4.1 Requirements for a Small Entity Analysis

Under the Regulatory Flexibility Act (RFA), EPA is required to analyze the impacts of proposed regulations to determine whether they will cause a significant impact on a substantial number of small entities.[6] Because the RFA does not provide concrete definitions of "small entity," "significant impact," or "substantial number," EPA has established guidelines setting the standards to be used in evaluating impacts on small businesses.[7] The guidelines specify that size definitions set by the U.S. Small Business Administration (SBA) should be used as the initial determination of a "small entity," but that EPA can use an alternative definition if it better captures the point at which entities are adversely affected simply because of their size. The guidelines further specify that a "substantial number" can be either a large fraction of the affected population of small entities or a large number of small entities. Finally, the guidelines set four criteria for determining whether impacts will be significant:

- Annual compliance costs increase total cost of production for small businesses by more than 5 percent;

- Compliance costs as a percentage of sales for small businesses are at least ten percent higher than compliance costs as a percentage of sales for large businesses;

- Capital costs of compliance represent a significant portion of capital available to small businesses; or

[5] For example, wet bottom and cyclone boilers require low ash fusion temperature coals and there are few low sulfur coals with these characteristics in the East.

[6] 5 USC 601.

[7] U.S. Environmental Protection Agency, Memorandum to Assistant Administrators, "Compliance with the Regulatory Flexibility Act," EPA Office of Policy, Planning and Evaluation, 1984 (no date).

- The requirements of the regulations are likely to result in closures of small businesses.

The net effect of the regulations will be to reduce the cost of meeting the objectives of CAA, and small entities are likely to be the primary beneficiaries of the costs reduction. However, an assessment of the impact of compliance with the implementation regulations compared to compliance with the statute by itself is included.

5.4.2 Definition of Small Entity

For purposes of this analysis, EPA has adopted the SBA definition that a "small" electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year.[8] Not all small utilities are affected by the acid rain title of CAA. Utilities will be unaffected if (1) all of their units are exempt (*e.g.*, units using non-fossil sources or existing simple gas turbines), or (2) they fall below statutory minimums for electric generating capacity (existing units smaller than 25 MW).

After excluding utilities exempt from the provisions of CAA, EPA has determined that about 105 of the 241 Phase II affected utilities (about 44 percent) are small.[9] [10] Collectively, affected small utilities accounted for about 5 percent of total 1988 electricity generation by affected utilities (*i.e.*, about 119 billion kilowatt-hours of electric power generation during 1988).

Characteristics of Small Utilities

Small utilities differ from large utilities in several important respects: (1) ownership; (2) generation mix; and (3) cost of achieving emissions reductions. Exhibit 5-6 shows the ownership patterns of all Phase II affected utilities, disaggregated by size. As shown in the exhibit, it is more common for small utilities to be operated by municipal governments than is the case for larger utilities: 60 percent (63 out of 105) of the small utilities whose generation is shown in Exhibit 5-6 are run by municipal governments, while the comparable figure for large utilities is only four percent (5 out of 132). Municipal governments operating their own small utilities are likely to administer small cities as well; thus, an analysis that examines the effects of the acid rain regulations on small utilities also serves as an examination of the effects on small affected municipalities.[11]

This section treats utilities as the unit of analysis, rather than individual power plants or individual generating units within power plants. The reason for concentrating on utilities is that they are separate financial entities, while power plants and generating units are owned (generally) by utilities. As a practical matter, smaller utilities tend to have only one power plant, and the analysis assumes that all units owned by a given utility will be affected by the regulations. To some extent,

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8 13 CFR 121.

9 In making this determination, EPA counted all individual operating companies that operate at least one affected unit. Because some of the operating companies are owned by one or more large utilities, the actual number of affected utilities and affected small utilities will both be smaller. Four affected utilities could not be characterized because their generation rates are unknown.

10 None of the Phase I affected utilities are considered small.

11 The assumption that small municipal utilities serve small municipalities is based on the fact that more than 60 percent (38 out of 63) of small municipal utilities are in cities with populations of less than 50,000. County and City Data Book, U.S. Bureau of the Census, 1988.

this assumption could overstate the impact of the program, since utilities with some unaffected generating units will face proportionately smaller changes in their costs.

EXHIBIT 5-6
OWNERSHIP CHARACTERISTICS OF AFFECTED PHASE II OPERATING UTILITIES, BY SIZE CATEGORY
(number of utilities)

	1988 Generation (billion kilowatt-hours per year)						
	Large Utilities			Small Utilities[a]			
Ownership	More than 20	10 to 20	4 to 10	1 to 4	0.5 to 1	Less than 0.5	Total[b]
Investor	35	29	41	19	1	5	130
Co-op	0	2	12	9	2	1	26
Municipal	1	1	3	15	2	46	68
Federal	2	3	3	2	1	2	13
Total	38	35	59	45	6	54	237

[a] Small utilities are defined by the Small Business Administration as utilities generating less than 4 billion kwh/yr.
[b] Total does not include two investor-owned, one co-op, and one municipal utility for which generation rates are unknown.
Source: National Allowance Data Base Version 1.0 and ICF Analysis of the Clean Air Act Amendments of 1990.

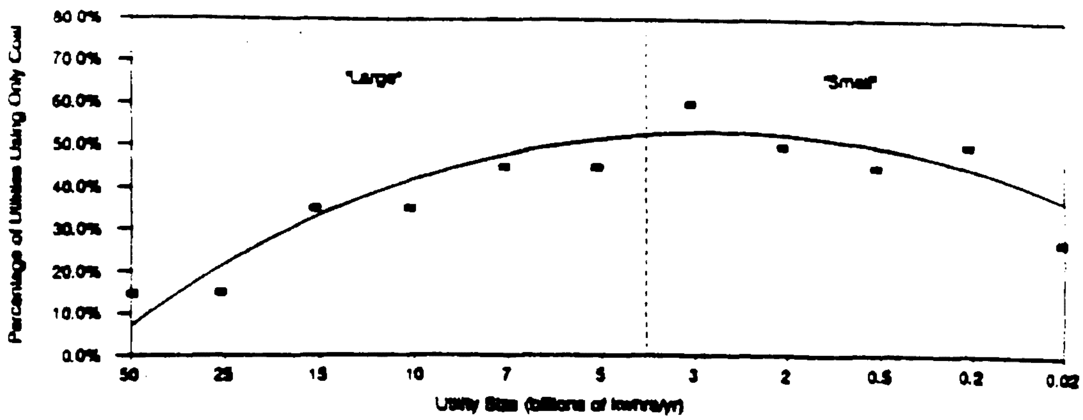
Exhibit 5-7 shows the types of fossil fuels used by utilities with different generation rates. As seen in the exhibit, smaller utilities are more likely to depend exclusively on either oil/gas or coal, rather than a combination of oil/gas and coal at different units. In addition, very small utilities are more dependent on oil and gas as opposed to coal.

A preliminary review of publicly available data and information on unit characteristics suggests that, all other things being equal, emissions from smaller power plants tend to be relatively costly to control. In other words, it is generally more expensive per kilowatt-hour (kwh) of electricity generated for a small plant to reach a given emissions target than for a large plant to reach the same target. This is believed to be true for several reasons. First, relative to larger units, smaller units typically require more fuel (measured in Btu) per kwh produced. Consequently, their costs of switching to higher priced, lower sulfur fuels will generally be higher per kwh produced than for larger units, even if they are able to switch to a lower sulfur fuel without any other cost. Second, smaller units are at a relative disadvantage if capital improvements are needed in order to allow the use of lower sulfur fuels. Smaller units cannot achieve the same "economies of scale" as larger units and thus incur higher capital costs per unit kwh. Also, because smaller units tend to be older than larger units, their shorter remaining useful lifetime over which to depreciate capital costs contributes to a higher cost per kwh produced. Third, designing equipment for smaller units that is comparable to equipment used at larger units is frequently more difficult, because smaller units generally have less space available for adding equipment.

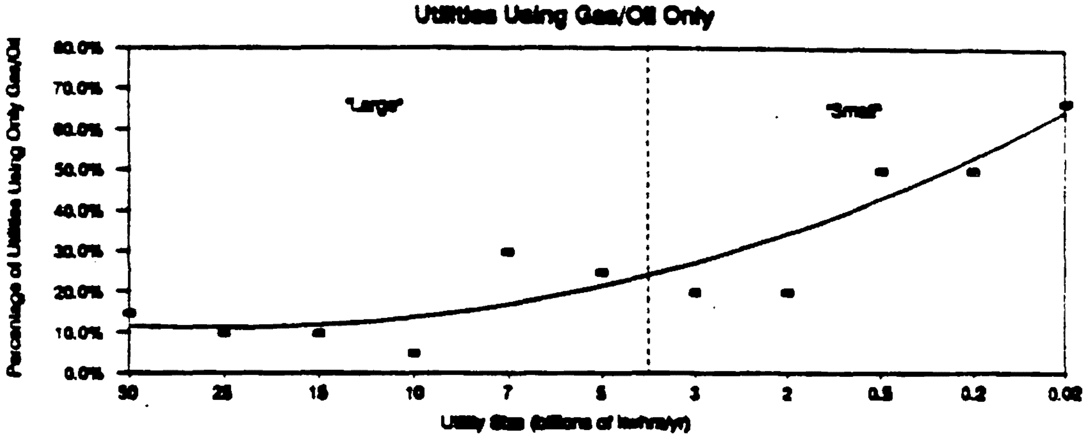
EXHIBIT 5-7

FUEL USE CHARACTERISTICS BY UTILITY SIZE

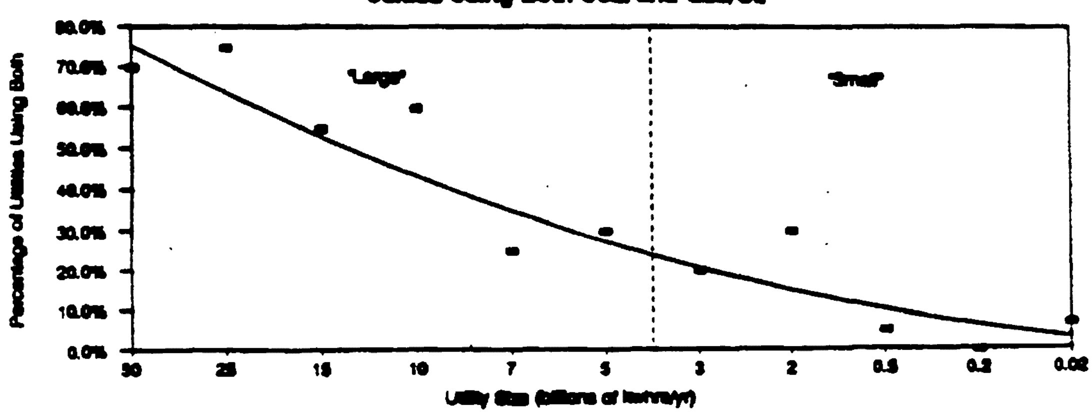
Utilities Using Coal Only



Utilities Using Gas/Oil Only



Utilities Using Both Coal and Gas/Oil



"Small" and "Large" refer to SBA definition of 4 Billion kwhrs/year

5.4.3 Estimation of Impacts of Statute and Implementation Regulations

This section presents analyses of how the total costs of the statute and the implementation regulations vary with utility sizes, fuel types, and ownership types. The costs due to the effects under the absent regulations case are compared to the effects under the regulatory case. Costs under the absent regulations case include the costs of SO_2 emissions reductions and the installation of basic CEMS. Estimated costs under the regulatory case include SO_2 emissions control costs as reduced by emissions trading and banking, plus the costs of transactions, additional CEMS monitoring requirements (including data reporting), and permits. Results are based on the high scenario in the year 2000, which is believed to provide a reasonable basis for evaluating maximum potential impacts of the regulations on small entities.

In examining effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. It was important to include model utilities using different fuel types because the cost of controlling SO_2 emissions for coal plants is different from the cost for oil or gas plants, and different allowance allocations are made depending on fuel type. There were also two factors considered in choosing model utilities of varying sizes. First, relatively smaller utilities would tend to experience greater impacts if they were subject to the same statutory provisions as relatively larger utilities. Second, it was necessary to include utilities of all sizes because the statute contains provisions which grant additional allowances to a subgroup of small utilities--those with high emissions rates, no power plants larger than 75 MW, and total fossil steam generating capacity below 250 MW. It was necessary to differentiate among utilities that were affected by these provisions and those that were not.[12]

To allow for the effects of utility size, EPA developed two sizes of model plants by first dividing the universe of small entities into four size groups; each group contains one-fourth of the affected small entities. EPA identified characteristics of the plants at the points dividing the size groups (*i.e.*, the utilities that were greater in size than 25, 50 and 75 percent of all small utilities, termed the lower quartile, median, and upper quartiles respectively). EPA then developed model plants that corresponded to the plants at the lower quartile and median points. EPA determined that utilities at the median were generally on the borderline of meeting the statutory requirements that provide additional allowances. Consequently, utilities at the median are about the smallest that are subject to the same level of stringency as large plants and are, therefore, likely to incur the largest impacts. Utilities at the lower quartile will be typical of the smaller utilities potentially eligible for additional allowances. The smallest existing units covered by the regulations are 25 MW, but new units less than 25 MW are also covered under some options. Under Option 5, units less than 25 MW will not be required to have CEMS and permits. Impacts on those units less than 25 MW are considered briefly in an attachment to this document.

To allow for differences across fuel types, two of the model utilities burn coal; two burn oil; and two burn natural gas. The two coal-fired utilities are relatively "dirty," with pre-statute emissions rates of SO_2 of about 5 lbs/mmBtu. The two oil-fired utilities have emissions rates of SO_2 of about 1.5 lbs/mmBtu, whereas the two gas-fired utilities have virtually no SO_2 emissions. The larger coal-fired utility has total (year 2000) generation of about 2.1 bkwh/yr (billion kwhs per year), which is about half SBA's current definition of a small utility and about 5 times as great as the median of all

[12] More detail on these provisions, and on the number of utilities affected by them, is provided in Appendix 5.

small utilities in 1988.[13] The larger gas-fired utility has a total generation rate of about 1.3 bkwh/yr. The larger oil-fired utility has a total generation rate of about 0.5 bkwh/yr. Each of the three smallest model utilities have generation rates of about 0.1 bkwh/yr. In the case of the larger oil and coal utilities, their total capacity exceeds 250 MW. Hence, they must effectively reduce their emissions to 1.2 lbs/mmBtu based on their baseline fuel consumption. The larger oil and coal utilities are worst-case examples because all of their units are assumed to be affected, and have to reduce emissions significantly at high unit costs. In contrast, the smaller coal and oil utilities have total capacity less than 250 MW and hence receive allowances equal to their current emissions levels (that is, their baseline times their current emissions rate) and are not forecast to experience any utilization increases in the future. Accordingly, they do not need to reduce their emissions.

Another important regulatory distinction relates to gas units of differing utilization patterns. As discussed in Chapter 4, gas and oil units used ten percent of the time or less (that is, "peaking" units) are permitted to use monitoring methods other than CEMS that will cut monitoring costs substantially. The model utilities assumed for this analysis concentrated on non-peaking units, since they are both more common and more likely to incur significant costs. In reviewing the results, however, it should be kept in mind that impacts for some small oil- and gas-fired units will be substantially lower than those presented here.

Results of Model Utility Cost Impact Analysis

Exhibit 5-8 shows the cost of the regulations in millions of dollars per year. Cost categories examined include the costs of SO_2 reductions; transactions costs associated with buying and selling allowances; costs of CEMS; and permit-related costs. Costs for the auctions, sales, IPP guarantees, and conservation and renewables are not included, as these are voluntary programs with minimal costs to participants.

Costs of SO_2 reductions are the incremental costs of acid rain controls, relative to the pre-statute case, under the absent regulations and regulatory cases. Costs for the model utilities were estimated using the results of the CEUM[14] and additional calculations to adapt the model's results to the model utilities that were constructed. The assumed responses of the utilities under the absent regulations case and the regulatory case are shown in Exhibit 5-9. Allowance trading and banking lead to cost savings (or no change) relative to the absent regulations case for each model utility; for the small oil utility and the two gas utilities, the allowance trading and banking system leads to net savings relative to the pre-statute case.

EPA has not made precise estimates of the costs of allowance transactions to individual small utilities. Instead, impacts have been estimated on the basis of relative values of transactions costs and volumes and the cost savings from trading and banking. A small utility's transaction costs per allowance traded are assumed to be four times higher than the industry average.[15] Transaction

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13 Generation rates are not strictly comparable, however, because the generation rate in 2000 incorporates estimates of utility growth.

14 ICF's Coal and Electric Utilities Model (CEUM) is a detailed linear programming, engineering-economic model that contains a coal supply segment, a transportation segment, an electric utility demand sector, transmission, and non-utility energy demand segments and is linked with databases and other supporting models. This model is the primary analytic tool used by ICF in analyses for EPA, other federal agencies, and private companies for proposed acid rain policy initiatives and bills.

15 See Appendix 4A.

costs for the industry as a whole are assumed to be three percent of the savings realized through allowance trading.[16] If the per-unit transaction costs for small entities are four times as great as for the industry as a whole, then transactions costs equal twelve percent (that is, four times three percent) of the savings from trading and banking. The costs shown in Exhibit 5-8 reflect a twelve percent transactions cost. (This is likely to be an overestimate for the largest small utilities, as their allowance transactions may be about as large as the average industry-wide transaction. If so, their transactions cost might be no higher than the industry average.) The auctions, direct sales, and IPP written guarantee program should help keep transactions down for small entities, as they are expected to aid in the development of a well-functioning market.

