increase the demand for and value of low-sulfur coal. These effects are partly borne out in projections of the coal market under each alternative. Thus, implementing Options I or IV would tend to perpetuate the trend observed during the 1970s, during which low-sulfur coal production grew and western coal sales expanded eastward. Option II, because of its low scrubbing requirement and high emissions floor, also would promote the use of low-sulfur coal. Only continuing the current NSPS or adopting Option III, both of which would entail sizable amounts of scrubbing, would tend to counter that trend, fostering greater use of high-sulfur coal from the East and the Midwest.

Neither the current NSPS or any of the alternatives examined appears to have great potential to stem the growth of western coal production or the penetration of western low-sulfur coal into markets to the east. Even the current NSPS, with their universal requirement of scrubbing, can only slow the rate of shipments of western coal to utilities in the Midwest and the East. Options I and IV would offer no provisions that would counter this trend, and Options II and III, with some scrubbing requirements but less than the current NSPS, would have almost as little effect. As has been observed since the early 1970s, inherent factors in western and coal production are expected to continue to overwhelm any influence on coal markets arising from pollutant emissions standards. Circumstances that could significantly alter this projected pattern include higher-than-anticipated rail shipment rates and significantly lower costs for control technology.

CONCLUDING REMARKS

Which of the federal government's goals receives higher Congressional priority would determine which of the options analyzed offers the better prospects. The Clean Air Act's current NSPS are best suited to holding down emissions and safeguarding midwestern coal production, but at sizable costs to the utility industry. The utilities would be better served by Options II or III, but at some sacrifice in pollution abatement. Under Options I or IV, the act's pollution control goals would be advanced to different degrees at minimal costs, but the coal producers of the Midwest would pay a price in markets lost to western suppliers. In short, the analysis suggests that the several objectives of constraining sulfur dioxide emissions, easing the electric utilities' financial burden, and protecting midwestern coal producers cannot all be pursued with equal emphasis.

THE CLEAN AIR ACT,

THE ELECTRIC UTILITIES, AND THE COAL MARKET

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CHAPTER I. INTRODUCTION

Federal policies that would protect the nation's air quality and others that would ensure a reliable, low-cost supply of electricity can sometimes interact in difficult ways. This study examines the question of whether clean air and energy policies as they affect the electric utilities are in fact on a collision course. The mechanisms by which the air quality goal is sought are embodied in the Clean Air Act, administered by the Environmental Protection Agency (EPA) and last amended in 1977. 1/ The establishment of a secure and inexpensive power supply rests on encouraging greater use of the United States' most abundant energy source: coal.

Since 1970, coal combustion has supplied roughly half of all yearly electrical production and promises to furnish an even greater share in the coming decades. Though plentiful and not vulnerable to foreign supply interruptions--and inexpensive in comparison with oil and gas--coal is also a major source of air pollution. The burning of coal by utility plants, which account for more than four-fifths of the nation's total coal consumption, accounts for approximately 60 percent of all sulfur dioxide emissions in the United States, 25 percent of all nitrogen oxide emissions, and 15 percent of all particulate emissions. 2/ The control of these pollutants--especially sulfur dioxide--is expensive, complicating the interaction between clean air policy and the desire to promote coal use in electricity production.

COAL AND POLLUTANT EMISSIONS

Chemical characteristics unique to coal have had a direct bearing on the shaping of federal emissions control regulations and their effects both

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1. First enacted in 1968 as Public Law 88-206, the Clean Air Act has undergone several major legislative revisions since that date. The structure of the act that prevails today, underlying the analysis in this paper, was adopted under the Clean Air Act Amendments of 1977 (Public Law 95-95).

2. These data, supplied by the EPA, reflect estimated pollutant levels for 1979, the most recent year for which data are available.

on utility companies and on the coal industry itself. When coal is burnt, it generates noxious gases (sulfur dioxide and nitrogen oxides) and particulate matter (unburnt material and ash). In particular, the generation of sulfur dioxide has the greatest bearing on how emissions regulations can affect the utility and coal industries. The amount of sulfur dioxide produced during coal combustion is a direct function of the sulfur content of the raw fuel. Coal's sulfur content varies from source to source, ranging between less than 1 to greater than 4 percent by weight. Mines in the West generally produce coal low in sulfur content; medium- and high-sulfur coals predominate in the Midwest; eastern mines produce coals with a full range of sulfur contents. The higher coal's sulfur content, the higher its emissions of sulfur dioxide. The evolution of emissions regulations for utility plants under the Clean Air Act, and the debate surrounding such regulations, reflect these particular properties of coal.