EXHIBIT 5-8
ESTIMATED COST OF THE ACID RAIN PROGRAM TO MODEL SMALL UTILITIES

Model Utility	Case	Cost (Millions of Dollars)				
		SO_2 Reductions	Transactions	CEMS	Permits	Total
Coal (more than 250 MW capacity)	Absent regulations	23.516		0.055	0.000	23.571
	Regulatory	7.296	1.946	0.109	0.003	9.355
	Difference	-16.220	1.946	0.055	0.003	-14.216
Coal (less than 250 MW capacity)	Absent regulations	0.000		0.055	0.000	0.055
	Regulatory	0.000	0.000	0.109	0.003	0.113
	Difference	0.000	0.000	0.055	0.003	0.058
Oil (more than 250 MW capacity)	Absent regulations	2.655		0.055	0.000	2.710
	Regulatory	1.845	0.097	0.125	0.003	2.070
	Difference	-0.810	0.097	0.070	0.003	-0.639
Oil (less than 250 MW capacity)	Absent regulations	0.000		0.055	0.000	0.055
	Regulatory	-0.062	0.007	0.125	0.003	0.074
	Difference	-0.062	0.007	0.070	0.003	0.019
Gas (more than 250 MW capacity)	Absent regulations	0.000		0.055	0.000	0.055
	Regulatory	-0.066	0.008	0.104	0.003	0.049
	Difference	-0.066	0.008	0.049	0.003	-0.006
Gas (less than 250 MW capacity)	Absent regulations			0.055	0.000	0.055
	Regulatory	-0.007	0.001	0.104	0.003	0.101
	Difference	-0.007	0.001	0.049	0.003	0.047

Source: ICF analysis.
All units are assumed to have capacity factors greater than ten percent.

The absent regulations case assumes costs for purchasing CEMS but no costs for data reporting. The cost of CEMS in the regulatory case assumes a variant Option 5, which is the

16 Exhibit 4-22 shows the high estimate of transactions costs to be $400 million, while Exhibit 4-23 shows the high estimate of savings from trading to be $13.8 billion. The transactions costs as a percentage of savings, then, are equal to $0.4 billion/$13.8 billion or about three percent.

proposed option.[17] It includes annual costs of $1,800 per source (based on Exhibit 4-10 on page 4-24) for data reporting in Phase II. Costs of permits are based on the total annualized Phase II costs to participants ($2,646,000) divided by the total number of sources (827) that are required to obtain permits (see Exhibit 4-19 on page 4-37).

EXHIBIT 5-9
ASSUMED RESPONSES OF MODEL UTILITIES

Model Utility		Absent Regulations Case	Regulatory Case
COAL	above 250 MW	Scrubs all units	Switches to low-sulfur coal and buys allowances
	below 250 MW	(No response)	(No response)
OIL	above 250 MW	Switches to gas	Buys allowances
	below 250 MW	(No response)	Sells allowances
GAS	above 250 MW	(No response)	May sell a few allowances
	below 250 MW	(No response)	May sell a few allowances

Source: ICF analysis of cost-effective responses.

The three smallest model utilities are worse off under the regulatory case than under the absent-regulations case. The increase in costs is moderately small (less than $60,000 per year) and is due largely to the additional CEMS requirements.

Exhibit 5-10 shows the results in mills (tenths of a cent) per kwh for small utilities compared to the industry as a whole. Although reliable electricity generation costs for the model utilities in the pre-statute case were not available, the results can be compared to the average price of electricity of roughly 60 mills/kwh.[18] For four model facilities (the two gas-fired facilities and the smaller coal and oil facilities) cost increases under the absent-regulations case are less than 1 mill/kwh, which is comparable to the overall cost to all utilities. This increase represents about one percent of the average price of electricity, and should cause minimal impacts. The difference in costs for these four facilities under the regulatory case are minimal as well.

For the larger coal and oil-fired model utilities, though, impacts in the absent regulations case are serious -- 5 to 11 mills/kwh, which is about ten to twenty percent of the approximately 60 mills/kwh value of the electricity generated. These utilities are helped significantly more by the implementation regulations than the industry average. After transactions costs, the trading provisions reduce the costs of SO_2 reductions to the larger model coal-fired utility by about 6.8 mills/kwh. The

17 The regulatory case does not fully reflect CEMS cost savings now incorporated into Option 5, and overstates CEMS costs by about 10 percent for gas-fired units and 25 percent for oil-fired units. The overall thrust of the results are not affected by these differences in cost estimates.

18 Edison Electric Institute Statistical Yearbook.

overall savings of the regulatory case is roughly 60 percent of the costs under the absent regulations case. For the larger oil-fired utility, the net cost savings of the trading provisions is about 1.2 mill/kwh; overall, the regulatory case is 25 percent less costly than the absent regulations case.

EXHIBIT 5-10
INCREASE IN ELECTRICITY GENERATION COSTS TO MODEL SMALL UTILITIES AND THE NATIONAL AGGREGATE FOR ALL UTILITIES -- YEAR 2000, HIGH SCENARIO

		Costs (mills per kwh)				
Model Utility	Case	Reductions	Transactions	CEMS	Permits	Total
Coal (more than 250 MW capacity)	Absent regulations	11.187	0.000	0.026	0.000	11.213
	Regulatory	3.471	0.926	0.052	0.002	4.451
	Difference	-7.716	0.926	0.026	0.002	-6.763
Coal (less than 250 MW capacity)	Absent regulations	0.000	0.000	0.391	0.000	0.391
	Regulatory	0.000	0.000	0.782	0.023	0.805
	Difference	0.000	0.000	0.391	0.023	0.414
Oil (more than 250 MW capacity)	Absent regulations	5.057	0.000	0.104	0.000	5.161
	Regulatory	3.514	0.185	0.238	0.006	3.944
	Difference	-1.543	0.185	0.134	0.006	-1.218
Oil (less than 250 MW capacity)	Absent regulations	0.000	0.000	0.421	0.000	0.421
	Regulatory	-0.477	0.057	0.961	0.025	0.566
	Difference	-0.477	0.057	0.541	0.025	0.146
Gas (more than 250 MW capacity)	Absent regulations	0.000	0.000	0.041	0.000	0.041
	Regulatory	-0.049	0.006	0.077	0.002	0.036
	Difference	-0.049	0.006	0.037	0.002	-0.004
Gas (less than 250 MW capacity)	Absent regulations	0.000	0.000	0.405	0.000	0.405
	Regulatory	-0.049	0.006	0.770	0.024	0.751
	Difference	-0.049	0.006	0.365	0.024	0.346
National aggregate[a]	Absent regulations	1.388	0.000	0.056	0.000	1.444
	Regulatory	0.587	0.009	0.061	0.001	0.658
	Difference	-0.801	0.009	0.005	0.001	-0.786

[a] National aggregate is estimated by dividing total cost by total generation.
Source: ICF analysis.
All units are assumed to have capacity factors greater than ten percent.

Even after the reductions in cost provided by the implementation regulations the impact on small coal- and oil-fired utilities is still significant. The regulatory cost to the larger coal-fired model utility of 4.5 mills/kwh represents more than seven percent of the 60 mills/kwh value of the electricity produced, whereas the regulatory cost to the larger oil-fired model utility of 3.9 mills/kwh represents less than 7 percent of the value of the electricity produced. About 36, or one-third of the 105 affected small utilities, could face impacts of up to this magnitude, although as noted the larger coal and oil model utilities represent worst case examples. The other two-thirds have regulatory impacts that are comparable to or less than the impacts on all utilities as a group. EPA believes that by implementing the trading provisions, it has provided all relief available under the statute to help the most affected small utilities. Costs of the CEMS and permit provisions represent a minor part of the overall cost to these utilities.

5.4.4 Impacts on Small Municipal Utilities

Exhibit 5-6 showed the strong association between small utilities and municipal ownership: almost all municipal utilities (63 of 68) are small, and a majority of small utilities (63 of 105) are municipal. Because of the large number of municipally-owned small utilities, it is important to consider whether the impacts of the Acid Rain Program will differ according to the ownership of the utilities.

The impacts of the Acid Rain Program could potentially differ between municipally-owned and investor-owned utilities for two reasons: if the same cost changes could have different impacts depending on the financial structure of the owners; or if the mix of sizes and types of power plants owned by municipalities is different than the mix owned by investors.

Of these two potential reasons for differing effects on municipally-owned utilities, EPA has considered only the second in detail. EPA has no reason to expect that the Acid Rain Program will affect power plant costs differently solely on the financial structure of the owner. The fact that municipally-owned utilities rely more heavily on borrowed capital (as opposed to equity capital) than do investor-owned utilities is not seen as likely to change the impacts of cost differences; if anything, the use of tax-exempt municipal bonds as a financing mechanism may provide municipally-owned utilities with a minor cost advantage. Combined with the lack of a profit incentive for municipally owned utilities, the net cost under the regulatory case to the consumer may well be smaller for municipally-owned utilities as compared to investor-owned utilities.

Because the size and fuel type of a utility has a significant impact on the costs of compliance, however, it is important to consider the mix of power plants owned by municipal utilities compared to investor-owned utilities and co-operatives. Exhibit 5-11 shows a breakdown of small affected utilities by capacity and fuel type for federally owned, investor-owned, municipally owned, and co-operative-owned utilities. Capacities are divided into those above and those below 250 MW, because those below 250 MW with substantial emissions are more likely to be eligible to receive additional allowances.[19] Fuel types are divided into coal, oil, and gas.

The power plants most affected under the absent-regulations case are likely to be those at utilities with capacities above 250 MW that burn coal or oil. As seen in the exhibit, a relatively small fraction of municipally-owned utilities (9 of 63, or 14 percent) fall into these categories. By contrast, most small investor-owned utilities (16 of 25, or 64 percent) fall into the categories likely to be most affected. Co-operatives are similar to investor-owned utilities in that a large fraction (8 of 12, or 67 percent) burn coal and have capacities greater than 250 MW. Thus, relatively few municipal utilities are likely to be seriously affected in the absent-regulations case, or to gain significantly under the regulatory case.[20]

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19 As seen in Appendix 5A, about 58 of the 66 utilities with less than 250 MW of fossil steam generating capacity are granted additional allowances, 17 because they meet statutory criteria of having an emissions rate of more than 1.2 lb/mmBtu and no individual unit greater than 75 MW capacity, and 41 because they have an emissions rate less than 1.2 lb/mmBtu.

20 Impacts on municipal utilities with new small generating units, given the exception for certain new units under 25 MW, are discussed separately in a brief attachment to this document.

EXHIBIT 5-11
FUEL USED AT SMALL UTILITIES BY TYPE OF OWNERSHIP

		Less than 250 MW Capacity		More than 250 MW Capacity		
Ownership	Fuel Type	Number	Percentage (of ownership)	Number	Percentage (of ownership)	Total
Co-operative	Coal	3	25%	8	67%	11
	Gas	1	8%	0	0%	1
Federal	Coal	1	20%	2	40%	3
	Oil	2	40%	0	0%	2
Investor	Coal	4	16%	14	56%	18
	Gas	0	0%	2	8%	2
	Oil	3	12%	2	8%	5
Municipal	Coal	25	40%	8	13%	33
	Gas	20	32%	2	3%	22
	Oil	7	11%	1	2%	8
Total		66		39		105

Source: ICF analysis.

5.4.5 Conclusions Regarding Small Entities

In conclusion, virtually all of the impacts on small businesses are caused by statutory provisions of CAA. Although EPA is considering regulations that are intended to mitigate some of the burden on small businesses (see the brief attachment to this document), the statutory provisions restrict the amount of relief that can be given. EPA's regulatory flexibility analysis is summarized in the following observations.

- The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be similar to the savings for larger utilities. Absolute savings measured in mills per kwh, on the other hand, will typically be greater for those small utilities that face significant costs than for larger utilities.

- Among small entities, most of the savings provided by the regulations will be concentrated among those utilities experiencing the largest cost increases under the absent regulations case: relatively larger small utilities burning coal and, to a lesser degree, oil.

- The auctions, direct sales, and IPP written guarantee programs are likely to have net positive impacts on small entities.

- The proposed CEMS regulations (Option 5) will impose disproportionate costs on small entities because they require the same equipment at all facilities regardless of size. The proposed regulations, however, would allow the use of monitoring methods other than CEMS for gas-fired units. This will mitigate the disproportionate impacts to some degree, because small utility plants are more likely to burn gas. Further mitigation of impacts for new small units is discussed in a brief attachment to this document.

- Permit regulations will impose greater costs per kwh on the smallest oil and coal utilities than on other utilities. The permit costs are mandated by the statute, and are thus not imposed by EPA.

- A relatively small percentage of affected municipally-owned utilities -- no more than 14 percent -- will face significant cost increases as a result of the Acid Rain Program.

CHAPTER 6
BENEFITS OF SO_2 REDUCTIONS

This chapter describes the benefits that are expected to result from the SO_2 reductions that would result under the acid rain program. Where possible, the beneficial effects have been expressed quantitatively; however, none of the effects have been expressed in terms of dollar values.

The five sections of this chapter discuss five areas in which acid rain is known or suspected to cause damage: Acid levels in surface water; visibility; human health; forests; and materials. Each section also discusses the extent to which the 10 million ton per year reduction in SO_2 emissions mandated by Title IV may be able to reduce these damages.

6.1 Acidification of Surface Water

A principal effect of acid rain (or more accurately, acidic deposition, which includes acid rain, snow, and fog, as well as gases and particulates) is increased acidity of lakes and streams.

Based on measurements taken under the National Surface Water Survey, it is estimated that four percent of the lakes in the United States larger than 10 acres and eight percent of streams are currently acidic.[1] These percentages represent hundreds of lakes and thousands of miles of streams. Acidic lakes and streams are even more prevalent in Canada than in the United States. The Canadian government reports that more than 14,000 lakes in Southeastern Canada are acidic due to acid deposition.[2] In addition, there are many more surface water bodies which become temporarily acidic at times of high acidic deposition capacity to neutralize acid, threatening biological life such as fish. Including these bodies triples the number of lakes and streams seriously affected by acidification.

SO_2 emissions have been identified as a principal cause of acid rain, which is estimated to be responsible for three-fourths of lake acidification and half of stream acidification.[3] Thus, significant reductions in SO_2 emissions can be expected to reduce the problem of surface water acidification. For example, analyses of the Adirondack region, which is particularly affected by acid deposition, showed that a 50 percent reduction in sulfate (a transformation product of SO_2) deposition would reduce the number of acidic lakes from the current level of 14 percent to 3 percent over a period of years in that area.[4] Other areas that would benefit from reduced SO_2 emissions include lakes and streams in New England, the Mid-Atlantic Highlands and Coastal Plain, the upper Midwest, the Southeastern Highlands, and Florida.[5]

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1 National Acid Precipitation Assessment Program (NAPAP). Integrated Assessment External Review Draft. August 1990.

2 "U.S. - Canada Air Quality Agreement Progress Report", March, 1992.

3 See footnote 1.

4 See footnote 1.

5 NAPAP Integrated Assessment, 1990.

Most acidified surface waters are unable to support fish or plant life. While there are species (yellow perch, for example) that are resistant to acid and can live in some acidic waters, sensitive species such as brook trout have been wiped out in many areas. The degradation of these habitats has many harmful effects, in reduced value to sport fishers as well as in the more intangible area of reduced biodiversity and the value our society attaches to ensuring that the natural environment can support wildlife. Acid sensitive species occur in all major groups of aquatic organisms including algae, zooplankton, invertebrates, fish and amphibians. Thus, by reducing SO_2 emissions, the Acid Rain Program is predicted to provide the benefits, such as a rich and diverse population of aquatic species, associated with restored capacity of surface water to support life by reducing acidic deposition and thereby reducing surface water acidification. The further and future acidification of surface waters, both due to chronic and episodic acidification, will also be substantially reduced in many areas by significant reductions in acid deposition.

6.2 Reductions in Visibility

Another important impact of SO_2 emissions is reduced visibility. Visibility degradation manifests itself as haze, which is particularly common in the eastern part of the United States. The link between increased levels of sulfate in the air and visibility reduction is firmly established in the scientific literature, and increased sulfate levels have, in turn, been found to be directly related to SO_2 emissions. Sulfates account for more than half of the visibility problem in the East and about a fourth of the problem in the West.[6]

Because a large part of the visibility degradation is caused by SO_2 emissions, reduced emissions translate almost immediately into improved visibility. The ten million ton reduction in SO_2 emissions mandated by Title IV is projected to increase visibility by about 30 percent in the eastern part of the United States.[7]

The increased visibility that would be provided by the SO_2 reductions in the acid rain program create two major types of benefits: increased safety and improved aesthetics. Increased safety may be manifested in terms of reduced accident rates for aircraft and motor vehicles. Improved aesthetics, particularly in national parks and other scenic vistas, are highly valued by the public. Improved visibility will affect national parks including the Great Smokey and Shenandoah Mountains in the east. Visitors to the parks and wilderness areas will benefit from improved visual range and increased ability to see form, texture and color in a view.

6.3 Effects on Human Health

SO_2 emissions, and especially air concentrations of acid sulfate aerosols, have been implicated by a growing body of evidence from epidemiological studies and laboratory studies of humans and animals as responsible for a variety of human health effects. Some studies directly relate acid aerosols to breathing problems in asthmatics, children, and other sensitive subpopulations. Acute exposures may result in wheezing, coughing and shortness of breath. Other studies implicate the effect of long-term exposure to acid aerosols on the development of chronic lung disease. Sulfate concentrations have been shown by one study to be associated with an increase in hospital admissions

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[6] See footnote 1.

[7] See footnote 1.

for respiratory ailments, and several researchers have suggested that sulfates are responsible for an excess in mortality.[8]

A number of inherent uncertainties exist in some of the analyses concerning the effects of SO_2 on human health, especially with regard to the association between sulfates and excess mortality. Consequently, definitive statements concerning the amounts and types of health effects caused by SO_2 are limited. Nevertheless, the consistent findings across several studies and indications of ongoing health studies support the belief that a reduction in SO_2 will result in a significant — and, for some health effects, immediate — reduction in adverse human health effects.

6.4 Effects on Forests

Acid deposition appears to be a major contributor to damage to high elevation spruce trees that populate the Appalachian Mountains and other mountain ranges in the eastern part of the United States. This damage is manifested by a loss of foliage, which can lead to a reduction in tree populations in high elevation areas and, in turn, an increase in erosion and other adverse effects.

Acid deposition also is a concern for forest soils. As acidic compounds moves through the soil, they can strip away vital plant nutrients and thus pose a threat to future forest productivity. Furthermore, as the acidity of the soils increases and the capacity of the soil to absorb acidic deposition decreases, acidic water begins to pass through to surface waters, thus increasing the adverse effects to aquatic organisms (discussed in Section 6.1) and to an entire watershed area.

A reduction of SO_2 emissions is expected to not only result in an elimination of damage to foliage and soil, but to allow for the recovery of previously damaged tree populations. Constant or increased emissions, on the other hand, are expected to result in increased foliage damage and an increase in soil acidity.

6.5 Damage to Materials

Through the use of controlled experiments that imitate current conditions, acidic deposition has been shown to corrode certain commercially important coatings, such as paint, and a variety of structural materials, such as those used in items ranging from statues to buildings.[9] Many public monuments and other cultural objects are constructed of some of the most susceptible of these materials. Furthermore, the areas in the U.S. having the largest number of cultural materials coincide with the regions of highest acidic depostion. These cultural resources include historic buildings, monuments, statues and gravemarkers. Recent data also indicate that acid deposition may damage automobile paint often resulting in car owners or dealerships repainting the damaged surfaces. Secondary benefits (*e.g.*, reduced soiling) will accrue through reduction in particulate matter (PM), which will occur when SO_2 emissions are reduced. A reduction in SO_2 emissions would also likely extend the life (including functionality and appearance) of many of these materials and structures, resulting in economic benefits associated with reduced damage and need for extensive maintenance or repair.

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[8] See footnote 1.

[9] See footnote 1.

APPENDIX 3B
EPA Pollution Control Cost Assumptions

Scrubber Costs

Scrubber cost assumptions for the RIA analysis were the same as those used in EPA 1989-90 acid rain analyses, including the Administration bill analysis in 1989[1/] and the previously cited Senate and House bill analyses.[2/] The scrubber cost assumptions were based on EPRI/Stearns-Rogers cost assumptions as interpreted by RCG/Hagler, Bailly, Inc. (Several key assumptions were made: (1) a contingency factor of 15 percent was used, (2) one spare module was assumed, and (3) scrubbers were assumed to be designed with no reheat in contrast to assumptions in the 1987 EPA Base Case.) The cost assumptions for a new powerplant meeting NSPS-Da requirements resulting from this assessment are presented in Table III-B-1.

The net effect of these assessments was that wet scrubbing was assumed to be employed at all unplanned new powerplants, because wet scrubbing cost estimates were lower than dry scrubbing costs estimates.

For the House and Senate bill analyses and this RIA analysis, three further sets of scrubber costs assumptions were used:

- Retrofits. Retrofit scrubber costs assumed that 90 percent SO_2 removal (using wet scrubber technology) would be the most cost-effective scrubbing option. These cost assumptions for a "base" generic installation were developed using the same methodology and sources as described above, and are presented in Table III-B-2. In addition, all retrofit scrubber installations were then applied "retrofit factors" to reflect the relative ease or difficulty of installing scrubbers at various existing sites. These cost add-ons range from 10 to 100 percent of the "base" scrubber capital cost, and from 7.5 to 75 percent of the "base" fixed O&M cost.

- 95 Percent Removal at New Plants. Under Title IV, most sources built after enactment must obtain emission allowances from "affected" sources in Phase II. Over time, the marginal cost of obtaining allowances for new plants would increase very significantly, to the point where increased SO_2 removal from new sources (beyond New Source Performance Standards, subpart Da requirements) would be economic and desirable. For this analysis, new coal plants were given the option to install scrubbers to achieve 95 percent SO_2 removal in the trading cases and were required to achieve 95 percent SO_2 removal in the no-trading cases. To achieve 95 percent SO_2 removal, it was conservatively assumed (after discussion with architectural/engineering firms) that current, conventional NSPS-Da wet scrubbing alone would be insufficient, and that adipic acid injection or a modified/refined scrubbing system would be required. To account for these added costs, capital costs were increased by $30/kw and variable O&M costs by 0.2 mill/kwh over 90 percent wet scrubber removal cost levels for a very high sulfur coal, or total levelized costs of about 0.7-

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1/ See *Economic Analysis of Title V (Acid Rain Provisions) of the Administration's Proposed Clean Air Act Amendments (H.R.3030/S.1490)*, September 1989.

2/ Op cit p. 3-2.

0.8 mills/kwh. (For a low sulfur coal, the costs were assumed to be about 0.4 mills/kwh.) These estimates are likely to be conservative, and compare to industry total cost estimates of about 0.3-0.5 mills/kwh for incorporating an adipic acid system into conventional scrubbing designs. These resulting costs are presented in Table III-B-3.

EXHIBIT 3B-1
Wet Scrubber Costs For New Utility Powerplants Meeting NSPS Subpart Da Regulations

	Sulfur Level						
	Very Low	Low	Low Medium	Medium	High Medium	High	Very High
Capital Costs (early '86 $/kw)	108.00	110.00	110.00	124.00	133.00	145.00	154.00
Fixed O&M Costs (early '86 $/kw-yr)	4.92	4.98	5.00	5.45	5.74	6.11	6.39
Variable O&M Costs (early '86 mills/kwh)	0.25	0.32	0.46	0.69	0.92	1.36	1.80
Energy Penalty (%)	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Capacity Penalty (%)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Reliability Penalty (%)	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Annual Emission Rate (lbs. SO_2/mmBtu)	0.22	0.29	0.48	0.48	0.48	0.60	0.80

Sulfur Level	Lbs. SO_2/mmBtu
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.54-5.00
Very High Sulfur	More than 5.00

NOTE: EPA estimates except for reliability penalty, which is based on earlier EPRI estimates. More recent scrubber availability data suggests that these reliability estimates may be conservatively high.

EXHIBIT 3B-2
"Base" Wet Scrubber Costs For Retrofit Installations*

	Sulfur Level						
	Very Low	Low	Low Medium	Medium	High Medium	High	Very High
Capital Costs (early '86 $/kw)	125.00	119.00	128.00	133.00	138.00	148.00	156.00
Fixed O&M Costs (early '86 $/kw-yr)	5.46	5.48	5.56	5.82	5.88	6.18	6.46
Variable O&M Costs (early '86 mills/kwh)	0.26	0.34	0.49	0.71	0.93	1.37	1.81
Energy Penalty (%)	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Capacity Penalty (%)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Reliability Penalty (%)	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Annual Emission Rate (lbs. SO_2/mmBtu)	0.08	0.11	0.17	0.25	0.33	0.50	0.67

Sulfur Level	Lbs. SO_2/mmBtu
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.54-5.00
Very High Sulfur	More than 5.00

* Does <u>not</u> include "retrofit factors" (cost add-ons to reflect relative ease or difficulty of installing scrubbers at existing sites).

NOTE: EPA estimates except for reliability penalty, which is based on earlier EPRI estimates. More recent scrubber availability data suggests that these reliability estimates may be conservatively high.

EXHIBIT 3B-3
Wet Scrubber Costs For New Utility Powerplants Achieving 95 Percent Removal with Adipic Acid

	Sulfur Level						
	Very Low	Low	Low Medium	Medium	High Medium	High	Very High
Capital Costs (early '86 $/kw)	139.00	142.00	148.00	158.00	164.00	178.00	187.00
Fixed O&M Costs (early '86 $/kw-yr)	5.38	5.48	5.56	5.72	5.90	6.18	6.47
Variable O&M Costs (early '86 mills/kwh)	0.29	0.38	0.54	0.79	1.04	1.54	2.04
Energy Penalty (%)	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Capacity Penalty (%)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Reliability Penalty (%)	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Annual Emission Rate (lbs. SO_2/mmBtu)	0.04	0.05	0.08	0.13	0.17	0.25	0.33

Sulfur Level	Lbs. SO_2/mmBtu
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.54-5.00
Very High Sulfur	More than 5.00

NOTE: EPA estimates except for reliability penalty, which is based on earlier EPRI estimates. More recent scrubber availability data suggests that these reliability estimates may be conservatively high.

Repowering

The amount of repowering in the future, with or without acid rain legislation, is very uncertain. Accordingly, EPA assumed for the 1989 Base Case analysis that utilities would undertake a small to significant amount of repowering at certain existing coal-fired units. Repowering (using a "generic clean coal" technology) was assumed at EPA's direction to have much greater market penetration in the Low Base Case than in the High Base Case. Repowering candidates were assumed to include only those unscrubbed SIP coal units greater than 75 megawatts and less than 400 megawatts, since current evidence suggests that repowering technologies may be uneconomic or technically infeasible at very small or very large units. Units were assumed to become part of the candidate pool upon reaching 35 years of age beginning in 2000 (with only units built before 1950 assumed to be too old to repower).

In the Low Base Case, it was assumed a total of one third of all such candidates would repower by 2010 with lower percentages (five percent by 2000 and 20 percent by 2005) assumed in earlier years. In the High Base Case, much lower market penetration was assumed with only 10 percent of candidate units repowering by 2010 (five percent by 2005 and no repowering in 2000).

Under this RIA analysis of Title IV, as well as earlier Senate and House bill analyses, no additional repowering was assumed to result under the High Cases, but about 6 gigawatts of repowering candidates assumed to repower between 2005-2010 in the Low Base Case were assumed to repower earlier in 2004 under the Low Cases in order to take advantage of the proposals' repowering incentives.

In the assumed first year of repowering in both the High and Low Cases, units between 75 and 150 Mw and built before 1960 were generally selected for repowering. In later years, units up to 400 Mw and those built in the late 1960s and early 1970s were assumed to be selected for repowering. Smaller units were assumed to be selected first because utilities would wish to develop their design and construction expertise in simpler, less expensive settings. Older units were selected first because they are generally smaller and because many utilities would tend to repower units as they reached the end of their useful lives (assuming no major refurbishment). Repowered units were selected regionally so as to roughly reflect the proportional distribution of available candidate capacity. Future utility regional capacity requirements were taken into account in selecting the repowered units. Capacity was only selected to the extent new capacity was needed in the region to meet reserve margin requirements.

The capacity of repowered units under the cases analyzed is presented in Table III-B-4. Note that capacity affected by these repowering assumptions are in addition to those units which have already repowered (e.g., TVA's Shawnee 10, NSP's Black Dog 4, MDU's Heskett 2, Colorado-Ute's Nucla 4) or have firm plans to repower (AEP's Tidd and Sporn projects, SPS's Nichols 3). Together, these units total roughly 1 gigawatt of capacity, in contrast to about 38 gigawatts of repowered capacity that results by 2010 from the repowering assumptions of the Low Case.[3/]

The cost and performance characteristics of future repowering candidates is also very uncertain. The assumed cost and performance characteristics of the repowering technology are discussed below, and are generally representative of a fluidized bed combustion (FBC) technology.

3/ In addition, other projects (using other emissions control technologies which do not increase capacity) that were approved for funding in DOE's Clean Coal Technology development program (through Round II) were also included in this Base Case analysis.

- Capacity at those units that were selected for repowering was assumed to increase by 50 percent upon repowering. DOE assumes that atmospheric FBC (AFBC) repowering would lead to a 15 percent increase in capacity, pressurized FBC (PFBC) repowering would lead to a 30-50 percent capacity increase, and integrated gasifier combined cycle (IGCC) repowering would lead to a 150 percent increase in capacity.[4] The 50 percent capacity increase assumption was thus chosen as a reasonable average capacity gain for repowering projects to reflect a "representative" repowering technology, weighted heavily towards FBC technology for a typical installation (given the current relatively advanced state of FBC development, demonstration, and economic refinement). This 50 percent average capacity gain assumption is in agreement with EPRI's current assumptions.

- A heat rate of 9500 Btu/kwh was assumed for all repowering projects. This is in rough accord with EPRI TAG estimates for the candidate repowering technologies (9000 Btu/kwh for PFBC and IGCC, 10000 Btu/kwh for AFBC).[5]

- Capital costs (for units assumed to repower earlier under the Senate and House Low cases) were assumed to equal $794/kw (in 1988 $). This assumption is in approximate accord with previous preliminary ICF analyses, which indicated that the economics of repowering with PFBC versus building new coal capacity under the earlier Administration proposal would break even at roughly $800/kw (in 1988 $).

- O&M cost estimates for the generic repowering projects were also derived using EPRI TAG information (see PFBC combined cycles). Assuming the use of a four percent sulfur bituminous coal, fixed O&M costs were assumed to be $38.60/kw-yr, while variable O&M costs were assumed to equal 5.5 mills/kwh (costs in early 1986 $).

- A minimum capacity (turndown) of 50 percent was assumed for repowered units also in line with EPRI's assessment of PFBC technology.

- Additionally, it was further assumed that repowering would not affect a unit's availability (forced and scheduled outage rates were assumed not to improve).

- Emissions rates were assumed to meet current NSPS requirements for SO_2 and TSP. NO_x rates from repowered projects were assumed to equal 0.3 lbs. NO_x per million Btu.

4/ *America's Clean Coal Commitment.* U.S. Department of Energy, Office of Fossil Energy. February 1987.

5/ *TAG - Technical Assessment Guide, Volume 1: Electricity Supply - 1986.* Electric Power Research Institute (EPRI p. 4463-SR), December 1986.

EXHIBIT 3B-4
Repowered Coal Capacity*
(gigawatts)

	High Cases	Low Cases	
		Base	Baseline/ Regulatory
2000	0	4	4
2005	6	20	29
2010	10	38	38

* Includes 50 percent increase in capacity due to repowering.

APPENDIX 4A
Overview of ICF's Coal and Electric Utilities Model (CEUM)

APPENDIX 4A
ICF'S COAL AND ELECTRIC UTILITIES MODEL (CEUM)

The complexity of the coal and electric utility industries in the United States poses difficult challenges for strategic planners, market analysts, and policymakers. Numerous uncertainties regarding changing economic trends and future government policies increase the difficulties of forecasting future market conditions. Because of interactions between these two closely-coupled industries, attempts to analyze either one in isolation are necessarily incomplete. Yet the complex characteristics of these industries often strain the limits of traditional analytic methods.

Both the coal and electric utility industries face rapidly changing markets. Recent years have brought about dramatic changes in the growth of electricity demand, price of alternative fuels, cost of nuclear plant construction, and much more. Market conditions have swung broadly from undercapacity to overcapacity. The markets continue in a state of transition, and the importance of understanding the timing and magnitude of such changes is great.

Further, both industries are heavily influenced by a wide-range of government policies and regulations. Government regulation affects nearly every aspect of each of these industries including environmental protection, miner health and safety, transportation, taxation, price regulation, and ratemaking. The implications of possible policy changes are substantial, and government and industry planners place great value on understanding these effects.

To address the full range of these considerations, ICF Incorporated has developed a system of models and databases for analyzing the coal and electric utility industries in an integrated manner. At the core of this system of models and data bases is ICF's Coal and Electric Utilities Model (CEUM). The CEUM system is a set of interrelated models, data bases, and report writers which beyond CEUM consists of mine costing models, numerous data bases including the Coal and Utility Information System (CUIS), coal reserve data, coal transportation networks, and much more.

The CEUM system of models is the product of over ten years of research, development, and intensive analysis of the coal and electric utility markets. The "roots" of the system go back to the early and mid-1970s when, for the Federal Energy Administration, ICF pioneered the development of coal supply concepts and models to link the coal and electric utility markets. Over several years and hundreds of analyses for scores of clients, these models and data bases have grown and evolved to meet the ever-changing needs of the marketplace.

Over the last several years, these models have been used individually or in tandem for EPA for a wide variety of analytical fronts. The most common purpose has been the analysis of the impacts of alternative environmental regulations on utility emission, costs, fuel consumption, coal production and compliance choices as well as the effects of alternative existing and new control technologies on these measures.

CEUM SYSTEM OVERVIEW

ICF's CEUM system is composed of a number of interrelated models and data bases. The components of the system are structured to operate in either a stand-alone environment or as part of a broader analytic system.

Components of the CEUM System

The centerpiece of the CEUM system of models is ICF's Coal and Electric Utilities Model (CEUM). CEUM, perhaps the best-known component of this system, serves as the integrating tool which links together all the other models and data bases. The CEUM forecasts key attributes of both the coal and electric utility industries. For the coal industry, forecasts are made of coal consumption by type of user, production by region and method of mining, mine-mouth prices by type of coal, transportation patterns, and delivered prices. For the electric utility industry, forecasts can be made of generation, capacity expansion, capacity utilization, fuel use, generation costs, capital investment requirements, air emissions and solid wastes. For other coal consuming sectors, forecasts are made of coal consumption, sourcing, quality, and price.

As the integrating component of this modelling system, CEUM is closely linked with the other models and data bases that form the complete CEUM modeling system. Frequently, many of these models are run jointly with CEUM either as a pre-processor or as a post-processor. Alternatively, many of these models and data bases can be used in a stand-alone environment to address specific analytic problems. These other components include the following:

- **The Coal and Utility Information System** (CUIS) is a powerful data base management system containing detailed information on every electric generation unit, both present and planned. The CUIS develops the electric utility data inputs of CEUM, and can also be used independently as a market analysis tool. Moreover, this system is used in disaggregating the forecasts from CEUM to develop estimates of individual utility, powerplant, and generating unit impacts.

- **The Reserve Allocation and Coal Mine Costing Models** estimate costs, productivity, and minimum selling prices for different types of mines in different supply regions. Together with data bases on coal reserves and coal mining capacity, these models develop the coal supply functions used in CEUM. As stand-alone models, they can be used to analyze the effects of alternative mining plans and financial conditions, and can be used in evaluating the relative profitability of different mining operations.

- **Numerous other models and data bases** serve within the CEUM system primarily as front-end processors to CEUM or the other models described above. Although typically not used in a stand-alone mode, these other models and data bases represent important and powerful components of the entire system, and include the following:

  - coal mining capacity data base.
  - coal reserves data base.
  - coal transportation networks.

- electricity demand forecasting model.
- load curve forecasting model.
- coal contract data base.
- industrial boiler model.
- process heat model.
- coking coal demand model.
- world coal model.

System Capabilities

Collectively, the models and data bases comprising the CEUM system provide the analyst with a set of tools which can be used to analyze or address a number of different economic, policy or other questions regarding the fuel and electric utility industries.

These capabilities are best illustrated by identifying some of the analyses which have been performed with these models:

- **Air Emissions.** How will growth in coal consumption affect future air emissions? What are the environmental effects of powerplant life extension? What are the costs and coal market impacts of Title IV of the Clean Air Amendments? How would changes in emissions standards for new industrial boilers affect the use of coal versus alternative fuels? How will EPA's "Tall Stack" regulations affect utility costs, emissions, and fuel use?

- **Power Generation Technologies.** What is the market outlook for different technologies for power generation and pollution control? How would acid rain mitigation program affect the attractiveness of dry scrubbing or LIMB technologies? What are the prospects for combined cycle units vis-à-vis conventional coal-fired technology?