REGULATORY MECHANISMS

In its present form, the act is designed to protect air quality through several chief mechanisms. 3/ The primary objective of the act is to ensure that all areas of the country achieve air quality equal to or better than national ambient air quality standards (NAAQS), which are established by the EPA. These standards reflect the maximum acceptable pollutant concentrations that offer a safe environment for the public's health and welfare. Two important programs are designed around the NAAQS. A "nonattainment program" requires states to develop plans providing for attainment of all NAAQS in areas not currently meeting them; the prevention of significant deterioration (PSD) program directs the EPA and the states to limit the increase of pollution in areas with air better than the NAAQS. Finally, as an aid in limiting pollution growth and maintaining the NAAQS, the act directs the EPA to establish uniform nationwide emissions limits for most major new facilities. These standards, termed new source performance standards (NSPS), apply to specific categories of new and modified air pollution sources nationwide, and they reflect the minimum acceptable levels of control for these facilities. The effects of these NSPS on the utility and coal industries are a major focus of this study.

Since the act's passage, the EPA has twice established NSPS for the electric utility industry. These regulations affect all new and modified

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3. For further information on the Clean Air Act, see National Commission on Air Quality, To Breathe Clean Air, Final Report (March 1981).

facilities built after the effective date of the particular standard and limit the emissions of most gaseous and solid pollutants. In general, these standards have met with little controversy; however, the emissions control requirements for sulfur dioxide have remained a subject of intense debate.

The first set of NSPS was established in 1971 and was designed to allow the utilities to meet sulfur dioxide emissions standards using either low-sulfur coal alone or high-sulfur coal with special equipment developed to reduce sulfur dioxide emissions. The equipment used to reduce such emissions is flue gas desulfurization technology, commonly referred to as "scrubbers." Though available at the time of the first NSPS, scrubbers were expensive, and since they were not mandatory, utility managers generally avoided installing them in new units. Instead, low-sulfur coal was typically employed as an emissions control strategy. As a result, controversy arose over the 1971 regulations with respect to their possible effects on the nation's coal market, focusing on whether they would encourage the production of low-sulfur coal (primarily a western product) at the expense of medium- and high-sulfur coal produced in the Midwest and East.

In amending the Clean Air Act in 1977, the Congress changed the criteria on which the EPA bases emissions standards for facilities using fossil fuels. Two factors underlay the change: concern over the apparent regional inequities in the coal market fostered by the old regulations, and intent to encourage use of pollution control technology. The new emissions regulations the EPA adopted--the NSPS of 1978, which are still in effect--require that all newly built power plants curb sulfur dioxide emissions from any coal they burn. In effect, these NSPS dictate that scrubbers be installed in all new utility units, since no other commercially available technology can meet the EPA standards. As a result, since scrubbers became virtually mandatory, utility managers now have little motivation to use low-sulfur coal except where it is most readily available--that is, where it is locally produced. Implemention of these regulations, it was believed, would minimize new emissions everywhere and would correct regional inequities in coal production.

ISSUES BEFORE THE CONGRESS

Two controversies now surround the NSPS for sulfur dioxide emissions:

- o Whether the high capital costs of scrubbers overburden the utility industry in proportion to the control they achieve; and

- o Whether the costs of scrubbers jeopardize the economic advantage of coal relative to costlier fuels, namely oil and gas.

With these issues in mind, the Congress has already begun to consider further revisions to the Clean Air Act. For a third time, legislators will likely reassess the provisions by which the act requires the utilities to control emissions.

To assist in clarifying the issues under Congressional debate, this study explores four critical questions:

- o What is the likely future effect of the current NSPS on sulfur dioxide and other pollutant emissions?
- o What are likely to be the costs of reducing pollutant emissions at coal-fired power plants, and what financial burden do these costs put on electric utilities?
- o How might emissions standards influence the patterns of coal production and use in the United States?
- o What other forms might emissions control standards take, and what might their effects be on the utility and coal industries?

As before, questions of economic efficiency will probably arise again in the course of the debate. Will the societal benefits of pollution abatement warrant their considerable economic costs? Only so long as the benefits outweigh the costs can those costs be justified. In considering this question, the Congress will want to identify emissions regulations that will achieve an economically correct level of abatement. Because the damage that environmental deterioration may cause--to public health, agriculture, structures, and other national assets--is difficult to quantify, the benefits to be gained from clean air policy are equally difficult to gauge. Though critically important in Congressional decisionmaking, these issues are beyond the scope of this paper.