- **Inter-Regional Transmission Potential.** Where do current opportunities exist for increased interregional transmission of electricity between regions? What are the avoided costs of providing power from one region and displacing power generation in another. What are the impacts of electricity imports from Canada?

- **Regional Coal Development.** Where and to what extent will coal production continue to grow? What are the impacts on coal production and mining employment associated with sulfur dioxide control programs? How might changes in Federal coal leasing policies or state severance taxes affect the demand for western coal?

- **Coal Prices.** How and when will coal prices change as the markets move from an overcapacity situation to a balanced market? How will this vary with different economic outlooks and/or policy changes? Can changes in mining technologies and labor productivity offset the cost impacts of resource depletion? How will changes in coal prices affect coal reserve values?

- **Coal Transportation**. How will growing demand for coal change transportation patterns? What are the impacts of the Staggers' Rail Act and resulting ICC regulations on regional coal production patterns? How might individual railroads fare under alternative acid rain mitigation strategies? How would a network of coal slurry pipeline affect revenues and regional coal production?

- **Fuel Price and Availability**. What are the impacts of changing oil and gas prices on the coal markets? How will electricity rates change as overcapacity in the coal markets is worked off? What are the financial and economic impacts of converting powerplants from oil and gas to coal?

- **Tax Policy**. How would changes in the percentage depletion allowance affect regional and national coal production? How would changes in investment tax credits affect electricity rates? How would limits on state severance taxes affect coal production patterns in western states?

System Attributes

The CEUM system of models and data bases has been developed with the objective of helping government policy-makers and private sector decision-makers solve real-world problems. Each component of the system was designed from its inception to incorporate and display the level of detail necessary to address problems in a realistic manner.

The models incorporate a very high degree of resolution. This resolution is important in accurately assessing complex questions. Experience has shown that smaller and simpler models, while providing computational speed and programming efficiency, often are not capable of addressing complex questions at a level of detail meaningful to analysts. For example, in assessing the costs and economics of emission reduction compliance strategies for individual powerplants, it is important to have the resolution and flexibility to assess the impact of plant specific retrofit scrubbing costs, fuel switching constraints and changes in utilization in meeting overall state or plant specific reduction targets.

As a result of these types of issues and questions the models of the CEUM system have been structured to provide a very fine level of detail. For example, CEUM has forty different coal supply regions each with up to fifty types of coal, and fifty demand regions each with six consuming sectors. In each demand region, there are over thirty different types or categories of powerplants which can be modeled in the electric utility sector. Over twenty of these are coal, wit most coal powerplants categorized individually. The coal transportation network used in CEUM has over two thousand routes connecting the various types of movements from coal supply origin to final consumer end-use destination. The coal mine costing models reflect over one hundred different mining configurations, each which can be adapted to reflect different state taxation policies, union affiliation, and other variables.

A high degree of resolution provided by these models has value only if it can be understood and reviewed. To this end, the CEUM system has been developed as a system of "structural" models incorporating well-known engineering and financial relationships. Unlike econometric approaches, the CEUM models are not based upon abstract concepts and statistical fits, but instead express the engineering (technical and economic) relationships of the overall coal and electric utility markets important to the investment and operating decisions within each market. Using these relationships, the CEUM system of models attempt to replicate the normative decisions made within the coal and electric utility industries. The structural approach of the models allow the reasonableness and impact of each data input and assumption to be evaluated directly. The analyst is not forced to rely solely upon a series of indirect statistical measures.

The models "solve" using criteria which replicate real-world decision making. Each of the CEUM models follow decision rules consistent with rational decision-making. Generally, this implies a cost minimization model in which each decision maker (e.g., electric utility) is trying to minimize their own costs while competing in the market place with others who are trying to do likewise. Constraints can be placed upon this cost minimization framework to reflect the realities at hand. planned capacity underway, environmental regulations, technological limitations, long-term contracting, regulatory practices, and many other factors which decision-makers must consider.

Because the models have such a high degree of resolution, the data inputs required are often quite large. ICF has developed an extensive set of data bases linked closely with every aspect of the coal and electric utility market. In a number of instances, these data bases were developed using publicly available data as the original source with extensive updating and refinements of this information over time. However, often it has necessitated the development of original data collection and management efforts, where public data was either absent or unreliable. For example, in ICF's Coal and Utility Information System (CUIS) certain powerplant characteristics (e.g., capacities, plant types) were based on DOE-EIA's Inventory of Powerplants[1] and Generating Unit Reference File (GURF). However, virtually all other data elements or revisions to the DOE data over time reflect numerous surveys of the industry in order to collect and maintain detailed statistics on every powerplant unit in the nation. The coal reserve data base goes well beyond government published statistics, and incorporates hundreds of documents which are missing or incompletely used in published compilations. Prior to 1980, coal reserve characterizations were based mostly on the Demonstrated Reserve Base (DRB).[2] However, since that time, reserve characterizations and data have been largely based on detailed analyses of region and state specific reserved conducted by ICF as well as other information obtained from states and coal companies.

Despite these data collection efforts and maximum use of publicly available sources, gaps remain in the available data. Out of necessity, all models must forecast with imperfect information. The structural approach employed by the CEUM system of models require that gaps in knowledge be acknowledged explicitly since each data element or economic relationship also must be specified explicitly. It forces the analyst to evaluate key issues and permits an understanding of the relative importance of incomplete information. Over time, as more precise information becomes known, it can be readily incorporated into the models.

The CEUM system provides a great deal of flexibility in the types of issues that can be analyzed and the relevant timeframes over which they can be addressed. The structure and content of all of the models and databases have evolved substantially since their initial conception, reflecting improvements in analytic approaches and adaptations to changing market conditions. As future markets and analytic needs change, the CEUM system will similarly change. The models also have capabilities of addressing a wide range of forecast periods. Near-term analyses (e.g., 1987) are

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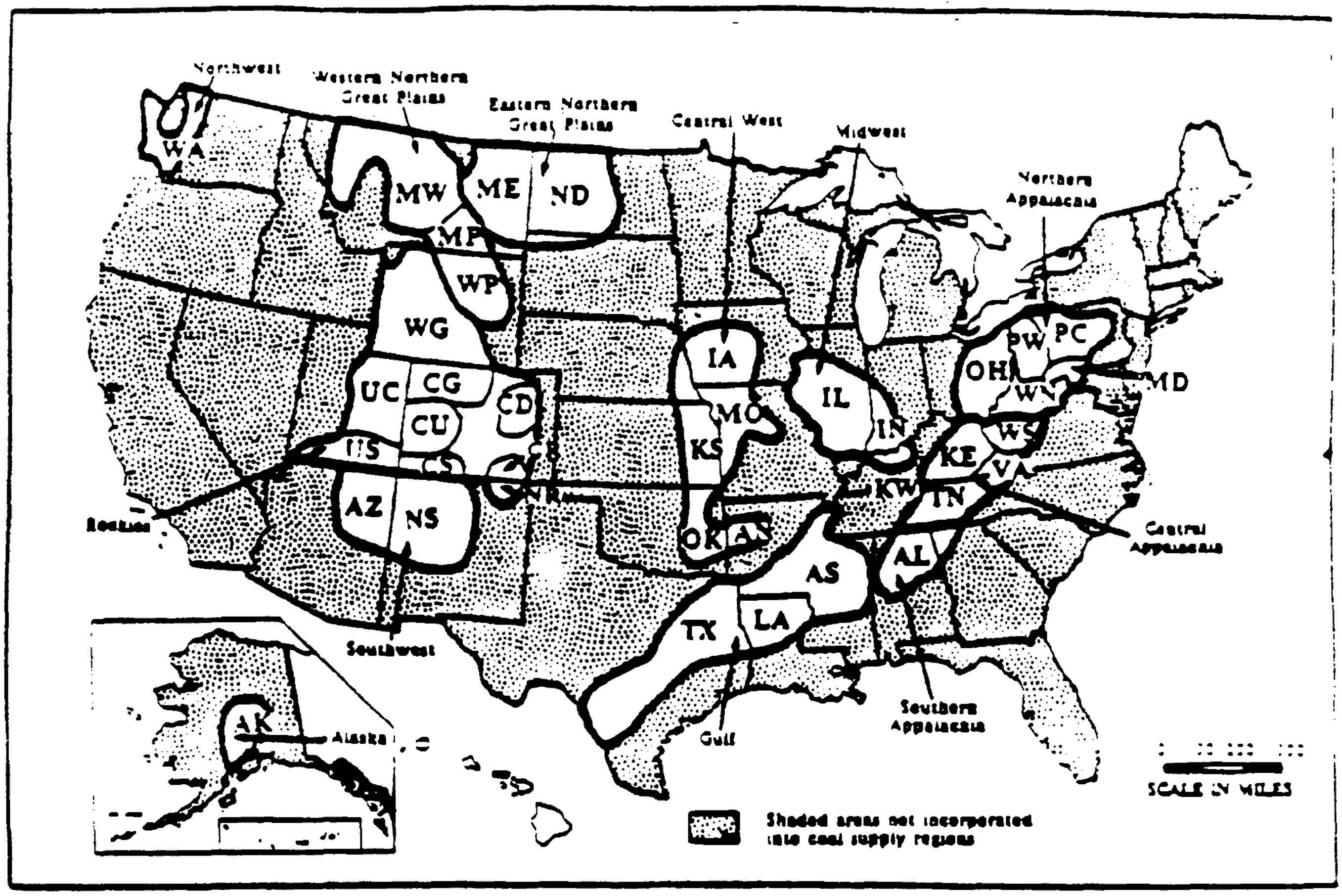
1 See DOE/EIA-0095 (81) <u>Inventory of Powerplants in the United States, 1981 Annual</u> September, 1982.

2 See Bureau of Mines <u>Demonstrated Reserve Base</u> 1975.

characterized by substantial constraints on capacity additions, fuel supply, and fuel contracts. Over time (e.g., 1990 to 2000), the constraints on capital stock and other factors become less binding, thereby increasing the options available to decision makers. In the very long-term (e.g., 2010 and beyond), new technologies can be postulated and evaluated. The models in the CEUM system have been used to address issues spanning all of these timeframes.

EXHIBIT 4A-1
MAP OF COAL SUPPLY REGIONS



<u>**Primarily High Sulfur Coal Reserves**</u>

Northern Appalachia
- Pennsylvania, Central (PC)
- Pennsylvania, West (PW)
- Ohio (OH)
- Maryland (MD)
- West Virginia, North (MD)

Midwest
- Illinois (IL)
- Indiana (IN)
- Kentucky, West (KW)

<u>**High & Low Sulfur Coal Reserves**</u>

Gulf
- Texas (TX)
- Louisiana (LA)
- Arkansas South/Mississippi (AS)

Central West
- Iowa (IA)
- Missouri (MO)
- Kansas (KS)
- Arkansas, North (AN)
- Oklahoma (OK)

<u>**Primarily Low Sulfur Coal Reserves**</u>

Central Appalachia
- West Virginia, South (WS)
- Virginia (VA)
- Kentucky, East (KE)
- Tennessee (TN)

Southern Appalachia
- Alabama (AL)

Eastern Northern Great Plains
- North Dakota (ND)
- Montana, East (ME)

Western Northern Great Plains
- Montana, Powder River (MP)
- Montana, West (MW)
- Wyoming, Powder River (WP)

Rockies
- Wyoming, Green River (WG)
- Colorado, Green River (CG)
- Colorado, Denver (CD)
- Colorado, Raton (CR)
- Colorado, Uinta (CU)
- Colorado, San Juan (CS)
- Utah, Central (UC)
- Utah, South (US)
- New Mexico, Raton (NR)

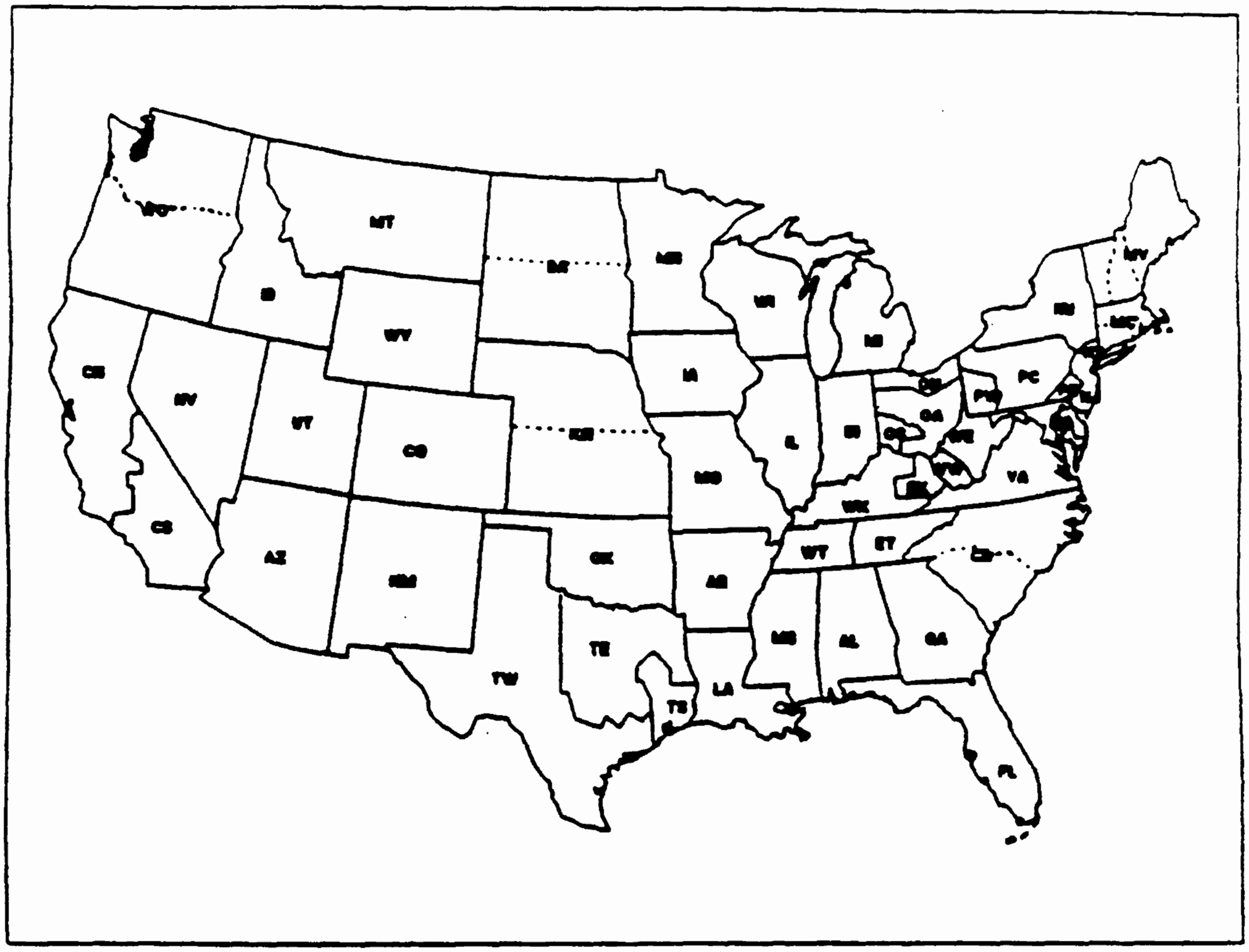
Southwest
- New Mexico, San Juan (NS)
- Arizona (AZ)

Northwest
- Washington (WA)

Alaska
- Alaska (AK)

Electricity Demand Regions in CEUM

CEUM Regions



MV	Maine/Vermont/ New Hampshire	MD	Maryland/Delaware/ District of Columbia	WE	West Virginia, East	DA	North Dakota/ South Dakota	CO	Colorado
MC	Massachusetts/ Connecticut/ Rhode Island	VA	Virginia	WW	West Virginia, West	KN	Kansas/Nebraska	NM	New Mexico
NU	New York, Upstate	CA	North Carolina/ South Carolina	MI	Michigan	MO	Missouri	ID	Idaho
NY	New York, Downstate	GA	Georgia	WI	Wisconsin	AR	Arkansas	UT	Utah
PE	Pennsylvania, East	AL	Alabama	IL	Illinois	OK	Oklahoma	NV	Nevada
PC	Pennsylvania, Central	MS	Mississippi	IN	Indiana	LA	Louisiana	AZ	Arizona
PW	Pennsylvania, West	FL	Florida	EK	Kentucky, East	TE	Texas, East	WO	Washington/Oregon
NJ	New Jersey	ON	Ohio, North	WK	Kentucky, West	TS	Texas, South	CN	California, North
		OS	Ohio, South	ET	Tennessee, East	TW	Texas, West	CS	California, South
				WT	Tennessee, West	MT	Montana		
				MN	Minnesota				

APPENDIX 2A
Background on Other Industries Affected by the Acid Rain Title

APPENDIX 2A
BACKGROUND ON OTHER INDUSTRIES AFFECTED BY THE ACID RAIN TITLE

COAL INDUSTRY

The U.S. coal industry is closely linked to the U.S. electric power industry; over 78 percent of total coal production in 1989 (766 out of 981 million tons) was supplied to electric powerplants. Over the last three decades coal production has increased about 125 percent in response to powerplant demand. Continued growth in coal production is expected over the next few years as existing coal-fired utility plants are more highly utilized. After 2000, the potential for growth will be determined primarily by the amount of new coal-fired generating capacity.

U.S. coal production is also consumed by (1) non-electric industrial boilers and process plants (77 million tons in 1989); (2) the U.S. steel industry for the production of coke, a feedstock to steelmaking (40 million tons); and (3) net exports to foreign powerplants and steelmakers (98 million tons).

Coal is a very heterogenous material composed of the fossilized remains of plants and animals and other minerals. The two most important differences between coals are:

- **Coal Rank/Energy Content**[1] - Coal falls into one of four categories established by the geochemical community:

    (1) high energy content bituminous,[2] accounting for over two-thirds of the coal mined in the U.S. in 1989;

    (2) medium to low energy sub-bituminous, accounting for about 24 percent of 1989 production;

    (3) low energy lignite, accounting for about nine percent of production; and

    (4) very high energy anthracite, accounting for less than one percent of production.

- **Sulfur Content** - Coal sulfur content varies considerably. The U.S. reserves of bituminous coal include both low- and high-sulfur coals. Reserves of sub-bituminous coals are mostly low-sulfur coals, and lignite coals are mostly medium-sulfur coal.

U.S. coal production primarily occurs in several regions with significant differences in coal quality between the various regions (listed below). Thus, regulations favoring one type of coal (e.g., low-sulfur coal) can shift the regional distribution of coal output:

1 While coal rank correlates with energy content, the classification by rank reflects other geochemical factors as well.

2 Energy content is measured in BTU per ton; in 1989 the average heat content of all coal mined in the U.S. was 21.8 million BTU per ton.

Geographic Area	Sulfur Content	Tons (1989)
Northern Appalachia	medium to high	164 million
Central and Southern Appalachia	low to medium	296 million
Midwest	mostly high	134 million
Lignite Regions of Texas and the Dakotas		83 million
Powder River Basin	low	188 million
Other West	low	116 million

There are a large number of coal-mining companies, including some very large multi-regional companies, such as Peabody Coal, and a large number of small companies, especially in Appalachia. The top 15 producers accounted for more than 45 percent of the coal produced in 1989. The top five producers, their production, and market share are shown below:

Producer	Production (mmtons)	Market Share	Region
Peabody Holding Group	86.7	8.9%	Midwest/Natl.
Consolidation Coal Company	53.5	5.5	Appalachia
AMAX Coal Industries Inc.	38.4	3.9	PRB/Natl.
ARCO Coal Company	31.1	3.2	PRB
Texas Utilities Mining Company	29.9	3.1	Texas

The number of active coal mines in the U.S. producing at least 10,000 tons annually fell in 1989 to 2,821 mines from a 1988 level of 2,915. About 51 percent of these mines are underground mines and the rest are surface mines. Some differences between surface and underground mines include:

- **Location** - Most of the underground production is located in the East, while surface mines tend to predominate in the Western region;
- **Productivity** - Surface mines have higher productivity than underground mines, due to the fact that surface mining enjoys greater economies of scale, thus, requires fewer workers. Also advancements in mining technology, such as the longwall mining system, have further increased productivity for surface mines; and
- **Size** - Surface mines are generally larger and higher producing than underground mines. Several surface mines produced more than 10 million tons per year. The average surface mine produced 419 thousand tons in 1989, compared with an average of 275 thousand tons for underground mines.

The F.O.B. mine price of coal varies by region, type of mining, and quality. On average, Western coal is cheaper than Appalachian or Interior coal because it is more efficiently mined and has a lower heat content.

OTHER FOSSIL FUEL PRODUCERS

Crude oil and natural gas are also important fuels for the electric utility industry, but much less important than coal; in 1989, oil-powered plants accounted for only 6 percent of total electric generation, and natural gas-powered plants, only 9 percent. In recent years, the share of oil and gas generation capacity has decreased, while coal and nuclear capacity has increased, in response to the rising oil and gas prices of the 1970s. Most recently, lower oil and gas prices and a reluctance to build capital-intensive coal and nuclear plants have caused many to expect a resurgence in utility oil and gas usage.

Oil and gas usage by utilities is a very small share of total U.S. usage of these fuels. In 1989, the total U.S. natural gas consumption was about 19 trillion cubic feet; utilities accounted for only about 15 percent of natural gas consumption. Oil consumption was 17 million barrels per day, accounting for 42 percent of total U.S. energy consumption, but utilities usage of oil by electric utilities accounted for only about 4 percent of total oil consumption.

U.S. crude oil production was 7.63 million barrels per day in 1989 (produced by 603,000 oil wells), and crude oil imports were 5.81 million barrels per day. The U.S. and non-U.S. oil markets are highly integrated due to relatively low transportation costs, and many of the nation's largest oil companies are involved in production. Also, many other small companies are involved. Oil moves from the producing well to the refinery where it is refined into various petroleum products, which are then shipped to the end-user markets. The U.S. oil market can be characterized as highly competitive.

The U.S. is a leading producer and consumer of natural gas; however, the U.S. natural gas industry is much less integrated with the rest of the world than the oil industry because of the far greater transportation costs for natural gas. In 1989, 261,000 producing gas wells produced 17 trillion cubic feet of natural gas in the U.S. Natural gas is produced at the wellhead, gathered and processed, and then transmitted to distribution companies, who supply it to the end-use customer. The gas market consists of many localized markets. Pipelines provide an efficient means to transport the gas to the markets. The pipelines deliver the gas to Local Distribution Companies (LDCs), who receive the gas at "citygates" and distribute it to the consumers. Generally, LDCs are granted franchise rights by the state authorities to serve specific communities, and are subject to rate regulation by these authorities. End-use consists primarily of gas consumption equipment such as a furnace, a home stove or water heater, an industrial boiler or oven, or an electric utility turbine.

POLLUTION CONTROL EQUIPMENT/SCRUBBERS

The provisions of the 1990 Clean Air Act Acid Rain Amendments create new potential markets for pollution control equipment such as "scrubbers" (devices installed at powerplants to remove sulfur dioxide from powerplant flue gases) and equipment controlling the formation of nitrogen oxides. There are several types of scrubber technologies:

- **Wet Scrubbers** - Utilities generally use limestone or lime slurries to wash the flue gas and produce a wet waste product. There are about 60 million kilowatts of scrubbed coal-fired capacity in the U.S. out of about 300 million kilowatts total.

- **Dry Scrubbers** - To a much lesser extent, utilities use dry scrubbers which use lime, sodium, or other powders to wash the flue gas and produce dry waste products. This technology is generally used only for low-sulfur coal applications.

- **Reusable Product Scrubbers** - These systems create sulfur and sulfuric acid waste streams. Only a very few of these systems exist in the U.S.

Since scrubbers were first installed at utility full-scale operations in the early 1970s, five firms have accounted for a vast majority of utility scrubber sales:

(1) Asea/Brown-Boveri (Combustion Engineering) - 29 percent;
(2) GE Environmental Services - 22 percent;
(3) Babcock and Wilcox - 15 percent;
(4) Research Cottrell - 15 percent; and
(5) Joy - 9 percent.

Ten other firms have accounted for about 10 percent of utility sales.

The DOE Clean Coal Program is a $5 billion joint effort of the federal government and private sector to encourage the rapid development of new technologies for sulfur dioxide and particulate matter emissions control and the repowering of powerplants. The program structure includes five solicitations or "rounds" for projects; Round III is currently underway, and solicitations have been requested for Round IV. This program involves many companies, some experienced in the scrubber industry and some newcomers, and a vast range of new technologies, such as sorbent injection, coal gasification, nitrogen oxide controls, and fluidized bed combustion.

APPENDIX 3A
EPA Base Case Assumptions

DETAILED BASE CASE ASSUMPTIONS

	1989 EPA Base: High Case	1989 EPA Base: Low Case
ELECTRIC UTILITY ENERGY DEMAND		
o Electricity Growth Rate (% Per Year)	1990 = 2.8 1995 = 2.8 2000 = 2.8 2005 = 2.3 2010 = 2.3	1990 = 2.4 1995 = 2.1 2000 = 1.7 2005 = 1.4 2010 = 1.4
	1988-2000 = 2.8 2001-2010 = 2.3	1988-2000 = 2.0 2000-2010 = 1.4
o Total U.S. Nuclear Capacity (gw)	1995 = 104 2000 = 104 2005 = 102 2010 = 77	1995 = 104 2000 = 104 2005 = 104 2010 = 102
o Nuclear Capacity Factors (%)	1995 = 70 2000 = 71 2005 = 66 2010 = 67	1995 = 70 2000 = 71 2005 = 66 2010 = 68
o Utility Capital Costs (Early-1986 $/Kw)	Coal = 900-1010 Turbine = 275-315 Comb. Cycle = 510-590 Scrubbers, Wet = 108-154	Coal = 900-1010 Turbine = 275-315 Comb. Cycle = 510-590 Scrubbers, Wet = 108-154
o Generation O&M (Early-1986 $/kw-year)	Coal = 12.20 - 19.50 Combined Cycle = 9.70 - 11.10 Turbine = 3.70 - 4.30	Coal = 12.20 - 19.50 Combined Cycle = 9.70 - 11.10 Turbine = 3.70 - 4.30
o Power Plant Lifetime (Years)	Coal/Oil/Gas Steam 65 yrs. 45 years if <50 Mw	Coal/Oil/Gas Steam 55 yrs. 45 years if <50 Mw
	Nuclear 35 years Turbine 20 years	Nuclear 40 years Turbine 20 years

DETAILED BASE CASE ASSUMPTIONS

	1989 EPA Base: High Case	1989 EPA Base: Low Case
ELECTRIC UTILITY ENERGY DEMAND (continued)		
o Repowering/Refurbishment Assumptions	Repowered Capacity (includes 50% increase from repowering) 2000: 0 2005: 6 gw 2010: 10 gw All other coal capacity refurbishes at 30 years of age.	Repowered Capacity (includes 50% increase from repowering) 2000: 4 gw 2005: 20 gw 2010: 38 gw All other coal capacity refurbishes at 30 years of age.
o Coal Powerplant Heat Rates	0.25% per year increase over current levels. After refurbishment heat rates are improved (decreased) by five percent from previous forecast levels.	0.25% per year increase over current levels. After refurbishment heat rates are improved (decreased) by five percent from previous forecast levels.
Minimum Turndown Rates	Coal 35% Oil/Gas Steam 20%	Coal 35% Oil/Gas Steam 20%
Canadian Power Imports (billions of kwhrs)	1995 = 64 2000 = 76 2005 = 75 2010 = 75	1995 = 64 2000 = 76 2005 = 75 2010 = 75
Cogeneration (billions of kwhrs)	1995 = 175 2000 = 208 2005 = 255 2010 = 313	1995 = 195 2000 = 291 2005 = 382 2010 = 474

DETAILED BASE CASE ASSUMPTIONS

	1989 EPA Base: <u>High Case</u>	1989 EPA Base: <u>Low Case</u>
FINANCIAL PARAMETERS		
o Tax Depreciation Life (years)	15	15
Retrofit Pollution Control	15	15
Others		
o Real Discount Rates (% Per Year)	Coal Mine = 6.00% Utility = 5.38%	Coal Mine = 6.00% Utility = 5.38%
o Real Capital Charge Rates		
Coal/Nuclear/Combined Cycle	9.4%	9.4%
New Scrubbers/Particulate Equip	9.4%	9.4%
Combustion Turbines	11.5%	11.5%
Retrofit Scrubbers	9.4%	9.4%
o Book Life (years)		
Coal/Nuclear/Combined Cycle	30	30
Combustion Turbine	20	20
Pollution Control-Retrofit	30	30
Pollution Control-New	30	30
o Input Year Dollars	Early 1986	Early 1986
o Output Year Dollars	Mid 1988	Mid 1988
o Escalation Input to Output Dollars	1.073	1.073
o Industrial/Retail Coal Use (millions of tons)	1995 = 90 2000 = 95 2005 = 97 2010 = 100	1995 = 90 2000 = 95 2005 = 97 2010 = 100

DETAILED BASE CASE ASSUMPTIONS

	1989 EPA Base: High Case	1989 EPA Base: Low Case
NON-UTILITY COAL DEMAND		
o Coal Exports (millions of tons)		
-- Steam Coal	1995 = 30 2000 = 36 2005 = 35 2010 = 37	1995 = 30 2000 = 36 2005 = 35 2010 = 37
-- Metallurgical Coal Exports	1995 = 45 2000 = 35 2005 = 30 2010 = 31	1995 = 45 2000 = 35 2005 = 30 2010 = 31
o Domestic Metallurgical Coal Use (millions of tons)	1995 = 32 2000 = 30 2005 = 29 2010 = 27	1995 = 32 2000 = 30 2005 = 29 2010 = 27
o Synthetics (Coal Input in millions of tons)	1995 = 6 2000 = 6 2005 = 6 2010 = 6	1995 = 6 2000 = 6 2005 = 6 2010 = 6
COAL SUPPLY		
o Coal Transportation Rates		
-- Rail	Long-run marginal costs based on engineering analysis.	Long-run marginal costs based on engineering analysis.
-- Truck; Barge	Based on full costs.	Based on full costs.

DETAILED BASE CASE ASSUMPTIONS

	1989 EPA Base: High Case	1989 EPA Base: Low Case
COAL SUPPLY (continued)		
o Mining Costs (% Annual Real Escalation)	Capital = 0.0% Labor = 2.0% Materials = 0.0% Gross Labor Productivity: Deep 1988 = 7.0% 1989 = 5.0% 1990 = 4.0% 1991-on = 3.0% Surface = 2.0% Capital Productivity Deep = 0.0% Surface = 1.5%	Capital = 0.0% Labor = 2.0% Materials = 0.0% Gross Labor Productivity: Deep 1988 = 7.0% 1989 = 5.0% 1990 = 4.0% 1991-on = 3.0% Surface = 2.0% Capital Productivity Deep = 0.0% Surface = 1.5%
OTHER GOVERNMENTAL REGULATIONS		
o Federal Leasing Policy	Enough	Enough
o Air Pollution Regulations	Up-to-date reassessment of federal and state rules, including proposed changes in SIPs, state acid rain programs and proposed federal tall stacks regulations. Large industrial boilers must scrub by 1995.	Up-to-date reassessment of federal and state rules, including proposed changes in SIPs, state acid rain programs and proposed federal tall stacks regulations. Large industrial boilers must scrub by 1995.

DELIVERED OIL PRODUCT PRICES and DELIVERED GAS PRICES

	1995		2000		2005		2010	
	High	Low	High	Low	High	Low	High	Low
World Oil Price (1988$/bbl)	18.00	25.00	22.00	29.00	25.00	31.50	29.50	34.00
Census Region/Product (1988$/mmbtu)								
New England								
Gas	3.55	3.85	4.10	4.40	4.45	4.75	4.95	5.15
Distillate	4.19	5.45	4.91	6.17	5.45	6.62	6.26	7.07
1.0% Residual	3.11	4.29	3.77	4.94	4.24	5.32	4.99	5.74
2.8% Residual	2.62	3.74	3.26	4.39	3.72	4.76	4.44	5.16
Middle Atlantic								
Gas	3.55	3.85	4.10	4.40	4.45	4.75	4.95	5.15
Distillate	4.17	5.42	4.88	6.14	5.42	6.59	6.23	7.04
1.0% Residual	3.09	4.27	3.75	4.92	4.22	5.30	4.97	5.72
2.8% Residual	2.60	3.73	3.24	4.37	3.70	4.74	4.42	5.15
South Atlantic								
Gas	3.55	3.85	4.10	4.40	4.45	4.75	4.95	5.15
Distillate	4.15	5.40	4.86	6.12	5.40	6.57	6.21	7.02
1.0% Residual	3.02	4.19	3.68	4.85	4.15	5.23	4.89	5.64
2.8% Residual	2.52	3.65	3.16	4.29	3.63	4.67	4.35	5.07
East North Central								
Gas	3.50	3.80	4.05	4.35	4.40	4.70	4.90	5.10
Distillate	4.05	5.29	4.76	6.00	5.29	6.45	6.09	6.89
1.0% Residual	3.18	4.36	3.84	5.01	4.31	5.39	5.06	5.81
2.8% Residual	2.69	3.82	3.33	4.46	3.79	4.84	4.51	5.24
East South Central								
Gas	3.55	3.85	4.10	4.40	4.45	4.75	4.95	5.15
Distillate	4.13	5.38	4.85	6.10	5.38	6.55	6.19	6.99
1.0% Residual	3.24	4.53	3.96	5.25	4.48	5.67	5.30	6.13
2.8% Residual	2.75	3.99	3.45	4.69	3.96	5.11	4.76	5.55
West North Central								
Gas	3.75	4.05	4.30	4.60	4.65	4.95	5.15	5.35
Distillate	3.96	5.20	4.67	5.91	5.20	6.35	6.00	6.80
1.0% Residual	3.12	4.29	3.78	4.95	4.25	5.33	5.00	5.75
2.8% Residual	2.62	3.75	3.27	4.39	3.73	4.77	4.45	5.17

NOTE: (1) Gas prices are on an average annual interruptible basis. Gas prices shown herein do not include any forecasted price increases due to incremental utility gas demands in the Administration cases.

(2) Residual product prices shown for 1.0% and 2.8% Resid. Actual sulfur level of residual oil used in specific states and modelled in the base case varies.

	1995		2000		2005		2010	
	High	Low	High	Low	High	Low	High	Low
West South Central								
Gas	2.85	3.45	3.50	4.00	3.95	4.35	4.55	4.75
Distillate	3.94	5.18	4.65	5.89	5.18	6.33	5.98	6.78
1.0% Residual	2.87	4.03	3.52	4.68	3.99	5.06	4.73	5.47
2.8% Residual	2.37	3.49	3.01	4.13	3.47	4.50	4.18	4.90
Mountain								
Gas	3.35	3.65	3.90	4.20	4.25	4.55	4.75	4.95
Distillate	3.88	5.12	4.59	5.83	5.12	6.27	5.92	6.17
1.0% Residual	3.09	4.27	3.75	4.92	4.22	5.30	4.97	5.72
2.8% Residual	2.60	3.73	3.24	4.37	3.70	4.74	4.42	5.15
Pacific								
Gas	3.75	4.05	4.30	4.60	4.65	4.95	5.15	5.35
Distillate	3.94	5.18	4.65	5.89	5.18	6.33	5.98	6.78
1.0% Residual	2.97	4.13	3.62	4.78	4.08	5.16	4.83	5.57
2.8% Residual	2.47	3.59	3.11	4.22	3.57	4.60	4.28	4.99

APPENDIX 4B
Detailed Forecasts

EXHIBIT A-1

SULFUR DIOXIDE FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN MILLIONS OF TONS)

Utility SO2 Emissions	Pre-Statute Case 1995	Absent Regulation Case 1995	Regulatory Case 1995	Pre-Statute Case 2000	Absent Regulation Case 2000	Regulatory Case 2000
		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
(millions of tons)						
37-Eastern States						
Coal						
SIP	13.93	-3.35	-3.65	14.67	-8.96	-7.30
NSPS	2.16	.07	.04	2.30	-.15	.00
ANSPS	.07	.00	.00	.15	-.04	-.05
TOTAL COAL	16.16	-3.27	-3.60	17.12	-9.06	-7.36
OIL/GAS	1.35	.04	.03	1.52	-.80	-.19
TOTAL 37-EASTERN STATES	17.51	-3.24	-3.57	18.63	-9.85	-7.54
11-Western States						
Coal						
SIP	.44	.00	.00	.44	-.10	-.04
NSPS	.20	.00	.00	.20	-.03	.00
ANSPS	.01	.00	.00	.14	-.08	-.05
TOTAL COAL	.65	.00	.00	.78	-.22	-.10
OIL/GAS	.03	.00	.00	.03	-.03	-.03
TOTAL 11-WESTERN STATES	.68	.00	.00	.81	-.25	-.12
United States						
Coal						
SIP	14.38	-3.36	-3.65	15.10	-8.96	-7.35
NSPS	2.36	.07	.04	2.50	-.18	.00
ANSPS	.08	.00	.00	.29	-.13	-.10
TOTAL COAL	16.81	-3.28	-3.60	17.89	-9.28	-7.45
OIL/GAS	1.38	.04	.03	1.55	-.82	-.22
TOTAL UNITED STATES	18.19	-3.24	-3.57	19.44	-10.10	-7.67

NOTE: Totals may not add due to independent rounding.