PLAN OF THE PAPER

Chapter II of this paper describes the costs of the Clean Air Act to the electric utility industry. Chapter III reviews the present financial condition of utilities and examines the costs to them of pollution control. Chapter IV analyses the effects of the Clean Air Act on the prospects for conversion and replacement of oil- and gas-fired generating capacity with coal. The focus of Chapter V is on the Clean Air Act's implications for the U.S. coal market. The closing portion of the paper, Chapter VI, outlines four alternative emissions standards for the utilities, exploring the potential of those choices on sulfur dioxide emissions, on utilities' capital and operating costs, and on the U.S. coal market.

CHAPTER II. STANDARDS AFFECTING THE ELECTRIC UTILITY INDUSTRY--THEIR EFFECTS ON EMISSIONS AND COSTS

The current air pollution control regulations required by the Clean Air Act will bring about a generation of power-producing facilities that will be significantly cleaner than their predecessors, but at considerable expense to the electric utility industry. Meeting the act's emissions control requirements will require significant capital investment for the industry during the coming two decades. According to the Congressional Budget Office's analysis, the total electric capacity of U.S. utilities between 1980 and the year 2000 will increase by some 44 percent, from 588 gigawatts to 844 gigawatts. 1/ The cumulative capital requirements for new nuclear and coal plants alone (not including transmission and distribution facilities) are projected to be $320 billion over this period; of that sum, roughly $176 billion will be attributable to an anticipated 168 gigawatts of new coal-fired capacity. Efforts to meet the federal new source performance standards (NSPS) for utility plants and, to a lesser extent, local air pollution control regulations, will account for roughly one-fifth ($33.4 billion) of that $176 billion. This chapter presents an analysis of how the NSPS and other key provisions of the Clean Air Act influence both the quantity of pollutant emissions nationwide and the costs of generating electricity.

CLEAN AIR ACT REQUIREMENTS AFFECTING ELECTRIC UTILITIES

To help meet and maintain national ambient air quality standards (that is, the act's NAAQS) several key provisions of the act serve to regulate pollutant emissions from electric utility plants. For plants built before the first federal emissions regulations for utilities in 1971, the states are required to develop plans, including emissions limits for individual plants, to achieve and maintain the NAAQS. These plans are called state implementation plans. The act also requires the EPA to limit the amount of air pollution that a new or modified facility may emit. These regulations are the NSPS, and they are established (and reviewed every four years) by the

1. A gigawatt is a unit of power equal to one billion watts. A commercial generator of 500 megawatts (0.5 gigawatts) operating at a 70 percent capacity factor can produce approximately 3.1 billion kilowatt-hours of electricity a year, the amount consumed by roughly 371,000 households.

EPA for many categories of pollution sources, including utilities. Finally, to ensure that areas already meeting NAAQS preserve their good air quality, the EPA, together with the states, operate the prevention of significant deterioration (PSD) program. This program establishes an elaborate review and permit procedure for new facilities and allows states and the EPA to adopt control measures even tighter than the NSPS. (The PSD provisions are discussed in greater detail below; their effects on utility emissions limits and administrative costs are discussed in Appendix A.)

The main focus of this study is on the NSPS (particularly the sulfur dioxide limits) for electric utilities; to a lesser extent, the study also considers the PSD provisions. The majority of future electric generating capacity will be built in areas already meeting the NAAQS, and the majority of future costs for air pollution control will be attributable to the NSPS, although a small portion of these expenses will result from the tighter state and local standards, implemented in most cases under the PSD provisions of the act.

The New Source Performance Standards of 1971 and 1978

Because of the great variation in sulfur content of coal across the country, coal-fired power plants could emit sulfur dioxide in widely differing amounts if such emissions were not controlled. For example, an uncontrolled 500-megawatt power plant could emit sulfur dioxide at rates ranging from less than 0.5 to more than 6 pounds of that gas per one million British thermal units (BTUs) of fuel consumed. In the course of a year, this range would translate into less than 7,665 and more than 91,980 tons of sulfur dioxide. The NSPS introduced in 1971 under the Clean Air Act focused directly on this problem, setting a uniform nationwide limit of 1.2 pounds of sulfur dioxide emissions per million BTUs for all new or modified power plants burning coal. 2/ Similar limits were established under the NSPS for nitrogen oxides and particulate emissions. The 1971 NSPS were set with considerations of economic effects, energy costs, and environmental and public health concerns taken into account.