EXHIBIT A-1

SULFUR DIOXIDE FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN MILLIONS OF TONS)

Utility SO2 Emissions	Pre-Statute Case 2005	CHANGE FROM PRE-STATUTE: Absent Regulation Case 2005	CHANGE FROM PRE-STATUTE: Regulatory Case 2005	Pre-Statute Case 2010	CHANGE FROM PRE-STATUTE: Absent Regulation Case 2010	CHANGE FROM PRE-STATUTE: Regulatory Case 2010
(millions of tons)						
37-Eastern States						
Coal						
SIP	14.69	-9.08	-8.98	14.42	-9.41	-9.11
NSPS	2.32	-.19	-.09	2.16	-.16	-.13
ANSPS	.93	-.53	-.54	2.44	-1.55	-1.51
TOTAL COAL	17.94	-9.80	-9.61	19.02	-11.12	-10.75
OIL/GAS	1.17	-.51	-.72	.84	-.37	-.81
TOTAL 37-EASTERN STATES	19.11	-10.32	-10.33	19.86	-11.49	-11.57
11-Western States						
Coal						
SIP	.41	-.09	-.04	.40	-.09	-.05
NSPS	.21	-.03	.00	.18	-.04	.00
ANSPS	.24	-.16	-.10	.33	-.23	-.14
TOTAL COAL	.85	-.28	-.14	.92	-.35	-.19
OIL/GAS	.03	-.01	.00	.00	.00	.00
TOTAL 11-WESTERN STATES	.88	-.29	-.14	.92	-.35	-.19
United States						
Coal						
SIP	15.10	-9.17	-9.02	14.82	-9.50	-9.16
NSPS	2.53	-.23	-.09	2.35	-.19	-.13
ANSPS	1.17	-.69	-.64	2.77	-1.78	-1.65
TOTAL COAL	18.79	-10.08	-9.75	19.94	-11.47	-10.94
OIL/GAS	1.19	-.52	-.72	.85	-.37	-.82
TOTAL UNITED STATES	19.99	-10.61	-10.67	20.78	-11.84	-11.76

NOTE: Totals may not add due to independent rounding.

EXHIBIT A-2

FUEL CONSUMPTION FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN QUADS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 1995	Absent Regulation Case 1995	Regulatory Case 1995	Pre-Statute Case 2000	Absent Regulation Case 2000	Regulatory Case 2000
37 Eastern States						
COAL						
LOW SULFUR	3.83	.21	.30	3.93	4.06	2.31
LOW-MEDIUM SULFUR	2.67	.48	.40	3.27	-.19	.66
HIGH-MEDIUM SULFUR	4.66	.79	.05	4.79	-1.88	-.91
HIGH SULFUR	3.88	-1.47	-.75	4.15	-2.12	-2.04
TOTAL	15.03	.01	-.01	16.13	-.13	.02
11 Western States						
COAL						
LOW SULFUR	1.16	.06	.00	2.37	-.43	-.26
LOW-MEDIUM SULFUR	.65	-.05	-.02	.76	.30	.27
HIGH-MEDIUM SULFUR	.26	-.01	.02	.30	.05	.00
HIGH SULFUR	.00	.00	.00	.00	.00	.00
TOTAL	2.07	.00	.00	3.43	-.08	.00
Total U.S.						
COAL						
LOW SULFUR	5.00	.27	.31	6.30	3.63	2.05
LOW-MEDIUM SULFUR	3.32	.43	.37	4.04	.12	.93
HIGH-MEDIUM SULFUR	4.91	.78	.07	5.09	-1.84	-.91
HIGH SULFUR	3.88	-1.47	-.75	4.15	-2.12	-2.04
TOTAL	17.11	.01	-.01	19.58	-.21	.02

EXHIBIT A-2

FUEL CONSUMPTION FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN QUADS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 2005	Absent Regulation Case 2005	Regulatory Case 2005	Pre-Statute Case 2010	Absent Regulation Case 2010	Regulatory Case 2010
37 Eastern States						
COAL						
LOW SULFUR	4.83	2.76	3.32	5.81	2.23	3.66
LOW-MEDIUM SULFUR	4.17	.03	.15	4.61	.48	.56
HIGH-MEDIUM SULFUR	5.93	-1.16	-1.27	7.06	-.47	-.76
HIGH SULFUR	4.88	-1.78	-2.20	7.86	-2.51	-3.21
TOTAL	19.81	-.15	.01	25.34	-.27	.26
11 Western States						
COAL						
LOW SULFUR	3.30	-.36	-.32	3.85	-.30	-.55
LOW-MEDIUM SULFUR	.82	.51	.50	.83	.66	.72
HIGH-MEDIUM SULFUR	.63	-.20	-.17	.64	-.43	-.16
HIGH SULFUR	.00	.00	.00	.00	.00	.00
TOTAL	4.58	-.05	.00	5.31	-.07	.00
Total U.S.						
COAL						
LOW SULFUR	8.13	2.39	3.00	9.66	1.95	3.11
LOW-MEDIUM SULFUR	4.99	.54	.65	5.44	1.14	1.28
HIGH-MEDIUM SULFUR	6.37	-1.36	-1.44	7.69	-.90	-.91
HIGH SULFUR	4.88	-1.78	-2.20	7.86	-2.51	-3.21
TOTAL	26.37	-.20	.01	30.85	-.34	.27

EXHIBIT A-3

COAL PRODUCTION AND SHIPMENT FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN MILLIONS OF TONS)

	Pre-Statute Case 1995	Absent Regulation Case 1995 (Change from Pre-Statute)	Regulatory Case 1995 (Change from Pre-Statute)	Pre-Statute Case 2000	Absent Regulation Case 2000 (Change from Pre-Statute)	Regulatory Case 2000 (Change from Pre-Statute)
COAL PRODUCTION						
NORTHERN APPALACHIA	186.	0.	-6.	197.	-55.	-31.
CENTRAL APPALACHIA	261.	29.	21.	280.	68.	59.
SOUTHERN APPALACHIA	23.	1.	1.	22.	3.	3.
MIDWEST	131.	-38.	-20.	149.	-67.	-64.
WEST	420.	4.	0.	491.	38.	30.
TOTAL COAL REGIONS	1022.	-3.	-2.	1138.	-12.	-4.
COAL TRANSPORTATION						
WESTERN COAL TO EAST	51.	-1.	0.	53.	26.	12.

EXHIBIT A-3

COAL PRODUCTION AND SHIPMENT FORECASTS
ABSENT REGULATION AND REGULATORY
HIGH CASES
(IN MILLIONS OF TONS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 2005	Absent Regulation Case 2005	Regulatory Case 2005	Pre-Statute Case 2010	Absent Regulation Case 2010	Regulatory Case 2010
COAL PRODUCTION						
NORTHERN APPALACHIA	239.	-51.	-52.	290.	-65.	-61.
CENTRAL APPALACHIA	317.	79.	96.	324.	108.	140.
SOUTHERN APPALACHIA	29.	-3.	-2.	35.	-6.	-5.
MIDWEST	181.	-61.	-76.	306.	-101.	-129.
WEST	582.	26.	30.	675.	27.	38.
TOTAL COAL REGIONS	1348.	-11.	-6.	1629.	-18.	4.
COAL TRANSPORTATION						
WESTERN COAL TO EAST	55.	15.	12.	51.	12.	18.

EXHIBIT A-6

CHANGE IN ANNUALIZED NET
UTILITY COSTS BY REGION 1/
(MILLIONS OF 1990 DOLLARS)

	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE
	HIGH REG. CASE 1995	HIGH REG. CASE 1995	HIGH REG. CASE 2000	HIGH REG. CASE 2000	HIGH REG. CASE 2005	HIGH REG. CASE 2005	HIGH REG. CASE 2010	HIGH REG. CASE 2010
NEW ENGLAND	-20	-11	-49	62	-15	116	-18	73
MIDDLE ATLANTIC	-4	94	-326	323	-111	486	-90	406
UPPER S. ATLANTIC	47	161	-361	251	-85	411	-32	349
LOWER S. ATLANTIC	-89	23	-210	348	-82	402	-127	361
EAST N. CENTRAL	-102	468	-819	280	-262	955	-476	1161
EAST S. CENTRAL	-79	79	-293	348	-165	376	-104	395
WEST N. CENTRAL	-83	56	-186	344	-142	308	-164	396
WEST S. CENTRAL	-337	3	-347	40	-400	273	-175	306
MOUNTAIN	0	20	-161	98	-280	102	-186	191
PACIFIC	0	0	-71	-25	-107	0	-76	41
TOTAL U.S.	(668)	874	(2,822)	2,068	(1,610)	3,426	(1,446)	3,678

1/ Includes gas price increases (as gas demands increase), but does not include costs of higher gas prices for other sectors.

EXHIBIT A-5

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (I.E., LEVELIZED BASIS) 1/ (PERCENT)

	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE
	HIGH REG. CASE 1995	HIGH REG. CASE 1995	HIGH REG. CASE 2000	HIGH REG. CASE 2000	HIGH REG. CASE 2005	HIGH REG. CASE 2005	HIGH REG. CASE 2010	HIGH REG. CASE 2010
NEW ENGLAND	-0.2	-0.1	-0.4	0.6	-0.1	0.5	-0.0	0.2
MIDDLE ATLANTIC	-0.0	0.3	-0.9	0.9	-0.2	1.0	-0.2	0.8
UPPER S. ATLANTIC	0.4	1.1	-2.4	1.4	-0.5	2.5	-0.2	1.8
LOWER S. ATLANTIC	-0.3	0.1	-0.5	0.8	-0.1	0.6	-0.2	0.4
EAST N. CENTRAL	-0.2	1.1	-1.8	0.6	-0.5	1.9	-0.9	2.1
EAST S. CENTRAL	-0.4	0.4	-1.3	1.5	-0.5	1.4	-0.3	1.2
WEST N. CENTRAL	-0.5	0.3	-1.0	1.8	-0.6	1.4	-0.7	1.6
WEST S. CENTRAL	-1.5	0.0	-1.1	0.1	-0.4	0.3	-0.2	0.4
MOUNTAIN	0.0	0.1	-0.6	0.3	-0.8	0.3	-0.4	0.4
PACIFIC	0.0	0.0	-1.4	-0.5	-0.1	0.0	0.1	0.0
TOTAL U.S.	-0.3	0.4	-1.1	0.8	-0.4	0.9	-0.3	0.9

1/ Calculated as follows:

$$\left[\frac{\text{Emission Reduction Case Annualized Cost - Pre-Statute Annualized Cost}}{\text{In-State Generation after Distribution Losses}} \right] \div \text{1986 Average Electricity Rates}$$

EXHIBIT A-6
HIGH CASE 1995
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	BANKED ALLOWANCES 1/ (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	32	0	32	26	(6)	(1)	(20)	(20)	-0.2
MIDDLE ATLANTIC	706	(108)	598	683	86	11	(15)	(4)	-0.0
UPPER S. ATLANTIC	637	(151)	486	508	22	3	44	47	0.4
LOWER S. ATLANTIC	715	(6)	709	447	(261)	(35)	(55)	(89)	-0.3
EAST N. CENTRAL	2,257	(600)	1,658	1,601	(57)	(7)	(95)	(102)	-0.2
EAST S. CENTRAL	950	(77)	874	829	(44)	(6)	(73)	(79)	-0.4
WEST N. CENTRAL	402	0	402	663	261	34	(118)	(83)	-0.5
WEST S. CENTRAL	0	0	0	0	0	0	(337)	(337)	-1.5
MOUNTAIN	0	0	0	0	0	0	0	0	0.0
PACIFIC	0	0	0	0	0	0	0	0	ERR
TOTAL U.S.	5,699	(942)	4,757	4,758	0	0	(668)	(668)	-0.3

NOTE: Totals may not add due to independent rounding.

1/ "Banked Allowances" reflect extension allowances and "banked" emission reductions generated by Phase I technology in 1995.

EXHIBIT A-7
HIGH CASE 2000 1/
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	EMISSIONS CREDITS & BANKING (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	294	0	294	429	135	58	(107)	(49)	-0.4
MIDDLE ATLANTIC	936	194	1,130	1,556	426	181	(507)	(326)	-0.9
UPPER S. ATLANTIC	748	334	1,082	1,130	48	20	(382)	(361)	-2.4
LOWER S. ATLANTIC	1,417	11	1,428	1,677	249	106	(316)	(210)	-0.5
EAST N. CENTRAL	2,324	1,344	3,668	2,583	(1,085)	(461)	(358)	(819)	-1.8
EAST S. CENTRAL	1,096	160	1,256	1,428	172	73	(366)	(293)	-1.3
WEST N. CENTRAL	924	0	924	1,148	224	95	(279)	(184)	-1.0
WEST S. CENTRAL	1,033	0	1,033	950	(84)	(36)	(312)	(347)	-1.1
MOUNTAIN	624	0	624	575	(49)	(21)	(141)	(161)	-0.5
PACIFIC	140	0	140	104	(36)	(15)	(56)	(71)	-1.4
TOTAL U.S.	9,536	2,042	11,578	11,578	0	0	(2,822)	(2,822)	-1.1

NOTE: Totals may not add due to independent rounding.

1/ "Allowable SO2 Emissions" include extra non-transferrable allowances for units repowering by 2005. Also, "Emissions Credits & Banking" reflect extension allowances, and "banked" emissions reductions used in 2000.

EXHIBIT A-8
HIGH CASE 2005
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	285	146	(139)	(87)	72	(15)	-0.1
MIDDLE ATLANTIC	917	887	(29)	(18)	(93)	(111)	-0.2
UPPER S. ATLANTIC	740	992	251	157	(242)	(85)	-0.5
LOWER S. ATLANTIC	1,410	1,430	19	12	(95)	(82)	-0.1
EAST N. CENTRAL	2,260	2,117	(144)	(90)	(152)	(242)	-0.5
EAST S. CENTRAL	1,072	1,198	125	78	(223)	(145)	-0.5
WEST N. CENTRAL	913	941	29	18	(160)	(142)	-0.6
WEST S. CENTRAL	1,033	954	(80)	(50)	(351)	(400)	-0.4
MOUNTAIN	622	627	6	4	(284)	(280)	-0.8
PACIFIC	140	102	(38)	(24)	(83)	(107)	-0.1
TOTAL U.S.	9,393	9,393	0	0	(1,610)	(1,610)	-0.4

NOTE: Totals may not add due to independent rounding.

EXHIBIT A-9
HIGH CASE 2010
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	274	229	(45)	(23)	5	(18)	-0.0
MIDDLE ATLANTIC	893	898	5	3	(93)	(90)	-0.2
UPPER S. ATLANTIC	726	829	103	53	(85)	(32)	-0.2
LOWER S. ATLANTIC	1,321	1,106	(215)	(111)	(16)	(127)	-0.2
EAST N. CENTRAL	2,111	2,089	(21)	(11)	(463)	(474)	-0.9
EAST S. CENTRAL	1,060	1,185	125	64	(168)	(104)	-0.3
WEST N. CENTRAL	852	967	115	59	(223)	(164)	-0.7
WEST S. CENTRAL	1,001	917	(84)	(43)	(132)	(175)	-0.2
MOUNTAIN	589	631	42	22	(207)	(186)	-0.4
PACIFIC	123	99	(23)	(12)	(64)	(76)	0.1
TOTAL U.S.	8,950	8,950	(0)	(0)	(1,446)	(1,446)	-0.3

NOTE: Totals may not add due to independent rounding.

EXHIBIT A-10
HIGH CASE 1995 1/
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	BANKED ALLOWANCES (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	32	0	32	26	(6)	(1)	(10)	(11)	-0.1
MIDDLE ATLANTIC	706	(108)	598	683	86	11	83	94	0.3
UPPER S. ATLANTIC	637	(151)	486	508	22	3	138	141	[illegible]
LOWER S. ATLANTIC	715	(6)	709	447	(261)	(35)	58	23	0.1
EAST N. CENTRAL	2,257	(600)	1,658	1,601	(57)	(7)	475	468	[illegible]
EAST S. CENTRAL	950	(77)	874	829	(44)	(6)	85	79	0.4
WEST N. CENTRAL	402	0	402	663	261	34	22	56	0.3
WEST S. CENTRAL	0	0	0	0	0	0	3	3	0.0
MOUNTAIN	0	0	0	0	0	0	20	20	0.1
PACIFIC	0	0	0	0	0	0	0	0	0.0
TOTAL U.S.	5,699	(942)	4,757	4,758	0	0	874	874	0.4

NOTE: Totals may not add due to independent rounding.

1/ "Banked Allowances" reflect extension allowances and "banked" emission reductions generated by Phase I technology in 1995.

EXHIBIT A-11
HIGH CASE 2000 1/
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	EMISSIONS CREDITS & BANKING (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	294	0	294	429	135	58	4	62	0.6
MIDDLE ATLANTIC	936	194	1,130	1,556	426	181	142	323	0.9
UPPER S. ATLANTIC	748	334	1,082	1,130	48	20	231	251	1.6
LOWER S. ATLANTIC	1,417	11	1,428	1,677	249	106	242	348	0.8
EAST N. CENTRAL	2,324	1,344	3,668	2,583	(1,085)	(461)	741	280	0.6
EAST S. CENTRAL	1,096	160	1,256	1,428	172	73	275	348	1.5
WEST N. CENTRAL	924	0	924	1,148	224	95	249	344	1.8
WEST S. CENTRAL	1,033	0	1,033	950	(84)	(36)	75	40	0.1
MOUNTAIN	624	0	624	575	(49)	(21)	119	98	0.3
PACIFIC	140	0	140	104	(36)	(15)	(10)	(25)	-0.5
TOTAL U.S.	9,536	2,042	11,578	11,578	0	0	2,068	2,068	0.8

NOTE: Totals may not add due to independent rounding.

1/ "Allowable SO2 Emissions" include extra non-transferrable allowances for units repowering by 2005. Also, "Emissions Credits & Banking" reflect extension allowances, and "banked" emissions reductions used in 2000.

EXHIBIT A-12
HIGH CASE 2005
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	285	146	(139)	(87)	201	114	0.5
MIDDLE ATLANTIC	917	887	(29)	(18)	504	486	1.0
UPPER S. ATLANTIC	740	992	251	157	254	411	2.5
LOWER S. ATLANTIC	1,410	1,430	19	12	390	402	0.6
EAST N. CENTRAL	2,260	2,117	(144)	(90)	1,045	955	1.9
EAST S. CENTRAL	1,072	1,198	125	78	296	374	1.4
WEST N. CENTRAL	913	941	29	18	290	308	1.4
WEST S. CENTRAL	1,033	954	(80)	(50)	323	273	0.3
MOUNTAIN	622	627	6	4	98	102	0.3
PACIFIC	140	102	(38)	(24)	24	0	0.0
TOTAL U.S.	9,393	9,393	0	0	3,426	3,426	0.9

NOTE: Totals may not add due to independent rounding.

EXHIBIT A-13
HIGH CASE 2010
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	274	229	(45)	(23)	96	73	0.2
MIDDLE ATLANTIC	893	898	5	3	403	406	0.8
UPPER S. ATLANTIC	726	829	103	53	296	349	1.8
LOWER S. ATLANTIC	1,321	1,106	(215)	(111)	472	361	0.4
EAST N. CENTRAL	2,111	2,089	(21)	(11)	1,172	1,161	2.1
EAST S. CENTRAL	1,060	1,185	125	64	331	395	1.2
WEST N. CENTRAL	852	967	115	59	337	396	1.6
WEST S. CENTRAL	1,001	917	(84)	(43)	350	306	0.4
MOUNTAIN	589	631	42	22	169	191	0.4
PACIFIC	123	99	(23)	(12)	53	41	-0.0
TOTAL U.S.	8,950	8,950	(0)	(0)	3,678	3,678	0.9

NOTE: Totals may not add due to independent rounding.

EXHIBIT B-1

SULFUR DIOXIDE FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN MILLIONS OF TONS)

Utility SO2 Emissions	Pre-Statute Case 1995	CHANGE FROM PRE-STATUTE: Absent Regulation Case 1995	CHANGE FROM PRE-STATUTE: Regulatory Case 1995	Pre-Statute Case 2000	CHANGE FROM PRE-STATUTE: Absent Regulation Case 2000	CHANGE FROM PRE-STATUTE: Regulatory Case 2000
(Millions of Tons)						
37 Eastern States						
Coal						
SIP	13.38	-3.32	-3.35	13.70	-7.91	-5.24
NSPS	2.09	-0.03	0.02	2.20	-0.11	0.03
ANSPS	0.06	0.00	-0.00	0.08	0.01	0.00
Total Coal	15.53	-3.35	-3.33	16.00	-8.01	-5.21
Oil/Gas	0.46	0.00	-0.00	0.40	0.00	-0.02
Total 37 Eastern States	15.99	-3.35	-3.33	16.40	-8.01	-5.23
11 Western States						
Coal						
SIP	0.44	-0.00	-0.00	0.43	-0.10	-0.03
NSPS	0.20	0.00	0.00	0.20	-0.03	0.00
ANSPS	0.01	0.00	0.00	0.01	-0.00	0.00
Total Coal	0.65	-0.00	-0.00	0.64	-0.13	-0.03
Oil/Gas	0.01	0.00	0.00	0.03	-0.03	0.00
Total 11 Western States	0.66	-0.00	-0.00	0.68	-0.16	-0.03
United States						
Coal						
SIP	13.82	-3.32	-3.35	14.14	-8.01	-5.27
NSPS	2.29	-0.03	0.02	2.42	-0.14	0.03
ANSPS	0.07	0.01	-0.00	0.09	0.01	0.00
Total Coal	16.18	-3.35	-3.33	16.64	-8.15	-5.23
Oil/Gas	0.46	0.00	-0.00	0.43	-0.08	-0.02
Total United States	16.64	-3.35	-3.33	17.07	-8.23	-5.26

EXHIBIT B-1

SULFUR DIOXIDE FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN MILLIONS OF TONS)

Utility SO2 Emissions	Pre-Statute Case 2005	CHANGE FROM PRE-STATUTE: Absent Regulation Case 2005	CHANGE FROM PRE-STATUTE: Regulatory Case 2005	Pre-Statute Case 2010	CHANGE FROM PRE-STATUTE: Absent Regulation Case 2010	CHANGE FROM PRE-STATUTE: Regulatory Case 2010
(Millions of Tons)						
37 Eastern States						
Coal						
SIP	13.03	-7.69	-7.03	11.85	-7.00	-6.51
NSPS	2.20	-0.11	-0.02	2.08	-0.11	-0.03
ANSPS	0.33	-0.01	-0.04	0.73	0.07	0.00
Total Coal	15.56	-7.81	-7.09	14.66	-7.05	-6.54
Oil/Gas	0.33	-0.06	-0.03	0.25	-0.06	-0.06
Total 37 Eastern States	15.89	-7.87	-7.12	14.91	-7.11	-6.59
11 Western States						
Coal						
SIP	0.39	-0.10	-0.04	0.38	-0.08	-0.02
NSPS	0.21	-0.04	-0.01	0.20	-0.04	0.00
ANSPS	0.13	-0.03	-0.04	0.18	-0.03	-0.05
Total Coal	0.73	-0.16	-0.08	0.75	-0.16	-0.06
Oil/Gas	0.02	-0.01	-0.00	0.01	-0.01	-0.00
Total 11 Western States	0.75	-0.18	-0.09	0.76	-0.16	-0.06
United States						
Coal						
SIP	13.42	-7.79	-7.07	12.22	-7.09	-6.52
NSPS	2.41	-0.14	-0.03	2.28	-0.15	-0.03
ANSPS	0.46	-0.04	-0.08	0.90	0.03	-0.04
Total Coal	16.29	-7.97	-7.17	15.41	-7.20	-6.59
Oil/Gas	0.35	-0.08	-0.03	0.26	-0.07	-0.06
Total United States	16.64	-8.06	-7.20	15.67	-7.27	-6.65

EXHIBIT B-2

FUEL CONSUMPTION FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN QUADS)

	Pre-Statute Case 1995	Absent Regulation Case 1995	Regulatory Case 1995	Pre-Statute Case 2000	Absent Regulation Case 2000	Regulatory Case 2000
		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
37 Eastern States						
COAL						
LOW SULFUR	3.74	-.93	-.97	3.85	1.92	-.38
LOW-MEDIUM SULFUR	2.52	.00	-.12	2.75	.13	.51
HIGH-MEDIUM SULFUR	4.47	.09	-.61	4.64	-2.41	-1.20
HIGH SULFUR	3.74	-1.69	-.85	3.88	-2.15	-1.41
TOTAL	14.47	-2.54	-2.55	15.13	-2.52	-2.48
11 Western States						
COAL						
LOW SULFUR	1.17	1.24	1.16	1.27	1.21	1.09
LOW-MEDIUM SULFUR	.64	.36	.64	.57	.47	.58
HIGH-MEDIUM SULFUR	.27	.73	.73	.25	.66	.71
HIGH SULFUR	.00	.10	.10	.00	.05	.10
TOTAL	2.08	2.42	2.43	2.09	2.38	2.67
Total U.S.						
COAL						
LOW SULFUR	4.91	.30	.20	5.12	3.13	.71
LOW-MEDIUM SULFUR	3.16	.36	.32	3.32	.60	1.09
HIGH-MEDIUM SULFUR	4.75	.82	.12	4.90	-1.76	-.49
HIGH SULFUR	3.76	-1.59	-.76	3.88	-2.11	-1.32
TOTAL	16.58	-.12	-.12	17.22	-.13	-.01

EXHIBIT 8-2

FUEL CONSUMPTION FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN QUADS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 2005	Absent Regulation Case 2005	Regulatory Case 2005	Pre-Statute Case 2010	Absent Regulation Case 2010	Regulatory Case 2010
37 Eastern States						
COAL						
LOW SULFUR	3.80	1.61	1.04	3.99	.89	.60
LOW-MEDIUM SULFUR	3.12	-.11	.01	3.56	-.10	-.12
HIGH-MEDIUM SULFUR	5.15	-2.28	-1.77	4.97	-1.70	-1.22
HIGH SULFUR	4.20	-1.86	-1.91	4.91	-2.01	-2.19
TOTAL	16.26	-2.65	-2.63	17.42	-2.93	-2.93
11 Western States						
COAL						
LOW SULFUR	2.14	1.23	1.02	2.74	1.27	1.19
LOW-MEDIUM SULFUR	.77	.60	.74	.79	.91	.93
HIGH-MEDIUM SULFUR	.26	.77	.81	.26	.87	.87
HIGH SULFUR	.00	.09	.13	.00	.10	.12
TOTAL	3.18	2.69	2.69	3.79	3.15	3.11
Total U.S.						
COAL						
LOW SULFUR	5.96	2.84	2.06	6.73	2.16	1.79
LOW-MEDIUM SULFUR	3.89	.49	.75	4.34	.81	.81
HIGH-MEDIUM SULFUR	5.41	-1.51	-.96	5.24	-.86	-.35
HIGH SULFUR	4.20	-1.77	-1.79	4.91	-1.91	-2.07
TOTAL	19.44	.05	.06	21.21	.22	.18

EXHIBIT B-3

COAL PRODUCTION AND SHIPMENT FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN MILLIONS OF TONS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 1995	Absent Regulation Case 1995	Regulatory Case 1995	Pre-Statute Case 2000	Absent Regulation Case 2000	Regulatory Case 2000
COAL PRODUCTION						
NORTHERN APPALACHIA	179.	2.	1.	191.	-51.	-12.
CENTRAL APPALACHIA	250.	28.	17.	256.	75.	39.
SOUTHERN APPALACHIA	23.	1.	0.	21.	3.	1.
MIDWEST	129.	-43.	-22.	140.	-64.	-39.
WEST	618.	1.	-3.	424.	31.	11.
TOTAL COAL REGIONS	[illegible]	-11.	-7.	1030.	-7.	-1.
COAL TRANSPORTATION						
WESTERN COAL TO EAST	68.	-3.	-2.	52.	19.	6.

EXHIBIT 8-3

COAL PRODUCTION AND SHIPMENT FORECASTS
ABSENT REGULATION AND REGULATORY
LOW CASES
(IN MILLIONS OF TONS)

		CHANGE FROM PRE-STATUTE			CHANGE FROM PRE-STATUTE	
	Pre-Statute Case 2005	Absent Regulation Case 2005	Regulatory Case 2005	Pre-Statute Case 2010	Absent Regulation Case 2010	Regulatory Case 2010
COAL PRODUCTION						
NORTHERN APPALACHIA	208.	-49.	-32.	220.	-45.	-32.
CENTRAL APPALACHIA	262.	74.	64.	250.	106.	94.
SOUTHERN APPALACHIA	24.	-1.	-1.	27.	-4.	-5.
MIDWEST	155.	-56.	-58.	189.	-71.	-75.
WEST	484.	32.	26.	522.	21.	20.
TOTAL COAL REGIONS	1132.	0.	-2.	1207.	6.	2.
COAL TRANSPORTATION						
WESTERN COAL TO EAST	48.	15.	8.	46.	3.	4.

EXHIBIT B-4

CHANGE IN ANNUALIZED NET
UTILITY COSTS BY REGION 1/
(MILLIONS OF 1990 DOLLARS)

	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE
	LOW REG. CASE 1995	LOW REG. CASE 1995	LOW REG. CASE 2000	LOW REG. CASE 2000	LOW REG. CASE 2005	LOW REG. CASE 2005	LOW REG. CASE 2010	LOW REG. CASE 2010
NEW ENGLAND	-22	2	-60	-16	-61	-33	-44	-29
MIDDLE ATLANTIC	-5	96	-253	110	68	267	44	69
UPPER S. ATLANTIC	36	136	-226	157	-54	291	-25	139
LOWER S. ATLANTIC	-102	-41	-205	76	-130	571	-186	-55
EAST N. CENTRAL	-80	377	-435	401	-225	603	-355	521
EAST S. CENTRAL	-91	36	-282	200	-133	391	-79	135
WEST N. CENTRAL	-106	15	-178	152	-149	333	-209	217
WEST S. CENTRAL	20	23	-157	9	-184	-35	-133	1
MOUNTAIN	16	-21	-179	28	-225	203	-190	28
PACIFIC	0	1	-66	-7	-63	-25	-100	-17
TOTAL U.S.	(335)	626	(2,041)	1,111	(1,156)	2,567	(1,279)	1,008

1/ Includes gas price increases (as gas demands increase), but does not include costs of higher gas prices for other sectors.

EXHIBIT B-5

PERCENT CHANGE IN ELECTRICITY RATES BASED ON
ANNUALIZED COSTS (I.E., LEVELIZED BASIS) 1/
(PERCENT)

	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE	CHANGE FROM ABSENT REGULATION	CHANGE FROM PRE-STATUTE
	LOW REG. CASE 1995	LOW REG. CASE 1995	LOW REG. CASE 2000	LOW REG. CASE 2000	LOW REG. CASE 2005	LOW REG. CASE 2005	LOW REG. CASE 2010	LOW REG. CASE 2010
NEW ENGLAND	-0.3	0.0	-0.8	-0.2	-0.9	-0.5	-0.6	-0.4
MIDDLE ATLANTIC	-0.0	0.3	-0.8	0.3	0.2	0.8	0.1	0.2
UPPER S. ATLANTIC	0.3	1.1	-1.8	1.3	-0.4	2.3	-0.2	1.1
LOWER S. ATLANTIC	-0.3	-0.1	-0.6	0.2	-0.4	1.6	-0.5	-0.1
EAST N. CENTRAL	-0.1	0.6	-1.0	1.0	-0.5	1.6	-0.8	1.2
EAST S. CENTRAL	-0.5	0.2	-1.3	0.9	-0.6	1.8	-0.3	0.6
WEST N. CENTRAL	-0.6	0.1	-1.0	0.8	-0.8	1.9	-1.1	1.1
WEST S. CENTRAL	0.1	0.1	-0.5	0.0	-0.6	-0.1	-0.3	0.0
MOUNTAIN	0.1	-0.1	-0.9	0.1	-0.9	0.8	-0.6	0.1
PACIFIC	0.0	0.0	0.0	0.0	-0.4	-0.1	-0.7	-0.1
TOTAL U.S.	-0.1	0.2	-0.9	0.5	-0.5	1.1	-0.5	0.4

1/ Calculated as follows:

$$\left[\frac{\text{Emission Reduction Case Annualized Cost - Pre-Statute Annualized Cost}}{\text{In-State Generation after Distribution Losses}} \right] \div \text{1986 Average Electricity Rates}$$

EXHIBIT 8-6
LOW CASE 1995 1/
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	BANKED CREDITS (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	32	0	32	26	(6)	(1)	(22)	(22)	-0.3
MIDDLE ATLANTIC	706	(108)	598	634	37	4	(9)	(5)	-0.0
UPPER S. ATLANTIC	637	(151)	486	514	28	3	33	36	0.3
LOWER S. ATLANTIC	715	(6)	709	490	(218)	(22)	(80)	(102)	-0.3
EAST N. CENTRAL	2,257	(600)	1,658	1,578	(80)	(8)	(72)	(80)	-0.1
EAST S. CENTRAL	950	(77)	874	861	(13)	(1)	(89)	(91)	-0.5
WEST N. CENTRAL	402	0	402	655	253	26	(132)	(106)	-0.6
WEST S. CENTRAL	0	0	0	0	0	0	20	20	0.1
MOUNTAIN	0	0	0	0	0	0	16	16	0.1
PACIFIC	0	0	0	0	0	0	0	0	0.0
TOTAL U.S.	5,699	(942)	4,757	4,758	0	0	(335)	(335)	-0.1

NOTE: Totals may not add due to independent rounding.

1/ "Banked Allowances" reflect extension allowances and "banked" emission reductions generated by Phase I technology in 1995.

EXHIBIT B-7
LOW CASE 2000 1/
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	EMISSIONS CREDITS & BANKING (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	292	0	292	206	(86)	(17)	(43)	(60)	-0.8
MIDDLE ATLANTIC	1,033	155	1,188	1,387	199	39	(292)	(253)	-0.8
UPPER S. ATLANTIC	791	267	1,059	1,094	35	7	(233)	(226)	-1.8
LOWER S. ATLANTIC	1,507	9	1,516	1,626	110	22	(227)	(205)	-0.6
EAST N. CENTRAL	2,498	1,075	3,572	2,667	(906)	(180)	(255)	(435)	-1.3
EAST S. CENTRAL	1,121	128	1,249	1,575	326	65	(347)	(282)	-1.3
WEST N. CENTRAL	976	0	976	1,466	491	97	(276)	(178)	-1.3
WEST S. CENTRAL	1,027	0	1,027	971	(56)	(11)	(146)	(157)	-0.5
MOUNTAIN	618	0	618	539	(79)	(16)	(164)	(179)	-0.9
PACIFIC	139	0	139	104	(36)	(7)	(59)	(66)	0.3
TOTAL U.S.	10,003	1,634	11,637	11,636	0	(0)	(2,040)	(2,041)	-0.9

NOTE: Totals may not add due to independent rounding.

1/ "Allowable SO2 Emissions" include extra non-transferrable allowances for units repowering by 2005. Also, "Emissions Credits & Banking" reflect extension allowances, and "banked" emissions reductions used in 2000.