In 1978, these standards were revised, with much stricter sulfur dioxide and other emissions limits set for the electric utilities. The revisions in

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2. Regulations under both the NSPS apply also to gas- and oil-fired plants. The limit set for new oil-burning plants was 0.8 pounds of sulfur dioxide emissions per million BTUs of fuel consumed.

1978 reflected a fundamental change in the act's NSPS provisions, changes that were designed, in part, to encourage the use of control technology and to foster the use of local coal regardless of its sulfur content. Table 1 contrasts the provisions of the two sets of new source performance standards.

TABLE 1. NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED ELECTRIC UTILITIES

Pollutant	1971 Maximum Allowable Emissions	1978 Maximum Allowable Emissions
Sulfur Dioxide	1.2 pounds per million BTUs of any coal consumed	No more than 1.2 pounds per million BTUs of fuel consumed plus 90 percent emissions reduction, no more than 0.6 pounds per million BTUs of fuel consumed plus 70 percent emissions reduction
Nitrogen Oxide	0.7 pounds per million BTUs of all anthracite, bituminous, and subbituminous coals consumed; 0.6 pounds for lignite	0.6 pounds per million BTUs of anthracite, bituminous, and lignite coal consumed
Particulate Emissions	0.1 pounds per million BTUs of fuel consumed	0.03 pounds per million BTUs of fuel consumed

SOURCE: U.S. Environmental Protection Agency.

NOTE: Table does not show emissions limits applying to either oil-or gas-fired utility plants. See 36 Federal Register 15703 (December 23, 1971) and 44 Federal Register 33580 (June 11, 1979).

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The 1978 revisions did not supersede the older NSPS. Plants licensed to operate under the 1971 NSPS remained (and still are) subject to them. Rather, the new standards added stringent requirements for those new plants to which they would apply. Besides limiting emissions to 1.2 pounds of sulfur dioxide per million BTUs generated from coal, new or modified plants burning coal (or any fossil fuel) must now also remove a finite percentage of that pollutant from emissions. 3/ The level of mandatory pollutant removal is not uniform, however, requiring that between 70 and 90 percent of all sulfur dioxide emissions be eliminated. The determinant of what percentage sulfur dioxide removal a plant must achieve, based on its final emissions rate, is whether the plant will burn high- or low-sulfur coal.

Methods of Compliance and Effects. A typical method for a utility plant's meeting the 1971 NSPS was to use fuel with inherently low emissions characteristics--that is, low-sulfur coal or oil. Under the new NSPS, however, sulfur dioxide emissions must be reduced from any variety of coal being burnt. At present, the only commercially available device that can achieve the required reductions in conventional power plants is a scrubber; thus, in effect, the 1978 NSPS mandates the use of scrubbers in all new coal-fired power plants. Though no new or modified coal-fired utility generators planning to use scrubbers under the 1978 regulations are yet in full commercial operation, the effect of scrubbing will be to cut emissions by more than a half from levels allowed under the old NSPS. 4/

The 70-90 percent sliding scale for sulfur dioxide emissions removal effectively gives utilities an economic choice between using "wet" and "dry" scrubbers, depending on the sulfur content of the coal they plan to burn. 5/

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3. The regulation chiefly affects new coal plants, since the Power Plant and Industrial Fuel Use Act of 1978 prohibits the burning of oil or gas in major new power plants.

4. In view of the time lag that intervenes between a firm's decision to build a new plant and the time that plant is actually generating power, the effects of the 1978 NSPS cannot be expected to materialize before well into the 1990s.

5. Wet scrubbers remove sulfur dioxide by passing exhaust gases through an aqueous chemical spray that absorbs the sulfur dioxide, leaving the exhaust gas with a lower sulfur dioxide concentration. (Particulates are

Wet scrubbers, which can remove 90 percent or more of the sulfur dioxide a power plant emits, are by far the costlier choice; installation of a wet scrubber can add as much as 20 percent of the initial capital costs of a new plant. They do, however, permit combustion of medium- and even high-sulfur-content coal. Dry scrubbers, capable of 70 percent sulfur dioxide removal and considerably cheaper--accounting for perhaps 10 percent of initial capital outlays for a new plant--are suitable only for low-sulfur coal combustion under the present regulations. Commercial experience with dry scrubber systems on utility plants is lacking, because the technology is relatively new; however, it is a fairly well proven technology, and many utility systems have dry scrubbers on order for their new plants.

Prevention of Significant Deterioration

For areas now attaining the NAAQS, the Clean Air Act mandates that, if possible, air quality be prevented from deteriorating to the level of the NAAQS because of new air pollution. The act's provisions applying to such regions are encompassed in the PSD program, and as the term implies, they cover regions where the air quality is relatively good at the time a utility firm or other industry contemplates locating a new plant there. The PSD provisions are designed to preserve air quality while at the same time avoiding hindrance of industrial growth. The amount of pollution-caused degradation allowed in an area (possibly up to but not exceeding the NAAQS) is denoted by specified increments or classes, shown in Table 2. The Clean Air Act Amendments of 1977 classified certain areas, such as national parks, as mandatory Class I. Other public use areas, such as national recreation areas, were originally classified as Class II and may not be changed to Class III. All other areas were originally classified as Class II and may be redesignated by the state with the governor's approval.

Under the PSD program, a utility considering construction of a new power plant undergoes a rigid preliminary review process, of which two components are especially influential both to costs and to air quality. First, the planners of a new facility must demonstrate to the state and regional

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5. (Continued)
removed prior to scrubbing.) The product of the scrubber is a precipitate of high water content, which typically is filtered and chemically stabilized before disposal. A dry scrubber involves much less water and combines both particulate and sulfur dioxide removal in the final step, leaving a dry product for disposal.

TABLE 2. NATIONAL AMBIENT AIR QUALITY STANDARDS AND ALLOWABLE INCREMENTS UNDER PREVENTION OF SIGNIFICANT DETERIORATON PROVISIONS
(In micrograms per cubic meter)

		Increments Under PSD		
Pollutants	NAAQS	Class I a/	Class II b/	Class III c/
Sulfur Dioxide				
Annual average	80	2	20	40
24-hour average d/	365	5	91	182
Three-hour average d/	1,300	25	512	700
Total Suspended Particulate Matter				
Annual average	75	5	19	37
24-hour average d/	150	10	37	75

SOURCE: U.S. Environmental Protection Agency.

a/ Designed to protect pristine areas such as National Parks.

b/ Areas meeting NAAQS but not originally designated Class I in 1977.

c/ Certain Class II areas may be redesignated to Class III to allow greater development; none have been redesignated to date.

d/ Not to be exceeded more than once a year.

environmental protection authorities that emissions from the plant contemplated, combined with emissions already present from other sources in the same locale, will not exceed certain maximum limits established by PSD increments (see Table 2). Background pollution levels, plus the specified PSD increment, are combined to establish the upper bound of allowed pollution in the area, provided such totals would not jeopardize the NAAQS. Emissions from any new facility in the area must not cause a violation of this maximum allowable limit.

A second critical feature in the PSD review process entails the use of the "best available control technology" (BACT) in a new generating facility. Determinations of what the best available control technology actually is, in light of specific costs, environmental effects, energy costs, and other considerations, are made on a case-by-case basis by the reviewing agencies, including both federal and state environmental officials.

In theory, best available control technology should be strict enough to allow further growth in the area and preserve PSD air pollution limits, while never exceeding the applicable NSPS--and often surpassing it in stringency. In practice, however, the reviewing agencies commonly establish BACT at levels commensurate with the applicable NSPS, unless siting choices and the characteristics of the area would cause emissions at NSPS levels to violate the applicable PSD increment. In the case of power plants locating in PSD areas, BACT limits have been set tighter than NSPS only in certain instances; this has occurred more often under the NSPS of 1971 than under the NSPS of 1978. Since adoption of the 1978 NSPS, most BACT designations for new power plants require no more than NSPS-mandated levels, except in some western states. For the purpose of this analysis, the NSPS are considered the dominant influence on future utility emissions, except for assumptions regarding some western states' emissions limits (see Appendix A and assumptions outlined in Appendix B).

EFFECTS ON POLLUTANT EMISSIONS

The NSPS promulgated in 1971 have had mixed effects on national utility emissions of the three pollutants discussed in this study. As of 1979, the most marked improvement--attributed in part to the federal NSPS and in part to stricter state regulations--was in particulate emissions. These declined by a full 62 percent from 1970 levels, despite major increases in the utilities' use of coal (which rose by 50 percent). 6/ Effects on gaseous emissions, however, were inconsistent. The clearer improvement was in emissions of sulfur dioxide, which increased only slightly, primarily because of utilities' efforts to use more low-emissions fuels--mostly oil and low-sulfur coal. Success in controlling nitrogen oxide emissions was minimal, however; these increased by 50 percent. This apparent failure is ascribed largely to the lack of available control methods for this pollutant.