EXHIBIT 8-8
LOW CASE 2005
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	283	203	(80)	(32)	(29)	(61)	-0.9
MIDDLE ATLANTIC	910	1,053	143	57	11	68	0.2
UPPER S. ATLANTIC	736	864	129	51	(105)	(54)	-0.4
LOWER S. ATLANTIC	1,396	1,258	(138)	(55)	(75)	(130)	-0.4
EAST N. CENTRAL	2,249	2,095	(154)	(61)	(165)	(225)	-0.5
EAST S. CENTRAL	1,064	1,254	191	76	(208)	(133)	-0.6
WEST N. CENTRAL	904	955	51	20	(169)	(149)	-0.8
WEST S. CENTRAL	1,027	978	(49)	(19)	(165)	(184)	-0.6
MOUNTAIN	618	561	(57)	(22)	(203)	(225)	-0.9
PACIFIC	139	102	(37)	(15)	(48)	(63)	-0.4
TOTAL U.S.	9,327	9,326	0	(0)	(1,155)	(1,156)	-0.5

NOTE: Totals may not add due to independent rounding.

EXHIBIT B-9
LOW CASE 2010
REGULATORY CASE RELATIVE TO "ABSENT REGULATION" CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	274	202	(72)	(25)	(20)	(44)	-0.6
MIDDLE ATLANTIC	893	970	76	26	17	44	0.1
UPPER S. ATLANTIC	726	818	91	31	(57)	(25)	-0.2
LOWER S. ATLANTIC	1,320	1,230	(90)	(31)	(155)	(186)	-0.5
EAST N. CENTRAL	2,110	1,888	(222)	(76)	(279)	(355)	-0.8
EAST S. CENTRAL	1,060	1,210	151	52	(131)	(79)	-0.3
WEST N. CENTRAL	855	947	92	32	(241)	(209)	-1.1
WEST S. CENTRAL	1,001	997	(4)	(1)	(132)	(133)	-0.3
MOUNTAIN	588	587	(2)	(1)	(190)	(190)	-0.6
PACIFIC	123	102	(21)	(7)	(93)	(100)	-0.7
TOTAL U.S.	8,950	8,950	(0)	(0)	(1,279)	(1,279)	-0.5

NOTE: Totals may not add due to independent rounding.

EXHIBIT B-10
LOW CASE 1995
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	BANKED CREDITS 1/ (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	32	0	32	26	(6)	(1)	2	2	0.0
MIDDLE ATLANTIC	706	(108)	598	634	37	4	93	96	0.3
UPPER S. ATLANTIC	637	(151)	486	516	28	3	133	136	1.1
LOWER S. ATLANTIC	715	(6)	709	490	(218)	(22)	(19)	(41)	-0.1
EAST N. CENTRAL	2,257	(600)	1,658	1,578	(80)	(8)	385	377	0.6
EAST S. CENTRAL	950	(77)	874	861	(13)	(1)	37	36	0.2
WEST N. CENTRAL	402	0	402	655	253	26	(11)	15	0.1
WEST S. CENTRAL	0	0	0	0	0	0	23	23	0.1
MOUNTAIN	0	0	0	0	0	0	(21)	(21)	-0.1
PACIFIC	0	0	0	0	0	0	1	[illegible]	0.0
TOTAL U.S.	5,699	(942)	4,757	4,758	0	0	623	626	0.2

NOTE: Totals may not add due to independent rounding.

1/ "Banked Allowances" reflect extension allowances and "banked" emission reductions generated by Phase I technology in 1995.

EXHIBIT 8-11
LOW CASE 2000 1/
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	ALLOWABLE SO2 EMISSIONS (MTONS)	EMISSIONS CREDITS & BANKING (MTONS)	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	292	0	292	206	(86)	(17)	1	(16)	-0.2
MIDDLE ATLANTIC	1,033	155	1,188	1,387	199	39	71	110	0.3
UPPER S. ATLANTIC	791	267	1,059	1,096	35	7	150	157	1.3
LOWER S. ATLANTIC	1,507	9	1,516	1,626	110	22	55	76	0.2
EAST N. CENTRAL	2,498	1,075	3,572	2,667	(906)	(180)	581	401	1.0
EAST S. CENTRAL	1,121	128	1,249	1,575	326	65	135	200	0.9
WEST N. CENTRAL	976	0	976	1,466	491	97	55	152	0.8
WEST S. CENTRAL	1,027	0	1,027	971	(56)	(11)	20	9	0.0
MOUNTAIN	618	0	618	539	(79)	(16)	44	28	0.1
PACIFIC	139	0	139	106	(36)	(7)	0	(7)	0.0
TOTAL U.S.	10,003	1,634	11,637	11,636	0	(0)	1,111	1,111	0.5

NOTE: Totals may not add due to independent rounding.

1/ "Allowable SO2 Emissions" include extra non-transferrable allowances for units repowering by 2005. Also, "Emissions Credits & Banking" reflect extension allowances, and "banked" emissions reductions used in 2000.

EXHIBIT B-12
LOW CASE 2005
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	283	203	(80)	(32)	(1)	(33)	-0.5
MIDDLE ATLANTIC	910	1,053	143	57	210	267	0.8
UPPER S. ATLANTIC	736	864	129	51	240	291	2.3
LOWER S. ATLANTIC	1,396	1,258	(138)	(55)	626	571	1.6
EAST N. CENTRAL	2,249	2,095	(154)	(61)	664	603	1.6
EAST S. CENTRAL	1,064	1,256	191	76	315	391	1.8
WEST N. CENTRAL	904	955	51	20	313	333	1.9
WEST S. CENTRAL	1,027	978	(49)	(19)	(15)	(35)	-0.1
MOUNTAIN	618	561	(57)	(22)	226	203	0.8
PACIFIC	139	102	(37)	(15)	(10)	(25)	-0.1
TOTAL U.S.	9,327	9,326	0	(0)	2,567	2,567	1.1

NOTE: Totals may not add due to independent rounding.

EXHIBIT 8-13
LOW CASE 2010
REGULATORY CASE RELATIVE TO PRE-STATUTE CASE

STATE/REGION	TOTAL ALLOWABLE SO2 EMISSIONS (MTONS)	AFFECTED SOURCE SO2 EMISSIONS (MTONS)	NET TRADES (MTONS)	CASE TRADING COSTS ($MM)	CASE COMPLIANCE COSTS ($MM)	CASE TOTAL COSTS ($MM)	ELECTRICITY RATE INCREASES (%)
NEW ENGLAND	274	202	(72)	(25)	(6)	(29)	-0.4
MIDDLE ATLANTIC	893	970	76	26	43	69	0.2
UPPER S. ATLANTIC	726	818	91	31	108	139	1.1
LOWER S. ATLANTIC	1,320	1,230	(90)	(31)	(26)	(55)	-0.1
EAST N. CENTRAL	2,110	1,888	(222)	(76)	597	521	1.2
EAST S. CENTRAL	1,060	1,210	151	52	83	135	0.6
WEST N. CENTRAL	855	947	92	32	185	217	1.1
WEST S. CENTRAL	1,001	997	(4)	(1)	2	1	0.0
MOUNTAIN	588	587	(2)	(1)	28	28	0.1
PACIFIC	123	102	(21)	(7)	(10)	(17)	-0.1
TOTAL U.S.	8,950	8,950	(0)	(0)	1,008	1,008	0.6

NOTE: Totals may not add due to independent rounding.

ATTACHMENT
Impacts of Regulation of New Small Utility Units Under the Acid Rain Program

1. INTRODUCTION

ICF has conducted a preliminary analysis of the savings to utilities resulting from an exception for utility units with a capacity of 25 megawatts (MW) or less. The savings to utilities of an exception for small units are estimated at approximately $2 million in the first year. Because additional small units would be purchased each year, the annual savings would increase by about the same amount each year.

Under the Clean Air Act Amendments of 1990, utility generating units of 25 MW or less capacity are exempt from all statutory requirements if they were built before November 15, 1990 (the date of enactment of the statute). The statute does not specify whether new units will be exempt. Under proposed regulations, a utility operating a new unit of any size would be subject to all requirements, including the requirements to (1) install a continuous emission monitoring system (CEMS) and (2) hold allowances equal to its SO_2 emissions. A proposed exception to these requirements for units using very-low-sulfur fuel that were used infrequently would reduce costs per unit significantly. EPA received numerous comments questioning the need for monitoring requirements for small units. Commenters have requested that EPA provide relief to utilities purchasing new small units.

EPA has decided to grant an exception to the CEMS requirements and associated allowance and permit requirements for new units of 25 MW or less capacity that (1) are fueled with very-low-sulfur fuel (i.e., natural gas or very-low-sulfur diesel fuel) and (2) are used ten percent of the time or less. Owners and operators of such units seeking to qualify for the exception would be required to certify their use of very-low-sulfur fuel, but would not be required to hold allowances for their SO_2 emissions.

2. ANALYTICAL APPROACH

For this preliminary estimate of the savings to the utility industry from an exception for small units, ICF has examined several issues: (1) the number of new small units that may be purchased by utilities each year; (2) the savings per unit of a small unit exception; and (3) potential incentives to use two smaller units under 25 MW instead of one larger unit over 25 MW. The analysis also considered the extent to which the benefits of an exception will accrue to municipal utilities and other small utilities.

3. THE NUMBER OF NEW SMALL UNITS THAT MAY BE PURCHASED BY UTILITIES EACH YEAR

According to utility projections reported to the Energy Information Administration in 1988, utilities were planning 28 small units for 1989.[1] While the number of planned units for later years decreased, with only nine units planned for 1990 and zero to three units planned each year thereafter, data for these years are less reliable because utilities do not need to plan far in advance in order to install a small unit. Many small units, notably diesel or dual-fuel generators, are purchased off-the-shelf rather than constructed on-site. Because utilities may generally purchase and install these units and receive permit approval in a short period of time, there is often no need for them to plan for a small unit years in advance. This analysis uses the 28 small

[1] Based on Form EIA-860 Annual Electric Generator Report for 1988.

units planned for 1989 as the estimated number of small units that would be ordered by utilities each year.

Of the 28 units planned for 1989, the utilities planning the units expected to burn liquid fuels in 18 of the units, natural gas in nine of the units, and coal in one unit. Of the liquid-burning units, 16 were expected to be fueled with number 2 oil, (equivalent to diesel fuel), and two were expected to be fueled with number 6 oil. Any of these units could instead burn very-low-sulfur diesel oil, which costs somewhat more than higher-sulfur oil. The coal unit could not burn very-low-sulfur fuel without a capital investment for conversion; it is assumed in this preliminary analysis that such a conversion would not be economical. Therefore, it is assumed that 27 units per year could potentially qualify for a small unit exception.

4. THE SAVINGS TO UTILITIES FROM A SMALL UNIT EXCEPTION

A small unit exception yields savings to utilities that purchase new small units, because the utilities are not required to (1) install a CEMS on the unit, (2) obtain a permit for the unit, or (3) purchase allowances for the unit's SO_2 emissions. An exception results in additional costs for the purchase of very-low-sulfur fuel, except when (1) the utility would have used natural gas, a qualifying fuel, in the absence of an exception, or (2) the utility would have used very-low-sulfur diesel fuel in the absence of an exception, because higher sulfur diesel fuel was locally unavailable.

The annualized costs per unit for a CEMS are substantial. EPA has estimated the total annual capital and operating costs of a CEMS on a diesel unit at $73,000 (in 1990 dollars). Annual costs for a CEMS for a gas turbine have been estimated at $58,000, but in this preliminary analysis of the savings for all small units, savings are estimated using the CEMS cost for a diesel unit. Annual data reporting costs in Phase II are estimated to be about $1,800 per unit.[2]

The costs of allowances for a 25 MW unit in the absence of an exception depends on the amount of time the units are in use. Utilities use small units to generate peaking power during times of peak demand, such as hot summer afternoons when many air conditioners are in use. In this analysis it was assumed that a typical small unit is operated 200 hours per year. A new 25 MW diesel unit operated for 200 hours per year would produce an estimated ten tons of SO_2 per year.[3] The owner or operator of such a unit would need to purchase ten allowances each year. Allowance prices are uncertain; in the only publicly reported trades to date, allowance prices have been in the $250 to $400 range. Even at a price of $500 each, ten allowances would cost $5,000. At a maximum, small utilities could purchase ten allowances each year through the direct sales program at a cost of $1,500 each for a total of $15,000; this may be considered an overestimate of

[2] U.S. EPA Acid Rain Division, Regulatory Impact Analysis of the Final Acid Rain Implementation Regulations, U.S. EPA Acid Rain Division, October 1992, p. 4-23.

[3] Based on a fuel sulfur content of 0.4 percent by weight, a heat rate of 10,000 Btu/kWh, and an emissions factor of 1.7 grams of SO_2 per kWh. This sulfur content is conservatively high. By October 1993, diesel fuel for motor vehicles may contain only 0.05 percent sulfur by weight; petroleum marketers in some areas may choose not to sell higher-sulfur diesel fuel for any purpose after that date.

allowance costs per unit. The annualized permitting costs per source in Phase II have been estimated at $3,200.[4]

When small unit exceptions are available, utilities incur extra costs to purchase very-low-sulfur fuel (for those units that would otherwise have used higher-sulfur fuel). To qualify for the small unit exception, a small unit must burn fuel with a sulfur content no greater than 0.05 pounds per million Btu (i.e., natural gas or very-low-sulfur diesel). The Clean Air Act requires that motor vehicle diesel fuel sold after October 1, 1993 may not contain sulfur in excess of 0.05 percent by weight. A small unit using such very-low-sulfur diesel fuel would qualify for the exemption. Based on previous studies, EPA estimates that such fuel may cost as much as two cents per gallon more than conventional diesel fuel, if both grades are available in a geographic region. This estimate is believed, however, to represent a maximum value of the differential cost of fuel to utilities. In some less-populated regions, such as the Midwest, the cost of providing separate distribution channels for conventional diesel and very-low-sulfur diesel may exceed the cost of manufacturing all diesel to meet the 0.05 percent sulfur specification. Because conventional, higher sulfur diesel may be unavailable in these regions, utilities would incur no incremental costs to use the very-low-sulfur diesel. Based on an incremental cost of 2 cents per gallon, the use of very-low-sulfur fuel would increase the annual costs for a utility operating a 25 MW unit for 200 hours per year by an estimated $9,000.

This preliminary analysis of the savings from a small unit exception considers only the CEMS costs, because (1) the avoided costs of CEMS far outweigh the avoided costs for allowances and permits, and the incremental costs under an exception for very-low-sulfur fuel, and (2) the additional costs for very-low-sulfur fuel tend to balance out the avoided costs for allowances and permits.

Assuming that a small unit exception allows utilities to avoid CEMS costs on 27 small units in the first year, and that annual CEMS costs are $73,000, the annual savings for utilities for units purchased in the first year would be approximately $2.0 million. Each year, assuming that utilities continue to purchase 27 new units that qualify for the exception, the annual savings to utilities would rise by about the same amount.

5. POTENTIAL INCENTIVES TO USE TWO SMALL UNITS INSTEAD OF ONE LARGER UNIT

A utility deciding what size generating unit to purchase will encounter decreasing capital costs per MW capacity as the size of the generator increases, due to economies of scale. If a CEMS is not required for new units of 25 MW or less capacity, however, the cost per MW capacity for units of 25 MW will be lower than the cost per MW capacity for units slightly larger than 25 MW.[5]

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[4] U.S. EPA Acid Rain Division, Regulatory Impact Analysis of the Final Acid Rain Implementation Regulations, U.S. EPA Acid Rain Division, October 1992, p. 4-36.

[5] For generators using diesel oil, this cost savings and the savings in avoided operating costs for CEMS will be slightly offset by the higher cost of low-sulfur diesel fuel, as required under the CEMS exception. However, because so little fuel is used in a peaking unit, the capital cost savings will dominate

The exception for units of 25 MW or less could thus provide an incentive to limit new small units to this size. A utility considering installing a single 40 MW unit, for example, might have an incentive to install two 20 MW units instead. This decision will turn on whether the annual CEMS, permit, and allowance savings exceed the higher annualized capital costs of "splitting" a larger unit in half (and losing some economies of scale). The balance between regulatory compliance costs and the economies of scale will depend, in turn, on the magnitude of the scale economies in constructing small electrical generating units.

To assess the relative importance of regulatory compliance costs for units above 25 MW and higher capital costs per kW for smaller units, ICF estimated the costs for gas turbine units ranging up to 50 MW (excluding costs of land and buildings) using the following cost equation:

$$Cost=\$542.3*(Size(MW))^{0.7}$$

The exponent in the equation expresses the degree to which there are economies of scale in manufacture of the units. The exponent of 0.7 indicates minimal scale economies in the manufacture of gas turbines: the cost per kW capacity drops approximately three percent as the size of the unit increases by ten percent. The exponent value of 0.7 for gas turbines is based on previous EPA analyses of gas turbine costs.[6] This analysis does not consider relative heat rates, fuel costs, and operating costs. Because of the limited annual operating time for small units, such costs are likely to be relatively minor relative to the capital costs.

On the basis of this preliminary analysis, ICF concluded that the only units likely to be split in order to take advantage of the small unit exception would be those just slightly larger than 25 MW. A utility planning a 26 MW gas turbine, for example, may have an economic incentive to instead purchase one 25 MW unit and one one-megawatt unit. Units in a range slightly larger than 25 MW would account for a small percentage of all new small generating units. The emissions consequences of this small shift in unit sizes would be minimal, given the small size of the units affected, their generally low utilization rates, and the fact that they would be required to use fuel with an extremely low sulfur content in order to qualify for the exception.

6. DISTRIBUTION OF SAVINGS TO SMALL UTILITIES

Small municipal utilities own a large number of small units.[7] This preliminary analysis assumes that many of the new small units purchased by utilities would be purchased by municipal utilities, to replace small units being retired. Thus, the cost savings from a small unit exception are expected to accrue largely to municipal utility companies.

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in the firm's decision.

[6] EPA Office of Air Quality Planning and Standards, "Air Emissions from Municipal Solid Waste Landfills -- Background Information for Proposed Standards and Emissions Guidelines," EPA-450/3-90-011a, May 30, 1991.

[7] ICF analysis of 1988 Energy Information Administration data from Form EIA-860.

7. CONCLUSIONS

From the foregoing analysis, several conclusions follow:

- The savings to utilities of an exception for small units are estimated at approximately $2 million in the first year. Because additional small units would be purchased each year, the annual savings would increase by about the same amount each year.

- Relatively few new small units are likely to be purchased each year.

- Regulations that require full CEMS for new small units would achieve the monitoring of very low amounts of annual emissions, especially where very-low-sulfur fuel is used.

- An exception for small units would distort a utility's choice of unit size only in a small number of cases.