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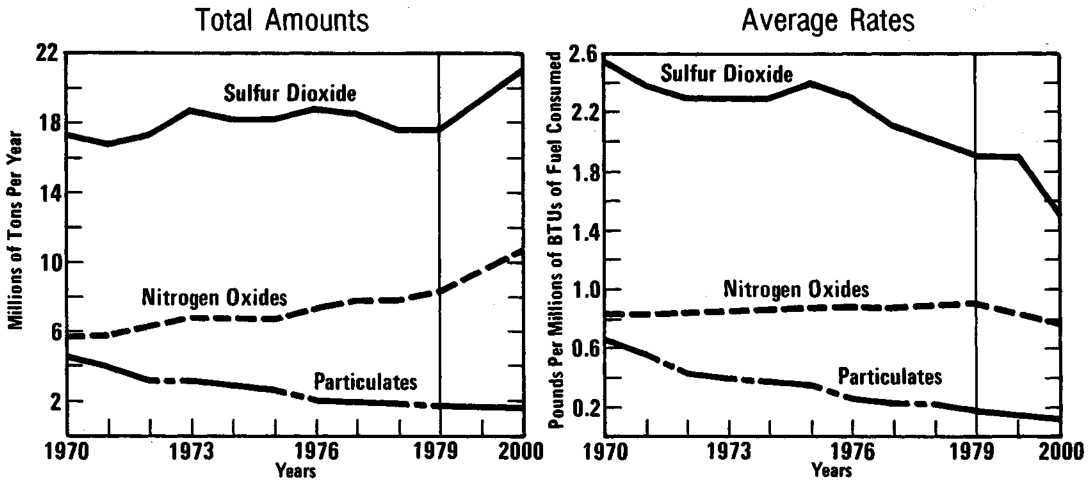
6. See Environmental Protection Agency, National Air Pollution Emission Estimates 1970-1979 (March 1981).

In spite of the sharp tightening of the NSPS enacted in 1978, projections of the national utility emissions trends over the coming two decades show no dramatic reversals in overall emissions, although the average emissions rates of the industry should fall as cleaner facilities are added to existing total capacity (see Figure 1). Particulate emissions from utility combustion are likely to continue declining by as much as 6 percent (from the 1.7 million tons of 1979 to 1.6 million tons by the year 2000). Emissions of sulfur dioxide are likely to rise somewhat more steeply than in the 1970s, increasing by 17 percent (from 18 million to 21 million tons). The problem of nitrogen oxide emissions is expected to worsen, with emissions increasing by 29 percent (from 8.3 million tons to 10.7 tons). The cause underlying the continued high emissions levels will be the utilities' continuing use of older-generation (pre-NSPS) power generators. By far the bulk of anticipated emissions of each pollutant--as much as 80 percent--will be attributable to these older sources, at least through the year 2000 and perhaps until 2010.

After the turn of the next century, however, the prospects should brighten as antiquated generators are phased out and newer ones capable of emitting far less pollution take their place. Sometime around the year 2010, a trend in significantly lower emissions can reasonably be expected. The remainder of this chapter examines the costs of attaining that improvement through the coming two decades.

Figure 1.

Actual and Projected Pollutant Emissions from Electric Utility Plants—Total Amounts and Average Rates



SOURCES: Actual data derived from U.S. Environmental Protection Agency, *National Air Pollution Emission Estimates* (March 1981), and U.S. Department of Energy, *The 1980 Annual Report to Congress* (April 1981). Projections based on CBO/ICF analysis (see Appendix B).

NOTES: Shows only those pollutant emissions regulated under Clean Air Act new source performance standards. Projection period starts at 1979, the last year of actual data.

NATIONWIDE POLLUTION CONTROL COSTS TO UTILITIES AND TO ELECTRICITY CONSUMERS

To meet federal and state air pollution control requirements established over the last decade, the utility industry has already made sizable capital investments. Between 1973 and 1980, the utilities' expenditures for pollution control rose at an average annual rate of 10.7 percent, while total capital expenditures rose at the slower rate of 8.9 percent. 7/ During this period, investments in pollution control equipment ranged between 5 and 7 percent of the industry's total yearly expenditures. In 1980, the industry's total capital commitments reached $29.2 billion, of which $1.8 billion (6 percent) went for pollution control.

The trend of high capital investment for pollution control is expected to continue over the next two decades. The principal cause underlying the persistence of high utility capital investment commited to pollution control is the rigid standards established in 1978. Between 1980 and the year 2000, the utility industry will invest more than $176 billion in new coal-fired power plants alone, with roughly $33.4 billion (19 percent) dedicated to air pollution control. Because of the requirements of meeting the 1978 NSPS, the utilities' air pollution control investment costs will be higher by $19.4 billion that they would be if only the older NSPS were in force.

Aggregate data on the capital costs exacted by controlling air pollutant emissions give only a partial picture; other essential components include the charges for operating pollution control equipment (scrubbers and particulate control devices) in plants burning high-sulfur coal and the incremental costs of using low-sulfur fuels as a means to control emissions in place of less expensive, higher-sulfur fuels. In 1980, these two factors combined entailed an annual expense totaling $5.4 billion, with control equipment accounting for $4.2 billion and low-sulfur fuel premiums accounting for $1.2 billion. By the year 2000, costs of these two components are expected nearly to triple, reaching an annual total of $14.1 billion.

Expressed in terms of average generating charges per kilowatt-hour for all forms of electricity generation, this $5.4 billion in 1980 breaks down

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7. Gary Rutledge and others, "Capital Expenditures by Business for Pollution Abatement," Survey of Current Business, U.S. Department of Commerce (June 1978 and June 1980).

into an average of 2.34 mills per kilowatt-hour. The average charge in 1980 to residential consumers of electricity was 53.6 mills per kilowatt-hour. 8/ Thus, from the ratepayers' standpoint, the cost of air pollution control in 1980 accounted for 4.4 percent of an average residential electricity bill. By the year 2000, however, ratepayers are likely to see an increase of 44 percent, bringing the cost for pollution control to 3.43 mills per kilowatt-hour purchased--just 1.09 mills more than in 1980 or 6 percent of that year's electricity rate. Although this reflects a potentially sharp increase in operating costs for control air pollution, the average nationwide contribution of this expense to total future generating costs should remain quite small. Regional costs will differ markedly, however.

Regional Differences in Air Pollution Control Costs

Aggregate and average national data, though useful for policy analysis, mask regional differences that have very explicit cost consequences for both utility companies and consumers in different areas of the country. (Figures 6 and 7 in Chapter V display the coal-producing and coal-demand regions of the United States.) Three principal factors influence the regional variations in pollution control costs: what fuel is burnt, what state and local emissions standards apply, and the vintage of most of the electricity generators in use.

In an area where a low-emissions fuel predominates--the Gulf states, where indigenous natural gas is the primary energy source, are an example--air pollution control costs are negligible. The New England states, in contrast, typify a different situation; there, though low-emissions fuels (mainly oil) furnish most utility generation, pollution control costs are higher because of the premiums paid to meet rigid local emissions standards with low-sulfur fuels. The costs of air pollution control ranges between 3.7 and 6.2 mills per kilowatt-hour generated in that area.

A utility plant's age also influences regional differences in pollution control costs, particularly with regard to coal-fired plants. In an area where the majority of electricity comes from coal-burning facilities that predate the first NSPS of 1971, pollution costs may be high but only modestly so,

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8. Average residential consumers of electricity use between 500 and 1,000 kilowatt-hours per month in the course of a year; thus, average electricity bills in 1980 ranged from $27 to $54 per month, of which 4.4 percent could be attributed to air pollution control.

precisely because of the relative lenience of the governing standards. The Ohio River Valley, where many existing coal-fired generators are not subject to either NSPS, air pollution control costs average 3.9 mills per kilowatt-hour for these facilities, which is near the low end of the oil-fired power plant costs in New England.

Since the mid-1970s, most new major capacity that has been constructed is coal-fired. Newer plants built under the 1971 NSPS incur control costs ranging from a high of roughly 8.6 mills per kilowatt-hour in the East and North Central areas to less than 3.2 mills per kilowatt-hour in the western Mountain region. In some cases, strict local standards in several areas of the West result in costs at the higher end of this range.

The highest-cost electricity plants in terms of air pollution control will be those coal-fired generators that are being built subject to 1978 NSPS, which implicitly require use of scrubbers. Here again, though, wide variations will occur, with emissions control costs ranging from 5.7 mills to 10.1 mills per kilowatt-hour. Costs in the eastern Central states should fall at the upper end of the range, around 10 mills per kilowatt-hour, because medium- and high-sulfur coals predominate there, necessitating use of expensive wet scrubbers. In the Pacific and Mountain regions, low-sulfur coal is readily available, permitting utilities to meet the rigid federal standards with cheaper dry scrubbers, bringing pollution control costs nearer to the 5.7 mills per kilowatt-hour rate.

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CHAPTER III. POLLUTION CONTROL AND THE ELECTRIC UTILITIES' FINANCIAL CONDITION

The financial condition of the electric utility industry has undergone a steady deterioration over the past two decades. Years of inadequate revenues in the face of escalating real costs for equipment, fuel, and financing have combined to weaken the utilities' economic position. Few of these factors, particularly equipment and interest costs, show signs of improving soon, and although only moderate electrical capacity growth is expected throughout the remainder of this century, the high cost of construction already is expected to strain the financial capacities of the industry at least through this decade. With respect to the Clean Air Act, two interrelated questions arise in this context:

- To what extent are emissions control standards mandated under the act responsible for the utilities' declining financial state? And conversely,

- What implications do the utility industry's poor financial prospects have for the federal government's future pursuit of clean air policy? In other words, will a financially weakened power industry provide an adequate instrument for carrying out the nation's clean air policy?

Emissions control standards, because of their attendant high capital costs to electric utilities, have often been cited as contributors to the financial pressures the utilities are feeling. Available evidence suggests, however, that, though capital investment in air pollution control probably does not enhance a utility's financial performance, it probably cannot be blamed for impairing it either. Instead, the most influential determinants of a utility's financial condition appear to be the regulations imposed on the industry by state public utility commission's (PUCs)--the rate-setting bodies within each state--and management decisions made by a particular firm (a factor that is difficult to gauge). This chapter attempts to assess the relative influence of emissions regulations on the utilities' financial performance, measured here as creditworthiness; in so doing, it explores reasons why PUC rate-making decisions can overwhelm other influences.

FINANCIAL CONDITION OF THE INDUSTRY AND REGULATION BY PUBLIC UTILITY COMMISSIONS

Among several factors, the continued slow erosion of adequate revenues and the increased costs and difficulty of obtaining capital are strong contributors to a general deterioration of the power industry's financial health. Although the situation differs markedly among individual companies, actual rates of return are generally below allowed rates and even farther below the actual costs of equity. In 1980, actual returns on equity were about 11.5 percent, while allowed returns were in the 14 percent range and the cost of capital above 16 percent. Investors have responded to these trends. An average share of common stock for the 100 largest privately owned utilities sold at about 75 percent of book value by the end of 1980. As a result, utility managements are reluctant to enter equity markets to seek new capital, since every share sold dilutes the value of the shares of present stockholders. Debt markets are similarly constrained, since requirements for interest coverage bar many companies from this source of capital. (Utilities' interest coverage, which is the rates of total earnings to total interest charges, as a general rule is prohibited from falling below two). To a large extent, the PUCs' rate-making decisions have exacerbated these problems.

Treatment of Capital and Fuel Costs

Accounting procedures unique to the industry and imposed by PUCs have contributed to the financial difficulties of utilities, chiefly through regulations that increase the costs and risks of capital investment. Typically, a utility may include in its rate base only the costs of those facilities that the PUCs define as "used and useful", meaning that the costs for a new power plant--once requiring from five to eight years of construction and now requiring from eight to 12 years--cannot be recouped until the plant begins operation.

To offset the costs of building a new plant, an electric utility firm usually is granted an "allowance for funds used during construction" (AFUDC) account. This account represents a return--generally equal to the company's approximate cost of capital--on all "construction work in progress" (CWIP). Each year, the AFUDC account is treated as part of the firm's net income, though it does not represent real cash flow. Only when the plant is completed, and the AFUDC account is added to the plant's total rate base, can the utility realize a return on its investment. Before plant operation begins, however, the costs of construction must be borne solely by the company.

Since an AFUDC account represents noncash income, it can lower the quality of actual earnings. Furthermore, it can degrade the market value of the firm's stock, putting upward pressure on the costs of capital. Figure 2 shows trends in both the amount of AFUDC representing income and the ratio of market price to book value in stocks of the investor-owned